Pacific Gas and Electric Company®

GAS STORAGE SAFETY REPORT

AUGUST 22, 2016

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY

GAS STORAGE SAFETY REPORT

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED AUGUST 22, 2016

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Introduction

Scope and Purpose

This Gas Storage Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision (D.) 16-06-056 in Pacific Gas and Electric Company's (PG&E) 2015 Gas Transmission and Storage (GT&S) Rate Case (Application (A.) 13-12-012). Ordering Paragraph (OP) 15 directs PG&E to submit, within 60 days of the effective date of the decision, a report on PG&E's "gas storage risk management and safety initiatives" (Storage Safety Report). This Storage Safety Report is being served on each of the five Commissioners, the Director of the Safety and Enforcement Division, the General Counsel, the Executive Director, the State Oil and Gas Supervisor and Northern District Deputy for the Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR), the California State Assembly's Committee on Utilities and Commerce, and the California State Senate's subcommittee on Gas, Electric and Transportation Safety. A courtesy copy of the report is also being served on the service list of the 2015 Gas Transmission and Storage Rate Case proceeding (A.13-12-012).

OP 15 of D.16-06-056 requires that:

> Pacific Gas and Electric Company (PG&E) shall provide a report as described below on its gas storage risk management and safety initiatives within 60 days of the effective date of this Decision. The report shall include, at a minimum, 1) an overview of the work performed on PG&E's proposed Well Integrity Management Program, 2) an overview of data centralization efforts, 3) supply copies of Gamma-Ray Neutron surveys, noise and temperature surveys, and casing inspection surveys, as well as any analysis of such surveys and an overview of any follow-up measures performed or proposed, 4) the status of PG&E's proposed Storage Rework Projects, and 5) responses to the questions below about PG&E's gas storage facilities.

Questions About Gas Storage Facilities

1. What is the state of downhole safety valves at McDonald Island, at Pleasant Valley [*sic*][1] and at Los Medanos? How many wells lack such valves, and how many of

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[1] The reference to "Pleasant Valley" is interpreted to refer to PG&E's gas storage facility at Pleasant Creek.

the existing valves are operational? Do storage re-work projects prioritize the need for downhole safety valves, or do they prioritize maintaining a maximum gas withdrawal rate? Provide records of recent downhole safety valves tests.

2. When and how does PG&E decide to replace its downhole safety valves? How frequently are these valves tested as they near replacement?
3. Explain how current data is adequate to protect against the risk of corrosion. What tests or surveys are necessary to improve analysis of the risk of corrosion, when were those tests or surveys last performed, and when are those tests or surveys next scheduled?
4. How will PG&E assess its well integrity management program? What metrics will demonstrate whether the program is successful and how it might be improved?
5. In the event of a leak failure, does PG&E have an emergency response plan in place for each storage facility? Are there Californians who live or work in the vicinity that may be affected in the event of a leak on the scale seen at Aliso Canyon? Does PG&E's emergency response plan have adequate measures to notify, shelter, and protect nearby populations? What would be the effects on gas supply in the event of such a leak during a period of peak gas usage?
6. How does the Aliso Canyon leak affect PG&E's assessment of its gas storage facilities?"[2]

Report Summary

This Storage Safety Report addresses in detail the current state of PG&E Gas storage facilities along with the following continuous improvements, including the new regulations set by the state of California,[3] PG&E has made and continues to make, including:

- Creation and maintenance of Well Integrity Management Program (WELL);[4]
- Improved data centralization efforts relating to storage facilities;[5]

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2 D.16-06-056, pp. 478-479.

3 See Requirements for Underground Gas Storage Projects, California Code of Regulations (CCR) Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, and Section 1724.9.

4 See Section 1 Well Integrity Management Program and Section 5-4 Assessment of Well Integrity Management Program.

5 See Section 2 Data Centralization.

- Use of survey data to drive decisions that include but are not limited to: assessments, storage rework projects, and replacement of downhole safety valves (DHSV);[6]
- Constant monitoring and evaluation of corrosion on its storage facilities;[7]
- Evaluation of PG&E's emergency response plan;[8] and
- PG&E's commitment to the public, DOGGR, and other agencies.[9]

This Storage Safety Report describes PG&E's integrated approach to the safe, reliable operations of its storage assets, including an overview of integrity survey data, storage rework projects and data about other safety equipment, such as DHSVs. The report also provides a summary of the effects on gas supply during peak usage if a leak similar to that which occurred at Southern California Gas Company's (SoCalGas) Aliso gas storage facility were also to occur at PG&E's gas storage facilities. Finally, this report includes analysis of how the Aliso Canyon leak and new state regulations have led to PG&E's assessment of its storage facilities. PG&E continues to evaluate the scope and pace of the integrity work at its storage fields and to improve safe operation of its assets.

PG&E monitors and inspects its storage facilities, and has a team of gas subject matter experts who are prepared and trained to quickly respond to any potential safety issues. In light of the natural gas leak incident at the SoCalGas Aliso Canyon gas storage facility and the emergency regulations effective February 5, 2016 stemming from that event, PG&E has been working closely with DOGGR and other stakeholders to complete these emergency regulations. As further discussed in Section 5-6 of this Storage Safety Report, by August 30, 2016, PG&E will have completed all seven requirements in DOGGR's emergency regulations. PG&E is fully embracing all of the new regulations as an opportunity to make even further enhancements to its natural gas system.

As directed by the Commission, PG&E shall include any subsequent updates to this Storage Safety Report as part of its 2019 GT&S application. In addition to providing an update to this Storage Safety Report in PG&E's 2019 GT&S application, PG&E remains

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6 See Section 3 Surveys; Section 4, Storage Rework Projects; Sections 5-1 and 5-2.

7 See Section 5-3, Corrosion.

8 See Section 5-5, Emergency Response Plan.

9 See Section 5-6, Effect of Aliso Canyon Leak.

committed to transparency with the public, DOGGR, and other agencies. Examples of PG&E's commitment to transparency include, but are not limited to: review and revision of PG&E's risk management plan on a periodic basis, and providing continuous updates to DOGGR regarding risk assessment results. The following table summarizes a schedule of deliverables to be submitted to DOGGR regarding risk assessment results:

TABLE 1
SCHEDULE OF RISK ASSESSMENT DELIVERABLES TO BE SUBMITTED TO DOGGR

Deliverable	Schedule
Identified Anomalous Conditions	Immediately
Yearly Storage Well Evaluation Report	Annually by January 31
Gas Injection and Production Reports	Monthly
Water Production Report	Quarterly
Inventory Verification Report	Annually by November 30
Asset Management Plan	Annually by September 30

<u>Storage Facility Description and Physical Characteristics</u>

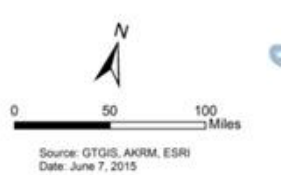
PG&E's storage facilities have two primary system operational purposes: (1) support system reliability especially in times of high customer demand; and (2) balance the overall gas system.[10]

Physical Assets

PG&E owns and operates three underground gas storage fields: McDonald Island, Los Medanos, and Pleasant Creek. See Figure 1, Map of Gas Storage Facilities.

10 PG&E's storage facilities also are an important factor in service affordability by helping to smooth out seasonal natural gas price differences.

FIGURE 1
MAP OF GAS STORAGE ASSET FACILITIES



These three storage fields were originally gas production fields and were subsequently converted to storage operations as the demand for gas on PG&E's system increased. PG&E also has a 25 percent ownership of the Gill Ranch storage field that is operated by Gill Ranch Storage LLC. This Storage Safety Report focuses on the storage wells in the three storage fields operated by PG&E.[11] These storage fields include:

- 117 wells
- 89 Downhole Safety Valves (DHSV) and 217 Uphole Safety Valves (UHSV)
- 191 well measurement meters

Table 2 provides further details on the characteristics of each of the three storage fields.

TABLE 2
PG&E STORAGE FIELD STATISTICAL SUMMARY

Description	McDonald Island (Operated)	Los Medanos (Operated)	Pleasant Creek (Operated)
Operator	PG&E	PG&E	PG&E
Location-County	San Joaquin	Contra Costa	Yolo
Discovery Date	1936	1958	1948
Year Placed in Storage Service	1975	1973	1960
Number of Injection and/or Withdrawal (I/W) Wells	81	21	7
Number of Observation Wells	7	1	–
Number of Salt Water Disposal (SWD) Wells	–	–	–
Compressor Units	5	1	1
Compression Horsepower (Brake Horsepower-bhp)	12,256	3,733	749
Discovery Pressure-Wellhead (Pounds Per Square Inch Gauge (psig)	2,086	1,599	1,268
Discovery Pressure-Bottom Hole (Pounds Per Square Inch Atmosphere - psia)	2,365	1,774	1,367
Max Storage Pressure-Wellhead (psig)	2,070	1,600	1,250
Max Storage Pressure-Bottom Hole (psia)	2,365	1,774	1,353
Facility MAOP (psig)	2,160	1,800	1,300
Facility MOP (psig)	2,160	1,610	1,260
Cushion Gas (Billion Cubic Feet- Bcf)	54.5	11.2	5.1
Working Gas (Bcf)	82	17.9	2.3
Total Inventory (Bcf)	136.5	29.1	7.4
Max Withdrawal (Million Cubic Feet Per Day-MMcf/d)	1,680	400	70
Max Injection (MMcf/d)	400	125	32
Reservoir Depth (feet)	5,200	4,100	2,800
Areal Extent (acres)	2,760	244	400
Number of Downhole Safety Valves	68	21	–
Number of Uphole Safety Valves (UHSV)	162	41	14
Miles of Production Casing / Production Liner/ Scab Liner	97.8	18.7	4.0
Miles of Production Tubing	90.5	17.5	4.2
Miles of Transmission Pipe in Storage Asset Family[(a)]	10	2	2
Miles of High Consequence Area (HCA) Transmission Pipe in Storage Asset Family[(b)]	2.5	–	–
Number of Well Meters	149	21	21

(a) Transmission pipe within the Storage asset family transport storage gas from storage wells, not production wells. Therefore there are no gathering lines within the Storage asset family.

(b) PG&E, like the industry, uses the diameter and maximum operating pressure to calculate the area in which people would be adversely impacted by a pipeline failure. This area is called the "potential impact radius" or "PIR." The PIR is used in federal safety regulations as one way to define HCAs to which the integrity management principles must apply. See 49 Code of Federal Regulations (CFR) 192.903 which defines a potential impact radius as the circle within which the potential failure of a pipeline could have significant impact on people or property. The regulation provides the mathematical formula for determining the radius of the circle.

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11 As stated above, this Storage Safety Report focuses on the storage wells at each of the three PG&E owned and operated storage fields. A general overview of the equipment at the storage facilities is provided for context.

McDonald Island

McDonald Island, located in San Joaquin County, is the largest of the three gas storage fields with a maximum design working capacity of approximately 82 Bcf. PG&E converted McDonald Island to storage in 1975. McDonald Island has 81 injection and withdrawal wells and seven observation wells for monitoring reservoir integrity. McDonald Island is designed for a maximum withdrawal capability of 1.68 Bcf per day to the Bay Area Loop pipeline area.

Los Medanos

Los Medanos, located in Contra Costa County, was placed into storage service in 1973. It became fully operational in 1980, and is the second largest of the three storage fields with a design working capacity of approximately 17.9 Bcf. Los Medanos has 21 injection/withdrawal wells and one observation well for monitoring reservoir integrity. Los Medanos is designed for a maximum withdrawal capability of 0.4 Bcf per day to meet load demands on the west part of the East Bay, and oil refineries located in the San Francisco Bay Area.

Pleasant Creek

Pleasant Creek, located in Yolo County, was placed into storage service in 1960 with a design working capacity of approximately 2.3 Bcf. Pleasant Creek has seven injection and withdrawal wells which includes one horizontal well that was drilled and completed in 2012. Pleasant Creek is designed for a maximum withdrawal capability of 0.07 Bcf per day and is on the L-400/401 lines.[12]

General Well Construction

The construction of the storage wells in PG&E's storage facilities is similar, yet the diameters, dimensions, and materials vary based on design and operating parameters. A typical storage well consists of the following elements that are illustrated in Figure 2 (the element numbers correspond to the numbers in Figure 2):

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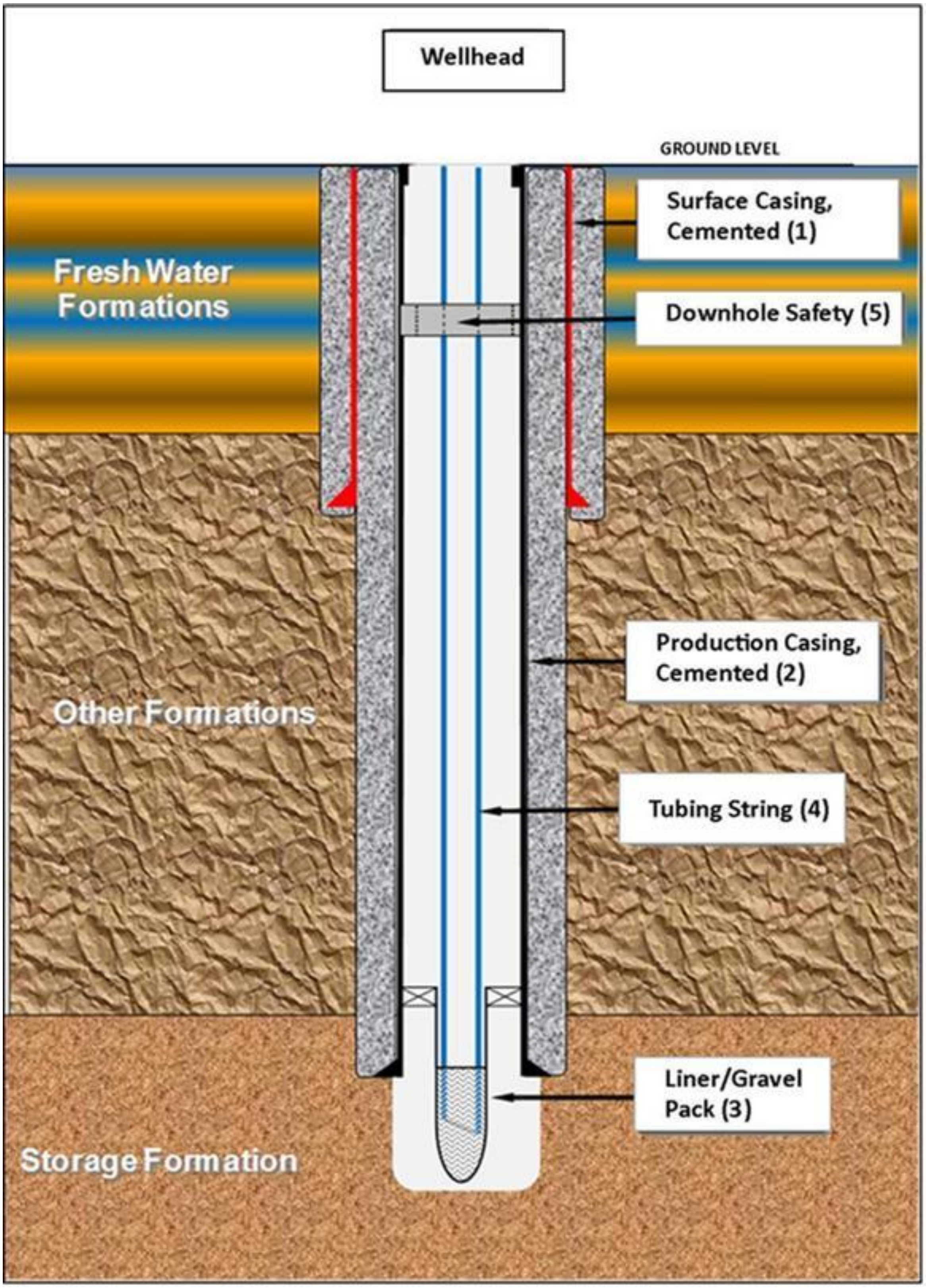
12 Lines 400 and 401 are gas transmission pipelines that are parts of PG&E's northern backbone system.

FIGURE 2
TYPICAL STORAGE WELL CONSTRUCTION



1) Surface Casing, Cemented: An outer steel surface casing pipe with cement sheath to a depth of 900 to 1,000 feet to seal off and protect the fresh water formations below surface ground level.
2) Production Casing, Cemented: Steel production casing pipe with cement sheath to a depth of 2,600 to 5,100 feet to provide a safe conduit to move gas in and out of the storage formation, prevent a loss of storage gas to other shallow porous formations, and prevent other subsurface fluids from migrating into the well.
3) Liner/Gravel Pack: Screen liner with gravel pack installed at the lower end of the production casing pipe to allow gas to flow unimpeded, but prevents solid particulates and fines in the storage formation from flowing into the storage well.
4) Tubing String: An inner steel tubing pipe, called a tubing string, to approximately 20 feet above the lowest point of the screen liner designed to allow gas to flow up the well from the formation when the pressures in the storage field are at the lowest.
5) Downhole Safety: A downhole safety valve system installed on the tubing string at a depth of 250 feet below the ground level designed to shut off the flow of gas from both tubing and casing of the well in the event any surface piping or valves catastrophically fail or rupture.

Gas Safety Excellence

Gas Safety Excellence is PG&E's Gas Operations strategic framework to achieve the vision of becoming the safest, most reliable gas utility in the nation. This framework is designed to improve safety, manage risk, drive continuous improvement, and help guide the long-term strategy for Gas Safety. PG&E's Gas Safety Excellence is an overlapping combination of three key standards based programs, Safety Culture or Safety Management System, Process Safety, and Asset Management.[13]

To help manage the diversity of PG&E's natural gas assets and as a foundational step in implementing an asset management system consistent with Publicly Available Specification (PAS) 55 and International Organization for Standardization (ISO) 55001, PG&E established eight separate asset families within its Gas Operations business. PG&E's three storage facilities fall under the Gas Storage Asset Family.

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13 While Gas Safety Excellence permeates throughout Gas Operations, for the purposes of this Storage Safety Report, discussion about PG&E's Gas Safety Excellence is limited to PG&E's three storage facilities and is taken in context with the Commission's questions as outlined above.

Associating each asset with a family helps Gas Operations to: (1) identify threats; (2) assess asset condition and data quality; (3) identify and assess risks facing the assets; (4) develop and effectively execute mitigation efforts; and (5) follow a consistent process for managing assets and maintaining alignment across asset families. Each asset family has an Asset Family Owner who is responsible for knowing the asset condition, the risks to the assets, and for developing a risk-based Asset Management Plan.

Gas Storage Asset Management Plan

PG&E has implemented an asset management system to help drive the business toward achieving its commitment to the safe, reliable, affordable management and operation of PG&E's gas assets. Using the international PAS 55-1 and ISO 55001 standards as guidance, PG&E's asset management system focuses on:

- Identifying and reducing operational and enterprise risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;
- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations and requirements in an environmentally sustainable manner.

Gas Operations sets annual corporate Line of Sight (LoS) goals that cascade throughout the organization. The Gas Operations safety goal is to identify the right work and improve the condition of our assets to eliminate all public safety incidents. Within the framework of these LoS goals, the Gas Storage Asset Family analyzes asset risk and conditions. The Gas Storage Asset Family establishes a high-level Storage strategic objective with more specific objectives related to each asset.

PG&E's GP-1108: Gas Storage Asset Management Plan is utilized to ensure effective and efficient asset management of gas storage facilities and to optimize the condition of our assets based on prioritization of risk.[14]

Well Integrity Management Program

PG&E's storage wells are constructed and operated according to the regulations of California's oversight agency, DOGGR, effective at the time they were constructed.[15] These regulations require storage wells to demonstrate integrity.

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14 See Appendix A, GP-1108: Gas Storage Asset Management Plan.

15 See CCR Title 14, Division 2, Chapter 4.

Regarding storage well integrity, the Gas Storage Asset Family drew on industry best practices given the absence of industry standards on the functional integrity of natural gas wells and fields. In 2012, the industry recognized the existence of a gap in industry standards. Through the efforts of storage operators and regulators, American Petroleum Institute (API) agreed to establish a task team to develop API Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs (API RP 1171) that addresses the functional integrity of natural gas storage wells and fields.[16]

The Well Integrity Management Program (WELL), documented in PG&E's "Underground Storage Risk and Integrity Management Plan," incorporates industry best practices for assessing existing reservoir and well integrity, and for monitoring of existing reservoir and well operations in order to demonstrate and verify that the gas stored in the facility remains contained in the reservoir and protects against undesired gas migration or loss of integrity of the wells.[17] PG&E continues to use API RP 1171 to enhance its current operating practices.

The WELL Program identifies potential threats and hazards to reservoir and well integrity; assesses risks based on potential severity and estimated likelihood of occurrence; identifies the preventive and monitoring processes employed to mitigate the risk; and specifies a process for periodic review and reevaluation of the risk assessment and prevention protocols.[18]

Furthermore, PG&E has undergone a rigorous certification process for both PAS 55-1 and ISO 55001 regarding the management of its physical assets, including its gas storage fields. PG&E's comprehensive integrity management efforts are designed to mitigate and manage the potential risks of significant issues occurring at any of its storage facilities.

The Storage Asset Family periodically reviews and updates both the Asset Management Plan and the WELL Program based on the practices of API RP 1171, practices of the ISO, and regulatory requirements related to the safe design, operation, and maintenance of assets.

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16 See Section 5-4 for further discussion on API RP 1171.

17 See Section 1 for more detail regarding the WELL Program.

18 See Appendix B, Underground Storage Risk and Integrity Management Plan.

Security of Gas Storage Facilities

PG&E invests in physical security improvements as part of its risk based asset management program. In 2014, PG&E engaged a consultant to conduct a Vulnerability Assessment and Protection Study (VAPS) on its gas transmission assets. This study included the development of physical security threat scenarios and a threat mitigation framework.

Based on the VAPS results, a multi-year implementation plan was developed to improve physical security measures and mitigate identified threat scenarios. Physical security measures specified for this program include various combinations of solutions ranging from barriers, high security chains and locks, shout-down/public address systems, equipment and perimeter shields, thermal imaging cameras and analytics for deterrence, and detection and assessment.

This systemwide approach includes cooperation and collaboration with federal, state, and local agencies incorporating industry best practices to strengthen physical security and situational awareness around PG&E's gas transmission assets.

Storage Safety Report Format

This Storage Safety Report is organized to address each of the Commission's specific items, including all subparts, in sequence. This Storage Safety Report provides data, in most cases, back to January 1, 2006. Data prior to January 1, 2006 are not readily available. Should the Commission require additional years of reporting data, PG&E will provide it to the extent the data are available. Where PG&E does not have reporting data dating back to 2006, PG&E so indicates in its response and provides available data.[19]

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19 For example, both Gamma Ray Neutron inspections and Casing Inspections began in 2013.

1. Well Integrity Management Program

Pacific Gas and Electric Company (PG&E) shall provide a report as described below on its gas storage risk management and safety initiatives within 60 days of the effective date of this Decision. The report shall include, at a minimum, 1) an overview of the work performed on PG&E's proposed Well Integrity Management Program

Response

The WELL is used to assess the risks related to the storage wells and recommend actions to prevent or mitigate these risks. The WELL risk management process considers risks to individual wells. This risk management process gathers, reviews, and integrates data to prioritize preventive and mitigative measures, and monitor for operational changes that may require additional actions.

Prior to implementation of WELL, PG&E managed well and reservoir integrity using practices that are now included in the WELL Program. In 2013, PG&E began formalizing WELL through documentation of practices in the "Underground Storage Risk and Integrity Management Plan." A draft of WELL was completed in 2015 and then finalized in 2016.

Work performed through WELL includes maintaining reservoir integrity, ensuring mechanical integrity of wells, monitoring casing and annuli pressures, maintaining safety valves, monitoring and evaluating corrosion, evaluating wells and attendant production facilities, identifying potential threats and risks, and prioritizing risk mitigation efforts. WELL documents mitigation activities associated with each of the aforementioned categories and also includes stakeholders, update frequencies, the integrity management process, the data management process, and a communication plan.

PG&E verifies reservoir integrity by monitoring potential storage gas migration. The risk of gas migration beyond the storage reservoir is mitigated through activities such as inventory-bottom hole pressure surveys/shut-in test or other pressure decline analysis methods, monitoring observation wells, monitoring third-party existing and new wells, performing gas measurement correlation/ audits, and lost and unaccounted for gas studies.

Mechanical integrity of wells is verified by reviewing the condition of active and plugged wells within the buffer zone, performing logging and employing casing inspection tools. As part of the 2016 well rework and assessment program, PG&E expanded the integrity assessment of each well to include ultrasonic and caliper surveys, in addition to the four other types of surveys already used for assessment: Cement Bond Logs (CBL), Gamma-Ray Neutron (GRN), Noise and Temperature (N&T), and Magnetic Flux Leakage (MFL).[20] The ultrasonic and caliper logs were introduced to corroborate the results of the MFL casing inspection survey. The addition of these survey tools is also consistent with the testing being conducted at SoCalGas' Aliso Canyon. See Table 3 for a status of well integrity assessment that is current as to the date of the submission of this Storage Safety Report.

20 See Section 3 Surveys for survey results and Appendix C Description of Well Integrity Tests.

TABLE 3
STATUS OF PG&E'S WELL INTEGRITY TESTS

Integrity Test[(a)]	Current Frequency	2016 Status
Temperature Surveys	Annually[(b)]	Surveys completed: Los Medanos – Planned for Fall 2016 McDonald Island – Completed July 2016 Pleasant Creek – Planned for Fall 2016
Noise Surveys	Annually[(c)]	Surveys completed: Los Medanos – Planned for Fall 2016 McDonald Island – Completed July 2016 Pleasant Creek – Planned for Fall 2016
Casing Wall Thickness Inspection	Ranges 1 to 15 years based on risk	No anomalies identified that required remedial action. Magnetic Flux Leakage (MFL) baseline performed on 18 wells.
Cement Bond Log (CBL)	Once when the well is initially drilled and completed. Existing wells re-logged when initial CBL didn't cover entire depth of well or no CBL run previously.	Since 2013, 12 wells have been re-logged.
Multi-Arm Caliper Inspection	Ranges 1 to 15 years based on risk	No anomalies based on 1 well inspected in 2015. In 2016, plan to inspect 6 wells.
Pressure Test	Performed during well rework	No failed pressure tests.

(a) See Appendix C Description of Well Integrity Tests.
(b) In a December 15, 1999 letter from DOGGR to PG&E, DOGGR stated they had "evaluated [PG&E's] annual testing program of running both noise and temperature surveys and we feel this is adequate to determine casing integrity."
(c) *Id.*

In addition to the methods described above, PG&E also performs casing pressure tests and annulus monitoring to monitor well integrity. PG&E performs wellbore mechanical integrity tests (MIT) or hydrostatic tests during well rework projects prior to returning the well to service. Also, surface casing annuli (SCA) and tubing casing annuli (TCA) are monitored daily for potential indications which may require remediation. Engineers will analyze anomalous pressures found through daily inspections and develop a plan of action.

WELL also includes safety valve maintenance practices. Testing results for both DHSVs and UHSVs are used to prioritize replacement.

In addition, corrosion monitoring and evaluation is performed at storage facilities to evaluate the potential for corrosion and the effectiveness of mitigative measures. Corrosion monitoring data are also utilized to establish integrity assessment priorities and the results of integrity assessments are used to further evaluate the effectiveness of the corrosion control program at storage facilities. WELL discusses the methods to monitor for corrosion potential on wells, pipeline, and production facilities.

Wells and attendant production facilities are evaluated by analyzing casing pressure changes at the wellhead, facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures.

WELL describes PG&E's organizational structure which facilitates the integration of risk management and investment planning. The risk management process provides the framework for evaluation of the likelihood of events and consequences related to threats and risks associated with operation of PG&E's underground gas storage, risk ranking to develop preventive and mitigating measures to monitor or reduce risk, documentation of risk evaluation and description of the basis for selection of preventive and mitigation measures, provision for data feedback and validation, and regular risk assessment reviews to update information and evaluate risk management effectiveness. Risk mitigation efforts are then prioritized based on potential severity and estimated likelihood of occurrence.

Refer to Appendix B: "Underground Storage Risk and Integrity Management Plan" for PG&E's Well Integrity Management Program.

Recent McDonald Island Assessment

One example of how PG&E leveraged monitoring of its storage wells and current conditions occurred during assessments at McDonald Island in June 2016. PG&E's reservoir and well integrity management practices that are incorporated in the WELL Program allowed PG&E to be proactive in identifying and responding to recent minor methane releases adjacent to gas storage wells at McDonald Island.

On June 16, 2016, as part of regular gas safety monitoring, a PG&E employee identified small amounts of gas bubbling in a well cellar. PG&E quickly took action to ensure safe operations of the McDonald Island Storage Facility.

The well monitoring activities at McDonald Island included:

- Hourly visual and auditory monitoring at all wells with identified gas bubbling
- Daily leak concentration readings
- Echo fluid level readings on isolated wells
- Leak Surveys:
  – Daily Foot survey of all wells;
  – Daily vehicle-mounted leak detection survey of facility and perimeter;
  – Daily Forward Looking Infrared Camera survey of platform stations and each peripheral well locations; and
  – Rapid repair plan for identified leak indications.
- Completion of N&T Surveys on all 88 wells
- Aerial leak surveys

PG&E subject matter experts and engineers have been working with DOGGR and industry experts to determine the cause of the minor leaks.

The minor seepage at McDonald Island did not pose public safety, health, environmental or reliability risk. Following PG&E's initial investigations, DOGGR, the Commission, and the California Air Resources Board (CARB) approved putting the facility back into service with ongoing monitoring and reporting. PG&E created a well monitoring and integrity assessment plan to address what was found and provided the plan to DOGGR on July 5, 2016. As soon as the leak source is confirmed, PG&E will initiate the final stages of the repair plan and continue outreach to federal, state, and local regulators.

2. Data Centralization

Pacific Gas and Electric Company (PG&E) shall provide a report as described below on its gas storage risk management and safety initiatives... The report shall include, at a minimum… 2) an overview of data centralization efforts…

Response

In 2014, PG&E initiated the Gas Storage Asset Management Systems (GSAMS) project to create a single source system for collecting, storing, and compiling gas compositions, measurements, pressures, and other operational data from PG&E's gas storage fields.

The current condition of Gas Storage assets has been qualitatively assessed by subject matter experts and by numerous quantitative integrity tests. One of PG&E's strategic goals is to enhance and improve data informed assessments over the next four years. A roadmap has been developed to illustrate how data improvement programs and existing programs work towards utilizing more data informed decisions.[21] Currently, data for this asset family is limited in terms of organization and accessibility to support quantitative analysis of asset condition and risk. Enhancing data collection and accessibility is an area of focus to enhance decision-making going forward. Furthermore, the ability to collect, organize, and monitor the impact on risk reduction and tracking metrics are part of the programs such as the Asset Health Scorecard (AHS) and GSAMS.

Record Centralization

Storage record centralization began in 2014 to expand the availability of storage well records for review and assessment. During the period 2014-2016, PG&E consolidated all storage well file records into a central electronic repository. The activities to consolidate files were as follows:

- Identified inventory records located in the field and office locations;
- Reviewed and updated well schematic drawings (completed in 2016);
- Identified a central point to store the records and structure of stored files;
- Tracked and monitored physical movement of the files;
- Implemented physical review and consolidation of the duplicative physical records;

[21] See Appendix A.

- Tracked and monitored scanning of the consolidated records; and
- Filed physical records and scanned records.

Asset Management Backbone and Stations

As part of PG&E's Asset Management Backbone and Stations (AMBBS) project, PG&E incorporated the storage well asset descriptive and measurement point information into PG&E's SAP system in order to store and maintain the asset descriptive information (e.g., tubular sizes and types, depths of wells, types of equipment installed in or on well). Historically, the information has been maintained on spreadsheets which were susceptible to errors and multiple copies of similar data being maintained by varying groups and individuals.

This project is continuing and is anticipated to be completed by December 2016.

System Automations

PG&E established the GSAMS project to improve information accessibility and assessment efficiency of data associated with storage well assets.

The two existing data collection systems in use today are Cimplicity (a Supervisory Control and Data Acquisition system used to collect gas temperature, pressure, flow, and volume data) and FlowCal (a system used to provide gas composition data). These systems currently work independently of each other and rely heavily on manual input to report on field status and to provide reports necessary for various engineering evaluations. The GSAMS project will integrate these independent systems with a Plant Information (PI) server installed at each storage field location. Field data will be automatically compiled into a single source system which will allow the Reservoir Engineering team to have easier access to operational data for each gas well in the system. Also, the operational data on the system of wells will be centralized and will provide current and real-time operational status.

Prior to the new system going online, the PI servers will collect, store, and compile historical data in a digital format for easier access, retrieval, and analysis. The GSAMS project will be completed in December 2016.

These systems lay the foundation for PG&E to integrate continuous measurement of storage assets and leak detection technology. This includes projects to: (1) install transducers at the well heads to remotely and continuously monitor the pressures in the well SCA and the TCAs; (2) install flow measurements on each well's injection flow stream (McDonald Island only); and (3) replace obsolete or outdated field well flow controls to prevent overflowing of the wells to minimize sand production.

3. Surveys

Pacific Gas and Electric Company (PG&E) shall provide a report as described below on its gas storage risk management and safety initiatives within 60 days of the effective date of this Decision. The report shall include, at a minimum… supply copies of Gamma-Ray Neutron surveys, noise and temperature surveys, and casing inspection surveys, as well as any analysis of such surveys and an overview of any follow-up measures performed or proposed…

Response

As part of the risk management and integrity assessment process, PG&E performs several types of surveys on its well assets to assess condition. These surveys include, but are not limited to CBL, GRN, N&T, and MFL casing inspection surveys.[22]

N&T surveys provide data to assess if a leak is present in the well's casing pipe. PG&E performs N&T logging on its wells annually.

GRN and MFL casing inspection surveys are additional tools used to assess well integrity and PG&E began using them in 2013. GRN tools provide data to assess if gas may be present behind a well's casing pipe and can verify where the surface casing pipe and other equipment are placed within a storage well. MFL casing pipe inspection tools, similar to In-Line Inspection tools, are utilized to assess if a storage well production casing pipe has internal or external defects and verifies placement of equipment in a storage well. PG&E is in the process of performing these surveys on the full inventory of wells and to date has completed 108 GRN surveys and 20 MFL casing inspection surveys. PG&E plans to perform baseline integrity inspections of all wells by 2025 and complete reassessments of previously logged wells based on a frequency of inspection decision tree. PG&E also conducts annual assessments based on the prior year inspections and well risk assessment to determine if the current pace to complete the baseline by 2025 is the proper frequency. Based on the recent events at the SoCalGas Aliso Canyon facility, PG&E is assessing whether the baseline inspections should be accelerated based on an assessment of risk.

See Appendix D, E and F for a file index for the N&T, MFL, and GRN logs contained in the attached DVDs.

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[22] See Appendix C, Description of Well Integrity Tests.

PG&E provides the Yearly Well Evaluations Reports to DOGGR annually;[23] refer to Table 4 for a list of the reports provided. Additional assessment results are summarized in PG&E's Inventory Verification Reports.[24] The inventory verification studies verify the inventory of the storage reservoirs and confirm the fields are not experiencing gas loss or migration. The well integrity survey results are reviewed as part of the inventory analysis and summaries of the surveys are contained within the inventory reports. Results from the Los Medanos and McDonald Island baseline MFL casing inspection surveys are summarized in Table 5.

TABLE 4
YEARLY WELL EVALUATION REPORTS[(a)]

Yearly Well Evaluation Reports
2011_Yearly Well Evaluation Report
2012_Yearly Well Evaluation Report
2013_Yearly Well Evaluation Report
2014_Yearly Well Evaluation Report
2015_Yearly Well Evaluation Report

(a) See Appendix G.

23 See Appendix G, Yearly Well Evaluation Reports.

24 See Appendix H for a file index of the Annual Inventory Verification Reports provided in the attached DVD.

TABLE 5
BASELINE CASING INSPECTION LOG SUMMARY

Field	Well No	Initial MVRT log Run Date	Initial HRV log Run Date	Number of Total Joints Logged	Maximum % Loss	Maximum % Loss Depth	Class 2 Average % Metal Loss	Class 3 Average % Metal Loss	Class 4 Average % Metal Loss	Number of Joints Class 2 & above		Deepest Reading	PBTD	Year of Anticipated Relog
										OD	ID			
McDonald Island	TC-11N	-	6/4/2013	142	30	1,372	25				2	5,184	5,220	2025
McDonald Island	TC-10N	-	6/22/2013	118	29	3,269	25				2	4,698	5,587	2025
McDonald Island	TC-2N	7/28/2013	-	125	36	2,509	24				1	5,089	5,336	2021
McDonald Island	TC-1N	8/17/2013	-	134	40	948	23			54	2	5,321	5,580	2021
McDonald Island	TC-8N	-	8/5/2014	123	24	1,052					1	4,992	5,375	2026
McDonald Island	TC-17N	-	8/22/2014	119								5,004	5,647	2026
McDonald Island	TC-8S	-	9/4/2014	130	28	5,090	23				3	5,390	5,592	2026
McDonald Island	TC-9S	-	9/14/2014	105	28	1,638	23			5	5	3,888	5,807	2026
McDonald Island	TC-12S	-	9/28/2014	137	26	3,589	23				6	5,070	5,358	2026
McDonald Island	TC-13S	-	10/14/2014	150								5,550	5,760	2026
McDonald Island	WS-01W	-	10/3/2015	131	39	5,614	39			1		5,751	5,790	2027
McDonald Island	TC-14S	-	7/16/2015	121	22	3,092	21				3	4,495	5,610	2027
McDonald Island	WS-03E	-	8/31/2015	125								5,100	5,343	2027
McDonald Island	TC-15S	-	8/11/2015	141								5,211	5,398	2027
Los Medanos	LM-4B	-	4/30/2013	92	34	1,497	29				3	3,822	4,200	2025
Los Medanos	LM-5B	5/15/2013	-	97	40	3,947	25	40		6	18	3,989	4,209	2018
Los Medanos	LM-11C	-	6/10/2015	96								3,998	4,180	2027
Los Medanos	LM-21D	-	6/1/2015	85								3,559	3,981	2027

4. Storage Rework Projects

The status of PG&E's proposed Storage Rework Projects

Response

PG&E's storage rework projects are part of PG&E's WELL Program.[25] While the WELL Program contains elements that are included in PG&E's Underground Storage Risk and Integrity Management Plan,[26] the WELL Program also considers risks to individual wells.

Two categories of the WELL Program are: (1) well remediation and conditioning (i.e., rework projects); and (2) well integrity assessment.

The rework projects category of work includes: (1) assessment of the storage wells' condition, and additional corrective work for mitigating any potential risks. To complete this work, the existing DHSVs in wells have to be removed and replaced in order for the well casing pipe to be inspected and the corrective work to be completed;[27] (2) replacement of DHSVs in wells that are identified as not functional based on the annual test results; and (3) if necessary, installation of new gravel pack to restore well deliverability due to natural degradation from cyclical injection and withdrawal operations, which can damage the gravel pack.

The well integrity assessment includes: (1) assessment of the storage wells' condition, and additional corrective work for mitigating any potential risks and if necessary; and (2) replacement of DHSVs.

Since January 2015, PG&E has completed eight rework projects and plans to complete an additional four by the end of 2016. PG&E's current plan is to complete integrity assessments on the remaining 99 wells and rework of wells by 2025 (see Table 6 below). Every well that PG&E reworks is assessed for casing and wellbore integrity. PG&E routinely monitors the pace of the well reworks based on available information collected during the fields operation, performance testing of the storage wells and DHSV and prior year integrity assessment information (N&T surveys and Casing inspection logging). As the risk and integrity management program has been enhanced since 2013, reworks in 2016

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[25] For additional discussion about the WELL Program, see Section 1.

[26] See Appendix B.

[27] DHSVs must be replaced every time they are removed.

and later include only wells needing integrity assessment based on risk and re-working of a well to replace non-functioning DHSVs or gravel packs.

PG&E is developing plans to complete well assessments of 5 additional wells at McDonald Island in 2016 and return the wells to service in 2017. Timing to complete this work is contingent on the availability of third party equipment and integrity services.

PG&E has developed a prioritization process to determine the order in which to conduct well rework projects. Factors include the number of years a storage well has been in service, excessive annular pressure build rate, downhole safety valve test results, the presence of sand that has accumulated in transmission piping, and any decline in the productive capability of a well. Wells scheduled for assessment take into consideration the relative risk ranking of individual wells. Last, the schedule of reworks and assessments are finalized based on the ability to effectively and efficiently conduct the work, minimize unnecessary equipment mobilization, and reduce the amount of outage time at the storage facilities.

TABLE 6
STORAGE REWORKS AND INTEGRITY ASSESSMENTS

	McDonald Island	Los Medanos	Pleasant Creek	Total
2016	4	2	0	6
2017	7	1	0	8
2018	4	2	2	8
2019	7	2	0	9
2020	4	4	2	10
2021	7	0	3	10
2022	5	5	0	10
2023	11	1	0	12
2024	10	2	0	12
2025	14	0	0	14
Total	73	19	7	99

5. Responses to Specific Questions

5-1. State of Downhole Safety Valves

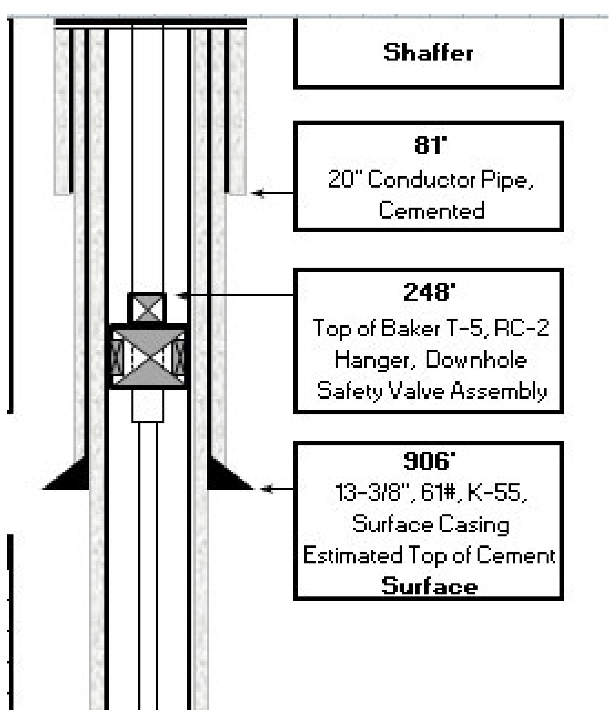
What is the state of downhole safety valves at McDonald Island, at Pleasant Valley [sic] and at Los Medanos? How many wells lack such valves, and how many of the existing valves are operational? Do storage rework projects prioritize the need for downhole safety valves, or do they prioritize maintaining a maximum gas withdrawal rate? Provide records of recent downhole safety valves tests.

<u>**Response**</u>

State of DHSV

There are 117 wells at the three PG&E-owned and operated storage facilities (McDonald Island, Los Medanos, and Pleasant Creek) and DHSVs are installed on 89 of the 117 wells (see Table 7). DHSVs are installed approximately 250 feet below ground level (see Figure 3 below).

FIGURE 3
INSTALLATION OF A TYPICAL DOWNHOLE SAFETY VALVE



The number of DHSVs at each storage field is shown on Table 7 below. PG&E has installed DHSVs at wells at the McDonald Island and Los Medanos storage facilities, but has not installed DHSVs in the 7 wells at the Pleasant Creek

Storage Facility, 20 wells at McDonald Island, and in 1 observation well at Los Medanos.

TABLE 7
NUMBER OF WELLS WITH DHSV YEAR END 2015

	McDonald Island	Los Medanos	Pleasant Creek	Total
# Wells With DHSV	68	21	0	89
# Wells	88	22	7	117

Pressure tests have been conducted on all DHSVs based on criteria established with DOGGR prior to the DOGGR Emergency Regulations effective on February 5, 2016.[28] Based on functional tests conducted in 2016 after February 5, 2016 where PG&E opened and closed the valves, all safety valves were functional except valves on five wells that were either not functional or unavailable for testing. PG&E submitted a letter to DOGGR in May 2016 with a plan to replace these valves during the 2016 well rework program. PG&E typically replaces about six to eight valves annually due to a loss of valve functionality.

In 2014, PG&E completed a Coarse Quantitative Risk Analysis at the McDonald Island Storage Facility. The analysis indicated that wells equipped with DHSVs present an elevated safety risk to personnel due to replacement maintenance (average life around 5-7 years) required for DHSVs in addition to increasing the overall personal safety risk exposure by requiring more personnel to be onsite to perform replacement maintenance and general operations. While the DHSVs may prevent an escalation in the case of a gas loss, the overall risk to PG&E may be higher due to the required maintenance of DHSVs.

Prioritization of Storage Rework Projects and DHSV

Maintaining deliverability is only one factor to be considered in prioritizing rework projects. In summary, there are a number of factors used to determine whether a well should be reworked, such as the number of years a storage well has been in service, excessive annular pressure build rate, DHSV test results, the

28 See Section 5-6 Effect of Aliso Canyon Leak for discussion about DOGGR Emergency Regulations.

presence of sand that has accumulated in transmission piping, and any decline in the productive capability of a well.

Records of Recent Downhole Safety Valves Tests

Each year PG&E assesses the DHSVs for functional and operational integrity. Depending on the DHSV type/model, either leakage rate or pressure buildup tests are performed to determine leakage across the DHSV when closed. The leakage rate or pressure buildup is measured by leak classifications with a rating system.

DHSV tests are rated on a scale of 0-4 as shown on Table 8 and described below:

TABLE 8
CONDITION KEY

Rating	Condition[a]
0	No Leakage
1	1 - 100 psig
2	101 - 200 psig
3	201 - 300 psig
4	300 psig or higher

(a) Measures pressure that is seen past the valve after it is closed.

- Wells with DHSV leak rating of 4 are considered either as “not holding pressure” or “failed to operate correctly in either closed/opened position.” Based on further evaluation of the DHSV failure data, the DHSVs are prioritized for replacement.
- Wells with DHSV leak rating of 3 are considered valves with potential failures/deteriorating in its performance. The DHSVs could sustain and maintain DHSVs functionality; hence the test results are acceptable.
- Wells with DHSV leak rating of 0-2 are considered acceptable and have the ability to sustain and maintain DHSVs functionality.

Recent DHSV records from year 2013-2015 are provided in this report and reflect DHSV test data and results.[29]

[29] See Appendix I 2013-2015 Downhole Safety Valve (DHSV) Test Data: McDonald Island & Los Medanos. See Appendix J 2013-2015 DHSV Test Results: McDonald Island & Los Medanos for leak classifications.

The previous year's DHSV testing results and this year's targets are shown in Table 9. Trends from the past five years of safety valve testing can be seen in Figure 4.

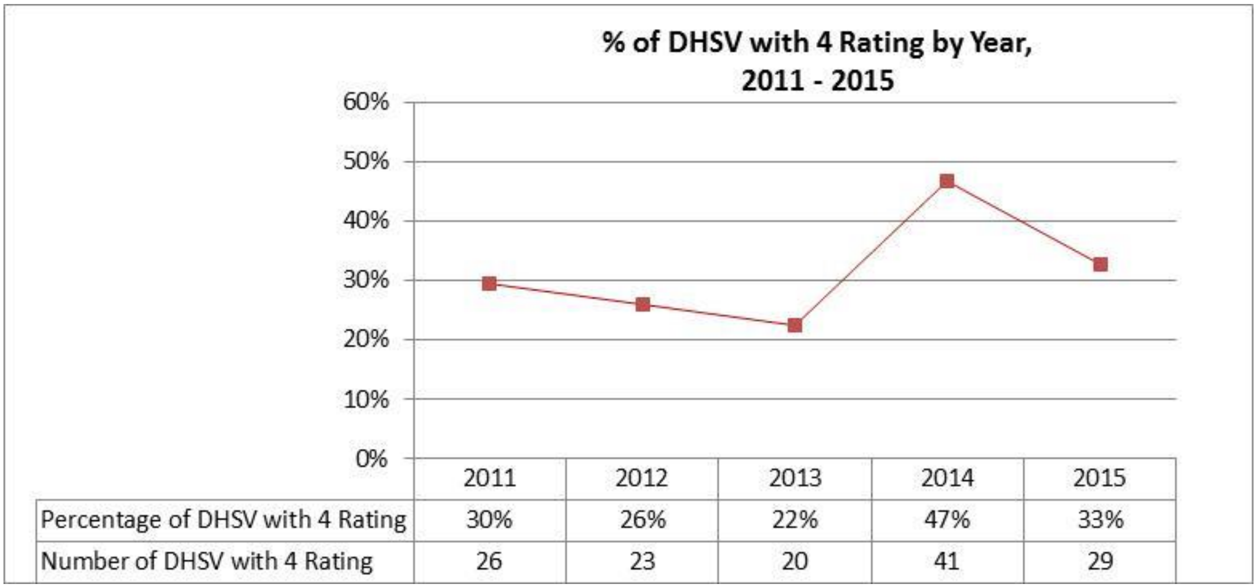
The DHSV 5-year condition trend shows a decrease in wells with a "4" rating in 2015 after an increase in wells with a "4" rating in 2014. The increase in the number of wells having an increased rating in 2014 was at McDonald Island's Whiskey Slough Station. The potential reason for the increase is that these DHSVs were not exercised monthly due to the DHSV hydraulic control system being taken out of service for more than nine months as part of the Whiskey Slough production measurement and controls and piping system upgrade in 2013.

The DHSV manufacturer recommends functionally exercising the DHSVs at a minimum of once a month to keep the valves working properly and reliably. However, this could not be done when the hydraulic system was out of service. PG&E is working with the valve manufacturer to assess the DHSV design and to improve valve performance. PG&E is also working with the manufacturer to develop a new DHSV design to extend the service life of these valves and to evaluate designs that allow DHSVs to be set at a greater depth in a storage well.

TABLE 9
2015 YEAR-END DHSV CONDITION SUMMARY

	McDonald Island	Los Medanos	Total
# Valves Available for Testing	68	21	89
4 Rating	21	8	29
% of Total	31%	38%	33%
# Being Replaced in 2016	4	2	6
2016 Target (% of 4 Rating to Total # of Valves)	25%	29%	26%

FIGURE 4
DHSV 5-YEAR CONDITION TREND



	2011	2012	2013	2014	2015
Percentage of DHSV with 4 Rating	30%	26%	22%	47%	33%
Number of DHSV with 4 Rating	26	23	20	41	29

5-2. Replacement of Downhole Safety Valves

When and how does PG&E decide to replace its downhole safety valves? How frequently are these valves tested as they near replacement?

<u>Response</u>

As discussed earlier in this Report, PG&E uses various factors in determining when and how to replace its DHSVs. See Section 4 Storage Rework Projects for a discussion of replacement of DHSVs[30] and Section 5-1 State of Downhole Safety Valves on how PG&E rates the functional testing data.[31]

The current emergency regulation[32] put forth by DOGGR, which PG&E follows, requires functional testing of DHSV by May 5, 2016 and every six months thereafter. This functional DHSV testing is to open and close the valves witnessed by DOGGR staff.

PG&E also pressure tests all DHSVs annually, regardless of condition. This annual testing includes collecting pressure build-up and leak volume data to ensure that a DHSV is functioning properly and sealing.

PG&E's Underground Storage Risk and Integrity Management Plan, Appendix R, Practice 14 Annual Downhole Safety Valve Testing, provides more information about DHSV testing.[33]

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30 See Section 4 Storage Rework Projects.

31 See Section 5-1 State of Downhole Safety Valves.

32 CCR Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, and Section 1724.9.

33 See Appendix B.

5-3. Corrosion

Explain how current data is adequate to protect against the risk of corrosion. What tests or surveys are necessary to improve analysis of the risk of corrosion, when were those tests or surveys last performed, and when are those tests or surveys next scheduled?

Response

PG&E monitors and evaluates corrosion on its storage facilities. Subject Matter Experts analyze storage well, pipeline, and equipment data to evaluate for the risk of corrosion and target where additional mitigation and monitoring may be needed. The following details the assessments performed on storage wells, pipelines, and other facilities.

Storage Wells

Storage well integrity is assessed for metal loss potentially due to corrosion or mechanical damage. The following assessments are used:

- Noise and Temperature Logs (N&T): Run annually on all wells to inspect for anomalies. These logs provide information that may indicate wellbore tubular leak. While the logs do not directly indicate if the leak is due to corrosion, it does provide a depth location for further investigations. Prior to 2013, noise and temperature logging was PG&E's primary assessment tool for evaluating risk of a well casing loss of integrity.
- Cement Bond Logs (CBL): Used to evaluate cement sheath in the annulus between casing and formation and potential for gas migration paths. The cement sheath can provide a layer of protection against external corrosion and understanding the depth of cement coverage provides locations of corrosion risk. Cement Bond Logs are performed once when the well is initially drilled and completed. Existing wells are re-clogged when the initial CBL didn't cover entire depth of well or the top of the cement sheath was not covered with a previous log.
- Casing Wall Thickness Inspection: Magnetic Flux Leakage (MFL) is used to evaluate casing for metal loss potentially related to internal corrosion, external corrosion, or cathodic protection. All wells scheduled for rework or assessment are inspected in a given year. Based on the indications from the log the wells are then rescheduled for subsequent logging. PG&E has a plan to conduct baseline assessment logging of all wells by 2025.

- Gamma Ray Neutron (GRN) Logs: Identifies "gas behind pipe," or potential gas behind the well production casing and cement sheath. GRN was introduced in 2013 to set a baseline for wells at all storage fields.
- Caliper Inspections: Used to evaluate casing geometry and changes of internal diameter. All wells scheduled for rework or assessment are inspected in a given year. PG&E has a plan to conduct baseline assessment logging of all wells by 2025.
- Ultrasonic Surveys: Used to evaluate casing wall thickness which could be an indication of metal loss potentially related to internal corrosion, external corrosion, or cathodic protection. All wells scheduled for rework or assessment are inspected in a given year. Based on the indications from the log the wells are then rescheduled for subsequent logging. PG&E has a plan to conduct baseline assessment logging of all wells by 2025.
- Pressure Tests: Performed to demonstrate the well casing has integrity to hold pressure. All wells scheduled for rework or assessment are pressure tested in a given year. Based on the indications from the MFL and ultrasonic logs the wells are then rescheduled for subsequent logging and pressure testing. PG&E has a plan to conduct baseline assessment logging of all wells by 2025.
- Pressure Monitoring: PG&E monitors individual wells' surface and production pressures daily which may provide an indication if a well's casing condition has failed.

Pipeline and Surface Equipment

<u>Pipeline Assessments</u>

PG&E applies the Transmission Integrity Management Program to all transmission pipe, including pipe operating within storage fields meeting the requirements of 49 CFR part 192 Subpart O. This includes HCA analysis, threat identification and risk assessment on all transmission pipe on an annual basis. For HCAs, assessments and reassessments of the identified threats are performed within the code-prescribed timeframes and may include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment, In-Line Inspection (ILI), and Hydrostatic Testing. In addition, PG&E is currently considering a threat assessment program to assess non-HCA pipe in exceedance of minimum code requirements.

Cathodic Protection

Buried and/or submerged piping is protected by underground coating systems and impressed current cathodic protection (CP) systems that are monitored. CP is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current CP system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system.

Internal Corrosion Site Specific Plans

High risk pipeline areas are targeted for additional inspection by using radiography and/or ultrasonic thickness (UT) testing to further evaluate the potential for internal corrosion (IC). Additional monitoring to include weight loss coupons, UT monitoring probes, and/or electrical resistance probes will be utilized as required. Other metallic facilities that store or transport gas (such as filter separators) are inspected for IC on a risk based schedule.

PG&E began radiographic direct inspections for IC in 2014 and has currently inspected 40 percent of the highest risk storage assets for IC. The site specific plans for each storage area will target a goal of 100 percent of the high risk assets every seven years. This translates to roughly 14 percent of the high risk areas annually.

Areas where damage in excess of 20 percent wall loss is found have a UT probe installed to monitor for IC depth growth. These probes are monitored bi-monthly. This also helps determine areas where IC is either historical or possibly active.

When liquid samples are available, they will be analyzed for corrosive constituents including, but not limited to: pH, chlorides, and bacteria (types that initiate microbiologically induced corrosion).

PG&E conducts sand cap inspections typically twice a year to monitor for sand that may cause erosion corrosion damage in the pipelines and downstream equipment.

Test/Survey Schedule

The following Table 10 summarizes the tests and surveys that may indicate an anomaly and possible risk of corrosion, when PG&E last performed them, and the future schedule. PG&E is current with meeting schedules for regulatory requirements on noise and temperature logs, cement bond logs, rectifier monitoring, and CP testing. Other assessments listed below are best practices and enhance corrosion monitoring.

TABLE 10
CORROSION TEST/SURVEY SCHEDULE

Type of Asset(s)	Test/Survey	Test/Survey Last Performed	Future Test/Survey to be Performed
Well	Noise and Temperature Logs	2015: All 22 wells at Los Medanos, All 7 wells at Pleasant Creek June – July 2016: All 88 wells at McDonald Island	2016: All wells at Los Medanos and Pleasant Creek 2017: All wells at McDonald Island
Well	Cement Bond Logs (CBL)	2013 – 2015: 12 wells re-logged	2016: 11 wells
Well	Casing Wall Thickness Inspection	2013 – 2015: Baseline Magnetic Flux Leakage (MFL) performed on 18 wells	2016: MFL on 6 wells
Well	Gamma Ray Neutron (GRN) Logs	2013 – 2015: Baseline performed on 107 wells	2016: 12 wells
Well	Caliper Inspections	2015: 1 well	2016: 6 wells
Well	Ultrasonic Surveys	N/A (new survey)	2016: 11 wells
Well	Pressure Tests	2015: 6 wells	2016: 6 wells
Well	Pressure Monitoring	Pressures collected daily	Pressures collected daily
Pipeline	Cathodic Protection Systems: Rectifier Monitoring	July 2016: Los Medanos July 2016: McDonald Island July 2016: Pleasant Creek	Sept 2016: Los Medanos Sept 2016: McDonald Island Sept 2016: Pleasant Creek
Pipeline	Cathodic Protection Systems: Annual CP Testing	Mar – Apr 2016: Los Medanos May 2016: Portion of McDonald Island with other portion to be completed between Aug – Oct 2016 Apr 2016: Pleasant Creek	Mar – Apr 2017: Los Medanos May – Oct 2017: McDonald Island Apr 2017: Pleasant Creek
Pipeline	External Corrosion Direct Assessment (ECDA)	2012: 1.8 miles	2017: 1.8 miles
Pipeline	Internal Corrosion Direct Assessment (ICDA)	Not applicable. To begin in 2020.	2020: 2.7 miles
Pipeline	In-Line Inspection (ILI)	2015: 0.3 miles	Not applicable. Plan to deactivate 0.3 miles.
Pipeline and Surface Equipment	Internal Corrosion Site Specific Plans through Radiography and/or Ultrasonic Thickness Testing	2014 – 2015: Baseline assessments complete for Los Medanos, McDonald Island, and Pleasant Creek Storage Facilities	2016 – Ongoing: Annual inspections of highest risk areas

5-4. Assessment of Well Integrity Management Program

How will PG&E assess its well integrity management program? What metrics will demonstrate whether the program is successful and how it might be improved?

Response

PG&E is currently comparing WELL to API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs to evaluate enhancements to its current operating practices. Enhancements including strengthening existing mitigations to be more robust or performing additional monitoring are targeted to be incorporated starting in 2017. In addition to using API RP 1171, PG&E will continuously improve WELL by gathering best practices from other storage operators.

Well Integrity Management Metrics

Specific trending on the metrics detailed in the table below can provide an indication of well integrity and can help PG&E evaluate how to improve the WELL Program.

TABLE 11
WELL INTEGRITY MANAGEMENT METRICS

Metric Name	Description	Threats Assessed
Number of Anomalies per Well Logged with Noise and Temperature and Gamma Ray Neutron	An industry practice is to establish a baseline assessment of the casing condition with the Gamma Ray Neutron (GRN) log. Reoccurring assessments can be compared to the baseline to establish if gas is accumulating behind the well casing or cement and confirm if anomalies from noise and temperature logs are casing leaks.	Internal Corrosion/ Erosion, External Corrosion
Number of Anomalies Per Well Baseline Inspected	An industry best practice for tracking casing condition to establish a baseline with a MFL tool to evaluate if metal loss is occurring over time. The corrosion rate can then be used to establish the remaining life of production casing.	Internal Corrosion/ Erosion, External Corrosion
Number of Wells at Reduced Rate (due to sand production)	Understanding injection and withdrawal flow rates enables tracking of potential internal corrosion and erosion of wells. Also this metric shows performance against contracted service levels.	Internal Corrosion/ Erosion
Number of Wells at Reduced Rate (due to degradation)	Understanding injection and withdrawal flow rates enables tracking of degradation of well integrity. Also this metric shows performance against contracted service levels.	Internal Corrosion, Equipment, Construction/ Fabrication
Number of Wells Unavailable – Unplanned	Wells out of service due to unplanned conditions may indicate potential mechanical issues or incorrect operations.	Manufacturing, Equipment, Third-Party Damage, Incorrect Operations

Insight into causes of anomalies in wells, reduced well flowrates, and unplanned conditions can lead to enhancing mitigation and monitoring efforts. Similarly, if metric trends indicate a reduction in anomalies, fewer wells flowing at reduced rates, and more wells available it can correlate to improved well condition and the success of the Well Integrity Management Program.

Strategic Objectives, Programs and Mitigations Alignment

The Storage asset family strategic objectives and associated metrics as they correspond to Well Integrity management are detailed in Table 12 below.

TABLE 12
STORAGE ASSET FAMILY STRATEGIC OBJECTIVES AND METRICS

Strategic Objective	Metric (as of August 2016)
Integrity Management – Effective and efficient asset management of gas storage facilities to identify the right work and to optimize the condition of our assets based on prioritization of risk. • Complete baseline well production casing assessments by 2025. • Evaluate WELL enhancements and incorporate by 2017.	• 18 percent Complete • 33 percent Complete
Data – Improve data quality, availability, and accessibility to enhance risk analyses and decision-making, moving from solely Subject Matter Expert input to more data informed. Develop and implement GSAMS and AHS data to enhance risk analysis on well assets for 2019 Session D.	• 50 percent Complete

As shown on Table 13, PG&E has developed the following programs to meet these strategic objectives, using the aforementioned risk-based investment strategy to address asset level risks, meet compliance requirements and maintain asset condition.

TABLE 13
PROGRAMS, MITIGATIONS, AND STRATEGIC OBJECTIVES

Programs & Mitigations	Asset Family Strategic Objectives					
	Asset Management	Process Safety	Facility Performance	Capacity	Compliance	Data
WELL – Integrity Assessments	X	X	X	X	X	X
WELL – Remediation and Conditioning	X	X	X	X	X	
WELL – Controls and Continuous Monitoring	X	X	X	X	X	X
WELL – Repair and Replace	X	X	X	X	X	
Asset Health Scorecard (AHS)	X	X	X			X
Gas Storage Asset Management Systems (GSAMS) and Gas Storage Database (GSDB)	X	X				X
Asset Management Backbone and Stations (AMBBS)	X	X	X			X
Research Projects	X	X	X	X	X	X

Also, research and development efforts as summarized in Table 14 will enhance the desired state of safer and more reliable gas storage assets. Completed and pending projects can improve well and pipe integrity assessments and methane emissions detection. The outcomes from these projects can have long-term benefits which improve integrity management through the WELL Program.

TABLE 14
RESEARCH PROJECTS

Description	Vendor	Status	Planned Completion
Factors Affecting Downhole MFL Accuracy (US-3B)	PRCI-2013	Completed	2013
Cement Degradation Mechanisms (US-3A)	PRCI-2012	Completed	2013
Field Applied Coatings Performance	OTD-GTI	Completed	2014
Demonstration of a Cyber Security Device	SecLab	Completed	2014
Develop an Alternate Method for Potential Measurement to Satisfy the Cathodic Protection Criteria	PRCI-2013	Completed	2014
Internal Corrosion Sample Collection Guidelines	PRCI-2014	Completed	2014
Robotics (Explorer) Crack Sensor	NYSEARCH	Completed	2015
UC Merced Applicability of Unmanned Aerial Systems for Leak	UC Merced	Completed	2015
Real-Time Active Pipeline Integrity Detection System	CEC	Completed	2015
Girth Weld Integrity Underground Movement	JIP CRESS	Completed	2016
Explorer Hardness Tester	NYSEARCH	Active	2016
ILI Technology Comparative Testing (US-3J)	PRCI-2015	Active	2016
Defect Characterization of Well Casing Pipe Using NDT to Confirm Field ILI Tool Accuracy (US-3H)	PRCI-2015	Active	2016
Assess the Accuracy of MFL Inspection Tools, US-3K	PRCI-2016	Active	2016
Field Evaluation of Cement Bond Log Tool, US-4-1	PRCI-2016	Active	2016
Unmanned Aerial System (UAS) Regulatory and Assessment	NYSEARCH	Active	2016
Fast, Accurate, Automated System to Find and Quantify Natural Gas Leaks (ROW-3H)	PRCI-2014	Active	2016
Improving Casing Assessments: Downhole Stress Effects on MFL and Confirmation of RSTRENG Accuracy (US-3B)	PRCI-2014	Active	2016
Methane Emissions Quantification Project	LBNL	Active	2016
Review Methane Emission Qualification Techniques, US-4-2	PRCI-2016	Active	2016
NYSEARCH – Robot to Visually Inspect Pipe Casing	NYSEARCH	Active	2016
Application of Miniature Methane/Ethane Sensors on Small-UAV ROW-3H	PRCI-2016	Active	2017

Continuous Improvement Initiatives

PG&E's strategic objectives are developed to optimize asset life cycle by maintaining and improving asset condition and adequately mitigating risks. These strategic objectives have been established to align investment in the Storage asset family with the Asset Management Strategy, reduce risks and ultimately ensure safe and reliable service of PG&E's gas storage operations.

Using these inputs, a long-term investment and asset management plan has been developed, but will need to incorporate future changes to regulations. For example, currently proposed changes to regulations following SoCalGas' Aliso Canyon well incident and a proposed regulation for air quality (e.g., methane emission reduction) will potentially impact operations and investments of the storage asset family's wells and surface equipment. These changes will need to be incorporated into PG&E's investment and asset management planning. The desired state for the storage well assets is carried out by the development and implementation of a robust WELL Program. Refer to the GP-1108: Gas Storage Asset Management Plan's Appendix K for a roadmap providing an overview of milestones for data improvement and mitigation programs utilized in the Storage asset family to assess condition and risk.[34]

34 See Appendix A.

5-5. Emergency Response Plan

In the event of a leak failure, does PG&E have an emergency response plan in place for each storage facility? Are there Californians who live or work in the vicinity that may be affected in the event of a leak on the scale seen at Aliso Canyon? Does PG&E's emergency response plan have adequate measures to notify, shelter, and protect nearby populations? What would be the effects on gas supply in the event of such a leak during a period of peak gas usage?

Response

PG&E's Emergency Response Plan in the Event of a Leak Failure

PG&E maintains and practices numerous emergency response plans that are specific to the type of risk to the system. The emergency plans that are most relevant to storage facilities include the following:

EMER 3003 – Gas Emergency Response Plan (GERP) Version 5.0, 2015: This plan is an all-hazard emergency response plan for gas operations, and outlines how PG&E responds to all gas incidents including an event at the storage fields and coordinates with external agencies.

1. The following items are also typically covered in the GERP:
   - Security issues in the area;
   - Communication procedure with the local authorities, partners, families, and the media;
   - The consequences of the blowout (medical, medi-vac, pollution control, etc.); and
   - Procedures and contacts for general contracting, administration, procurement, emergency organizations, etc.
2. The Stations and Gas Storage Annex of the Catastrophic Plan: This plan provides a general framework for activation, mobilization, and execution of a response to a major earthquake or other related disaster involving PG&E natural gas stations and storage fields. The gas storage fields include Los Medanos, McDonald Island, and Pleasant Creek. Stations include compressor stations, terminals and regulation (pressure control) stations in both transmission and distribution. The Stations and Gas Storage Annex is chosen as a method of damage assessment and response. This annex provides guidance to personnel immediately following the event and activation of personnel.

3. Well Control Tactical Considerations (WCTC): This plan is a result of a 2015 strategic objective to update the storage plan to be more site-specific. The Tactical Considerations Plan was written in consultation with Wild Well Control, a company that specializes in resolving well-control incidents. The plan is undergoing revisions as PG&E continues to work with Wild Well Control to include surface intervention and relief well planning for each of the storage facilities. The purpose of this WCTC is to establish a common framework for managing the activities required to regain control of a well in the event of a blowout. The framework includes tactical considerations and establishes a process for responding to and safely managing well control emergencies using a standard, uniform approach. The equipment and procedures specified in this WCTC address various well control scenarios ranging from routine well control operations to situations involving a total loss of well control necessitating the immediate mobilization of intervention equipment and personnel. This process includes the following responsibilities:
   - Protect personnel at the site in the event of a well control emergency;
   - Define the notification protocols and methods;
   - Prevent further environmental or facility damage or personnel injury while adequate equipment and personnel are being mobilized;
   - Define the critical information that is required to determine the appropriate response level and strategy;
   - Organize personnel and provide guidelines for their role in the emergency response and subsequent management;
   - Preselect source locations for personnel, equipment, material, and services typically required for implementation of well control procedures; and
   - Modification of the mobilization plan and intervention strategy may be necessary depending on the circumstances of the incident.

The operations consist of gas storage facilities in three separate depleted gas fields along with associated workover operations. The WCTC covers the planned response necessary to respond to an incident at these locations. The WCTC covers the activities required to assess the blowout incident, develop an intervention plan, and execute response measures to ultimately regain control of the well.

PG&E manages multiple layers of emergency plans related to all types of risks to the gas system. Within this family of plans the Well Control Tactical Considerations is the most detailed plan that would drive PG&E's response to a storage facility emergency. The plan was published in December 2015. Additionally, in February 2016, PG&E storage facility and emergency preparedness staff were trained so that those responsible for implementing the plan are familiar with their role in the event of an emergency.

Individuals Who Live or Work in the Vicinity of a Gas Storage Facility

PG&E works with local government and first responders to prepare for and mitigate any risk to the public. Below are the populations who live or work in the vicinity of PG&E's gas storage facilities.

Figures 5 through 7 are aerial photographs of the three storage facilities along with buffer zones measured by one, two, and three mile radii stemming from the center of each facility:

FIGURE 5
MCDONALD ISLAND MAIN OVERVIEW

FIGURE 6
LOS MEDANOS GAS WELLS MAIN OVERVIEW

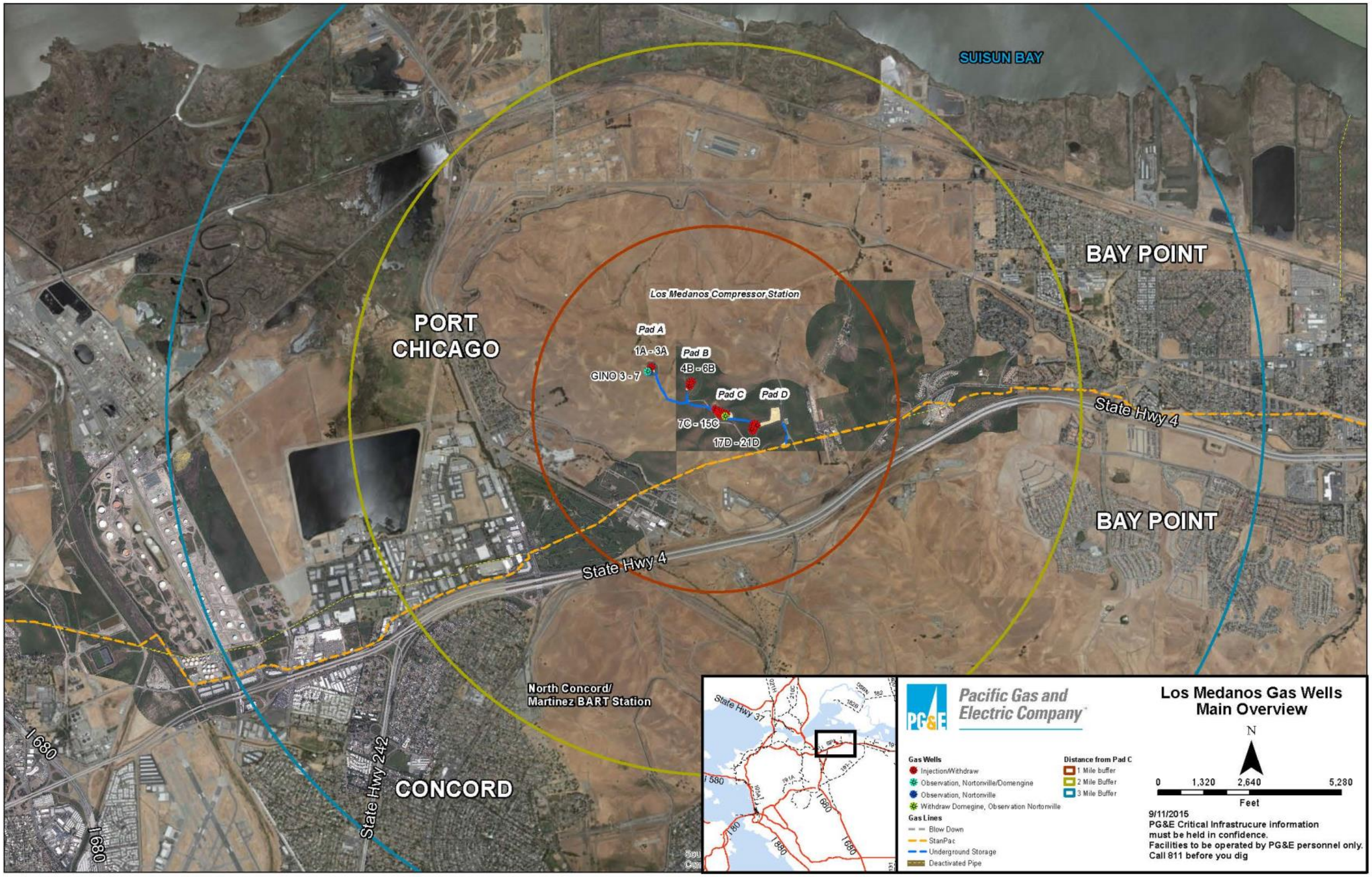
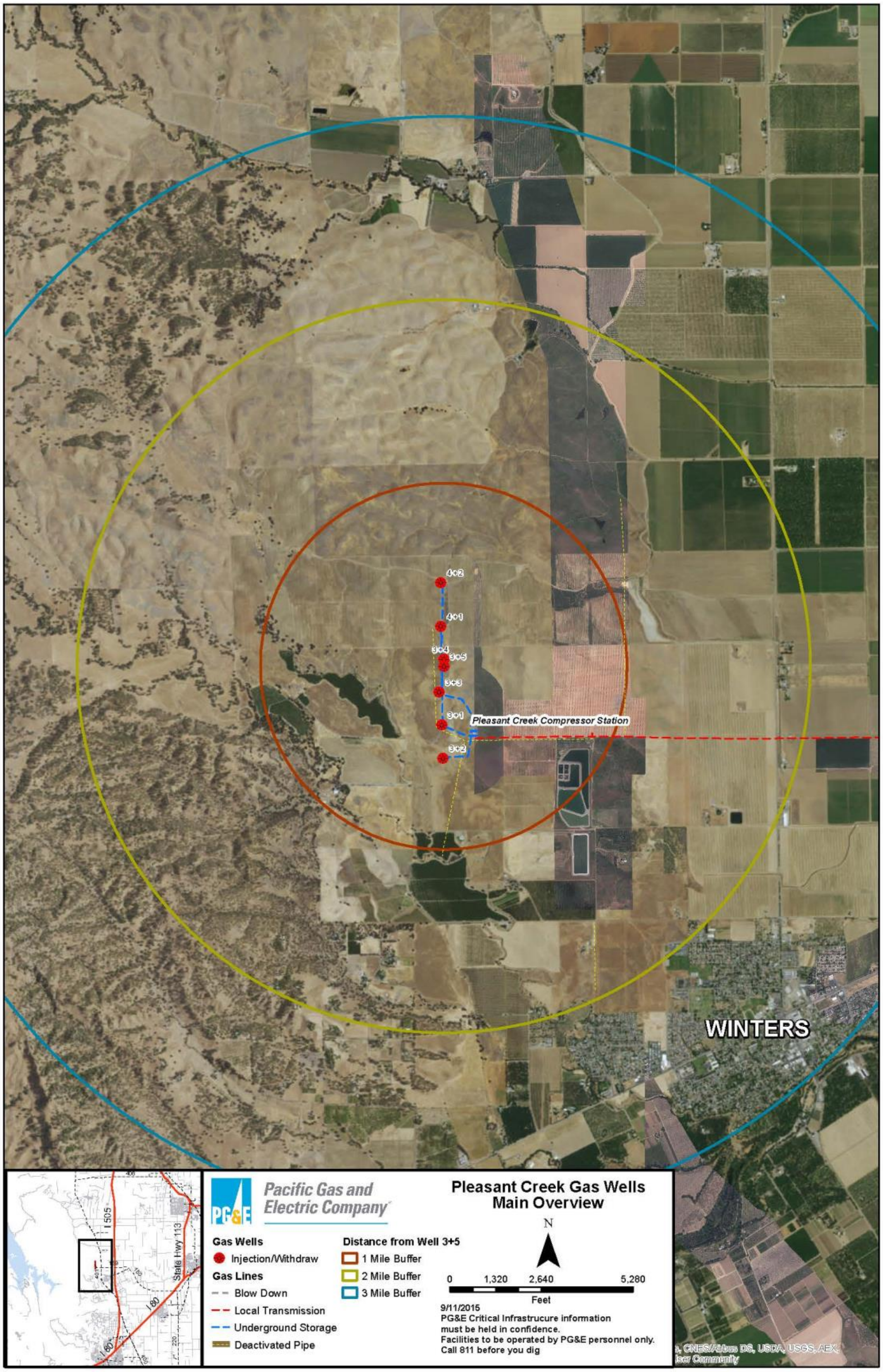


FIGURE 7
PLEASANT CREEK GAS WELLS MAIN OVERVIEW



PG&E also has maps depicting Public Assembly Points[35] in proximity to the three storage facilities. See Figures 8 through 10 for the Public Assembly Point maps.

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[35] PG&E's Utility Procedure TD-4110P-03 includes the following definition of a Public Assembly Location: "For leak survey purposes, public building locations include the following:

- Schools – university, community college, high school, middle, elementary, and licensed day care
- Hospitals – general hospital, emergency hospital, outpatient surgery, clinic, skilled nursing facility
- Churches – church, synagogues, temple, mosque, monastery."

FIGURE 8
MCDONALD ISLAND COMPRESSOR STATION & SURROUNDING PUBLIC ASSEMBLY POINTS

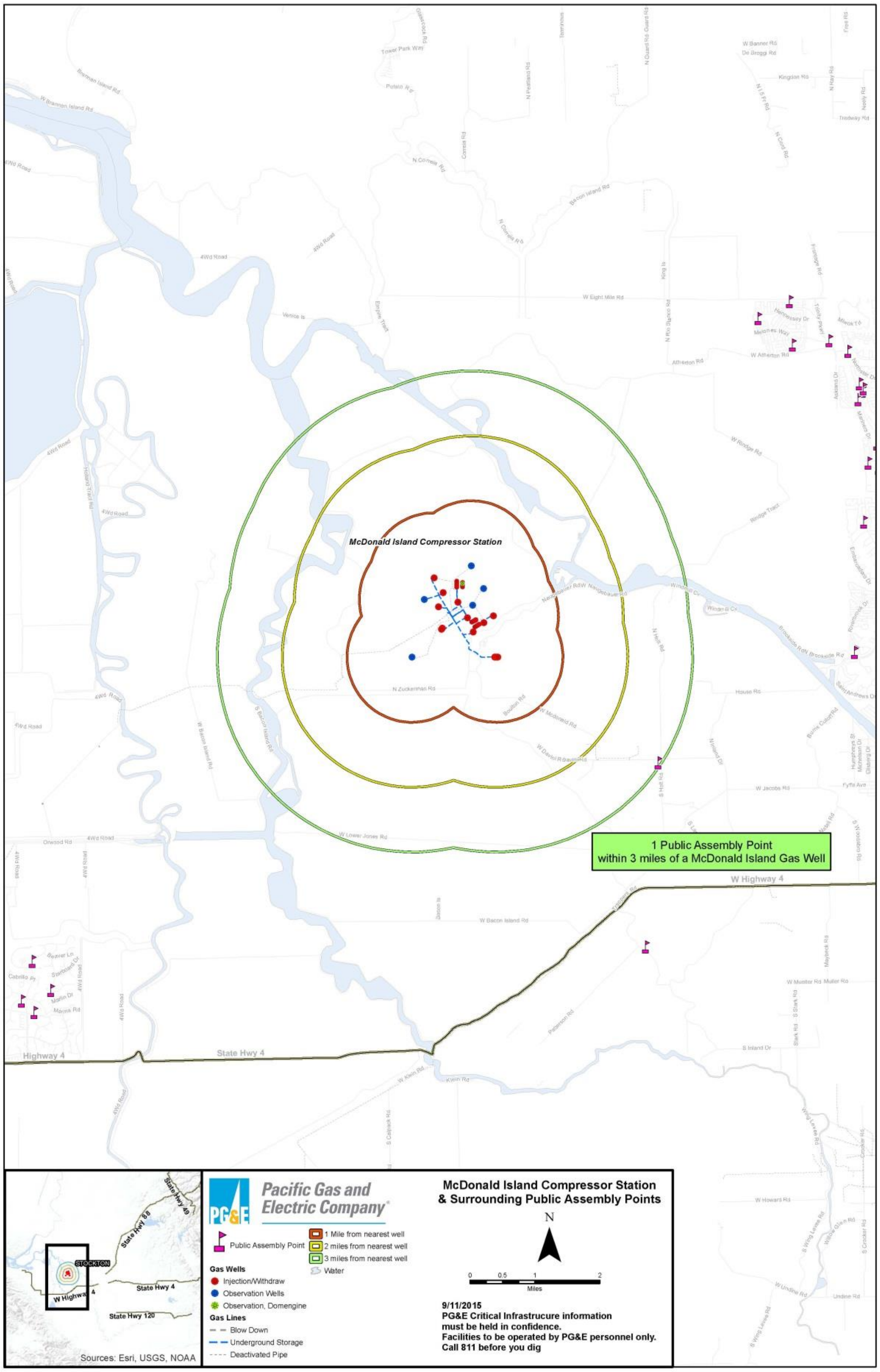


FIGURE 9
LOS MEDANOS GAS WELLS & SURROUNDING PUBLIC ASSEMBLY POINTS

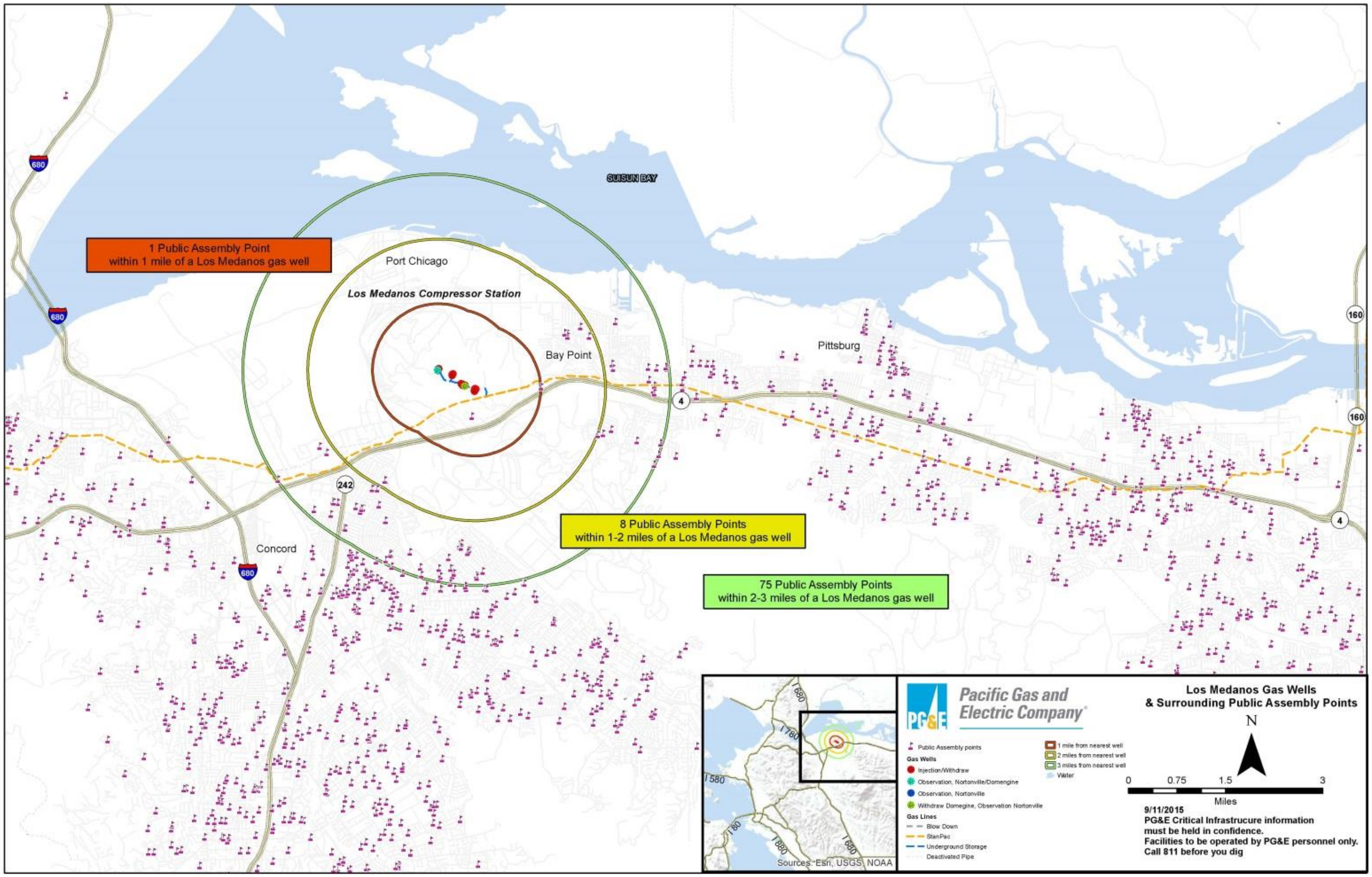
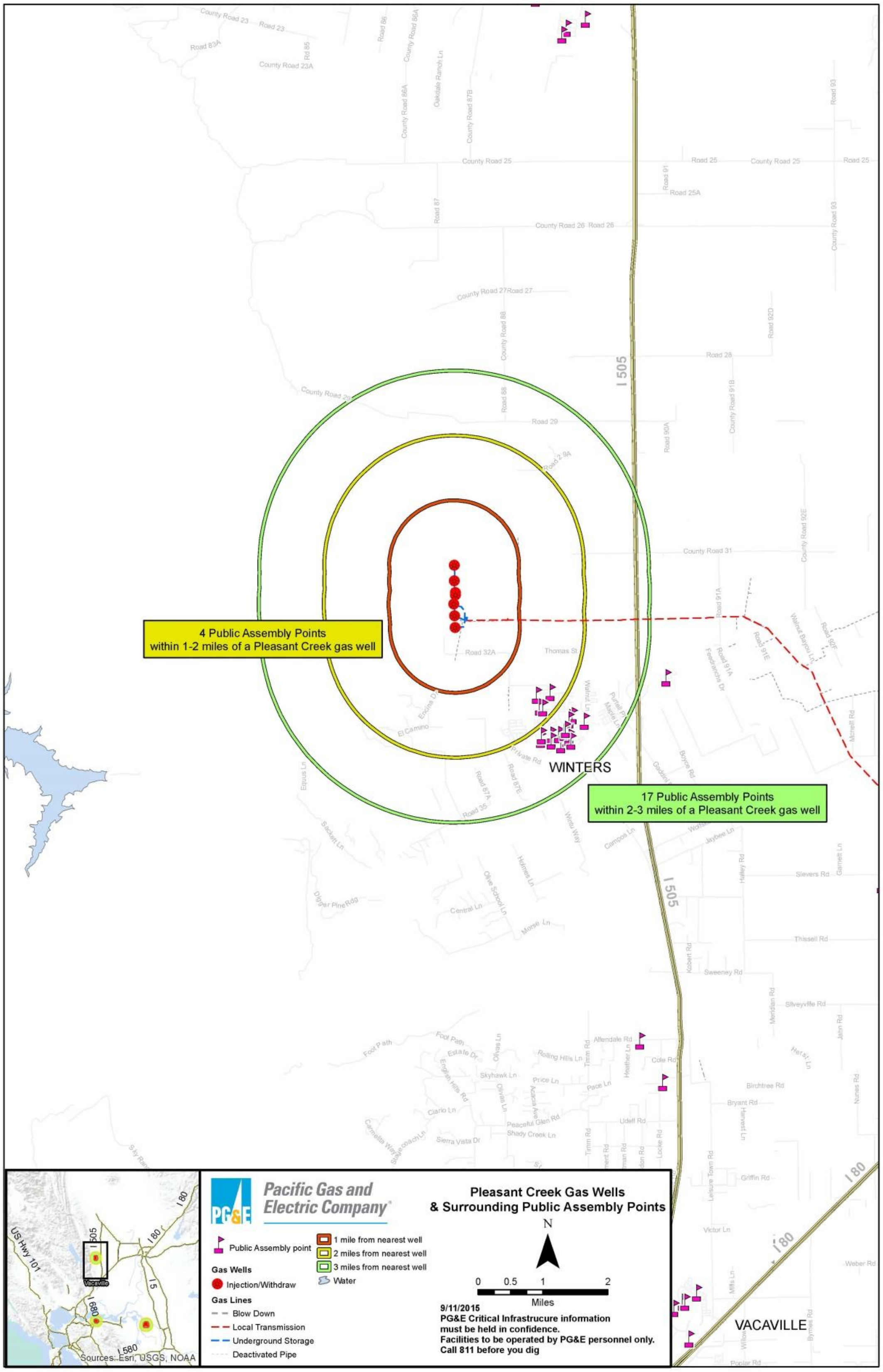


FIGURE 10
PLEASANT CREEK & SURROUNDING PUBLIC ASSEMBLY POINTS



Public Assembly Points generally can include locations such as schools, churches, fire departments, hospitals, etc., where individuals can gather. PG&E's Public Assembly Point maps relating to its gas storage facilities include one, two, and three mile radii from the actual wells within each storage facility. McDonald Island has one Public Assembly Point within three miles of a McDonald Island gas well. Los Medanos has eight Public Assembly Points within one to two miles of a Los Medanos gas well and 75 Public Assembly Points within two to three miles of a Los Medanos gas well. Pleasant Creek has four Public Assembly Points within one to two miles of a Pleasant Creek gas well and 17 Public Assembly Points within two to three miles of a Pleasant Creek gas well.

In addition to the aerial photographs of the three storage facilities and the maps of the Public Assembly Points, PG&E has identified an individual count of "Businesses: Landowners, Farmers, Residential" based on a 1,000 foot distance of the gas storage facilities as shown in Table 15:

TABLE 15
INDIVIDUAL COUNT OF BUSINESSES, LANDOWNERS, FARMERS, AND RESIDENTIAL WITHIN 1,000 FEET FROM THE PROPERTY BOUNDARY OF EACH STORAGE FACILITY

	McDonald Island	Los Medanos	Pleasant Creek
	Description of location: Approximately 20 miles west of Stockton, population over 300,000.	Description of location: Approximately 5 miles north of Concord, population over 122,000; Approximately 3 miles west of Bay Point, population over 21,000.	Description of location: Approximately 2 miles northwest of Winters, population 6,600.
Businesses	0 businesses	15 businesses	0 businesses
Landowners	0 landowners	3 landowners	3 landowners
Farmers	0 farmers	1 farmer	4 farmers
Residences	0 residences	0 residences	3 residences

Beginning in 2012, PG&E began sending a brochure to those located within 1,000 feet of the boundary of each storage facility and compressor station.[36] The brochures discuss PG&E's 24/7 monitoring of its pipeline system and provide

36 See Appendix K for Storage Compressor brochures distributed to those within 1,000 feet of a gas storage facility. PG&E plans to distribute another Storage Compressor brochure in sometime in the fall 2016.

the recipient information on the identification and purpose of pipeline markers as well as a depiction of storage facilities and compressor stations. The brochures also provide information regarding PG&E's response in the event of a gas-related emergency. Additionally, the brochures provide readers the website where they can go to learn more about the pipelines located in their communities.

Additionally, PG&E facilitates discussions (workshops, seminars, and tabletop exercises) and operation based exercises (drills, functional and full-scale) annually. PG&E invites local first responders to attend and, depending on the complexity of the exercise, PG&E will also invite local public and non-profit agencies to attend. For example, in October 2014, PG&E ran a full-scale exercise at Los Medanos Compressor Station including local police, fire, emergency medical services, county sheriff, Bay Area Rapid Transit, California Highway Patrol, the Salvation Army, and the United States Army.

As previously stated, in the event of an emergency at a PG&E storage facility, PG&E will work closely with local government and first responders to identify and mitigate any risk to the public. PG&E will utilize plume models and gas dispersion analyses to determine Lower Explosive Limits concentration or blast radius/radiant heat in order to effectively protect the public.

PG&E's Emergency Response Plan to Notify, Shelter, and Protect Nearby Populations

While the emergency plans do not specifically address the specific procedures for sheltering the impacted population, PG&E has the capabilities to notify, shelter, and protect the public in the event of an emergency, and has performed these functions during previous emergencies. PG&E's Customer Care department would take appropriate actions to notify customers impacted by the emergency and provide further instructions. PG&E in coordination with local response agencies and authorities would develop plans to ensure the safety, security and well-being of the public. PG&E would provide resources to support the community such as pre-loaded debit cards for meals and expenses, establish warming shelters during winter months, set up feeding stations for the impacted community and responders, and arrange for temporary and long term housing for impacted customers.

Effects on Gas Supplies at Gas Storage Facilities in the Event of a Leak During a Period of Peak Gas Usage

There are eight separate gas storage fields in PG&E's service area. Supplies withdrawn from the facilities are used to supplement supplies coming from the interstate pipelines during periods of peak use and to balance the daily supply and usage within the PG&E market. The time of peak natural gas usage is in the winter during periods of cold weather.

Five of the fields are operated by Independent Storage Providers (ISP). The loss of withdrawal capacity from any one of the ISP facilities would likely not have an impact on the reliability of the PG&E system. There would be adequate alternative supplies from the other storage providers such that it is unlikely that any noncore customer (large commercial, industrial or electric generation) would need to be curtailed.

The three fields operated by PG&E vary substantially in size. Loss of withdrawal capacity from PG&E's smallest facility, Pleasant Creek, would not have any significant impact on reliability. Loss of withdrawal capacity at PG&E's Los Medanos facility would likely have some impact on natural gas prices and reliability. Loss of withdrawal from Los Medanos during an extreme cold event would increase noncore curtailments by about 125 MMcf/d.

Loss of withdrawal capacity from PG&E's largest facility, McDonald Island Storage Facility would have a significant impact on reliability. If the McDonald Island storage facility were unavailable during a once-in-two-year cold period, noncore curtailments would be approximately 490 MMcf/d or about 20 percent of the noncore demand. During an extreme cold event noncore curtailments could increase by as much as 700MMcf/d or about 40 percent of noncore load.

Furthermore with the loss of McDonald Island Storage Facility core customers could lose up to 25 Bcf or 75 percent of their current PG&E storage supplies and would be required to purchase supplies at the City gate.

Although no core customer curtailments are anticipated; in order to incent non-core supplies to be available to the core, Emergency Flow Orders and possible supply Diversions would most likely be required.

PG&E's storage fields play a critical role in PG&E's Gas Operations ability to manage the daily balancing of supplies and demands. Without the use of Los Medanos or McDonald Island Storage fields it is expected that more frequent Operational Flow Orders will be required to keep the system inventory within operating limits.

5-6. Effect of Aliso Canyon Leak

How does the Aliso Canyon leak affect PG&E's assessment of its gas storage facilities?

Response

Background

Prior to SoCalGas' Aliso Canyon natural gas leak, PG&E had existing assessments in place across its service territory to monitor the conditions of its gas storage facilities. However, in response to the Aliso Canyon leak, PG&E expanded its scope for certain measures to improve assessments of its gas storage facilities. The section below describes the condition of these assessments prior to and in response to the SoCalGas, Aliso Canyon natural gas leak.

Governor's Emergency Declaration

On January 6, 2016, Governor Edmund G. Brown Jr. declared a State of Emergency in Los Angeles County and issued a proclamation as a result of the ongoing natural gas leak detection at the Aliso Canyon storage facility. The proclamation established 14 directives[37] that require the CPUC, California Energy Commission, CARB, California Independent System Operator, DOGGR, and other state agencies to work together to address specific items related to gas storage wells.

Directive No. 13 authorizes DOGGR to issue emergency regulations for California gas storage operators, including PG&E. As discussed in detail below, PG&E expanded the scope of its existing safety measures as a result of DOGGR's emergency regulations. Since issuing the emergency regulations, PG&E has expanded and improved its gas storage assessment capabilities.

DOGGR's Emergency Regulations

DOGGR's emergency regulations are based on the Governor's Emergency Proclamation Directive No. 13.[38]

Prior to DOGGR's issuance of the emergency regulations, PG&E conducted multiple types of assessments on its gas storage facilities on a daily, weekly, and annual basis. As a result of DOGGR's enacted emergency regulations, PG&E

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37 See Appendix L, Governor's Emergency Proclamation.

38 See Requirements for Underground Gas Storage Projects, CCR Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, and Section 1724.9.

has expanded the scope of these assessments by increasing the frequency of leak and safety valve inspections on an annual basis, as well as taking pressure readings on a daily basis. Table 16 lists the emergency regulations promulgated by DOGGR and PG&E's status of its assessments prior to and post-regulations with general results of these modifications.

TABLE 16
STATUS OF PG&E'S RESPONSE TO DOGGR'S EMERGENCY REGULATIONS

DOGGR's Emergency Regulations	PG&E Status		
	Pre-Regulation[a]	Post-Regulation	Reason/Result
§1724.9(a) Provide Required Data to DOGGR	PG&E provided all data requested by DOGGR and other agencies.	PG&E continues to provide all data requested by DOGGR and other agencies.	Transparency with the public, DOGGR, and other agencies.
§1724.9(b) Establish minimum and maximum pressure limits for each gas storage facility in the state	PG&E established maximum pressure limits for each storage reservoir and flowing pressure differential to protect cap rock and mitigate sand production.	PG&E continues to operate within established maximum pressure limits for each storage reservoir and flowing pressure differential to protect cap rock and mitigate sand production.	There has been no change in operating pressure limits.
§1724.9(c) Verification of mechanical integrity of all gas storage wells	PG&E performed mechanical integrity verification as an ongoing practice. PG&E performs annual inventory verification and annual noise-temperature surveys on its wells. PG&E performed weekly pressure monitoring on wellheads and maintains casing inspection programs with remedial action plans.	PG&E continues to perform daily inspections of wells, and sight, sound, and visual inspections. PG&E has increased frequency of pressure reading from a weekly basis to a daily basis.	Inspections improve the safety of gas storage facilities because it identifies the need for preventative maintenance and mitigates damage from threats or hazards.
§1724.9(d) Functional test of all safety valve systems used in wells by May 5, 2016 and every 6 months thereafter	PG&E performs annual functional tests on the uphole and downhole safety valves on equipped wells.	PG&E now performs semi-annual functional tests on the uphole and downhole safety valves on equipped wells.	Inspections improve the safety of gas storage facilities because it identifies the need for preventative maintenance and mitigates damage from threats or hazards.

TABLE 16
STATUS OF PG&E'S RESPONSE TO DOGGR'S EMERGENCY REGULATIONS
(CONTINUED)

DOGGR's Emergency Regulations	PG&E Status		
	Pre-Regulation[a]	Post-Regulation	Reason/Result
§1724.9(e) Daily wellhead inspection using leak detection technology	• Daily visual /audio inspection of wellheads at McDonald Island and Los Medanos with correctives per existing standards. • Visual /audio inspection of wellheads 2-3x/week at Pleasant Creek with correctives per existing standard. • Annual leak survey and repair.	PG&E commenced daily wellhead inspection and leak survey activities at all storage sites on January 22, 2016. PG&E submitted its Leak Survey Protocol to DOGGR on February 26, 2016. At the request of DOGGR, PG&E sent subsequent revisions of its Leak Survey Protocol on March 17, 2016 (Revision 1) and May 16, 2016 (Revision 2).	Inspections improve the safety of gas storage facilities because it identifies the need for preventative maintenance and mitigates damage from threats or hazards.
§1724.9(f) Functional test of master and isolation valves by May 5, 2016 and annually thereafter	Functional tests of uphole and downhole safety valves were conducted on an annual basis.	PG&E began functional tests of master valves (master gates and casing wings).PG&E will conduct functional tests of uphole and downhole safety valves and master valves functional tests annually as required.	Inspections improve the safety of gas storage facilities because it identifies the need for preventative maintenance and mitigates damage from threats or hazards.
§1724.9(g) Submit a Risk Management Plan to DOGGR for approval by August 5, 2016	PG&E utilizes a Risk Management Plan in assessing the Storage Asset Family assets. One function of the plan is to evaluate the condition of the gas storage facilities. These plans have been internal documents.	On August 5, 2016, PG&E prepared and submitted the risk management plan to DOGGR for their review and approval.	Inspections improve the safety of gas storage facilities because it identifies the need for preventative maintenance and mitigates damage from threats or hazards.

(a) PG&E status prior to the Governor's Directives and DOGGR's emergency regulations.

By August 30, 2016, PG&E will have completed all seven requirements prompted by DOGGR's emergency regulations.

The final item to be completed in August 2016 is developing supporting documentation for pressure limits. As mentioned earlier in this report, PG&E maintains an Asset Management Plan and a Risk Management Plan that was developed to protect the public, environment, and company personnel. As part of the emergency regulations, PG&E is now required to submit the risk management plan to DOGGR for their review and approval. Pursuant to this requirement, on August 5, 2016, PG&E submitted "Underground Storage Risk and Integrity Management Plan to DOGGR" for their review and approval.[39]

Additionally, PG&E subject matter experts evaluated and updated the impact scores of "*a loss of well integrity risk.*" The Aliso Canyon natural gas leak event did not impact PG&E's estimation for the ***likelihood of occurrence*** within its gas storage facilities.

Well Integrity Testing

Following the Aliso Canyon leak, DOGGR further required SoCalGas to conduct a safety review requiring that each of their 114 active wells located at the Aliso Canyon facility either pass six well integrity tests to resume gas injection or be taken out of operation and isolated from the underground gas reservoir.

Prior to the Aliso Canyon leak, PG&E has conducted well integrity tests on each of its wells. As described in the Introduction, PG&E developed WELL based on industry best practices to examine the functional integrity of natural gas wells and fields. This program is also used to assess the risk related to the storage wells and prescribe action to prevent or mitigate these risks. PG&E recently conducted various analyses and enhanced WELL prior to the effective date of DOGGR's emergency regulations. Table 3 in Section 1 Well Integrity Program describes the integrity tests that are also required at Aliso Canyon.

Overall Assessment

PG&E continues to safely and reliably manage its gas storage facilities and continues daily inspections of these facilities on behalf of its customers and the public. As stated above, the current condition of Gas Storage assets has been qualitatively assessed by subject matter experts and quantitatively assessed

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39 See Appendix B.

through various integrity tests that are standard in the industry. PG&E has assessed 18 of its storage wells production casing integrity and plans to complete the remaining wells by 2025. Programs to mitigate the threats as discussed in the Asset Management Plan will provided the means for PG&E to continue to effectively management the storage assets with metrics helping to determine the effectiveness. The Risk Management Plan frames the programs that have been and are used to assess the storage well integrity.

The Gas Storage Asset Family's strategic objectives are developed to optimize the assets' life cycle by maintaining and improving its condition to adequately mitigate risks.

Continued research and development efforts will further enhance the desired state of safe and reliable gas storage assets. Completed and pending projects can improve well and pipe integrity assessments and methane emissions detection. The outcomes from these projects can have long-term benefits which improve integrity management through PG&E's many programs.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

GP-1108: GAS STORAGE ASSET MANAGEMENT PLAN

REDACTED PUBLIC VERSION

GP-1108 - Gas Storage Asset Management Plan

Gas Plan

Document Number: GP-1108

August 1, 2016

Document Owner: Larry Kennedy

Document Approver: Sumeet Singh

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1. Executive Summary

This asset management plan provides an assessment of condition and risk of the Gas Storage asset family and includes a program plan detailing risk mitigations based on strategic objectives and asset maintenance, applied over the life cycle of the assets.

On October 23, 2015, a leak was detected at Southern California Gas Company's (SoCal Gas) Aliso Canyon underground storage facility and was permanently plugged on February 18, 2016. During the leak on January 6, 2016, the California Governor issued a state of emergency through a proclamation with 14 directives. The Division of Oil, Gas, and Geothermal Resources (DOGGR) then issued Emergency Regulations (Requirements for Underground Gas Storage Projects, California Code of Regulations Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, Section 1724.9) based on the Governor's Emergency Proclamation Directive #13 with an effective date of February 5, 2016. As of the writing of this Asset Management Plan, PG&E has completed five of the seven items included in the DOGGR Emergency Regulations. The pending two items on track for completion in August 2016 include developing supporting documentation for pressure limits and a risk management plan which incorporates PG&E's current risk and integrity management procedures and processes (refer to Appendix J for more details). Pending DOGGR permanent regulation and Senate Bill 887 are anticipated to be issued in the coming months which may impact operations. The consequences of the SoCal Gas incident led PG&E to update the impact scores of a loss of well integrity risk; however, has not changed PG&E's likelihood of risk.

The plan is developed with a 5-year planning horizon to align with the Gas Operations 5-year financial outlook and will be updated annually. It describes the physical assets included in this asset family, the current condition and desired future state of the assets, the key risks associated with the asset family, and the investments planned or in progress including continued research and development of new technologies to mitigate and reduce these risks. Beyond the physical assets, the plan considers the impact on support areas such as training and guidance documents.

This asset management plan is consistent with the Strategic Asset Management Plan, the guidance document for the development of asset management plans.

1.1 Asset Overview

PG&E owns and operates the following three underground gas storage fields:

1. McDonald Island – San Joaquin County
2. Los Medanos – Contra Costa County
3. Pleasant Creek – Yolo County

The Gas Storage asset management plan looks at the following assets within these underground gas storage fields:

Table 1 - Primary Gas Storage Assets

Physical Asset	Quantity
Storage Wells*	117
Transmission Pipe (miles)**	14
Downhole Safety Valves	89
Uphole Safety Valves	217
Well Meters	191
Storage Reservoirs (Acres)	3,404

* Includes 200 miles of casing and tubing
** Includes 2.5 miles in High Consequence Areas (HCAs)

PG&E also has a 25% interest in the Gill Ranch Storage Field; however this plan does not assess these assets, but directs PG&E to continue to work with Gill Ranch Storage Limited to operate, assess and maintain the assets utilizing a risk-based asset management approach. The DOGGR Emergency Regulations set criteria and require each Storage operator to develop and submit a Risk Management Plan. PG&E has been benchmarking with Gill Ranch on these efforts.

The transmission pipe and surface equipment (including wellhead measurement and flow controls) included in this asset family are managed utilizing the Transmission Integrity Management Program (TIMP) and Facility Integrity Management Program (FIMP) like those assets in the Transmission Pipe, Compression & Processing, and Measurement & Control asset families. Detailed information about these programs is included in the respective asset management plans.

1.2 Strategic Objectives

Gas Operations sets annual corporate Line of Sight (LoS) goals that cascade throughout the organization. Asset Family objectives are created using these LoS goals as a framework and developed both from a bottom-up and top-down approach. Alignment with LoS goals is presented in Section 4. After analyzing asset risk and condition within the LoS framework, a high-level Storage strategic objective is listed with more specific objectives related to different asset types as follows:

1. **Asset Management -** Effective and efficient asset management of gas storage facilities to identify the right work and to optimize the condition of our assets based on prioritization of risk.
    - Complete baseline well production casing assessments by 2025.
    - Evaluate Well Integrity Management Plan (WELL) enhancements and incorporate by 2017.
    - Assess work on transmission pipe through TIMP by 2017.
    - GPOM, FIMP, and Reservoir Engineering identify, prioritize, and develop a plan to complete open corrective work by 2017.
2. **Process Safety -** Ensure safe design, operations, maintenance, and execution of right work through the integration of process safety in the gas storage facilities.
    - Continue Process Hazard Analysis (PHA) and Pre-Startup Safety Reviews (PSSR) on all well, surface equipment, and pipeline in the storage asset family.

- Conduct annual emergency response drills which incorporate Well Control Tactical Considerations Plan in Gas Emergency Response Plan and participate in Gill Ranch emergency response drills by the end of 2017.

3. **Facility Performance -** Foster a culture of continuous improvement to optimize facility performance and risk reduction through design, operations, maintenance, and execution of the right work.
   - Gas Operations continue to evaluate proposed regulatory and legislative initiatives and its impact on facility performance and risk reduction mitigations.
4. **Capacity -** Meet system and customer storage capacity needs by optimizing short and long-term performance through the use of operational and maintenance procedures and workforce involvement.
   - Gas Operations continue to evaluate capacity requirements from storage to meet system needs and balancing risk reduction mitigations and reliable projects executed in 2017-2020.
   - Continue to conduct full field maximum flow tests annually and publish results.
   - Continue to conduct individual well flow tests annually and publish results.
5. **Compliance -** Satisfy commitments with regard to Integrity Management, Accounting and Environmental regulations by achieving no violations through auditing processes and procedures.
6. **Data -** Improve data quality, availability, and accessibility to enhance risk analyses and decision-making, moving from solely Subject Matter Expert input to more data informed.
   - Develop and implement Gas Storage Asset Management Systems (GSAMS) and Asset Health Scorecard (AHS) data to enhance risk analysis on well assets for 2019 Session D.
7. **Training** - Recruit, retain, and train a qualified and motivated workforce (employees and contractors) through identifying the needed training and developing line of progression for the operation and maintenance of the storage facilities.
   - Identify, analyze, and implement 5-year training/development profiles for Reservoir Engineering by 2016.
   - Review, revise, and develop operator training for storage well operations by 2018.

1.3 Asset and Data Condition

The current condition of Gas Storage assets has been qualitatively assessed by subject matter experts. One of the strategic goals is move toward more data informed assessment. A roadmap (Appendix K) has been developed to illustrate how data improvement programs and existing programs work towards utilizing more data informed decisions. Currently, data for this asset family is limited in terms of organization and accessibility to support quantitative analysis of asset condition and risk. Specific areas that have received focus include internal corrosion of the transmission pipe in the Storage asset family and internal/external corrosion of the storage well surface and production casing. Further, the ability to collect, organize, and monitor the impact on risk reduction and tracking metrics are part of the programs such as the Asset Health Scorecard (AHS) and Gas Storage Asset Management Systems (GSAMS). Enhancing data collection and accessibility is an area of focus in this plan to improve decision making going forward.

1.4 Key Risks

This asset management plan takes a risk-based approach to managing the asset to reduce risk. Proposed programs of work are risk scored with a process for prioritization across all asset families in an effort to implement programs that provide the greatest risk reduction

Gas Operations identifies risks for each asset family. For each threat (as defined in ANSI B31.8S), risk drivers and risks are identified for each asset family based on available data and SME input. The result of this process is a set of Gas Operations risks as shown in Figure 1. For this effort, risk is defined as the potential for an adverse event that can impact company's ability to achieve its objectives. Risk drivers are defined as factor(s) that could cause risk to occur. These risks are defined with a significant degree of granularity. From an asset family basis, risks are defined and discussed in the Asset Management Plans based on the risks defined here.

PG&E also defines risks at the enterprise level. The enterprise level assessment ensures that all lines of business have risks defined at a consistent basis for enterprise level decision-making. For the enterprise assessment, the Gas Operations risks are consolidated or rolled-up to provide a higher level of risk definition consistent with all PG&E lines of business. The development of the Gas Operations enterprise risks is performed by treating the Gas Operations risks as "risk drivers" to develop higher level enterprise risks. Therefore, the enterprise risks incorporate many of the "risk drivers" (or risks from the Gas Operations histogram).

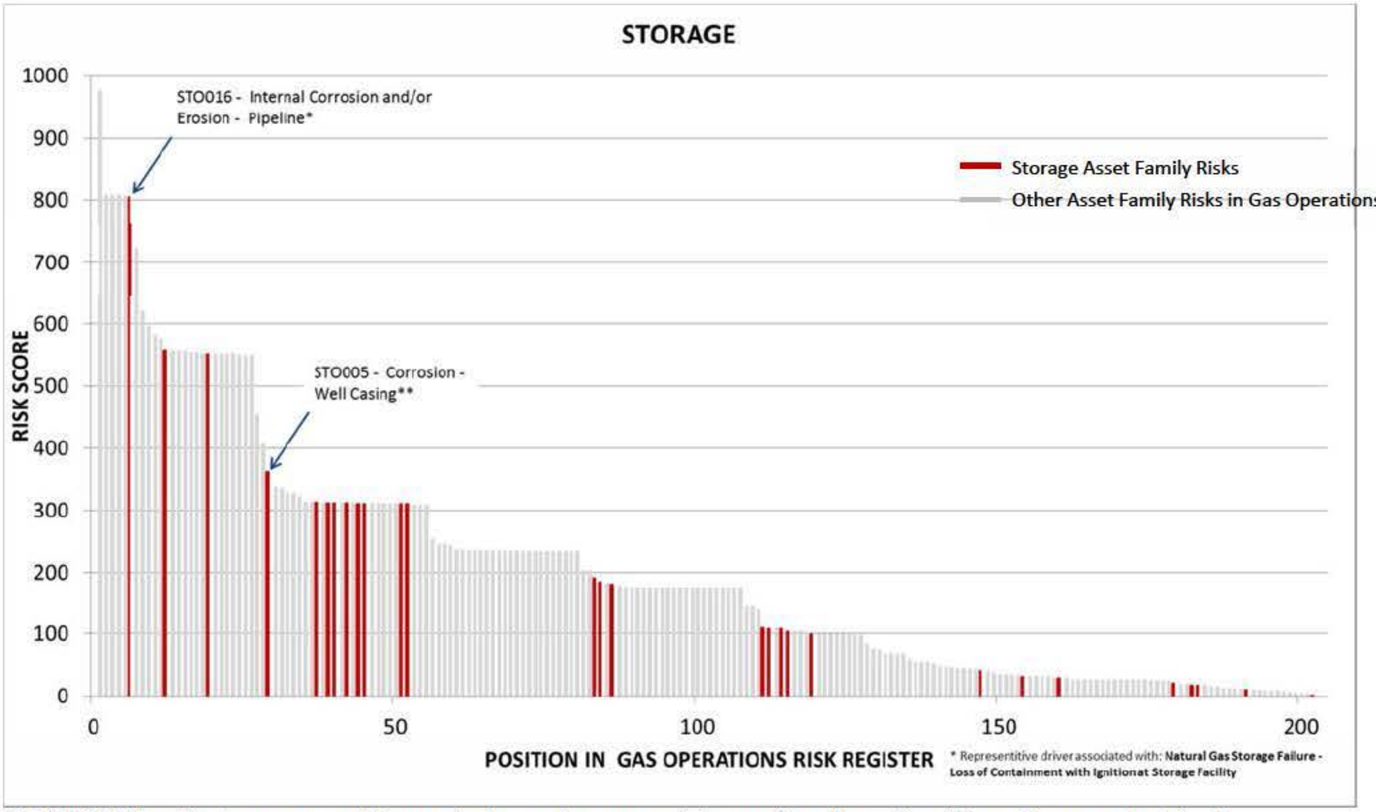
This asset management plan is based on the risks developed for Gas Operations. The enterprise risk and risk drivers for the Storage asset family are shown below:

Table 2 - Enterprise Risk for Storage Asset Family

Enterprise Risk	Risk Drivers
Natural Gas Storage Failure - Loss of Containment with Ignition at Storage Facility	STO016 – Internal Corrosion and/or Erosion – Pipeline
	STO017 – External Corrosion – Pipeline
	STO026 – Weather and Outside Forces – Seismic
	STO005 – Corrosion – Well Casing
	STO020 – Manufacturing – Pipeline
	STO015 – Erosion – Valves
	STO012 – Equipment – Meters
	STO018 – Fatigue – All Segments
	STO037 – Internal Corrosion and/or Erosion – Pressure Vessels
	STO030 – 1st, 2nd, 3rd Party Damage – All Segments
	STO003 – Construction by 1st & 2nd Party – Reservoir
	STO019 – Third Party Damage – Pipeline

The histogram below in Figure 1 displays the position of the Gas Storage asset family risks (red) within the Gas Operations risk register. Of the 204 Gas Operations Risks, the highest Storage risk (STO016) is ranked sixth.

Figure 1 - Gas Operations Risk Profile



** STO005 reflects rescored impacts based on new information from the Aliso Canyon incident.

The key identified Gas Storage risks, briefly described in Table 3, are derived based on a risk score that considers the likelihood and consequence of failure. The risks highlighted below are the highest among multiple threats that have been identified across the Gas Storage assets. The full extent of risks identified is addressed in detail in Appendix C.

1.5 High Level Program Overview

The asset management plan focuses on managing and reducing risk in the most efficient and effective manner possible. As the plan matures, focus on optimizing risks, performance and costs will continue to be strengthened. Proposed programs involve both capital and expense funding and in some cases address more than one area of risk. Detailed descriptions of the scope of each program are found in Section 4. The pace, trajectory, and scope for these proposed programs align with the submittals included in the Gas Transmission and Storage Rate Case.

The primary mitigations used to reduce risk are shown in Table 3 along with a metric to track progress.

Table 3 - Key Gas Storage Threats and Risks

Threat	Risk ID	Asset Type	Risk Description	Primary Mitigation	Mitigation Metric
Internal Corrosion and/or Erosion	STO016	Pipeline	Rupture of pipeline due to internal corrosion and/or erosion may result in loss of containment, and/or uncontrolled gas flow that may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.	Internal Corrosion Site Specific Plan	Development of site specific internal corrosion and erosion monitoring and assessment plans and Storage 10 Year Pipe Plan
External Corrosion	STO017	Pipeline	Rupture due to external corrosion of the pipeline which may result in the loss of pipeline isolation and access as well as an uncontrolled flow or lost production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Assessment Pressure Test	Leaks on pipeline due to external corrosion and development of Storage 10 Year Pipe Plan
Weather and Outside Forces (Seismic)	STO026	All Segments	Loss of withdrawal platform, buildings and equipment due to seismic activity/earthquake that may result in the loss of containment or ability to provide storage service. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage.	Pilot Seismic Assessment Program Condition Assessment Program	Progress of Pilot Seismic Assessment Program

Threat	Risk ID	Asset Type	Risk Description	Primary Mitigation	Mitigation Metric
Corrosion	STO005	Well Casing	Loss of well integrity due to well casing corrosion (internal, external, or stress corrosion cracking) that may result in an uncontrolled flow of gas outside of well casing with ignition source, drinking water contamination, gas migration, or gas loss. This may lead to major impact on public or employee safety, facility outage or net replacement of supply, property damage and/or environmental damage.	Casing Inspections	% of completed vs. planned well baseline assessments by 2025
Manufacturing	STO020	Pipeline	Rupture of pipeline due to manufacturing may result in loss of containment, and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Assessment Pressure Test	Development of Storage 10 Year Pipe Plan
Erosion	STO015	Valves	Erosion of valves may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Preventive Maintenance	Corrective vs. Preventive Maintenance
Equipment	STO012	Meters	Compromised measurement may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Preventive Maintenance	Corrective vs. Preventive Maintenance

Threat	Risk ID	Asset Type	Risk Description	Primary Mitigation	Mitigation Metric
Fatigue	STO018	All Segments	Failure of pipeline, equipment, and pipeline controls due to fatigue from internal pressure cycling or vibration may result in loss of containment. This may lead to significant impact on public or employee safety, outages, property damages and/or environmental damage.	Assessment Pressure Test	Development of Storage 10 Year Pipe Plan
Internal Corrosion and/or Erosion	STO037	Pressure Vessels	Through wall leaks in pressure vessels due to internal corrosion and/or erosion that may result in uncontrolled flow of gas. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or environmental damage.	Internal Corrosion Site Specific Plans	Development of site specific internal corrosion and erosion monitoring and assessment plans
1st, 2nd, 3rd Party Damage	STO030	All Segments	Rupture of belowground pipeline or uncontrolled flow from other storage assets due to 1st, 2nd, and 3rd Party damage caused by equipment/vehicles who may not have followed work procedures that may result in uncontrolled flow of gas, outages or replacement of gas supply. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or minor environmental damage.	Public Awareness & Damage Prevention	Dig-ins at Storage facilities

Threat	Risk ID	Asset Type	Risk Description	Primary Mitigation	Mitigation Metric
Construction by 1st & 2nd Party	STO003	Reservoir	Loss of reservoir integrity due to 1st and 2nd party drilling through storage field or reworking 1st and 2nd Party well that may result in an improper completion of the well or uncontrolled flow or loss containment with ignition source that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	PHAs conducted and PSSRs conducted
Third Party Damage	STO019	Pipeline	Rupture of pipeline due to mechanical damage by 3rd party may result in the loss of pipeline isolation and access as well as uncontrolled flow and loss in production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Public Awareness & Damage Prevention	Dig-ins at Storage facilities

2. Asset Inventory and Condition Overview

2.1 Asset Overview

The physical assets in the Storage asset family include all PG&E owned and operated underground gas storage fields and associated equipment installed system-wide. The different asset types that comprise the Storage asset family is listed in Table 4.

Table 4 - Asset Overview

Asset	Description
McDonald Island	- Storage Reservoirs - Storage Wells - Transmission Pipe - Surface Equipment
Los Medanos	
Pleasant Creek	
Gill Ranch	PG&E has a 25% interest stake and Gill Ranch Ltd owns the additional 75% and operates the field

The total design working gas capacity of the three PG&E-owned fields is 102 Bcf. They are designed for a maximum withdrawal capacity of 2,150 MMcf/D. The total design maximum injection capacity is 557 MMcf/D. The design maximum field pressure of the three fields ranges from 1,250 psig to 2,070 psig.

Assets within Gas Storage are grouped into four asset sub-categories:

1. Storage Reservoirs
2. Storage Wells
3. Transmission Pipe
4. Surface Equipment

A statistical summary of assets, broken down for each individual storage field can be seen in Table 5. This summary includes assets from other asset families in order to provide a complete view of the assets used by PG&E to provide storage services.

Regulations for the safety, construction, operations, and maintenance of the surface and pipeline up to the wellhead assets are under the jurisdiction of the California Public Utility Commission (CPUC). The reservoir and storage wells are under the California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR). Many other federal, state, and local agencies also have authority to regulate.

Table 5 - PG&E Storage Field Statistical Summary

Description of Statistic	McDonald Island (operated)	Los Medanos (operated)	Pleasant Creek (operated)	Gill Ranch (non-operated) [1]
Operator	PG&E	PG&E	PG&E	Gill Ranch
Location-County	San Joaquin	Contra Costa	Yolo	Madera/Fresno
Discovery Date	1936	1958	1948	1942/1957
Year Placed in Storage Service	1975	1973	1960	2010
Number of Injection and/or Withdrawal (I/W) Wells	81	21	7	12
Number of Observation Wells	7	1	-	7
Number of Salt Water Disposal (SWD) Wells	-	-	-	1
Compressor Units	5	1	1	5
Compression Horsepower (bhp)	12,256	3,733	749	45,000
Discovery Pressure-Wellhead (psig)	2,086	1,599	1,268	2,320 - 2,425
Discovery Pressure-Bottom Hole (psia)	2,365	1,774	1,367	2,610 - 2,777
Max Storage Pressure-Wellhead (psig)	2,070	1,600	1,250	3,179
Max Storage Pressure-Bottom Hole (psia)	2,365	1,774	1,353	3,655
Facility MAOP (psig)	2,160	1,800	1,300	3,150
Facility MOP (psig)	2,160	1,610	1,260	3,150
Cushion Gas (Bcf)	54.5	11.2	5.1	3.5
Working Gas (Bcf)	82	17.9	2.3	20
Total Inventory (Bcf)	136.5	29.1	7.4	23.5
Max Withdrawal (MMcf/d)	1,680	400	70	650
Max Injection (MMcf/d)	400	125	32	400
Reservoir Depth (feet)	5,200	4,100	2,800	5,700-6,300
Areal Extent (acres)	2,760	244	400	5,020
Number of Downhole Safety Valves (DHSV)	68	21	-	-
Number of Uphole Safety Valves (UHSV)	162	41	14	24
Miles of Production Casing / Production Liner/ Scab Liner	97.8	18.7	4.0	16.9
Miles of Production Tubing	90.5	17.5	4.2	14.7
Miles of Transmission Pipe in Storage Asset Family[2]	10	2	2	-
Miles of High Consequence Area (HCA) Transmission Pipe in Storage Asset Family[2]	2.5	-	-	-
Number of Well Meters	149	21	21	16

[1] Gill Ranch capacities listed are 100% of facility (PG&E owns 25%).
[2] Transmission pipe within the Storage asset family transport storage gas from storage wells, not production wells. Therefore there are no gathering lines within the Storage asset family.

A map of the four storage facilities is displayed in the figure below.

Figure 2 - Map of Gas Storage Asset Family

2.2 Asset Inventory and Condition

The availability of asset condition data varies across asset types within Gas Storage. An effort is underway to improve data collection and data accessibility via the Gas Storage Asset Management Systems (GSAMS) and the Asset Health Scorecard, which are discussed in further detail in Section 2. Section 4 contains details of programs and objectives that maintain and improve reservoir health. Asset inventory and condition is detailed by asset type in the following sections, including 2016 targets and 2015 results. A dashboard of condition from the Asset Health Scorecard with preliminary results can be found in Appendix H.

2.2.1 Storage Reservoirs

PG&E stores gas in storage reservoirs at McDonald Island, Los Medanos, and Pleasant Creek. Reservoir condition is assessed via percent gas migration, with an annual goal of 0% from the reservoirs ensuring that gas recorded as being in storage fields is confined to the storage reservoir (as shown in the table below).

Table 6 - Storage Reservoir Condition Data

Description	Gas Migration from Reservoirs
Assessment Method	Pressure Volume Hysteresis, Shut-In Testing
Frequency	Semi-Annually (Report issued annually in November)
2016 Target	0%
2015 Results	0%

Reservoirs are assessed using a combination of the storage well condition and operation data. The following assessments are used to determine the condition of storage well surface casing:

- **Well integrity:** Indicates if a storage well does not provide a conduit for gas loss or migration
- **Reservoir pressure, volume and fluid monitoring:** Provides an indication of gas loss, migration, and the influence operations have on the storage reservoir

2.2.2 Storage Wells

Storage well tubulars consist of production and surface casing on injection/withdraw and observation wells. PG&E operates 109 injection/withdrawal wells and 8 observation wells with wells having been in operation since 1936 through 2012. All 117 wells are equipped with steel casing. A list of storage fields and well-type are listed in Table 7.

Table 7 - Well Inventory by Storage Field

Field	Injection/Withdrawal Wells	Observation Wells
McDonald Island	81	7*
Los Medanos	21	1
Pleasant Creek	7	0
TOTAL	109	8

* 3 injection/withdrawal wells are planned to be converted to observation wells (refer to Section 2.2.3 for details)

Storage well condition is tracked by assessing the condition of surface casing and production casing. Surface casing is installed in each of the storage wells as a regulatory requirement to protect all freshwater zones. Storage well industry experience suggests the vintage of a well's tubulars should not be a factor in determining the well's integrity. The best in industry technology such as Magnetic Flux Leakage (MFL) tools, Ultrasonic Tools, Vertilog, or Casing Inspection Tools indicate that there is not a linkage between age and integrity.

Surface Casing

Surface casing is assessed using a combination of leak history and cement records. The following assessments are used to determine the condition of storage well surface casing:

- **Cement Records:** Indicate if a cement sheath is protecting the casing from external corrosion.
- **Production Casing Cementing:** Reduces threat of internal corrosion.
- **Annular pressure, volume and/or fluid monitoring:** Provides an indication of the surface casing condition. In 2016, PG&E began daily monitoring of the shut-in surface casing pressure.

An assessment of surface casing is in progress at this time and will be documented via an Asset Health Scorecard going forward. Current results for surface casing are listed in Table 8.

Table 8 - Storage Tubulars – Surface Casing Condition Data

Tubulars: Surface Casing Condition Data	
Description	Surface Casing Leak
Assessment Method	Pressure monitoring
Frequency	Daily
2016 Target	Tracking Only
2015 Results	0

Production Casing

Production casing is assessed for metal loss to determine condition. The following assessments are used to determine the condition of storage well production casing:

- **Noise & Temperature Logging:** Run annually on all wells to inspect for anomalies that may indicate wellbore tubular leak.
- **Magnetic Flux Leakage (MFL):** Used to evaluate casing for metal loss potentially related to internal corrosion, external corrosion, or cathodic protection. Approximately 6 - 8 rework wells are inspected using Vertilog annually.
- **Gamma Ray Neutron (GRN) Logs:** Identifies "gas behind pipe", or potential gas behind the well production casing and cement sheath. GRN was introduced in 2013 to set a baseline for wells at all storage fields.
- **Caliper Inspections:** Used to evaluate casing geometry and changes of internal diameter.
- **Ultrasonic Surveys:** Used to evaluate casing wall thickness which could be an indication of metal loss potentially related to internal corrosion, external corrosion, or cathodic protection.
- **Pressure tests:** Performed on approximately 6 - 8 wells during well reworks to ensure integrity of well.
- **Pressure, volume and fluid monitoring:** Provides an indication of the production casing condition.

Using these assessments, the targets and current conditions documented in Table 9 have been determined for PG&E storage field production casing.

Table 9 - Production Casing Condition Data

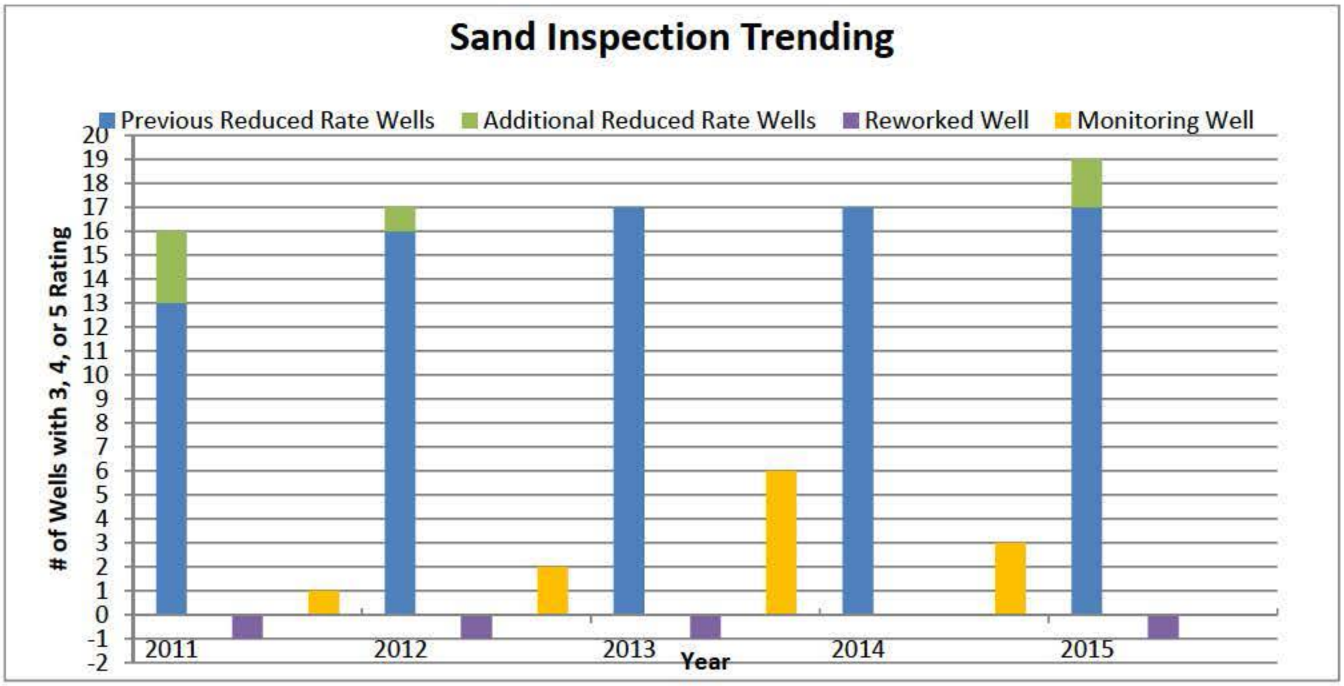
Production Casing Condition Data		
Description	Potential Casing Leak Path	Wall Thickness, Number of wells with Class 3 or greater apparent metal loss
Assessment Method	Noise & Temperature Logging	Magnetic Flux Leakage, Caliper, Ultrasonic
Frequency	Annually	Ranges from 1 to 15 years and risk based
2016 Target	0 wells	0 wells
Cumulative Results	2 wells – remediation not required	1 well – remediation not required

The noise and temperature logs have indicated potential anomalies on two wells (Los Medanos' Gino 3-7 and McDonald Island's WS-11W). The MFL indicated a Class 3 of greater apparent metal loss on one well (Los Medanos' 5B). All three wells do not currently require remediation; however, Reservoir Engineering will continue to monitor these wells and, if necessary, provide additional recommendations for evaluating the wells' integrity or remedial work.

Sand Inspections

When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further, the presence of sand is an indicator of a potential failure of the wells gravel pack and screen liner to prevent sand production. The sand inspections occur twice during the winter withdrawal period. If sand is detected, Reservoir Engineering will evaluate whether to reduce rate, shut-in a well, or re-gravel pack and install a new liner. The sand inspection trending for the last five years is shown in Figure 3 below. The figure shows the total number of wells with a 3, 4, or 5 sand production rating. The blue bar represents the number of wells with reduced rates prior to that particular year whereas the green bar shows the number of wells with rates reduced in that particular year. The purple bar represents the number of reworked wells due to sand production and lastly the orange bar shows wells which sand production that are continuing to be monitored.

Figure 3 - Sand Inspection Trending



2.2.3 Transmission Pipe

PG&E's gas storage fields include transmission pipe between the wells and compression and processing equipment. Within the three storage fields there are approximately 14 miles of transmission pipe, including 2.5 miles in High Consequence Areas (HCA). All 2.5 miles of HCA transmission pipe are located at McDonald Island.

This asset management plan provides a general condition assessment of the transmission pipe in the Gas Storage asset family. There is evidence that internal/external corrosion and erosion exists within the transmission pipe but a complete assessment is still in progress. Pipe within the Storage asset family has more potential for moisture and corrosive agents. There were indications of microbiologically induced corrosion (MIC) found during 2013 McDonald Island Whiskey Slough rebuild project with wall loss on the majority of pipe between wells and processing equipment. Site-specific Internal Metal Loss Action Plans (IMLAP) are currently being developed for all the storage fields and further detailed in Section 4. Results from 2014 and 2015 baseline investigations being used to develop the Site-specific plans show multiple indications of wall loss. As a result, several Ultrasonic Thickness (UT) probes have been installed and utilized to determine corrosion growth rate changes.

At McDonald Island a non-traditional in-line inspection (ILI) was performed on a segment of L57A-MD1 in August 2015. A significant number of anomalies and one dent were found. The affected portion is currently shut-in with a project in progress to permanently deactivate then retire the segment between valve V-11 and injection/withdrawal wells Tilden 1, Roberts 1, and Roberts 2. The three injection/withdrawal wells will then be converted to observation wells.

At Los Medanos, an external corrosion leak was found near well LM-18D in late 2015. Pipe coating was found to be disbonded on segments of pipe nearby. A project is in progress to replace the affected pipe.

Out of the 10 miles of Storage Asset Family pipe reviewed in the 2015 ILI Piggability Study, 6.5 miles are identified as potentially non-traditional ILI and 3.5 miles as not piggable.

2.2.4 Surface Equipment

Surface equipment includes but is not limited to safety and isolation valves, well flow measurement, and controls.

Most injection and withdrawal wells also have "downhole" safety valves (DHSV), installed approximately 250 feet below ground level. All injection and withdraw wells have safety valves installed "uphole" (UHSV) at the wellhead for the casing and tubing flow to provide emergency shutdown. The inventory of wells with DHSV and UHSV are shown in Table 10.

Table 10 - Number of Wells with DHSV and UHSV

Valve Type	Number of Wells
Downhole Safety Valves (DHSV)	89 (77% of wells)
Uphole Safety Valves (UHSV)	109 (94% wells)

Pressure tests have been conducted on all UHSVs and all DHSVs based on criteria established with the California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR) prior to the DOGGR Emergency Regulations effective on February 5, 2016. Based on tests in 2016, all safety valves were functional except valves on 5 wells that were either not functional or unavailable for testing. PG&E submitted a letter to DOGGR in May 2016 with a plan to replace the valves during the 2016 rework program. To mitigate nonfunctional valves, PG&E has a replacement program to replace 6 - 8 DHSVs annually as part of the well rework program. Beginning in 2015 a program has been developed to repair/replace UHSV of reworked wells and other non-functioning valves as identified. Safety valves are rated on the scales indicated in Table 11.

The previous year's DHSV and UHSV testing results and this year's targets are shown in Table 12. Trends from the past five years of safety valve testing can be seen in Figures 4 and 5.

The DHSV 5-year condition trend shows a decrease in wells with a "4" rating in 2015. The DHSV 5-year condition trend shows an increase in wells with a "4" rating in 2014. The increase in the number of wells having an increased rating was at McDonald Island Whiskey Slough Station. The potential reason for the increase is that the DHSVs were not exercised monthly due to the DHSV hydraulic control system being taken out of service for more than 9 months as a result of the Whiskey Slough production measurement and controls and piping system upgrade in 2013. Of note, the DHSV manufacturer recommends functionally exercising the DHSVs at a minimum once a month to keep the DHSVs working properly and reliably. Additionally, the Storage asset family is working with PG&E's Applied Technology Services (ATS) and the valve vendor to assess the DHSV design and improve valve performance.

The trending for UHSV with a "4" rating at McDonald Island is gradually increasing. Los Medanos trending has decreased over the five years; however, due to obsolescence, repairing valves is no longer an option. A program has been developed at Los Medanos to phase the replacement of the obsolete UHSVs and repair/replace McDonald Island nonfunctional UHSV. Pleasant Creek has remained flat at zero valves with a "4" rating following valve testing since all UHSVs were replaced in 2011.

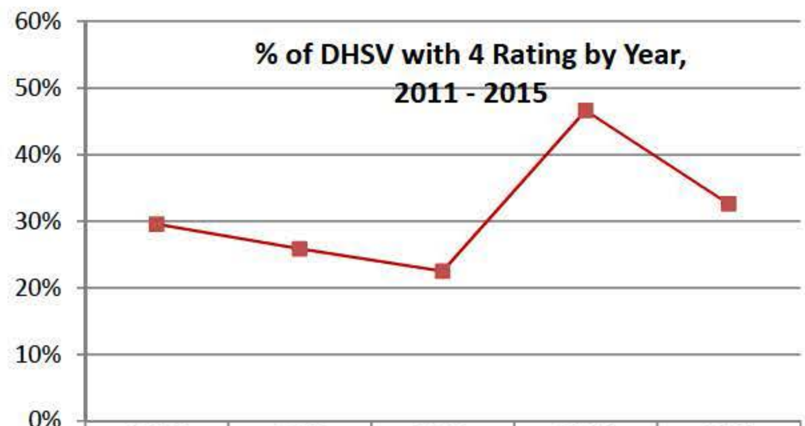
Table 11 - DHSV and UHSV Condition Key

Rating	Condition
0	No Leakage
1	1 - 100 psig
2	101 - 200 psig
3	201 - 300 psig
4	300 psig or higher

Table 12 - 2015 Year End DHSV and UHSV Condition Summary

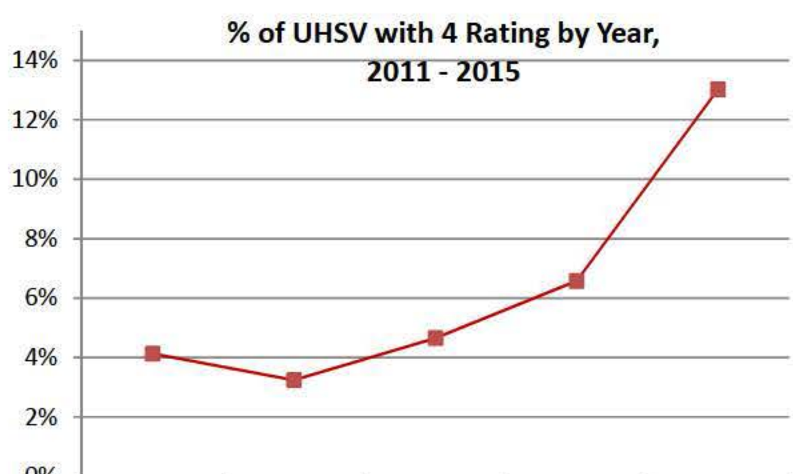
2015 Year-End Safety Valve Condition Results							
	DHSV			UHSV			
	MI	LM	Total	MI	LM	PC	Total
# Valves Available for Testing	68	21	89	160	41	14	215
4 Rating	21	8	29	25	3	0	28
% of Total	31%	38%	33%	16%	7%	0%	13%
# Replacing in 2016	4	2	6	8	8	0	16
2016 Target **(% of 4 Rating to Total # of Valves)**	25%	29%	26%	11%	0%	0%	6%

Figure 4 - DHSV 5-Year Condition Trend



	2011	2012	2013	2014	2015
Percentage of DHSV with 4 Rating	30%	26%	22%	47%	33%
Number of DHSV with 4 Rating	26	23	20	41	29

Figure 5 - UHSV 5-Year Condition Trend



	2011	2012	2013	2014	2015
Percentage of UHSV with 4 Rating	4%	3%	5%	7%	13%
Number of UHSV with 4 Rating	9	7	10	14	28

Further details of condition assessments of other surface equipment are contained within the Measurement & Control and Compression & Processing Asset Management Plans. *Please refer to documents GP-1104: Measurement & Control Asset Management Plan and GP-1105: Compression & Processing Asset Management Plans for more details.*

2.2.5 Leak Survey

In response to the CPUC's January 2016, directive to California owners and operators of underground gas storage facilities, PG&E performed a leak survey and submitted a report with the number of leaks repaired and the number of leaks scheduled for repair at McDonald Island, Los Medanos, and Pleasant Creek summarized in the tables below. PG&E will provide an additional update(s) to the CPUC when these repairs are completed. Of note, PG&E is continuing to conduct daily inspections and leak surveys on the wellheads for the three storage fields owned and operated by PG&E.

Leaks were identified during condition baseline assessments (performed January 15-21, 2016), daily inspections (performed January 22-26, 2016), and the SED Directive Leak Survey (performed January 26- February 1, 2016). All identified leaks were located on fittings, valves, or flanges. No leaks were identified on well production casings or the transmission pipe body and were also not located in close proximity to any buildings intended for human occupancy or found migrating to a confined space.

Table 13 - 2016 Leak Survey Results

Leak Survey Results	PG&E Underground Storage Facilities			Total
	Los Medanos	Pleasant Creek	McDonald Island	
Leaks Identified	23	29	32	84
Storage Well Production Casing Leaks	0	0	0	0
Above Ground - Wellhead Equipment	6	4	8	18
Above Ground - Other	17	25	23	65
Below Ground	0	0	1	1

Leak Repair/Mitigation	PG&E Underground Storage Facilities			Total
	Los Medanos	Pleasant Creek	McDonald Island	
Repaired/Mitigated Leaks	23	28	26	77
Above Ground - Wellhead Equipment	6	4	3	13
Above Ground - Other	17	24	22	63
Below Ground	0	0	1	1
Pending Repair/Mitigation	0	1	6	7
Above Ground - Wellhead Equipment	0	0	5	5
Above Ground - Other	0	1	1	2
Below Ground	0	0	0	0

Of the seven reported leaks pending repair as of June 2016, they are isolated and scheduled for repairs with vendor support in 2016. One leak at McDonald Island is on an observation well, so Reservoir Engineering is currently evaluating it for a potential rework.

On June 16, 2016, a PG&E employee identified gas bubbling in a well cellar. PG&E quickly took action and isolated the well to ensure safe operations of the McDonald Island Storage Facility. In the subsequent days, PG&E observed gas bubbling in additional well cellars. There is no public safety, health, environmental or reliability risk. PG&E is utilizing a number of new techniques and technologies to monitor the leak and identify its source. PG&E experts and engineers have been working with DOGGR and industry experts to determine what's causing the minor leaks. PG&E has created a repair plan to address what is found and has shared that with DOGGR. As soon as the leak source is confirmed, PG&E will initiate the final stages of the repair plan and continue outreach to local, state and federal regulators.

2.2.6 Data

Data for the storage wells and reservoirs is currently maintained and stored either as a hardcopy (Well File) or a scanned version in the Reservoir Engineering Department's shared drive. Data includes spot temperature, pressure, rate readings collected during inspections and testing, well logs, well files that contain the physical characteristics of the storage well, wellhead, permits, and operational histories. A summary of the data source, availability and quality of asset data is summarized in Table 14. This asset data can be used in developing performance indicators and desired metrics for tracking performance in managing threats.

Currently available asset data falls into three categories, 1) equipment type and installation records, 2) maintenance and condition data and 3) operating and performance information. Data quality is evaluated on the following scale:

- **Good** – Meets most data availability and quality requirements. Nearly all data available, some data quality issues, but minimal impact on data reliability for asset management purposes
- **Fair** – Meets some data availability and quality requirements. Some data missing, known data quality issues, but available data is valuable for asset management purposes
- **Poor** – Meets few, if any, data availability and quality requirements. Significant amounts of data missing or data quality is too problematic to be useful for asset management purposes
- **N/A** – Not available at present

Table 14 - Data Summary

Data Sources	Availability and Quality	Comments
Equipment Type & Installation		
• Site specific documentation (record drawings, field photographs, job files, well files)	Good	• Well Shared Drive specific documentation varies by storage field • Reservoir Shared Drive specific documentation varies by storage field
Maintenance and Condition		
• Computer based maintenance management – PLM transitioning to SAP • Results, trends from predictive tests, inspections, investigations, and analyses • Station log books • Well Files (inspection data, casing inspection logs, etc.)	Fair	• Maintenance records documented in PLM / SAP, corrective maintenance data is limited and difficult to extract • Documents are partially centrally maintained and there is no index to aid in finding a report • Results or trends from predictive tests, inspections, investigation and analysis

Data Sources	Availability and Quality	Comments
Operating and Performance		
• Process Hazard Analyses (PHAs) • SCADA • Unit and station PLCs • Data historians • Event tracking databases (Overpressure Event Report, CAP) • Project tracking – PSRS • Well Files (pressure/volume monitoring data)	Fair	• Not all well flowrates/pressures available via SCADA • Paper and Shared Drive data is consolidated into spreadsheets. Gas Storage Database (GSDB) resulted in digitized and centralized records. • Assigned facility and reservoir engineers tracking asset condition & performance issues

While the accessibility of the data varies by type and source, the data sources listed in the table are adequate to support threat assessment and trending and reporting of the metrics for Storage assets.

The transmission pipe, wellhead measurement, auxiliary equipment, and flow controls included in this asset family are assessed primarily by the Transmission and Facility Integrity Management teams. An objective of this plan is to utilize the framework of these teams to assess the data sources' condition and move toward more data informed assessment. A roadmap (Appendix K) has been developed to illustrate how data improvement programs and existing programs work towards utilizing more data informed decisions. Further details on pipe and surface equipment data availability and quality can be found in the Transmission Pipe, Measurement & Control, and Compression & Processing Asset Management Plans.

Currently, data for this asset family is limited in terms of organization and accessibility to support quantitative analysis of asset condition and risk. Specific areas of data that have received focus over the past year include internal corrosion of the transmission pipe in the Storage asset family and internal/external corrosion of the storage well surface and production casing. Further, the ability to collect, organize, and monitor the impact on risk reduction and tracking metrics, are part of the programs such as the Asset Health Scorecard (AHS) and Gas Storage Asset Management Systems (GSAMS). Enhancing data collection and accessibility is an area of focus in this plan to improve decision making going forward.

3. Threats and Risks

Risks are tracked in an enterprise-wide risk register, a central repository where risk names, descriptions and scores as determined by utilization of Enterprise and Operational Risk Management's (EORM) risk criteria along with other pertinent information are documented. The risk register is updated and refined as additional information is obtained and evaluated.

The risk management framework is fully integrated into PG&E's Integrated Planning Process (IPP). This framework complements risk assessment processes already in place via integrity management programs. Additional information about the Integrated Planning process can be found in the Strategic Asset Management Plan, GP-1100.

3.1 Threat and Risk Identification

The Asset Family Owners (AFOs) work with their teams to identify the threats to the assets in their families. The AFO relies on American Society of Mechanical Engineers (ASME) Standard B31.8S and 49 Code of Federal Regulations (CFR) Part 192, Subpart O as the basis for categorizing and evaluating the threats, as seen in Table 15. In addition, the Storage Asset Family Owner has included threats as identified in American Petroleum Institute's Recommended Practice 1171.

Table 15 - Storage Threat Categories

Threat Category	Description	Specific Threats
Time-dependent	Potentially increase over time	• External Corrosion • Internal Corrosion • Stress Corrosion Cracking
Stable or "Resident"	Present, or potentially inherent in the pipeline, but do not grow over time or pose a threat unless influenced by another condition or failure mechanism	• Manufacturing • Construction/Fabrication • Equipment threats
Time-Independent	Not influenced by time	• Third Party Damage • Incorrect Operation • Weather and Outside Forces

In addition to these threat categories, PG&E recognizes risks related to its obligation to serve, both in terms of ensuring reliable delivery of natural gas and increasing capacity to meet demand, as well as risks posed by an inadequate response to and recovery from emergencies.

Threats are identified through available data sources including the Corrective Action Program (CAP), Process Hazard Analyses (PHAs), Pre-Startup Safety Reviews (PSSRs), various on-going maintenance, and assessment programs. Each AFO works with his/her team and other Subject Matter Experts (SMEs) to determine the relative risk, including impact and frequency levels, associated with each threat. Gas Storage risks are calibrated across both Gas Operations and enterprise-wide.

3.1.1 Primary Threats and Mitigations

The threat matrix in Appendix B lists the primary threats that are deemed applicable to the Gas Storage asset family. The discussion below highlights the key reason for the threat and primary mitigation measures. These threats guide the identification of the risks contained in the Storage Risk Register.

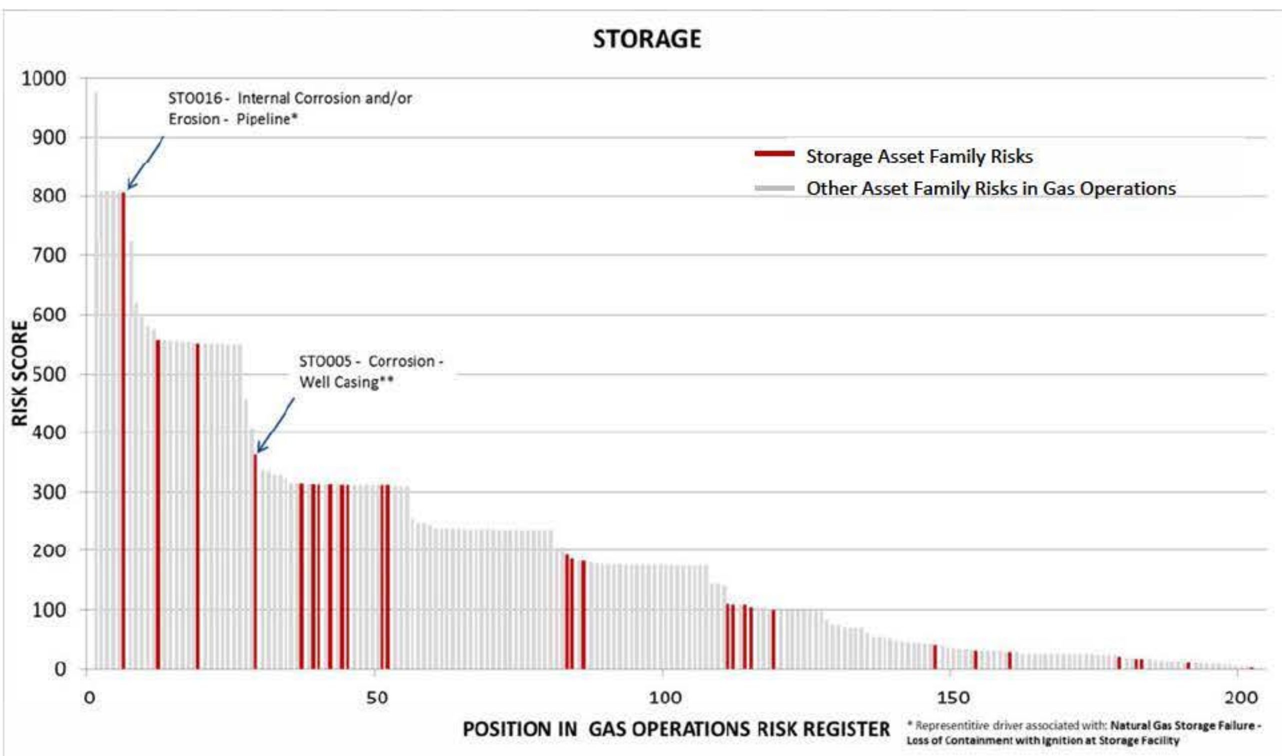
3.1.2 Key Gas Storage Risks

Using the identified threats from the threat matrix, risks have been identified and annually updated for the storage asset family, and prioritized for both Gas Operations (addressing risks across asset families) and within the asset family (as part of the risk and compliance process).

The Storage asset family identified 36 risks in 2016. Of the 36 Storage asset family risks, one risk was introduced in 2016 related to internal corrosion and/or erosion of pressure vessels (STO037). Two Storage risks were retired including the records management risk (STO032) and the employee qualifications risk (STO036) since they're both covered by cross-cutting Gas Operations risks. Two risks were rescored due to new information including increasing impact scores for the corrosion of well casing risk (STO005) based on SoCal Gas' Aliso Canyon well leak incident and increasing the frequency score for the external corrosion of pipeline risk (STO017) based on recent evidence of external corrosion at Los Medanos. The highest Storage risk (STO016) ranked sixth among the 204 risks in Gas Operations.

Below is a histogram that displays the position of the Storage asset family risks within the Gas Operations risk register.

Figure 6 - Gas Operations Risk Profile



** STO005 reflects rescored impacts based on new information from the Aliso Canyon incident.

The key risks for the storage asset family are detailed in the table below.

Table 16 - Key Gas Storage Risks

Risk ID	Asset Type	Threat	Risk Description
STO016	Pipeline	Internal Corrosion and/or Erosion	Rupture of pipeline due to internal corrosion and/or erosion may result in loss of containment, and/or uncontrolled gas flow that may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.
STO017	Pipeline	External Corrosion	Rupture due to external corrosion of the pipeline which may result in the loss of pipeline isolation and access as well as an uncontrolled flow or lost production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.
STO026	All Segments	Weather and Outside Forces (Seismic)	Loss of withdrawal platform, buildings and equipment due to seismic activity/earthquake that may result in the loss of containment or ability to provide storage service. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage.
STO005	Well Casing	Corrosion	Loss of well integrity due to well casing corrosion (internal, external, or stress corrosion cracking) that may result in an uncontrolled flow of gas outside of well casing with ignition source, drinking water contamination, gas migration, or gas loss. This may lead to major impact on public or employee safety, facility outage or net replacement of supply, property damage and/or environmental damage.
STO020	Pipeline	Manufacturing	Rupture of pipeline due to manufacturing may result in loss of containment, and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.
STO015	Valves	Erosion	Erosion of valves may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.
STO012	Meters	Equipment	Compromised measurement may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.
STO018	All Segments	Fatigue	Failure of pipeline, equipment, and pipeline controls due to fatigue from internal pressure cycling or vibration may result in loss of containment. This may lead to significant impact on public or employee safety, outages, property damages and/or environmental damage.

Risk ID	Asset Type	Threat	Risk Description
STO037	Pressure Vessels	Internal Corrosion and/or Erosion	Through wall leaks in pressure vessels due to internal corrosion and/or erosion that may result in uncontrolled flow of gas. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or environmental damage.
STO030	All Segments	1st, 2nd, 3rd Party Damage	Rupture of belowground pipeline or uncontrolled flow from other storage assets due to 1st, 2nd, and 3rd Party damage caused by equipment/vehicles who may not have followed work procedures that may result in uncontrolled flow of gas, outages or replacement of gas supply. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or minor environmental damage.
STO003	Reservoir	Construction by 1st & 2nd Party	Loss of reservoir integrity due to 1st and 2nd party drilling through storage field or reworking 1st and 2nd Party well that may result in an improper completion of the well or uncontrolled flow or loss containment with ignition source that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.
STO019	Pipeline	Third Party Damage	Rupture of pipeline due to mechanical damage by 3rd party may result in the loss of pipeline isolation and access as well as uncontrolled flow and loss in production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.

**For all Storage risks see Appendix C

3.2 Integrity Management Programs

In addition to the EORM process to identify scenario based risks, some asset families leverage information from related integrity management programs to identify asset level risks.

Based on the components in the storage asset family, the following integrity management programs apply:

Well Integrity Management Program (WELL)
This program is used to assess the risk related to the storage wells and recommend actions to prevent or mitigate these risks. While the WELL risk management process contains elements that overlap with risk assessment processes within the risk register, it is a separate process that considers threats to individual wells. The risk process for this program gathers, reviews, and integrates data to prioritize preventive and mitigative measures, and monitor for operational changes that may require additional actions.

PG&E's storage wells are constructed and operated according to the regulations of California's Division of Oil, Gas, and Geothermal Resources (DOGGR) that were in effect at the time the storage wells were constructed. These regulations require storage wells to demonstrate integrity and can be considered as a lagging indicator. The program includes both leading and lagging indicators. The leading indicators are designed to assess the condition and take preventive steps prior to failure. The lagging indicators are designed to identify potential failure and steps to mitigate the failure. WELL draws on industry best practices given the absence of industry standards on the functional integrity of natural gas wells and fields. In 2012, the industry recognized that this gap existed. Through the efforts of storage operators and regulators, American Petroleum Institute (API) agreed to establish a task team to develop API Recommended Practice 1171 that addresses the functional integrity of natural gas storage wells and fields. A current PG&E employee participated on the API task team. This guidance document was published in 2015. On February 5, 2016 DOGGR implemented Emergency Regulations to develop and submit a Risk Management Plan by August 5, 2016. One of the 2015 Storage Asset Management Plan’s strategic objectives was to conduct an analysis of API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs in 2016 to identify enhancements to its current operating practices. PG&E is currently conducting the analysis and enhancing a well integrity management plan prior to the effective date of the DOGGR Emergency Regulations.

While WELL focuses on storage reservoirs and wells, other storage assets such as transmission pipe and surface equipment fall under other integrity management programs as described below.

Transmission Integrity Management Program (TIMP)
The transmission pipe in this asset family is assessed primarily by the Transmission Integrity Management Program (TIMP). The TIMP program is a mature, well-defined program for assessing the risk related to different segments of pipe on the system and taking action to prevent or mitigate these risks. The approach for assessing risk is based on an assessment of likelihood and consequence of a leak or rupture, and uses the nine threats listed in the threat matrix to identify high-risk segments. While the TIMP risk management process contains many elements that overlap with risk assessment processes within the risk register, it is a separate process that considers threats to individual segments of pipe as opposed to the system as a whole.

Facility Integrity Management Program (FIMP)
One of the strategic objectives is to apply Facility Integrity Management principles to all transmission and distribution stations by 2025. PG&E’s goal is to develop a world-class facility integrity management program. This task consists of preparing the roadmap and FIMP plan to guide the development and implementation of various program elements. This task includes working with PG&E stakeholders to prepare and review the plan and to define implementation actions. The FIMP plan will be prepared to address the following issues as well as recommendations from the station condition assessment program. The plan will focus on the integration of current activities along with newly identified actions.

1. Data gathering (including storage and retrieval)
2. Threat identification and consequences
3. Risk assessment and prioritization
4. Integrity-related activities (including the specification of maintenance and inspection activities to address compliance and reliability needs)
5. Response actions for inspection and maintenance findings
6. FIMP performance management
7. Reporting and communication of FIMP issues

8. Facility change management (how to address changes to facilities so that appropriate asset management information is updated and tracked)
9. Quality control requirements to ensure FIMP requirements are being met and lessons learned are incorporated into the program
10. Design-related activities to ensure that FIMP requirements are included in design of facilities

The Compression & Processing Asset Management plan will become a part of the FIMP. This plan will also apply to the Storage Asset Family surface equipment. *Please refer to document GP-1105: Compression & Processing Asset Management Plan for more details.*

4. Desired State, Strategic Objectives, Programs and Risk Mitigations

The Storage asset family's strategic objectives are developed to optimize asset life cycle by maintaining and improving asset condition and adequately mitigating risks and threats. These strategic objectives, which support Gas Operation's Line of Sight (LoS) goals, have been established to align investment in the asset family with the Asset Management Strategy, reduce risks and ultimately realize PG&E's corporate vision.

Using these inputs, a long-term plan has been defined to meet Storage Asset Management and corporate objectives. An underlying assumption in the development of these strategic objectives is current regulations remain static. For example, currently proposed regulation changes following SoCal Gas' Aliso Canyon well incident and proposed regulation for air quality (e.g. methane emission reduction) will potentially impact operations and investments of the storage asset family's wells and surface equipment.

Three key programs, including WELL, TIMP, and FIMP, lay out the long-term vision for the Storage asset family. The desired state for Storage well assets is carried out by the development and implementation of a robust Well Integrity Management Program (WELL). The WELL defines the long-term desired state for the condition and the management of the Storage well assets. For Storage pipe assets, Transmission Integrity Management Program (TIMP) is developing a long-term strategy to hydrotest, assess, or replace the Storage asset family's 10 miles of transmission pipe. As for Storage surface equipment assets, a robust Facility Integrity Management Program (FIMP) which is still under development will define the desired state for asset condition and management.

Also, research and development efforts will enhance the desired state of safer and more reliable gas storage assets. Completed and pending projects can improve well and pipe integrity assessments and methane emissions detection. The outcomes from these projects can have long-term benefits which improve integrity management through WELL, TIMP, and FIMP. Please refer to Appendix I for more details.

4.1 Strategic Objectives, Programs and Mitigations Alignment

The Storage strategic asset objectives and associated metrics as they correspond to Gas Operations' LoS goals are detailed in the table below. A high-level strategic objective is listed with more specific objectives related to different asset types.

Table 17 - Storage Strategic Objectives

Gas Operations LoS Goals	Strategic Objective	Metric
Safe	**Asset Management** - Effective and efficient asset management of gas storage facilities to identify the right work and to optimize the condition of our assets based on prioritization of risk. • Complete baseline well production casing assessments by 2025. • Evaluate Well Integrity Management Plan (WELL) enhancements and incorporate by 2017. • Assess work on transmission pipe through TIMP by 2017. • GPOM, FIMP, and Reservoir Engineering identify, prioritize, and develop a plan to complete open corrective work by 2017.	• % Complete • % Complete • % Complete • % Complete
Safe	**Process Safety** - Ensure safe design, operations, maintenance, and execution of right work through the integration of process safety in the gas storage facilities. • Continue Process Hazard Analysis (PHA) and Pre-Startup Safety Reviews (PSSR) on all well, surface equipment, and pipeline in the storage asset family. • Conduct annual emergency response drills which incorporate Well Control Tactical Considerations Plan in Gas Emergency Response Plan and participate in Gill Ranch emergency response drills by the end of 2017.	• # of PHA and # of PSSR • Annual drill complete
Affordable	**Facility Performance** - Foster a culture of continuous improvement to optimize facility performance and risk reduction through design, operations, maintenance, and execution of the right work. • Gas Operations continue to evaluate proposed regulatory and legislative initiatives and its impact on facility performance and risk reduction mitigations.	• % Complete
Reliable / Customer	**Capacity** - Meet system and customer storage capacity needs by optimizing short and long-term performance through the use of management of change, operational and maintenance procedures, and workforce involvement. • Gas Operations continue to evaluate capacity requirements from storage to meet system needs and balancing risk reduction mitigations and reliable projects executed in 2017-2020. • Continue to conduct full field maximum flow tests annually and publish results. • Continue to conduct individual well flow tests annually and publish results.	• % Complete • % Complete • % Complete

Gas Operations LoS Goals	Strategic Objective	Metric
Compliance	**Compliance** - Satisfy commitments with regard to Integrity Management, Accounting and Environmental regulations by achieving no violations through auditing processes and procedures.	• # of Notice of Violations (NOVs)
Safe	**Data** - Improve data quality, availability, and accessibility to enhance risk analyses and decision-making, moving from solely Subject Matter Expert input to more data informed. • Develop and implement Gas Storage Asset Management Systems (GSAMS) and Asset Health Scorecard (AHS) data to enhance risk analysis on well assets for 2019 Session D.	• % Complete
Safe / People	**Training** - Recruit, retain, and train a qualified and motivated workforce (employees and contractors) through identifying the needed training and developing line of progression for the operation and maintenance of the storage facilities. • Identify, analyze, and implement 5-year training/development profiles for Reservoir Engineering by 2016. • Review, revise, and develop operator training for storage well operations by 2018.	• % Complete • % Complete

PG&E has developed the following programs to meet these strategic objectives, using the aforementioned risk-based investment strategy to address both enterprise and asset level risks, meet compliance requirements and maintain asset condition. An overview of the storage multi-year plan, or roadmap, can be seen below in its entirety in Appendix K. Detailed program plans and timeframes follow in Section 4.2.

The programs and mitigations related to the Storage asset family are shown in Table 18 along with linkage to the strategic objectives identified in Table 17. The timeframes for the following programs and mitigations are based on the proposed rate case targets as of the publish date of this Asset Management Plan and detailed in Tables 19 through 22.

Table 18 - Programs, Mitigations, and Strategic Objectives

Programs & Mitigations	Asset Family Strategic Objectives						
	Asset Management	Process Safety	Facility Performance	Capacity	Compliance	Data	Training
WELL – Integrity Assessments	X	X	X	X	X	X	
WELL – Remediation and Conditioning	X	X	X	X	X		

Programs & Mitigations	Asset Family Strategic Objectives						
	Asset Management	Process Safety	Facility Performance	Capacity	Compliance	Data	Training
WELL – Controls and Continuous Monitoring	X	X	X	X	X	X	
WELL – Repair and Replace	X	X	X	X	X		
WELL – Other	X	X	X	X		X	
Asset Health Scorecard	X	X	X			X	
Gas Storage Asset Management Systems (GSAMS) and Gas Storage Database (GSDB)	X	X				X	
Asset Management Backbone and Stations (AMBBS)	X	X	X			X	
Internal Metal Loss Action Plans (IMLAP)	X	X	X		X	X	
Corrosion Control	X	X	X		X	X	
Patrolling / Continuing Surveillance	X	X	X		X		
In-Line Inspection (ILI)	X	X	X		X	X	
Direct Assessment (DA)	X	X	X		X	X	
Pressure Test	X	X	X		X	X	
Leak Survey & Repair	X	X	X		X	X	
Public Awareness / Damage Prevention	X	X	X		X		
Vintage Pipe Replacement	X	X	X				
Locate & Mark	X	X	X		X		
Shallow Pipe Program	X	X	X		X		
Cathodic Protection	X	X	X		X	X	
Atmospheric Corrosion Inspection Program	X	X	X		X	X	
Supervisory Control and Data Acquisition (SCADA) / Network Visibility	X	X	X		X	X	

Programs & Mitigations	Asset Family Strategic Objectives						
	Asset Management	Process Safety	Facility Performance	Capacity	Compliance	Data	Training
Fault Crossing	X	X	X				
Geotechnical Hazard Monitoring	X	X	X				
Water & Levee Crossing	X	X	X		X		
Engineering Critical Assessment (ECA) Phase 1	X	X	X		X	X	
Engineering Critical Assessment (ECA) Phase 2	X	X	X		X	X	
Hydrostatic Testing Station Facilities	X	X	X		X		
Critical Documents	X	X	X		X	X	
Physical Security	X	X	X				
Routine Expense and Routine Capital Spend	X	X	X				
Emergency Shutdown (ESD) System Upgrades	X	X	X		X		
Install Active Fire Suppression Systems	X	X	X		X		
Hard to Turn Valve Replacement Program	X	X	X		X		
Preventive Maintenance	X	X	X		X		
Guidance Documents	X	X	X		X	X	X
Cyber Security Measures	X	X	X			X	
Station Design Standardization	X	X	X			X	X
Training	X	X	X		X	X	X
External Corrosion Control	X	X	X		X	X	
Process Safety	X	X	X		X		X
Emergency Response	X	X			X		X
Research Projects	X	X	X	X	X	X	

4.2 Programs and Mitigations Overview

Table 19 - Program Summary - Storage Reservoirs & Wells

Program:	WELL – Integrity Assessments
Scope: This includes storage well survey and data logging to assess and inspect well casing pipe integrity for all 117 wells by 2025. Well integrity inspections may include Temperature and Noise surveys, Magnetic Flux Leakage (MFL), Gamma Ray/Neutron logs, Cement Bond Logging (CBL), Ultrasonic Surveys, and caliper inspections.	
Desired State:	Assess and inspect well casing pipe integrity.
Risks Addressed:	STO005, STO005.1, STO011
Timeframe:	Baseline from 2013 – 2025; Reevaluations on-going beyond 2026
Responsibilities:	Reservoir Engineering
Program:	WELL – Remediation and Conditioning
Scope: This includes: 1) assessment of the storage wells' condition, and additional remedial work for mitigating any potential risks/threats. Of note, the existing Downhole Safety Valves (DHSVs) in wells have to be pulled in order for the well casing pipe to be inspected and remedial work and new DHSVs are to be installed.; 2) Replacement of DHSVs in wells that are identified as not functionally holding pressure or the leak rate being above the API standards based on the annual test results; and 3) if necessary, installation of gravel pack to restore well deliverability due to natural degradation from cyclical injection and withdrawal operations and fouling of the gravel pack.	
Desired State:	Replace downhole safety valves which are unable to isolate storage gas and restore well deliverability.
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO015, STO016, STO016.1
Timeframe:	On-going
Responsibilities:	Reservoir Engineering
Program:	WELL – Controls and Continuous Monitoring
Scope: This includes the projects that are to install 1) transducers at the well heads to remotely and continuously monitor the pressures in the well surface casing annuli (SCA) and tubing and casing annulus (TCA); 2) flow measurements in the injection flow stream (McDonald Island only), and 3) replacement of obsolete or outdated field well flow controls to prevent overflowing of the wells to minimize sand production.	
Desired State:	Enhance monitoring and protect wells from overflowing.
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO015, STO016, STO016.1
Timeframe:	2016 – 2018
Responsibilities:	Reservoir Engineering, Operations & Maintenance, Facility Integrity Management Program
Program:	WELL – Repair and Replace
Scope: This program includes Uphole Safety Valve (UHSV) replacements, pipeline replacements, and sand inspection valve replacements.	
Desired State:	Replace pipeline due to corrosion. Repair safety valves and sand inspection valves to improve reliability
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO015, STO016, STO016.1, STO017, STO17.1, STO031, STO031.1
Timeframe:	On-going
Responsibilities:	Reservoir Engineering, Operations & Maintenance, Facility Integrity Management Program
Program:	WELL – Other
Scope: This includes engineering support and data analysis software.	
Desired State:	Improve analytical capabilities

Risks Addressed:	STO005, STO005.1
Timeframe:	On-going
Responsibilities:	Reservoir Engineering
Program:	Asset Health Scorecard (AHS)
Scope: The Asset Health Scorecard will summarize the physical and operational condition of assets based on health properties identified and developed by the Storage asset family. These scorecards enable fact based decisions making for long term investment planning and emergent work. Scorecard output can provide high level analysis for asset management planning. The asset health scorecard timeline for the Storage asset family is as follows: • <u>Developed</u> asset health scoring business process requirements (2014) • <u>Implement</u> asset health scoring process (2015) • <u>Automate</u> asset health scoring process (2015 - 2017)	
Desired State:	Condition data is collected and analyzed with scoring methodology.
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO014, STO015, STO016, STO016.1
Timeframe:	2014-2018
Responsibilities:	Business Technology, Reservoir Engineering
Program:	Gas Storage Asset Management Systems (GSAMS) and Gas Storage Database (GSDB)
Scope: Reservoir Engineering and Records & Information Management (RIM) have identified the need to consolidate and secure the paper and electronic records for the reservoirs and 117 storage wells. The scope of the project includes: • Consolidation of records • Determination of the applicable systems (PLM, SAP, Documentum, etc.) to be used • Development of processes to access and track the condition/health of the storage well assets with the data.	
Desired State:	Records are consolidated in centralized repository and system of record.
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO014, STO015, STO016, STO016.1
Timeframe:	2014-2019
Responsibilities:	Business Technology, Reservoir Engineering
Program:	Asset Management Backbone & Stations (AMBBS)
Scope: Migrate the Backbone, Stations, and Storage asset information from multiple systems and platforms into SAP, as a single system of record. By employing emerging mobile technologies, the project will be enhancing management of Transmission preventive and corrective maintenance, enabling mobile device to capture maintenance information, and provide greatly enhanced access and retrieval of storage asset information.	
Desired State:	Ensure one source of asset and maintenance related data and for use in ongoing health determination.
Risks Addressed:	STO005, STO005.1, STO011, STO012, STO014, STO015, STO016, STO016.1
Timeframe:	2015-2019
Responsibilities:	Work Management Solutions, Reservoir Engineering
Program:	Internal Metal Loss Action Plans (IMLAP)
Scope: PG&E is improving the internal corrosion control program with more prescriptive standards and procedures which include the development of site-specific Internal Metal Loss Action Plans (IMLAP). Each IMLAP will contain internal corrosion control monitoring, testing and inspection requirements. Site-specific plans include key points where liquids are most likely to accumulate based on operating and design characteristics such as hydraulic flow rates, operating pressures, and topography. The plans document type and frequency of tasks (e.g., Non Destructive Examinations (NDE), liquid sampling and testing, drip blowing and assessments, operational pigging, corrosion monitoring coupons).	

Desired State:	Site specific internal corrosion control plans for each gas storage field.
Risks Addressed:	STO016, STO016.1, STO037
Timeframe:	Develop baseline 2014-2015; Develop plan 2016; Implement recommendations starting mid-2016 and continue on-going assessments.
Responsibilities:	Corrosion Engineering

The pipe and surface equipment (including wellhead measurement and flow controls) included in this asset family are managed utilizing the Transmission Integrity Management Program (TIMP) and Facility Integrity Management Program (FIMP) like those assets in the Transmission Pipe, Compression & Processing, and Measurement & Control asset families. Detailed information about these programs is included in the respective asset management plans (refer to Appendix A for links).

In the table below, Transmission Pipe asset family programs and mitigations that also apply to the transmission pipe within the Storage asset family are listed. In addition to these programs aligning with Transmission Pipe strategic objectives, they also tie to Storage asset family strategic objectives as shown in Table 17. Please refer to Appendix A for a link to the Transmission Pipe asset family Asset Management Plan.

Table 20 - Program Summary - Transmission Pipe

Program:	Corrosion Control
Scope: Corrosion is a threat that adversely affects the longevity and reliability of natural gas pipelines, valves, pressure vessels, and other pipeline appurtenances. There are several types of corrosion threats to pipelines: external, internal, atmospheric, and stress corrosion cracking. To protect against external corrosion, pipelines are well coated and have adequate cathodic protection (CP). Some of the mitigation programs in place to reduce the risk of external corrosion include: • Electrical Interference Monitoring – Alternating Current (AC) and Direct Current (DC) • Casing Monitoring • Atmospheric Corrosion Inspection To protect against internal corrosion, the quality of the gas is monitored for certain constituents, including oxygen, hydrogen sulfide, and/or carbon dioxide. One of the mitigation programs in place to reduce the risk of internal corrosion includes: • Internal Corrosion Site Specific Plans To protect against stress corrosion cracking, pipelines are well coated and have adequate cathodic protection (CP). Some of the mitigation activities in place to reduce the risk of stress corrosion cracking includes: • Monitoring and control of compressor station discharge temperature • Close Interval Survey • Magnetic Particle Inspection during H-Form Inspections	
Desired State:	Protect assets against internal corrosion, external corrosion, and stress corrosion cracking
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO031, STO031.1
Timeframe:	Ongoing
Responsibilities:	Gas Operations*

Program:	Patrolling / Continuing Surveillance
Scope: The Pipeline Patrol Program is a means of preemptive threat identification and can observe a myriad of potential threats ranging from construction activity, landslides, ground movement, vegetation encroachments, right-of-way (ROW) encroachments, leaks, corrosion, missing markers, etc. If left identified and unmitigated, many of these threats could result in a failure/rupture of company assets. These patrols are conducted to achieve compliance with 49 CFR Part 192.705 and to fulfill commitments to the CPUC.	
Desired State:	• Increased patrolling of areas with high risk of dig-ins, such as agricultural areas, HCA's, Class 3 locations, and targeted distribution pipelines • Acquire seven (7) additional centralized ground patrol personnel to assist with vegetative cover patrols, landslide patrols, and ground investigations • LiDAR technology under consideration for patrolling vegetative cover areas, identification of new construction, and historic earth disturbance change detection
Risks Addressed:	STO017, STO017.1, STO019, STO022, STO023, STO029, STO030, STO030.1
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	In-Line Inspection (ILI)
Scope: ILI is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe. ILI enables a pipeline operator to learn about the condition of its pipelines and to predict the integrity of those pipelines into the future to address time dependent as well as other threats to pipeline integrity. It involves running technologically advanced inspection tools, often called "smart pigs," through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigation or repair.	
Desired State:	• Targeting 65 percent system piggable by 2026 • Apply both short and long-term recommendations from the McKinsey Capital Productivity Effort • Complete development and testing of custom ILI tools from ROSEN including 12"x16", 10"x12", and 24"x30", including full API 1163 qualification for each • Improve ILI run success rate to 90% for first-time ILI and 95% for ILI re-inspections
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO019, STO021, STO022, STO023, STO030, STO030.1
Timeframe:	2026; Ongoing
Responsibilities:	Transmission Integrity Management
Program:	Direct Assessment (DA)
Scope: DA is used to evaluate the possibility of time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking. Each evaluation methodology is designed to proactively address the pipeline threat of corrosion and is meant to discover and prevent anomalies from growing to a size that affects the structural integrity of the pipeline. Application of DA involves applying a four-step process consisting of: (1) Pre-Assessment; (2) Indirect Inspection; (3) Direct Examination; and (4) Post Assessment.	
Desired State:	Proactively address the threat of corrosion
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO031, STO031.1

Timeframe:	Ongoing
Responsibilities:	Transmission Integrity Management
Program:	Pressure Test
Scope: The objective of the Pressure Test program is to validate the integrity and assure a margin of safety for those gas transmission pipelines that lack a documented strength test record. This program identifies stable/resident threats by evaluating the yield strength of segments of pipe for the presence of manufacturing defects, which is then followed by implementation of mitigation measures.	
Desired State:	All pipe with traceable, verifiable, and complete pressure test records
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO020, STO020.1
Timeframe:	2023; Ongoing
Responsibilities:	Transmission Integrity Management
Program:	Leak Survey & Repair
Scope: PG&E conducts leak surveys on the gas transmission pipeline system by implementing foot, mobile, and aerial leak surveys. 1) **Foot survey:** Foot survey is the most common method to conduct leak survey and requires personnel to carry a portable gas leak detector in close proximity to the pipeline route. 2) **Aerial survey:** Aerial leak surveys using Light Detection and Ranging Infra-Red (IR) technology are being used more frequently, and are typically transported by helicopter along the pipeline right-of-way. 3) **Mobile survey:** Ground-based mobile technology is a portable gas detector transported on all-terrain vehicles (or possibly cars or trucks) along the pipeline right-of-way. For each case, leaks are detected and recorded on the instrument before being downloaded to a database for repair.	
Desired State:	Identify, prioritize, monitor and repair leaks
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO031, STO031.1
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Public Awareness / Damage Prevention
Scope: The Public Awareness Program informs people living in proximity to transmission pipelines of the risks associated with natural gas pipelines and what actions to take in the event of an emergency. In an effort to continuously promote safety and awareness, PG&E has sent informational letters and safety brochures to homeowners and businesses located within about 2,000 feet of a natural gas transmission pipeline, and provided useful gas safety information online. The Damage Prevention Program identifies excavation companies that consistently adhere to safe excavation practices by recognizing them through PG&E's Gold Shovel program. In addition, the Damage Prevention Program identifies excavation companies that do not adhere to safe excavation practices and works with these companies to reduce damage to our pipeline systems.	

Desired State:	Enhance public safety, emergency preparedness and environmental protection through increased public awareness and knowledge
Risks Addressed:	STO017, STO017.1, STO019, STO030, STO030.1
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Vintage Pipe Replacement
Scope: PG&E considers vintage construction and fabrication threats interacting with land movement as one of the top risks facing the transmission pipe asset and the Vintage Pipe Replacement Program will significantly reduce that risk. PG&E's vision for its Vintage Pipe Replacement Program is to replace all known pipe segments containing vintage fabrication and construction threats that are subject to the threat of land movement that are in proximity to population by the end of 2030.	
Desired State:	• Targeting reducing risk to the population toward the 90% goal as soon as possible (2025). • Expected Completion Date – Based off remaining miles from program snapshot from current year if 15 miles/year is the execution rate. • Primary focus is to reduce the risk to the impacted population (that is within the vicinity of our pipelines) by 2030. • Incorporate LiDAR data to improve identification of land movement threats as managed through the geo-hazard identification program. • Incorporate IMU data from ILI to determine bending stresses in the pipeline, verifying land movement concerns.
Risks Addressed:	STO021
Timeframe:	2025
Responsibilities:	Transmission Integrity Management
Program:	Locate & Mark
Scope: This program is intended to prevent excavation damages to PG&E's transmission pipeline assets by third-party contractors, PG&E construction crews, or others by accurately locating and marking transmission assets and returning to the site when excavation activities are occurring near or over these assets. Activities under this program include responding to notifications in a timely manner and physically locating PG&E transmission pipelines near the proposed excavations. To properly respond to excavation notifications, transmission work crews have personnel assigned to monitor the regional one-call notifications from "811 – Call Before You Dig" systems.	
Desired State:	Prevent excavation damage
Risks Addressed:	STO019, STO029, STO030, STO030.1
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Shallow Pipe Program

Scope: The purpose of this program is to identify, prioritize and mitigate locations that have insufficient cover and are vulnerable to exposure from third parties. Capital remediation options include: replacement or relocation of the pipeline at an acceptable depth of cover in parallel, or along an alternate route and retirement of the shallow location and retirement of those shallow pipelines not necessary for operations. Expense remediation options include: excavation along the length of the pipeline to allow lowering to an acceptable depth of cover (only an option if the required depth of cover can be met without adding excessive external stresses to the pipeline) and protection of the pipeline by installing additional cover, concrete cap, or permanent bridging structure over the shallow location.	
Desired State:	• 3 year cyclical monitoring plan for continual surveillance established. • Primary focus is to reduce the risks at locations of agriculture/farming, external loading concerns on pipe, and erosion leading to exposure of pipeline. • Continued performance of public awareness.
Risks Addressed:	STO019, STO022, STO023, STO029, STO030, STO030.1
Timeframe:	2017; Ongoing
Responsibilities:	Transmission Integrity Management
Program:	Cathodic Protection
Scope: As part of this program, PG&E plans to enhance cathodic protection levels by adopting a more conservative protection criterion of -850 mV "off" as described in the NACE Standard Practice 0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." PG&E currently uses the -850 mV "on" criteria and transitioning to the "off" criteria will provide a more accurate indicator of system protection levels because it considers the soil IR voltage drop between pipe and reference cell when recording a pipe-to-soil potential. Including voltage drop can yield less conservative pipe-to-soil readings and potentially mask areas with inadequate levels of CP.	
Desired State:	• Establish internal engineering team including expert corrosion engineer, program manager, associate engineers, and data analyst to develop a program methodology, manage the program and provide engineering analysis and remedial CP System designs and upgrades to achieve 850 Off transmission pipeline CP levels. • Establish team of field engineers to survey the 6,750 miles of transmission pipeline within a 4 year period for CP status and collect the data necessary to support the Engineering recommendations to meet 850 Off criteria for all transmission pipeline. • Eliminated notifications and NOVs for inadequate CP • Improved compliance for bi-monthly and annual CP reads
Risks Addressed:	STO017, STO017.1
Timeframe:	2019; Ongoing
Responsibilities:	Corrosion Engineering
Program:	Atmospheric Corrosion Inspection Program

Scope: Two major aspects of the program are: • Improve current procedures and training to ensure atmospheric corrosion inspections are performed correctly and uniformly throughout the company. As well as create new automated processes and procedures for when remediation are required to ensure they are completed within the compliance window. • Review existing records and to find existing deficiencies and prioritize the remediation based risk. This includes a review of all systems of record (PLM, SAP, and paper), inspecting for issues, and creating remediation projects.	
Desired State:	• Developed new inspection procedures and training, reduce and simplify forms. • Improved system of record across different asset types (spans, vaulted assets, etc.) • Implemented mobile solution to facilitate quicker turn-around of field inspection results. • Over two thirds of station projects completed. • Over two thirds of span projects completed.
Risks Addressed:	STO017, STO017.1
Timeframe:	2021; Ongoing
Responsibilities:	Corrosion Engineering
Program:	Supervisory Control and Data Acquisition (SCADA) / Network Visibility
Scope: The Gas Transmission Control Center (GTCC) SCADA system is designed to provide greater visibility to the gas system operators and increased situational awareness, which means faster detection of abnormal conditions, and more robust response. The system can accommodate advanced applications such as the real-time line break detection application, improved control room management including improved audit documentation, emergency response tools, and other applications	
Desired State:	Provide visibility into gas system operations and increase situational awareness
Risks Addressed:	STO027, Major Emergency or Disaster
Timeframe:	2013-2021
Responsibilities:	Gas Operations*
Program:	Fault Crossing
Scope: The Fault Crossings program serves to address and mitigate the specific threat of land movement strains on transmission pipe that results from seismic activity. By conducting detailed studies that focus on geologic movement as well as the pipeline's mechanical properties, PG&E is able to gather critical information to determine how best to manage the integrity of these segments of pipe. In order to improve the margin of safety at each fault crossing, this program implements mitigation measures such as modified trench designs, trench adjustment, pipe replacement, or the installation of automated isolation valves.	
Desired State:	Mitigate threat of land movement strains resulting from seismic activity
Risks Addressed:	STO026
Timeframe:	2012-2018
Responsibilities:	Gas Operations*

Program:	Geotechnical Hazard Monitoring
Scope: The Geotechnical Hazard Monitoring Program supplements PG&E's Vintage Pipeline Replacement Program by refining data that will help it more effectively address the interactive threats caused by land movement. There are currently gaps in knowledge that inhibit PG&E from adequately mitigating for this threat. To address this issue, the geo-hazard identification and mitigation program provides more granular, site-specific information where slow land movement or subsidence may be straining our pipelines. By building upon this current basis of information, PG&E can enhance its risk evaluation of this threat.	
Desired State:	Address interactive threats caused by land movement
Risks Addressed:	STO022, STO023, STO026
Timeframe:	2014-2016
Responsibilities:	Gas Operations*
Program:	Water & Levee Crossing
Scope: The Water and Levee Crossing Program improves system safety and reliability by identifying and evaluating erosion, third-party damage threats, and other hazards to trenched-in pipeline installations located under waterways and within levee structures. This program has three components related to transmission pipeline installations: jurisdictional water crossing, jurisdictional levee crossing and the non-jurisdictional water crossing.	
Desired State:	Identify and evaluate hazards to pipeline located under waterways and within levee structures
Risks Addressed:	STO024
Timeframe:	Ongoing
Responsibilities:	Gas Operations*

* Stakeholders for these programs are as shown in Appendix D

In the table below, C&P and M&C asset families' programs and mitigations that also apply to the Storage asset family are listed. In addition to these programs aligning with C&P and M&C strategic objectives, they also tie to Storage asset family strategic objectives as shown in Table 17. Please refer to Appendix A for links to the other asset family Asset Management Plans

Table 21 - Program Summary - Surface Equipment

Program:	Engineering Critical Assessment (ECA) Phase 1
Scope: PG&E began performing an ECA - Phase 1 for its station facilities at the start of 2015. This work is preceded by a record retrieval and document research project that was completed late 2014. The work carried out under ECA - Phase 1 reviews and identifies the issues that may compromise station asset integrity. ECA - Phase 1 represents a comprehensive and fundamental element of improving asset knowledge. This project also helps identify situations that require additional risk mitigation, or changes to equipment or operations to achieve compliance, and will help prioritize downstream projects of ECA - Phase 2 and Hydrostatic Testing.	
Desired State:	Identification of discrepancies that require mitigation
Risks Addressed:	Gas Operations Records Management Risk
Timeframe:	2014 – 2019

Responsibilities:	Facility Integrity Management Program
Program:	Engineering Critical Assessment (ECA) Phase 2
Scope: The scope of this program will mitigate discrepancies identified during the ECA Phase 1 program. This program begun in 2015 and continues through 2019. ECA Phase 2 will use techniques such as determination of material property via non-destructive and destructive testing, fatigue life calculations and other evaluations that can substitute for a pressure test. The program may include small scale pipe or component replacement when the cost and/or operational impact of replacement is more favorable than the cost and/or operational impact created by station hydrostatic testing.	
Desired State:	Minimize the number of discrepancies that must be mitigated through pressure testing
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO018, STO020, STO020.1
Timeframe:	2015 – 2019
Responsibilities:	Gas Operations*
Program:	Hydrostatic Testing Station Facilities
Scope: This program provides for the hydrotest of sections of pipe within C&P facilities that require it. The full scope potentially includes up to the 3 gas storage facilities, [redacted] compressor stations, and [redacted] compressor stations, but will be limited to stations/sections that require testing after ECA Phase 1 identifies risks that cannot be successfully mitigated by ECA Phase 2. This program will extend beyond the 5-year period.	
Desired State:	Mitigate discrepancies remaining after completion of ECA Phase 1 and Phase 2 work
Risks Addressed:	STO016, STO016.1, STO017, STO017.1, STO018, STO020, STO020.1
Timeframe:	2018 – 2037
Responsibilities:	Gas Operations*
Program:	Critical Documents
Scope: PG&E has developed and implemented a Utility Standard (TD-4551S) for the critical drawings that are required for each individual station based on the complexity of the operations at the station. Beginning in 2012, this program is expected to be completed by 2019.	
Desired State:	Compliance with the requirements of TD-4551S
Risks Addressed:	STO010, STO013, Records Management Risk
Timeframe:	2012 – 2019
Responsibilities:	Gas Operations*
Program:	Physical Security

Scope: This program has been developed in order to implement physical security measures at large station facilities. Many of the critical defined Transportation Security Agency (TSA) facilities have been outfitted with security technology, including alarms, access systems and cameras. However, even with these security enhancements, additional security measures will be required in the future to meet a changing threat/risk. Projects moving forward would include a Security Vulnerability Assessment, performed by Lawrence Livermore National Lab, similar to the assessment being conducted at Metcalf substation, to clearly identify mitigation measures to address small arms, Improvised Explosive Devices and protection of other critical components associated with gas delivery. Security enhancements would include dedicating easement for a buffer zone, utilizing barriers to prevent vehicle attacks, including Vehicular Improvised Explosive Devices (VIEDs), deploying new radar/thermal imaging technology to identify threats outside the fence line, measures to protect communication/operating systems from physical attacks and utilizing ballistic protection around critical components. Also, the security enhancement would be deployed outside the facilities to improve protection of exposed transmission pipe, valves, and related communication systems.	
Desired State:	Reduced vulnerability of critical infrastructure to terrorist-type attacks
Risks Addressed:	STO029
Timeframe:	2015 – 2020
Responsibilities:	Gas Operations*
Program:	Routine Expense and Routine Capital Spending
Scope: These programs have been established to capture routine expense and capital projects that arise in the course of normal operation of assets and that must be performed to maintain current levels of service and reliability.	
Desired State:	Current levels of service and reliability are maintained
Risks Addressed:	All
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Emergency Shutdown (ESD) System Upgrades
Scope: It is anticipated that 1 ESD System will be replaced per year; new ESD system will be integrated with a new fire and gas detection system; new system will consist of 15 UVIR fire detectors, 8 gas detection sensors, 2 local control panels, and a main PLC in control building; all new conduit will be required; existing ESD valves do not need replacement except for replacement of solenoids. This program will continue beyond the 5-year period.	
Desired State:	Faster response to fires to minimize damage and facility outage time
Risks Addressed:	All
Timeframe:	2015 – 2025
Responsibilities:	Gas Operations*
Program:	Install Active Fire Suppression Systems

Scope: This program has been established to install active fire suppression units in compressor and control buildings. Assume fire suppression system will be water in 1 gas compressor building; inert gas in 3 electrical and controls buildings; system will include firewater tank, firewater pumps, controllers, backup generator, piping, valves and nozzles.	
Desired State:	Improve safety of personnel [redacted] facilities and mitigate spread of fire, reducing damage and outage time
Risks Addressed:	All
Timeframe:	2016 – 2025
Responsibilities:	Gas Operations*
Program:	Hard to Turn Valve Replacement Program
Scope: This program has been established to identify valves that are hard-to-turn and systematically remove and replace. It is anticipated that we will replace 10 six-inch diameter valves per year; valves are ANSI CL600, carbon steel ball valves; valves are buried and weld-end; and x-ray inspection is required. The costs for this program are captured in the Transmission Pipe program and will continue beyond the 5-year period.	
Desired State:	Improved operability
Risks Addressed:	STO014
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Preventive Maintenance
Scope: This program has been established to ensure that our preventative maintenance programs continue to meet or exceed code requirements and are consistent with best industry practices. The costs for this program are included in the District / Division maintenance budgets. This is an on-going program and will continue beyond the 5-year period.	
Desired State:	Minimize corrective maintenance backlog and deferred maintenance
Risks Addressed:	STO012, STO014, STO015
Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Guidance Documents
Scope: This program has been developed to ensure that comprehensive reference and guidance documentation is available or specifically prepared for all applicable processes that encompass the work performed. This includes applicable Utility Standards; methodology for compliance with federal and state codes and standards; applicable API, ASME, ANSI and other trade association and industry standards; engineering and design standards; recommended equipment operation and maintenance reference documents; and all other applicable documentation. Costs for this program will be captured in the operating plan of the Codes and Standards group.	
Desired State:	Guidance documents that have sufficient detail to ensure safe operation and maintenance of C&P asset components
Risks Addressed:	STO004, STO010, STO013, STO027, Records Management Risk

Timeframe:	Ongoing
Responsibilities:	Gas Operations*
Program:	Cyber Security Measures
Scope: Implement cyber security for all GT assets. Cyber security standards have been created because sensitive information is stored on computers that are attached to the Internet. Also, many tasks that were once done by hand are carried out by computer; therefore there is a need for Information Assurance (IA) and security. Applicable security management practice standards will be utilized in the development and implementation of this program. This program is on-going to address 3rd party threats and will continue past the 5-year period.	
Desired State:	Recommended actions for protecting critical data and systems
Risks Addressed:	STO029, Enterprise Cyber Security Risk
Timeframe:	Ongoing
Responsibilities:	Enterprise Cyber Security organization
Program:	Station Design Standardization
Scope: This program has been developed to ensure consistency between engineering and design work; to ensure that designs comply with applicable regulations and employ best safety practices; to ensure cost-effective design methodology; to provide uniformity in selection of equipment; and to streamline required training and operation & maintenance of installed systems. The Gas Transmission Engineering & Design Manual is being developed to accomplish these objectives. The costs for development of this manual are captured in the operating plan for the Engineering & Design Group.	
Desired State:	Published set of station design standards and guides
Risks Addressed:	STO010, STO013, Records Management Risk
Timeframe:	2018
Responsibilities:	Gas Operations*
Program:	Training
Scope: This program has been established to ensure that the training regimens for District / Division and engineering personnel are comprehensive, cover operation and maintenance requirements of all applicable equipment, and reflect best industry practices. The costs for this program are included in the individual PCC Standard Rates. This program is developed to ensure training of personnel and will be on-going past the 5-year period.	
Desired State:	Maintenance personnel have the necessary training to safely operate and maintain compression and processing assets
Risks Addressed:	STO004, STO010, STO013, STO027, Gas Operations Records Management Risk
Timeframe:	Ongoing
Responsibilities:	Gas Operations*

Program:	External Corrosion Control (such as Coatings, Cathodic Protection, External Corrosion Direct Assessment)
Scope: This program has been established to ensure that adequate coatings are present on equipment at C&P facilities. This program provides a methodology to inspect coatings on aboveground equipment, vessels and piping and provides for recoating these facilities as warranted. These costs are captured in the Integrity Management plan.	
Desired State:	Implementation of structured corrosion monitoring program for facilities
Risks Addressed:	STO017, STO017.1
Timeframe:	2016 to establish site specific programs, On-going
Responsibilities:	Gas Operations*
Program:	Process Safety
Scope: This program is designed to ensure that safety is incorporated in all of the engineering and design work performed. This will include measures such as performing HAZOP reviews on process designs. A pilot program to ensure that safety is embedded in our designs has been established for the McDonald Island Whisky Slough Station Rebuild project. The costs of these process safety improvements are typically captured at the project level. This program is on-going and processes will be continually updated to meet regulatory and technology changes. This program will extend beyond the 5-year period.	
Desired State:	Process safety elements integrated into facility designs
Risks Addressed:	All
Timeframe:	Ongoing
Responsibilities:	Gas Operations*

* Stakeholders for these programs are as shown in Appendix D

The following table describes emergency response and research projects applicable to all assets in the Storage asset family.

Table 22 - Program Summary Emergency Response and Research Projects - All assets

Program:	Emergency Response
Scope: An annual update of the Storage Well Emergency Response Plan should be completed along with an exercise of the Well Plan and Gas Emergency Response Plan (GERP). Develop site specific plans to enhance response times in the event of a storage well blowout.	
Desired State:	Enhance emergency response related to storage well blowout
Risks Addressed:	All
Timeframe:	2016 – 2018
Responsibilities:	Reservoir Engineering, Emergency Preparedness
Program:	Research Projects
Scope: Develop technology to reduce risks to the storage asset family. Appendix I contains a list of projects completed or in development that address various risks in the asset family.	

Desired State:	Develop and implement technology to reduce risks to storage asset family
Risks Addressed:	STO005, STO005.1, STO016, STO016.1, STO017, STO017.1, STO018, STO020, STO020.1, STO022, STO023, STO024, STO026, STO031, STO031.1
Timeframe:	On-going
Responsibilities:	Research & Development

The latest program investment plan information can be found at the following links:

- Transmission S1: 2015 GT S1
- Transmission S2: 2015 GT S2

5. Areas for Continuous Improvement

There are some areas in the asset management plans that have not been fully built out at this stage; these are highlighted in the table below. These are areas that will continue to evolve and improve as more thorough data sets and understanding of asset condition are developed over time.

Table 23 - Areas for Continuous Improvement

Areas for Continuous Improvement
Repair vs. Replace • Documented criteria and decision-marking when repairing vs. replacing a component
Asset Criticality • Improved understanding of critical component assets – To be developed through Asset Health Scorecard • Collaborate with Gill Ranch on risk and asset management • Evaluate long-term plan for storage capacity needs
Data • Refinement of leading and lagging performance indicators in order to measure, monitor and report on asset performance and condition • More comprehensive data assessment and identification of gaps in existing data (if any) • Develop programs/processes to address data organization, accessibility, and identified gaps (if any) • Analyze trends from data
Asset Management Plan • Continue to work with other asset families to develop consistency in plan content • Ensure asset management plans are the primary source of asset family information and incorporates information from the Threat Matrices, Risk & Compliance Committee meetings, Session D, S1, and S2 • Continue to refine mitigation program "Desired State" and develop metric to measure progress toward the desired state • Improve criteria for identifying mitigation program status, including benchmarking criteria, program effectiveness metrics, and funding fulfillment • Work toward distinguishing assets between asset families to obtain granularity into trends
Personnel Implications • Additional or supplemental personnel in supporting Storage to perform proactive risk, asset, and process safety management activities. • Additional resources to develop and implement data organization and accessibility issues resolution process • Identify development plans for subject matter experts to ensure their skills/expertise remain current • Identify succession plans for subject matter experts and Asset Management Principals and begin skill/expertise development for succession • Continue developing skills of Asset Family Owner and Asset Management Principals

APPENDICES

A. Related Documents

The following table lists documents associated with this asset management plan.

Table 24 - Related Documents

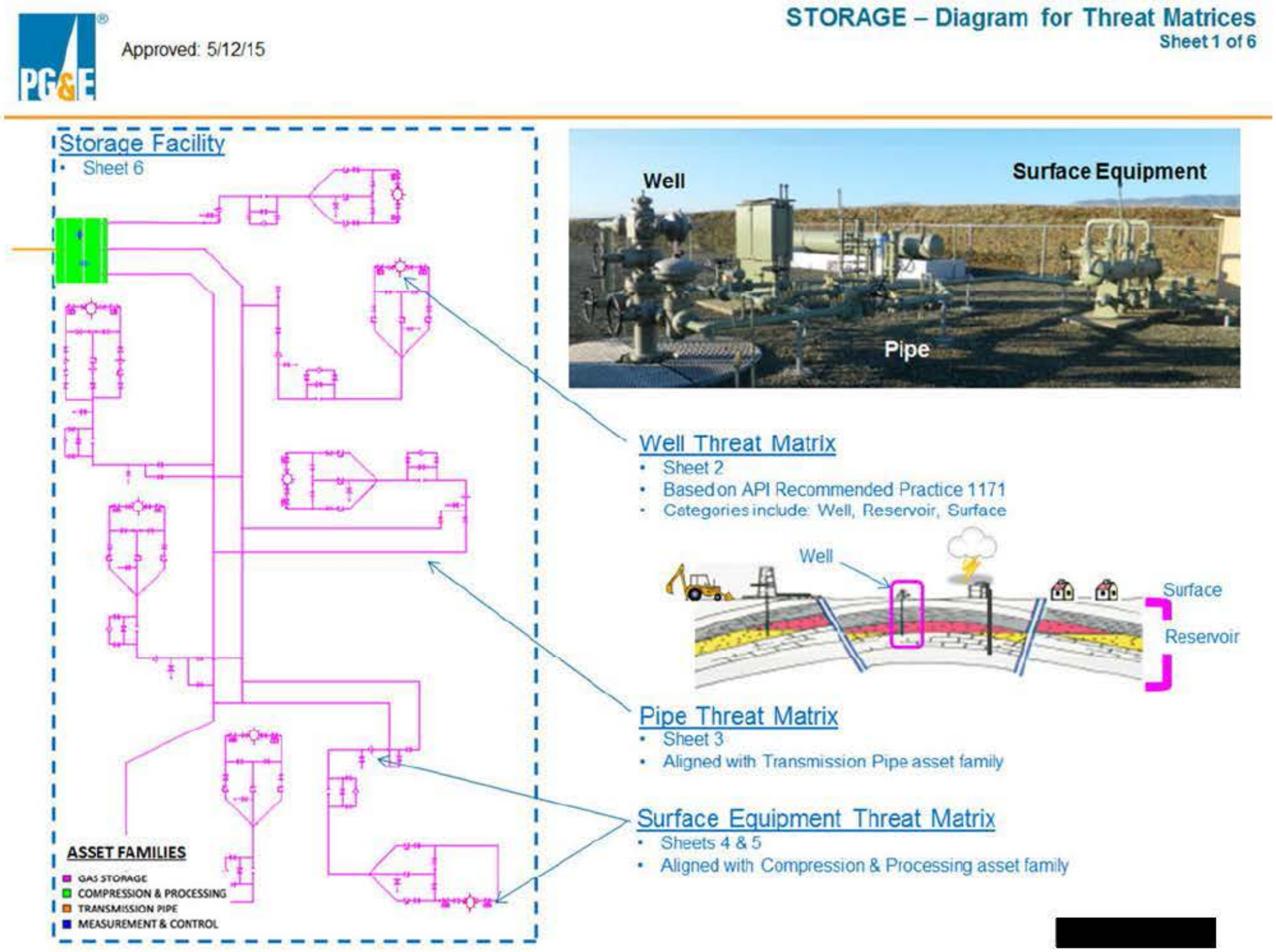
Related Document	Document Number / Description	Link
Storage Asset Family Video	Asset Family Owner introduces the Gas Storage Asset Family and how what you do every day makes a difference in how we are managing and maintaining the health of our assets.	GAS-T759 Gas Storage
Gas Storage Risk Register	The risk register captures all risks outlined in this plan at the data of publish	http://gasrisk/
Asset family investment planning forecast	Retained by investment planning for S1 and S2 planning purposes.	2015 GT S1 2015 GT S2
Enterprise and Operational Risk Management Standard and Procedure	RISK-5001S, RISK-5001P-01	http://pgeatwork/Guidance/RiskCompliance/Pages/default.aspx
Gas Asset Management Policy	TD-01	TD-01
Gas Operations Asset Management System Risk Management Standard	TD-4011S	TD-4011S
Gas Operations Risk and Compliance Committee Charter	GOV-1021S	http://pgeatwork/Guidance/Governance/Pages/default.aspx
Strategic Asset Management Plan	GP-1100	Gas Safety Plans / Asset Management
Transmission Pipe Asset Management Plan	GP-1101	
Distribution Mains and Services Asset Management Plan	GP-1102	
Customer Connected Equipment Asset Management Plan	GP-1103	
Measurement and Control Asset Management Plan	GP-1104	
Compression and Processing Asset Management Plan	GP-1105	
LNG/CNG Portable Supplies Asset Management Plan	GP-1106	
CNG Station Asset Management Plan	GP-1107	

Related Document	Document Number / Description	Link
Gas Storage Asset Management Plan	**GP-1108**	

B. Threat Matrices and Key Threats

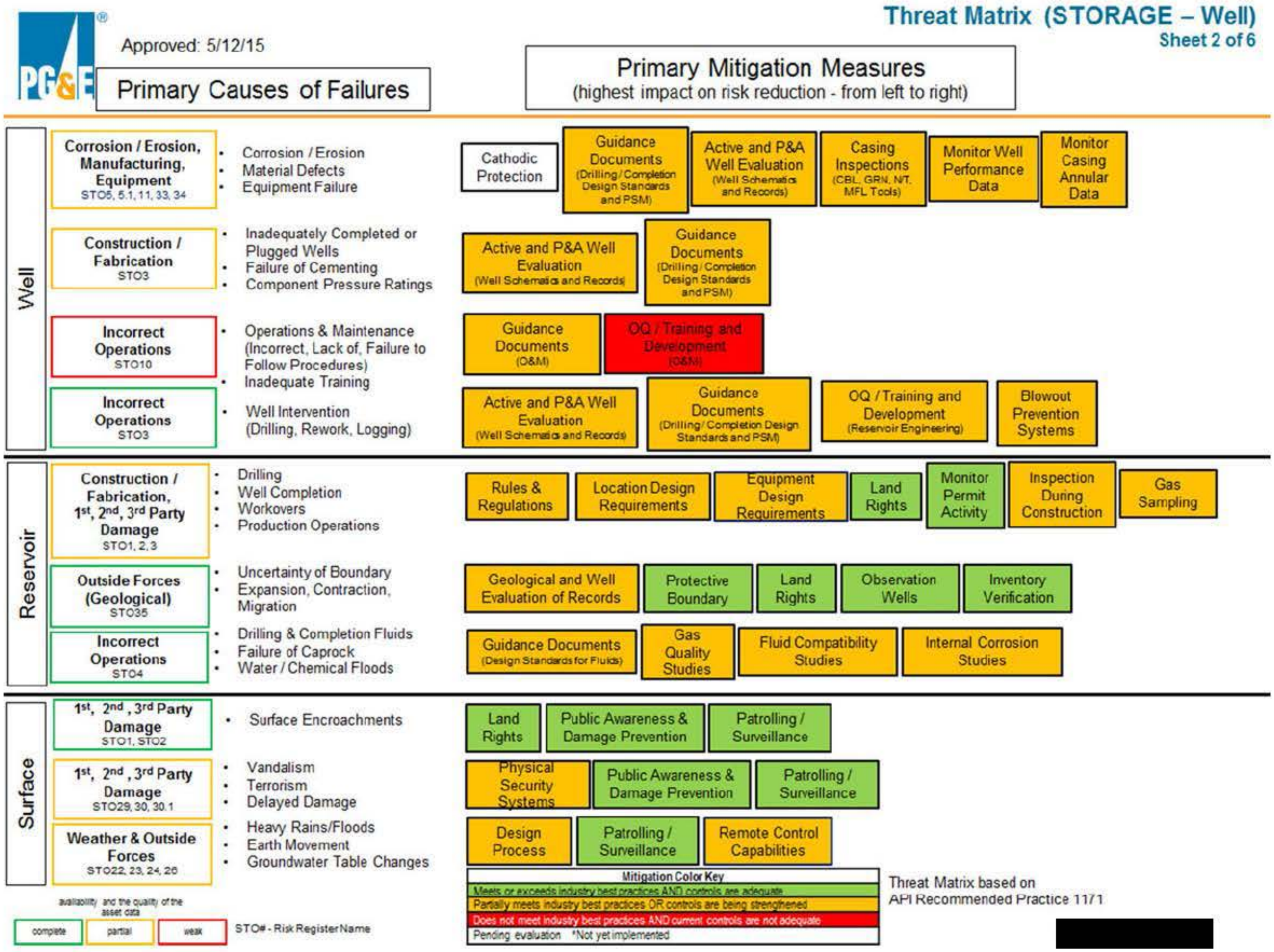
The threat matrices below display threats, drivers, and mitigations associated with this asset family. The threats are outlined with a red, amber, or green status denoting the current availability and quality of asset data. The mitigations are color coded with white, red, amber, or green status to display how it currently compares to industry best practices as well as the strength of the controls.

Figure 7 - Storage – Diagram for Threat Matrices



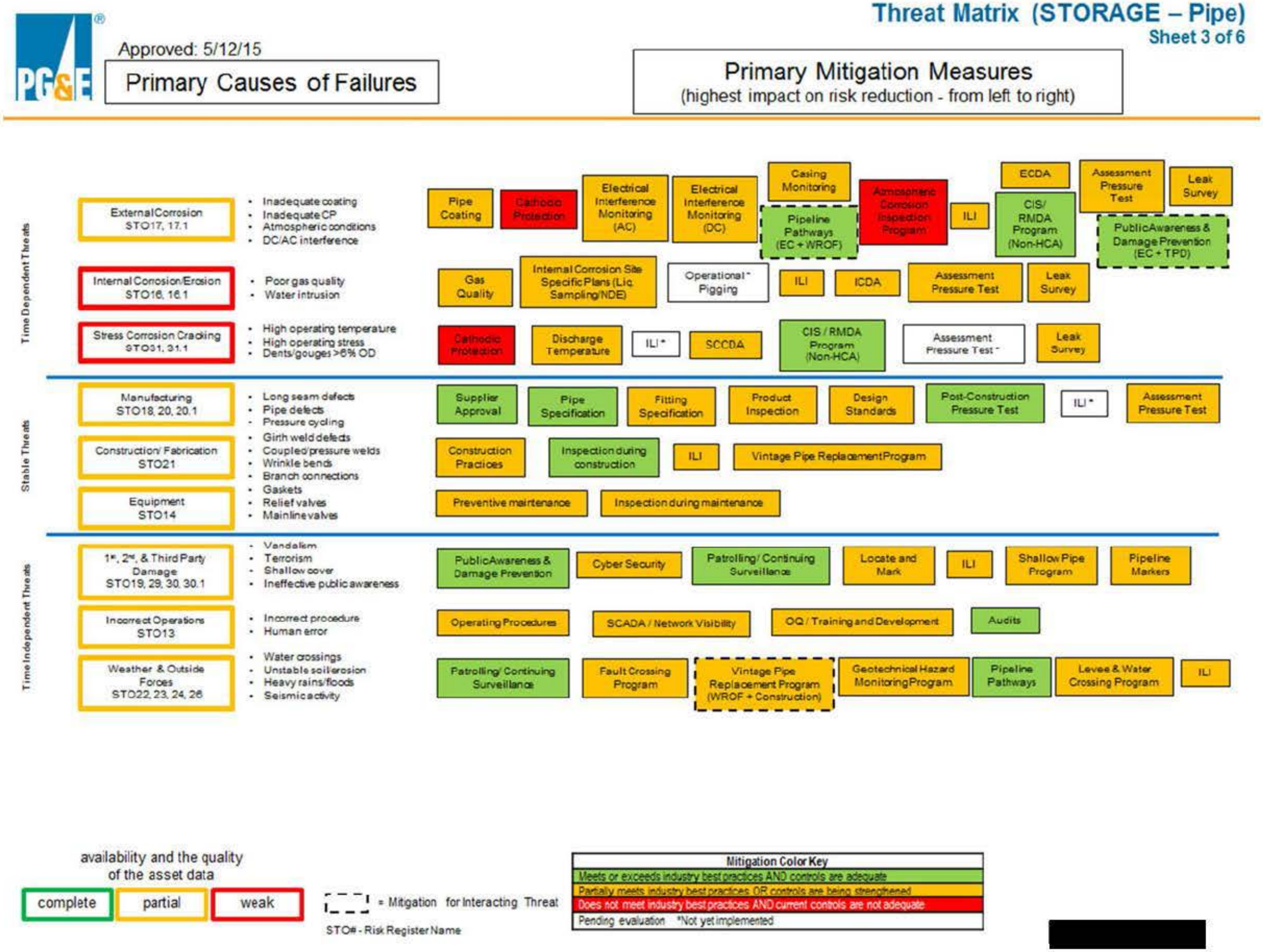
A-57

Figure 8 - Threat Matrix (Storage – Well)



A-59

Figure 9 - Threat Matrix (Storage – Pipe)



A-60

Figure 10 - Threat Matrix (Storage – Surface Equipment)

Approved: 5/12/15

Threat Matrix (STORAGE – Surface Equipment)

Sheet 4 of 6

	Primary Causes of Failures		Primary Mitigation Measures (highest impact on risk reduction - from left to right)					
Time Dependent Threats	External Corrosion	• Condensation under pipe insulation • Inadequate coating • Atmospheric conditions	Cathodic Protection	Regular Inspection	Pipe Coating Program	Insulation Removal Assessment		
	Internal Corrosion / Erosion STO12, 15	• MIC/CO2 • Low spots • Liquids	Site Specific Corrosion Plans	Inspection / Testing	Gas Quality	Design Specs		
	Stress Corr. Crack	• Discharge temperature • Pressure cycling • pH	Cathodic Protection	Discharge Temperature	SCC Direct Assessment	Strength Test *		
Stable Threats	Equipment Related STO14, 25	• Aging electrical (480 V) • Age, obsolescence • Incorrect sizing/design • Deferred maintenance • Emission requirements	Preventive maintenance	Condition Assessment	Equipment Obsolescence Program	Process Safety	Work Procedures	Design Reviews
	Manufacturing STO18, 20, 20.1	• Poor quality manufacture • Inadequate specifications • Inadequate Records • Age	Material Specifications	Vendor QC	Factory Acceptance Testing	Condition Assessment	ECA 1 & 2 Strength Test	Ongoing O&M / Projects
	Construction/ Fabrication STO21	• Poor construction practices • Inadequate construct. specs • Inadequate QC/inspection	Process Safety	Field QC/Inspection	Construction Procedures	Construction Specifications		

availability and the quality of the asset data

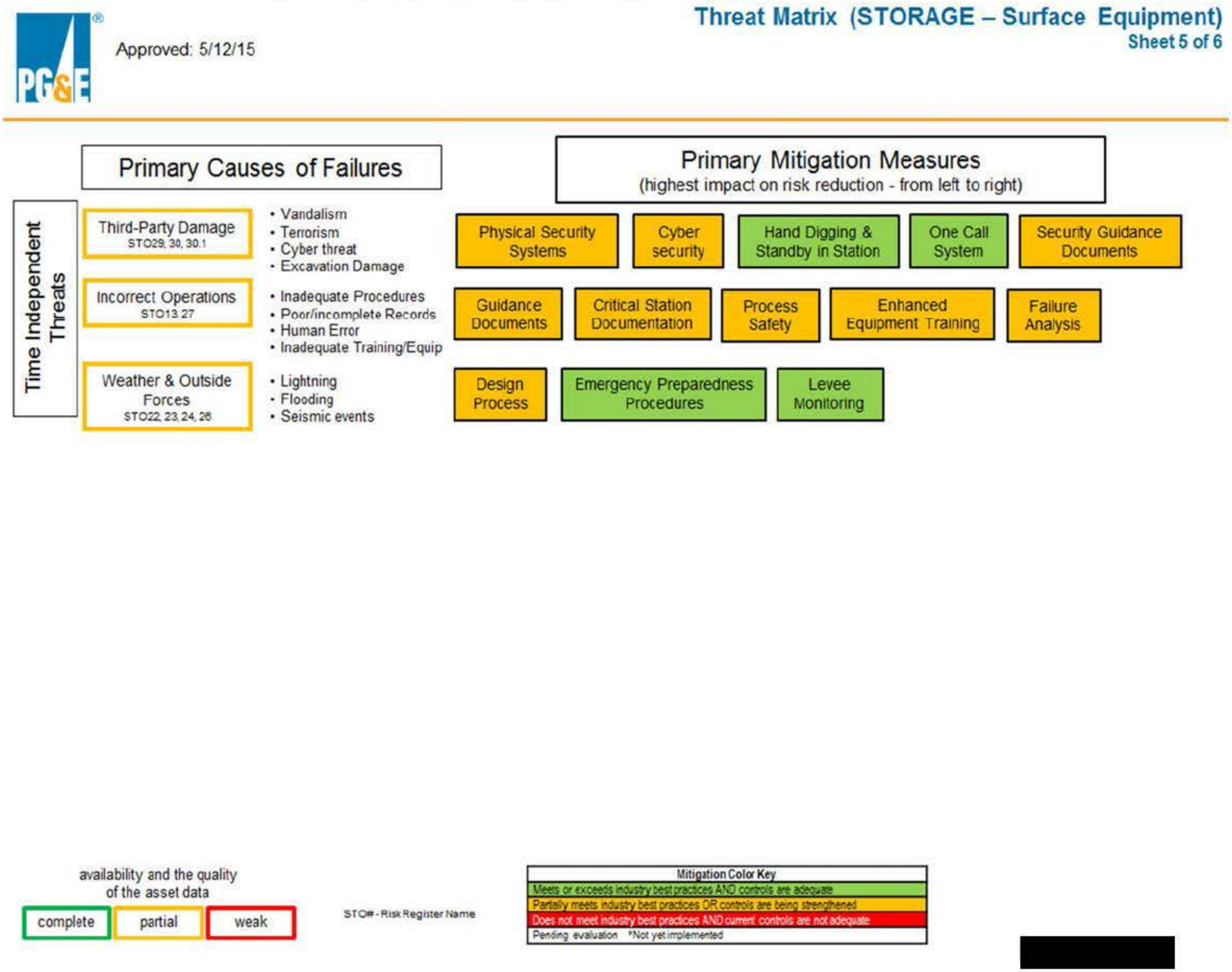
complete	partial	weak

STO# - Risk Register Name

Mitigation Color Key
Meets or exceeds industry best practices AND controls are adequate
Partially meets industry best practices OR controls are being strengthened
Does not meet industry best practices AND current controls are not adequate
Pending evaluation *Not yet implemented

[redacted]

Below is a continuation of the Threat Matrix for Storage – Surface Equipment.



A-61

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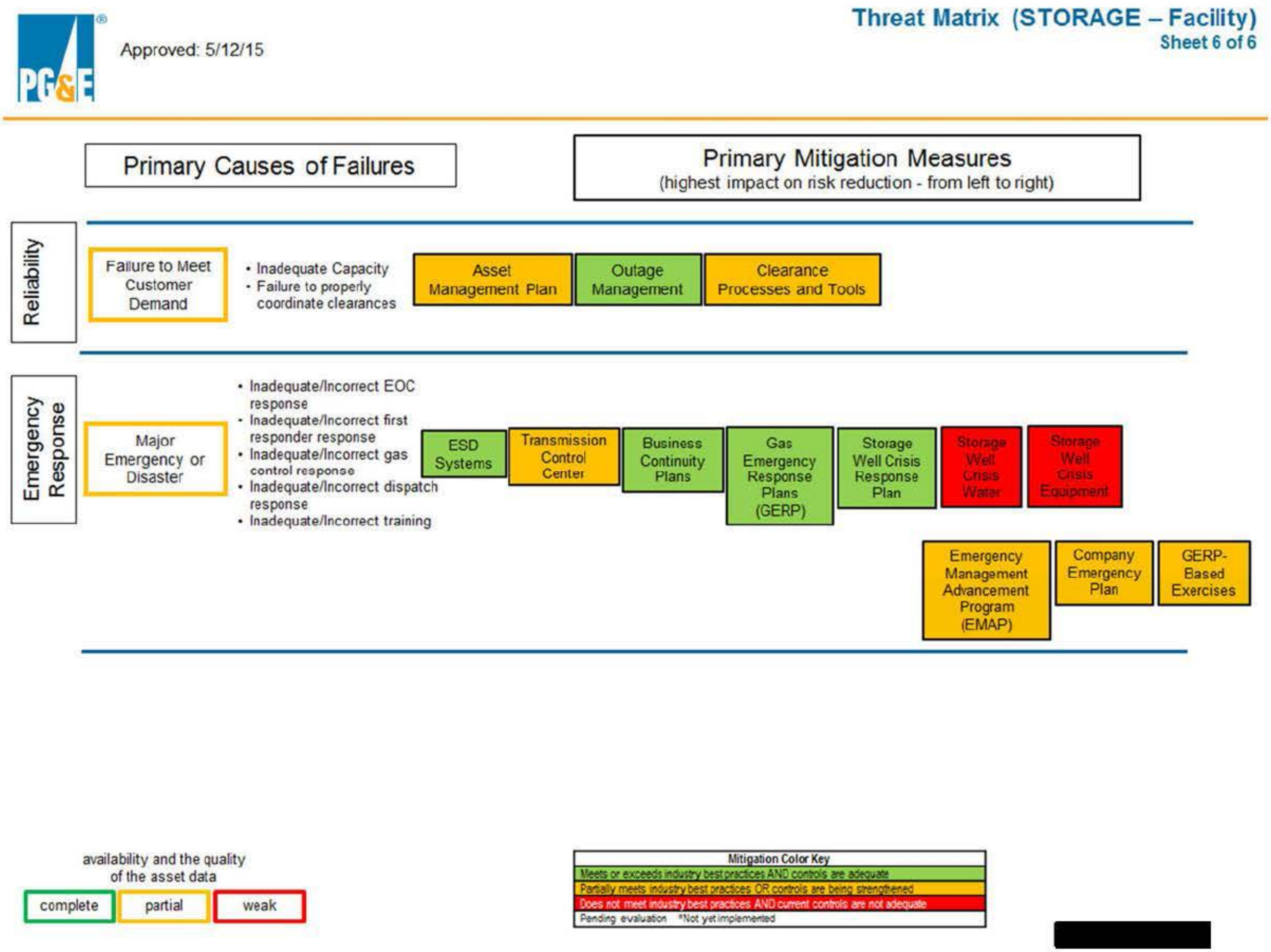
Figure 11 - Threat Matrix (Storage – Facility)



Key Threats and Risks

The key threats and risks associated with the Gas Storage asset family, identifies the causes, inspection methods, primary preventative actions and mitigative actions taken as part of the ongoing management of the assets. The risk maybe triggered by a number of threats requiring identification, prevention and mitigation which is paramount to risk management.

The discussion below highlights the reason for the threat, possible consequences, and likelihood of failure. These threats guided the identification of the risks contained in the Storage Risk Register. The risks (labeled by Risk ID) associated with the threats are shown in Appendix C.

Internal Corrosion and Erosion (All Components Including Well Tubulars)

Internal corrosion and erosion are threats to all components of the storage asset. The associated risks are the loss of integrity of the component which may result in loss of containment of the storage gas with pressures ranging from 600 psig to 2,160 psig. This is a high risk to the Gas Storage asset family due to the gas quality of the storage gas being withdrawn from the storage formation. In storage operations the gas withdrawn from the storage formation and moved through the storage asset generally contains water, sand, and other gas components (e.g. CO_2, H_2S) that can cause either corrosion or erosion of the internal components. Due to the geological nature and completion of PG&E's storage fields and wells, the high potential to produce sand increases the likelihood of a risk of erosion at the impingement points (e.g. valves, elbows, tees) within the surface components.

Internal corrosion may also impact assets downstream of the Storage asset family. Whenever there is gas storage of natural gas delivered directly into the system there is the potential for moisture and corrosive agents to be introduced into the gas stream creating the potential for internal corrosion. This can happen, for instance, if dehydration or separation equipment does not function properly. Moreover, Microbiologically Induced Corrosion (MIC) is a threat to PG&E's storage assets which can also become a threat to PG&E's transmission pipe assets since MIC can travel via the gas stream to other parts of the system.

External Corrosion (All Components Including Well Tubulars)

External corrosion is a threat to transmission pipelines in the storage asset family and the risk associated with this threat is the loss of integrity of the component which may result in the loss of containment of storage gas with pressure ranges of 600 psig up to 2,160 psig. This risk is also applicable to the surface and production casings in the storage wells as the likelihood of failure due to external corrosion can be found where the cement sheath surrounding the tubulars is not present. The consequences of failure due to external corrosion can result in a loss of isolation and access to the storage service, uncontrolled flow or lost production from a storage well which could have multiple impacts such as: employee/public health and safety, regulatory non-compliance, fluids potentially entering the surface and groundwater or other environmentally sensitive areas, reduction of service to PG&E's customers, financial impacts to the public/company, and trust in PG&E. An event involving storage wells may also require a prolonged response to bring the well under control.

Stress Corrosion Cracking (SCC)

Material deterioration from corrosion may cause leaks and potential failure of piping downstream of compressor stations. Stress corrosion risks are produced by deterioration of material over time due to a combination of factors from pressure cycling, chemicals, stress, and material types. The risk associated with the threat of stress corrosion cracking is the loss of integrity of the component as the components experience pressure ranges of 600 psig to 2160 psig as gas is injected and withdrawn from the facility. In the development of the risk register for the asset family the risk of stress corrosion cracking was not perceived as a high likelihood of failure based on the Stress Corrosion Cracking Direct Assessments (SCCDA) conducted on approximately 2.5 miles of HCA pipe within the Gas Storage asset family.

The risk associated of SCC for storage is considered a known unknown as there is no documented case of failure per the subject matter experts whom reviewed the Risk Register.

Manufacturing

Manufacturing issues related to long seam and pipe defects of the storage asset can result in risk such as the loss in integrity of the component as the components experience pressure that ranges of 600 psig to 2,160 psig as gas is injected and withdrawn from the facility. In the development of the risk register for the asset family the risk of manufacturing threats was not perceived as a high likelihood of failure based on the judgment of the subject matter experts and the existing GIS and storage well file records.

Construction/Fabrication

Construction/fabrication threat from a Third Party or PG&E drilling through and/or into the storage reservoir, and/or reworking storage wells can result in an improperly completed and poorly constructed well. The risk associated with improper connection of the tubulars and/or a bad cement job is the loss of integrity of the well or storage caprock to contain the storage gas.

Risks associated with poor construction of girth welds, coupled/pressure welds, wrinkle bends, and branch connections include a loss of integrity of the component as the components experience pressure ranges of 600 psig to 2,160 psig as gas is injected and withdrawn from the facility. In the development of the risk register for the asset family the risk of manufacturing threats was not perceived as a high likelihood of failure risk based on the judgment of the subject matter experts and the existing GIS and storage well file records.

Equipment

The safety valves, surface flow control valves, and well measurement for the storage wells have been automated at Los Medanos and McDonald Island. As gas is injected and withdrawn from the facility, the risk of automation controls failing could result in either a loss in integrity of the transmission pipe or damage of the storage well gravel pack. The subject matter experts perceive there is a moderate likelihood of failure risk and a full assessment is in progress.

An event with a storage well may also require a prolonged response to bring the well under control. Overflow of a storage well can also result in the gravel pack being damaged resulting in a reduction in performance and any associated sand being produced has the potential to erode impingement points in the storage piping and wellhead.

Third Party Damage or Cyber Threats

Third party threats and the risks associated with vandalism, immediate hits, and delayed damage could result in either a loss in integrity of the transmission pipe as gas is injected and withdrawn from the facility. In addition, there is a risk that third parties drill into the storage field because PG&E does not have all the licenses / rights to storage gas. This would allow the third party to produce storage gas. PG&E has completed annual assessment of its gas storage rights. The assessment indicates there is a low likelihood of failure at McDonald Island, Los Medanos, and Pleasant Creek as PG&E has the necessary rights to store gas in the fields. A risk does exist as PG&E must meet the terms of the agreements (e.g. rentals and royalties).

PG&E has historically implemented mitigation measures to improve physical security at critical gas transmission facilities including compressor stations and gas storage facilities. Upgrades have been made in compliance with internal PG&E standards based on TSA guidelines.

With convergence of information technology and control systems such as Supervisory Control and Data Acquisition (SCADA) and process control, the threat of third party damage is expanded to include risk of unauthorized operation along with loss of service and reliability due to cyber security. This risk is currently managed through established IT processes governing design and access of databases and systems critical to operations.

Incorrect Operations

The threat of incorrect operations can lead to the risk of incorrect procedures of all asset components and human error that could result in a loss in integrity of the transmission pipe as gas is injected and withdrawn from the facility. There is a risk of over-pressurization during injection of fluids by a third party or PG&E that results in the caprock integrity becoming compromised which leads to the migration, loss of gas, or need to abandon the storage field indefinitely. Storage fields are designed not to exceed the lowest of the three pressures of the storage formation and caprock:

1) Fracture gradient pressure that causes the formation to separate (frac)
2) Threshold pressure in which fluid can be displaced from the pore space of the caprock
3) Original reservoir pressure of the storage formation

The mitigation measures that are available to PG&E to reduce the risks include correct operating procedures, visibility of the operating pressures and volumes on a real-time basis, having a well trained staff, and audits of the operations. Storage reservoir integrity risk is not visible and not easily recognizable as these tend to be small leakages and require extensive reservoir studies to identify.

The reservoir composition is a threat for the storage asset family as each gas storage reservoir is unique when examining the petrophysics, mineralogy, and cementation of the rock within the storage reservoir. Without understanding the rock of the reservoir there is a threat that utilizing the incorrect fluids could result in clay swelling or participating solids into the pore throats of the rock which impedes the flow of the storage gas.

Industry research has demonstrated that most chemicals utilized to treat the surface pipes for hydrates and corrosion have potential to damage the storage reservoirs. The consequences of failure due to not having an understanding of the storage reservoir could result in a reduction in field production capability.

Weather and Outside Forces

The threat of outside forces is associated with the risk of cold weather, lightening, heavy rains/flooding, and earth movement that could result in a loss in integrity of the transmission pipe as gas is injected and withdrawn from the facility or access to the asset. Further evaluation shows that PG&E participates in the Reclamation District which maintains the McDonald Island levee. The Reclamation District maintenance of the levee system is directed by 1985 study that set out priorities of maintenance and repair. The District is in the process of evaluating the need to update the 1985 study to consider sea level rising and impact of climate change and need to develop GIS based databases. The facility is located in a flood plain in the Delta region and is vulnerable to flooding. The PG&E-owned compression and processing equipment are installed on platforms that elevate the piping and equipment above the flood plain, enabling the facility to operate in the event of a levee break. However, prolonged flooding would increase the risk of failure of transmission pipelines due to corrosion, potential collision of debris into the storage wellheads resulting in a loss of well containment, or well controls failing at those locations that are not located on the platforms.

Additionally, subsidence (i.e. lower land level) due to peat soils and agricultural practices is evident on McDonald Island. Ground settlement puts stress on the platform supports and on the gas lines running from the wellheads to the flow meter runs. Subsidence at McDonald Island is a known threat and requires continuous monitoring and mitigation such as was relieving the stress in the connected pipe to the McDonald 5A well. There is a risk of loss of service and safety impacts due to possible loss of containment.

Other – Completion and Reservoir Geological Characteristics

The reservoir petrophysical and geological characteristics are a threat for the storage asset family as each gas storage reservoir is unique when examining the petrophysics, mineralogy, and cementation of the rock within the storage reservoir. Without understanding the rock of the reservoir there is a threat in utilizing the incorrect fluids could result in clay swelling or participating solids into the pore throats of the rock which impedes the flow of the storage gas. Industry research has demonstrated that most chemicals utilized to treat the surface pipes for hydrates and corrosion will damage the storage reservoirs. Additionally, poor cementation of the reservoir will allow for the migration of reservoir particulates and fines to reduce the pore throats size within the gravel pack.

C. Asset Family Risks

The Storage asset family risks below are sorted below by risk ranking. Also, related risks are listed for Storage (STO), Transmission Pipe (TRA), Compression & Processing (CP), and Measurement & Control (MC) asset family risks.

Table 25 - Storage Risks and Related Risks

Risk ID	Asset Type	Threat	Risk	Related Risks
STO016	Pipeline	Internal corrosion and/or Erosion	Rupture of pipeline due to internal corrosion and/or erosion may result in loss of containment, and/or uncontrolled gas flow that may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.	Calibrated with TRA008 Related to STO016.1
STO017	Pipeline	External Corrosion	Rupture due to external corrosion of the pipeline which may result in the loss of pipeline isolation and access as well as an uncontrolled flow or lost production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Calibrated with TRA001 Related to STO017.1
STO026	All Segments	Weather and Outside Forces (Seismic)	Loss of withdrawal platform, buildings and equipment due to seismic activity/earthquake that may result in the loss of containment or ability to provide storage service. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage.	N/A
STO005	Well Casing	Corrosion	Loss of well integrity due to well casing corrosion (internal or external, or stress corrosion cracking) that may result in an uncontrolled flow of gas outside of well casing with ignition source, drinking water contamination, gas migration, or gas loss. This may lead to major impact on public or employee safety, facility outage or net replacement of supply, property damage and/or environmental damage.	Related to STO005.1
STO020	Pipeline	Manufacturing	Rupture of pipeline due to manufacturing may result in loss of containment, and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Calibrated with TRA004 Related to STO020.1

Risk ID	Asset Type	Threat	Risk	Related Risks
STO015	Valves	Erosion	Erosion of valves may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	N/A
STO012	Meters	Equipment	Compromised measurement may result in uncontrolled flow and release of gas. This may lead to a significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	N/A
STO018	All Segments	Fatigue	Failure of pipeline, equipment, and pipeline controls due to fatigue from internal pressure cycling or vibration may result in loss of containment. This may lead to significant impact on public or employee safety, outages, property damages and/or environmental damage.	N/A
STO037	Pressure Vessels	Internal Corrosion and/or Erosion	Through wall leaks in pressure vessels due to internal corrosion and/or erosion that may result in uncontrolled flow of gas. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or environmental damage.	Calibrated with CP010
STO030	All Segments	1st, 2nd, 3rd Party Damage	Rupture of belowground pipeline or uncontrolled flow from other storage assets due to 1st, 2nd, and 3rd Party damage caused by equipment/vehicles who may not have followed work procedures that may result in uncontrolled flow of gas, outages or replacement of gas supply. This may lead to major impact on public or employee safety, outages or replacement of gas supply, property damage and/or minor environmental damage.	Calibrated with TRA006 and TRA0014 Related to STO030.1
STO003	Reservoir	Construction by 1st & 2nd Party	Loss of reservoir integrity due to 1st and 2nd party drilling through storage field or reworking 1st and 2nd Party well that may result in an improper completion of the well or uncontrolled flow or loss containment with ignition source that can lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	N/A

Risk ID	Asset Type	Threat	Risk	Related Risks
STO019	Pipeline	3rd Party Damage	Rupture of pipeline due to mechanical damage by 3rd party may result in the loss of pipeline isolation and access as well as uncontrolled flow and loss in production. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Calibrated with TRA006
STO021	Pipeline	Construction	Rupture of pipeline due to vintage construction which may result in loss of containment and/or uncontrolled gas flow. This may lead to significant impact on public safety, property damage, prolonged outages or loss of supply, and/or significant environmental damage.	Calibrated with TRA003
STO029	All Segments	3rd Party Damage	Vandalism and/or vehicular damage on above ground pipeline, equipment, wellheads, or valves that may result in damage, over-pressurization, and/or loss of containment. This may lead to impact on public or employee safety, minor outages, property damage and/or minor environmental damage.	Calibrated with CP019 and TRA023
STO023	McDonald Island	Weather and Outside Force	Rupture of pipeline and/or failure of well structure due to subsidence at McDonald Island which may result in uncontrolled flow of gas. This may lead to significant impact on public or employee safety, prolonged outages or replacement of supply, property damage, and/or environmental damage.	Calibrated with STO022 and TRA012
STO013	Valves	Incorrect Operations	Incorrect valve operations which may result in the failure of control valves to open, close, or shut-in. This may lead to minor impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage. (P50)	N/A
STO031	Pipeline	Stress Corrosion Cracking	Rupture of pipeline due to stress corrosion cracking (SCC) may result in loss of containment, and/or uncontrolled gas flow. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage.	Calibrated with TRA009 Related to STO031.1

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Risk ID	Asset Type	Threat	Risk	Related Risks
STO011	Wells	Erosion	Damage to the wellhead due to erosion that may result in loss of well isolation and access or uncontrolled flow with ignition source. This may lead to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.	N/A
STO010	Wells	Incorrect Operations	Failure of well control system during an emergency due to incorrect operations from not following procedures or equipment impairment which may result in uncontrolled gas flow with ignition source. This may lead to significant impact on public or employee safety, and/or prolonged outages or net replacement of supply.	N/A
STO004	Reservoir	Incorrect Operations	Over-pressurization that may result in compromising caprock integrity, gas migration, loss of gas, drinking water contamination, or need to abandon the storage field indefinitely. This may lead to impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.	N/A
STO022	Los Medanos and Pleasant Creek	Weather and Outside Force	Rupture of pipeline and/or failure of well structure due to subsidence at Los Medanos and Pleasant Creek which may result in uncontrolled flow of gas. This may lead to significant impact on public or employee safety, prolonged outages or replacement of supply, property damage, and/or environmental damage.	Calibrated with STO023 and TRA012
STO025	Storage Field Facilities	Equipment	Interruption of power and failure of backup system at the facilities which may result in loss of operation of equipment and monitoring technologies. This may lead to minor impact on public or employee safety, outages or net replacement of supply or property damage. (P50)	N/A
STO020.1	Pipeline	Manufacturing	Leak in pipeline due to manufacturing may result in loss of containment, and/or uncontrolled gas flow. This may lead to minor impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage. (P50)	Calibrated with TRA005 Related to STO020

Risk ID	Asset Type	Threat	Risk	Related Risks
STO027	Storage Field Facilities	Incorrect Operations	Technology used for monitoring and controlling assets is incorrectly maintained or damaged which may result in loss of well control, manual operations or not being able to operate storage facilities. This may lead to significant impact on outages or net replacement of supply.	N/A
STO016.1	Pipeline	Internal Corrosion and/or Erosion	Leak in pipeline due to internal corrosion and/or erosion may result in loss of containment, and/or uncontrolled gas flow or lost production. This may lead to minor impact on public or employee safety, outages or net replacement of supply, property damage and/or environmental damage. (P50)	Calibrated with TRA015 Related to STO016
STO014	Valves	Equipment	Failure of valves to control due to incorrectly or poorly maintained equipment which may result in a well overflow. This may lead to impact on public or employee safety, prolonged outages or net replacement of supply, property damage.	N/A
STO002	Reservoir	Construction by 3rd Party	Construction by a 3rd Party drilling through storage field or reworking 3rd Party well that may result in an improper completion of the well or uncontrolled flow or loss of containment. This may lead to impact on public or employee safety, outages or replacement of supply, and property damage.	N/A
STO031.1	Pipeline	Stress Corrosion Cracking	Leak in pipeline due to stress corrosion cracking (SCC) may result in loss of containment, and/or uncontrolled gas flow. This may lead to minor impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage. (P50)	Related to STO031
STO030.1	All Segments	1st, 2nd, 3rd Party Damage	Leak of belowground pipeline or mechanical damage to storage assets due to 1st, 2nd, and 3rd Party equipment/vehicles who may not have followed work procedures that may result in uncontrolled flow of gas, outages or replacement of gas supply. This may lead to minor impact on public or employee safety, outages or replacement of gas supply, property damage and/or minor environmental damage. (P50)	Related to STO030

Risk ID	Asset Type	Threat	Risk	Related Risks
STO024	McDonald Island	Weather & Outside Forces	McDonald Island levee break that may result in loss of well, reservoir or facility isolation and access, and uncontrolled flow. This may lead to significant impact on prolonged outages or replacement of supply, property damage, and/or environmental damage.	Calibrated with CP004
STO033	Gill Ranch – Disposal Well	Incorrect Operations, Equipment	Failure to dispose of produced fluids in a Gill Ranch disposal well which may result in the curtailment of gas production.	N/A
STO017.1	Pipeline	External Corrosion	Leak on the pipeline due to external corrosion which may result in the loss of pipeline isolation and access as well as an uncontrolled flow or lost production. This may lead to minor impact on public or employee safety, prolonged outages or net replacement of supply, property damages and/or environmental damage. (P50)	Calibrated with TRA002 Related to STO017
STO034	Gill Ranch – Disposal Well	Internal/External Corrosion	Failure of casing integrity due to corrosion may result in the loss of Gill Ranch disposal well isolation, curtailment of gas production, and/or environmental damage.	N/A
STO005.1	Well Casing	Corrosion	Leak in well casing pipe due to corrosion which may result in the minor loss of well isolation and access, uncontrolled flow of gas and loss of production which may result in minor impact on public or employee safety, outages or net replacement of supply, property damages and/or minor environmental damage. (P50)	Related to STO005
STO001	Reservoir	3rd Party Damage	A 3rd party drilling into a storage field if PG&E does not have the rights/licenses or has lease payment lapse to store gas in all of the acreage which may result in a loss of gas and PG&E trespass. This may lead to replacement of gas supply and property damage.	N/A
STO035	Reservoir	Outside Forces (Geological)	Geological uncertainty which may result in the loss of inventory or gas migration from the storage reservoir or influx of reservoir fluids impounding or trapping storage gas.	N/A

D. Stakeholder Roles and Responsibilities Matrix

The key contacts are stakeholders who are involved in each phase of the asset life cycle, managing and operating the assets to operate as planned.

Table 26 - Stakeholder Roles and Responsibilities Matrix

Stakeholder Group	Primary Contact	Creation / Enhancement				Utilization	Maintenance	Decommission / Dispose
		Conception	Design	Procure	Construct / Start-up			
Facility Integrity Management & Technical Services	Director	X	X	X	X	X	X	X
Reservoir Engineering	Director	X	X		X	X		X
Compliance	Director	X	X	X	X	X	X	X
Transmission Engineering & Design	Director	X	X	X	X			X
Transmission Project Management	Director	X	X	X	X			X
Backbone Planning	Manager	X	X			X		X
Local Transmission Planning	Sr. Manager	X	X			X		X
Gas Transmission Control Center	Manager	X			X	X	X	X
Gas Control Strategy & Support	Director	X	X					X
Gas Pipeline Operations & Maintenance	Director		X		X		X	X
Wholesale Marketing & Business Development	Director	X				X		X
General Construction	Sr. Director				X			X
Transmission Integrity Management	Director	X	X	X	X	X	X	X

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E. Summary of Integrated Programs

The table below summarizes the programs of work contained within this asset management plan that are relevant to and documented in other asset family asset management plans. The table highlights which programs are applicable to multiple asset families and which plan has included forecast costs. This also ensures there is no duplication in forecasted program costs.

Table 27 - Programs Relevant to Multiple Asset Families

Programs of Work	Transmission Pipe	Gas Storage	M&C	C&P	Other
Locate & Mark	X	X			
Gas transmission routine pipeline maintenance & monitoring	X	X			
Gas transmission routine pipeline reliability & expense projects	X	X			
Corrosion control	X	X	X	X	
ILI assessments	X	X			
ILI upgrades	X	X			
ILI anomalies rectification	X	X			
ILI inspected by other means	X	X			
ECDA	X	X			
ICDA	X	X			
SCCDA	X	X			
Close Interval Surveys (CIS)	X	X			
Stress corrosion cracking	X	X			
Pressure testing	X	X			
Shallow pipe	X	X			
Class location program	X	X			
Valve automation	X	X			
Public awareness	X	X			
Inoperable & Hard-to-Turn Valves	X	X	X	X	

Programs of Work	Transmission Pipe	Gas Storage	M&C	C&P	Other
Preventative maintenance program	X	X	X	X	X
Guidance documents	X	X	X	X	X
Training	X	X	X	X	X
Process safety	X	X	X	X	X
Cyber security	X	X	X	X	X
Physical security	X	X	X	X	

F. Glossary of Acronyms and Abbreviations

The following is a glossary of acronyms and abbreviations used in this asset management plan and related documents.

Table 28 - Acronyms and Abbreviations

Acronym	Meaning
AC	Atmospheric Corrosion
AF	Asset Family
AFO	Asset Family Owner
AHS	Asset Health Scorecard
AMBBS	Asset Management Backbone & Stations
AMP	Asset Management Plan
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Bcf	Billion cubic feet
BHP	Brake Horsepower
C&P	Compression & Processing
CAP	Corrective Action Program
CIS	Close Interval Survey
CNG	Compressed Natural Gas
CP	Cathodic Protection
CPUC	California Public Utilities Commission
DHSV	Downhole Safety Valve
DOGGR	Division of Oil, Gas and Geothermal Resources
DOT	Department of Transportation
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
EORM	Enterprise and Operational Risk Management

Acronym	Meaning
ESD	Emergency Shut Down
FIMP	Facility Integrity Management Program
GC	Gas Chromatograph
GIS	Geographic Information System
GPOM	Gas Pipeline Operations & Maintenance
GRC	General Rate Case
GRN	Gamma Ray Neutron
GSDB	Gas Storage Database
GT	Gas Transmission
GTI	Gas Technology Institute
GT&S	Gas Transmission and Storage
HAZOP	Hazard and Operability
HCA	High Consequence Area
HP	Horsepower
I/W	Injection/Withdrawal
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
ILI	In-Line Inspection
IM	Integrity Management
IMLAP	Internal Metal Loss Action Plan
I&R	Instrument & Regulation
LM	Los Medanos
LNG	Liquefied Natural Gas
LOB	Line of Business
M&C	Measurement and Control

Acronym	Meaning
MAOP	Maximum Allowable Operating Pressure
MAT	Major Activity Type
Mcf	Thousand cubic feet
MFL	Magnetic Flux Leakage
MMcf	Million cubic feet
MI	McDonald Island
MIC	Microbiologically Induced Corrosion
MIT	Mechanical Integrity Test
ML	Microlog
MMCF	Millions of Cubic Feet
MOP	Maximum Operating Pressure
NDE	Non-Destructive Examination
NOV	Notice of Violation
OBS	Observation
OPP	Over-Pressure Protection
OSHA	Occupational Safety and Health Administration
PC	Pleasant Creek
PCC	Provider Cost Center
PG&E	Pacific Gas and Electric
PHA	Process Hazard Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	Programmable Logic Controller
PLM	Pipeline Maintenance
PM	Preventive Maintenance

Acronym	Meaning
PRCI	Pipeline Research Council International
PSIG	Pounds per Square Inch Gauge
PSRS	Project Status Reporting System
PSSR	Pre-Startup Safety Review
RIM	Records Integrity Management
SAP	Systems, Applications, Products
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SME	Subject Matter Expert
SWD	Salt Water Disposal
TCS	Turner Cut Station
TIMP	Transmission Integrity Management Program
TSA	Transportation Security Administration
UHSV	Uphole Safety Valve
USA	Underground Service Alert
UVIR	Ultra Violet InfraRed
VIED	Vehicular Improvised Explosive Device
WD	Withdrawal
WELL	Well Integrity Management Program
WSS	Whiskey Slough Station

G. Change Log

The following table summarizes revisions since the previous publication of GP-1108: Gas Storage Asset Management Plan, Revision 2, 8/12/2015.

Table 29 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
2	Added sand inspection and leak survey results	Provide more condition data.	
4	Added details about desired state.	Provide clarity.	Maturing of asset management.
Appendix J	Added DOGGR Emergency Regulations	Provide PG&E status	
Entire Asset Management Plan	Updated charts and table	Updated with current data.	

H. Asset Health Scorecard

The Asset Health Scorecards (AHS) for gas storage wells and their associated components is a method that quantifies the overall health of aggregated wells within a gas storage field by utilizing a set of metrics to score major components within a gas well and using these component scores to grade the well condition. The individual well scores roll-up to an overall pad/platform score and the pad/platform condition scores roll-up to an overall field condition score. The AHS will provide the asset family owner with asset reporting, improved analytics, and insight into asset performance and condition by:

- Using actual asset attribute data uploaded into a database system.
- Generating reports which assess asset health using diagnostic testing data.
- Presenting data metrics which identifies assets in poor condition.

The basic elements evaluated when performing a condition assessment of Gas Storage Facilities are the individual components (pieces of equipment) within the well. The condition assessment of these components makes use of specific properties to determine the relative ranking of health of the component. The individual property scores are combined using a weighted summation to compute an overall score for the evaluated component. The individual component scores are combined to calculate the overall health score of their associated well. The individual component weighing factors are summarized in Tables 30 and 31. The well scores that comprise the wells associated with a specific pad/platform contribute to the health score of that pad/platform. Table 32 shows an example of well weighing factors for a specific pad/platform. The pad/platform scores in each field cascade to the overall health score of the field. Weighing factors for calculating the overall health score of a field are shown in Table 33. The Asset Hierarchy for Gas Storage is summarized in Figure 12.

Table 30 - Example of Property Weightings at Component Level

Health Property	Health Property Weighting Factor	Component Grade
Wellhead Leak	15%	∑ of Health Property Scores
Hydraulic Port Leak	15%	
Casing Wing Valve1 External Leak	10%	
Casing Wing Valve 2 External Leak	10%	
Master Gate Valve (Tubing) External Leak	10%	
Casing Wing Valve 1 Internal Leak	10%	
Casing Wing Valve 2 Internal Leak	10%	
Master Gate Valve (Tubing) Internal Leak	10%	
Physical Condition	10%	

Table 31 - Example of Component Weightings at Well Level

Component	Component Weighting Factor	Well Grade
Wellhead Including Flanges	5%	∑ of Component Scores
Well Location	5%	
Surface Casing	15%	
Up Hole Safety Valve - Tubing	12.5%	
Up Hole Safety Valve - Casing	12.5%	
Gravel Pack/ Liner	15%	
Down Hole Safety Valve	15%	
Production Casing	20%	
Tubing	0%	

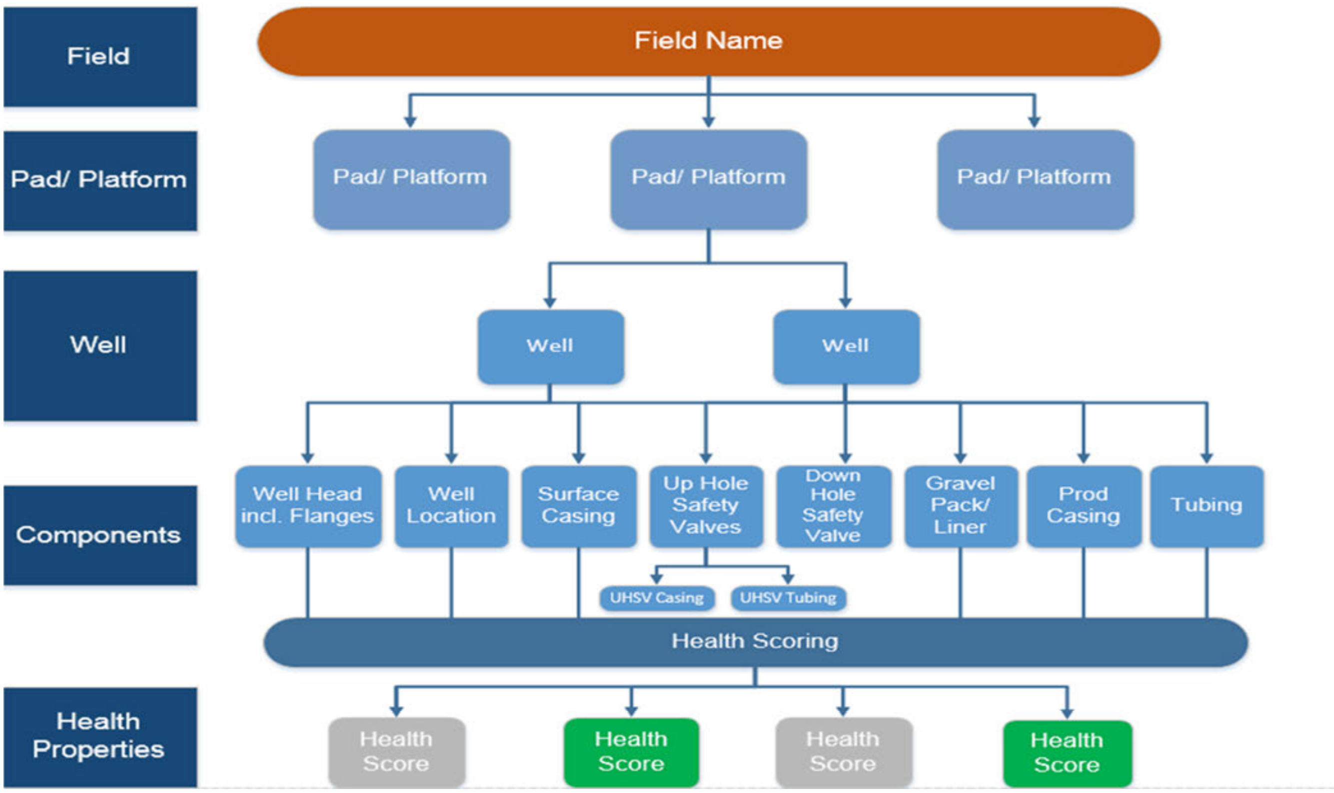
Table 32 - Example of Well Weightings at Pad/Platform Level

Well	Well Weighting Factor	Pad A Grade
LM-1A	~ 33%	∑ of Well Scores
LM-2A	~ 33%	
LM-3A	~ 33%	

Table 33 - Example of Field Pad/Platform Weightings at Field Level

Pad/Platform	Pad/Platform Weighting Factor	Field Grade
Whiskey Slough	~ 39%	∑ of Pad/Platform Scores
Turner Cut	~ 39%	
Peripheral / Non-Platform Wells	~ 15%	
Observation Wells	~ 7%	

Figure 12 - Storage Asset Health Scorecard Hierarchy



The data evaluated includes properties that measure the condition of the component. The data measured by these properties is evaluated and quantified as a numerical score, using a point scale with a range of 1 to 10, where lower scores indicate better component condition. Then a weighted summation of the individual health property scores for a component are subsequently rolled up to a well, pad/platform, and field level which are also on a 1 through 10 score.

A red, amber, green (RAG) status for scores and dashboard of preliminary results of the well assets for the Asset Health Scorecard (AHS) is as follows:

Table 34 - Storage AHS Red, Amber, Green Status

RAG Status:
$1 \le x \le 3.3$
$3.3 < x \le 6.6$
$6.6 < x \le 10$

Figure 13 - Storage Asset Health Dashboard - Preliminary Results

Storage Asset Health Dashboard

Average Scores			
	Pad	Well	Component
Los Medanos	3.14	3.19	2.60
McDonald Island	2.66	2.84	2.39
Pleasant Creek	2.14	2.14	1.98

Component RAG Counter			
	Green	Amber	Component
Los Medanos	127	26	21
McDonald Island	420	97	70
Pleasant Creek	28	0	7

Highest Asset Health Score						
	Los Medanos		McDonald Island		Pleasant Creek	
		Score		Score		Score
Pad/Platform	PAD A	3.54	Turner Cut	3.12	Pleasant Creek	2.14
Well	LM-17D	3.75	TC-12N	4.27	PC 4-1	2.28

At the time of this Asset Management Plan's publication, the Storage asset family was performing quality assurance on the calculated condition health scores. Another phase of the development of this scorecard will be to analyze the weighting of scores. Future progress of the Asset Health Scorecard will be to adopt the scoring methodology developed by the Transmission Pipe, Compression & Processing, and Measurement & Control asset families and incorporate them into the health of the Storage facilities.

I. Research Projects

The following table shows an overview of research projects in progress, completed projects, and the related risks being addressed.

Table 35 - Research Projects 2013 – 2017

Ref.	Risks	Description	Vendor	Status	Planned Completion
1	STO018, STO020, STO020.1	Explorer Hardness Tester	NYSEARCH	Active	2016
2	STO031, STO031.1	Robotics (Explorer) Crack Sensor	NYSEARCH	Completed	2015
3	STO005, STO005.1	Factors Affecting Downhole MFL Accuracy (US-3B)	PRCI-2013	Completed	2013
4		Improving Casing Assessments: Downhole Stress Effects on MFL and Confirmation of RSTRENG accuracy (US-3B)	PRCI-2014	Active	2015
5		ILI Technology Comparative Testing (US-3J)	PRCI-2015	Active	2016
6		Defect Characterization of Well Casing Pipe Using NDT to Confirm Field ILI Tool Accuracy (US-3H)	PRCI-2015	Active	2016
7		Cement Degradation Mechanisms (US-3A)	PRCI-2012	Completed	2013
13		Assess the Accuracy of MFL Inspection Tools, US-3K	PRCI-2016	Active	2016
20		Field Evaluation of Cement Bond Log Tool, US-4-1	PRCI-2016	Active	2016
8	STO022, STO023, STO024, STO026	Unmanned Aerial System (UAS) Regulatory and Assessment	NYSEARCH	Active	2016
14		Application of Miniature Methane/Ethane Sensors on Small-UAV ROW-3H	PRCI-2016	Active	2017
15		Fast, Accurate, Automated System to Find and Quantify Natural Gas Leaks (ROW-3H)	PRCI-2014	Active	2016
16		UC Merced Applicability of Unmanned Aerial Systems for Leak	UC Merced	Completed	2015
9	Methane	Methane Emissions Quantification Project	LBNL	Active	2016

Ref.	Risks	Description	Vendor	Status	Planned Completion
12	Reduction	Review Methane Emission Qualification Techniques, US-4-2	PRCI-2016	Active	2016
10	STO017, STO017.1	Field Applied Coatings Performance	OTD-GTI	Completed	2014
11	STO029	Demonstration of a cyber security device	SecLab	Completed	2014
17	STO005, STO005.1	NYSEARCH - Robot to visually inspect pipe casing	NYSEARCH	Active	2016
18	STO016, STO016.1, STO017, STO017.1	Develop an Alternate Method for Potential Measurement to Satisfy the Cathodic Protection Criteria	PRCI-2013	Completed	2014
19		Internal Corrosion Sample Collection Guidelines	PRCI-2014	Completed	2014
21		Real-Time Active Pipeline Integrity Detection System	CEC	Completed	2015
22	STO022, STO023, STO024, STO026	Girth weld integrity underground movement	JIP CRESS	Completed	2016

J. DOGGR Emergency Regulations

On October 23, 2015, a leak was detected at Southern California Gas Company's (SoCal Gas) Aliso Canyon underground storage facility and was permanently plugged on February 18, 2016. During the leak on January 6, 2016, the California Governor issued a state of emergency through a proclamation with 14 directives. The Division of Oil, Gas, and Geothermal Resources (DOGGR) then issued Emergency Regulations (Requirements for Underground Gas Storage Projects, California Code of Regulations Title 14, Division 2, Chapter 4, Subchapter 1, Article 3, Section 1724.9) based on the Governor's Emergency Proclamation Directive #13 with an effective date of February 5, 2016. As of the writing of this Asset Management Plan, PG&E has completed five of the seven items included in the DOGGR Emergency Regulations with the pending two items on target for completion by August 2016. The following table lists the status of PG&E's efforts related to the DOGGR Emergency Regulations as of June 2016.

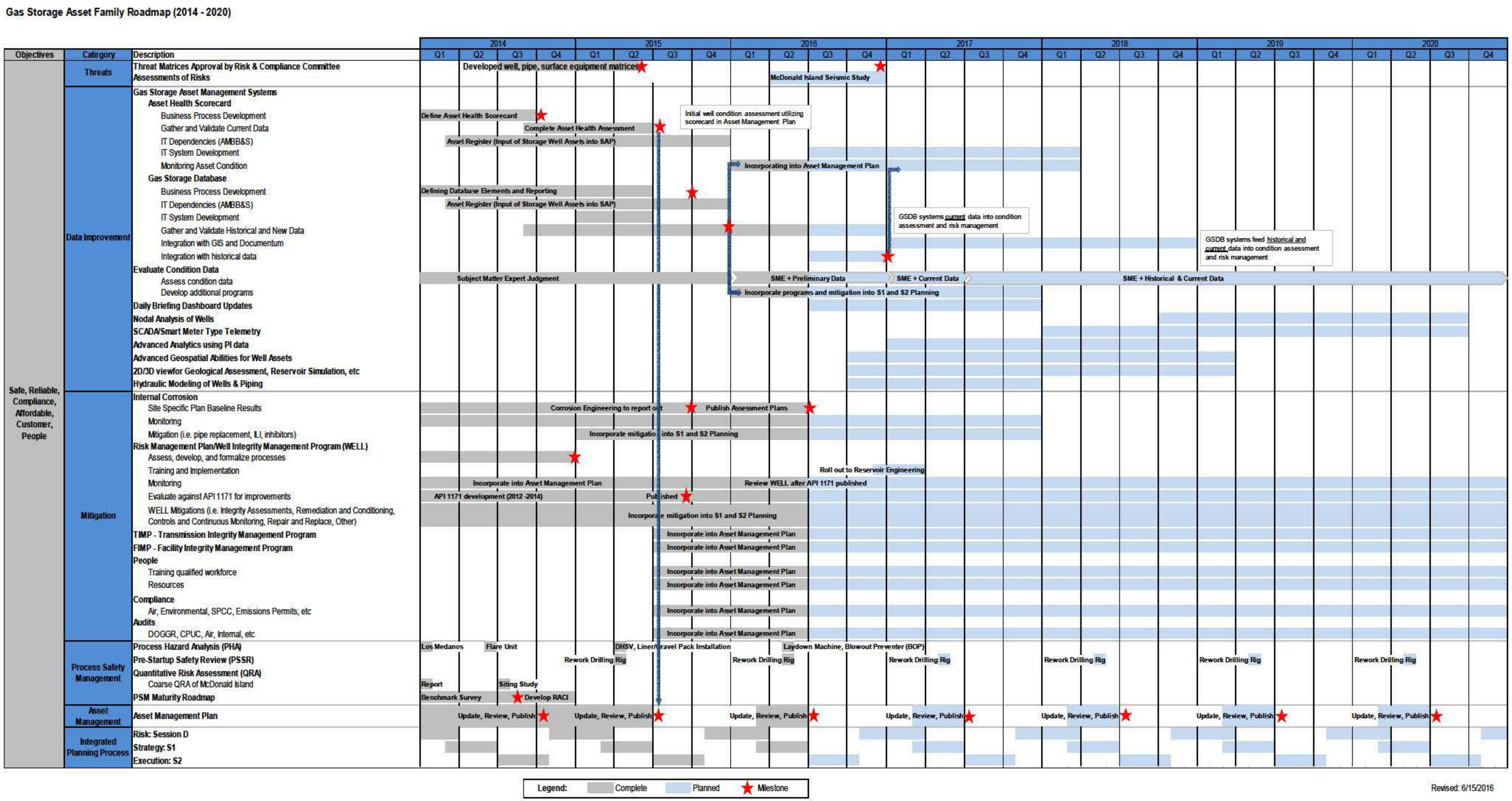
Table 36 - PG&E's Status of DOGGR Emergency Regulations

Directive #	Description	Status
13a	Providing required data.	• On-going. • PG&E has submitted responses in timely manner.
13b	Establish minimum and maximum pressure limits for each gas storage facility in the state.	• In progress. • Developing supporting documentation due Aug 18, 2016.
13c	Verification of the mechanical integrity of all gas storage wells.	• Complete and on-going.
13d	Regular testing of all safety valves used in wells.	• Complete. • PG&E submitted letter to DOGGR on May 25, 2016, regarding 5 wells' valves to be replaced during 2016 rework program.
13e	Daily inspections of gas storage well heads, using gas leak detection technology.	• Complete. • Daily inspections and leak survey implemented Jan 23, 2016. • Submitted protocol Feb 26, 2016. • Received DOGGR feedback April 5, 2016. • Submitted revised protocol May 16, 2016. • DOGGR and ARB reviewing week of June 6, 2016.
13f	Regular testing of master valves and isolation valves.	• Complete. • DOGGR witnessed testing. • All valves had successful functional test.
13g	Establish a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipe and equipment.	• In progress and on track to meet Aug 5, 2016 deadline.

K. Roadmap

The following figure shows an overview of milestones for data improvement and mitigation programs utilized in the Storage asset family to assess condition and risk.

Figure 14 - Gas Storage Asset Family Roadmap for 2014 – 2020



PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

UNDERGROUND STORAGE RISK AND INTEGRITY MANAGEMENT PLAN

Underground Storage Risk and Integrity Management Plan

SUMMARY

Pacific Gas and Electric Company (PG&E) underground natural gas storage fields help provide customers with safe, reliable and affordable gas throughout the year and provide peak day gas supply during high-demand periods. The gas in the storage fields belongs to PG&E and customers and is injected, stored, and withdrawn as required.

This Underground Storage Risk and Integrity Management Plan (the "Plan") has been developed to protect the public, environment, company and contract personnel in compliance with the California Code of Regulations Title 14, Division 2, Chapter 4. The Plan also provides a means to verify that the gas stored in the facility remains contained in the reservoir and that the reservoirs are protected from undesired gas migration or loss of integrity of the wells.

Implementation of this Plan allows PG&E to identify potential threats and hazards to reservoir and well integrity; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate the risk associated with each threat; and specify a process for periodic review and reevaluation of the risk assessment and prevention protocols. The Plan specifies a schedule for submission of risk assessment results to the Division of Oil, Gas and Geothermal Resources (DOGGR).

The Plan provides practices for assessing existing reservoir and well integrity, and for monitoring of existing reservoir and well operations in order to demonstrate and verify that the gas stored in the facility remains contained in the reservoir and protected from undesired reservoir gas migration or breaches in the wells. Requirements for new storage field design and construction, expansion of existing storage capacity, commissioning of new or expanded capacity and drilling of new wells are not covered in the Plan.

The Plan does not replace or restrict PG&E's compliance with any specific requirements applicable to pipelines and associated facilities pursuant to the United States Code of Federal Regulations Parts 190-199 of Title 49 and California Public Utilities Commission General Order No. 112.

Principles of Process Safety have also been incorporated into the practices as identified in the Plan.

TARGET AUDIENCE

Employees involved with Gas Storage Operations such as Operations & Maintenance, Reservoir Engineering, Station Services, Corrosion Engineering, Pipeline Services, Transmission Integrity Management Program, and Leak Management.

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Requirements

1 Regulatory Jurisdiction for Company Gas Storage Fields

Company natural gas storage fields are subject to the jurisdiction of California Public Utility Commission (CPUC) which has issued Certificates of Public Convenience and Necessity for each PG&E storage facility. Additionally, the safety, design, construction, operation, and maintenance are under the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA), CPUC, and Department of Conservation rules and regulations.

2 Roles and Responsibilities

The stakeholders who are involved in the Plan are listed in the following table.

Table 1: Stakeholders

Department	Responsibilities Related to Storage Assets
Gas Storage Asset Family Owner	• Understand the condition of Storage assets • Understand the risks to Storage assets • Develop and implement asset risk reduction strategies • Develop long term financial plan
Operations & Maintenance	• Operate the Storage assets • Perform preventive and corrective maintenance on equipment
Reservoir Engineering	• Maintain integrity of wells and reservoirs within Storage facilities
Station Services	• Maintain integrity of pipe and surface equipment within Storage facilities
Corrosion Engineering	• Develop corrosion site specific plans for Storage facilities
Pipeline Services	• Maintain integrity for transmission pipe system including pipe near Storage facilities
Transmission Integrity Management Program	• Identify threats, assess asset condition, and prioritize mitigation work for transmission pipe system including pipe near Storage facilities
Leak Management	• Provide guidance and coordinate leak survey of Storage facilities

3 Flow of Plan Activities and Frequency of Plan Updates

PG&E uses the guidance provided by American Petroleum Institute (API) Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs for the design, operation, and maintenance of storage facilities. The Plan will be reviewed on a frequency not to exceed 5 years for the entire document. The first updates are to be completed according to the following schedule:

Table 2: Section Update Frequency

Sections to be Reviewed	Frequency
Section 1 through 15, Appendix A through Appendix G, Practice 3, Appendix W through Z	18 months after publication
Appendix H, Practice 4 through Appendix O, Practice 11	36 months after publication
Appendix P, Practice 12 through Appendix V, Practice 18	54 months after publication

4 UGS Integrity Management Process

The following tasks are performed to demonstrate and verify reservoir and well integrity:

- Reservoir Characterization
- Reservoir Design Basis
- Field Integrity/Inventory Verification
- Observation Well Monitoring
- Monitor Third Party Wells
- LUAF (Lost & Unaccounted For)
- Measurement Correlation
- Inventory Verification Study
- Audit of Inventory report by Consultant
- Well Integrity
- Downhole Logging
- Annular Pressure Monitoring
- Gas Sampling
- Safety Valve Maintenance/Testing
- Wellhead Maintenance
- Remedial Action and Well Construction
- Well Pressure and Flow Monitoring
- Wellhead Inspections and Leak Survey

5 Data Management

Traceable, verifiable, and complete gas storage asset data is maintained in an accessible manner for periodic regulatory inspection. Also, data is maintained to evaluate the health of the facility.

6 Reservoir Integrity

Ongoing verification and demonstration of the integrity of the reservoir includes demonstration that reservoir integrity will not be adversely impacted by operating conditions. Reservoir integrity is verified by inventory-bottomhole pressure surveys/shut-in test or other pressure decline analysis methods, monitoring observation wells, monitoring third-party existing and new wells, performing measurement correlation/audits, and lost and unaccounted for gas studies.

6.1 Reservoir Characterization

Geological and engineering characteristics of the reservoir influence its performance and integrity capability. As new information that could influence integrity is available, the reservoir characterization is reviewed and updated. The reservoir characterization addresses rock characteristics such as lithology and lithologic variation, porosity, permeability, average thickness, areal extent, caprock thickness, caprock threshold pressure, reservoir/caprock fracture gradient, locations and characteristics of faults and fractures, location and characteristics of any offset hydrocarbon operations, reservoir temperature, original and conversion pressure, original and produced native oil, gas and water, original and current fluid properties such as density, viscosity and chemistry The characterization is illustrated in the form of structure maps, isopachous maps, and geologic cross section drawn through at least one well location with a type log incorporating the deepest producing zone. Illustrations are clearly labeled as to scale and purpose and clearly identify wells, boundaries, zones, contacts and other relevant data. Updated characterizations are made available to appropriate regulatory agencies.

6.2 Reservoir Design Basis

The reservoir design basis states the purpose of the storage service and incorporates operating limits that are updated to keep current. The design basis addresses the injection and withdrawal plans and method, well type and distribution, maximum design reservoir and well flow rates, minimum design operating pressure and evidence for not exceeding geo-mechanical strength, maximum design operating pressure and evidence for not exceeding geo-mechanical or surface facility strength, observation well purposes and locations, cathodic protection systems, water source wells if any, water disposal operation, and surface and subsurface safety systems employed. The design basis is illustrated in maps showing all well locations and key pipeline facilities, cathodic protection facilities if any, water source and disposal wells if any, An updated design basis is made available to appropriate regulatory agencies, particularly as it accompanies intended changes or well additions requiring prior regulatory approval.

6.3 Inventory BHP Surveys/Shut-in Test or Other Pressure Decline Analysis Methods

Storage field inventory studies verify the volume of gas in the storage reservoirs compared to the company booked volumes. Gas volumes that need reconciliation consist of native base gas, injected base gas, injected and withdrawn working gas (less fuel) and other losses, both measured and estimated. These studies consist of conducting a pressure-inventory analysis for each storage reservoir as described below. A detailed description of the methodology, terms, and definitions related to inventory studies is included in Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification.

6.4 Observation (OBS) Well Monitoring

Observation (OBS) wells are utilized to monitor gas pressure movement within a storage zone and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone. Some OBS wells were originally oil/gas production wells obtained with the acquisition of the field and others were drilled as part of the development of the field.

Observation well pressure data is utilized to monitor the reservoir pressure versus inventory relationship and trends indicating field stabilization or anomalies which may be indicative of gas loss or migration.

Gas samples are obtained and analyzed from OBS wells and selected injection/withdrawal wells to determine if changes in gas composition occur over time. The samples may be taken from OBS wells completed in the fringe area of the storage zone and/or OBS wells completed in porous zones above or below the storage zone. This information is recorded in the Gas Storage Database (GSDB). Changes in gas composition may indicate movement of storage gas toward storage boundaries. This information is valuable for identification of potential storage gas migration.

Some injection/withdrawal (I/W) wells that are connected to the transmission pipe of the respective storage fields are not utilized to flow gas into or out of the reservoirs but are utilized for reservoir monitoring purposes similar to OBS wells. The following is a summary of questions PG&E attempts to answer in its evaluation of the pressure response and gas sample data from an OBS well or an I/W well.

- Are pressure changes observed at the surface or bottom hole?
- What is the fluid observed in the well – oil, gas, brine, etc.? If gas, does the gas sample reflect native or storage gas?
- Which formation is the OBS well monitoring – the storage zone, fringe area of the storage zone or potential porous zones above or below the storage zone into which gas could migrate?
- Status of nearby wells – what does the data from offsetting wells provide?
- Well mechanical integrity history
- Does annular pressure monitoring data indicate the integrity of tubing or casing?
- Are apparent defects present on casing inspection logs? If so, what is the rate of change of apparent defects?
- Well location – is the well near houses, buildings, roads or waterways?
- Does the pressure of this well track closely with the reservoir pressure?
- Is this well being used for gas injection and/or gas withdrawal?
- Is the drainage area from this well a low percentage?
- Is the gas analysis from this well similar to the gas analysis from the remainder of the reservoir?

6.5 Monitor Third-Party Existing and New Wells

An important part of maintaining storage field integrity is verifying that any third-party wells within the protection acreage and/or penetrating the storage reservoir are adequately designed to prevent the leakage of gas from the reservoir. PG&E also attempts to periodically monitor these wells to detect leaks that may develop later in the life of a well.

PG&E seeks to obtain written access agreements with the operators of existing and new third-party wells to minimize operational misunderstandings and future problems. PG&E also seeks assurances that all planned third-party wells that will penetrate its storage reservoirs comply with state regulations; PG&E does not waive any state regulation nor accept attempts to lessen any requirement. If allowed by the operator, PG&E monitors the drilling, cementing and logging of any third-party well.

The following criteria are used to evaluate existing and new third-party wells that are within the protection acreage and/or penetrate the storage reservoir.

1. Existing Wells

   - Thoroughly review the state regulations for third-party wells penetrating gas storage reservoirs and specific state regulations pertaining to individual reservoirs and verify that these rules are strictly followed.
   - Identify well location, serial, and state permit or API number, production interval, total depth, and operator.
   - Obtain available well data, schematics, and logs, and conduct a thorough review of state files.
   - Obtain gas, oil, and water production data from the state and/or well data from service companies.
   - Monitor production data annually and look for anomalies.
   - Sample the storage reservoir gas and, if necessary, obtain a gas analysis from the existing well to be used for comparison purposes.
   - Open dialogue with outside operator and obtain written permission to perform the following, if practicable:
   - Routinely monitor all annular and tubing pressures.

- Sample the gas streams including the tubing and the tubing-casing annuli (TCA), and perform a gas analysis at least once but more often if anomalies are identified. Resample if the producing horizon changes.

2. New Wells

- Review the design and completion of the well. Verify that the storage zone will be properly isolated by cement and that the casing design is adequate for storage field pressures.
- To the extent practicable, monitor the drilling, cementing, logging, and perforating operations of third-party wells.
- Review all available logs and identify any anomalies.
- If PG&E suspects that the integrity of its storage reservoir has been breached by a new well, PG&E will contact the operator and attempt to negotiate a plan for remedial action.

6.6 Measurement Correlation and Lost and Unaccounted For (LUAF) Studies

Metering errors and fuel/station gas usage for underground gas storage operations represent gas "losses" from inventory and are accounted for monthly. The following potential gas losses are considered to verify gas inventory.

- Engine starting gas utilized (number of starts times the volume of a typical start).
- Venting volume of compressor and piping each time a unit is shut down and the number of times it is shut down each month.
- Emergency shut down (ESD) blow down volumes.
- Other equipment depressurizing (volume of each event).
- Station fuel.
- Well blow downs (number of wells, starting pressure, and volume of each).
- Transmission pipe system header blow downs.
- Relief valve discharge occurrences and estimate of volume.
- Flash gas from atmospheric tanks.

- Flare gas, where applicable.
- Diffuse gas losses from leaking valves, flanges, and screwed pipe.

7 Mechanical Integrity of Wells

Ongoing verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage are performed. The protocols for verifying and demonstrating well integrity shall not be limited to compliance with the mechanical integrity testing requirements under Section 1724.10(j), and include consideration of risk-based decisions for each well.

Gas storage wells may be in service for 75 or more years. Therefore, it is prudent to design the wells to remain intact for that time period and to monitor and maintain the integrity to prevent gas leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging, cathodic protection and monitoring, MIT (Mechanical Integrity Test), and annular pressure monitoring. Refer to Appendix Z which illustrates the process flow for the testing regime to demonstrate well integrity.

7.1 Well Characterization and Analysis

Each active and plugged well within the buffer zone is characterized for its mechanical "as is" condition by means of a wellbore schematic (and wellhead diagram for active wells) utilizing the practices in Appendices F and G. The schematics and diagrams are maintained in a current state and reflect the most recent well entry findings, workovers, integrity tests, and equipment changes.

Each active and plugged well within the buffer zone is analyzed for its current mechanical integrity utilizing a barrier analysis methodology to identify any deficiencies that need to be addressed. The barrier analysis incorporates tubular and wellhead design safety factors and cementing standards that meet or exceed minimum regulatory requirement.

7.2 Storage Well Logging

1. Wells are logged to identify potential problems and may include the following types of cased hole logs (type of log/survey identified in parenthesis).
    - Reductions to casing wall thickness (MFL, Caliper, and Ultrasonic Casing Inspection Tools)
    - Identification of gas presence behind the casing (Gamma Ray-Neutron – GRN)
    - Presence of a corrosion cell (Casing Potential Profile – CPP)

- Temperature logs
- Noise logs
- Downhole video cameras
- E-Log-I surveys

2. In addition, for future new storage wells, the following list of logs shall be considered to be run during drilling and completion. The principle (how the log works) and the identification (purpose of the log) are presented in Appendix A, Well Logging Criteria for New Wells, along with the list of logs.

    a. Open Hole Logs

    - Caliper
    - Density w/Pe (Litho-Density)
    - Compensated Neutron Log (CNL)
    - Spontaneous Potential (SP)
    - Gamma Ray (GR)
    - Resistivity Logs (Dual-Induction or Array Induction)
    - Microlog (ML)

    b. Cased Hole Logs

    - Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)
    - Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator
    - Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator

7.3 Casing Inspection Tools

Casing Inspection Tools are beneficial to get a baseline on the condition of the casing and tubing. The following criteria summary should be utilized (See Appendix C, Casing Inspection Survey Frequency Decision Tree for further details):

- Run baseline logs (casing inspections and/or GRN) on every well when the tubulars are removed.

- Follow-up casing inspections are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe.

- Follow-up casing inspections on tubing and packer completed wells are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection run.

- Annual Noise, Temperature, and GRN logs will be run on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review.

For more details, please refer to Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments.

7.4 Casing Potential Profile (CPP)

Coordination and communication with the Operations department to verify that wells are protected by a cathodic protection system. Periodically, E-Log-I surveys may be conducted by Corrosion department to verify that adequate cathodic protection current is being applied to each well's production casing string.

8 Casing Pressure Tests and Annulus Monitoring

8.1 Mechanical Integrity Test (MIT)

Wellbore Mechanical Integrity Tests (MIT) are hydrostatic tests that demonstrate that the well casing is capable of holding a pressure at the time the test was conducted. Performing MIT on wells completed with tubing and packer is relatively simple due to the nature of the completion. A pump truck is connected to the casing valve and fluid is slowly pumped until the annular pressure reaches the desired pressure. The pressures test is one hour at 115% of Maximum Operating Pressure (MOP) or the minimum yield strength of the casing and tubing, whichever is less. A passing pressure test is a pressure loss not exceeding 10% for any 30 minute period during the one hour long test. A casing MIT test is to be performed on a well upon completion and for a well completed with tubing and packer, at a rate of not less than one test every five years. If, during the five years the tubing and packer is removed and replaced, a MIT will be conducted prior to returning the well to service. Refer to Appendix Z for details.

8.2 Annulus Monitoring

Monitoring of well Surface Casing Annuli (SCA) and Tubing Casing Annulus (TCA) is completed daily and more frequent if determined necessary. To minimize corrosion in the surface casing and casing for wells where the surface casing is not cemented to surface, the SCA should be liquid filled and shut-in to prevent atmospheric corrosion in the annular space. Any anomalous SCA or TCA pressures must be reported immediately to the manager, supervisor, and engineer. A plan of action should be developed to assess the anomalous pressure and could include taking the well out of service, collecting gas sample(s), and conducting a blow down test. Based on results, remedial action will be determined and the well will remain out of service until repairs are completed or the well will be placed back in service. All documentation will be kept in the well file.

8.3 Tubing Casing Annulus (TCA) Monitoring for Wells Completed with Tubing Set on Packer

Monitoring of Tubing Casing Annulus (TCA) is completed daily, and if a well exceeds its historically observed pressures by 100 psi, it will be reported on the monthly field reports and scheduled for a blow down test. If it is a new event within the documented history of the well, a blow down test will be conducted immediately. The only exception will be in the case of elevated pressures following a MIT that utilized water as opposed to natural gas. It is common with MIT that utilizes water to observe elevated pressure anomalies immediately following the MIT due to expansion caused by high bottom hole temperatures. If it is not a new event within the documented history of the well, a blow down test will be conducted during the next collection of monthly manual well pressure readings.

Initial pressure, final pressure, and blow down time should be recorded on all blow down testing and submitted to engineer. Based on blow down test results, any required remedial action including gas analysis and work overs will be determined and a decision to keep the well in service will be made by the manager, supervisor, and engineer. If a well decreases in pressure by 100 psi or goes on vacuum, it will be reported on the monthly field reports and evaluated for the cause, i.e., packer fluid leaking from the annulus versus cooling effects.

8.4 Surface Casing Annulus (SCA) Monitoring / Bradenhead Test Procedure

Monitoring of Surface Casing Annulus (SCA) is completed daily. For more details, please refer to Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring.

9 Safety Valve Maintenance

Many of the PG&E wells are equipped with a "downhole" safety valve (DHSV) installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellheads master valves or flow control as a result of accidents caused by runaway trucks, explosions, outside natural forces, vandalism/terrorism, or other nearby construction activities. These downhole safety valves are hydraulically operated and are "fail safe" type valves.

In addition, all injection and withdraw wells have "uphole" safety valves (UHSV) installed at the wellhead (one for the casing and tubing flow) to provide emergency shutdown to protect well and pipeline integrity from abnormal low pressure downstream of the well.

Safety valve leak tests shall be performed with a severity leak rate determined and evaluated using the tables included in Appendix I, Practice 5: Uphole Safety Valve (UHSV) Test Procedures and Appendix R, Practice 14: Downhole Safety Valve (DHSV) Testing.

10 Wellhead Valve Maintenance

Storage wellhead valves need to be maintained in order to shut off gas flow or close a well in the event of an emergency or for routine maintenance. All wellhead valves should be inspected and the inspection may include three components.

- Visual inspection of the external condition of the valve (corrosion, cracks, etc.)
- Observance of packing leaks
- Determine if the valve isolates the well (proper operation, grease valve, etc.)

> **NOTE**
>
> Downhole valves can only be tested for proper operation and isolation of the well.

The level of inspection varies depending on whether the visit to a well site is for routine data gathering or during the semi-annual shut-in test when valve isolation is typically evaluated. If an inspection includes all three components, it is considered a full inspection. All wellhead valves (including downhole) in the direct line of gas flow have a full inspection conducted annually, but the period between inspections should not exceed 15 months. All other valves that are not in the direct line of gas flow should have a full inspection once every two years, but the period between inspections should not exceed 24 months (these valves are typically installed on surface casing annulus and tubing/packer completed well annulus).

11 Corrosion Monitoring and Evaluation

Corrosion monitoring and evaluation is performed at Storage facilities to evaluate the potential for corrosion and the effectiveness of mitigative measures. Corrosion monitoring data is also utilized to establish integrity assessment priorities and the results of integrity assessments are used to further evaluate the effectiveness of the corrosion control program at Storage facilities. Elements of the corrosion monitoring and evaluate program are discussed below.

11.1 Tubular Integrity

Evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage is performed by using a casing inspection tool and visual inspection during well reworks. For more details on casing inspections, refer to Section 7.3: Casing Inspection Tools.

During well reworks a visual inspection is performed on tubing for apparent external corrosion including:

- Corrosion in the threads of the tool joints
- Apparent pits and holidays
- Excessive rust and scales

11.2 Wellbore Produced Fluids and Solids

Gas, liquid, and solids samples will be collected from active flow lines during withdrawal season to evaluate the corrosive potential of the product stream. Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate liquid sampling from individual flow lines. Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures is discussed below.

1. Operating Pressure

   Minimum withdrawal flow rates are established to lift fluid from the bottom of the well to the surface. Fluid production is necessary to allow the wells to continue production to meet demand.

   As the corrosive potential of produced liquids is related to operating pressures, pressures will be recorded during each gas sampling event to further evaluate the corrosion potential of produced gas and liquids.

2. Gas Sampling

   Permanent gas sample locations are currently being evaluated at / near each wellhead. Corrosion evaluations will utilize gas sampling results for water vapor, carbon dioxide, and hydrogen sulfide content. Carbon dioxide and hydrogen sulfide concentrations will be converted to partial pressures to further evaluate the corrosion potential based on reservoir pressure.

   Gas samples will initially be collected at each wellhead on a monthly basis to establish a baseline for a gas withdrawal season. PG&E has historically spot sampled gas quality at wellheads and historic data indicates minimal changes in gas quality during the withdrawal season. Results of the baseline sampling will be evaluated to determine whether changes in the sampling frequency can be supported.

3. Produced Liquid / Sludge Sampling

Produced liquid / sludge will be collected from active flow lines during withdrawal season to evaluate the corrosive potential of the product stream. Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate liquid sampling from individual flow lines.

Once facility modifications have been made to facilitate sampling of produced liquid / sludge at each flow line, liquid / sludge samples will initially be collected on a monthly basis to establish a baseline for a gas withdrawal season. All samples will be analyzed for pH, acid producing bacteria, sulfide reducing bacteria, and chloride concentrations. Additional laboratory analysis may be conducted to further characterize the corrosive nature of produced liquids. PG&E has historically sampled liquids at traps / drains / separators installed downstream of individual flow lines. Results of the baseline sampling will be evaluated to evaluate and compare the corrosive potential of produced liquids from individual wells and flow lines to historic data obtained from the comingled product stream. This analysis will determine whether changes in the sampling frequency and / or locations can be supported.

4. Sand Inspections

When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further, the presence of sand is an indicator of a potential failure of the well's gravel pack and screen liner to prevent sand production. The sand inspections occur twice during the winter withdrawal period under a standard clearance: typically once in January and once in March. If sand is detected, Reservoir Engineering will evaluate whether to reduce rate, shut-in a well, or re-gravel pack and install a new screen liner. For details, please refer to the Appendix H, Practice 4 - Sand Inspection.

11.3 Annular Packer Fluid

To minimize the corrosion potential of the annular between the casing and the tubing, packer fluid with corrosion inhibitor is placed in annular and packer behind the scab liner / inner string. Annular filled with packer fluid can minimize the annular exposure to atmospheric corrosion (oxidation).

11.4 Current Flows Associated with Cathodic Protection Systems

Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system. Results are integrated with downhole metal loss and casing potential logs to further evaluate the performance of the corrosion control systems.

11.5 Formation Fluids

Corrosion potential of all formation fluids is further reduced when cement is placed between the formation and production casing to isolate fluid from contacting the casing from the above storage zone. For more details, please refer to Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment.

11.6 Uncemented Casing Annuli

Methods to monitor corrosion potential of the uncemented casing annuli include running MFL, Ultrasonic, and Caliper logs to determine metal loss and a decrease in casing thickness due to corrosion or erosion.

11.7 Pipeline and Other Production Facilities

1. Pipeline Assessments

PG&E applies the Transmission Integrity Management Program (TIMP) to all transmission pipe, including pipe operating within storage fields meeting the requirements of 49 CFR part 192 Subpart O. This includes High Consequence Area (HCA) analysis, threat identification and risk assessment on all transmission pipe on an annual basis. For HCAs, assessments and reassessments of the identified threats are performed within the code-prescribed timeframes and may include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), In-Line Inspection (ILI), and Hydrostatic Testing. In addition, PG&E is currently considering a threat assessment program to assess non-HCA pipe in exceedance of minimum code requirements.

2. Atmospheric Coating Systems

Above grade piping, to include wellheads and gas measurement / treatment equipment, is protected with atmospheric coating systems that are inspected on three year intervals.

3. Cathodic Protection

Buried and/or submerged piping is protected by underground coating systems and impressed current cathodic protection systems that are monitored at intervals described in Section 11.4. Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system.

4. Internal Corrosion Site Specific Plans

Internal corrosion monitoring, flow modeling, and nondestructive examination (NDE) is utilized to monitor and mitigate the threat of internal corrosion. High risk pipeline areas are targeted for additional inspection by using radiography and/or ultrasonic thickness (UT) testing to further evaluate the potential for internal corrosion. Additional monitoring to include weight loss coupons, UT monitoring probes, and/or electrical resistance (ER) probes will be utilized as required. Other metallic facilities that store or transport gas (such as filter separators) are inspected for internal corrosion on a risk based schedule.

PG&E began radiographic direct inspections for internal corrosion (IC) in 2014 and has currently inspected 40% of the highest risk storage assets for IC. The site specific plans for each storage area will target a goal of 100% of the high risk assets every 7 years. This translates to roughly 14% of the high risk areas annually.

Areas where damage in excess of 20% wall loss is found have an ultrasonic thickness (UT) probe installed to monitor for internal corrosion depth growth. These probes are monitored bi-monthly. This also helps determine areas where IC is either historical or possibly active.

When liquid samples are available, they will be analyzed for corrosive constituents including, but not limited to: pH, chlorides, and bacteria (types that initiate microbiologically induced corrosion).

PG&E conducts sand inspections to monitor for sand that may cause erosion corrosion damage in the pipelines and downstream equipment as described in Section 11.2.4.

12 Evaluation of Wells and Attendant Production Facilities

Protocols for evaluation of wells and attendant production facilities include monitoring of casing pressure changes at the wellhead, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.

12.1 Casing Pressure Changes at the Wellhead

Casing pressure changes at the wellhead are monitored and evaluated. For more details, please refer to Appendix L, Practice 8 – Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring and Appendix N, Practice 10 – Wellhead Production Casing and Tubing Pressure Monitoring.

12.2 Facility Flow Erosion

Flow erosion mitigation is incorporated into facility design, past and present. Examples include targeted tees and long radius bends/sweeps.

12.3 Hydrate Potential

If not prevented, hydrates can plug or rupture lines and may cause extensive equipment damage. Dehydration systems, heaters, insulated/heat traced lines, and methanol injection can help prevent hydrates from forming. All three of PG&E storage facilities have gas dehydrators. In addition, Los Medanos has heaters located at well meters. Also, at McDonald Island a majority of aboveground well lines are insulated and heat traced, and the facility uses a methanol injection system.

12.4 Facility Component Capacity and Fluid Disposal Capability

Facility components are designed (sized) for station maximum capacity, and fluid disposal systems for respective capacities. For more details on capacities, please refer to Appendix Y, Production Fluid Facility Capacity Tables.

12.5 Operating Pressure Range

Minimum withdrawal flow rates are established within the operating pressure range to lift fluid from the bottom of the well to the surface. Fluid production is necessary to allow the wells to continue production to meet customer demands. Each well shall have established well operating parameters within limits. This should include pressures and/or flow rates to minimize flows that could lift sand or erosion due to velocity.

12.6 Well Risk Ranking

The risks on a well by well basis are relatively ranked based on a score incorporating likelihood and consequences of failure. The factors contributing to the likelihood of an event on a particular well include age of the wellbore, the presence of a downhole safety valve (DHSV), and the top of cement. Consequences of failure include the well's flow rate, proximity to offset wells, proximity to water, proximity to roads, proximity to occupied structures, type of local activities, natural forces, physical security, and personnel exposure.

Two categories of well work in the integrity management program are: (1) well remediation and conditioning (i.e., rework projects); and (2) well integrity assessment.

The rework projects category of work typically includes: 1) assessment of the storage wells' condition, and additional corrective work for mitigating any potential risks/threats. To complete this work, the existing Downhole Safety Valves (DHSVs) in wells have to be pulled in order for the well casing pipe to be inspected and the corrective work to be completed; 2) replacement of DHSVs in wells that are identified as not functional based on the test results; and 3) if necessary, installation of new gravel pack to restore well deliverability due to natural degradation from cyclical injection and withdrawal operations, which can damage the gravel pack. Every well that PG&E reworks is assessed for casing and wellbore integrity.

The well integrity assessment includes 1) assessment of the storage wells' condition, and additional corrective work for mitigating any potential risks/threats and if necessary 2) replacement of DHSVs as these are not reusable after being removed for assessment.

PG&E routinely monitors the pace of the well reworks based on available information collected during the fields operation, performance testing of the storage wells and DHSV and prior year integrity assessment information (Noise/Temperature surveys and Casing inspection logging). As shown in the table below, PG&E's rework and integrity assessment programs are to complete integrity assessments and reworking of wells with nonfunctioning DHSV and gravel pack on 99 wells by 2025.

Table 3: Storage Reworks and Integrity Assessments[1]

Base Case				
	McDonald Island	Los Medanos	Pleasant Creek	Total
2016	4	2	0	6
2017	7	1	0	8
2018	4	2	2	8
2019	7	2	0	9
2020	4	4	2	10
2021	7	0	3	10
2022	5	5	0	10
2023	11	1	0	12
2024	10	2	0	12
2025	14	0	0	14
	73	19	7	99

PG&E has developed a prioritization process to determine the order in which to conduct well rework projects. Factors include the number of years a storage well has been in service, excessive annular pressure build rate, downhole safety valve test results, the presence of sand that has accumulated in transmission piping, and any decline in the productive capability of a well. Wells scheduled for assessment take into consideration the relative risk ranking of individual wells. Last, the schedule of reworks and assessments are finalized based on the ability to effectively and efficiently conduct the work, minimize unnecessary equipment mobilization, and reduce the amount of outage time at the storage facilities.

[1] The current program post 2018 is dependent on the prioritization of risk mitigations (refer to Section 14) and approved funding in future Gas Transmission and Storage rate cases.

Another method PG&E is currently developing to relatively rank well condition is the Asset Health Scorecard (AHS). The AHS quantifies the overall health of aggregated wells within a gas storage field by utilizing a set of metrics to score major components within a gas well and using these component scores to grade the well condition. The individual well scores roll-up to an overall pad/platform score and the pad/platform condition scores roll-up to an overall field condition score. This is an area of continuous improvement since the PG&E is currently performing quality assurance on the calculated condition health scores. Another phase of the development of this scorecard will be to analyze the weighting of scores.

13 Potential Threats and Risks

PG&E's organizational structure facilitates the integration of risk management and investment planning. The risk management process provides the framework for evaluation of the likelihood of events and consequences related to threats and risks associated with operation of PG&E's underground gas storage, risk ranking to develop preventive and mitigating measures to monitor or reduce risk, documentation of risk evaluation and description of the basis for selection of preventive and mitigation measures, provision for data feedback and validation, and regular risk assessment reviews to update information and evaluate risk management effectiveness.

13.1 Organizational Structures that Facilitate the Integration of Risk Management and Investment Planning

PG&E's risk management governance structure consists of the following:

1. Nuclear, Operations, and Safety Committee

   The Nuclear, Operations, and Safety Committee (NOS) consists of at least three directors from PG&E's Board of Directors, one of whom is appointed as the Committee's chair. The basic responsibility of the NOS Committee is to provide oversight and review of (i) significant safety (including public and employee safety), operational performance, and compliance issues related to PG&E's nuclear, generation, gas and electric transmission, and gas and electric distribution operations and facilities, and (ii) risk management policies and practices related to operations and facilities.

2. Risk and Compliance Committee

   The Risk and Compliance Committee (RCC) is chaired by the Gas Operations President and includes the Gas Operations Senior Vice President, all Vice Presidents and all Senior Directors. This Committee meets monthly and reviews and approves Session D materials in addition to monitoring compliance and risk management activities. Furthermore, Asset Family Owners (AFOs) present at least once a year on progress, issues, and next steps in their Asset Management Plans.

3. Gas Operations Risk Management Organization

This organization is led by the Manager of Risk Management who reports to the Senior Director of Asset Knowledge and Integrity Management. This organization is responsible for leading the Risk Management process resulting in Session D (focused on risk) and the creation of the Gas Operations Risk Register. The risk management team, consisting of a manager and a number of risk analysts, is also responsible for ensuring that Gas Operations' risk management process is fully integrated and aligned with the Integrated Planning process.

4. Asset Family Structure

In mid-2012, PG&E's Gas Operations divided gas assets into asset families and designated an individual responsible for each family, referred to as an Asset Family Owner (AFO), who is the single point of accountability for fully understanding and managing the health of the assets within the asset family. To help manage the diversity of these natural gas assets and as a foundational step in implementing an asset management system consistent with Publicly Available Specification (PAS) 55 and International Organization for Standardization (ISO) 55001, PG&E established eight separate asset families within its Gas Operations business.

The AFO is a subject matter expert (SME) on the particular type of asset and also has the ability to draw upon other resources within the company to better understand, assess, and manage that family of assets. Associating each asset with a family, and designating an AFO, helps Gas Operations to: (1) identify threats; (2) assess asset condition and data quality; (3) identify and assess risks facing the assets; (4) develop and effectively execute mitigation efforts; and (5) follow a consistent process for managing assets and maintaining alignment across asset families. The AFO represents its asset family in the Risk Management and Investment Planning processes. Each AFO is also responsible for developing an Asset Management Plan for their asset family.

Figure 1. Gas Operations Asset Families

5. Investment Planning Organization

This organization is led by the Director of Investment Planning and Resource Management. This organization is responsible for portfolio-level prioritization across all assets and all programs. Investment Planning leads the process to develop a multi-year investment plan that is informed by risk and operational constraints. This process feeds directly into the forecast development for Session 1 (focused on strategy), Session 2 (focused on execution), and rate case filings.

13.2 Risk Management Process

Gas Operations has adopted a risk management process that provides a consistent and transparent method to identify, assess, rank, and mitigate risk and has integrated this process into the Gas Operations Investment Planning process, which allows Gas Operations to prioritize its investment portfolio based on risk and constraints. The Gas Operations Risk Management and Investment Planning processes are linked directly to the Enterprise and Operational Risk Management (EORM) Program and enterprise-wide Integrated Planning process.

The Risk Management process can be categorized into four major steps: (i) Integrity Asset Threat Classification; (ii) Risk Identification and Evaluation; (iii) Risk Response; and (iv) Risk Monitoring and Reporting.

1. Integrity Asset Threat Classification

   Each AFO works with his/her team to identify the threats to the assets in their families. Typically, AFOs rely on the American Society of Mechanical Engineers (ASME) B31.8S standard as the basis for categorizing and evaluating threats to their assets. The standard identifies nine categories of threats, which are grouped into three main categories:

   a. Stable or Resident: These threats are either present or potentially inherent to the asset but do not grow over time or pose a threat unless influenced by another condition or failure mechanism, such as manufacturing defects influenced by land movement.

   b. Time Dependent: These threats, such as corrosion, are threats that potentially increase over time.

   c. Time Independent: These threats are not influenced by time such as third-party excavation damage, incorrect operations, or weather-related and outside force (e.g., natural forces).

   AFOs complete a Threat Matrix that documents the data quality status of each threat and the status of the various proposed mitigation programs to address those threats.

   In addition to ASME B31.8S, the Gas Storage asset family uses the American Petroleum Institute Recommended Practice (API RP) 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. Potential threats or hazards identified for the wells, reservoir, and surface are listed in the table below:

Table 4: Asset Type and Potential Threats or Hazards

Asset Type	Potential Threats or Hazards
Wells	Corrosion / Erosion, Manufacturing, Equipment
	Construction / Fabrication
	Incorrect Operations (Operation and Maintenance)
	Incorrect Operations (Well Intervention)
Reservoir	Construction / Fabrication, 1st, 2nd, 3rd Party Damage
	Outside Forces (Geologic Uncertainty)
	Incorrect Operations (Reservoir Fluid Compatibility Issues)
Surface	1st, 2nd, 3rd Party Damage (Surface Encroachments)
	1st, 2nd, 3rd Party Damage (Damage to Equipment)
	Weather & Outside Forces (Natural Causes)

Mitigations and prevention activities and guidance documents associated with threats are listed in Appendix X.

2. Risk Identification and Evaluation

Having identified the various threats applicable to the asset family, each AFO works with Subject Matter Experts (SMEs) and the Gas Operations' risk management team to identify the relative risk(s) which are high consequence and low frequency that are associated with each threat. A given threat may have the potential to give rise to or contribute to one or multiple risks. For example, the equipment-related threat results in a different risk for the Measurement and Control asset family than it does for the Distribution Mains and Services asset family. Next, SMEs use available internal and external data, system knowledge, and subject matter expertise to determine the impact and frequency scores using the enterprise Risk Evaluation Tool (RET) to calculate a relative risk score for each risk. The basic components of the RET include:

a. The RET score is a product of the potential impact and the frequency of a risk event, while accounting for the current strength of current controls. Each risk event is considered under a "probable worst case" scenario, otherwise known as a P95 scenario.

b. The potential impacts of the P95 scenario are scored across six impact categories – Safety, Environmental, Compliance, Reliability, Trust, and Financial. Each impact is scored from 1 (negligible impact) to 7 (catastrophic impact).

c. The potential frequency of the risk event is likewise given a score of between 1 (remote) to 7 (frequent).

d. A logarithmic scale is used in RET score calculations to increase differentiation between risks and provide a better view of the relative priority of risks.

e. A weighting factor for each category to indicate the relative importance of one category to another and ensure safety risks receive higher scores than non-safety risks, and as such, higher priority for mitigation consideration.

A series of calibration sessions occur at four levels where AFOs, SMEs, senior management, and officers have the opportunity to challenge and openly discuss the assumptions underlying the scores of the risks. The three levels of calibration are as follows:

(1) The first level of calibration occurs for all risks within each asset family and includes AFOs, SMEs, and the Gas Operations risk management team.

(2) The second level of calibration occurs for all risks across Gas Operations and includes AFOs, risk owners, SMEs, Gas Operations risk management team, and Gas Operations senior management.

(3) The third level of calibration occurs at the enterprise level across all Lines of Businesses (LOBs).

(4) The fourth level is a vertical slice calibration and occurs at the officer level for the enterprise.

The objectives of the calibration sessions are to improve consistency in the application of PG&E's risk model and SME input and judgment, and application of data, while continuously striving to improve repeatability and transparency. The calibrated risks are documented in the Gas Operations Risk Register, which is periodically updated and refined as additional information is obtained, reviewed, and evaluated.

13.3 Risk Response – Development of Mitigation Programs

Using the identified and evaluated risks, AFOs then identify the appropriate risk response plan. A risk response plan includes a set of metrics and mitigations that propose an appropriate course of action to reduce the risk, strengthen the controls, track the progress and assess the effectiveness of mitigations. This process is detailed below:

1. The first step of developing a risk response plan for a given risk is to determine the strategy. AFOs and SMEs identify if they want to reduce, accept, transfer, or avoid the risk.

2. As in most cases, if the plan's strategy is to reduce the risk, then the next step involves AFOs and SMEs assessing the current controls to reduce that risk, and identifying any new potential mitigation. These mitigations are possible future processes, programs, assets, or controls that will reduce the risk.

3. Metrics are developed for the risks to help track progress of risk reduction and to evaluate the results of mitigation plans.

4. The proposed mitigations are then submitted to Investment Planning for portfolio-level prioritization across all assets and all programs.

   The risk response plan for key risks is documented in the Session D presentation material. The mitigations are also documented in the Asset Management Plans and in the initial pre-prioritized program submission to Investment Planning. Note that each of these outputs represents a snapshot in time; therefore, the risk response plans are likely different across these outputs.

13.4 Risk Reporting and Monitoring (Outputs and Documentation)

The Risk Management process is reported, monitored and documented in the following key outputs and forums.

1. Threat Matrix

   A Threat Matrix is developed by the AFOs to document key threats, the data quality status of each threat, and the status of the various proposed mitigation programs to address those threats and is documented within the Session D presentation. Any change to the threat matrix is reviewed and approved by the Risk and Compliance Committee.

2. Risk Register

The calibrated risk scores, justifications, and assumptions resulting from the risk refresh and Session D process are documented in the Risk Register. It is important to note that the purpose of Session D is to communicate the top risks to PG&E's senior leadership. These top risks represent high consequence, yet low frequency events. Low consequence risks managed by ongoing safety, reliability, capacity, compliance and other programs are not typically included in the Risk Register. For example, some support work, such as minor building projects may not address a risk on the Risk Register, but is considered in our integrated planning process. Risks in the Risk Register are mitigated by programs listed in the Threat Matrix.

3. Session D Presentation

Session D reflects an assessment of enterprise risks, operational risks and compliance risks. The Session D process kicks off at the end of the third quarter of each year and deliverables include a risk refresh, the Risk Register, a Session D presentation and an executive discussion among senior PG&E officers across all LOBs. At the annual Session D meeting, senior officers discuss: (1) the top risks for the company and for each LOB; (2) risk reduction or mitigation progress to date; (3) strategies to manage any risk mitigation challenges; (4) future risk management plans; and (5) areas where collaboration across LOBs or additional resources may be required to manage risk.

The information collected in Session D informs PG&E's strategy and execution plans that are developed in Sessions 1 and 2.

4. Asset Management Plans

Gas Operations documents the management of each asset family through an Asset Management Plan (AMP). The AMPs are developed with a 5-year planning horizon to align with the Gas Operations 5-year financial outlook. They describe the: (1) physical assets of the respective asset family; (2) current condition and desired future state of the assets; (3) key risks associated with the asset family; and (4) investments planned or in progress to mitigate and reduce these risks. The AMPs also include Key Performance Indicators, which are metrics intended to measure progress and improvement in asset performance and the effectiveness of mitigation programs.

Asset Management Plans are living documents evolving as new data becomes available. The AMPs were designed to be revised periodically in recognition of the dynamic process involved in identifying, assessing and mitigating risks.

14 Prioritization of Risk Mitigation Efforts

Risk mitigation efforts are prioritized based on potential severity and estimated likelihood of occurrence of each threat.

14.1 Investment Planning Process

As described in Section 13.3, the AFOs submit a list of proposed mitigations to Investment Planning for portfolio-level prioritization across all assets and all programs. Investment Planning leads the process to develop a multi-year investment plan that is informed by risk. The objective of this prioritization is for Gas Operations to invest in its higher risks with the most effective mitigation programs given constraints including compliance obligations, obligations to serve, resources, system availability, executability, and cost. To accomplish this objective, Investment Planning leads the following steps, which include the Risk Informed Budget Allocation (RIBA) process:

1. Classification

   The first step in the process is to classify projects or programs (for example reworks and integrity assessments, refer to Section 12.6: Well Risk Ranking). This step identifies the key drivers for the work, which are used during prioritization in concert with the risk scores of each project or program. Classifications include, but are not limited to: Mandatory; Regulatory Compliance; Commitment; and Work at the Request of Others (WRO).

2. Program and Project Risk Scoring

   The next step in the process is to risk score the respective projects or programs. It is important to note that there is a distinction in purpose between the Risk Register risk score, and the Program and Project risk score. The purpose of the Risk Register risk score is to rank and prioritize high consequence, low frequency risks at the asset level. The purpose of the Program and Project risk score is to relatively capture the consequence and likelihood scores for Safety, Environmental, and Reliability to determine the worst credible event that could occur if PG&E does not invest in the program or project. The program and project risk scoring process uses a framework to assess consequence and likelihood that is aligned with the framework utilized in the development of the Gas Operations Risk Register. The calculations are different; however, they are aligned and that alignment is validated during the process as described in Section 14.1.3 below.

3. Program and Project Risk Score Validation

The next step is to validate the program and project risk score. To facilitate consistent application of risk scores within and across asset families, Investment Planning conducts calibration sessions. In addition, Investment Planning conducts analysis to validate that the program and project risk scores are aligned with the Risk Register risk scores.

4. Preliminary Portfolio

Based on the classification and calibrated risk scoring for projects or programs, Investment Planning builds a preliminary investment portfolio by first including all Compliance, WRO, and Commitment work and then by including programs ranked by their respective program and project risk score.

5. Constraints Analysis

Once the preliminary investment portfolio is compiled, Investment Planning collects information on constraints, including resources, system availability, and financials. Investment Planning then makes adjustments to the preliminary portfolio based on these constraints prior to the Investment Decision Meetings.

6. Investment Decision Meetings

Investment Planning then conducts a series of Investment Decision Meetings with the AFOs and other stakeholders to analyze the portfolio and make any adjustments to the portfolio informed by risks and constraints. These adjustments are typically in the form of increases or decreases to the scope or pace of a program. Investment Planning is responsible for providing portfolio analysis and facilitating the meetings; however, AFOs are accountable for making the investment decisions.

7. Investment Plan Approval and Reporting (Outputs and Documentation)

The Investment Planning process and deliverables are documented and reported in the following key outputs and forums.

a. Program and Project Scoring Sheets

A Program and Project Scoring Sheet is generated for each program considered in the Investment Planning process. The purpose of the program and project scoring sheets is to document and display pertinent information for each program including the classification, program and project risk score along with justifications, rate case forecast iterations throughout the forecast development process, and alignment to Session D.

b. RIBA Charts

The RIBA charts are a visual representation of the output of the Investment Planning process, which display: program cost; program and project risk score; and respective classification.

14.2 Investment Planning Summary

PG&E presents its forecast in rate cases being informed by risk. The work proposed represents an appropriate balance of cost and risk reduction over time, based on the resources available, while maintaining the ability to deliver gas to customers. The RIBA process provides a means of making expenditure decisions that are risk-informed while considering other important factors. Lastly, both the EORM Program and RIBA process involve personnel who are most familiar with the condition of assets and ensures that all levels of management are engaged. The rate cases propose a set of programs that will set PG&E on the right course to continue reducing the risk profile of PG&E's natural gas assets for years to come.

15 Communication Plan

The following table summarizes a schedule of deliverables to be submitted to the Division of Oil, Gas and Geothermal Resources (DOGGR) regarding risk assessment results.

Table 5: Schedule of Risk Assessment Results

Deliverable	Schedule
Identified anomalies	Immediately
Yearly Storage Well Evaluation Report	Annually by January 31
Gas Injection and Production Reports	Monthly
Water Production Report	Quarterly
Inventory Verification Report	Annually by November 30
Asset Management Plan	Annually by September 30

END of Requirements

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Code of Regulations Title 14, Division 2, Chapter 4.

APPENDICES

Appendix A, "Well Logging Criteria for New Wells"

Appendix B, "Additional Investigations"

Appendix C, "Casing Inspection Survey Frequency Decision Tree"

Appendix D, "Remedial Options and Decision Tree"

Appendix E, "Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment"

Appendix F, "Practice 2 - Creating and Updating Storage Wellbore Schematics"

Appendix G, "Practice 3 - Creating and Updating Storage Wellhead Diagrams"

Appendix H, "Practice 4 - Sand Inspection"

Appendix I, "Practice 5 - Uphole Safety Valve (UHSV) Test Procedures"

Appendix J, "Practice 6 - Christmas Tree Pressure Monitoring"

Appendix K, "Practice 7"

Appendix L, "Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring"

Appendix M, "Practice 9 - Individual Well Performance Monitoring"

Appendix N, "Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring"

Appendix O, "Practice 11 - Observation and Selected I/W Well Gas Sampling"

Appendix P, "Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification"

APPENDICES (continued)

DOCUMENT RECISION

This is a new document.

DOCUMENT APPROVER

Larry Kennedy

DOCUMENT OWNER

Larry Kennedy

DOCUMENT CONTACT

Karen Lee

REVISION NOTES

Where?	What Changed?
All	This is a new document.

Appendix A, Well Logging Criteria for New Wells

1.1 The following list of logs should be consideration newly drilled storage wells (vertical).

- Open-hole logs
- Array Induction or Dual Induction
- Density w/Pe (Litho-Density)
- Compensated Neutron (CNL)
- Spontaneous Potential (SP)
- Gamma Ray (GR)
- Microlog (ML) or equivalent

Appendix A, Well Logging Criteria for New Wells

Table A-1: Logs to Consider for Newly Drilled Storage Wells (Vertical)

Type of Log	Principle	Identification
Array Induction	A high frequency current of constant intensity is sent through a transmitter coil. The magnetic field induces currents in the formation surrounding the borehole. The currents are proportional to the conductivity of the formation.	Deep formation investigation to minimize borehole influences and measure resistivities. Fluid Contacts. Water Saturation.
Density	Medium energy gamma rays are emitted to the formation and scattered, if the formation is very dense the more scattering takes place and more gamma rays are absorbed, less dense formation the less scattering and less absorption.	Primarily used to measure bulk density. Can be related to porosity when lithology is known, gas detection, hydrocarbon density, and evaluation of shaly sands.
Compensated Neutron Logs ("CNL")	Neutron logs measure the formation's ability to slow the movement of neutrons through the formation. This measurement reflects the amount of hydrogen in the formation indicating the porosity of the formation. This log requires a fluid filled hole.	The compensated neutron log is recorded as apparent limestone, sandstone or dolomite porosity. It has the advantage of reduced borehole influences and is used to evaluate formation porosity and identify gas zones and gas/liquid contacts.
Gamma-ray ("GR")	Gamma-ray logs measure the natural gamma radiation	Used to identify lithology (distinguish shales from sandstones and carbonates). Also used for geologic correlations and for calculating the volume of shale in sandstone.
Spontaneous Potential ("SP")	The SP curve records the electrical potential produced by the interaction of formation water, conductive drilling fluid, shales.	The SP is used to identify permeable beds, locate boundaries of permeable beds, aid in determining water resistivity and as an indicator of formation shaliness.
Resistivity Logs	Electric current is passed through the formation, and voltages are measured between electrodes. The measured voltages provide the resistivity.	Various formation resistivities are calculated: flush zone, uninvaded zones, fluid contacts and water saturation.
Microlog ("ML")	Electric current is passed through the formation, and voltages are measured between two short-spaced electrodes with different depths of investigation. The measured voltages provide the resistivity	Comparison of the curves identifies mudcake which indicates invaded zones, thus permeable formations

Appendix A, Well Logging Criteria for New Wells

Page 3 of 3

1.2 Cased Hole Logs

- Casing Inspection Tools (ie.Vertilog, MicroVertilog, High-Resolution Vertilog)
- Cement Evaluation Tool with Gamma Ray and Casing Collar Locator
- Base line Gamma Ray-Neutron with Casing Collar Locator to be used in the analysis of gas migration.

Table A-2: Type of Cased Hole Logs

Type of Log	Principle	Identification
Casing Inspection Tools	The tool uses magnetic flux leakage measurements to identify corrosion and defects in casing	Evaluation of casing apparent metal loss or gain and internal or external corrosion defects
CBL-VDL (casing bond and variable density log)	The principle of the measurement is to record the transit time and attenuation of an acoustic signal after moving though the borehole fluid and the casing wall. This log requires a fluid filled hole.	The CBL is used to evaluate hydraulic seal, cement to casing bond and coverage. The VDL is used to assess the cement to formation bond and to detect the presence of channels and gas intrusion.
CMT or CET (cement mapping or cement evaluation tool) or SBT	The tool uses the casing resonance in its thickness mode to give a very fine resolution.	The tool is used to identify cement presence and quality.
CCL (casing collar log)	The CCL is a magnetic device which is sensitive to the increased metal at a casing collar.	It is run with cased hole logs and is primarily used for depth control.
GRN (gamma ray-neutron)	Gamma ray logs record the natural radioactivity of the formation, less dense formations will appear to be slightly more radioactive.	The GR is used for correlation and gives lithology control. Neutron identifies gas behind pipe, porosity and fluid contacts.

Appendix B, Additional Investigations

Page 1 of 2

A. Check well's cement bond log – top of cement and bond quality

1. If no bond log exists, consider cost/benefit to obtaining one.
2. Have there been any squeeze efforts or related cement improvement or remediation efforts?
3. Any temperature surveys?

B. Check well's nuclear log history

1. Gamma-neutron, pulsed neutron or other nuclear log
2. Noise, temperature, flowlog, or production/problem assessment log
3. Obtain annular fluid levels (AFL) and AFL history
4. Review logs for any prior history of annular gas or gas out of zone (occurrences adjacent to collars or to DV tools; correspondence to areas of inspection survey defects)

C. Check well's casing inspection history

1. Type of survey, compare survey results to present log
2. Have there been other integrity surveys run (magnelog, cathodic profile logging?)

D. Review well records for construction and rework history

1. When was casing installed; scratchers or centralizers, other external or internal tools applied
2. Any milling/drilling/spudding/cabling inside the casing
3. Any casing pressure tests or mechanical integrity tests
4. Cementing operations
5. Size, cement, problems or surface and intermediate casing strings
6. Natural hydrocarbon zones encountered while drilling
7. Other fluid flow or lost circulation zones encountered while drilling

Appendix B, Additional Investigations
Page 2 of 2

8. Perforations

9. Stimulation treatments

10. Position of well in transmission pipe system; position relative to cathodic protection system rectifiers and anodes

E. Review well's annulus pressure history

1. Occurrences of pressure or flow

2. Other external evidence of problems (water well surveys, vegetation stress issues, odors, audible leaks reported, regulatory citations)

If a well's file is deficient in a number of items listed above and the well's inspection survey shows defects increasing in magnitude and/or extent, appropriate logs should be run or tests and offset data should be obtained to help assess the problem and promote solution.

If internal corrosion is evident from survey, mechanical caliper and/or video camera surveys should be run at earliest possible convenience to confirm presence and magnitude of internal metal loss.

Appendix C, Casing Inspection Survey Frequency Decision Tree
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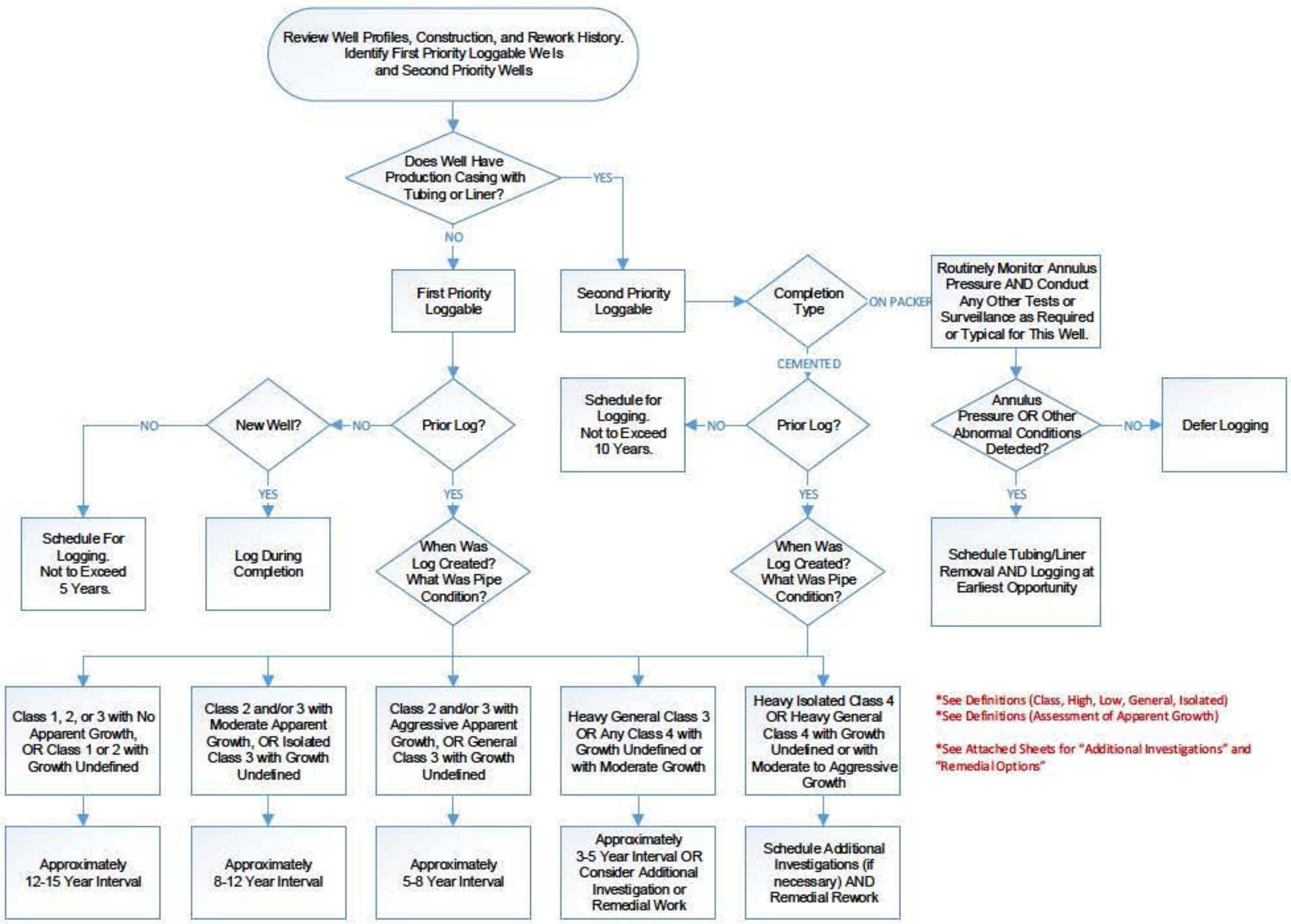

Figure C-1. Casing Inspection Survey Frequency Decision Tree

Appendix C, Casing Inspection Survey Frequency Decision Tree
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Definitions – Class, High, Low, General, Isolated

Class
Defect rating based on interpreted percentage of pipe wall thickness lost;
Class 1: <= 20% wall loss
Class 2: > 20% wall loss and <= 40% wall loss
Class 3: > 40% wall loss and <= 60% wall loss
Class 4: > 60% wall loss

High
In the upper 50% of the Class

Low
In the lower 50% of the Class

General
Many defects along the axis and/or circumference of the casing;
Baker/Atlas generally considers defect clusters appearing in nearly 40% or more of the sensors to be "general corrosion"

Isolated
Single flux leakage anomalies found by individual sensors or at most on less than 30 – 40% of sensors (which may be adjacent defects or single larger defects)

Internal
Anomalies on the internal wall of the casing, identified by eddy current anomalies corresponding to flux leakage anomalies on the same sensor pads; generally the eddy current anomaly should have a signature or response level beyond background noise for any joint of casing

Outer or External
Anomalies on the external or outside wall of the casing. Identified by lack of eddy current anomalies on the same sensor pads.

Appendix C, Casing Inspection Survey Frequency Decision Tree

Page 3 of 3

Definitions – Assessment of Apparent Growth

To be used when comparing a survey log to prior survey logs

Pit Depth

Interpretations of metal loss from flux leakage measurements are at best within +/- 10 – 15% of actual metal loss (this could be closer to 10 – 15% for isolated pitting and 15 – 20% for general corrosion)

Therefore, let WTp = percent metal loss in present survey
WTn = percent metal loss in earlier survey
Yp = year of present survey
Yn = year of earlier survey

Then,

Maximum Rate of Apparent Change is:
[(WTp + 15%) – (WTn – 15%)] / (Yp – Yn)

And Minimum Rate of Apparent Change is:
[(WTp – 15%) – (WTn + 15%)] / (Yp – Yn)

Rates of Change > 3 – 4% + wall thickness per year = AGGRESSIVE
Rates of Change in the 1 – 3% wall thickness per year = MODERATE
Rates of Change < 1% wall thickness per year = LOW

Holistic Qualitative Review of Anomaly Occurrence and Density

In comparing the present survey to an earlier survey, does there appear to be a greater number of defects, a greater density of defect, or a growth in the circumferential or axial extent of defects?

How does the present survey compare to prior surveys in regard to eddy current anomalies or response to casing jewelry (scratchers, centralizers, etc)?

Appendix D, Remedial Options and Decision Tree

A. Remedial Options

1. Note: Any pipe recovered in remedial operations should be inspected and selected pieces set aside for delivery to Applied Technology Services (ATS) for detailed metallographic analysis and pit depth measurement. They may:

   a Clean and photograph the pipe.

   b Measure pit depth and geometry

   c Measure unaltered pipe wall thickness

   d Perform tensile tests on unaltered pieces of casing

2. Also note: Make sure that casing conditions have been properly assessed to remove the influence of conditions on log interpretation:

   a Does casing need to be washed prior to logging? (past history may indicate a need)

   b Were significant defect areas repeated?

   c Were all background checks and cross checks made against well construction data and rework records?

B. Remediation Decisions

1. Based on metal loss and geometry interpretation from casing inspection logs.

2. Compared to previous survey to establish rough approximate metal loss.

3. Hydrostatic testing program had established confidence in fairly high threshold for failure pressure of typical pipe sizes and pitting geometries.

   (1) Typical failure pressure of unconfirmed, corroded casing pipe, especially isolated pits, with at or in excess of API minimum for unaltered pipe.

   (2) Failure pressure of unconfirmed, corroded pipe exceeded calculated failure pressure based on NG-18 formula for line pipe.

4. Remediation or shorter-frequency re-log depends on approximate metal loss and on nature of defect patterns (geometry and location), 115% of the well's Maximum Allowable Operating Pressure (MAOP), and a complete review of the well's operating history.

Appendix D, Remedial Options and Decision Tree

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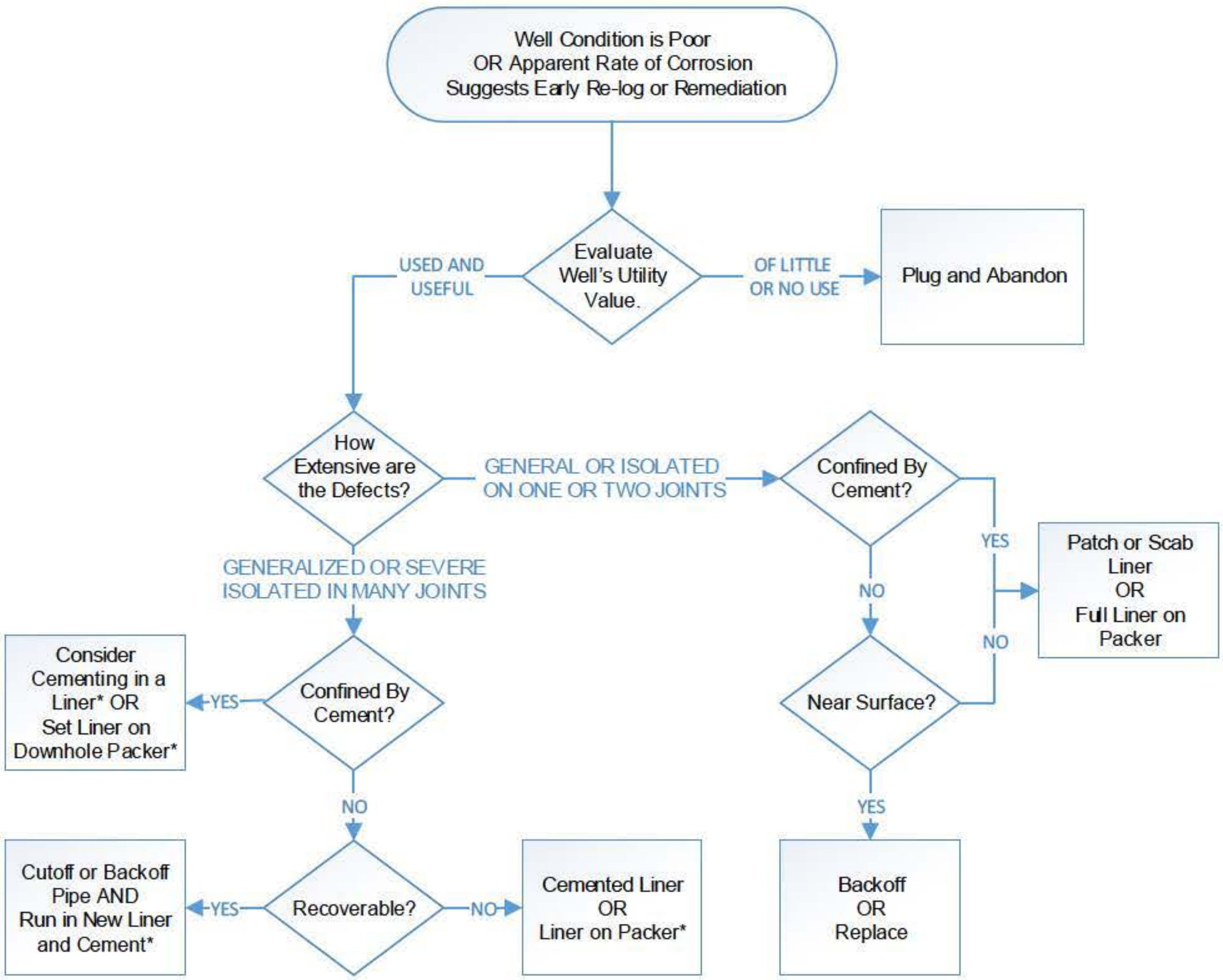

*If lining or tubing of the well will have a significant and adverse impact to well and field deliverability, consideration can be given to drilling additional or replacement wells with or without plugging of the well with corroded casing

Figure D-1: Remediation Decision Tree

DESIGN AND SPECIFICATIONS FOR CASING, TUBING, AND WELLHEAD EQUIPMENT

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to document the design and specifications for casing, tubing, and wellhead equipment.

Why: This document is to provide standard design and specifications for storage wells in each of the PG&E owned storage fields for ease of operation, maintenance, training, and troubleshoot.

When: This applies to new wells and reworks.

Who:

- Director Engineer (DE)
- Reservoir Engineers (RE)
- Reservoir Technicians (RT)

Reference:

- Casing and tubing: API 5CT – Specifications for Casing and Tubing
- Wellhead: API 6A – Specification for Wellhead and Christmas Tree Equipment

Design and Specifications

For PG&E owned storage field storage reservoir maximum pressure and formation depth refer to the "Gas Storage Field Statistics" file centralized with the Gas Operations Support Team.

1. Conductor casing: The purpose of the conductor casing is to support unconsolidated surface deposits. This casing shall be cemented at or driven to a maximum depth of 100 feet.

   A conductor pipe is drilled and set at a depth to keep the surface hole open.

   a Specific for McDonald Island:

   A 20" conductor pipe is drilled and set at approximately 80' to keep the surface hole open.

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

b Specific for Los Medanos:

A 16” conductor pipe is drilled and set at approximately 40’ to keep the surface hole open.

c Specific for Pleasant Creek:

A 16” conductor pipe is drilled and set at approximately 40’ to keep the surface hole open.

2. Surface Casing: The purpose of the surface casing is to protect such fresh water zones from contamination resulting from drilling operations. Surface casing shall be cemented into or through a competent bed and at a depth that will allow complete well shut-in without fracturing the formation immediately below the casing shoe. As a general guideline, the surface casing for prospect wells shall be cemented at a depth that is at least 10 percent of the proposed total depth, with a minimum of 200 feet and a maximum of 2,000 feet of casing and cement into or through a competent bed. The cement shall fill the annular space behind the surface casing from the base to the surface of the ground. Refer to DOGGR Field Rules for specific fields in Figures E-1 through E-3.

a Refer to DOGGR Field Rules for McDonald Island for surface casing minimum set depth.

Size: 13-3/8”; 61#, K-55

Depth: between 500’ and 1000’

Cement to surface

b Refer to DOGGR Field Rules for Los Medanos for surface casing minimum set depth.

Size: 10-3/4”; 40.5#, K-55

Depth: between 500’ and 1000’

Cement to surface

c Refer to DOGGR Field Rules for Pleasant Creek for surface casing minimum set depth.

Size: 10-3/4”; 40.5#, K-55

Depth: Approximately 500’

Cement to surface

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

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STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

NO.: 607-031

MCDONALD ISLAND GAS FIELD RULES

Date: 3/6/2007

Area(s)	Zone(s)/Pool(s)
N/A	McDonald Island

CASING PROGRAM

Casing String	Cementing Depth		Annular Cement Fill
	Marker or Zone	Remarks	
Surface	To at least 10% of the proposed TD and can be as deep as 2,000'.	Cement into or through a competent bed.	To surface.
Production	McDonald Island	Traditional or Barefoot completions	Across Zone to 500' above zone.
Intermediate (Optional)	---	100'+ of lap w/lap test unless casing is run to surface. See CCR 1722.4	Across Zone to 500' above zone.

GEOLOGIC DATA

Reference: DOGGR Publication TR10 California Oil and Gas Fields, Northern California. Well data from 122 wells drilled.

BLOWOUT PREVENTION EQUIPMENT PROGRAM (Referenced from MO7)

Operation	Surface Pressure Category	DOGGR Class	Additional Requirements
Drilling below surface casing	Medium	III B 2-5M	None
Completions/Rework	Medium	II 2-5M	None

Additional Comments: If air or foam drilling below the production casing, please refer to Division publication M07, Section 4-3, for blowout prevention equipment requirements.

BASE OF FRESH WATERS

Depth: 50-100'+/-	Marker: None	Comments: Base of Freshwater is above the casing shoe of the surface casing.

GENERAL COMMENTS

Field rules apply to development wells only. All operations are subject to California Code of Regulations (CCR)., Title 14, Division 2, Chapter 4.

Hal Bopp, State Oil and Gas Supervisor

By Original Signed (Signature), District Deputy (Title)
Robert S. Habel

Modified OGD125 (12/14/06)

Figure E-1: McDonald Island Gas Field Rules

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

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STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

NO.: 607-065

LOS MEDANOS GAS FIELD RULES

Date: May 30, 2007

Area(s)	Zone(s)/Pool(s)
Main, Northeast	All productive zones

CASING PROGRAM

Casing String	Cementing Depth		Annular Cement Fill
	Marker or Zone	Remarks	
Surface	To at least 10% of the proposed TD and can be as deep as 1,500'.	Cement into or through a competent bed.	To surface.
Production	Productive zone	Traditional or Barefoot completions	Across Zone to 500' above zone. Also across BFW and 100' above BFW, if BFW is below Surface Casing.
Intermediate (Optional)	---	100'+ of lap w/lap test unless casing is run to surface. See CCR 1722.4	Across Zone to 500' above zone. Also across BFW and 100' above BFW, if BFW is below Surface Casing.

GEOLOGIC DATA

Reference: DOGGR Publication TR10 California Oil and Gas Fields, Northern California. Well data from 50 wells drilled.

BLOWOUT PREVENTION EQUIPMENT PROGRAM (Referenced from MO7)

Operation	Surface Pressure Category	DOGGR Class	Additional Requirements
Drilling below surface casing	Medium	III B 2-5M	None
Completions/Rework	Medium	II 2-5M	None

Additional Comments: If air or foam drilling below the production casing, please refer to Division publication M07, Section 4-3, for blowout prevention equipment requirements.

BASE OF FRESH WATERS

Depth: 835' – 2140' ±	Marker: None	Comments:

GENERAL COMMENTS

Due to the result of a long production history, and a history of successful water shutoffs, testing and approval of water shutoffs by either field-testing or by review of production data is not required. However, the Division of Oil, Gas, and Geothermal Resources routinely monitors production data, and if anomalous water production is indicated, remedial action may be ordered.

Field rules apply to development wells only. All operations are subject to California Code of Regulations (CCR)., Title 14, Division 2, Chapter 4.

Hal Bopp, State Oil and Gas Supervisor

By Original Signed (Signature) Robert S. Habel, District Deputy (Title)

Modified OGD125 (12/14/06)

Figure E-2: Los Medanos Gas Field Rules

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

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STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

NO.: 607-074

PLEASANT CREEK GAS FIELD RULES

Date: May 30, 2007

Area(s)	Zone(s)/Pool(s)
N/A	All productive zones

CASING PROGRAM

Casing String	Cementing Depth		Annular Cement Fill
	Marker or Zone	Remarks	
Surface	To at least 10% of the proposed TD and can be as deep as 1500'.	Cement into or through a competent bed.	To surface.
Production	Productive zone	Traditional or Barefoot completions	Across Zone to 500' above zone. Also across BFW and 100' above BFW, if BFW is below Surface Casing.
Intermediate	---	100'+ of lap w/lap test unless casing is run to surface. See CCR 1722.4	Across Zone to 500' above zone. Also across BFW and 100' above BFW, if BFW is below Surface Casing.

GEOLOGIC DATA

Reference: DOGGR Publication TR10 California Oil and Gas Fields, Northern California. Well data from 25 wells drilled.

BLOWOUT PREVENTION EQUIPMENT PROGRAM (Referenced from M07)

Operation	Surface Pressure Category	DOGGR Class	Additional Requirements
Drilling below surface casing	Medium	III B 2-5M	None
Completions/Rework	Medium	II 2-5M	None

Additional Comments: If air or foam drilling below the production casing, please refer to Division publication M07, Section 4-3, for blowout prevention equipment requirements.

BASE OF FRESH WATERS

Depth: 1150'-2270'+/-	Marker: None	Comments:

GENERAL COMMENTS

Due to the result of a long production history, and a history of successful water shutoffs, testing and approval of water shutoffs by either field-testing or by review of production data is not required. However, the Division of Oil, Gas, and Geothermal Resources routinely monitors production data, and if anomalous water production is indicated, remedial action may be ordered.

Field rules apply to development wells only. All operations are subject to California Code of Regulations (CCR)., Title 14, Division 2, Chapter 4.

Hal Bopp, State Oil and Gas Supervisor

By Original Signed (Signature), District Deputy (Title)

Robert S. Habel

Modified OGD125 (12/14/06)

Figure E-3: Pleasant Creek Gas Field Rules

3. Production Casing: The production casing is for the purpose of isolating the storage formation/zone and providing a conduit as a means of communication between such zone and the surface. Casing shall have an external collapse pressure rating to handle cement design from total depth to surface. Refer to DOGGR Field Rules for specific fields in Figures E-1 through E-3.

   a Production Casing Design:

      (1) Estimated collapse pressure basing on the difference between the cement slurry density and the drilling fluid density

      (2) Choose casing collapse pressure higher than the above estimated collapse pressure

      (3) Maximum reservoir pressure, refer to the "Gas Storage Field Statistics" file centralized with the Gas Operations Support Team.

      (4) Choose casing internal minimum yield pressure greater than the maximum reservoir pressure

      (5) Choose casing size large enough to attain maximum withdrawal flow rate

   b Specific for McDonald Island: Storage well production casing is set at top of the storage formation (refer to Induction Electrical, or IE, log for set depth).

   Size: 8-5/8"; 36#, K-55

   Measured depth: between 5000' and 6000'

   Cement to surface, if possible. Otherwise refer to the DOGGR Field Rules for minimum cement requirement.

   c Specific for Los Medanos: Storage well production casing is set at top of the storage formation (refer to IE log for set depth).

   Size: 7"; 23#, K-55

   Measured depth: between 3800' and 4200'

   Cement to surface, if possible. Otherwise refer to the DOGGR Field Rules for minimum cement requirement.

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

d Specific for Pleasant Creek: Storage well production casing is set at top of the storage formation (refer to IE log for set depth).

Size: 7"; 23#, K-55

Measured depth: between 2700' and 3300'

Cement to surface, if possible. Otherwise refer to the DOGGR Field Rules for minimum cement requirement.

4. Production Liner and Gravel Pack: The production liner, in conjunction with the gravel pack, is for the purpose of filtering the storage formation fines from entering the wellbore to minimize sand production.

a Production Liner Design:

(1) For open hole completion, wire-wrapped screen is normally used to allow maximum exposure to the formation.

(2) Screen size is determined as follows:

(a) From the core having the smallest particle, determine the d50 (50%) particle size of the cumulative passing through sieve analysis

(b) Use Saucier's method to determine the grave size (6 x d50)

(c) The final design gravel sizes straddle the gravel size determined in (b) above.

(d) Use 75% the smallest gravel size for the screen opening.

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

(3) The length of the production liner depends on the formation thickness and should consist the following from top to bottom:

(a) Liner hanger

(b) Gravel packing equipment

(c) One joint of blank casing

(d) Shear-out safety joint

(e) One joint of blank casing

(f) A 10' slim pack pre-pack wire wrapped screen

(g) The wire-wrapped screen length should be the difference of total depth of the hole and the production casing shoe, less 5' +/-.

(h) O-ring seal sub

(i) Gravel pack set shoe.

b Gravel Pack Design:

(1) Specific for McDonald Island:

Production liner with screen size is 6" (5-1/2" base pipe)

Wire-wrapped screen opening is 12 gauge (0.012" opening)

Length from top to bottom: between 120' and 200'

Gravel size is combination of 20 and 40 mesh.

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment
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(2) Specific for Los Medanos:

Production liner with screen size is 4-1/2" (4" base pipe)

Wire-wrapped screen opening is 12 gauge (0.012" opening)

Length from top to bottom: between 200' and 300'

Gravel size is combination of 20 and 40 mesh.

(3) Specific for Pleasant Creek:

Production liner with screen size is 4-1/2" (4" base pipe)

Wire-wrapped screen opening is 12 gauge (0.012" opening)

Length from top to bottom: between 70' and 100'

Gravel size is combination of 20 and 40 mesh.

5. Production Tubing: The production tubing acts as a syphon tube and is for the purpose of providing a means to lift formation fluid in the bottom of the well bore during withdrawal operation.

a Production Tubing Design:

(1) The tubing size depending on the storage operations, reservoir performance, fluid dynamics, and characteristics.

(2) The length of the tubing should be hung 10 to 15' from bottom of the production liner.

(3) Based on the measured depth of the well, estimated the string weight below wellhead.

(4) Choose the tubing with yield strength higher than the total string weight determined in c. above.

(5) For well having DHSVs, the DHSVs are set at approximately 250' below ground.

b Specific for McDonald Island, tubing configuration is as follows from top to bottom:

3-1/2" (9.3 #, 8rd, EUE) tubing is hung from the wellhead to the DHSVs.

DHSVs are set at approximately 250' below ground.

2-3/8" (4.7 #, 8rd, EUE) tubing below the DHSVs and is landed at approximately 10' off bottom of the production liner.

c Specific for Los Medanos, tubing configuration is as follows from top to bottom:

3-1/2" (9.3 #, 8rd, EUE) tubing is hung from the wellhead to the DHSVs.

DHSVs are set at approximately 250' below ground.

3-1/2" (9.3 #, 8rd, EUE) tubing below the DHSVs and is landed at approximately 10' to 15' off bottom of the production line

d Specific for Pleasant Creek, tubing configuration is as follows from top to bottom:

2-3/8" (4.7 #, 8rd, EUE) tubing is hung from the wellhead and landed at approximately 5' to 10' off bottom of the production liner.

6. Wellhead: The wellhead is for the purpose of acting as an interface between the casing and tubing strings in wellbore and surface facilities. Wellhead provides suspending point for the casing and tubing strings running through the wellbore and also acts to contain the pressure inside the casing and tubing strings. Wellhead can be used for pressure monitoring for casings and annuli between different casing and tubing strings. Refer to API 6A Specification for Wellhead and Christmas Tree Equipment for detailed design requirements.

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

a Wellhead Design:

(1) Wellhead consists of casing head, tubing spool which includes casing valves, Christmas tree assembly which includes master gate valve, studded cross, and tubing valve. The components are as follows:

(a) Casing head:

- Casing head with two outlets
- Bull plug
- Nipple
- Ball valve
- API ring
- Casing slips and packing

(b) Tubing head:

- Tubing head with flanged outlets
- Double studded seal flange
- Flanged expanding gate valves
- Companion flanges
- Tubing hanger
- Gate valves
- API rings

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

(c) Christmas tree assembly:

- Master gate valve
- Single studded adapter
- Studded cross
- Flanged expanding gate valve
- Guiberson Christmas tree cap
- Companion flanges
- API rings
- Bull plug tapped ½"
- Nipple

(2) Specific for McDonald Island:

(a) Casing head:

i. Pressure rating: 3M

ii. 13-3/8" casing head with 2 2" outlets

iii. One 2" nipple

iv. One 2" ball valve for surface monitoring

v. One bull plug

(b) Tubing spool:

i. Pressure rating: 3M

ii. Double studded seal flange for 8-5/8" casing

iii. Two 4" flanged casing valves

iv. Tubing hanger for 3-1/2" tubing with hydraulic ports for surface DHSV control

v. One 3" gate valve equipped with pneumatic actuator

(c) Christmas tree assembly:

i. Pressure rating: 3M
ii. Single studded adapter
iii. 3-1/8" Master gate valve
iv. 3-1/8" Studded cross
v. One 3" gate valve equipped with pneumatic actuator
vi. 3-1/8" Guiberson union cap
vii. Two 3-1/8" companion flanges

(3) Specific for Los Medanos:

(a) Casing head:

viii. Pressure rating: 3M
ix. 10-3/4" casing head with 2 2" outlets
x. One 2" nipple
xi. One 2" ball valve for surface monitoring
xii. One bull plug

(b) Tubing spool:

i. Pressure rating: 3M

ii. Double studded seal flange for 7" casing

iii. Two 4" flanged casing valves

iv. Tubing hanger for 3-1/2" tubing with hydraulic ports for surface DHSV control

v. One 3" gate valve equipped with hydraulic actuator

(c) Christmas tree assembly:

i. Pressure rating: 3M

ii. Single studded adapter

iii. 3-1/8" Master gate valve

iv. 3-1/8" Studded cross

v. One 3" gate valve equipped with hydraulic actuator

vi. 3-1/8" Guiberson union cap

vii. Two 3-1/8" companion flanges

(4) Specific for Pleasant Creek:

(a) Casing head:

i. Pressure rating: 3M

ii. 10-3/4" casing head with 2 2" outlets

iii. One 2" nipple

iv. One 2" ball valve for surface monitoring

v. One bull plug

Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment

(b) Tubing spool:

i. Pressure rating: 3M

ii. Double studded seal flange for 7” casing

iii. Two 4” flanged casing valves

iv. Tubing hanger for 2-3/8” tubing

v. One 3” gate valve equipped with pneumatic actuator

(c) Christmas tree assembly:

i. Pressure rating: 3M

ii. Single studded adapter

iii. 3-1/8” Master gate valve

iv. 3-1/8” Studded cross

v. One 3” gate valve equipped with pneumatic actuator

vi. 3-1/8” Guiberson union cap

vii. Two 3-1/8” companion flanges

Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics
Page 1 of 2

CREATING AND UPDATING STORAGE WELLBORE SCHEMATICS

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to document wellbore schematics that include wellbore, downhole equipment and tubular, dimensions and installed depths, and anomalies detected from Vertilog, GR/N and T/N in each storage well for active wells only.

Why: The document is to ensure that the wellbore schematics are updated to reflect the current physical configuration of the storage wells.

When: Create wellhead diagram and update for any changes of wellbore, downhole equipment and tubular after rework operation, and anomalies detected from casing integrity surveys (Vertilog, GR/N and T/N).

Who:

- Reservoir Engineering (RE) creates wellbore schematics for active wells only in Excel
- RE reviews wellbore schematics for completeness
- RE updates wellbore schematics

Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics

Procedure:

1. RE create and document existing wellbore configurations including:
   - a Spud date
   - b Completion date
   - c Hole sizes
   - d Well location: S; T ;R and GPS
   - e Date of last rework
   - f KB measurement
   - g Conductor dimension and depth
   - h Surface casing dimension and depth and top of cement (estimated or from CBL)
   - i Production casing dimension and depth and top of cement (estimated or from CBL)
   - j Tubing dimension and depth
   - k DHSV dimension and depth
   - l Casing patch dimension and depth
   - m Production liner hanger and liner dimension and depth
   - n MD and TVD of each casing depth
   - o Vertilog anomalies depth
   - p GR/N anomalies depth
   - q T/N anomalies depth
   - r Stage collar depth
   - s Depth of known hole in the casing
   - t Current maximum production rate
   - u Footnote all measurements reference to KB
   - v Verification with DOGGR records
2. RE updates wellbore schematics for any changes of downhole equipment and tubular after well rework operation and anomalies detected from casing integrity surveys
3. RE reviews for completeness
4. RE submits to GSBD G:\RSRVRENG\GSAM Wellbore Schematic and Info Sheets

Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
Page 1 of 2

CREATING AND UPDATING STORAGE WELLHEAD DIAGRAMS

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to document wellhead diagrams including component dimensions and pressure rating using API Standards.

Why: The document is to ensure that the wellhead component dimensions and pressure rating reflect the current physical configuration of the storage wellhead.

When: Create wellhead diagram and update for any changes of components, as needed, or after rework operation.

Who:

- Reservoir Engineering (RE) provides component dimensions and pressure rating of wellhead to Design Drafting (DD)
- DD creates well head diagram in digital format
- RE reviews wellhead diagram generated by DD for completeness
- RE updates wellhead diagram for any changes of components or as needed
- DD updates wellhead diagram in digit format
- RE reviews updated wellhead diagram generated by DD for completeness

Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
Page 2 of 2

Procedure

1. RE document/verify component dimensions and pressure rating of wellhead diagram, or mark up an existing wellhead diagram as needed, including:
    a Type or make of wellhead
    b Casing head
    c Casing double studded flange
    d Tubing head
    e Tubing hanger
    f Seals
    g Test ports
    h Hydraulic control line ports
    i Surface casing valve
    j Casing wing valves
    k Tubing wing valves
    l Master Gate
    m Cross
    n Bonet
    o Date of last service and service performed
2. RE provides the above to DD
3. DD updates wellhead diagram
4. RE reviews for completeness
5. RE submits to GSBD

Appendix H, Practice 4 - Sand Inspection

SAND INSPECTION

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: Sand inspections are used to monitor wells for the presence of sand and to determine what action is to be taken when sand is found.

Why: When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further the presence of sand is an indicator of a potential failure of the wells gravel pack and screen liner to prevent sand production. When: Twice during the winter withdrawal period under a standard clearance: typically once in January and once in March.

Procedure:

Evaluation: Reservoir Engineering personnel inspect the sand residue, if any, scooped out from the sand traps.

1. The results of the inspections are entered into gas storage databases and rated based on the sand ratings below:

Rating	Sand Description
0 - No Sand	* - Formation Sand
1 - Slight Trace	** - Gravel Pack Sand
2 - Trace ie: Up To ¼ Teaspoon	*** - Both
3 - Measurable Amount ie: Up To 1 Tablespoon	
4 - Significant Amount ie: Up To 1 Cup	
5 - Critical Amount ie: More Than 1 Cup	

2. Reservoir Engineering will provide the results to Corrosion Department.

Appendix H, Practice 4 - Sand Inspection
Page 2 of 3

3. Reservoir Engineer will make a determination on whether to downgrade the well's performance utilizing the table below according to the sand ratings and review results with supervisor:

Rating	Recommended Action *
0 - No Sand	No Downgrade
1 - Slight Trace	Monitor
2 - Trace ie: Up To ¼ Teaspoon	Downgrade By 25%
3 - Measurable Amount ie: Up To 1 Tablespoon	Downgrade By 50%
4 - Significant Amount ie: Up To 1 Cup	Downgrade By 50%
5 - Critical Amount ie: More Than 1 Cup	Shut-In And Rework

* If the recommendation is not utilized an expectation should be prepared supporting variance.

4. Reservoir Engineer will update the maximum well safe flow rates table and gas storage database.

   Reservoir Engineering will communicate rate change to UGS District Operations, Station Services, and Gas System Planning.

   Figure H-1 shows a Tree Diagram for Sand Inspection Procedures.

Appendix H, Practice 4 - Sand Inspection
Page 3 of 3

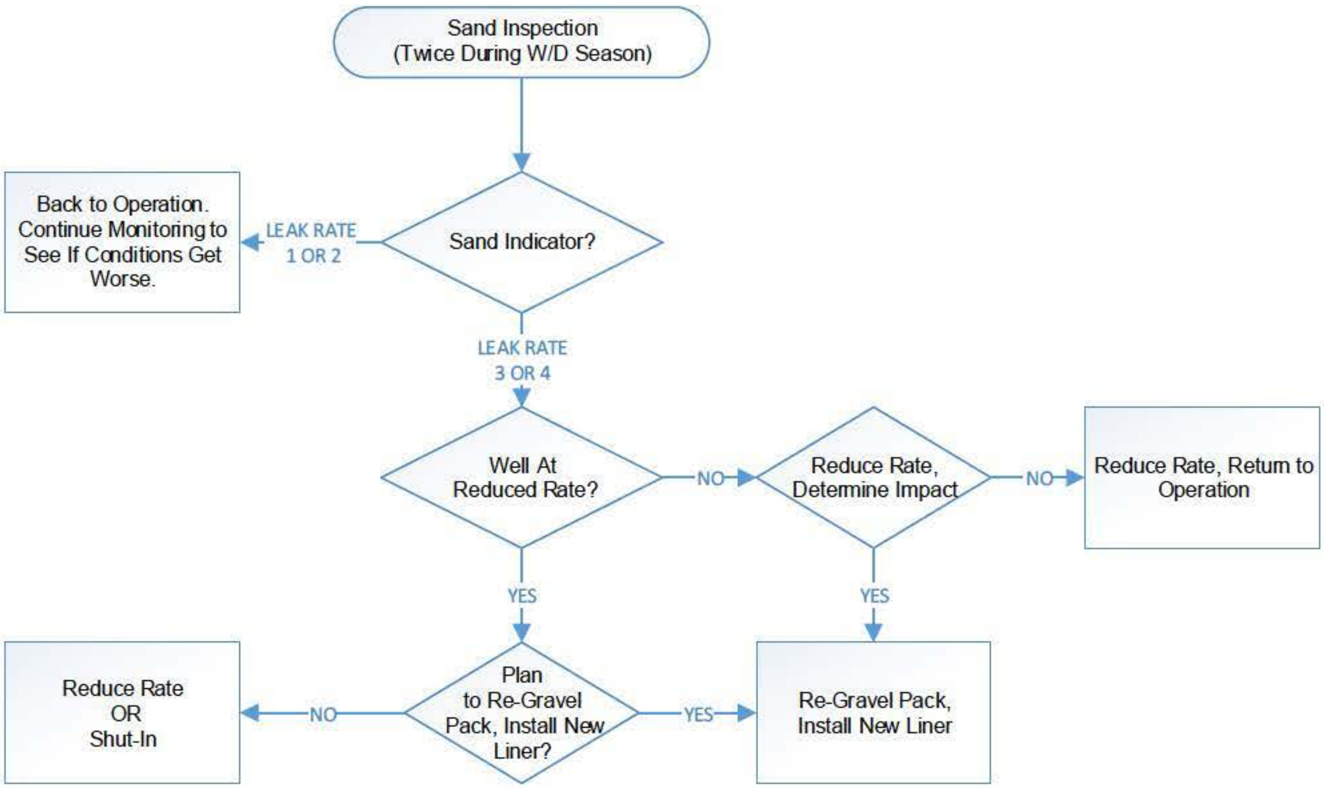

Figure H-1. Sand Inspection Decision Tree

Appendix I, Practice 5 - Uphole Safety Valve (UHSV) Test Procedures
Page 1 of 1

UHSV TEST PROCEDURES

Refer to Station Operating Procedures for Los Medanos, McDonald Island, and Pleasant Creek.

Appendix J, Practice 6 - Christmas Tree Pressure Monitoring
Page 1 of 2

CHRISTMAS TREE PRESSURE MONITORING

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: A Christmas tree is a typical vertical assembly of mechanical elements used in exploration and production of Oil and gas. It is mainly used for fluid control in and out of the well-bore. This test is to monitor Christmas tree pressure on all storage wells to provide wellhead integrity assurance and public and employee safety.

Figure J-1. A Typical PG&E Christmas Tree.

Why: This is to evaluate integrity of wellhead seals for maintenance and repair, if necessary, to assure wellhead integrity, and reduce risk of unsafe operation. "For surface and subsea Christmas trees, the production tree valves are to be tested in the direction of flow. If a well does not have a positive closed-in pressure, then testing the master valve in the direction of flow may not be practical. In this case, the master valve may be inflow tested. Acceptance of production tree valve tests may utilize the API PR 14B requirements providing the observation volume is adequately large to give a meaningful test." (NUST).

Appendix J, Practice 6 - Christmas Tree Pressure Monitoring

When: Quarterly.

Who:

- Reservoir Engineering (RE) collects quarterly Christmas tree pressure data
- RE reviews quarterly Christmas tree pressure data
- RE inputs the quarterly Christmas tree pressure data into the GSDB
- RE evaluates and analyzes the quarterly Christmas tree pressure data trends

Procedure:

1. Collects quarterly Christmas tree pressure data on all storage wells at quarter end using well pressure data forms for Los Medanos, McDonald Island, and Pleasant Creek.
2. Reviews quarterly Christmas tree pressure for reasonableness.
3. Inputs the quarterly Christmas tree pressure in the GSDB.
4. Reviews and analyzes the quarterly Christmas tree pressure data comparing to previous quarters.
5. Compile and trend historical data if available.
6. Develop decision criteria for acceptable operating limit for each wellhead variables.
7. Recommends action plans for wellhead maintenance activities.

Forms

1. Los Medanos well pressure data form.
2. McDonald Island well pressure data form.
3. Pleasant Creek well pressure data form.

Appendix K, Practice 7
Page 1 of 1

This appendix intentionally left blank for future use.

Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring

SURFACE CASING ANNULAR (SCA) PRESSURE AND GAS SAMPLING MONITORING

Purpose: Document the process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to establish the process for monitoring the Surface Casing Annulus (SCA).

Why: Monitor the SCA to improve well integrity, identify gas migration issues, and utilize the sampling data for the future usage for well casing integrity and employee and public safety. Annular spaces on gas storage wells shall be monitored on a periodic basis; this monitoring serves as one of the integrity checks on the wells.

A. Common Causes of Annular Pressure, Tips on Investigations and Remedial Programs

1. Loss of integrity in wellhead seals: could result in variable pressure but often could be high pressure but quick blow down, small volume since a very limited space can be filled. Remedial solutions: inject packing at wellhead seals;

2. Gas migration behind pipe through cement sheath of low integrity: may accumulate considerable volume over time but can be highly variable – depends on the transmissibility of the leak path and may depend on the ability of reservoir pressure to overcome the hydrostatic head of liquid in the annulus, and it may also depend on whether another zone has been charged by gas moving in the annulus over time. Good application for log investigations – cement bond, noise, temperature, neutron, etc. Remediation may include squeezing the leak path itself, block squeezing or squeeze cementing above the current top of cement (assuming there is no formation below that point that can be charged up as a leak collection pool for the gas). Seal-tite (and perhaps others) also claims to have a chemical solution, injecting a polymer down the annulus that gels at a pressure differential (this can be fairly expensive). Plugging the downhole formation and sealing it off from the annulus is an option if the well has little or no value in operations. Milling a window and squeeze cementing, along with running and cementing a full liner, also has been successful at shutting off these sorts of leaks.

3. Casing collar leaks: these may come and go and manifest themselves irregularly if hydrates can form to seal off these small leaks. On the other hand, the leaks may be fairly substantial and always show up. Noise, temperature, and neutron logs can be effective at defining the leak point(s). Remedial solutions include liners (cemented or on packers), internal casing patches, chemical seals (Seal-tite, see above in #2), or squeeze cementing. If close to the surface, sometimes the joints can be backed off and replaced.

Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring

4. Leak due to corrosion hole: this type of leak will suddenly manifest itself and can be variable in its pressure and rate depending on the size and depth of the hole and the annulus medium through which the gas must travel. Remedial options include liners, patches, back off and replace (if near the surface and un-cemented), etc. The probable presence of a pit or of pre-existing conditions leading to progressive corrosion pit growth should show up on a High Resolution vertilog or other similar casing inspection survey. Casing should be recovered where possible for pit geometry and depth characterization; a casing inspection log (e.g. High Resolution vertilog should be run prior to the casing recovery.

5. Leak due to gas emanating from a natural gas-bearing zone which is not isolated from the annulus; the presence of naturally occurring gas should be verified via well history and local information. Gas sampling to determine any differences between storage gas and native gas from another zone is important. It may be that gas in the annulus is a combination of native gas from another zone and gas leaking to or through the annulus from storage for whatever reason. Isolation efforts as described in (4) above are the best way to treat this problem if the amount of gas creates safety or environmental problems, or if native gas leaks may be combined with storage gas leaks. Log investigations can clarify issues related to potential dual source problems.

When: Shall be completed daily and more frequent if determined necessary.

Who:

- GPOM and Reservoir Engineering collects SCA pressure per procedure using calibrated equipment to collect SCA pressure and/or venting rate reads for all wells including injection/withdrawal wells and observation wells in three PG&E owned gas storage fields.
- PG&E Load Center analyzes the SCA gas samples
- Reservoir Engineering reviews SCA pressure, venting rate, and/or gas sample results for reasonableness.
- Reservoir Engineering inputs the SCA pressure, venting rate, and/or gas sample results into the database.
- Reservoir Engineering Engineers evaluate and analyze the SCA pressure, venting rate, and/or gas sample result trends

Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring

Procedure:

1. GPOM and Reservoir Engineering collect SCA pressure per procedure.
2. Reservoir Engineering delivers the SCA gas samples to PG&E load center for analysis.
3. Reservoir Engineering inputs the SCA pressure, venting rate, or gas sample results in the GSDB.
4. Reservoir Engineering Engineers trend SCA pressure, venting rate, and gas sampling data and performs field and well integrity evaluation.
5. Trending analysis includes pressure versus time and historical sampling comparisons
6. Upon receipt of the survey data, the engineer should perform the following functions:
   - a Identify and list wells with any amount of annular pressure
   - b Compare to pressure versus time and historical sampling comparisons
     - (1) Make a comment on each well: first time event; historical pattern of the annular pressure in about this range of volume; historical pattern of annular pressure but present survey finds more volume than usual; or other appropriate comment based on the history found in the data base.
     - (2) Make a list of "notable events" (wells with first time annular pressure or with pressure/volume outside and above historical patterns, or wells with other notable events).
     - (3) Also make a list of wells requiring annular valve repairs (technicians often will note valves with problem operation).
7. Any pressure data equal to or greater than 120 psig, anomalous data or trending shall be reported immediately to the Reservoir Engineering director, manager, supervisor and engineer.
   - a A plan of action should be developed to assess the anomalous pressure and could include shutting in the well immediately, conducting injection or withdraw testing, and collecting additional pressure data.

b Based on the plan of action results, remedial action could be determined and the well will remain out of service until repairs are completed or the well will be placed back in service.

c All plan of action documentation will be kept in the GSDB/well file.

8. For anomalous events, if the trend seems unusually large or if any of the survey data looks odd enough to require confirmation, request a re-test of the annular survey.

9. If a well exceeds its Maximum Allowable Surface Casing Pressure (MASCP) it will be reported on the weekly field reports and the following procedure followed. MASCP is equal to the surface casing depth (feet) x 0.25 psi. A list of wells shall be posted with their calculated MASCP based on this formula.

10. If the surface casing pressure exceeds the MASCP then;

a Reported on the weekly field reports

b Develop a plan of action that could include the following:

(1) Take well out of service.

(2) Collect gas sample(s).

(3) Conduct a surface casing blow down and build up test.

(a) Record blowdown pressures at 1, 2, 3, 4, 5, 10, 15, 20, 25, and 30 minutes.

(b) Record buildup pressures at intervals specified by engineer.

(4) Based on the plan of action results, remedial action could be determined. The well will remain out of service until repairs are completed or placed back in-service.

c All documentation should be kept in the well file.

d Review the well files: well completion and rework history, history of annulus pressure and any prior attempts to define sources of pressure or remedial/repair attempts, logs, especially gamma ray-neutron, cement bond, and casing inspection log (e.g. High Resolution vertilog). Provide a concise summary of the information.

Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring

e Estimate the gas loss if necessary.

f Write a plan of action report (may be an email or Word document). The report shall include:

(1) The list of anomalous events.

(2) The annular pressure or gas sampling reading and results.

(3) The actual or estimated vent volume (daily and annual).

(4) The concise summary of well completion, remedial/rework, log, and pressure history information.

(5) A recommendation for action. This recommendation may be: continue to monitor; run log investigations or other physical tests; gas sampling; wellhead packing; or other remedial action. The action should be related to the amount of the gas loss, safety and environmental concerns

Appendix M, Practice 9 - Individual Well Performance Monitoring
Page 1 of 2

INDIVIDUAL WELL PERFORMANCE MONITORING

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This plan is to provide individual well injection and withdrawal performance monitoring. Individual well performance monitoring is the real time surveillance solution that combines well data analysis to operator and Engineer's expertise thereby allowing them to make decisions based on hard facts and data collected.

Why: This document is to provide process to monitor individual well performance in order to optimize individual injection and withdrawal flow rate and troubleshoot well performance issues. It is important to provide system operations, marketing, and operations and maintenance organizations the baseline capacity to meet the needs of PG&E storage customers throughout the year. Through proper monitoring of wells, underperforming wells can be identified. This can help avoid some major issues such as:

- Void deferred production
- Reduce well asset maintenance costs
- Increase production
- Prioritize and optimize production operations
- Maximize field efficiency and oil recovery

When: On-going.

Who:

- UGS O&M provides daily well status
- Reservoir Engineering (RE) provides weekly well status and pressure reads
- RE reviews well status
- RE evaluates well performance
- RE communicates changes in well performance

Appendix M, Practice 9 - Individual Well Performance Monitoring

Procedure:

1. UGS O&M informs RE any well performance issues.
2. RE logs into the Cimplicity control system to review the issues.
3. RE investigates the above and troubleshoot, if necessary.
4. RE reports the results of investigation and troubleshoot.
5. RE inputs to the GSDB to keep track of well performance and remediation prioritization.
6. RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.
7. RE communicates the results to Gas System Operations, Wholesale Marketing & Business Development, Station Services, Operations & Maintenance, and Gas System Planning to provide well performance updates in a timely manner.

Appendix N, Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring
Page 1 of 3

WELLHEAD PRODUCTION CASING AND TUBING PRESSURE MONITORING

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to monitor wellhead production casing and tubing (C&T) pressure for field and well integrity evaluation. Surface Wellheads are used to support casing & tubing strings, isolate/and control pressure during the drilling operation and monitor annulus casing during production.

See Figure N-1, "A Typical PG&E Wellhead," and Figure N-2, "BHA string (Production casing and tubing)."

Figure N-1. A Typical PG&E Wellhead.

Underground Storage Risk and Integrity Management Plan

Appendix N, Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring
Page 2 of 3

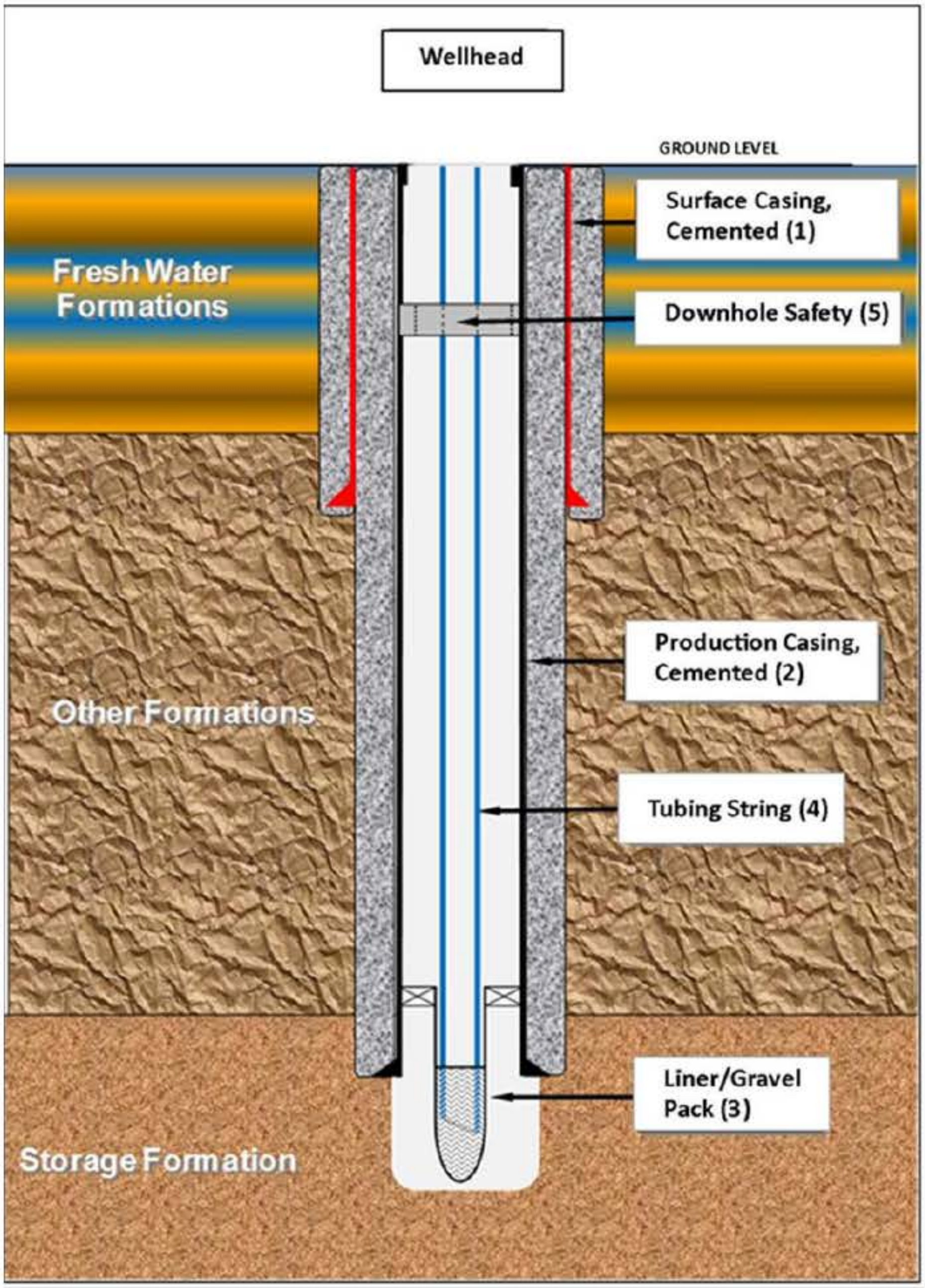

Figure N-2, BHA string (Production casing and tubing).

Appendix N, Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring

"Deliverability or Withdrawal rate": it is described as the measure or amount of gas that can be extracted during the normal operation of the storage gas facilities.

"Injection rate" or "injection capacity" is the complement of the deliverability or withdrawal rate – it is the amount of gas that can be injected into a storage facility during normal operations. As with deliverability, injection capacity is usually expressed in MMcf/day. The injection capacity of a storage facility is also variable, and is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage. The injection rate is highest when the reservoir is most empty and decreases as working gas is injected."

Why: This is to monitor the wellhead production casing and tubing (C&T) pressure for improving well integrity and safety, assurance of no gas loss for inventory verification, and utilization for gas reservoir engineering analysis

When: Weekly

Who:

- Reservoir Engineering (RE) collects weekly C&T pressure data
- RE review the data collected for reasonableness
- RE inputs the C&T pressure data into the GSDB
- RE evaluates and analyzes the C&T pressure trends

Procedure:

1. RE uses calibrated portable gauges to collect weekly C&T pressure reads for all wells including injection/withdrawal wells and observation wells in three PG&E owned gas storage fields.
2. RE field check to verify the C&T pressure data to ensure reasonableness.
3. RE inputs the C&T pressure data in the GSDB.
4. RE reviews C&T pressure data for completeness and reasonableness.
5. RE trends C&T pressure data and performs field and well integrity evaluation.
6. RE communicates anomalies and recommends actions.

Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling
Page 1 of 3

OBSERVATION WELL GAS SAMPLING

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to establish the process for taking Observation and selected Injection/Withdraw (I/W) well gas samples to provide an understanding of the storage gas quality, monitor gas movement within a storage zone and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone. An observation well is used to monitor the operational integrity and conditions in a gas reservoir, the reservoir protective area or the strata above or below the gas storage horizon. Natural gas is injected into the formation, building up pressure as more natural gas is added. "The higher the pressure in the storage facility, the more readily gas may be extracted. I/W Wells are used to inject and withdraw the storage gas." (GSR Industry Primer).

Why: This is to monitor the well gas samples to improve well integrity monitoring, identify potential storage gas movement / migration issues, differentiate between storage gas and other gases and utilize the sampling data for reservoir engineering analysis. Gas samples are obtained and analyzed to determine if changes in gas composition occur over time. The samples may be taken from OBS wells completed in the storage zone and/or OBS wells completed in porous zones above or below the storage zone. Changes in gas composition may indicate movement of storage gas toward storage boundaries. This information is valuable for identification of potential storage gas migration.

Two of the most important characteristics of an underground storage reservoir are its capacity to hold natural gas for use rate and the rate at which gas inventory can be withdrawn its deliverability rate. Through an observation and I/W well gas sampling program an operator can monitor for gas movement in the reservoir that maybe indications of gas movement or migration.

When: Monthly

Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling

Who:

- Reservoir Engineering (RE) collects monthly observation and selected I/W well gas samples
- PG&E Load Center analyzes the monthly observation and selected I/W well gas samples
- RE reviews monthly observation and selected I/W well gas sample results for reasonableness
- RE inputs the monthly observation and selected I/W well gas sample results into the GSDB
- RE evaluates and analyzes the monthly observation and selected I/W well gas sample result trends

Procedure:

1. RE collects monthly observation and selected I/W well gas samples.
2. RE delivers the monthly observation and selected I/W well gas samples to PG&E load center for analysis.
3. RE inputs the monthly observation and selected I/W well gas sample results in the GSDB.
4. RE reviews and analyzes the monthly observation and selected I/W well gas sample results comparing to the previous monthly storage gas sample results.

   a The following is a summary of questions the Reservoir Engineer attempts to answer in its evaluation of the pressure responses and gas sample data from an OBS well or an I/W well.

      (1) What is the fluid observed in the well – oil, gas, brine, etc.? If gas, does the gas sample reflect native or storage gas?

      (2) Which formation is the well monitoring – the storage zone, fringe area of the storage zone or potential porous zones above or below the storage zone into which gas could migrate?

      (3) Are pressure changes observed at the surface or bottom hole?

Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling

(4) Status of nearby wells – what does the data from offsetting wells provide?

(5) Well integrity history

(a) Does annular pressure monitoring data indicate the integrity of tubing or casing?

(b) Are apparent defects present on casing inspection logs? If so, what is the rate of change of apparent defects?

(6) Well location – is the well near houses, buildings, roads or waterways?

(7) Does the pressure of this well track closely with the reservoir pressure?

(8) Is this well being used for gas injection and/or gas withdrawal?

(9) Is the drainage area from this well a low percentage?

(10) Is the gas analysis from this well similar to the gas analysis from the remainder of the reservoir?

5. RE determines if any anomalies exist and recommends actions.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification
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FIELD SHUT IN TESTING FOR STORAGE GAS INVENTORY VERIFICATION

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This plan is to provide process for field shut in testing for storage gas inventory verification.

Why: This document is to provide process for storage gas inventory verification to meet SOX and company accounting and financial reporting requirements.

When: Weekly updates and final reports in November.

Who:

- Reservoir Engineering (RE) obtains weekly pressure reads
- RE obtains extended shut in pressure reads
- RE reviews pressure data
- RE evaluates storage gas inventory and pressure relationship
- RE communicates results

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

Procedure:

1. Weekly Monitoring:

   a RE obtains weekly wellhead pressure on every available storage wells

   b RE reviews pressure data for reasonableness and anomalies

   c RE calculates weekly average reservoir pressure for each storage field

   d RE plots hysteresis curves for each storage field to monitor behavior relative to history

   e RE reports weekly results

   f RE, if need be, investigates and troubleshoots anomalies of the hysteresis behavior

   g RE communicates findings

2. Annual Inventory Verification: (see "Inventory Study Definitions" below for additional detail and definitions)

   a RE obtains extended shut in wellhead pressure on every available storage wells at low inventory after the winter withdrawal and at high inventory after the summer injection

   b RE Conducts a production pressure-decline analysis that includes the following steps:

   c Monitoring of BHP/z, where "z" is the gas compressibility factor, versus inventory on a routine basis.

   d Individual wellhead pressures are recorded during the field shut-in tests but prior to interference from hysteresis effects or changing reservoir pore volumes.

   e Well pressures are reviewed for evidence of leaks and/or the presence of fluid in the wellbore. Pressure data is contoured to help identify if any low pressures are observed.

   f Surface pressures are converted to BHP by adding the weight of the gas column determined by direct BHP measurements and/or by calculation.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification
Page 3 of 7

g The factor z is computed using the properties of the stored gas from analyses of field and/or well samples.

h BHP/z pressure values are calculated for each well and an average BHP/z is determined or a single BHP/z is calculated from a field average wellhead pressure.

i The average field pressures are evaluated to establish a field stabilization trend or by using the actual production pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena.

j The average BHP/z is then plotted versus the company book volumes.

k RE inputs to the GSDB to keep track of well performance and remediation prioritization.

l RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.

m RE communicates the results to GSO, WM&BD, and GSO Planning to provide well performance updates in a timely manner.

Inventory Study Definitions

The following definitions are consistent with the BOP process which relates to the accounting and treatment of storage gas.

- Inventory: All gas molecules in the storage reservoir expressed in a volume at standard temperature and pressure.
- Adjustment(s): A volume of gas that impacts storage Inventory deriving from meter errors, fuel usage, diffuse gas losses and/or other operational factors.
- Non-Recoverable Gas: A volume of gas which supports the storage cycle under stabilized pressure conditions but cannot be recovered economically upon field abandonment. The initial determination of Non-Recoverable Gas will be made at or after the abandonment of the storage reservoir begins excluding volumes previously deemed Non-Recoverable Gas and written down. Any identified gas volume which is deemed Non-Recoverable Gas shall be written down at the time a determination of such volume is made (pursuant to XX Policy).
- Migrated Gas: A volume of gas believed to have been present in a storage reservoir which subsequently has left the storage reservoir and no longer supports its cyclic storage operation. Any Identified gas volume which is deemed Migrated Gas shall be written down.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

- Identified: The nature or the origin of the Adjustment, Non-Recoverable or Migrated Gas volume(s) is known to a Reasonable Engineering Certainty. No further research is required.
- Inconsequential: To a reasonable person, there is lack of worth or importance, and it is trivial in relation to the lowest level of external financial reporting. Or, lacking in worth or importance as deemed by a reasonable person.
- Consequential: To a reasonable person, it has magnitude or importance. Or, having magnitude or importance as deemed by a reasonable person.
- Unresolved/Loss Contingency: Items that require further research and/or additional data to determine proper classification as to a possible gain or loss and whose ultimate resolution depends upon whether one or more future events occur or fail to occur. The occurrence of such events can range from Probable to Remote as follows:
  - *Probable*. The future event or events are likely to occur.
  - *Reasonably Possible*. The chance of the future event or events occurring is more than Remote but less than Probable.
  - *Remote*. The chance of the future event or events occurring is slight.
- Annual Inventory Report: An annual analysis of the gas storage Inventory including, where applicable, Adjustments, Migrated Gas and Non-Recoverable Gas in each storage reservoir owned and/or operated, or in which an interest is owned by PG&E, based on operating data and engineering studies.
- Reasonable Engineering Certainty: A conclusion arrived at by a qualified engineer using all the pertinent available information and employing industry accepted engineering techniques and scientific concepts.

In addition to the terms identified above, a number of practical terms are used in this report to describe operational issues related to management of storage inventory. These terms identify portions of the booked gas volume which do not exhibit a pressure response in the storage reservoir during the semi-annual shut-in tests. The terms and their definitions are as follows.

- Non-Effective Gas: The volume of gas that does not exhibit a pressure response in the storage reservoir when a pressure decline analysis (PDA) is performed based on the fall and spring shut-in pressure data which, in general, are not indicative of fully stabilized storage reservoir conditions.
- Impounded Gas: That portion of the Non-Effective Gas which supports the storage cycle under stabilized pressure conditions but is not readily producible during the operating withdrawal cycle.
- Non-Effective Gas Calculation: The volume of Non-Effective Gas for an operating cycle is determined graphically by performing a PDA. The analysis involves measuring the volume of gas withdrawal from a storage reservoir and well shut-in pressures before and after withdrawal takes place. After plotting the starting and ending total Inventory with the corresponding bottom hole pressures corrected to account for the departure from the ideal gas law, a straight line is drawn through the points and extrapolated to zero psi. This line is used to determine the Non-Effective Gas volume for the operating cycle.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

The Pressure Decline Analysis (PDA) involves the following steps:

1. Individual wellhead pressures are recorded during the shut-in tests which take place every spring and fall and/or representative indicator well pressures are periodically recorded during storage operations. If inconsistencies are observed for individual pressures, estimates are made.
2. The wellhead pressures are converted to absolute by adding the barometric pressure.
3. These pressures are converted to BHP by adding the weight of the gas column using the well bore gas gradient and/or by calculation.
4. The compressibility factor z is computed using the properties of the stored gas.
5. The BHP/z pressure values are calculated for each well or a single BHP/z is calculated from field average wellhead pressures and/or representative indicator wells.
6. The BHP/z values are weighted to obtain a weighted average field BHP/z.
7. The weighted average field pressures are evaluated through the semi-annual shut-in test.
8. The final spring and fall BHP/z pressure values are plotted versus the total field inventory for those days. A straight line is drawn through the points and extrapolated to zero psi.
9. The Non-Effective Gas volume is determined at zero psi rather than the BHP at abandonment.
10. Pressure decline lines are plotted for the six most recent consecutive years of operation and are evaluated in terms of continuing or revising the operating mode to improve field performance.

- Gas-Per-Pound (Apparent/Effective Pore Volume): Reservoir gas-per-pound (GPPr) or Apparent Pore volume (PV) is the slope of the line connecting an individual BHP/z versus total field content and zero psi versus zero total field content. This is done for both the spring and fall shut-in test points and/or two other points determined by the intersection of the production decline trend (BHP/z) and two constant BHP/z's (generally one at maximum working inventory and one at low inventory). Cyclic Gas-Per-Pound (GPPc) or Effective Pore Volume (PVe) is the slope of the line that connects the current shut-in point and the previous shut-in point.
- Gas-Per-Pound Calculations: GPPr is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. For each semi-annual shut-in point, calculate total content divided by BHP/z and/or use points determined by production decline trend and the intersection of two constant BHP/z points.
2. Graphically connect all calculated points.

Cyclic Gas-Per-Pound (GPPc) is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. After each semi-annual shut-in test, calculate previous total field content less the current total field content divided by the previous BHP/Z less the current BHP/z and/or use the production decline trend and the corresponding inventories consistent with the two constant BHP/z points.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

2. All calculations that are performed using a spring shut-in as the current shut-in generate one set of data (the slope of all fall – spring cycle lines). Calculations performed using the fall shut-in as the current shut-in generate a second set of data (the slope of all spring-fall cycle lines) and/or in the case of the production decline trend use the two other points determined by the intersection of the production decline trend (BHP/z) and the two constant BHP/z points (one high and one low).
3. Graphically connect calculated points of the same cycle, for example, all of the calculated slopes for the fall – spring cycle are connected and/or the two but constant BHP/z points.

Operations from cycle to cycle can impact the storage reservoir pressure response data that is gathered during the semi-annual shut-in test. Thus, it is the trend over several cycles that could indicate what may be occurring in the storage reservoir.

- Pore Volume Ratio: The ratio of current pore volume compared to the original pore volume.
- Pore Volume Ratio Calculation: Pore Volume Ratio (PVR) is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. Calculate the original BHP/z times the current total content divided by the original total content times the current BHP/z for each semiannual shut-in and/or the two points generated by the production decline trend and the constant BHP/z points.
2. Graphically connect all calculated points.

- Inventory Variance: The difference between book (or metered) total inventory and total content calculated using a pressure-volume material balance relationship.
- Inventory Variance Calculation: Inventory Variance is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. Calculate the total content using the original discovery line and the current BHP/z.
2. Subtract the calculated total content from the current metered total content.
3. Graphically connect all calculated points. However, there may be merit in connecting spring points as one data set and fall points as a second data set.

Annual Inventory Verification:

1. RE obtains extended shut in wellhead pressure on every available storage wells at low inventory after the winter withdrawal and at high inventory after the summer injection
2. RE Conducts a production pressure-decline analysis that includes the following steps:
3. Monitoring of BHP/z, where “z” is the gas compressibility factor, versus inventory on a routine basis.
4. Individual wellhead pressures are recorded during the field shut-in tests but prior to interference from hysteresis effects or changing reservoir pore volumes.
5. Well pressures are reviewed for evidence of leaks and/or the presence of fluid in the wellbore. Pressure data is contoured to help identify if any low pressures are observed.
6. Surface pressures are converted to BHP by adding the weight of the gas column determined by direct BHP measurements and/or by calculation.

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

7. The factor z is computed using the properties of the stored gas from analyses of field and/or well samples.
8. BHP/z pressure values are calculated for each well and an average BHP/z is determined or a single BHP/z is calculated from a field average wellhead pressure.
9. The average field pressures are evaluated to establish a field stabilization trend or by using the actual production pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena.
10. The average BHP/z is then plotted versus the company book volumes.
11. RE inputs to the GSDB to keep track of well performance and remediation prioritization
12. RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.
13. RE communicates the results to GSO, WM&BD, and GSO Planning to provide well performance updates in a timely manner

Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
Page 1 of 2

MONITORING THIRD PARTY ACTIVITIES INSIDE AND OUTSIDE OF GAS STORAGE PROPERTIES

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to monitor third party activities inside and outside of gas storage asset properties including drilling and production for potential extraction of storage gas.

Why: This is to protect gas storage reservoir integrity and protect against loss of storage gas from potential extraction of storage gas by third parties.

When: Perform surveillance whenever working in gas storage facilities.

Who:

- Reservoir Engineering (RE) performs surveillance
- RE reviews third party drilling activities.
- RE evaluates potential third party wells and recommends course of actions, if any.

Procedure:

1. Survey and monitor third party drilling activities inside and outside of gas storage asset properties.
2. Monitor weekly Munger reports, if available, for drilling activities in the vicinity of storage fields.
3. Monitor DOGGR monthly drilling permit activities and proposed depths of wells in the vicinity of storage fields.
4. Obtain well logs from the DOGGR to determine zones of production, if available.
5. Obtain periodic wellhead pressures and gas samples from the production wells, if available.
6. Compare storage pressure and storage gas samples with the production wells.
7. Enforce no-drill through rights inside gas storage asset properties.

Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties

Page 2 of 2

8. If well is drilled within 75' from the gas storage asset property line, inform the DOGGR to shut down production.
9. Document process and plot well drilling and production activities on reservoir maps.
10. Update and plot activities on reservoir maps as new activities are obtained.
11. Communicate results to the Land, Operations & Maintenance, and Reservoir Engineering departments.
12. If third party drilling activities exhibits potential extraction of storage gas, elevate to higher level management for mitigation decision.

Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Testing

DOWNHOLE SAFETY VALVE TESTING

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to meet the California State Division of Oil and Gas regulation of Down Hole Safety Valves (DHSV) testing. The D.O.G. regulation states that the DHSV shall be tested for reliable operation and holding pressure (California Code of Regulations Title 14, Division 2, Chapter 4). A down hole safety valve is one of the major barrier in a well. The DHSV is closes automatically when the pressure is lost in the hydraulic control that operates the valve. When closed, the valve will be part of the primary barrier that is envelope and will isolate the reservoir fluid (gas) from the surface.

Operating Principle:

The DHSV is usually opened due to the hydraulic connection of the well control at the surface. Hydraulic pressure applied at the control station is related down through the control line thereby forcing a sleeve in the valve to open (slide downwards). This downward movement is due the compression of a large spring which forces the flapper of the valve to open downward. Releasing the hydraulic pressure forces the spring to be pushed backward, thereby collapses the flapper to close.

Appendix R, Practice 14 - Downhole Safety Valve Testing

Figure R-1. A DHSV In An Opened And Closed Position

Why: The testing is to ensure that the DHSVs are meeting the State regulation requirements and reliable operations to meet gas system and customer demands. The DHSV is a major preventive measure installed to prevent an uncontrolled release of the reservoir fluid is an emergency scenario such as an explosion or in situation where the wellhead integrity is lost. It is designed in such a way that the production causes it to close while the hydraulic control forces it open. The hydraulic control is usually operated from the surface as indicated earlier.

When: Test under a standard clearance: normally between April and October of the year.

Appendix R, Practice 14 - Downhole Safety Valve Testing

Who:

- Underground Gas Storage (UGS) Operations performs testing. Refer to Station Operating Procedures for Los Medanos, McDonald Island, and Pleasant Creek.
- Reservoir Engineering reviews test data for reasonableness and completeness.
- Reservoir Engineering evaluates test data and assigns ratings to prioritize the malfunctioning DHSVs for replacements.

Procedure: See detailed DHSV testing procedures and data collection form issued by Reservoir Engineering.

Evaluation:

1. The results of the evaluations are entered into gas storage database and rated based on the DHSV ratings below.
2. Reservoir Engineering will prioritize the DHSVs replacements and inputs in the GSDB and S1 and S2 processes.

Table R-1. RC DHSV, RC-2 DHSV Control Line Ratings

RATING	DHSV/ Control Line Ratings (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher

Appendix R, Practice 14 - Downhole Safety Valve Testing

Historical Evaluation Prior to 2014:

1. The results of the evaluations are entered into gas storage database and rated based on the DHSV ratings below:

2. Reservoir Engineering will prioritize the DHSVs replacements and inputs in the GSDB and S1 and S2 processes.

Table R-2. RC DHSV Ratings

RATING	RC DHSV/ Control Line Rating (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher

Table R-3. RC-2 DHSV Ratings

RATING	RC-2 DHSV Rating (Flow test / 10 mins)
1	≤ 50.0 cu/ft
4	> 50.0 cu/ft

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

CASING INSPECTION LOGGING AND DATA ASSESSMENTS

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: The Casing Inspection Logging provides a holistic program to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for well casing integrity monitoring.

Why: Gas storage wells may be in service for 75 or more years. Therefore, it is prudent to design the wells to remain intact for that time period and to monitor and maintain the integrity to prevent well leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging.

Wells are logged to identify potential problems and may include the following types of logs (type of log/survey identified in parenthesis.

- Reductions to casing wall thickness (Casing Inspection Tools)
- Caliper
- Identification of gas presence behind the casing (Gamma Ray Neutron – GRN)
- Presence of a corrosion cell (Casing Protection Profile – CPP)
- Temperature Logs
- Noise Logs
- Downhole video cameras and/or downhole video side view cameras
- E-Log-I Surveys

In addition, for future new storage wells certain logs shall be considered to be run during drilling and completion. The list of logs to consider, principle (how the log works), and the identification (purpose of the log) are presented in Appendix A.

- Open Hole Logs
    - Caliper
    - Density w/Pe (Litho-Density)
    - Compensated Neutron Log (CNL)
    - Spontaneous Potential (SP)
    - Gamma Ray (GR)
    - Resistivity Logs (Dual-Induction or Array Induction)
    - Microlog (ML)
- Cased Hole Logs
    - Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)
    - Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator
    - Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator

Casing Inspection Tools and CPP

Casing Inspection Tools and CPP are beneficial to get a baseline on the condition of the casing and the following criteria summary should be utilized (see Appendix A for further details).

- Run baseline logs (Casing Inspection tool and/or GRN) on every well when the tubulars are removed.
- Follow-up casing inspections are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe.
- Follow-up casing inspections on tubing and packer completed wells are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection tool run.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

- Annual Noise, Temperature, and GRN logs will be run on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review

- Coordination and communication with the Operations department to verify that wells are protected by a cathodic protection system.

Periodically, E-Log-I surveys to be conducted by Corrosion department in an attempt to ensure that sufficient bond current is being applied to each well's production casing string.

Casing Inspection Logging Using Electromagnetic Logs: This tool (Electromagnetic corrosion and protection evaluation log) measures the casing potential and resistance evaluation, thereby determining the extent of the corrosion. The Electromagnetic log used by the Reservoir Engineering department is the Verti-log. "The Verti-log is a casing inspection service which is now available to the oil and gas industry to determine the condition of the casing in existing wells. It is a quantitative measurement of corrosive damage, indicating if the metal loss is internal or external and if it is isolated or circumferential", (onepetro.org).

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments
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Figure S-1. Detailed Verti-log courtesy of Baker-Hughes.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

Figure S-2, Shows the verti-log of well TC-17N during the 2014 Rework program courtesy, Baker Hughes.

Figure S-2. TC-17 2014 Verti-log.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

Verti-log Class/color identification: The following class/color identification is based on the Baker-Hughes Verti-log correlation analysis whose penetration involves the acquired flux change, discriminator sensor management and the computed results.

- Class 1: Seen in white, includes 0-20% penetration
- Class 2: Seen in orange, includes a 20-40% penetration rate
- Class 3: Seen in pink, includes a 40-60% penetration
- Class 4: Seen in black, includes a 60-100% penetration.

When: Noise and Temperature surveying is completed annually, other logging is completed to establish a baseline, per an assessment logging plan and reoccurring frequency and more frequent if determined necessary. Need for specialized or additional logging should be considered when under a standard clearance and during well rework operations.

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.
2. Review logs when they arrive in office. Check for large defects that should be addressed immediately, confirm log header information and casing information is correct, confirm that all logs run have been received.
3. Use previously run log as base line and compare and correlate the apparent anomalies to identify potential casing integrity issues.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

4. Any anomalies or trending shall be reported immediately to the director, manager, supervisor and engineer. Appendix B contains additional investigations to consider, Appendix C lists definitions for metal loss and assessment of apparent growth, and Appendix D shows a remedial decision tree that should be used in aiding to develop a plan of action to assess the anomalies. Based on the plan of action results, remedial action will be determined and the well will remain shut-in until repairs are completed or the well will be placed back in service. All plan of action documentation will be kept in the GSDB/well file.

5. Prepare a summary report (one report per field) documenting results.

6. Select wells for next year's logging program based on a specific recommendation that had been made at the time of the previous review, or according to the "Casing Inspection Survey Frequency Decision Tree".

7. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

8. Communicate results to Operations & Maintenance and Reservoir Engineering departments.

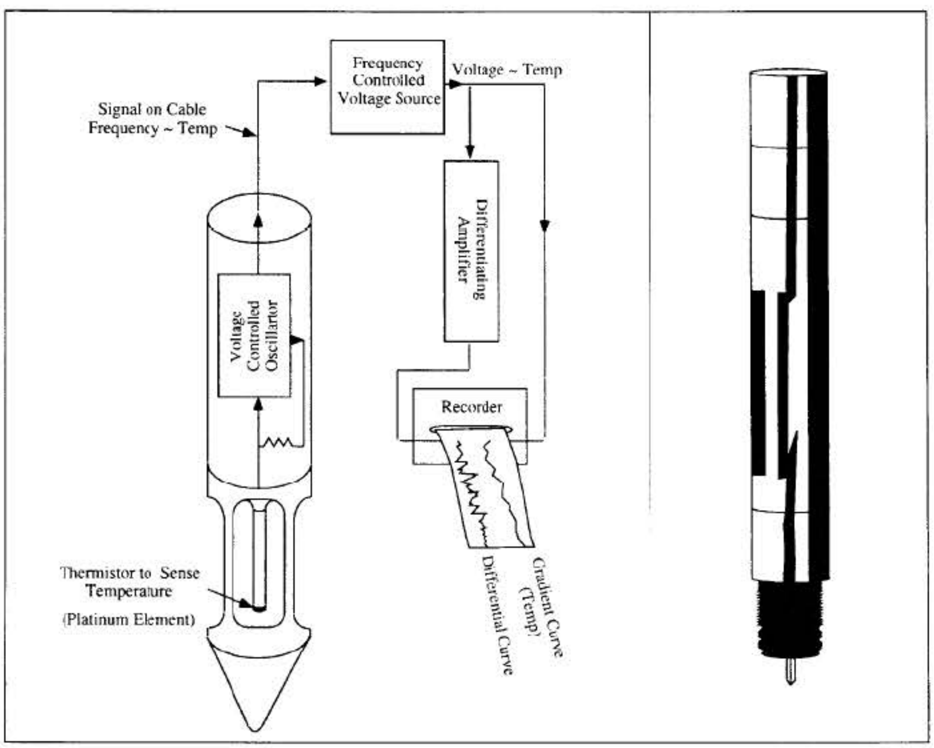
Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review
Page 1 of 6

ANNUAL TEMPERATURE / NOISE LOGGING AND DATA REVIEW

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: This is to comply with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity survey. A temperature survey is not only the oldest of the production surveying instruments, it is also unique in its logging, it is one of the logs that is least likely to mislead its interpreter except he/she is not thoroughly trained to its interpretation. Platinum is the preferred sensor in the temp log because the resistivity is stable and increases with temperature over a wide range.

The survey is usually conducted on an Analog/digital truck contracted by PG&E which transmits a count per minute which is converted to voltage by a counting circle and recorded on a pen-and-ink strip chart as a temperature or gradient trace. Figure T-1 (A&B) below shows an over view of the temp/acoustic tool.



(A) Schematic of Tool (B) Actual Tool

Figure T-1. Temp/Acoustic Tool.

Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review
Page 2 of 6

A noise logging tool is a microphone designed to handle wellbore conditions and measures sound at different positions in the borehole. Figure T-2 (A&B), Shows a schematic of an acoustic tool and piezoelectric crystals which converts the oscillating pressure associated with sound transmission within the wellbore to an oscillating voltage that input directly to an amplifier-cable driver combination.

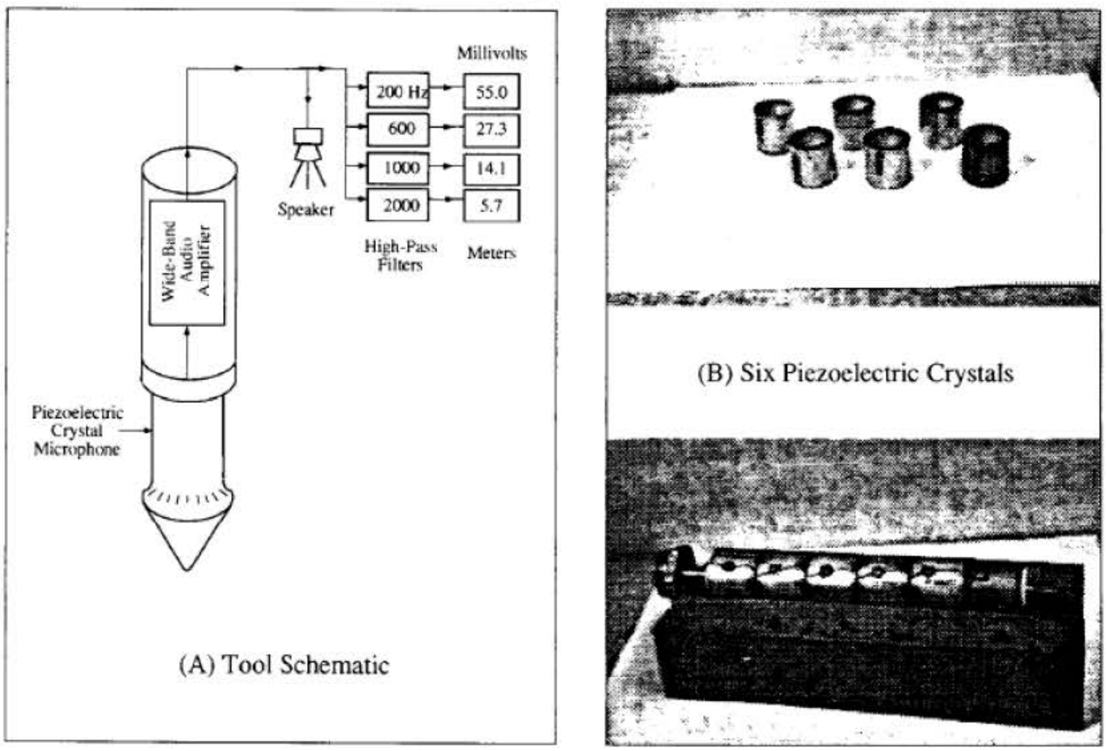


Figure T-2. Acoustic/Noise Tool Schematic and Piezoelectric Crystals

Why: The annual testing is conducted to comply with the State DOGGR regulation requirements that a mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones.

When: Test annually under a standard clearance: normally between April and October of the year.

Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Logging Procedure: Temperature survey sensors are located near the bottom end of the tool as much as possible. “This allows the sensor to contact fluids that has not been mixed vertically by the passage of the tool and wireline” (Tech-guide, ONLINE).

The temperature survey should start at least 100ft above the zone of interest to allow time for the moving tool to stabilize. Logging speed should not exceed 40ft/min with 30ft/min being preferable.

With the Acoustic/Noise logging, the most obvious procedural question is related to proper spacing between readings. The measured sound levels on a noise log are significant for two reasons:

- The level increase above ambient is obviously related to the severity of the problem.
- The level of sound on a noise/acoustic log is the best quality control index available in terms of analysis.

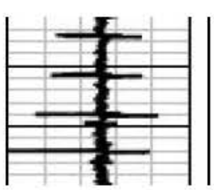


Figure T-3. Typical Noise/Temp Log Used by PG&E Operations.

As mentioned earlier, PG&E temp/noise survey is usually contracted out. Figure T-4. shows a temp/noise survey in progress on the Whiskey Slough plant station.

Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review
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Figure T-4. Tem/Noise Survey Being Conducted.

Reservoir Engineer/Operator inspects the progress of the logging.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.
2. Compare the apparent anomalies to the previous year survey results to determine the severity of the apparent anomalies.
3. Correlate the apparent anomalies with the Gamma Ray Neutron logs and the Casing Inspection results to identify casing integrity issues.
4. Communicate the results to DOGGR and the Reservoir Engineering department.
5. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review
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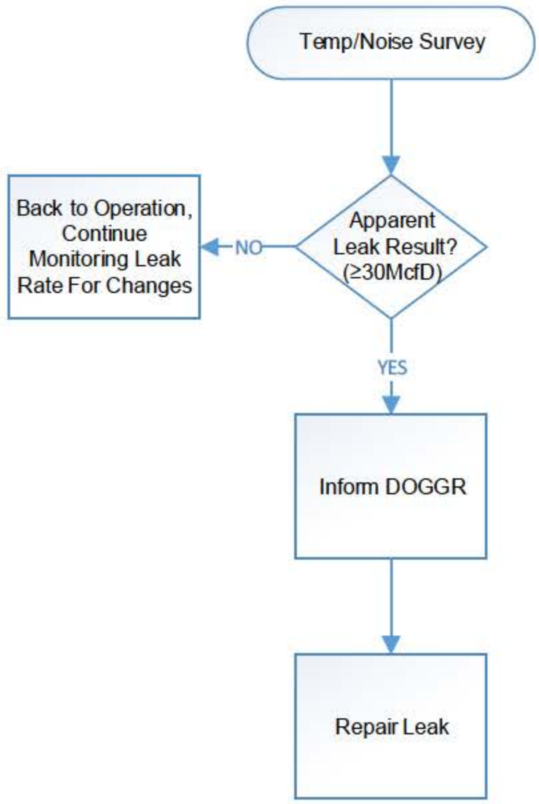

Figure T-5. Temp/Noise Survey Decision Tree.

Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review

GAMMA RAY NEUTRON LOGGING AND DATA REVIEW

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: The GRN logging is supplemental to the T/N (Temperature/Noise) logging to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity monitoring. The GRN log can be run in air, oil, gas or mud filled open or cased holes. There are three basic neutron logging tools each consisting of a chemical neutron source.

- CNL: Compensated Neutron Log
- SNL: Sidewall Epithermal Neutron Log
- GRN: Gamma Ray Neutron Log

The gamma-ray neutron (GRN) logs are one of the three classes of the neutron logging tool. The GRN is sensitive to capturing gamma rays that are emitted due to the absorption of thermal neutrons by the nuclei in the rocks.

Why: The GRN logging is supplemental to the T/N logging to provide additional correlations in evaluating casing integrity, to improve well casing integrity and safety, reduce the risk of gas leakage and unsafe operations. Also, the GRNL is unaffected by fluids and measures both the lithology and natural radioactivity of the formation using a scintilometer (Geiger counter). GRNL can also be useful for the following:

- Determination of porosity / Lithology
- Delineation of porous formations
- Gas detection (with other logs)
- Estimation of shale content (w/ other logs)

When: Test periodically under a standard clearance.

Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Principle of Operation:

- Neutrons emitted from radioactive source
- Collide and lose energy (Billiard ball effect)
- Primarily dependent on hydrogen concentration or index
- Detect either epithermal neutrons, thermal neutrons, capture gamma rays or combination
- Thus, measures the formations ability to attenuate the passage of neutrons

Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review

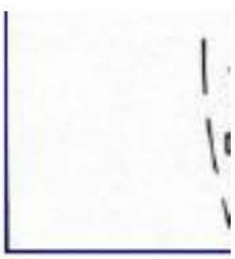

Figure U-1. Single Neutron Tool In A Bore-Hole.

Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review

Figure U-2. Density Logging Tool Schematic.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.

2. Use baseline GRN log if one has been established as base line and compare the apparent anomalies to determine the severity of the apparent anomalies and identify gas migration, if any.

3. Correlate the apparent anomalies with the T/N logs and the Casing Inspection results to identify casing integrity issues.

4. Communicate the results to the Reservoir Engineering department.

5. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

Appendix V, Practice 18 - Cement Bond Logging Survey

CEMENT BOND LOGGING SURVEY

Purpose: It is to document the standardize process, procedure, evaluations and reporting of the Well Integrity Management Plan.

What: The Cement Bond Logging is supplemental to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity monitoring. "Cement bond tools measures the bond between casing and the cement placed in the annulus between the casing and the wellbore", (Schlumberger). The measurement is made by using an acoustic sonic (Noise/temp) and ultrasonic tools.

Why: The Cement Bond Log (CBL) is to:

1. Evaluate integrity of cement sheath in the annulus between casing and formation.
2. Identify the top of cement (TOC) for potential gas migration paths, if leaks are detected. It is also for additional correlations to improve well casing integrity and safety and reduce the risk of gas leakage and unsafe operations.

When: Log is run on an as-needed basis under a standard clearance. (Note: Normally CBL is run right after the production casing is cemented in place. In some case, it is re-run to verify integrity and TOC and for correlation purposes if leaks behind casing are suspected. The only opportunity to re-run the CBL is during well rework because during rework the tubing is out of the hole and allow CBL tool to be run in the well.)

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs logging/testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Appendix V, Practice 18 - Cement Bond Logging Survey
Page 2 of 4

CBL Evaluation:

1. Review and evaluate the CBL survey logs to verify cement sheath bonding in the annulus between casing and formation.
2. Identify TOC and other areas that have cement bonding issues, and denote such on the well schematics for references.

CBL Technology:

- CBL utilizes the amplitude of sonic sound signal to determine bonding integrity between casing and formation.
- The tighter the bonding between the casing and formation, the less amplitude showing on the log. It is like ringing a bell and it is loud (high amplitude). The ringing bell is not as loud (low amplitude) by putting a hand on it.
- See example below for comparison between good bonding and no bonding.

Appendix V, Practice 18 - Cement Bond Logging Survey
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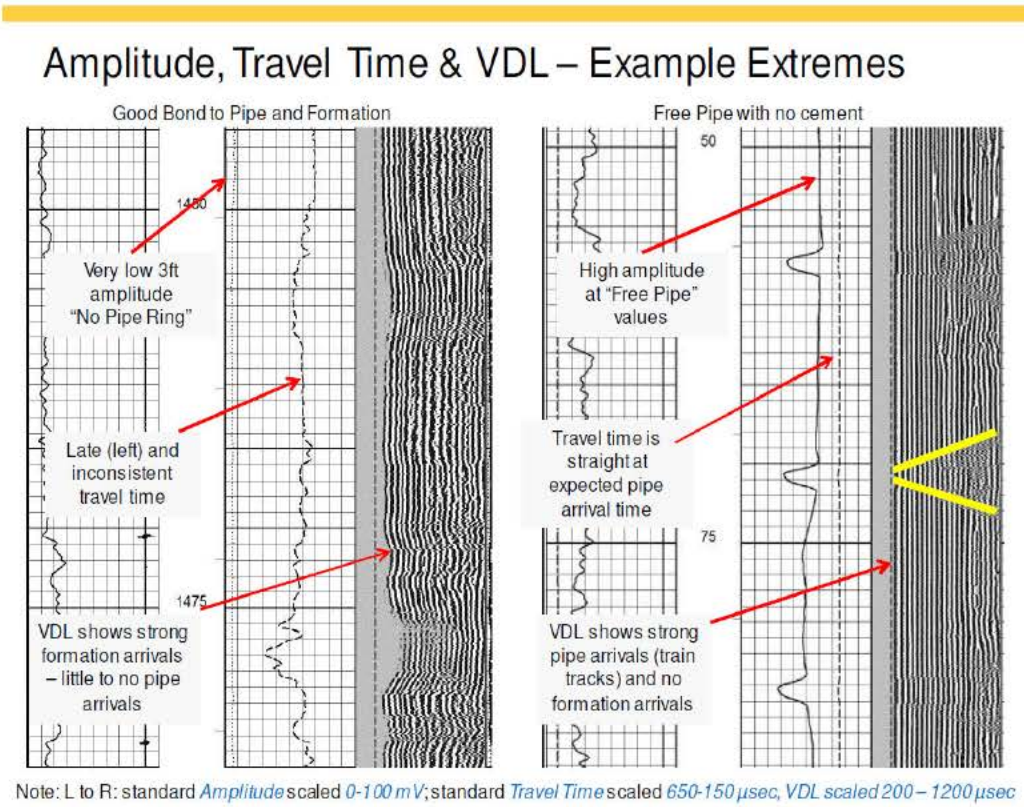

Figure V-1. Amplitude, Travel Time and VDL – Example Extremes.

Appendix V, Practice 18 - Cement Bond Logging Survey
Page 4 of 4

Well Integrity Evaluation and Communication:

Note: CBL is one of the components for evaluating/monitoring gas leaks and/or gas migration. For complete evaluation/analysis, it needs to correlate with other logs (T/N, GRN, Vertilog, IE logs, etc.).

1. Evaluate and correlate apparent anomalies with the all the integrity survey (CBL, T/N, GRN, and Vertilog) results and determine how to approach the next step if there are apparent cement sheath integrity issues which contribute to gas migration.
2. Communicate results to the Reservoir Engineering department.
3. If determine to have integrity issues, elevate to higher level management for mitigation decisions.
4. Reservoir Engineering, based on the above, will prioritize remedial work, update rework prioritization spreadsheet, and input in the GSDB and S1 and S2 processes.

Figure V-2 shows a decision tree for the Cement Bond Logging.

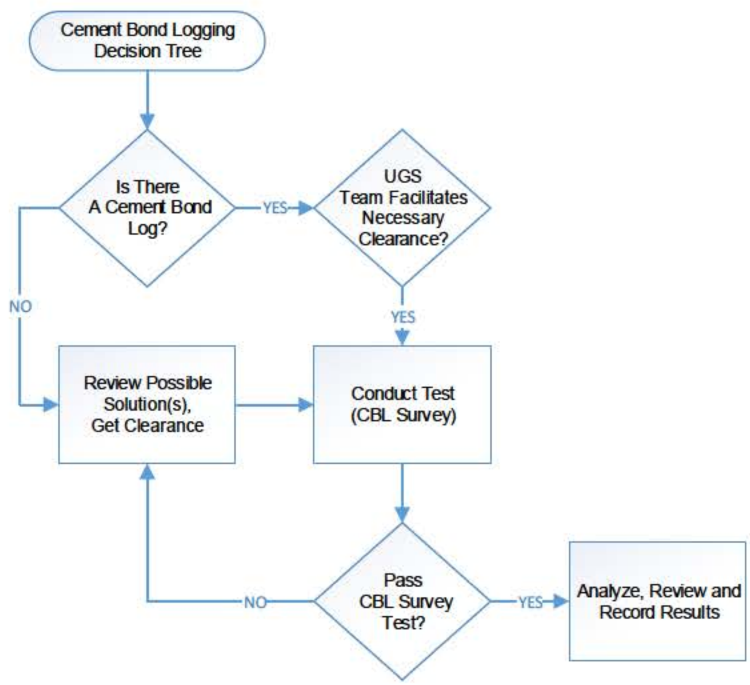

Figure V-2. Cement Bond Logging Decision Tree.

Underground Storage Risk and Integrity Management Plan

Appendix W, Glossary of Acronyms and Abbreviations

The following is a glossary of acronyms and abbreviations used in this asset management plan and related documents.

Table W-1 – Acronyms and Abbreviations

Acronym	Meaning
AFO	Asset Family Owner
AMP	Asset Management Plan
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BHP	Bottomhole Pressure
C&T	Casing & Tubing
CNL	Compensated Neutron Log
CPP	Casing Potential Profile
DOGGR	Division of Oil, Gas and Geothermal Resources
ECDA	External Corrosion Direct Assessment
EORM	Enterprise and Operational Risk Management
ESD	Emergency Shutdown
GSDB	Gas Storage Database
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
IE	Induction Electrical
ILI	In-Line Inspection
I/W	Injection/Withdrawal
LOB	Line of Business
LUAF	Lost and Unaccounted for
MOP	Maximum Operating Pressure

Acronym	Meaning
MASCP	Maximum Allowable Surface Casing Pressure
MFL	Magnetic Flux Leakage
MIT	Mechanical Integrity Test
ML	Microlog
NOS	Nuclear, Operations, and Safety
OBS	Observation
PDK	Pulse and Decay
RCC	Risk and Compliance Committee
RE	Reservoir Engineering
RET	Risk Evaluation Tool
RIBA	Risk Informed Budget Allocation
RP	Recommended Practice
SCA	Surface Casing Annulus
SCCDA	Stress Corrosion Cracking Direct Assessment
SME	Subject Matter Expert
SP	Spontaneous Potential
TCA	Tubing Casing Annulus
TDT	Thermal Decay Time
TIMP	Transmission Integrity Management Program
WRO	Work Requested by Others

Appendix X, Mitigations

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The table below display threats, drivers, and prevention measures associated with the Storage asset family. In the table below are different asset types (well, reservoir, surface), potential threats or hazards, drivers, and finally mitigation measures.

The following table is lists asset type, threat(s), prevention measures, department(s), and guidance documents.

Table X-1 – Prevention Measures and Guidance Documents

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Reference Document(s)
Well	Corrosion / Erosion, Manufacturing, Equipment	Cathodic Protection	Corrosion Engineering	• TD-4181P-201: Cathodic Protection Monitoring and Restoration
		Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment
		Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
		Casing Inspections (CBL, GRN, N/T, Caliper, Casing Inspection Tools)	Reservoir Engineering	• TD-4550P-20: Annual Gas Well Survey Procedures • WELL: Appendix C, Casing Inspection Survey Frequency Decision Tree • WELL: Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments • WELL: Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review • WELL: Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review • WELL: Appendix V, Practice 18 - Cement Bond Logging Survey

Appendix X, Mitigations

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
Well	Corrosion / Erosion, Manufacturing, Equipment	Monitor Well Performance Data	Reservoir Engineering	• WELL: Appendix H, Practice 4 - Sand Inspection • WELL: Appendix M, Practice 9 - Individual Well Performance Monitoring • WELL: Appendix N, Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring
		Monitor Casing Annular Data	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring
		Pressure Test	Reservoir Engineering	• WELL: Appendix Z, Well Integrity Testing Regime Process
		Leak Survey	Operations & Maintenance, Leak Survey	• Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
	Construction / Fabrication	Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
		Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
	Incorrect Operations (Operations & Maintenance)	Guidance Documents (Operating Standards	Operations & Maintenance, Station Services	• Operating Procedures
		Operator Qualifications (OQ) Training and Development (Operations & Maintenance)	OQ: Gas Training & Implementation Training and Dev: Operations & Maintenance	• OQ: Utility Standard TD-4008S: Operator Qualification Program Requirements • Training and Dev: Apprentice Station Operator: Administrative Procedures Manual
	Incorrect Operations (Well Intervention)	Active and P&A Well Evaluation (Well Schematics and records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams

Appendix X, Mitigations
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Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
Well	Incorrect Operations (Well Intervention)	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
		OQ / Training and Development (Reservoir Engineering)	Reservoir Engineering	• Reservoir Engineer Competencies • Reservoir Specialist Competencies
		Blowout Prevention Systems	Reservoir Engineering	• API RP 1171
Reservoir	Construction/ Fabrication, 1st, 2nd, 3rd Party Damage	Rules & Regulations	Reservoir Engineering	• DOGGR Regulations
		Location Design Requirements	Reservoir Engineering	• API RP 1171
		Equipment Design Requirements	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
		Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
		Monitor Permit Activity	Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
		Inspection During Construction	Reservoir Engineering	• API RP 1171
		Gas Sampling	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring • WELL: Appendix O, Practice 11 - Observation Well Gas Sampling
	Outside Forces (Geological)	Geological and Well Evaluation of Records	Reservoir Engineering	• Geologic and Seismic Review
		Protective Boundary	Reservoir Engineering	• API RP 1171

Appendix X, Mitigations

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
Reservoir	Outside Forces (Geological)	Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
		Observation Wells	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring • WELL: Appendix N, Practice 10 - Wellhead Production Casing and Tubing Pressure Monitoring • WELL: Appendix O, Practice 11 - Observation Well Gas Sampling
		Inventory Verification	Reservoir Engineering	• WELL: Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification
	Incorrect Operations	Guidance Documents (Design Standards for Fluids)	Reservoir Engineering	• API RP 1171
		Gas Quality Studies	Reservoir Engineering	• API RP 1171
		Fluid Compatibility Studies	Reservoir Engineering	• API RP 1171
		Internal Corrosion Studies	Reservoir Engineering	• API RP 1171
Surface	1st, 2nd, 3rd Party Damage (Surface Encroachments)	Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
		Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
		Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
	1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Physical Security Systems	Operations & Maintenance	• TD-4050S: Security Standard for Gas Operations • API RP 1171

Appendix X, Mitigations

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
Surface	1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
		Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
	Weather & Outside Forces	Design Process	Station Services (Facility Design), Reservoir Engineering (Wellhead Design)	• Gas Standards & Specifications • Geologic and Seismic Review • Catastrophic Emergency Response Plan - Gas Annex: Stations and Gas Storage • WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment
		Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
		Remote Control Capabilities	Operations & Maintenance	• Operating Procedures
All Asset Types	Major Emergency or Disaster	Emergency Shutdown Systems	Operations & Maintenance, Station Services	• Operating Procedures
		Transmission Control Center	Gas Control	• TD-4444P-02: Gas Transmission Control Center Emergency Response
		Business Continuity Plans	Gas Emergency Preparedness	• Business Continuity Plan
		Gas Emergency Response Plan (GERP)	Gas Emergency Preparedness	• Gas Emergency Response Plan
		Storage Well Crisis: Response Plan	Reservoir Engineering	• Well Control Tactical Considerations
		Storage Well Crisis: Water	Reservoir Engineering	• Well Control Tactical Considerations

Appendix X, Mitigations
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Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type	Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
All Asset Types	Major Emergency or Disaster	Storage Well Crisis: Equipment	Reservoir Engineering	• Well Control Tactical Considerations
		Emergency Management Advancement Program (EMAP)	Reservoir Engineering	• Catastrophic Emergency Response Plan - Gas Annex: Stations and Gas Storage
		Company Emergency Response Plan	Gas Emergency Preparedness	• EMER-3001M: Company Emergency Response Plan (CERP)
		GERP-Based Exercises	Gas Emergency Preparedness	• Gas Emergency Response Plan

Appendix Y, Production Fluid Facility Capacity Tables

Page 1 of 3

Capacities for production fluid facilities at Los Medanos, Pleasant Creek, and McDonald Island are listed in the tables below.

Table Y-1 – Production Fluid Containers – Los Medanos

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Production Fluids Storage Tanks (C-16 & C-21)	2	8,000	16,000
Production Fluid Tanks	1	1,800	1,800
Fluid Storage Convault Tank	1	1,000	1,000
Production Fluids Tanks (in concrete Convault) at Well Sites “A”, “B”, “C” and “D”	4	500	2,000
Production Liquids Tanks (in concrete Convault) at “Pressure Limiting Station”	1	2,000	2,000
Separator (C-8) at Well Site “D”	1	210	210

Table Y-2 – Production Fluid Containers – Pleasant Creek

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Production Fluids Storage Tank – Wellhead Yard #3-1, Wellhead Yard #4-1	2	500	1,000
Production Fluids Storage Tank – Wellhead Yard #3-2, Wellhead Yard #3-3, Wellhead Yard #3-4, Wellhead Yard #4-2	4	1,500	6,000
Production Fluids ConVault – Wellhead Yard #3-5	1	2,000	2,000

Appendix Y, Production Fluid Facility Capacity Tables
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Table Y-3 – Production Fluid Containers – McDonald Island

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Turner Cut Station			
Bulk Storage Container – Aboveground, Production Fluids Storage Tank C-30	1	27,707	27,707
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks C-5 and C-6	2	12,000	24,000
Separator Units C-11, C-12, C-13, C-14	4	60	240
Contactor Towers C-1, C-2, C-3, C-4	4	400	1,600
3-Phase Separators	2	150	300
Drain Dump System C-26	1	150	150
Whisky Slough Station			
Bulk Storage Container – Aboveground, Production Fluids Storage Tank C-30	1	27,707	27,707
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks C-5 and C-6	2	12,000	24,000
Separator Units C-11, C-12, C-13, C-14	4	60	240
Contactor Towers C-1, C-2, C-3, C-4	4	400	1,600
3-Phase Separators	2	150	300
Drain Dump System C-26	1	150	150
McDonald Island Compressor Station			
Bulk Storage Container – Aboveground, Pipeline Liquids Storage Tank D-1A	1	6,250	6,250
Mobile Container, Vacuum Truck	1	1,600	1,600
Separator Unites C-11, C-11A	2	75	150
Intake Scrubbers C-101, C-201	2	75	150

Appendix Y, Production Fluid Facility Capacity Tables

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Table Y-3 – Production Fluid Containers – McDonald Island (continued)

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
K7 – K9 Compressor Yard			
Bulk Storage Container Aboveground, Pipeline Liquids Storage Tank D-10	1	2,000	2,000
Intake Scrubbers K7 (2), K8 (2), K9 (2)	6	55	330
Discharge Scrubbers K7, K8, K9	3	64	192
Separator Unit	1	294	294
Remote Gas Wells			
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks	13	246	3,198

Appendix Z, Well Integrity Testing Regime Process

Page 1 of 1

The following flow chart illustrates the testing regime process that PG&E utilizes for assessing well integrity as included in the June 30, 2016, letter from DOGGR to PG&E. The individual flow charts and procedures for steps 4a through 7a are currently under development.

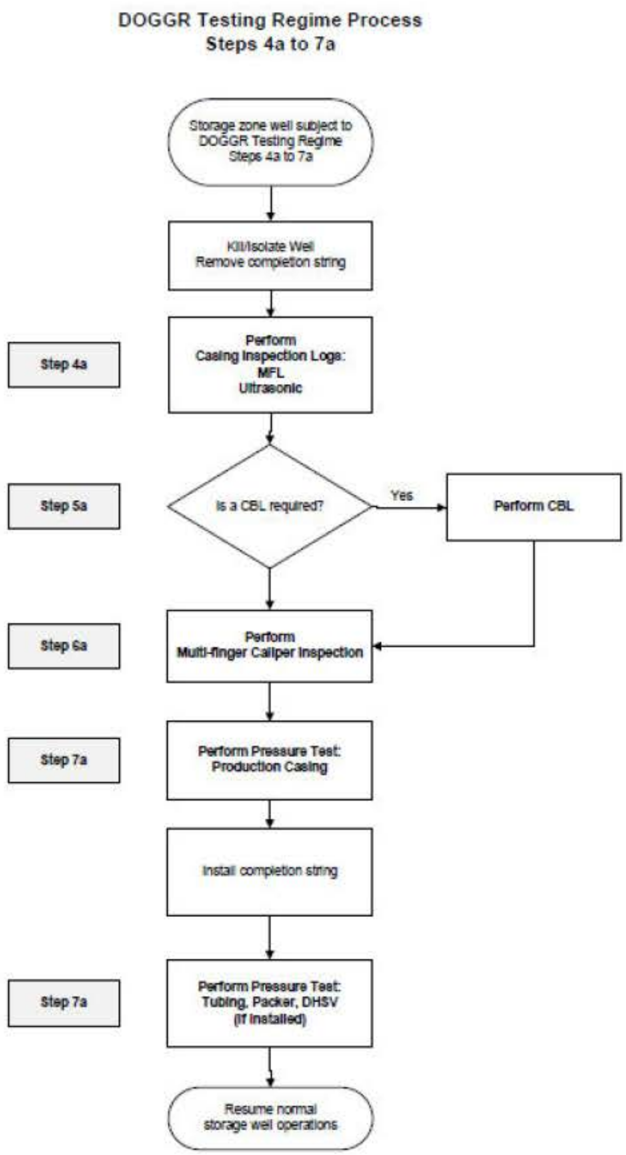

Figure Z-1 – Well Integrity Testing Regime Process

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

DESCRIPTION OF WELL INTEGRITY TESTS

Well Integrity Tests

Integrity Test	Description by DOGGR
Temperature Log	A sensor will be lowered down the depth of the well to measure the temperature of the material inside the metal tubing in the well. If the casing in the well is not intact, gas leaking out of the casing will expand and cool, and reduce temperatures within the well. A temperature test that verifies no cooling is taking place in any part of the well indicates that the casing has maintained integrity and no leaks exist.
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 will listen for any gas escaping from the well bore. If the well has a leak, gas will escape from the well bore causing a sound that can be detected by the sensor. The absence of sound above the reservoir indicates an effective seal of the well.
Casing Wall Thickness Inspection	The Thickness Inspection of the well that measures the thickness of the external casing of a well, as well as the amount of any corrosion that has occurred to that casing. For this test to be conducted, the interior metal tubing is removed from entire depth of the well, and measurements are taken directly from the inside wall of the casing. If the inspection reveals thinning of the casing, the current strength of the casing will be calculated. If the current strength of the casing has diminished to the point that it cannot withstand authorized operating pressures for the well plus a built-in additional safety factor of pressure, the well has failed this test. A passing test for a Casing Wall Thickness Inspection would show no thinning of the casing that diminishes the casing's ability to contain at least 115% of the well's maximum allowable operating pressure.

Well Integrity Tests (cont.)

Integrity Test	Description by DOGGR
Cement Bond Log	The Cement Bond Log is a sonic test that measures the adherence between cement and the external casing of the well, and also the contact between the cement anchor of the well and the underground gas reservoir. Cement should be solidly bonded to both the well's external casing and the geologic formation to ensure a seal that prevents fluids or gases from migrating up or down the outside of the well. The interior metal tubing for the entire well must be pulled to conduct this test. A passing test for a cement bond log shows no significant spaces between cement and casing, or between cement and the gas storage formation and cap rock.
Multi-Arm Caliper Inspection	This Inspection measures any internal degradation or significant changes to the well's geometry. In this inspection, metallic sensors or "arms" radiate out from a central wire that runs down the inside of the well's exterior casing to measure the shape of the casing. If the inspection reveals a thinning or deformity of the casing, the current strength of the casing will be calculated. If the current strength of the casing has diminished, such that it cannot withstand authorized operating pressures plus a built-in safety factor of additional pressure, the well fails this inspection.
Pressure Test	Pressure tests increase the pressure within the interior metal tubing of the well, and in the annular space between this interior tubing and the well's outer casing, to determine the well's ability to withstand normal operating pressures. The interior tubing is isolated and then pressure tested. Next the annular space between tubing and casing is pressure tested. This testing also evaluates the integrity of any packers, which seal the annular space between the tubing and casing. A passing test for a pressure test would show a minimum pressure loss when the pressure is raised to a level of 115% of the maximum operating pressure.

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APPENDIX D

INDEX FOR NOISE AND TEMPERATURE (N&T) SURVEYS

FILES PROVIDED ON DVD

Gas Storage Safety Report
Noise & Temperature Survey Files

Storage Field	Well Name	Survey Year	File Name
Los Medanos	Ginochio 3-7 (Gino 3-7)	2007	01300135_NoiseTemp_Gino 3-7_2007-11-12.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2008	01300135_NoiseTemp_Gino 3-7_2008-08-18.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2006	01300135_NoiseTemp_Gino 3-7_2006-06-08.TIF
Los Medanos	Ginochio 3-7 (Gino 3-7)	2006	01300135_NoiseTemp_Gino 3-7_2006-08-11.TIF
Los Medanos	Ginochio 3-7 (Gino 3-7)	2010	01300135_NoiseTemp_Gino 3-7_2010-07-26.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2011	01300135_NoiseTemp_Gino 3-7_2011-08-15.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2012	01300135_NoiseTemp_Gino 3-7_2012-07-24.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2013	01300135_NoiseTemp_Gino 3-7_2013-08-26.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2014	01300135_NoiseTemp_Gino 3-7_2014-11-21.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2015	01300135_NoiseTemp_Gino 3-7_2015-09-28.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	2009	01300135_NoiseTemp_Gino 3-7_2009-11-12.TIF
Los Medanos	Los Medanos 10C *(LM-10C)*	2006	01320131_NosieTemp_LM-10C_2006-08-15.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	2008	01320131_NoiseTemp_LM-10C_2008-08-20.TIF
Los Medanos	Los Medanos 10C *(LM-10C)*	2007	01320131_NoiseTemp_LM-10C_2007-11-15.TIF
Los Medanos	Los Medanos 10C *(LM-10C)*	2009	01320131_NoiseTemp_LM-10C_2009-11-13.TIF
Los Medanos	Los Medanos 10C *(LM-10C)*	2010	01320131_NoiseTemp_LM-10C_2010-07-28.TIF
Los Medanos	Los Medanos 10C *(LM-10C)*	2011	01320131_NoiseTemp_LM-10C_2011-08-17.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	2012	01320131_NoiseTemp_LM-10C_2012-07-23.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	2013	01320131_NoiseTemp_LM-10C_2013-08-28.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	2014	01320131_NoiseTemp_LM-10C_2014-11-19.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	2015	01320131_NoiseTemp_LM-10C_2015-09-28.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2006	01320128_NoiseTemp_LM-11C_2006-08-15.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2008	01320128_NoiseTemp_LM-11C_2008-08-20.TIF
Los Medanos	Los Medanos 11C *(LM-11C)*	2007	01320128_NoiseTemp_LM-11C_2007-11-15.TIF
Los Medanos	Los Medanos 11C *(LM-11C)*	2009	01320128_NoiseTemp_LM-11C_2009-11-12.TIF
Los Medanos	Los Medanos 11C *(LM-11C)*	2010	01320128_NoiseTemp_LM-11C_2010-07-28.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2011	01320128_NoiseTemp_LM-11C_2011-08-17.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2012	01320128_NoiseTemp_LM-11C_2012-07-23.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2013	01320128_NoiseTemp_LM-11C_2013-08-28.pdf

Gas Storage Safety Report
Noise & Temperature Survey Files

Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 11C *(LM-11C)*	2014	01320128_NoiseTemp_LM-11C_2014-11-19.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	2015	01320128_NoiseTemp_LM-11C_2015-09-29.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2006	01320307_NoiseTemp_LM-12C_2006-08-15.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2008	01320307_NoiseTemp_LM-12C_2008-08-19.TIF
Los Medanos	Los Medanos 12C *(LM-12C)*	2007	01320307_NoiseTemp_LM-12C_2007-11-14.TIF
Los Medanos	Los Medanos 12C *(LM-12C)*	2009	01320307_NoiseTemp_LM-12C_2009-11-12.TIF
Los Medanos	Los Medanos 12C *(LM-12C)*	2010	01320307_NoiseTemp_LM-12C_2010-07-28.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2011	01320307_NoiseTemp_LM-12C_2011-08-18.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2012	01320307_NoiseTemp_LM-12C_2012-07-24.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2013	01320307_NoiseTemp_LM-12C_2013-08-28.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2014	01320307_NoiseTemp_LM-12C_2014-11-18.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	2015	01320307_NoiseTemp_LM-12C_2015-09-30.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2006	01320299_NoiseTemp_LM-13C_2006-08-15.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2008	01320299_NoiseTemp_LM-13C_2008-08-19.TIF
Los Medanos	Los Medanos 13C *(LM-13C)*	2007	01320299_NoiseTemp_LM-13C_2007-11-14.TIF
Los Medanos	Los Medanos 13C *(LM-13C)*	2009	01320299_NoiseTemp_LM-13C_2009-11-13.TIF
Los Medanos	Los Medanos 13C *(LM-13C)*	2010	01320299_NoiseTemp_LM-13C_2010-07-28.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2011	01320299_NoiseTemp_LM-13C_2011-08-18.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2012	01320299_NoiseTemp_LM-13C_2012-07-23.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2013	01320299_NoiseTemp_LM-13C_2013-08-28.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2014	01320299_NoiseTemp_LM-13C_2014-11-18.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	2015	01320299_NoiseTemp_LM-13C_2015-09-29.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2006	01320298_NoiseTemp_LM-14C_2006-08-15.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2008	01320298_NoiseTemp_LM-14C_2008-08-19.TIF
Los Medanos	Los Medanos 14C *(LM-14C)*	2007	01320298_NoiseTemp_LM-14C_2007-11-14.TIF
Los Medanos	Los Medanos 14C *(LM-14C)*	2009	01320298_NoiseTemp_LM-14C_2009-11-13.TIF
Los Medanos	Los Medanos 14C *(LM-14C)*	2010	01320298_NoiseTemp_LM-14C_2010-07-27.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2011	01320298_NoiseTemp_LM-14C_2011-08-18.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2012	01320298_NoiseTemp_LM-14C_2012-07-23.pdf

Gas Storage Safety Report
Noise & Temperature Survey Files

Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 14C *(LM-14C)*	2013	01320298_NoiseTemp_LM-14C_2013-08-28.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2014	01320298_NoiseTemp_LM-14C_2014-11-19.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	2015	01320298_NoiseTemp_LM-14C_2015-09-29.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2006	01320121_NoiseTemp_LM-15C_2006-08-15.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2008	01320121_NoiseTemp_LM-15C_2008-08-20.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2007	01320121_NoiseTemp_LM-15C_2007-11-14.TIF
Los Medanos	Los Medanos 15C *(LM-15C)*	2009	01320121_NoiseTemp_LM-15C_2009-11-13.TIF
Los Medanos	Los Medanos 15C *(LM-15C)*	2010	01320121_NoiseTemp_LM-15C_2010-07-27.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2011	01320121_NoiseTemp_LM-15C_2011-08-18.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2012	01320121_NoiseTemp_LM-15C_2012-07-23.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2013	01320121_NoiseTemp_LM-15C_2013-08-29.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2014	01320121_NoiseTemp_LM-15C_2014-11-20.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	2015	01320121_NoiseTemp_LM-15C_2015-09-29.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2006	01320133_NoiseTemp_LM-16D_2006-08-14.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2008	01320133_NoiseTemp_LM-16D_2008-08-21.TIF
Los Medanos	Los Medanos 16D *(LM-16D)*	2007	01320133_NoiseTemp_LM-16D_2007-11-15.TIF
Los Medanos	Los Medanos 16D *(LM-16D)*	2009	01320133_NoiseTemp_LM-16D_2009-11-13.TIF
Los Medanos	Los Medanos 16D *(LM-16D)*	2010	01320133_NoiseTemp_LM-16D_2010-07-29.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2011	01320133_NoiseTemp_LM-16D_2011-08-16.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2012	01320133_NoiseTemp_LM-16D_2012-07-26.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2013	01320133_NoiseTemp_LM-16D_2013-08-29.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2014	01320133_NoiseTemp_LM-16D_2014-11-17.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	2015	01320133_NoiseTemp_LM-16D_2015-09-30.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2006	01320136_NoiseTemp_LM-17D_2006-08-14.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2008	01320136_NoiseTemp_LM-17D_2008-08-21.TIF
Los Medanos	Los Medanos 17D *(LM-17D)*	2007	01320136_NoiseTemp_LM-17D_2007-11-16.TIF
Los Medanos	Los Medanos 17D *(LM-17D)*	2009	01320136_NoiseTemp_LM-17D_2009-11-13.TIF
Los Medanos	Los Medanos 17D *(LM-17D)*	2010	01320136_NoiseTemp_LM-17D_2010-07-29.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2011	01320136_NoiseTemp_LM-17D_2011-08-16.pdf

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Noise & Temperature Survey Files

Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 17D *(LM-17D)*	2012	01320136_NoiseTemp_LM-17D_2012-07-26.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2013	01320136_NoiseTemp_LM-17D_2013-08-29.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2014	01320136_NoiseTemp_LM-17D_2014-11-17.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	2015	01320136_NoiseTemp_LM-17D_2015-09-29.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2006	01320135_NoiseTemp_LM-18D_2006-08-14.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2008	01320135_NoiseTemp_LM-18D_2008-08-21.TIF
Los Medanos	Los Medanos 18D *(LM-18D)*	2007	01320135_NoiseTemp_LM-18D_2007-11-16.TIF
Los Medanos	Los Medanos 18D *(LM-18D)*	2009	01320135_NoiseTemp_LM-18D_2009-11-13.TIF
Los Medanos	Los Medanos 18D *(LM-18D)*	2010	01320135_NoiseTemp_LM-18D_2010-07-29.TIF
Los Medanos	Los Medanos 18D *(LM-18D)*	2011	01320135_NoiseTemp_LM-18D_2011-08-16.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2012	01320135_NoiseTemp_LM-18D_2012-07-26.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2013	01320135_NoiseTemp_LM-18D_2013-08-29.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2014	01320135_NoiseTemp_LM-18D_2014-11-18.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	2015	01320135_NoiseTemp_LM-18D_2015-09-29.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2006	01320295_NoiseTemp_LM-19D_2006-08-14.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2008	01320295_NoiseTemp_LM-19D_2008-08-21.TIF
Los Medanos	Los Medanos 19D *(LM-19D)*	2007	01320295_NoiseTemp_LM-19D_2007-11-16.TIF
Los Medanos	Los Medanos 19D *(LM-19D)*	2009	01320295_NoiseTemp_LM-19D_2009-11-13.TIF
Los Medanos	Los Medanos 19D *(LM-19D)*	2010	01320295_NoiseTemp_LM-19D_2010-07-29.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2011	01320295_NoiseTemp_LM-19D_2011-08-16.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2012	01320295_NoiseTemp_LM-19D_2012-07-26.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2013	01320295_NoiseTemp_LM-19D_2013-08-30.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2014	01320295_NoiseTemp_LM-19D_2014-11-18.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	2015	01320295_NoiseTemp_LM-19D_2015-09-29.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	2008	01320373_NoiseTemp_LM-1A_2008-08-18.TIF
Los Medanos	Los Medanos 1A *(LM-1A)*	2006	-
Los Medanos	Los Medanos 1A *(LM-1A)*	2007	01320373_NoiseTemp_LM-1A_2007-12-08.TIF
Los Medanos	Los Medanos 1A *(LM-1A)*	2009	01320373_NoiseTemp_LM-1A_2009-11-12.TIF
Los Medanos	Los Medanos 1A *(LM-1A)*	2010	01320373_NoiseTemp_LM-1A_2010-07-27.TIF

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Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 1A *(LM-1A)*	2011	01320373_NoiseTemp_LM-1A_2011-08-15.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	2012	01320373_NoiseTemp_LM-1A_2012-07-25.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	2013	01320373_NoiseTemp_LM-1A_2013-08-26.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	2014	01320373_NoiseTemp_LM-1A_2014-11-21.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	2015	01320373_NoiseTemp_LM-1A_2015-09-28.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2006	01320287_NoiseTemp_LM-20D_2006-08-14.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2008	01320297_NoiseTemp_LM-20D_2008-08-21.TIF
Los Medanos	Los Medanos 20D *(LM-20D)*	2007	01320297_NoiseTemp_LM-20D_2007-11-15.TIF
Los Medanos	Los Medanos 20D *(LM-20D)*	2009	01320297_NoiseTemp_LM-20D_2009-11-13.TIF
Los Medanos	Los Medanos 20D *(LM-20D)*	2010	01320297_NoiseTemp_LM-20D_2010-07-29.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2011	01320297_NoiseTemp_LM-20D_2011-08-16.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2012	01320297_NoiseTemp_LM-20D_2012-07-26.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2013	01320297_NoiseTemp_LM-20D_2013-08-29.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2014	01320297_NoiseTemp_LM-20D_2014-11-17.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	2015	01320297_NoiseTemp_LM-20D_2015-09-30.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2006	01320308_NoiseTemp_LM-21D_2006-08-14.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2008	01320308_NoiseTemp_LM-21D_2008-08-21.TIF
Los Medanos	Los Medanos 21D *(LM-21D)*	2007	01320308_NoiseTemp_LM-21D_2007-11-16.TIF
Los Medanos	Los Medanos 21D *(LM-21D)*	2009	01320308_NoiseTemp_LM-21D_2009-11-13.TIF
Los Medanos	Los Medanos 21D *(LM-21D)*	2010	01320308_NoiseTemp_LM-21D_2010-07-29.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2011	01320308_NoiseTemp_LM-21D_2011-08-16.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2012	01320308_NoiseTemp_LM-21D_2012-07-26.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2013	01320308_NoiseTemp_LM-21D_2013-08-29.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2014	01320308_NoiseTemp_LM-21D_2014-11-18.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	2015	01320308_NoiseTemp_LM-21D_2015-09-29.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2008	01320138_NoiseTemp_LM-2A_2008-08-18.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2006	-
Los Medanos	Los Medanos 2A *(LM-2A)*	2007	01320138_NoiseTemp_LM-2A_2007-11-12.TIF
Los Medanos	Los Medanos 2A *(LM-2A)*	2010	01320138_NoiseTemp_LM-2A_2010-07-27.pdf

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Noise & Temperature Survey Files

Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 2A *(LM-2A)*	2011	01320138_NoiseTemp_LM-2A_2011-08-15.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2012	01320138_NoiseTemp_LM-2A_2012-07-25.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2013	01320138_NoiseTemp_LM-2A_2013-08-26.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2014	01320138_NoiseTemp_LM-2A_2014-11-21.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	2015	
Los Medanos	Los Medanos 2A *(LM-2A)*	2009	01320138_NoiseTemp_LM-2A_2009-11-12.TIF
Los Medanos	Los Medanos 3A *(LM-3A)*	2008	01320115_NoiseTemp_LM-3A_2008-08-18.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2006	-
Los Medanos	Los Medanos 3A *(LM-3A)*	2007	01320115_NoiseTemp_LM-3A_2007-11-12.TIF
Los Medanos	Los Medanos 3A *(LM-3A)*	2010	01320115_NoiseTemp_LM-3A_2010-07-27.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2011	01320115_NoiseTemp_LM-3A_2011-08-15.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2012	01320115_NoiseTemp_LM-3A_2012-07-25.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2013	01320115_NoiseTemp_LM-3A_2013-08-26.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2014	01320115_NoiseTemp_LM-3A_2014-11-21.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2015	01320115_NoiseTemp_LM-3A_2015-09-28.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	2009	01320115_NoiseTemp_LM-3A_2009-11-12.TIF
Los Medanos	Los Medanos 4B *(LM-4B)*	2006	01320093_NoiseTemp_LM-4B_2006-08-14.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2008	01320093_NoiseTemp_LM-4B_2008-08-19.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2007	01320093_NoiseTemp_LM-4B_2007-11-14.TIF
Los Medanos	Los Medanos 4B *(LM-4B)*	2010	01320093_NoiseTemp_LM-4B_2010-07-26.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2011	01320093_NoiseTemp_LM-4B_2011-08-15.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2012	01320093_NoiseTemp_LM-4B_2012-07-25.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2013	01320093_NoiseTemp_LM-4B_2013-08-27.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2014	01320093_NoiseTemp_LM-4B_2014-11-20.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2015	01320093_NoiseTemp_LM-4B_2015-09-29.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	2009	01320093_NoiseTemp_LM-4B_2009-11-12.TIF
Los Medanos	Los Medanos 5B *(LM-5B)*	2006	01320144_NoiseTemp_LM-5B_2006-08-14.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2008	01320144_NoiseTemp_LM-5B_2008-08-19.TIF
Los Medanos	Los Medanos 5B *(LM-5B)*	2007	01320144_NoiseTemp_LM-5B_2007-11-14.TIF

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Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 5B *(LM-5B)*	2009	01320144_NoiseTemp_LM-5B_2009-11-12.TIF
Los Medanos	Los Medanos 5B *(LM-5B)*	2010	01320144_NoiseTemp_LM-5B_2010-07-26.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2011	01320144_NoiseTemp_LM-5B_2011-08-15.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2012	01320144_NoiseTemp_LM-5B_2012-07-25.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2013	01320144_NoiseTemp_LM-5B_2013-08-27.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2014	01320144_NoiseTemp_LM-5B_2014-11-20.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	2015	01320144_NoiseTemp_LM-5B_2015-09-30.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2006	01320140_NoiseTemp_LM-6B_2006-08-14.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2008	01320140_NoiseTemp_LM-6B_2008-08-18.TIF
Los Medanos	Los Medanos 6B *(LM-6B)*	2007	01320140_NoiseTemp_LM-6B_2007-11-14.TIF
Los Medanos	Los Medanos 6B *(LM-6B)*	2009	01320140_NoiseTemp_LM-6B_2009-11-12.TIF
Los Medanos	Los Medanos 6B *(LM-6B)*	2010	01320140_NoiseTemp_LM-6B_2010-07-26.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2011	01320140_NoiseTemp_LM-6B_2011-08-18.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2012	01320140_NoiseTemp_LM-6B_2012-07-25.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2013	01320140_NoiseTemp_LM-6B_2013-08-27.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2014	01320140_NoiseTemp_LM-6B_2014-11-20.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	2015	01320140_NoiseTemp_LM-6B_2015-09-30.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2006	01320130_NoiseTemp_LM-7C_2006-08-14.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2008	01320130_NoiseTemp_LM-7C_2008-08-20.TIF
Los Medanos	Los Medanos 7C *(LM-7C)*	2007	01320130_NoiseTemp_LM-7C_2007-11-15.TIF
Los Medanos	Los Medanos 7C *(LM-7C)*	2009	01320130_NoiseTemp_LM-7C_2009-11-12.TIF
Los Medanos	Los Medanos 7C *(LM-7C)*	2010	01320130_NoiseTemp_LM-7C_2010-07-28.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2011	01320130_NoiseTemp_LM-7C_2011-08-17.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2012	01320130_NoiseTemp_LM-7C_2012-07-23.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2013	01320130_NoiseTemp_LM-7C_2013-08-27.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2014	01320130_NoiseTemp_LM-7C_2014-11-20.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	2015	01320130_NoiseTemp_LM-7C_2015-09-28.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2006	01320145_NoiseTemp_LM-8C_2006-08-14.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2008	01320145_NoiseTemp_LM-8C_2008-08-20.TIF

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Storage Field	Well Name	Survey Year	File Name
Los Medanos	Los Medanos 8C *(LM-8C)*	2007	01320145_NoiseTemp_LM-8C_2007-11-15.TIF
Los Medanos	Los Medanos 8C *(LM-8C)*	2009	01320145_NoiseTemp_LM-8C_2009-11-12.TIF
Los Medanos	Los Medanos 8C *(LM-8C)*	2010	01320145_NoiseTemp_LM-8C_2010-07-28.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2012	01320145_NoiseTemp_LM-8C_2012-07-23.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2013	01320145_NoiseTemp_LM-8C_2013-08-27.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2014	01320145_NoiseTemp_LM-8C_2014-11-19.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2015	01320145_NoiseTemp_LM-8C_2015-09-30.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	2011	01320145_NoiseTemp_LM-8C_2011-08-17.TIF
Los Medanos	Los Medanos 9C *(LM-9C)*	2006	01320123_NoiseTemp_LM-9C_2006-08-14.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2008	01320123_NoiseTemp_LM-9C_2008-08-20.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2007	01320123_NoiseTemp_LM-9C_2007-09-06.TIF
Los Medanos	Los Medanos 9C *(LM-9C)*	2007	01320123_NoiseTemp_LM-9C_2007-11-15.TIF
Los Medanos	Los Medanos 9C *(LM-9C)*	2009	01320123_NoiseTemp_LM-9C_2008-08-20.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2010	01320123_NoiseTemp_LM-9C_2010-07-28.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2011	01320123_NoiseTemp_LM-9C_2011-08-17.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2012	01320123_NoiseTemp_LM-9C_2012-07-23.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2013	01320123_NoiseTemp_LM-9C_2013-08-28.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2014	01320123_NoiseTemp_LM-9C_2014-11-19.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	2015	01320123_NoiseTemp_LM-9C_2015-09-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2006	-
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2007	07720196_NoiseTemp_TC-1N_2007-09-05.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2009	07720196_NoiseTemp_TC-1N_2009-06-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2010	07720196_NoiseTemp_TC-1N_2010-08-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2011	07720196_NoiseTemp_TC-1N_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2012	07720196_NoiseTemp_TC-1N_2012-11-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2013	07720196_NoiseTemp_TC-1N_2013-09-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2014	07720196_NoiseTemp_TC-1N_2014-10-21.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2015	07720196_NoiseTemp_TC-1N_2015-10-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	2008	07720196_NoiseTemp_TC-1N_2008-11-20.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2008	07720218_NoiseTemp_TC-1S_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2006	07720218_NoiseTemp_TC-1S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2007	07720218_NoiseTemp_TC-1S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2010	07720218_NoiseTemp_TC-1S_2010-08-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2011	07720218_NoiseTemp_TC-1S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2012	07720218_NoiseTemp_TC-1S_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2013	07720218_NoiseTemp_TC-1S_2013-09-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2014	07720218_NoiseTemp_TC-1S_2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2015	07720218_NoiseTemp_TC-1S_2015-10-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South (*TC-1S*)	2009	07720218_NoiseTemp_TC-1S_2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2008	07720228_NoiseTemp_TC-10N_2008-11-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2006	07720228_NoiseTemp_TC-10N_2006-11-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2007	07720228_NoiseTemp_TC-10N_2007-09-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2009	07720228_NoiseTemp_TC-10N_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2010	07720228_NoiseTemp_TC-10N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2011	07720228_NoiseTemp_TC-10N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2012	07720228_NoiseTemp_TC-10N_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2013	07720228_NoiseTemp_TC-10N_2013-09-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2014	07720228_NoiseTemp_TC-10N_2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	2015	07720228_NoiseTemp_TC-10N_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2008	07720251_NoiseTemp_TC-10S_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2006	07720251_NoiseTemp_TC-10S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2007	07720251_NoiseTemp_TC-10S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2009	07720251_NoiseTemp_TC-10S_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2010	07720251_NoiseTemp_TC-10S_2010-08-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2011	07720251_NoiseTemp_TC-10S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2012	07720251_NoiseTemp_TC-10S_2012-11-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2013	07720251_NoiseTemp_TC-10S_2013-09-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S*)	2014	07720251_NoiseTemp_TC-10S_2014-10-30.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 10 South (*TC-10S)*	2015	07720251_NoiseTemp_TC-10S_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2008	-
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2006	07720229_NoiseTemp_TC-11N_2006-11-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2007	07720229_NoiseTemp_TC-11N_2007-09-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2009	07720229_NoiseTemp_TC-11N_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2010	07720229_NoiseTemp_TC-11N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2011	07720229_NoiseTemp_TC-11N_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2012	07720229_NoiseTemp_TC-11N_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2013	07720229_NoiseTemp_TC-11N_2013-09-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2014	07720229_NoiseTemp_TC-11N_2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	2015	07720229_NoiseTemp_TC-11N_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2008	07720250_NoiseTemp_TC-11S_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2006	07720250_NoiseTemp_TC-11S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2007	07720250_NoiseTemp_TC-11S_2007-09-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2009	07720250_NoiseTemp_TC-11S_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2009	07720250_NoiseTemp_TC-11S_2009-11-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2010	07720250_NoiseTemp_TC-11S_2010-08-04.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2011	07720250_NoiseTemp_TC-11S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2012	07720250_NoiseTemp_TC-11S_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2013	07720250_NoiseTemp_TC-11S_2013-09-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2014	07720250_NoiseTemp_TC-11S_2014-10-30.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 South (*TC-11S)*	2015	07720250_NoiseTemp_TC-11S_2015-10-09.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2008	07720230_NoiseTemp_TC-12N_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2006	07720230_NoiseTemp_TC-12N_2006-11-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2007	07720230_NoiseTemp_TC-12N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2009	07720230_NoiseTemp_TC-12N_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2010	07720230_NoiseTemp_TC-12N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2011	07720230_NoiseTemp_TC-12N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2012	07720230_NoiseTemp_TC-12N_2012-11-15.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2013	07720230_NoiseTemp_TC-12N_2013-09-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2014	07720230_NoiseTemp_TC-12N_2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N)*	2015	07720230_NoiseTemp_TC-12N_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2008	07720248_NoiseTemp_TC-12S_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2006	07720248_NoiseTemp_TC-12S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2007	-
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2010	07720248_NoiseTemp_TC-12S_2010-08-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2011	07720248_NoiseTemp_TC-12S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2012	07720248_NoiseTemp_TC-12S_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2013	07720248_NoiseTemp_TC-12S_2013-09-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2014	07720248_NoiseTemp_TC-12S_2014-11-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2015	07720248_NoiseTemp_TC-12S_2015-10-09.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	2009	07720248_NoiseTemp_TC-12S_2009-06-01.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2008	07720234_NoiseTemp_TC-13N_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2006	07720234_NoiseTemp_TC-13N_2006-11-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2007	07720234_NoiseTemp_TC-13N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2009	07720234_NoiseTemp_TC-13N_2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2010	07720234_NoiseTemp_TC-13N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2011	07720234_NoiseTemp_TC-13N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2012	07720234_NoiseTemp_TC-13N_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2013	07720234_NoiseTemp_TC-13N_2013-09-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2014	07720234_NoiseTemp_TC-13N_2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N)*	2015	07720234_NoiseTemp_TC-13N_2015-10-09.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2008	07720247_NoiseTemp_TC-13S_2008-11-19.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2006	07720247_NoiseTemp_TC-13S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2007	07720247_NoiseTemp_TC-13S_2007-09-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2009	07720247_NoiseTemp_TC-13S_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2010	07720247_NoiseTemp_TC-13S_2010-08-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2011	07720247_NoiseTemp_TC-13S_2011-07-05.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2012	07720247_NoiseTemp_TC-13S_2012-11-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2013	07720247_NoiseTemp_TC-13S_2013-09-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2014	07720247_NoiseTemp_TC-13S_2014-11-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	2015	07720247_NoiseTemp_TC-13S_2015-10-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2008	07720244_NoiseTemp_TC-14S_2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2006	07720244_NoiseTemp_TC-14S_2006-08-21.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2007	07720244_NoiseTemp_TC-14S_2007-09-10.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2009	07720244_NoiseTemp_TC-14S_2009-06-10.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2010	07720244_NoiseTemp_TC-14S_2010-08-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2011	07720244_NoiseTemp_TC-14S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2012	07720244_NoiseTemp_TC-14S_2012-11-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2013	07720244_NoiseTemp_TC-14S_2013-09-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2014	07720244_NoiseTemp_TC-14S_2014-10-30.pdf
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	2015	07720244_NoiseTemp_TC-14S_2015-10-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2008	07720239_NoiseTemp_TC-15N_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2006	07720239_NoiseTemp_TC-15N_2006-11-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2007	07720239_NoiseTemp_TC-15N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2009	07720239_NoiseTemp_TC-15N_2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2010	07720239_NoiseTemp_TC-15N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2011	07720239_NoiseTemp_TC-15N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2012	07720239_NoiseTemp_TC-15N_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2013	07720239_NoiseTemp_TC-15N_2013-09-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2014	07720239_NoiseTemp_TC-15N_2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N)*	2015	07720239_NoiseTemp_TC-15N_2015-10-09.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2008	07720245_NoiseTemp_TC-15S_2008-11-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2008	07720245_NoiseTemp_TC-15S_2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2006	07720245_NoiseTemp_TC-15S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2007	07720245_NoiseTemp_TC-15S_2007-09-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2009	07720245_NoiseTemp_TC-15S_2009-06-10.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2010	07720245_NoiseTemp_TC-15S_2010-08-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2011	07720245_NoiseTemp_TC-15S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2012	07720245_NoiseTemp_TC-15S_2012-11-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2013	07720245_NoiseTemp_TC-15S_2013-09-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2014	07720245_NoiseTemp_TC-15S_2014-10-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	2015	07720245_NoiseTemp_TC-15S_2015-10-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2008	07720240_NoiseTemp_TC-16N_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2006	07720240_NoiseTemp_TC-16N_2006-11-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2007	07720240_NoiseTemp_TC-16N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2009	07720240_NoiseTemp_TC-16N_2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2010	07720240_NoiseTemp_TC-16N_2010-08-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2011	07720240_NoiseTemp_TC-16N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2012	07720240_NoiseTemp_TC-16N_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2013	07720240_NoiseTemp_TC-16N_2013-09-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2014	07720240_NoiseTemp_TC-16N_2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N)*	2015	07720240_NoiseTemp_TC-16N_2015-10-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2008	07720243_NosieTemp_TC-16S_2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2006	07720243_NosieTemp_TC-16S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2007	07720243_NosieTemp_TC-16S_2007-09-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2009	07720243_NosieTemp_TC-16S_2009-06-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2010	07720243_NosieTemp_TC-16S_2010-08-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2011	07720243_NosieTemp_TC-16S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2012	07720243_NosieTemp_TC-16S_2012-11-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2013	07720243_NosieTemp_TC-16S_2013-09-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2014	07720243_NosieTemp_TC-16S_2014-10-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 South (*TC-16S)*	2015	07720243_NosieTemp_TC-16S_2015-10-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2008	07720548_NoiseTemp_TC-17N_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2006	07720548_NoiseTemp_TC-17N_2006-11-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2007	07720548_NoiseTemp_TC-17N_2007-09-06.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2009	07720548 NoiseTemp TC-17N 2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2010	07720548 NoiseTemp TC-17N 2010-08-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2011	07720548 NoiseTemp TC-17N 2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2012	07720548 NoiseTemp TC-17N 2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2013	07720548 NoiseTemp TC-17N 2013-09-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2014	07720548_NoiseTemp_TC-17N_2014-11-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	2015	07720548 NoiseTemp TC-17N 2015-10-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2008	07720258 NoiseTemp TC-17S 2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2006	07720258 NoiseTemp TC-17S 2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2007	-
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2009	07720258 NoiseTemp TC-17S 2009-06-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2010	07720258 NoiseTemp TC-17S 2010-08-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2011	07720258 NoiseTemp TC-17S 2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2012	07720258_NoiseTemp_TC-17S_2012-11-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2013	07720258_NoiseTemp_TC-17S_2013-09-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2014	07720258 NoiseTemp TC-17S 2014-10-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 South (*TC-17S)*	2015	07720258 NoiseTemp TC-17S 2015-10-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2006	07720551 NoiseTemp TC-1AS 2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2007	07720551 NoiseTemp TC-1AS 2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2009	07720551 NoiseTemp TC-1AS 2009-06-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2010	07720551 NoiseTemp TC-1AS 2010-08-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2011	07720551 NoiseTemp TC-1AS 2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2012	07720551_NoiseTemp_TC-1AS_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2013	07720551 NoiseTemp TC-1AS 2013-09-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2014	07720551 NoiseTemp TC-1AS 2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2015	07720551 NoiseTemp TC-1AS 2015-10-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1S South (*TC-1AS)*	2008	07720551 NoiseTemp TC-1AS 2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2006	07720199 NoiseTemp TC-2N 2006-11-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2007	07720199 NoiseTemp TC-2N 2007-09-05.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2010	07720199_NoiseTemp_TC-2N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2011	07720199_NoiseTemp_TC-2N_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2012	07720199_NoiseTemp_TC-2N_2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2012	07720199_NoiseTemp_TC-2N_2012-11-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2013	07720199_NoiseTemp_TC-2N_2013-09-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2014	07720199_NoiseTemp_TC-2N_2014-10-21.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2015	07720199_NoiseTemp_TC-2N_2015-10-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2008	07720199_NoiseTemp_TC-2N_2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	2009	07720199_NoiseTemp_TC-2N_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2006	07720219_NoiseTemp_TC-2S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2007	07720219_NoiseTemp_TC-2S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2009	07720219_NoiseTemp_TC-2S_2009-06-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2010	07720219_NoiseTemp_TC-2S_2010-08-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2011	07720219_NoiseTemp_TC-2S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2012	07720219_NoiseTemp_TC-2S_2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2013	07720219_NoiseTemp_TC-2S_2013-09-10.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2014	07720219_NoiseTemp_TC-2S_2014-10-27.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2015	07720219_NoiseTemp_TC-2S_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South (*TC-2S)*	2008	07720219_NoiseTemp_TC-2S_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2006	-
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2007	07720201_NoiseTemp_TC-3N_2007-09-05.TIF
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2009	07720201_NoiseTemp_TC-3N_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2010	07720201_NoiseTemp_TC-3N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2011	07720201_NoiseTemp_TC-3N_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2012	07720201_NoiseTemp_TC-3N_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2013	07720201_NoiseTemp_TC-3N_2013-09-12.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2014	07720201_NoiseTemp_TC-3N_2014-10-21.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2015	07720201_NoiseTemp_TC-3N_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 North (*TC-3N)*	2008	07720201_NoiseTemp_TC-3N_2008-11-20.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2006	07720216_NoiseTemp_TC-3S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2007	07720216_NoiseTemp_TC-3S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2009	07720216_NoiseTemp_TC-3S_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2010	07720216_NoiseTemp_TC-3S_2010-08-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2011	07720216_NoiseTemp_TC-3S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2012	07720216_NoiseTemp_TC-3S_2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2013	07720216_NoiseTemp_TC-3S_2013-09-10.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2014	07720216_NoiseTemp_TC-3S_2014-10-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2015	07720216_NoiseTemp_TC-3S_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 3 South (*TC-3S)*	2008	-
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2006	-
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2007	07720202_NoiseTemp_TC-4N_2007-09-05.TIF
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2010	07720202_NoiseTemp_TC-4N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2011	07720202_NoiseTemp_TC-4N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2012	07720202_NoiseTemp_TC-4N_2012-11-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2013	07720202_NoiseTemp_TC-4N_2013-09-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2014	07720202_NoiseTemp_TC-4N_2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2015	07720202_NoiseTemp_TC-4N_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2008	07720202_NoiseTemp_TC-4N_2008-11-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North (*TC-4N)*	2009	07720202_NoiseTemp_TC-4N_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2006	07720203_NoiseTemp_TC-4S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2007	07720203_NoiseTemp_TC-4S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2010	07720203_NoiseTemp_TC-4S_2010-08-09.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2011	07720203_NoiseTemp_TC-4S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2012	07720203_NoiseTemp_TC-4S_2012-11-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2013	07720203_NoiseTemp_TC-4S_2013-09-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2014	07720203_NoiseTemp_TC-4S_2014-10-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2015	07720203_NoiseTemp_TC-4S_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S)*	2008	07720203_NoiseTemp_TC-4S_2008-11-17.pdf

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McDonald Island (Turner Cut Station)	Turner Cut 4 South (*TC-4S*)	2009	07720203_NoiseTemp_TC-4S_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2006	07720207_NoiseTemp_TC-5N_2006-11-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2007	07720207_NoiseTemp_TC-5N_2007-09-05.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2010	07720207_NoiseTemp_TC-5N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2011	07720207_NoiseTemp_TC-5N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2012	07720207_NoiseTemp_TC-5N_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2013	07720207_NoiseTemp_TC-5N_2013-09-23.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2014	07720207_NoiseTemp_TC-5N_2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2015	07720207_NoiseTemp_TC-5N_2015-10-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2008	07720207_NoiseTemp_TC-5N_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North (*TC-5N*)	2009	07720207_NoiseTemp_TC-5N_2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2006	07720204_NoiseTemp_TC-5S_2006-08-21.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2007	07720204_NoiseTemp_TC-5S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2010	07720204_NoiseTemp_TC-5S_2010-08-04.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2011	07720204_NoiseTemp_TC-5S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2012	07720204_NoiseTemp_TC-5S_2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2013	07720204_NoiseTemp_TC-5S_2013-09-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2014	07720204_NoiseTemp_TC-5S_2014-10-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2015	07720204_NoiseTemp_TC-5S_2015-10-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2008	07720204_NoiseTemp_TC-5S_2008-11-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South (*TC-5S*)	2009	07720204_NoiseTemp_TC-5S_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2006	-
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2007	07720208_NoiseTemp_TC-6N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2010	07720208_NoiseTemp_TC-6N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2011	07720208_NoiseTemp_TC-6N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2012	07720208_NoiseTemp_TC-6N_2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2013	07720208_NoiseTemp_TC-6N_2013-09-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2014	07720208_NoiseTemp_TC-6N_2014-10-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N*)	2015	07720208_NoiseTemp_TC-6N_2015-10-07.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N)*	2008	07720208 NoiseTemp TC-6N 2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North (*TC-6N)*	2009	07720208 NoiseTemp TC-6N 2009-06-10.TIF
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2006	07720205 NoiseTemp TC-6S 2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2007	07720205 NoiseTemp TC-6S 2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2010	-
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2011	07720205_NoiseTemp_TC-6S_2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2012	07720205 NoiseTemp TC-6S 2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2013	07720205 NoiseTemp TC-6S 2013-09-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2014	07720205 NoiseTemp TC-6S 2014-10-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2015	07720205 NoiseTemp TC-6S 2015-10-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2008	07720205 NoiseTemp TC-6S 2008-11-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South (*TC-6S)*	2009	07720205 NoiseTemp TC-6S 2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2006	07720225 NoiseTemp TC-7N 2006-11-08.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2007	07720225_NoiseTemp_TC-7N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2010	07720225_NoiseTemp_TC-7N_2010-08-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2011	07720225 NoiseTemp TC-7N 2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2012	07720225 NoiseTemp TC-7N 2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2013	07720225 NoiseTemp TC-7N 2013-09-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2014	07720225 NoiseTemp TC-7N 2014-10-22.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2015	07720225 NoiseTemp TC-7N 2015-10-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2008	07720225 NoiseTemp TC-7N 2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North (*TC-7N)*	2009	07720225 NoiseTemp TC-7N 2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2006	07720206_NoiseTemp_TC-7S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2007	07720206 NoiseTemp TC-7S 2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2010	07720206 NoiseTemp TC-7S 2010-08-04.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2011	07720206 NoiseTemp TC-7S 2011-07-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2012	07720206 NoiseTemp TC-7S 2012-11-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2013	07720206 NoiseTemp TC-7S 2013-09-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2014	07720206 NoiseTemp TC-7S 2014-10-30.pdf

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McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2015	07720206_NoiseTemp_TC-7S_2015-10-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2008	07720206_NoiseTemp_TC-7S_2008-11-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South (*TC-7S)*	2009	07720206_NoiseTemp_TC-7S_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2006	07720226_NoiseTemp_TC-8N_2006-11-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2007	07720226_NoiseTemp_TC-8N_2007-09-06.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2009	07720226_NoiseTemp_TC-8N_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2010	07720226_NoiseTemp_TC-8N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2011	07720226_NoiseTemp_TC-8N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2012	07720226_NoiseTemp_TC-8N_2012-11-14.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2013	07720226_NoiseTemp_TC-8N_2013-09-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2014	07720226_NoiseTemp_TC-8N_2014-11-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2015	07720226_NoiseTemp_TC-8N_2015-10-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	2008	07720226_NoiseTemp_TC-8N_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2006	07720533_NoiseTemp_TC-8S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2007	-
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2009	07720533_NoiseTemp_TC-8S_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2010	07720533_NoiseTemp_TC-8S_2010-08-04.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2011	07720533_NoiseTemp_TC-8S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2012	07720533_NoiseTemp_TC-8S_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2013	07720533_NoiseTemp_TC-8S_2013-09-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2014	07720533_NoiseTemp_TC-8S_2014-11-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2015	07720533_NoiseTemp_TC-8S_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	2008	07720533_NoiseTemp_TC-8S_2008-11-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2006	-
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2007	07720227_NoiseTemp_TC-9N_2007-09-07.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2010	07720227_NoiseTemp_TC-9N_2010-08-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2011	07720227_NoiseTemp_TC-9N_2011-07-07.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2012	07720227_NoiseTemp_TC-9N_2012-11-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N)*	2013	07720227_NoiseTemp_TC-9N_2013-09-18.pdf

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McDonald Island (Turner Cut Station)	Turner Cut 9 North *(TC-9N)*	2014	07720227_NoiseTemp_TC-9N_2014-10-28.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North *(TC-9N)*	2015	
McDonald Island (Turner Cut Station)	Turner Cut 9 North *(TC-9N)*	2008	07720227_NoiseTemp_TC-9N_2008-11-18.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 North *(TC-9N)*	2009	07720227_NoiseTemp_TC-9N_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2006	07720252_NoiseTemp_TC-9S_2006-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2007	07720252_NoiseTemp_TC-9S_2007-09-11.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2009	07720252_NoiseTemp_TC-9S_2009-06-09.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2010	07720252_NoiseTemp_TC-9S_2010-08-13.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2011	07720252_NoiseTemp_TC-9S_2011-07-05.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2012	07720252_NoiseTemp_TC-9S_2012-11-15.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2013	07720252_NoiseTemp_TC-9S_2013-09-17.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2014	07720252_NoiseTemp_TC-9S_2014-11-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2015	07720252_NoiseTemp_TC-9S_2015-10-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 9 South *(TC-9S)*	2008	07720252_NoiseTemp_TC-9S_2008-11-19.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2006	07720609_NoiseTemp_LilMac-1_2006-08-07.TIF
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2007	07720609_NoiseTemp_LilMac-1_2007-09-14.TIF
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2009	07720609_NoiseTemp_LilMac-1_2009-06-16.TIF
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2010	07720609_NoiseTemp_LilMac-1_2010-08-16.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2011	07720609_NoiseTemp_LilMac-1_2011-06-28.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2012	07720609_NoiseTemp_LilMac-1_2012-11-17.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2013	07720609_NoiseTemp_LilMac-1_2013-09-27.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2014	07720609_NoiseTemp_LilMac-1_2014-10-17.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2015	07720609_NoiseTemp_LilMac-1_2015-10-15.pdf
McDonald Island Peripheral	Lil Mac 1 *(LilMac-1)*	2008	07720609_NoiseTemp_LilMac-1_2008-11-18.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2006	07700085_NoiseTemp_MI-10_2006-08-09.TIF
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2007	07700085_NoiseTemp_MI-10_2007-09-13.TIF
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2009	07700085_NoiseTemp_MI-10_2009-06-16.TIF
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2010	07700085_NoiseTemp_MI-10_2010-08-16.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2011	07700085_NoiseTemp_MI-10_2011-06-27.pdf

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McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2012	07700085_NoiseTemp_MI-10_2012-11-06.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2013	07700085_NoiseTemp_MI-10_2013-09-26.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2014	07700085_NoiseTemp_MI-10_2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2015	07700085_NoiseTemp_MI-10_2015-10-13.pdf
McDonald Island Peripheral	McDonald Island Farms 10 *(MI-10)*	2008	07700085_NoiseTemp_MI-10_2008-11-13.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2006	07700086_NoiseTemp_MI-11_2006-08-07.TIF
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2007	-
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2009	07700086_NoiseTemp_MI-11_2009-06-16.TIF
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2010	07700086_NosieTemp_MI-11_2010-08-16.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2011	07700086_NoiseTemp_MI-11_2011-06-27.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2012	07700086_NoiseTemp_MI-11_2012-11-16.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2013	07700086_NoiseTemp_MI-11_2013-09-26.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2014	07700086_NoiseTemp_MI-11_2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2015	07700086_NoiseTemp_MI-11_2015-10-13.pdf
McDonald Island Peripheral	McDonald Island Farms 11 *(MI-11)*	2008	07700086_NoiseTemp_MI-11_2008-11-13.TIF
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2006	07700087_NoiseTemp_MI-12_2006-08-09.TIF
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2007	07700087_NoiseTemp_MI-12_2007-09-17.TIF
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2009	07700087_NoiseTemp_MI-12_2009-06-16.TIF
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2010	07700087_NoiseTemp_MI-12_2010-08-22.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2011	07700087_NoiseTemp_MI-12_2011-06-28.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2012	07700087_NoiseTemp_MI-12_2012-11-16.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2013	07700087_NoiseTemp_MI-12_2013-09-18.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2014	07700087_NoiseTemp_MI-12_2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2015	07700087_NoiseTemp_MI-12_2015-10-13.pdf
McDonald Island Peripheral	McDonald Island Farms 12 *(MI-12)*	2008	-
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2006	07700088_NoiseTemp_MI-13_2006-08-09.TIF
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2007	07700088_NoiseTemp_MI-13_2007-09-13.TIF
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2009	07700088_NoiseTemp_MI-13_2009-06-15.TIF
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2010	07700088_NoiseTemp_MI-13_2010-08-15.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2011	07700088 NoiseTemp MI-13 2011-06-28.pdf
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2012	07700088 NoiseTemp MI-13 2012-11-17.pdf
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2013	07700088 NoiseTemp MI-13 2013-09-11.pdf
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2014	07700088 NoiseTemp MI-13 2014-10-21.pdf
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2015	07700088 NoiseTemp MI-13 2015-10-13.pdf
McDonald Island Peripheral	McDonald Island Farms 13 *(MI-13)*	2008	07700088_NoiseTemp_MI-13_2008-11-18.TIF
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2006	07720441 NoiseTemp MI-14 2006-08-07.TIF
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2007	07720441 NoiseTemp MI-14 2007-09-11.TIF
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2009	07720441 NoiseTemp MI-14 2009-06-15.TIF
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2010	07720441 NoiseTemp MI-14 2010-08-15.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2011	07720441 NoiseTemp MI-14 2011-06-28.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2012	07720441 NoiseTemp MI-14 2012-11-17.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2013	07720441 NoiseTemp MI-14 2013-09-20.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2014	07720441_NoiseTemp_MI-14_2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2015	07720441_NoiseTemp_MI-14_2015-10-14.pdf
McDonald Island Peripheral	McDonald Island Farms 14 *(MI-14)*	2008	07720441 NoiseTemp MI-14 2008-11-14.TIF
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2006	07720444 NoiseTemp MI-15 2006-08-09.TIF
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2007	07720444 NoiseTemp MI-15 2007-09-10.TIF
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2009	07720444 NoiseTemp MI-15 2009-06-11.TIF
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2010	07720444 NoiseTemp MI-15 2010-08-15.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2011	07720444 NoiseTemp MI-15 2011-06-28.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2012	07720444 NoiseTemp MI-15 2012-11-17.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2013	07720444_NoiseTemp_MI-15_2013-09-20.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2014	07720444 NoiseTemp MI-15 2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2015	07720444 NoiseTemp MI-15 2015-10-14.pdf
McDonald Island Peripheral	McDonald Island Farms 15 *(MI-15)*	2008	07720444 NoiseTemp MI-15 2008-11-14.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2006	07700080 NoiseTemp MI-4 2006-18-08.TIF
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2007	07700080 NoiseTemp MI-4 2007-09-17.TIF
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2009	07700080 NoiseTemp MI-4 2009-06-11.TIF

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McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2010	07700080_NoiseTemp_MI-4_2010-08-02.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2011	07700080_NoiseTemp_MI-4_2011-06-29.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2012	07700080_NoiseTemp_MI-4_2012-07-30.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2013	07700080_NoiseTemp_MI-4_2013-09-13.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2014	07700080_NoiseTemp_MI-4_2014-10-15.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2015	07700080_NoiseTemp_MI-4_2015-08-19.pdf
McDonald Island Peripheral	McDonald Island Farms 4 *(MI-4)*	2008	07700080_NoiseTemp_MI-4_2008-11-14.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2006	07720552_NoiseTemp_MI-5A_2006-08-18.TIF
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2007	07720552_NoiseTemp_MI-5A_2007-09-14.TIF
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2009	07720552_NoiseTemp_MI-5A_2009-06-16.TIF
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2010	07720552_NoiseTemp_MI-5A_2010-08-16.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2011	07720552_NoiseTemp_MI-5A_2011-06-27.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2012	07720552_NoiseTemp_MI-5A_2012-11-06.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2013	07720552_NoiseTemp_MI-5A_2013-09-19.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2014	07720552_NoiseTemp_MI-5A_2014-10-20.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2015	07720552_NoiseTemp_MI-5A_2015-10-15.pdf
McDonald Island Peripheral	McDonald Island Farms 5A *(MI-5A)*	2008	07720552_NoiseTemp_MI-5A_2008-11-14.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2006	07700082_NoiseTemp_MI-6_2006-08-16.TIF
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2007	07700082_NoiseTemp_MI-6_2007-09-18.TIF
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2009	07700082_NoiseTemp_MI-6_2009-06-11.TIF
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2010	07700082_NoiseTemp_MI-6_2010-07-29.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2011	07700082_NoiseTemp_MI-6_2011-06-29.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2012	07700082_NoiseTemp_MI-6_2012-07-27.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2013	07700082_NoiseTemp_MI-6_2013-09-23.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2014	07700082_NoiseTemp_MI-6_2014-10-15.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2015	07700082_NoiseTemp_MI-6_2015-08-19.pdf
McDonald Island Peripheral	McDonald Island Farms 6 *(MI-6)*	2008	07700082_NoiseTemp_MI-6_2008-11-13.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2006	07700083_NoiseTemp_MI-7_2006-08-16.TIF
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2007	07700083_NoiseTemp_MI-7_2007-09-18.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2009	07700083_NoiseTemp_MI-7_2009-06-11.TIF
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2010	07700083_NoiseTemp_MI-7_2010-07-29.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2011	07700083_NoiseTemp_MI-7_2011-06-29.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2012	07700083_NoiseTemp_MI-7_2012-07-27.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2013	07700083_NoiseTemp_MI-7_2013-09-23.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2014	07700083_NoiseTemp_MI-7_2014-10-15.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2015	07700083_NoiseTemp_MI-7_2015-08-19.pdf
McDonald Island Peripheral	McDonald Island Farms 7 *(MI-7)*	2008	07700083_NoiseTemp_MI-7_2008-11-13.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2006	07700084_NoiseTemp_MI-9_2006-08-09.TIF
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2007	07700084_NoiseTemp_MI-9_2007-09-13.TIF
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2009	07700084_NoiseTemp_MI-9_2009-06-15.TIF
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2010	07700084_NoiseTemp_MI-9_2010-08-15.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2011	07700084_NoiseTemp_MI-9_2011-06-27.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2012	07700084_NoiseTemp_MI-9_2012-11-17.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2013	07700084_NoiseTemp_MI-9_2013-09-26.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2014	07700084_NoiseTemp_MI-9_2014-10-21.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2015	07700084_NoiseTemp_MI-9_2015-10-13.pdf
McDonald Island Peripheral	McDonald Island Farms 9 *(MI-9)*	2008	07700084_NoiseTemp_MI-9_2008-11-14.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2009	07720524_NoiseTemp_RI-1_2009-06-16.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2006	07720524_NoiseTemp_RI-1_2006-08-08.TIF
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2007	07720524_NoiseTemp_RI-1_2007-09-11.TIF
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2010	07720524_NoiseTemp_RI-1_2010-08-02.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2011	07720524_NoiseTemp_RI-1_2011-06-28.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2012	07720524_NoiseTemp_RI-1_2012-11-05.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2013	07720524_NoiseTemp_RI-1_2013-09-20.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2014	07720524_NoiseTemp_RI-1_2014-10-16.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2015	07720524_NoiseTemp_RI-1_2015-10-14.pdf
McDonald Island Peripheral	Roberts Island 1 *(RI-1)*	2008	07720524_NoiseTemp_RI-1_2008-11-18.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2006	07720523_NoiseTemp_RI-2_2006-06-16.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2006	07720523_NoiseTemp_RI-2_2006-08-07.TIF
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2007	07720523_NoiseTemp_RI-2_2007-09-11.TIF
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2009	07720523_NoiseTemp_RI-2_2009-06-16.TIF
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2010	07720523_NoiseTemp_RI-2_2010-08-02.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2011	07720523_NoiseTemp_RI-2_2011-06-28.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2012	07720523_NoiseTemp_RI-2_2012-11-05.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2013	07720523_NoiseTemp_RI-2_2013-09-20.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2014	07720523_NoiseTemp_RI-2_2014-10-17.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2015	07720523_NoiseTemp_RI-2_2015-10-14.pdf
McDonald Island Peripheral	Roberts Island 2 *(RI-2)*	2008	07720523_NoiseTemp_RI-2_2008-11-18.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2006	07700090_NoiseTemp_Tilden-1_2006-08-07.TIF
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2007	07700090_NoiseTemp_Tilden-1_2007-09-10.TIF
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2009	07700090_NoiseTemp_Tilden-1_2009-06-16.TIF
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2010	07700090_NoiseTemp_Tilden-1_2010-08-02.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2011	07700090_NoiseTemp_Tilden-1_2011-06-28.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2012	07700090_NoiseTemp_Tilden-1_2012-11-05.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2013	07700090_NoiseTemp_Tilden-1_2013-09-11.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2014	07700090_NoiseTemp_Tilden-1_2014-10-17.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2015	07700090_NoiseTemp_Tilden-1_2015-10-14.pdf
McDonald Island Peripheral	Tilden Community 1 *(Tilden-1)*	2008	07700090_NoiseTemp_Tilden-1_2008-11-18.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2006	07700091_NoiseTemp_Zuck-1_2006-08-18.TIF
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2007	07700091_NoiseTemp_Zuck-1_2007-09-13.TIF
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2009	07700091_NoiseTemp_Zuck-1_2009-06-11.TIF
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2009	07700091_NoiseTemp_Zuck-1_2009-11-11.TIF
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2010	07700091_NoiseTemp_Zuck-1_2010-07-29.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2011	07700091_NoiseTemp_Zuck-1_2011-06-29.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2012	07700091_NoiseTemp_Zuck-1_2012-07-30.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2013	07700091_NoiseTemp_Zuck-1_2013-09-23.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2014	07700091_NoiseTemp_Zuck-1_2014-10-28.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2015	07700091_NoiseTemp_Zuck-1_2015-08-20.pdf
McDonald Island Peripheral	Weyl-Zuckerman 1 *(Zuck-1)*	2008	07700091_NoiseTemp_Zuck-1_2008-11-18.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2006	07700093_NoiseTemp_Zuck-3_2006-08-09.TIF
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2007	07700093_NoiseTemp_Zuck-3_2007-09-13.TIF
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2009	07700093_NoiseTemp_Zuck-3_2009-06-15.TIF
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2010	07700093_NoiseTemp_Zuck-3_2010-08-15.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2011	07700093_NoiseTemp_Zuck-3_2011-06-29.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2012	07700093_NoiseTemp_Zuck-3_2012-11-17.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2013	07700093_NoiseTemp_Zuck-3_2013-09-11.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2014	07700093_NoiseTemp_Zuck-3_2014-10-21.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2015	07700093_NoiseTemp_Zuck-3_2015-10-14.pdf
McDonald Island Peripheral	Weyl-Zuckerman 3 *(Zuck-3)*	2008	07700093_NoiseTemp_Zuck-3_2008-11-18.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2006	07720010_NoiseTemp_ZuckHenn-1_2006-08-18.TIF
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2007	07720010_NoiseTemp_ZuckHenn-1_2007-09-17.TIF
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2009	07720010_NoiseTemp_ZuckHenn-1_2009-06-11.TIF
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2010	07720010_NoiseTemp_ZuckHenn-1_2010-07-29.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2011	07720010_NoiseTemp_ZuckHenn-1_2011-06-29.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2012	07720010_NoiseTemp_ZuckHenn-1_2012-07-30.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2013	07720010_NoiseTemp_ZuckHenn-1_2013-09-26.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2014	07720010_NoiseTemp_ZuckHenn-1_2014-10-15.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2015	07720010_NoiseTemp_ZuckHenn-1_2015-08-20.pdf
McDonald Island Peripheral	Zuckerman-Henning 1 *(ZuckHenn-1)*	2008	07720010_NoiseTemp_ZuckHenn-1_2008-11-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2014	07720168_NoiseTemp_WS-1E_2014-10-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2015	07720168_NoiseTemp_WS-1E_2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2006	07720168_NoiseTemp_WS-1E_2006-08-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2007	07720168_NoiseTemp_WS-1E_2007-09-13.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2009	07720168_NoiseTemp_WS-1E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2010	07720168_NoiseTemp_WS-1E_2010-08-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	2011	07720168_NoiseTemp_WS-1E_2011-06-30.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E)*	2012	07720168 NoiseTemp WS-1E 2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E)*	2008	07720168 NoiseTemp WS-1E 2008-11-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2006	07720215 NoiseTemp WS-1W 2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2007	07720215 NoiseTemp WS-1W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2009	07720215_NoiseTemp_WS-1W_2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2010	07720215 NoiseTemp WS-1W 2010-08-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2011	07720215 NoiseTemp WS-1W 2011-08-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2012	07720215 NoiseTemp WS-1W 2012-11-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2013	07720215 NoiseTemp WS-1W 2013-12-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2014	07720215 NoiseTemp WS-1W 2014-10-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2014	07720215 NoiseTemp WS-1W 2014-12-18.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2015	07720215 NoiseTemp WS-1W 2015-08-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2015	07720215_NoiseTemp_WS-1W_2015-10-29.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W)*	2008	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2006	07720190 NoiseTemp WS-10E 2006-08-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2007	07720190 NoiseTemp WS-10E 2007-09-18.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2009	07720190 NoiseTemp WS-10E 2009-06-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2010	07720190 NoiseTemp WS-10E 2010-08-17.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2011	07720190 NoiseTemp WS-10E 2011-06-29.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2012	07720190 NoiseTemp WS-10E 2012-07-27.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2014	07720190 NoiseTemp WS-10E 2014-10-15.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2015	07720190_NoiseTemp_WS-10E_2015-08-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2008	07720190 NoiseTemp WS-10E 2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W)*	2008	07720534 NoiseTemp WS-10W 2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W)*	2006	07720534 NoiseTemp WS-10W 2006-08-18.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W)*	2007	07720534 NoiseTemp WS-10W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W)*	2009	07720534 NoiseTemp WS-10W 2009-11-10.TIF

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2010	07720534 NoiseTemp WS-10W 2010-08-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2011	07720534 NoiseTemp WS-10W 2011-08-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2012	07720534 NoiseTemp WS-10W 2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2014	07720534 NoiseTemp WS-10W 2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2015	07720534 NoiseTemp WS-10W 2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2006	07720253 NoiseTemp WS-11E 2006-08-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2007	07720253 NoiseTemp WS-11E 2007-09-18.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2009	07720253 NoiseTemp WS-11E 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2010	07720253 NoiseTemp WS-11E 2010-08-17.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2011	07720253 NoiseTemp WS-11E 2011-07-01.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2012	07720253 NoiseTemp WS-11E 2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2014	07720253 NoiseTemp WS-11E 2014-10-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2015	07720253_NoiseTemp_WS-11E_2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2008	07720253_NoiseTemp_WS-11E_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2008	07720265 NoiseTemp WS-11W 2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2007	07720265 NoiseTemp WS-11W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2009	07720265 NoiseTemp WS-11W 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2010	07720265 NoiseTemp WS-11W 2010-08-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2011	07720265 NoiseTemp WS-11W 2011-08-24.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2012	07720265 NoiseTemp WS-11W 2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2014	07720265_NoiseTemp_WS-11W_2014-10-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2015	07720265 NoiseTemp WS-11W 2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E*)	2006	07720255 NoiseTemp WS-12E 2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E*)	2007	07720255 NoiseTemp WS-12E 2007-09-14.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E*)	2009	07720255 NoiseTemp WS-12E 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E*)	2010	07720255 NoiseTemp WS-12E 2010-08-17.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2011	07720255_NoiseTemp_WS-12E_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2012	07720255_NoiseTemp_WS-12E_2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2014	07720255_NoiseTemp_WS-12E_2014-10-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2015	07720255_NoiseTemp_WS-12E_2015-10-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2008	07720255_NoiseTemp_WS-12E_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2006	07720264_NoiseTemp_WS-12W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2007	07720264_NoiseTemp_WS-12W_2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2008	07720264_NoiseTemp_WS-12W_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2009	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2010	07720264_NoiseTemp_WS-12W_2010-08-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2011	07720264_NoiseTemp_WS-12W_2011-08-25.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2012	07720264_NoiseTemp_WS-12W_2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2014	07720264_NoiseTemp_WS-12W_2014-10-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2015	07720264_NoiseTemp_WS-12W_2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2006	07720265_NoiseTemp_WS-11W_2006-08-18.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2006	07720256_NoiseTemp_WS-13E_2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2007	07720256_NoiseTemp_WS-13E_2007-09-13.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2009	07720256_NoiseTemp_WS-13E_2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2010	07720256_NoiseTemp_WS-13E_2010-08-17.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2011	07720256_NoiseTemp_WS-13E_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2012	07720256_NoiseTemp_WS-13E_2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2014	07720256_NoiseTemp_WS-13E_2014-10-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2015	07720256_NoiseTemp_WS-13E_2015-10-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2008	07720256_NoiseTemp_WS-13E_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2007	07720241_NoiseTemp_WS-13W_2007-09-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2009	07720241_NoiseTemp_WS-13W_2009-11-10.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2010	07720241 NoiseTemp WS-13W 2010-08-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2011	07720241 NoiseTemp WS-13W 2011-08-25.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2012	07720241 NoiseTemp WS-13W 2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2014	07720241 NoiseTemp WS-13W 2014-10-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2015	07720241 NoiseTemp WS-13W 2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2008	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2006	07720257 NoiseTemp WS-14E 2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2007	07720257 NoiseTemp WS-14E 2007-09-13.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2009	07720257 NoiseTemp WS-14E 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2010	07720257 NoiseTemp WS-14E 2010-08-18.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2011	07720257 NoiseTemp WS-14E 2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2012	07720257 NoiseTemp WS-14E 2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2014	07720257_NoiseTemp_WS-14E_2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2015	07720257_NoiseTemp_WS-14E_2015-10-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2008	07720257 NoiseTemp WS-14E 2008-11-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2006	07720233 NoiseTemp WS-15W 2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2007	07720233 NoiseTemp WS-15W 2007-09-07.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2009	07720233 NoiseTemp WS-15W 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2010	07720233 NoiseTemp WS-15W 2010-08-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2011	07720233 NoiseTemp WS-15W 2011-08-25.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2012	07720233_NoiseTemp_WS-15W_2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2014	07720233 NoiseTemp WS-15W 2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2015	07720233 NoiseTemp WS-15W 2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2006	07720241 NoiseTemp WS-13W 2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2008	07720233 NoiseTemp WS-15W 2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W)*	2006	07720231 NoiseTemp WS-16W 2006-08-17.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2007	07720231_NoiseTemp_WS-16W_2007-09-07.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2009	07720231_NoiseTemp_WS-16W_2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2010	07720231_NoiseTemp_WS-16W_2010-08-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2011	07720231_NoiseTemp_WS-16W_2011-08-24.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2012	07720231_NoiseTemp_WS-16W_2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2014	07720231_NoiseTemp_WS-16W_2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2015	07720231_NoiseTemp_WS-16W_2015-10-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2008	07720231_NoiseTemp_WS-16W_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2006	07720166_NoiseTemp_WS-17W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2007	07720166_NoiseTemp_WS-17W_2007-09-07.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2009	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2010	07720166_NoiseTemp_WS-17W_2010-08-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2011	07720166_NoiseTemp_WS-17W_2011-08-24.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2012	07720166_NoiseTemp_WS-17W_2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2014	07720166_NoiseTemp_WS-17W_2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2015	07720166_NoiseTemp_WS-17W_2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2008	07720166_NoiseTemp_WS-17W_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2006	07720465_NoiseTemp_WS-18W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2007	07720465_NoiseTemp_WS-18W_2007-09-07.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2009	07720465_NoiseTemp_WS-18W_2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2010	07720465_NoiseTemp_WS-18W_2010-08-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2011	07720465_NoiseTemp_WS-18W_2011-08-25.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2012	07720465_NoiseTemp_WS-18W_2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2014	07720465_NoiseTemp_WS-18W_2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2015	07720465_NoiseTemp_WS-18W_2015-10-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2008	07720465_NoiseTemp_WS-18W_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W*)	2013	-

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2006	07720536_NoiseTemp_WS-1AE_2006-08-08.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2007	07720536_NoiseTemp_WS-1AE_2007-09-13.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2009	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2010	07720536_NoiseTemp_WS-1AE_2010-08-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2011	07720536_NoiseTemp_WS-1AE_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2012	07720536_NoiseTemp_WS-1AE_2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2014	07720536_NoiseTemp_WS-1AE_2014-10-06.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2015	07720536_NoiseTemp_WS-1AE_2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2008	07720536_NoiseTemp_WS-1AE_2008-11-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2006	07720544_NoiseTemp_WS-1AW_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2007	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2009	07720544_NoiseTemp_WS-1AW_2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2010	07720544_NoiseTemp_WS-1AW_2010-08-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2011	07720544_NoiseTemp_WS-1AW_2011-08-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2012	07720544_NoiseTemp_WS-1AW_2012-11-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2014	07720544_NoiseTemp_WS-1AW_2014-10-06.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2015	07720544_NoiseTemp_WS-1AW_2015-10-29.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2008	07720544_NoiseTemp_WS-1AW_2008-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2006	07720169_NoiseTemp_WS-2E_2006-08-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2007	07720169_NoiseTemp_WS-2E_2007-09-18.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2009	07720169_NoiseTemp_WS-2E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2010	07720169_NoiseTemp_WS-2E_2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2011	07720169_NoiseTemp_WS-2E_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2012	07720169_NoiseTemp_WS-2E_2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2014	07720169_NoiseTemp_WS-2E_2014-10-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2015	
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E)*	2008	07720169_NoiseTemp_WS-2E_2008-11-10.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2006	07720212 NoiseTemp WS-2W 2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2007	07720212 NoiseTemp WS-2W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2009	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2010	07720212 NoiseTemp WS-2W 2010-08-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2011	07720212_NoiseTemp_WS-2W_2011-08-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2012	07720212 NoiseTemp WS-2W 2012-11-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2014	07720212 NoiseTemp WS-2W 2014-10-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2015	07720212 NoiseTemp WS-2W 2015-10-28.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2008	07720212 NoiseTemp WS-2W 2008-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2006	07720535 NoiseTemp WS-20W 2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2007	07720535 NoiseTemp WS-20W 2007-09-06.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2009	07720535_NoiseTemp_WS-20W_2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2010	07720535_NoiseTemp_WS-20W_2010-08-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2011	07720535 NoiseTemp WS-20W 2011-08-24.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2012	07720535 NoiseTemp WS-20W 2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2014	07720535 NoiseTemp WS-20W 2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2015	07720535 NoiseTemp WS-20W 2015-10-19.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2008	07720535 NoiseTemp WS-20W 2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2006	07720173 NosieTemp WS-3E 2006-08-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2007	07720173_NosieTemp_WS-3E_2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2009	07720173 NosieTemp WS-3E 2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2010	07720173 NosieTemp WS-3E 2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2011	07720173 NosieTemp WS-3E 2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2012	07720173 NosieTemp WS-3E 2012-11-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2014	
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2015	07720173 NosieTemp WS-3E 2015-10-23.pdf

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2008	07720173 NosieTemp WS-3E 2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2006	07720213 NoiseTemp WS-3W 2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2007	07720213 NoiseTemp WS-3W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2009	07720213 NoiseTemp WS-3W 2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2010	07720213_NoiseTemp_WS-3W_2010-08-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2011	07720213 NoiseTemp WS-3W 2011-08-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2012	07720213 NoiseTemp WS-3W 2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2014	07720213 NoiseTemp WS-3W 2014-10-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2015	07720213 NoiseTemp WS-3W 2015-10-28.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2008	07720213 NoiseTemp WS-3W 2008-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2006	07720178 NoiseTemp WS-4E 2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2007	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2009	07720178_NoiseTemp_WS-4E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2010	07720178 NoiseTemp WS-4E 2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2011	07720178 NoiseTemp WS-4E 2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2012	07720178 NoiseTemp WS-4E 2012-11-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2014	07720178 NoiseTemp WS-4E 2014-10-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2015	07720178 NoiseTemp WS-4E 2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2008	07720178 NoiseTemp WS-4E 2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2006	07720214_NoiseTemp_WS-4W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2007	07720214 NoiseTemp WS-4W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2009	07720214 NoiseTemp WS-4W 2009-11-09.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2010	07720214 NoiseTemp WS-4W 2010-08-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2011	07720214 NoiseTemp WS-4W 2011-08-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2012	07720214 NoiseTemp WS-4W 2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	2014	07720214 NoiseTemp WS-4W 2014-10-08.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W)*	2015	07720214_NoiseTemp_WS-4W_2015-10-28.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W)*	2008	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2006	07720179_NoiseTemp_WS-5E_2006-08-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2007	07720179_NoiseTemp_WS-5E_2007-09-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2009	07720179_NoiseTemp_WS-5E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2010	07720179_NoiseTemp_WS-5E_2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2011	07720179_NoiseTemp_WS-5E_2011-07-01.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2012	07720179_NoiseTemp_WS-5E_2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2014	07720179_NoiseTemp_WS-5E_2014-10-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2015	07720179_NoiseTemp_WS-5E_2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2008	07720179_NoiseTemp_WS-5E_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2006	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2007	07720211_NoiseTemp_WS-5W_2007-09-13.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2009	07720211_NoiseTemp_WS-5W_2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2010	07720211_NoiseTemp_WS-5W_2010-08-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2011	07720211_NoiseTemp_WS-5W_2011-08-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2012	07720211_NoiseTemp_WS-5W_2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2014	07720211_NoiseTemp_WS-5W_2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2015	07720211_NoiseTemp_WS-5W_2015-10-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2008	07720211_NoiseTemp_WS-5W_2008-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2006	07720185_NoiseTemp_WS-6E_2006-08-16.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2007	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2009	07720185_NoiseTemp_WS-6E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2010	07720185_NoiseTemp_WS-6E_2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2011	07720185_NoiseTemp_WS-6E_2011-07-01.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E)*	2012	07720185_NoiseTemp_WS-6E_2012-11-08.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E*)	2014	07720185_NoiseTemp_WS-6E_2014-10-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E*)	2015	07720185_NoiseTemp_WS-6E_2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E*)	2008	07720185_NoiseTemp_WS-6E_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2006	07720192_NoiseTemp_WS-6W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2007	07720192_NoiseTemp_WS-6W_2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2009	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2010	07720192_NoiseTemp_WS-6W_2010-08-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2011	07720192_NoiseTemp_WS-6W_2011-08-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2012	07720192_NoiseTemp_WS-6W_2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2014	07720192_NoiseTemp_WS-6W_2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2015	07720192_NoiseTemp_WS-6W_2015-10-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2008	07720192_NoiseTemp_WS-6W_2008-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2006	07720187_NoiseTemp_WS-7E_2006-08-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2007	07720187_NoiseTemp_WS-7E_2007-09-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2009	07720187_NoiseTemp_WS-7E_2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2010	07720187_NoiseTemp_WS-7E_2010-08-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2011	07720187_NoiseTemp_WS-7E_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2012	07720187_NoiseTemp_WS-7E_2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2014	07720187_NoiseTemp_WS-7E_2014-10-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2015	07720187_NoiseTemp_WS-7E_2015-10-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2008	07720187_NoiseTemp_WS-7E_2008-11-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	2006	07720193_NoiseTemp_WS-7W_2006-08-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	2007	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	2009	07720193_NoiseTemp_WS-7W_2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	2010	07720193_NoiseTemp_WS-7W_2010-08-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	2011	07720193_NoiseTemp_WS-7W_2011-08-25.pdf

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McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W)*	2012	07720193 NoiseTemp WS-7W 2012-11-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W)*	2014	07720193 NoiseTemp WS-7W 2014-10-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W)*	2015	07720193 NoiseTemp WS-7W 2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W)*	2008	07720193 NoiseTemp WS-7W 2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2006	07720188_NoiseTemp_WS-8E_2006-08-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2007	07720188 NoiseTemp WS-8E 2007-09-17.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2009	07720188 NoiseTemp WS-8E 2009-11-11.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2010	07720188 NoiseTemp WS-8E 2010-08-17.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2011	07720188 NoiseTemp WS-8E 2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2012	07720188 NoiseTemp WS-8E 2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2014	07720188 NoiseTemp WS-8E 2014-10-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2015	07720188 NoiseTemp WS-8E 2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2008	07720188_NoiseTemp_WS-8E_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E)*	2013	-
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2006	07720194 NoiseTemp WS-8W 2006-08-21.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2007	07720194 NoiseTemp WS-8W 2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2010	07720194 NoiseTemp WS-8W 2010-08-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2011	07720194 NoiseTemp WS-8W 2011-08-25.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2013	07720194 NoiseTemp WS-8W 2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2014	07720194 NoiseTemp WS-8W 2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2015	07720194 NoiseTemp WS-8W 2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2008	07720194_NoiseTemp_WS-8W_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2009	07720194 NoiseTemp WS-8W 2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W)*	2012	07720194 NoiseTemp WS-8W 2012-11-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2006	07720189 NoiseTemp WS-9E 2006-08-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2007	07720189 NoiseTemp WS-9E 2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2009	07720189 NoiseTemp WS-9E 2009-05-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2010	07720189 NoiseTemp WS-9E 2009-11-10.TIF

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Storage Field	Well Name	Survey Year	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2011	07720189_NoiseTemp_WS-9E_2010-08-17.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2012	07720189_NoiseTemp_WS-9E_2011-06-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2013	07720189_NoiseTemp_WS-9E_2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2014	07720189_NoiseTemp_WS-9E_2014-10-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2015	07720189_NoiseTemp_WS-9E_2015-10-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E)*	2008	07720189_NoiseTemp_WS-9E_2008-11-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2006	07720195_NoiseTemp_WS-9W_2006-08-21.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2007	07720195_NoiseTemp_WS-9W_2007-09-12.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2009	07720195_NoiseTemp_WS-9W_2009-11-10.TIF
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2010	07720195_NoiseTemp_WS-9W_2010-08-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2011	07720195_NoiseTemp_WS-9W_2011-08-23.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2012	07720195_NoiseTemp_WS-9W_2012-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2014	07720195_NoiseTemp_WS-9W_2014-10-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2015	07720195_NoiseTemp_WS-9W_2015-10-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2008	07720195_NoiseTemp_WS-9W_2008-11-12.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W)*	2013	-
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2006	11300063_NoiseTemp_PC 3-1_2006-08-10.TIF
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2007	11300063_NoiseTemp_PC 3-1_2007-11-13.TIF
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2008	11300063_NoiseTemp_PC 3-1_2008-11-10.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2009	11300063_NoiseTemp_PC 3-1_2009-11-06.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2010	11300063_NoiseTemp_PC 3-1_2010-07-30.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2011	11300063_NoiseTemp_PC 3-1_2011-06-27.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2012	11300063_NoiseTemp_PC 3-1_2012-11-06.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2013	11300063_NoiseTemp_PC 3-1_2013-10-31.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2014	11300063_NoiseTemp_PC 3-1_2014-11-15.pdf
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	2015	11300063_NoiseTemp_PC 3-1_2015-08-17.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2008	11320192_NoiseTemp_PC 3-2_2008-11-10.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2006	11320192_NoiseTemp_PC 3-2_2006-08-10.TIF
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2007	11320192_NoiseTemp_PC 3-2_2007-11-13.TIF

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Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2009	11320192 NoiseTemp PC 3-2 2009-11-06.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2010	11320192 NoiseTemp PC 3-2 2010-07-30.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2011	11320192 NoiseTemp PC 3-2 2011-06-27.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2012	11320192 NoiseTemp PC 3-2 2012-11-05.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2013	11320192 NoiseTemp PC 3-2 2013-10-31.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2014	11320192_NoiseTemp_PC 3-2_2014-11-15.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	2015	11320192 NoiseTemp PC 3-2 2015-08-17.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2008	11320193 NoiseTemp PC 3-3 2008-11-10.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2006	11320193 NoiseTemp PC 3-3 2006-08-10.TIF
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2007	11320193 NoiseTemp PC 3-3 2007-11-13.TIF
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2009	11320193 NoiseTemp PC 3-3 2009-11-06.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2010	11320193 NoiseTemp PC 3-3 2010-07-30.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2011	
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2012	11320193_NoiseTemp_PC 3-3_2012-11-06.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2013	11320193_NoiseTemp_PC 3-3_2013-10-31.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2014	11320193 NoiseTemp PC 3-3 2014-11-15.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	2015	11320193 NoiseTemp PC 3-3 2015-08-17.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2008	11320194 NoiseTemp PC 3-4 2008-11-10.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2006	11320194 NoiseTemp PC 3-4 2006-08-10.TIF
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2007	11320194 NoiseTemp PC 3-4 2007-11-13.TIF
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2009	11320194 NoiseTemp PC 3-4 2009-11-06.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2010	11320194 NoiseTemp PC 3-4 2010-07-30.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2011	11320194_NoiseTemp_PC 3-4_2011-06-27.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2012	11320194 NoiseTemp PC 3-4 2012-11-06.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2013	11320194 NoiseTemp PC 3-4 2013-11-01.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2014	11320194 NoiseTemp PC 3-4 2014-11-14.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	2015	11320194 NoiseTemp PC 3-4 2015-08-18.pdf
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2008	-
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2006	-

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Storage Field	Well Name	Survey Year	File Name
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2007	-
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2009	-
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2010	-
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2011	-
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2012	11321279_NoiseTemp_PC 3-5_2012-11-06.pdf
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2013	11321279_NoiseTemp_PC 3-5_2013-10-31.pdf
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2014	11321279_NoiseTemp_PC 3-5_2014-11-15.pdf
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	2015	11321279_NoiseTemp_PC 3-5_2015-08-18.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2006	11300064_NoiseTemp_PC 4-1_2006-08-10.TIF
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2007	11300064_NoiseTemp_PC 4-1_2007-11-13.TIF
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2009	11300064_NoiseTemp_PC 4-1_2009-11-06.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2010	11300064_NoiseTemp_PC 4-1_2010-07-30.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2011	11300064_NoiseTemp_PC 4-1_2011-06-27.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2012	11300064_NoiseTemp_PC 4-1_2012-06-11.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2013	11300064_NoiseTemp_PC 4-1_2013-11-01.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2014	11300064_NoiseTemp_PC 4-1_2014-11-14.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2015	11300064_NoiseTemp_PC 4-1_2015-08-18.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	2008	11300064_NoiseTemp_PC 4-1_2008-11-10.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2006	11320195_NoiseTemp_PC 4-2_2006-08-10.TIF
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2007	11320195_NoiseTemp_PC 4-2_2007-11-13.TIF
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2009	11320195_NoiseTemp_PC 4-2_2009-11-06.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2010	11320195_NoiseTemp_PC 4-2_2010-07-30.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2011	11320195_NoiseTemp_PC 4-2_2011-06-27.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2012	11320195_NoiseTemp_PC 4-2_2012-11-06.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2013	11320195_NoiseTemp_PC 4-2_2013-11-01.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2014	11320195_NoiseTemp_PC 4-2_2014-11-14.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2015	11320195_NoiseTemp_PC 4-2_2015-08-18.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	2008	11320195_NoiseTemp_PC 4-2_2008-11-10.pdf

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX E

INDEX FOR MAGNETIC FLUX LEAKAGE (MFL) SURVEYS

FILES PROVIDED ON DVD

2015 GT&S Storage Report
Magnetic Flux Leakage Casing Inspection Survey Files

Storage Field	Well Name	File Name
Los Medanos	Los Medanos 4B *(LM-4B)*	01320093_MFL_LM-4B_2013-04-30.PDF
Los Medanos	Los Medanos 5B *(LM-5B)*	01320144_MFL_LM-5B_2013-05-15.pdf
Los Medanos	Los Medanos 21D *(LM-21D)*	01320308_MFL_LM-21D_2015-05-31.PDF
Los Medanos	Los Medanos 11C *(LM-11C)*	01320128_MFL_LM-11C_2015-06-04.PDF
Los Medanos	Los Medanos 2A *(LM-2A)*	01320138_MFL_LM-2A_2016-06-12.PDF
Los Medanos	Los Medanos 12C *(LM-12C)*	01320307_MFL_LM-12C_2016-05-15.PDF
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N)*	07720229_MFL_TC-11N_2013-06-04.TIF
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N)*	07720228_MFL_TC-10N_2013-06-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 2 North (*TC-2N)*	07720199_MFL_TC-2N_2013-07-28.TIF
McDonald Island (Turner Cut Station)	Turner Cut 1 North (*TC-1N)*	07720196_MFL_TC-1N_2013-08-17.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 North (*TC-8N)*	07720226_MFL_TC-8N_2014-08-05.TIF
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N)*	07720548_MFL_TC-17N_2014-08-22.TIF
McDonald Island (Turner Cut Station)	Turner Cut 8 South (*TC-8S)*	07720533_MFL_TC-8S_2014-09-04.TIF
McDonald Island (Turner Cut Station)	Turner Cut 9 South (*TC-9S)*	07720252_MFL_TC-9S_2014-09-14.TIF
McDonald Island (Turner Cut Station)	Turner Cut 12 South (*TC-12S)*	07720248_MFL_TC-12S_2014-09-28.TIF
McDonald Island (Turner Cut Station)	Turner Cut 13 South (*TC-13S)*	07720247_MFL_TC-13S_2014-10-14.TIF
McDonald Island (Turner Cut Station)	Turner Cut 14 South (*TC-14S)*	07720244_MFL_TC-14S_2016-07-16.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 South (*TC-15S)*	07720245_MFL_TC-15S_2015-08-11.pdf
McDonald Island (Whiskey Slough)	Whiskey Slough 3 East (*WS-3E)*	07720173_MFL_WS-3E_2015-08-31.pdf
McDonald Island (Whiskey Slough)	Whiskey Slough 1 West (*WS-1W)*	07720215_MFL_WS-1W_2015-09-19.pdf

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

INDEX FOR GAMMA RAY NEUTRON (GRN) SURVEYS

FILES PROVIDED ON DVD

2015 GT&S Storage Report
Gamma Ray Neutron Files

Storage Field	Well Name	File Name
Pleasant Creek	Pleasant Creek 3-1 *(PC 3-1)*	11300063 GRN PC 3-1 2013-03-28.pdf
Pleasant Creek	Pleasant Creek 3-2 *(PC 3-2)*	11320192 GRN PC 3-2 2013-03-28.pdf
Pleasant Creek	Pleasant Creek 3-3 *(PC 3-3)*	11320193 GRN PC 3-3 2013-03-28.pdf
Pleasant Creek	Pleasant Creek 3-4 *(PC 3-4)*	11320194 GRN PC 3-4 2013-03-29.pdf
Pleasant Creek	Pleasant Creek 3-5 *(PC 3-5)*	11321279 GRN PC 3-5 2013-03-28.pdf
Pleasant Creek	Pleasant Creek 4-1 *(PC 4-1)*	11300064 GRN PC 4-1 2013-04-03.pdf
Pleasant Creek	Pleasant Creek 4-2 *(PC 4-2)*	11320195 GRN PC 4-2 2013-04-03.pdf
Los Medanos	Los Medanos 1A *(LM-1A)*	01320373 GRN LM-1A 2007-12-08.TIF
Los Medanos	Los Medanos 1A *(LM-1A)*	01320373 GRN LM-1A 2013-03-19.pdf
Los Medanos	Los Medanos 2A *(LM-2A)*	01320138 GRN LM-2A 2013-03-19.pdf
Los Medanos	Los Medanos 3A *(LM-3A)*	01320115 GRN LM-3A 2013-03-19.pdf
Los Medanos	Los Medanos 4B *(LM-4B)*	01320093 GRN LM-4B 2013-03-18.pdf
Los Medanos	Los Medanos 5B *(LM-5B)*	01320144 GRN LM-5B 2013-05-16.pdf
Los Medanos	Los Medanos 6B *(LM-6B)*	01320140 GRN LM-6B 2013-03-18.pdf
Los Medanos	Los Medanos 7C *(LM-7C)*	01320130 GRN LM-7C 2013-03-20.pdf
Los Medanos	Los Medanos 8C *(LM-8C)*	01320145 GRN LM-8C 2013-03-20.pdf
Los Medanos	Los Medanos 9C *(LM-9C)*	01320123 GRN LM-9C 2013-03-20.pdf
Los Medanos	Los Medanos 10C *(LM-10C)*	01320131 GRN LM-10C 2013-03-21.pdf
Los Medanos	Los Medanos 11C *(LM-11C)*	01320128_GRN_LM-11C_2013-03-21.pdf
Los Medanos	Los Medanos 12C *(LM-12C)*	01320307_GRN_LM-12C_2013-03-25.pdf
Los Medanos	Los Medanos 13C *(LM-13C)*	01320299_GRN_LM-13C_2013-03-22.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	01320298 GRN LM-14C 2013-03-22.pdf
Los Medanos	Los Medanos 14C *(LM-14C)*	01320298 GRN LM-14C 2013-03-27.pdf
Los Medanos	Los Medanos 15C *(LM-15C)*	01320121 GRN LM-15C 2013-03-21.pdf
Los Medanos	Los Medanos 16D *(LM-16D)*	01320133 GRN LM-16D 2013-03-27.pdf
Los Medanos	Los Medanos 17D *(LM-17D)*	01320136 GRN LM-17D 2013-03-25.pdf
Los Medanos	Los Medanos 18D *(LM-18D)*	01320135 GRN LM-18D 2013-03-26.pdf
Los Medanos	Los Medanos 19D *(LM-19D)*	01320295_GRN_LM-19D_2013-03-26.pdf
Los Medanos	Los Medanos 20D *(LM-20D)*	01320287_GRN_LM-20D_2013-03-26.pdf

2015 GT&S Storage Report
Gamma Ray Neutron Files

Storage Field	Well Name	File Name
Los Medanos	Los Medanos 21D *(LM-21D)*	01320308_GRN_LM-21D_2013-03-25.pdf
Los Medanos	Ginochio 3-7 (Gino 3-7)	01300135_GRN_Gino 3-7_2013-03-27.pdf
McDonald Island (Peripheral)	Lil Mac 1 *(LilMac-1)*	07720609_GRN_Lil Mac-1_2013-04-11.pdf
McDonald Island (Peripheral)	McDonald Island Farms 6 *(MI-6)*	07700082_GRN_MI-6_2013-04-02.pdf
McDonald Island (Peripheral)	McDonald Island Farms 9 *(MI-9)*	07700084_GRN_MI-9_2013-04-02.pdf
McDonald Island (Peripheral)	McDonald Island Farms 10 *(MI-10)*	07700085_GRN_MI-10_2013-04-05.pdf
McDonald Island (Peripheral)	McDonald Island Farms 11 *(MI-11)*	07700086_GRN_MI-11_2013-04-10.pdf
McDonald Island (Peripheral)	McDonald Island Farms 12 *(MI-12)*	07700087_GRN_MI-12_2013-04-10.pdf
McDonald Island (Peripheral)	McDonald Island Farms 13 *(MI-13)*	07700088_GRN_MI-13_2013-04-08.pdf
McDonald Island (Peripheral)	McDonald Island Farms 14 *(MI-14)*	07720441_GRN_MI-14_2013-04-09.pdf
McDonald Island (Peripheral)	McDonald Island Farms 15 *(MI-15)*	07720444_GRN_MI-15_2013-04-09.pdf
McDonald Island (Peripheral)	Tilden Community 1 *(Tilden-1)*	07700090_GRN_Tild-1_2013-04-11.pdf
McDonald Island (Peripheral)	Weyl-Zuckerman 1 *(Zuck-1)*	07700091_GRN_Zuck-1_2013-04-04.pdf
McDonald Island (Peripheral)	Weyl-Zuckerman 3 *(Zuck-3)*	07700093_GRN_Zuck-3_2013-04-04.pdf
McDonald Island (Peripheral)	Zuckerman-Henning 1 *(ZuckHenn-1)*	07720010_GRN_ZuckHenn-1_2013-04-08.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 North *(TC-1N)*	07720196_GRN_TC-1N_2013-05-06.pdf
McDonald Island (Turner Cut Station)	Turner Cut 1 South *(TC-1S)*	07720218_GRN_TC-1S_2013-06-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 North *(TC-2N)*	07720199_GRN_TC-2N_2013-05-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 2 South *(TC-2S)*	07720219_GRN_TC-2S_2013-06-19.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 North *(TC-4N)*	07720202_GRN_TC-4N_2013-05-03.pdf
McDonald Island (Turner Cut Station)	Turner Cut 4 South *(TC-4S)*	07720203_GRN_TC-4S_2013-06-20.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 North *(TC-5N)*	07720207_GRN_TC-5N_2013-05-02.pdf
McDonald Island (Turner Cut Station)	Turner Cut 5 South *(TC-5S)*	07720204_GRN_TC-5S_2013-06-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 North *(TC-6N)*	07720208_GRN_TC-6N_2013-05-02.pdf
McDonald Island (Turner Cut Station)	Turner Cut 6 South *(TC-6S)*	07720205_GRN_TC-6S_2013-06-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 North *(TC-7N)*	07720225_GRN_TC-7N_2013-05-01.pdf
McDonald Island (Turner Cut Station)	Turner Cut 7 South *(TC-7S)*	07720206_GRN_TC-7S_2013-06-26.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 North *(TC-8N)*	07720226_GRN_TC-8N_2013-05-01.pdf
McDonald Island (Turner Cut Station)	Turner Cut 8 South *(TC-8S)*	07720533_GRN_TC-8S_2013-06-26.pdf

2015 GT&S Storage Report
Gamma Ray Neutron Files

Storage Field	Well Name	File Name
McDonald Island (Turner Cut Station)	Turner Cut 9 North (*TC-9N*)	07720227_GRN_TC-9N_2013-04-30.pdf
McDonald Island (Turner Cut Station)	Turner Cut 10 North (*TC-10N*)	07720228_GRN_TC-10N_2013-04-30.pdf
McDonald Island (Turner Cut Station)	Turner Cut 11 North (*TC-11N*)	07720229_GRN_TC-11N_2013-04-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 12 North (*TC-12N*)	07720230_GRN_TC-12N_2013-04-29.pdf
McDonald Island (Turner Cut Station)	Turner Cut 13 North (*TC-13N*)	07720234_GRN_TC-13N_2013-04-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 15 North (*TC-15N*)	07720239_GRN_TC-15N_2013-04-25.pdf
McDonald Island (Turner Cut Station)	Turner Cut 16 North (*TC-16N*)	07720240_GRN_TC-16N_2013-04-24.pdf
McDonald Island (Turner Cut Station)	Turner Cut 17 North (*TC-17N*)	07720548_GRN_TC-17N_2013-04-24.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A East (*WS-1AE*)	07720536_GRN_WS-1AE_2013-05-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1A West (*WS-1AW*)	07720544_GRN_WS-1AW_2013-05-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 East (*WS-1E*)	07720168_GRN_WS-1E_2013-05-20.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 1 West (*WS-1W*)	07720215_GRN_WS-1W_2013-05-21.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 East (*WS-2E*)	07720169_GRN_WS-2E_2013-05-13.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 2 West (*WS-2W*)	07720212_GRN_WS-2W_2013-05-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 East (*WS-3E*)	07720173_GRN_WS-3E_2013-05-16.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 3 West (*WS-3W*)	07720213_GRN_WS-3W_2013-05-22.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 East (*WS-4E*)	07720178_GRN_WS-4E_2013-05-15.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 4 West (*WS-4W*)	07720214_GRN_WS-4W_2013-05-28.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 East (*WS-5E*)	07720179_GRN_WS-5E_2013-05-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 5 West (*WS-5W*)	07720211_GRN_WS-5W_2013-05-28.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 East (*WS-6E*)	07720185_GRN_WS-6E_2013-05-14.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 6 West (*WS-6W*)	07720192_GRN_WS-6W_2013-05-29.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 East (*WS-7E*)	07720187_GRN_WS-7E_2013-05-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 7 West (*WS-7W*)	07720193_GRN_WS-7W_2013-05-29.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 East (*WS-8E*)	07720188_GRN_WS-8E_2013-05-09.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 8 West (*WS-8W*)	07720194_GRN_WS-8W_2013-05-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 East (*WS-9E*)	07720189_GRN_WS-9E_2013-05-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 9 West (*WS-9W*)	07720195_GRN_WS-9W_2013-05-30.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 East (*WS-10E*)	07720190_GRN_WS-10E_2013-04-01.pdf

2015 GT&S Storage Report
Gamma Ray Neutron Files

Storage Field	Well Name	File Name
McDonald Island (Whiskey Slough Station)	Whiskey Slough 10 West (*WS-10W)*	07720534_GRN_WS-10W_2013-06-04.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 East (*WS-11E)*	07720253_GRN_WS-11E_2013-05-08.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 11 West (*WS-11W)*	07720265_GRN_WS-11W_2013-06-04.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 East (*WS-12E)*	07720255_GRN_WS-12E_2013-05-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 12 West (*WS-12W)*	07720264_GRN_WS-12W_2013-06-05.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 East (*WS-13E)*	07720256_GRN_WS-13E_2013-05-07.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 13 West (*WS-13W)*	07720241_GRN_WS-13W_2013-06-06.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 14 East (*WS-14E)*	07720257_GRN_WS-14E_2013-05-06.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 15 West (*WS-15W)*	07720233_GRN_WS-15W_2013-06-06.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 16 West (*WS-16W)*	07720231_GRN_WS-16W_2013-06-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 17 West (*WS-17W)*	07720166_GRN_WS-17W_2013-06-10.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 18 West (*WS-18W)*	07720465_GRN_WS-18W_2013-06-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 19 West (*WS-19W*)	07720467_GRN_WS-19W_2013-06-11.pdf
McDonald Island (Whiskey Slough Station)	Whiskey Slough 20 West (*WS-20W)*	07720535_GRN_WS-20W_2013-06-18.pdf

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX G

YEARLY WELL EVALUATION REPORTS

Pacific Gas and Electric Company

January 27, 2012

Mr. Mike Woods
District Deputy
Natural Resources Agency of California
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street, MS 20-22
Sacramento, CA 95814-3530

Dear Mr. Woods:

Attached is the 2011 Yearly Well Evaluation Report for PG&E's underground gas storage fields. The report is summarized as follows:

Down Hole Safety Valves (Subsurface Safety Devices)

The Down Hole Safety Valves (DHSVs) installed in wells at Los Medanos and McDonald Island gas storage fields have been tested for reliable operation. We have found a number of wells at both locations that have problems. The wells at Pleasant Creek gas storage field have no DHSVs.

At McDonald Island there are 25 DHSVs that have control line, tubing and/or casing valve problems, comparing to 31 in 2010. Of the 25 problem DHSVs, 22 are in high priority category for replacement, which is the same comparing to the number in 2010. Of the 22 high priority DHSVs, 14 are at Turner Cut Station and 8 are at Whisky Slough Station. Five of these 22 are scheduled to be replaced in 2012.

At Los Medanos there are 5 DHSVs with control line, tubing and/or casing valve problems, comparing to 4 in 2010. Of the 5 problem DHSVs, 4 are of high priority category due to pressure buildup of 301 psi or higher comparing to 4 in 2010. The remaining 1 problem DHSV is out of service due to the DHSV being stuck closed. One of these 5 is scheduled to be replaced in 2012.

Casing Integrity Surveys (Temperature and Noise Surveys)

Casing Integrity surveys have been performed in every injection, withdrawal, and observation well in all three storage fields, except one well at Los Medanos that the DHSV was stuck closed. Preliminary review of the survey logs indicates that temperature and noise anomalies have been encountered in some wells with no indications of major leaks in these wells. There are no indications of fluid levels in any wells affecting the fresh water bearing formations

At McDonald Island 4 wells have only temperature anomalies and 1 has only noise anomalies. Three wells have both temperature and noise anomalies with no apparent indication of major leaks. All these wells will be monitored very closely to insure that no casing leaks have developed and additional testing may be performed if warranted.

Casing Integrity Surveys (Temperature and Noise Surveys) - Continued

At Los Medanos none of the wells have any temperature and/or noise anomalies.

At Pleasant Creek one well has various minor noise anomalies in the well bore but no temperature anomalies. This well will be monitored very closely to ensure that no casing leaks have developed and additional testing may be performed if warranted.

Up Hole Safety Valves (Surface Safety Devices)

All Up Hole Safety Valves (UHSVs) at Los Medanos, McDonald Island, and Pleasant Creek gas storage fields were tested for holding pressure and found that 22 UHSVs (19 UHSVs at McDonald Island, 3 at Los Medanos, and none at Pleasant Creek) have either slight leaks or leaks. Maintenance will be performed on these valves to ensure reliable operation.

Please see the attachment to this report for details. If you have any questions, please call me at (925) 974-4223.

Sincerely,

Joseph C. Chan
Principal Gas Reservoir Engineer

Attachment

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

LOS MEDANOS GAS STORAGE FIELD

	DOWN HOLE SAFETY VALVE SYSTEM			UP HOLE SAFETY VALVES		TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE	TBG. VALVE	CSG. VALVE	MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1A**	4	OK	OK	OK	OK	127	None	None
2A	OK	OK	OK	LEAK	OK	122	None	None
3A	OK	OK	OK	OK	OK	124	None	None
4B**	OK	1	4	OK	OK	129	None	None
5B	OK	OK	OK	OK	OK	123	None	None
6B**	OK	OK	OK	OK	OK	139	None	None
7C	OK	OK	OK	OK	OK	123	None	None
8C**	O/S	O/S	O/S	OK	OK	N/A	None	None
9C**	NEW '11	OK	OK	OK	OK	126	None	None
10C	OK	OK	OK	OK	OK	127	None	None
11C	OK	OK	OK	OK	OK	124	None	None
12C	OK	OK	OK	OK	OK	125	None	None
13C	OK	OK	OK	OK	OK	130	None	None
14C	OK	OK	OK	LEAK	OK	125	None	None
15C	OK	OK	OK	OK	OK	131	None	None
16D	OK	2	4	OK	OK	124	None	None
17D	OK	OK	OK	OK	OK	123	None	None
18D	OK	OK	OK	OK	OK	123	None	None
19D**	OK	OK	OK	LEAK	OK	124	None	None
20D	OK	OK	OK	OK	OK	129	None	None
21D**	OK	4	4	OK	OK	123	None	None
Gino 3-7	NO DHSV (OBSERVATION WELL)			NO UHSV	NO UHSV	136	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes
O/S: Out of Service

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD

TURNER CUT NORTH SIDE

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE			TBG. VALVE		CSG. VALVE		MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1N**	OK	OK	4			OK		OK		144	None	None
2N	OK	1	3			OK		OK		151	None	None
3N**	OK	OK	OK			OK		OK		135	None	None
4N**	OK	OK	OK			OK		OK		152	None	None
5N	OK	4	1			OK		OK		153	None	None
6N**	OK	OK	OK			SL. LEAK		OK		151	None	None
7N	OK	2	1			OK		OK		152	None	None
8N	OK	4	1			OK		OK		135	None	None
9N**	OK	OK	OK			OK		OK		152	None	None
10N	OK	4	1			OK		OK		140	1400'/2800'	1400'/2300'/2800'
11N**	OK	OK	4			LEAK		OK		128	None	None
12N	OK	3	3			OK		OK		129	None	None
13N	OK	1	1			OK		OK		130	None	2200'
15N	OK	2	1			OK		OK		139	None	None
16N**	OK	OK	OK			OK		OK		143	None	None
17N	OK	2	4			OK		OK		128	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEAR: 2011

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD
TURNER CUT SOUTH SIDE

	DOWN HOLE SAFETY VALVE SYSTEM			UP HOLE SAFETY VALVES		TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE	TBG. VALVE	CSG. VALVE	MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1AS	OK	4	1	OK	OK	133	None	None
1S	1	1	1	OK	OK	135	None	None
2S	OK	1	1	OK	OK	150	None	None
3S**	OK	OK	OK	OK	OK	150	None	None
4S	OK	4	1	OK	OK	151	None	None
5S	OK	1	1	OK	OK	153	None	None
6S**	OK	OK	4	OK	OK	153	None	None
7S	OK	4	1	OK	OK	151	None	None
8S**	OK	OK	4	OK	OK	131	3200'	3200'/4200'
9S	4	1	1	OK	OK	142	None	None
10S**	OK	OK	OK	OK	OK	143	None	None
11S**	OK	OK	OK	OK	OK	143	None	None
12S**	OK	OK	OK	OK	OK	131	None	None
13S	OK	2	2	OK	OK	144	None	None
14S	OK	4	1	OK	OK	132	None	None
15S	4	4	1	OK	OK	128	None	None
16S	OK	2	1	OK	OK	127	None	None
17S	OK	2	1	OK	OK	142	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD WHISKY SLOUGH EAST SIDE								
	DOWN HOLE SAFETY VALVE SYSTEM			UP HOLE SAFETY VALVES		TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE	TBG. VALVE	CSG. VALVE	Max. Temp.	TEMP. ANOMALY	NOISE ANOMALY
1AE**	OK	OK	OK	SL. LEAK	OK	115	None	None
1E	OK	1	1	SL. LEAK	OK	141	None	None
2E	OK	1	2	SL. LEAK	SL. LEAK	143	None	None
3E	OK	2	1	OK	OK	140	None	None
4E**	OK	OK	OK	OK	OK	123	None	None
5E	OK	4	1	OK	OK	116	None	None
6E**	OK	OK	4	OK	OK	118	None	None
7E	OK	4	1	OK	OK	142	None	None
8E	OK	1	4	OK	OK	151	None	None
9E**	OK	OK	OK	LEAK	SL. LEAK	119	None	None
10E	Observation Well			N/A	N/A	147	None	None
11E**	OK	OK	OK	SL. LEAK	SL. LEAK	147	None	None
12E	4	OK	OK	LEAK	SL. LEAK	152	None	None
13E	OK	OK	OK	SL. LEAK	SL. LEAK	151	None	None
14E	OK	OK	OK	OK	OK	152	5400'	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD
WHISKY SLOUGH WEST SIDE

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE			TBG. VALVE		CSG. VALVE		MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1AW	OK	1	4			OK		OK		130	None	None
1W**	4	OK	OK			OK		OK		145	4900'	None
2W**	OK	OK	OK			OK		OK		141	None	None
3W	OK	4	1			OK		OK		135	None	None
4W**	OK	OK	OK			OK		OK		138	None	None
5W	OK	OK	1			OK		OK		140	None	None
6W**	OK	OK	OK			OK		OK		142	None	None
7W**	OK	OK	OK			OK		OK		137	None	None
8W**	OK	OK	OK			OK		OK		137	None	None
9W	OK	2	1			OK		OK		144	None	None
10W	OK	2	1			OK		OK		137	None	None
11W	OK	1	1			LEAK		SL. LEAK		138	None	None
12W**	OK	OK	OK			OK		OK		138	None	None
13W**	OK	OK	OK			OK		OK		141	None	None
15W**	OK	OK	OK			OK		OK		141	None	None
16W	OK	3	1			OK		OK		139	None	None
17W**	OK	OK	OK			OK		OK		131	None	None
18W**	OK	OK	OK			OK		OK		138	None	None
19W**	OK	OK	OK			LEAK		LEAK		135	None	None
20W	OK	1	1			OK		OK		131	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

MCDONALD ISLAND GAS STORAGE FIELD

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
McD#4		Observation Well				N/A		N/A		138	None	None
McD#5		NO DHSV				OK		SL. LEAK		121	4800'	None
McD#6		Observation Well				N/A		N/A		144	None	None
McD#7		Observation Well				N/A		N/A		144	None	None
McD#9		NO DHSV				OK		OK		124	4800'	None
McD#10		NO DHSV				OK		OK		125	None	None
McD#11		NO DHSV				OK		OK		120	2850'	1800'
McD#12		NO DHSV				OK		OK		124	None	None
McD#13		NO DHSV				OK		OK		125	None	None
McD#14		NO DHSV				OK		OK		131	None	None
McD#15		NO DHSV				OK		OK		134	None	None
Zuck#1		Observation Well				N/A		N/A		130	None	None
Zuck#3		NO DHSV				OK		OK		136	None	None
Til#1		NO DHSV				OK		OK		128	None	None
R.I.#1		NO DHSV				OK		OK		142	None	None
R.I.#2		NO DHSV				OK		OK		125	None	None
Z-H#1		Observation Well				N/A		N/A		128	None	None
L-M#1		NO DHSV				OK		OK		145	None	5100'

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2:101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

PLEASANT CREEK GAS STORAGE FIELD												
	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
3-1		NO DHSV				OK		OK		98	None	None
3-2		NO DHSV				OK		OK		102	None	None
3-3		NO DHSV				OK		OK		N/A	None	None
3-4		NO DHSV				OK		OK		97	None	None
4-1		NO DHSV				OK		OK		95	None	None
4-2		NO DHSV				OK		OK		95	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher

January 30, 2013

Mr. Mike Woods
District Deputy
Natural Resources Agency of California
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street, MS 20-22
Sacramento, CA 95814-3530

Dear Mr. Woods:

Attached is the 2012 Yearly Well Evaluation Report for PG&E's underground gas storage fields. The report is summarized as follows:

Down Hole Safety Valves (Subsurface Safety Devices)

The Down Hole Safety Valves (DHSVs) installed in wells at Los Medanos and McDonald Island gas storage fields have been tested for reliable operation. We have found a number of wells at both locations that have leak ratings 3 and 4. The wells at Pleasant Creek gas storage field do not have DHSVs.

At McDonald Island there are 19 DHSVs that have control line, tubing and/or casing valve leak with ratings of 3 and 4, comparing to 25 in 2011. Of the 19 leaky DHSVs, 18 are in rating 4 category for replacement. Of the 18, 10 are at Turner Cut Station and 8 are at Whisky Slough Station. Five of these 18 rating 4 DHSVs are scheduled to be replaced in 2013.

At Los Medanos there are 5 DHSVs that have control line, tubing and/or casing valve leak with rating 4. One of these 5 is scheduled to be replaced in 2013.

Casing Integrity Surveys (Temperature and Noise Surveys)

Casing Integrity surveys have been performed in every injection, withdrawal, and observation wells in all three storage fields. Preliminary review of the survey logs indicates that temperature and noise anomalies have been encountered in some wells with no apparent indications of major leaks in these wells, except well WS-1W at McDonald Island. The apparent leak in McDonald Island well WS-1W has been reported to the DOGGR. The plan is to run a radioactive tracer survey on January 31, 2013, to confirm the apparent leak and to perform remediation upon confirmation.

At McDonald Island with the exception of well WS-1W, there are 11 wells having only temperature anomalies and 8 having only noise anomalies. Four wells have both temperature and noise anomalies with no apparent indication of major leaks. All these wells will be monitored very closely to insure that no casing leaks have developed and additional testing may be performed if warranted.

Casing Integrity Surveys (Temperature and Noise Surveys) - Continued

At Los Medanos none of the wells have any temperature and/or noise anomalies.

At Pleasant Creek one well has minor noise anomalies in the well bore but no temperature anomalies. This well will be monitored very closely to ensure that no casing leaks have developed and additional testing may be performed if warranted.

There are no indications of fluid levels in any wells affecting the fresh water bearing formations.

Up Hole Safety Valves (Surface Safety Devices)

All Up Hole Safety Valves (UHSVs) at Los Medanos, McDonald Island, and Pleasant Creek gas storage fields were tested for holding pressure and found that 12 UHSVs (8 UHSVs at McDonald Island, 4 at Los Medanos, and none at Pleasant Creek) have either slight leaks or leaks. Maintenance will be performed on these valves to ensure reliable operation.

Please see the attachment to this report for details. If you have any questions, please call me at (925) 244-3207.

Sincerely,

Joseph C. Chan

Joseph C. Chan
Principal Gas Reservoir Engineer

Attachment

PACIFIC GAS & ELECTRIC COMPANY

YEAR: 2012

YEARLY STORAGE WELL EVALUATION REPORT

LOS MEDANOS GAS STORAGE FIELD

	DOWN HOLE SAFETY VALVE SYSTEM			UP HOLE SAFETY VALVES		TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE	TBG. VALVE	CSG. VALVE	MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1A**	4	1	1	OK	OK	125	None	None
2A	OK	1	1	LEAK	OK	120	None	None
3A	OK	1	1	OK	OK	120	None	None
4B**	OK	1	4	OK	OK	128	None	None
5B	OK	1	1	OK	OK	121	None	None
6B**	OK	1	1	OK	OK	127	None	None
7C	OK	1	1	OK	OK	121	None	None
8C**	OK	0	N/A	OK	OK	129	None	None
9C**	OK	1	1	LEAK	OK	123	None	None
10C	OK	1	2	OK	OK	123	None	None
11C	OK	2	2	OK	OK	128	None	None
12C	OK	1	4	OK	OK	125	None	None
13C	OK	1	1	OK	OK	130	None	None
14C	OK	1	1	LEAK	OK	123	None	None
15C	OK	1	1	OK	OK	131	None	None
16D	OK	2	4	OK	OK	120	None	None
17D	OK	1	1	OK	OK	121	None	None
18D	OK	1	1	OK	OK	121	None	None
19D**	OK	1	1	LEAK	OK	124	None	None
20D	OK	1	1	OK	OK	127	None	None
21D**	OK	4	4	OK	OK	119	None	None
Gino 3-7	N/A	Observation Well		No UHSV	NO UHSV	135	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes
O/S: Out of Service

PACIFIC GAS & ELECTRIC COMPANY

YEAR: 2012

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD												
TURNER CUT NORTH SIDE												
	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
1N**	OK	4	1			OK		OK		136	None	Various
2N	OK	1	3			OK		OK		142	None	None
3N**	OK	1	0			OK		OK		127	None	None
4N**	OK	1	4			OK		OK		144	2640'	None
5N	4	1	2			OK		OK		144	None	None
6N**	OK	1	1			OK		OK		143	2650'	600'
7N	OK	1	1			OK		OK		142	950-1400'	5360'-5600'
8N	OK	4	1			OK		OK		128	None	None
9N**	OK	1	1			OK		OK		144	None	None
10N	4	3	1			OK		OK		141	None	None
11N**	OK	4	4			LEAK		OK		128	None	None
12N	OK	1	2			OK		OK		130	None	None
13N	OK	1	1			OK		OK		130	None	None
15N**	REWORK WELL					OK		OK		141	None	None
16N**	OK	1	1			OK		OK		144	None	None
17N	OK	1	4			OK		OK		128	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD
TURNER CUT SOUTH SIDE

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE			TBG. VALVE		CSG. VALVE		MAX. TEMP.	TEMP. ANOMALY	NOISE ANOMALY
1AS	OK	2	1			OK		OK		128	None	None
1S	OK	1	1			OK		OK		131	None	None
2S	OK	1	1			OK		OK		142	None	3900'
3S **	OK	1	1			OK		OK		143	None	None
4S	OK	1	1			OK		OK		145	1400'	None
5S	OK	1	1			OK		OK		145	2800'	2800'
6S **	OK	1	1			OK		OK		145	None	None
7S	OK	0	1			OK		OK		143	None	None
8S **	OK	1	1			OK		OK		137	None	None
9S	4	4	2			OK		OK		143	None	None
10S **	OK	1	4			OK		OK		146	None	None
11S **	OK	1	1			OK		OK		145	None	None
12S **	OK	1	1			OK		OK		133	None	None
13S	OK	1	1			OK		OK		146	1200'	None
14S	4	3	1			OK		OK		132	None	None
15S	OK	2	1			OK		OK		130	None	None
16S	OK	2	1			OK		OK		129	5000'	None
17S	OK	1	1			OK		OK		144	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD
WHISKY SLOUGH EAST SIDE

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
WELL	CONTROL LINE	TUBING VALVE	CASING VALVE			TBG. VALVE		CSG. VALVE		Max. Temp.	TEMP. ANOMALY	NOISE ANOMALY
1AE**	OK	1	1			OK		OK		134	None	None
1E	OK	1	1			OK		OK		141	None	None
2E	OK	2	1			OK		OK		144	None	None
3E	OK	4	1			OK		OK		141	None	None
4E**	OK	1	1			OK		OK		137	None	Various
5E**	REWORK WELL					OK		OK		135	None	2400'
6E**	0	1	4			OK		OK		136	None	None
7E**	REWORK WELL					LEAK		OK		137	None	None
8E**	REWORK WELL					OK		OK		142	1100'	None
9E**	0	1	1			OK		OK		136	None	None
10E	OBSERVATION WELL					N/A		N/A		136	None	None
11E**	0	1	1			OK		OK		141	None	None
12E**	REWORK WELL					OK		OK		143	None	5540'
13E	OK	1	4			OK		OK		143	None	None
14E	OK	1	1			OK		OK		139	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEAR: 2012

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD WHISKY SLOUGH WEST SIDE												
	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
1AW	OK	1	3			LEAK		OK		137	None	None
1W**	OK	4	4			OK		OK		145	4950'	4950'
2W**	OK	0	1			OK		OK		142	None	None
3W**	REWORK WELL					OK		OK		142	None	None
4W**	OK	0	0			OK		OK		139	None	Various
5W	OK	1	1			OK		OK		142	None	None
6W**	OK	1	4			OK		OK		142	None	None
7W**	OK	1	4			OK		OK		137	900'	1200'
8W**	OK	1	1			OK		OK		138	None	None
9W	OK	3	1			OK		OK		146	1180'	None
10W	OK	1	1			OK		OK		139	None	None
11W	OK	1	1			LEAK		OK		139	None	None
12W**	OK	0	0			OK		OK		140	None	None
13W**	4	0	0			OK		OK		141	None	None
15W**	OK	1	1			OK		OK		143	None	None
16W	OK	4	1			OK		OK		142	None	None
17W**	OK	0	0			OK		OK		136	None	5020'
18W**	OK	1	0			LEAK		OK		140	None	None
19W**	OK	1	0			OK		OK		140	None	None
20W	OK	1	1			SL. LEAK		OK		138	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher
**RC-2 DHSV leak test not to exceed 50 cu ft per 10 minutes

PACIFIC GAS & ELECTRIC COMPANY

YEARLY STORAGE WELL EVALUATION REPORT

MCDONALD ISLAND GAS STORAGE FIELD												
	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
McD#4	OBSERVATION WELL					N/A		N/A		141	None	None
McD#5	N/A					OK		OK		133	4850'	None
McD#6	OBSERVATION WELL					N/A		N/A		134	None	None
McD#7	OBSERVATION WELL					N/A		N/A		135	None	None
McD#9	N/A					OK		OK		123	3200'/3840'/4750'	None
McD#10	N/A					OK		OK		133	None	None
McD#11	N/A					LEAK		OK		116	None	1800'
McD#12	N/A					OK		OK		126	None	None
McD#13	N/A					OK		OK		126	None	None
McD#14	N/A					OK		OK		128	None	None
McD#15	N/A					SL. LEAK		OK		128	None	None
R.I.#1	N/A					OK		OK		128	5400'-5600'	None
R.I.#2	N/A					OK		OK		132	5150'-5300'	None
Til#1	N/A					OK		OK		124	4850'/5100'	None
Zuck#1	OBSERVATION WELL					N/A		N/A		146	None	None
Zuck#3	N/A					OK		OK		126	None	None
L-M#1	N/A					OK		OK		123	None	None
Z-H#1	OBSERVATION WELL					N/A		N/A		149	None	5100'

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2:101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher

YEARLY STORAGE WELL EVALUATION REPORT

PLEASANT CREEK GAS STORAGE FIELD

	DOWN HOLE SAFETY VALVE SYSTEM					UP HOLE SAFETY VALVES				TEMPERATURE & NOISE LOGS		
	CONTROL	TUBING	CASING			TBG.		CSG.		MAX.	TEMP.	NOISE
WELL	LINE	VALVE	VALVE			VALVE		VALVE		TEMP.	ANOMALY	ANOMALY
3-1		NO DHSV				OK		OK		99	None	None
3-2		NO DHSV				OK		OK		101	None	None
3-3		NO DHSV				OK		SL. LEAK		100	None	None
3-4		NO DHSV				OK		OK		98	None	None
3-5		NO DHSV				OK		OK		101	None	None
4-1		NO DHSV				OK		OK		96	None	None
4-2		NO DHSV				OK		OK		97	None	None

DHSV RATING SYSTEM
Rating of #1: 0 to 100psi build up
Rating of #2: 101 to 200psi build up
Rating of #3: 201 to 300psi Build up
Rating of #4: 301psi or higher

Field: Los Medanos

PACIFIC GAS ELECTRIC COMPANY
2013 STORAGE WELL EVALUATION REPORT

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1A	4	1	1	2007	RC-2	1	1	126.4	NONE	NONE
2A	OK	1	1	2005	RC	1	1	122.8	NONE	NONE
3A	OK	1	1	2000	RC	1	1	123.7	NONE	NONE
4B	Rework well			2013	RC-2	1	1	126.4	NONE	NONE
5B	Rework well			2013	RC-2	1	1	125.0	NONE	NONE
6B	OK	1	1	2006	RC-2	1	4	127.8	NONE	NONE
7C	OK	1	1	1992	RC	1	1	122.2	NONE	NONE
8C	OK	4	N/A	2012	T5 only	1	N/A	131.9	NONE	NONE
9C	OK	1	1	2011	RC-2	1	1	124.1	NONE	NONE
10C	OK	1	4	2003	RC	1	1	125.2	NONE	NONE
11C	OK	4	1	1992	RC	1	1	124.9	NONE	NONE
12C	OK	1	1	1991	RC	1	1	123.6	NONE	NONE
13C	1	1	1	1990	RC	1	1	128.0	NONE	NONE
14C	1	1	1	1990	RC	4	1	124.5	NONE	NONE
15C	0	1	1	1999	RC	1	1	130.1	NONE	NONE
16D	0	2	4	2004	RC	1	1	123.6	NONE	NONE
17D	0	1	1	1997	RC	1	1	124.6	NONE	NONE
18D	OK	1	1	1992	RC	1	1	124.0	NONE	NONE
19D	0	1	1	2007	RC-2	1	1	125.1	NONE	NONE
20D	0	1	1	1990	RC	1	1	130.1	NONE	NONE
21D	1	1	4	2008	RC-2	1	1	124.3	NONE	NONE
Gino 3-7	N/A	servation Well		N/A	N/A	No UHSV	No UHSV	134.6	NONE	NONE

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

Uhsv Rating System *(Pressure Build-up/ 60 mins)*

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AE	0	1	0	2009	Baker RC-2	1	1	N/A	N/A	N/A
1E	0	1	1	2005	Baker RC-2	1	**4**	N/A	N/A	N/A
2E	0	3	1	2001	Baker RC	1	1	N/A	N/A	N/A
3E	**4**	1	1	2001	Baker RC	1	**4**	N/A	N/A	N/A
4E	0	1	1	2007	Baker RC-2	1	1	N/A	N/A	N/A
5E	0	1	1	2012	Baker RC-2	1	1	N/A	N/A	N/A
6E	0	1	**4***	2007	Baker RC-2	1	1	N/A	N/A	N/A
7E	0	1	0	2012	Baker RC-2	1	1	N/A	N/A	N/A
8E	0	1	1	2012	Baker RC-2	**4**	1	N/A	N/A	N/A
9E	0	1	1	2007	Baker RC-2	**4**	1	N/A	N/A	N/A
10E	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11E	0	0	1	2011	Baker RC-2	1	1	N/A	N/A	N/A
12E	0	1	1	2012	Baker RC-2	1	1	N/A	N/A	N/A
13E	0	1	1	2005	Baker RC-2	1	1	N/A	N/A	N/A
14E	0	3	1	2005	Baker RC	1	1	N/A	N/A	N/A

No Noise and Temp surveys were conducted at Whisky Slough Station in 2013 due to the rebuild project.

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

Uhsv Rating System *(Pressure Build-up/ 60 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

* Will not blowdown

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AW	4	1	4	2001	Baker RC	1	1	N/A	N/A	N/A
1W	0	1	1	2008	Baker RC-2	1	1	143.0	4970'	4970' to 5150'
2W	0	0	1	2009	Baker RC-2	1	1	N/A	N/A	N/A
3W	0	1	1	2012	Baker RC-2	1	1	N/A	N/A	N/A
4W	0	1	4*	2008	Baker RC-2	1	1	N/A	N/A	N/A
5W	0	4	1	1999	Baker RC	1	1	N/A	N/A	N/A
6W	0	0	1	2009	Baker RC-2	1	1	N/A	N/A	N/A
7W	0	1	1	2011	Baker RC-2	1	1	N/A	N/A	N/A
8W	0	1	1	2011	Baker RC-2	1	1	N/A	N/A	N/A
9W	0	1	1	1994	Baker RC	1	1	N/A	N/A	N/A
10W	0	1	1	1990	Baker RC	1	1	N/A	N/A	N/A
11W	0	1	1	1995	Baker RC	1	1	N/A	N/A	N/A
12W	4	1	1	2009	Baker RC-2	1	1	N/A	N/A	N/A
13W	0	0	1	2008	Baker RC-2	1	1	N/A	N/A	N/A
15W	0	1	1	2011	Baker RC-2	1	1	N/A	N/A	N/A
16W	0	4	1	2005	Baker RC	1	1	N/A	N/A	N/A
17W	0	1	1	2009	Baker RC-2	1	1	N/A	N/A	N/A
18W	0	1	1	2011	Baker RC-2	1	1	N/A	N/A	N/A
19W	0	1	1	2008	Baker RC-2	4	1	N/A	N/A	N/A
20W	0	3	0	1999	Baker RC	4	1	N/A	N/A	N/A

No Noise and Temp surveys were conducted at Whisky Slough Station in 2013 due to the rebuild project.

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

Uhsv Rating System *(Pressure Build-up/ 60 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AS	0	1	1	1991	Baker RC	1	1	129.0	4700'	None
1S	4	1	3	2002	Baker RC	1	1	130.0	None	5350'
2S	0	3	1	2004	Baker RC	1	1	141.0	None	None
3S	0	1	1	2010	Baker RC-2	1	1	140.0	None	None
4S	0	4	1	2004	Baker RC	1	1	145.0	None	250'
5S	0	1	1	2004	Baker RC	1	1	143.0	2750'	400'
6S	0	1	1	2010	Baker RC-2	1	1	142.0	None	None
7S	0	2	1	1993	Baker RC	1	1	141.0	None	None
8S	0	1	1	2007	Baker RC-2	1	1	135.0	None	None
9S	4 *	2	1	2002	Baker RC	1	1	141.0	None	None
10S	0	1	1	2010	Baker RC-2	1	1	143.0	None	None
11S	0	1	1	2009	Baker RC-2	1	1	143.0	None	5400' to 5550'
12S	3	1	1	2007	Baker RC-2	1	2	136.0	None	None
13S	0	3	3	1998	Baker RC	1	1	143.0	1300'	350', 5100', 5600'
14S	4 *	4	1	1993	Baker RC	1	1	129.0	320'	None
15S	0	1	1	2004	Baker RC	0	1	128.0	None	5300'
16S	0	2	2	2003	Baker RC	1	1	126.0	None	None
17S	0	0	0	2004	Baker RC	1	1	143.0	None	None

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

Uhsv Rating System *(Pressure Build-up/ 60 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

* Will not blowdown

Field: McDonald Island
TCS North Wells

PACIFIC GAS ELECTRIC COMPANY
2013 STORAGE WELL EVALUATION REPORT

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1N	0	1	1	2013	Baker RC-2	1	1	137.0	260'	None
2N	0	1	1	2013	Baker RC-2	0	0	143.0	None	None
3N	0	4*	4*	2010	Baker RC-2	1	1	134.0	None	None
4N	0	1	0	2006	Baker RC-2	1	1	143.0	260'	None
5N	0	1	1	2013	Baker RC-2	1	1	141.0	None	None
6N	0	1	1	2006	Baker RC-2	1	1	144.0	2660'	None
7N	0	2	1	2003	Baker RC	1	1	139.0	None	None
8N	0	4	4	2000	Baker RC	1	1	135.0	260'	None
9N	0	1	1	2006	Baker RC-2	1	1	146.0	None	None
10N	0	1	1	2013	Baker RC-2	1	1	142.0	260', 4650'	None
11N	0	1	1	2013	Baker RC-2	0	1	138.0	None	None
12N	0	1	2	2000	Baker RC	1	1	131.0	None	None
13N	0	1	1	1985	Baker RC	1	1	131.0	260'	None
15N	0	1	1	2012	Baker RC-2	0	0	131.0	5120'	5120'
16N	0	1	1	2010	Baker RC-2	1	1	143.0	260'	None
17N	0	4	4	2000	Baker RC	1	1	127.0	260'	None

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

Uhsv Rating System *(Pressure Build-up/ 60 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

* Will not blowdown

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
Mcd-4	OBSERVATION WELL			N/A	N/A	137.0	NONE	NONE
Mcd-5A	N/A			N/A	N/A	132.0	NONE	NONE
Mcd-6	OBSERVATION WELL			N/A	N/A	136.0	NONE	NONE
Mcd-7	OBSERVATION WELL			N/A	N/A	N/A	NONE	NONE
Mcd-9	N/A			0	0	123.0	3850', 4800'	1800', 3800', 4925'
Mcd-10	N/A			1	0	125.0	NONE	3400', 3800'
Mcd-11	N/A			4	1	120.0	NONE	NONE
Mcd-12	N/A			1	1	124.0	NONE	1800'
Mcd-13	N/A			1	1	127.0	NONE	NONE
Mcd-14	N/A			2	0	127.0	NONE	NONE
Mcd-15	N/A			0	1	128.0	NONE	NONE
Rob-1	N/A			1	0	126.0	NONE	150' - 450'
Rob-2	N/A			1	0	130.0	NONE	NONE
Tild-1	N/A			1	4	128.0	NONE	NONE
Zuck-1	OBSERVATION WELL			N/A	N/A	141.0	NONE	NONE
Zuck-3	N/A			1	1	123.0	NONE	400'
Lil Mac-1	N/A			0	0	124.0	NONE	NONE
Zuck-Hen	OBSERVATION WELL			N/A	N/A	144.0	NONE	NONE

Uhsv Rating System *(Pressure Build-up/ 60 mins)*

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

Observation Wells do not have Uhsv's
McD 5A out of service for UHSV test

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
3-1	NO DHSV			OK	OK	97.3	NONE	NONE
3-2	NO DHSV			OK	OK	98.7	NONE	NONE
3-3	NO DHSV			OK	OK	97.7	NONE	NONE
3-4	NO DHSV			OK	OK	96.0	NONE	NONE
3-5	NO DHSV			OK	OK	97.7	NONE	NONE
4-1	NO DHSV			OK	OK	95.1	NONE	NONE
4-2	NO DHSV			OK	OK	94.9	NONE	NONE

Uhsv Rating System *(Pressure Build-up/ 60 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

January 28, 2015

Ms. Joyce Jaszarowski
District Deputy
Natural Resources Agency of California
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street, MS 20-22
Sacramento, CA 95814-3530

Dear Ms. Joyce Jaszarowski:

Attached is the 2014 Yearly Well Evaluation Report for PG&E's underground gas storage fields. The report is summarized as follows:

Down Hole Safety Valves (Subsurface Safety Devices)

The Down Hole Safety Valves (DHSVs) installed in wells at Los Medanos and McDonald Island gas storage fields have been tested for reliable operation. We have found 50 of 89 wells through the testing at both storage fields that have ratings of 3 and 4, as compared to 26 wells in 2013. The wells at Pleasant Creek gas storage field do not have DHSVs.

At McDonald Island there are 37 DHSVs that have control line, tubing and/or casing valve ratings 3 and 4, as compared to 20 in 2013. Of the 37 DHSVs, 29 have a rating of 4. Four of these 29 DHSVs with rating of 4 are scheduled to be replaced in 2015.

Most of the increase in the number of wells having an increased rating is at McDonald Island Whisky Slough Station. The apparent and preliminary reason for the increase is that the DHSVs were not exercised monthly due to the DHSV hydraulic control system was taken out of service for more than 9 months as a result of the Whisky Slough production measurement and controls and piping system upgrade/rebuilt in 2013. Of note, the DHSV manufacturer recommends functionally exercising the DHSVs at a minimum once a month to keep the DHSVs working properly and reliably.

In addition, the testing methodology was changed to pressure build-up for the T5/RC2 type DHSVs instead of blowing down to zero pressure and measure the leak rates to determine the proper ratings. The change of testing methodology for the T5/RC2 type DHSVs is that the meters for the test do not meet the pressure rating to safely perform the tests. A new meter is being designed and tested to meet the required pressure rating and will be used for the 2015 tests if it meets the functionality.

At Los Medanos there are 13 DHSVs that have control line, tubing and/or casing valve a rating of 4, as compared to 6 in 2013. Two of these 13 DHSVs with rating of 4 will be replaced in 2015.

Six of the 13 DHSVs at Los Medanos are of age of more than 7 years. (Of note, the DHSV life expectancy is between 7 and 10 years.) Age is potentially one of the apparent contributing factors for the increase of number of malfunctioning DHSVs.

Casing Integrity Surveys

Casing Integrity (Temperature and Noise) surveys have been performed in injection, withdrawal, and observation wells in all three PG&E owned and operated gas storage fields. It was observed on the log data that there are temperature and noise anomalies in three wells. One of these three wells having apparent casing scab line leak (McDonald Island well Whisky Slough 1-W (see below)) will be repaired in 2015. The other two wells have no indications of apparent leaks.

The McDonald Island well Whisky Slough 1-W temperature and noise survey log data indicates apparent leaks in the casing scab liner at ~4950 ft. The apparent leaks were identified with a survey in 2012 and thereafter PG&E has been monitoring the well casing integrity. Subsequent analyses of well monitoring logs from 2012, 2013, and 2014 indicate apparent casing scab liner leaks when McDonald Island field pressure is greater than 1800 psig. The apparent casing scab liner leaks will be repaired in 2015 as part of PG&E's rework program.

None of the wells at Los Medanos and Pleasant Creek have any temperature and/or noise - anomalies. -

In addition to running the temperature and noise surveys, Gamma Ray/Neutron logs were also run in 3 wells at McDonald Island gas storage field to establish a baseline log for identifying any behind the casing leaks. Review of the logs did not indicate any apparent gas accumulation behind casing due to casing leaks.

Furthermore, electromagnetic casing inspection logs were run in 6 rework wells in 2014 as a means to detect casing pipe metal loss. The results indicated that there was no apparent metal loss in the casings in all 6 wells that require remediation. -

There are no temperature survey indications of fluid levels in any wells affecting the fresh water bearing formations.

Up Hole Safety Valves (Surface Safety Devices)

All Up Hole Safety Valves (UHSVs) at Los Medanos, McDonald Island, and Pleasant Creek gas storage fields were tested for holding pressure and found that 15 of 217 UHSV's (14 - UHSVs at McDonald Island, 1 at Los Medanos, and none at Pleasant Creek) had pressure - buildup when closed.. Maintenance will be performed on these valves to ensure reliable operation and, if necessary, will be replaced.. -

Please see the well evaluation report attachments to this report for details and included is a disk containing the noise temperature surveys conducted in 2014. If you have any questions, please call Adebola Okeowo at (925)-244-3162, Joseph Chan at 925-244-3207, or me at (925) 328-5890.

Sincerely,

Larry D. Kennedy Jr
Director, Gas Reservoir Engineering

Attachments

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1A	4	1	1	2007	RC-2	0*	0*	126.8	None	None
2A	1	3	1	2005	RC	0*	0*	122.8	None	None
3A	1	1	1	2000	RC	0*	0*	124.1	None	None
4B	0	4	1	2013	RC-2	0*	0*	126.4	None	None
5B	0	1	4**	2013	RC-2	0*	0*	123.5	None	None
6B	1	4	1	2006	RC-2	0*	0*	129.4	None	None
7C	1	1	1	1992	RC	0*	0*	122.1	None	None
8C	1	4	N/A	2012	T5 only	Leaked	N/A	130.6	None	None
9C	0	1	1	2011	RC-2	0*	0*	123.7	None	None
10C	0	1	4	2003	RC	0*	0*	124.2	None	None
11C	1	1	4	1992	RC	0*	0*	123.5	None	None
12C	1	1	1	1991	RC	0*	0*	123.5	None	None
13C	1	1	1	1990	RC	0*	0*	128.6	None	None
14C	1	1	1	1990	RC	Leaked	0*	123.4	None	None
15C	4	1	1	1999	RC	0*	0*	126.5	None	None
16D	0	2	4	2004	RC	0*	0*	123.9	None	None
17D	4	2	4**	1997	RC	0*	0*	123.5	None	None
18D	0	1	1	1992	RC	0*	0*	125.5	None	None
19D	1	1	1	2007	RC-2	0*	0*	127.4	None	None
20D	4	1	1	1990	RC	0*	0*	128.8	None	None
21D	0	4	4	2008	RC-2	0*	0*	123.7	None	None
Gino 3-7	N/A	Observation Well		N/A	N/A	N/A	N/A	132.8	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

RC-2 DHSV Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

** Will not blowdown

UHSV Rating System

0= No Leakage Indicated
1= ≤ 150 cu/ft-10 mins
4= > 150 cu/ft-10 mins

* No flow meter used

N/A = No DHSV nor UHSV

Temperature & Noise Logs

None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1AE	0	4*	3	2009	Baker RC-2	1	1	128.0	None	None
1E	0	1	1	2005	Baker RC-2	4	0	128.0	None	None
2E	4	3	1	2001	Baker RC	0	1	141.0	None	None
3E	Well Out Of Service			2001	Baker RC	0	0	N/A	N/A	N/A
4E	0	4	1	2007	Baker RC-2	4	0	131.0	None	None
5E	0	4	1	2012	Baker RC-2	4	1	129.0	None	None
6E	0	4	1	2007	Baker RC-2	1	0	130.0	None	None
7E	0	3	1	2012	Baker RC-2	4	1	131.0	None	None
8E	0	3	1	2012	Baker RC-2	1	0	141.0	250'&1400'	250'
9E	0	4	1	2007	Baker RC-2	1	0	137.0	None	None
10E	OBSERVATION WELL			N/A	N/A	N/A	N/A	138.0	None	None
11E	0	2	1	2011	Baker RC-2	0	0	139.0	None	None
12E	0	4	1	2012	Baker RC-2	4 *	0	141.0	None	None
13E	0	4	1	2005	Baker RC-2	0	0	140.0	None	None
14E	0	4	1	2005	Baker RC	1	0	140.0	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AW	0	1	4	2001	Baker RC	0	1	132.0	None	None
1W	0	4	4*	2008	Baker RC-2	4	4	137.0	None	4800'-5000'
2W	0	3	1	2009	Baker RC-2	0	1	129.0	None	None
3W	0	1	4*	2012	Baker RC-2	0	1	138.0	None	None
4W	0	4	1	2008	Baker RC-2	0	1	132.0	None	200'-400',4900'-5200'
5W	0	4	1	1999	Baker RC	2	2	138.0	None	None
6W	0	1	1	2009	Baker RC-2	0	0	136.0	None	None
7W	0	4	2	2011	Baker RC-2	2	2	129.0	None	None
8W	0	4	1	2011	Baker RC-2	0	0	130.0	None	None
9W	0	2	1	1994	Baker RC	1	1	134.0	None	None
10W	0	3	1	1990	Baker RC	1	1	132.0	None	None
11W	0	1	1	1995	Baker RC	4	4	135.0	None	None
12W	0	1	1	2009	Baker RC-2	1	1	134.0	None	None
13W	0	4	1	2008	Baker RC-2	2	2	139.0	None	None
15W	0	4	1	2011	Baker RC-2	4	4	140.0	None	None
16W	0	3	1	2005	Baker RC	2	2	143.0	None	None
17W	0	2	1	2009	Baker RC-2	1	1	131.0	None	None
18W	0	1	1	2011	Baker RC-2	1	1	138.0	None	None
19W	0	4*	4*	2008	Baker RC-2	1	1	138.0	None	None
20W	0	4*	4*	1999	Baker RC	1	1	136.0	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AS	0	2	1	1991	Baker RC	1	1	131.0	None	None
1S	0	1	3	2002	Baker RC	1	1	127.0	None	None
2S	0	1	1	2004	Baker RC	1	1	139.0	None	None
3S	0	1	1	2010	Baker RC-2	1	1	139.0	None	None
4S	0	3	1	2004	Baker RC	1	1	140.0	None	None
5S	0	1	1	2004	Baker RC	1	1	140.0	None	None
6S	0	1	1	2010	Baker RC-2	1	1	141.0	None	None
7S	4	3	1	1993	Baker RC	1	1	139.0	None	None
8S	Rework	1	1	2014	Baker RC-2	1	1	135.0	None	None
9S	Rework	1	1	2014	Baker RC-2	1	1	140.0	None	None
10S	0	2	1	2010	Baker RC-2	1	1	142.0	None	None
11S	0	4	1	2009	Baker RC-2	1	1	142.0	None	None
12S	Rework	1	1	2014	Baker RC-2	1	1	135.0	None	None
13S	Rework	1	1	2014	Baker RC-2	1	1	142.0	None	None
14S	0	4*	1	1993	Baker RC	1	1	133.0	None	None
15S	0	2	1	2004	Baker RC	1	2	131.0	None	None
16S	0	2	1	2003	Baker RC	1	1	128.0	None	None
17S	0	1	1	2004	Baker RC	1	1	141.0	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher
- * Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher
- * Will not blowdown
- N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1N	0	1	1	2013	Baker RC-2	Out of Service		127.0	None	None
2N	0	3	4*	2013	Baker RC-2	1	0	138.0	None	None
3N	0	4	4*	2010	Baker RC-2	2	0	126.0	None	None
4N	0	4	1	2006	Baker RC-2	1	1	141.0	None	None
5N	0	1	1	2013	Baker RC-2	1	1	137.0	None	None
6N	0	4	1	2006	Baker RC-2	1	0	140.0	None	None
7N	4	1	1	2003	Baker RC	1	0	141.0	None	None
8N	Rework	1	1	2014	Baker RC-2	1	1	133.0	None	None
9N	0	2	4*	2006	Baker RC-2	1	0	141.0	None	None
10N	0	1	1	2013	Baker RC-2	Out of Service		139.0	None	None
11N	0	1	1	2013	Baker RC-2	1	1	133.0	None	None
12N	0	1	3	2000	Baker RC	1	1	130.0	None	None
13N	0	1	1	1985	Baker RC	1	1	133.0	None	None
15N	0	1	1	2012	Baker RC-2	1	0	131.0	None	None
16N	0	1	1	2010	Baker RC-2	1	1	133.0	None	None
17N	Rework	1	1	2014	Baker RC-2	1	1	133.0	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
Mcd-4	OBSERVATION WELL			N/A	N/A	135.0	None	None
Mcd-5A	N/A			2	2	122.0	None	None
Mcd-6	OBSERVATION WELL			N/A	N/A	134.0	None	None
Mcd-7	OBSERVATION WELL			N/A	N/A	134.0	None	None
Mcd-9	N/A			0	0	126.0	None	None
Mcd-10	N/A			2	0	122.0	None	None
Mcd-11	N/A			1	0	120.0	None	None
Mcd-12	N/A			3	0	123.0	None	None
Mcd-13	N/A			1	0	128.0	None	None
Mcd-14	N/A			1	0	126.0	None	None
Mcd-15	N/A			2	0	126.0	None	None
Rob-1	N/A			1	1	126.0	None	None
Rob-2	N/A			3	0	126.0	None	None
Tild-1	N/A			1	4	123.0	None	None
Zuck-1	OBSERVATION WELL			N/A	N/A	140.0	None	None
Zuck-3	N/A			0	1	124.0	None	None
Lil Mac-1	N/A			0	0	120.0	None	None
Zuck-Hen	OBSERVATION WELL			N/A	N/A	144.0	None	None

Observation Wells do not have both DHSVs and UHSVs

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
3-1	N/A			0	0	99.4	None	None
3-2	N/A			0	0	99.9	None	None
3-3	N/A			0	0	99.0	None	None
3-4	N/A			0	0	97.1	None	None
3-5	N/A			0	0	98.9	None	None
4-1	N/A			0	0	96.8	None	None
4-2	N/A			0	0	97.1	None	None

UHSV Rating System

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

N/A = No DHSV nor UHSV

Temperature & Noise Logs

None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

January 28, 2015

Ms. Joyce Jaszarowski
District Deputy
Natural Resources Agency of California
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street, MS 20-22
Sacramento, CA 95814-3530

Dear Ms. Joyce Jaszarowski:

Attached is the 2015 Yearly Well Evaluation Report for PG&E's underground gas storage fields. The report is summarized as follows:

<u>Down Hole Safety Valves (Subsurface Safety Devices)</u>

The Down Hole Safety Valves (DHSVs) installed in wells at Los Medanos and McDonald Island gas storage fields have been tested for reliable operation. We have found 35 of 89 wells through the testing at both storage fields that have ratings of 3 and 4, as compared to 54 wells in 2014. The wells at Pleasant Creek gas storage field do not have DHSVs.

At McDonald Island there are 28 DHSVs that have control line, tubing and/or casing valve ratings 3 and 4, as compared to 41 in 2014. Of the 28 DHSVs, 23 have a rating of 4. Four of these 23 DHSVs with rating of 4 are scheduled to be replaced in 2016.

The testing methodology of pressure build-up for the T5/RC2 type DHSVs was utilized to determine the proper ratings. The testing methodology for the T5/RC2 type DHSVs was changed as the volume meters previously utilized did not meet the pressure rating to safely perform the tests. A new meter is still being designed and tested to meet the required pressure rating and is anticipated to be used for the 2016 testing if it meets the functionality requirements.

At Los Medanos there are 7 DHSVs that have a control line, tubing and/or casing valve rating of 4 as compared to 7 in 2014. Two of these 7 DHSVs with a rating of 4 will be replaced in 2016.

<u>Casing Integrity Surveys</u>

Casing Integrity (Temperature and Noise) surveys have been performed in injection, withdrawal, and observation wells in all three PG&E owned and operated gas storage fields. It was observed on the log data that there are temperature and/or noise anomalies in four wells. One of the three wells displayed an apparent leak (Los Medanos Gino 3-7). The other three wells have no indications of apparent leaks.

Of note, based on the 2014 survey data, the Whisky Slough 1W had an indication of an apparent leak and PG&E in 2015 remediated the well with the installation and cementing of 7 inch flush joint casing inside the original 8-5/8 inch casing.

None of the wells at Los Medanos and Pleasant Creek have any temperature and/or noise anomalies except for Los Medanos Gino 3-7. The temperature and noise survey on Los Medanos well Gino 3-7 exhibited an apparent anomaly at approximately 4,080 feet which is suspected to be an opened sliding sleeve. A well assessment is planned in February 2016 to evaluate the condition of the sleeve and if necessary provide additional recommendations for evaluating the well integrity or remedial work.

In addition to running the temperature and noise surveys, Gamma Ray/Neutron logs were also run in 2 wells at McDonald Island gas storage field to establish a baseline log for identifying any behind the casing leaks. Review of the logs did not indicate any apparent gas accumulation behind casing due to casing leaks.

There are no temperature survey indications of fluid levels in any wells affecting the fresh water bearing formations.

Furthermore, electromagnetic casing inspection logs were run in 6 rework wells in 2015 as a means to detect casing pipe metal loss. The results indicated that there was no apparent metal loss in the casings any of the 6 wells that required remediation.

Up Hole Safety Valves (Surface Safety Devices)

All Up Hole Safety Valves (UHSVs) at Los Medanos, McDonald Island, and Pleasant Creek gas storage fields were tested for holding pressure and found that–28 of 217 UHSV's 25 UHSVs at McDonald Island, 3 at Los Medanos, and none at Pleasant Creek) had pressure buildup when closed. Maintenance will be performed on these valves to ensure reliable operation and, if necessary, the valves will be replaced.

PG&E's natural gas storage fields are subject to the exclusive jurisdiction of the Department of Transportation (49 CFR Part 192), which defines pipeline to mean all parts of those physical facilities through which gas moves in transportation, including pipe, valves and other appurtenance attached to the pipe, compressor units, metering stations, regulator stations, delivery station, holders, and fabricated assemblies. Further, the California Public Utility Commission ("CPUC") has issued Certificates of Public Convenience and Necessity that state that the facilities have been found to be needed for public necessity and convenience.

Please see the well evaluation report attachments to this report for details and included is a disk containing the noise temperature surveys conducted in 2014. If you have any questions, please call Adebola Okeowo at (925)-244-3162, Joseph Chan at 925-244-3207, or me at (925) 328-5890.

Sincerely,

Larry D. Kennedy Jr
Director, Gas Reservoir Engineering
Attachments

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1A	4	1	1	2007	RC-2	0*	0*	126.8	None	None
2A	4	1	1	2005	RC	0*	0*		Well Out Of Service	
3A	1	1	1	2000	RC	Leaked	0*	123.4	None	None
4B	0	4	1	2013	RC-2	0*	0*	127.1	None	None
5B	0	1	1	2013	RC-2	0*	0*	120.8	None	None
6B	0	1	1	2006	RC-2	0*	0*	125.4	None	None
7C	0	1	4**	1992	RC	0*	0*	120.0	None	None
8C	0	2	N/A	2012	T5 only	Leaked	N/A	129.5	None	None
9C	0	1	1	2011	RC-2	0*	0*	121.3	None	None
10C	0	1	4	2003	RC	0*	0*	122.3	None	None
11C	Rework	1	1	2015	RC-2	0*	0*	124.4	None	None
12C	4	1	4**	1991	RC	0*	0*	123.2	None	None
13C	1	1	1	1990	RC	0*	0*	127.1	None	None
14C	1	1	1	1990	RC	Leaked	0*	121.8	None	None
15C	1	1	1	1999	RC	0*	0*	125.3	None	None
16D	0	1	4	2004	RC	0*	0*	124.0	None	None
17D	1	1	1	1997	RC	0*	0*	124.0	None	None
18D	0	1	1	1992	RC	0*	0*	124.0	None	None
19D	1	1	1	2007	RC-2	0*	0*	124.4	None	None
20D	4	1	1	1990	RC	0*	0*	128.3	None	None
21D	Rework	1	1	2015	RC-2	0*	0*	125.4	None	None
Gino 3-7	N/A	Observation Well		N/A	N/A	N/A	N/A	134.4	4050.0	4080.0

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

RC-2 DHSV Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

** Will not blowdown

UHSV Rating System
1= ≤ 150 cu/ft-10 mins
4= > 150 cu/ft-10 mins

* No flow meter used

N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1AE	0	4	1	2009	Baker RC-2	1	1	127.6	None	None
1E	0	1	1	2005	Baker RC-2	3	1	139.4	None	None
2E	4*	1	1	2001	Baker RC	4	1	Out of Service		
3E	Rework	1	1	2015	Baker RC-2	Rework	Rework	136.8	None	None
4E	0	4	1	2007	Baker RC-2	1	1	134.7	None	None
5E	0	4	1	2012	Baker RC-2	2	1	131.8	None	None
6E	0	4	1	2007	Baker RC-2	4	1	129.6	None	None
7E	0	2	1	2012	Baker RC-2	4	1	129.8	None	None
8E	0	1	1	2012	Baker RC-2	2	1	140.1	None	None
9E	0	4	4*	2007	Baker RC-2	2	1	133.1	None	None
10E	OBSERVATION WELL			N/A	N/A	N/A	N/A	137.3	None	None
11E	0	1	1	2011	Baker RC-2	1	1	137.9	None	None
12E	0	2	1	2012	Baker RC-2	4*	1	140.6	None	None
13E	0	4	1	2005	Baker RC-2	3	1	139.6	None	None
14E	0	3	1	2005	Baker RC	4	1	140.1	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
1AW	4	2	4	2001	Baker RC	4	4	132.9	None	None
1W	Rework	1	1	2015	Baker RC-2	4	4	135.8	None	None
2W	0	2	1	2009	Baker RC-2	1	1	135.4	None	4200'-4600'
3W	0	1	1	2012	Baker RC-2	1	1	139.7	None	None
4W	0	4	1	2008	Baker RC-2	1	1	135.1	None	None
5W	0	4	1	1999	Baker RC	1	1	140.4	None	None
6W	0	1	1	2009	Baker RC-2	3	1	140.6	None	None
7W	0	1	1	2011	Baker RC-2	3	1	130.7	None	None
8W	0	4	1	2011	Baker RC-2	1	1	133.3	None	None
9W	0	2	1	1994	Baker RC	1	1	135.4	None	None
10W	0	1	1	1990	Baker RC	1	1	133.9	None	None
11W	0	1	1	1995	Baker RC	2	1	138.3	None	None
12W	1	1	1	2009	Baker RC-2	2	2	138.1	None	None
13W	0	4	1	2008	Baker RC-2	2	2	140.7	None	None
15W	0	4	1	2011	Baker RC-2	3	1	141.3	None	None
16W	0	3	1	2005	Baker RC	3	1	140.0	None	None
17W	0	2	1	2009	Baker RC-2	2	2	129.9	None	None
18W	0	2	1	2011	Baker RC-2	3	2	139.6	None	None
19W	0	4	4*	2008	Baker RC-2	4	0	137.4	None	None
20W	0	4	4*	1999	Baker RC	3	1	138.3	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1AS	0	1	1	1991	Baker RC	1	1	125.5	None	None
1S	0	1	1	2002	Baker RC	2	1	128.8	None	None
2S	0	2	2	2004	Baker RC	2	2	139.4	None	None
3S	0	1	1	2010	Baker RC-2	4	3	139.0	None	None
4S	0	3	1	2004	Baker RC	3	1	140.2	None	None
5S	0	1	1	2004	Baker RC	4	2	140.9	None	None
6S	0	2	1	2010	Baker RC-2	3	1	141.9	None	None
7S	0	3	1	1993	Baker RC	4	2	140.0	None	None
8S	0	2	1	2014	Baker RC-2	4	2	132.3	None	None
9S	0	1	1	2014	Baker RC-2	3	1	139.5	None	None
10S	0	3	1	2010	Baker RC-2	3	1	142.0	None	320'-380'
11S	0	4	1	2009	Baker RC-2	3	3	142.0	None	None
12S	0	4	1	2014	Baker RC-2	4	2	129.6	None	None
13S	0	4	3	2014	Baker RC-2	2	1	141.5	None	None
14S	Rework	1	1	2015	Baker RC-2	1	1	133.7	None	None
15S	Rework	1	1	2015	Baker RC-2	4	4	132.7	None	None
16S	0	2	1	2003	Baker RC	1	1	132.0	None	None
17S	0	1	1	2004	Baker RC	4	1	140.0	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
0: No leakage
1: 1 to 100 psig
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3: 201 to 300 psig
4: 301 or higher
* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
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4: 301 or higher
* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING					UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE	TUBING UHSV	CASING UHSV	MAX TEMP °	TEMP ANOMALIES	NOISE ANOMALIES
1N	0	1	1	2013	Baker RC-2	4	1	127.3	None	None
2N	0	4	4*	2013	Baker RC-2	1	1	141.8	None	None
3N	0	2	4*	2010	Baker RC-2	0	4	127.9	None	None
4N	0	3	1	2006	Baker RC-2	4	2	143.9	None	None
5N	0	1	1	2013	Baker RC-2	1	1	NA	None	None
6N	0	3	1	2006	Baker RC-2	1	1	141.9	None	None
7N	0	O/S	1	2003	Baker RC	1	1	143.5	None	None
8N	0	1	1	2014	Baker RC-2	3	2	132.8	None	1450-1750'
9N	0	1	1	2006	Baker RC-2	2	1	141.0	None	None
10N	0	1	1	2013	Baker RC-2	2	2	140.3	None	None
11N	0	1	1	2013	Baker RC-2	4	2	136.9	None	None
12N	0	1	0	2000	Baker RC	3	4	130.6	None	None
13N	0	1	1	1985	Baker RC	1	1	134.1	None	None
15N	0	1	4	2012	Baker RC-2	1	1	138.3	None	None
16N	0	1	1	2010	Baker RC-2	3	1	136.1	None	None
17N	0	1	1	2014	Baker RC-2	4	4	129.6	None	None

RC DHSV/ Control Line Rating *(Pressure Build-up/ 45 mins)*
- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

* Will not blowdown

RC-2 Dhsv Rating *(Flow test/ 10 mins)*
- **1:** ≤ 50.0 cu/ft
- **4:** > 50.0 cu/ft

UHSV Rating System
(Pressure Build-up/ 60 mins)
- **0:** No leakage
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Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
Mcd-4	OBSERVATION WELL			N/A	N/A	135.6	None	None
Mcd-5A	N/A			1	1	121.8	None	None
Mcd-6	OBSERVATION WELL			N/A	N/A	134.6	None	None
Mcd-7	OBSERVATION WELL			N/A	N/A	134.7	None	None
Mcd-9	N/A			0	0	125.7	None	None
Mcd-10	N/A			0	0	131.8	None	None
Mcd-11	N/A			0	1	129.5	None	None
Mcd-12	N/A			1	0	125.7	None	None
Mcd-13	N/A			0	0	124.8	None	None
Mcd-14	N/A			3	1	127.2	None	None
Mcd-15	N/A			2	1	127.9	None	None
Rob-1	N/A			1	0	127.5	None	None
Rob-2	N/A			0	0	127.9	None	None
Tild-1	N/A			0	0	122.2	None	None
Zuck-1	OBSERVATION WELL			N/A	N/A	138.4	None	None
Zuck-3	N/A			0	0	123.1	None	None
Lil Mac-1	N/A			0	0	112.7	None	None
Zuck-Hen	OBSERVATION WELL			N/A	N/A	141.9	None	None

Observation Wells do not have both DHSVs and UHSVs

UHSV Rating System
(Pressure Build-up/ 60 mins)
0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher
* Will not blowdown
N/A = No DHSV nor UHSV

Temperature & Noise Logs
None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

WELL	DHSV TESTING			UHSV TESTING		TEMPERATURE & NOISE LOGS		
	CONTROL LINE	TUBING DHSV	CASING DHSV	TUBING UHSV	CASING UHSV	MAX TEMP º	TEMP ANOMALIES	NOISE ANOMALIES
3-1	N/A			0	0	97.5	None	None
3-2	N/A			0	0	99.0	None	None
3-3	N/A			0	0	97.6	None	None
3-4	N/A			0	0	96.6	None	None
3-5	N/A			0	0	97.7	None	None
4-1	N/A			0	0	95.3	None	None
4-2	N/A			0	0	94.9	None	None

UHSV Rating System

- **0:** No leakage
- **1:** 1 to 100 psig
- **2:** 101 to 200 psig
- **3:** 201 to 300 psig
- **4:** 301 or higher

N/A = No DHSV nor UHSV

Temperature & Noise Logs

None = No Temperature nor Noise anomalies

Depth(s) = Indication of Temperature or Noise anomalies presence at that depth(s)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX H

INDEX FOR ANNUAL INVENTORY VERIFICATION REPORTS

FILES PROVIDED ON DVD

Storage Field	File Name
Los Medanos	2011_Los Medanos Inventory VerificationReport.pdf
McDonald Island	2012_McDonald Island Inventory Verification Report.pdf
Pleasant Creek	2012_Pleasant Creek Inventory Verification Report.pdf
Los Medanos	2013_Los Medanos Inventory Verification Report.pdf
McDonald Island	2013_McDonald Island Inventory Verification Report.pdf
Pleasant Creek	2013_Pleasant Creek Inventory Verification Report.pdf
All Fields Combined	2014_Inventory Verification Combined Reports.pdf
All Fields Combined	2015_Inventory Verification Combined Reports.pdf

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX I

2013-2015 DOWNHOLE SAFETY VALVE (DHSV) TEST DATA:

MCDONALD ISLAND & LOS MEDANOS

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

Thick Black Border indicates a component that failed initial testing and was retested. Retested results are shown.

LAN ID:			BMRJ	BMRJ		BMRJ	BMRJ	BMRJ	BMRJ			J01Y	J81M	J81M	J81M	J01Y
DATE:	8/29/13	8/6/13	10/2/13	10/2/13	7/21/13	10/2/13	10/3/13	10/3/13	10/3/13	7/1/13	6/12/13	7/27/13	7/27/13	7/27/13	7/27/13	7/27/13
WELL NUMBER:	1-N	2-N	3-N	4-N	5-N	6-N	7-N	8-N	9-N	10-N	11-N	12-N	13-N	15-N	16-N	17-N
TYPE OF DHSV:	RC-2	RC	RC-2	RC-2	RC	RC-2	RC	RC	RC-2	RC	RC-2	RC	RC	RC-2	RC-2	RC
DATE INSTALLED:	2013	2013	2010	2006	2013	2006	2003	2000	2006	2013	2013	2000	1985	2012	2010	2000
CTRL LINE SHUT-IN PRESSURE:	REWORK	REWORK	4100	4000	REWORK	4000	4000	4000	4200	REWORK	REWORK	3900	3850	3900	3900	3800
Control Line Pressure :05	WELL	WELL	4000	4000	WELL	4000	4000	4000	4200	WELL	WELL	3900	3850	3800	3900	3800
Control Line Pressure :10			4000	4000		4000	4000	4000	4200			3900	3850	3800	3900	3800
BLED CONTROL LINE PRESSURE TO:			0	0		0	0	0	0			0	0	0	0	0
GAS IN CONTROL LINE:			N	N		Y	N	Y	N			N	N	N	N	N
OUNCES OF FLUID RETURNED:			16	14		16	8	15	6			8	6			
Control Line Build-up :05	REWORK	REWORK	0	0	REWORK	0	0	0	0	REWORK	REWORK	0	0	0	0	0
Control Line Build-up :10	WELL	WELL	0	0	WELL	0	0	0	0	WELL	WELL	0	0	0	0	0
Control Line Build-up :15			0	0		0	0	0	0			0	0	0	0	0
Control Line Build-up :30			0	0		0	0	0	0			0	0	0	0	0
Control Line Build-up :45			0	0		0	0	0	0			0	0	0	0	0
TUBING SHUT-IN PRESSURE:			2031	2046		2046	1954	1936	1795			1961	1955	1958	1960	1953
BLED TUBING PRESSURE TO:			N/A	0		0	1454	1536	0			1405	1191	0	0	1433
CONTROL LINE PRESSURE:			0	0		0	0	0	0			0	0	0	0	0
Tubing pressure Build-up :05							1491	1605				1405	1199			1473
Control Line Pressure:							0	0				0	0			0
Tubing pressure Build-up :10							1514	1660				1407	120			1535
Control Line Pressure:	0.1	15.5		4.5	4.1	5.5	0	0	20.0	1.4	0.6	0	0	0.2	0.1	0
Tubing pressure Build-up :15	cu/ft	cu/ft	TUB WILL NOT	cu/ft	cu/ft	cu/ft	1534	1711	cu/ft	cu/ft	cu/ft	1424	1205	cu/ft	cu/ft	1562
Control Line Pressure:	10 mins	10 mins	BLOWDOWN	10 mins	10 mins	10 mins	0	0	10 mins	10 mins	10 mins	0	0	10 mins	10 mins	0
Tubing pressure Build-up :30							1597	1820				1438	1206			1664
Control Line Pressure:							0	0				0	0			0
Tubing pressure Build-up :45							1643	1896				1443	1207			1757
Control Line Pressure:							0	0				0	0			0
CASING SHUT-IN PRESSURE:			2032	2049		2048	2050	2030	2030			2037	1957	1955	1969	1953
BLED CASING PRESSURE TO:			N/A	0		0	1550	1530	0			1532	1465	0	0	1388
CONTROL LINE PRESSURE:			0	0		0	0	0	0			0	0	0	0	0
Casing pressure Build-up :05							1561	1600				1555	1482			1483
Control Line Pressure:							0	0				0	0			0
Casing pressure Build-up :10							1562	1656				1575	1493			1594
Control Line Pressure:	0.4	3.7		0.0	1.3	2.5	0	0	0.4	0.5	1.1	0	0	0.2	4.0	0
Casing pressure Build-up :15	cu/ft	cu/ft	CAS WILL NOT	cu/ft	cu/ft	cu/ft	1563	1708	cu/ft	cu/ft	cu/ft	1590	1499	cu/ft	cu/ft	1653
Control Line Pressure:	10 mins	10 mins	B/D	10 mins	10 mins	10 mins	0	0	10 mins	10 mins	10 mins	0	0	10 mins	10 mins	0
Casing pressure Build-up :30							1563	1846				1638	1505			1807
Control Line Pressure:							0	0				0	0			0
Casing pressure Build-up :45							1563	2035				1681	1506			1908
Control Line Pressure:							0	0				0	0			0

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

Thick Black Border indicates a component that failed initial testing and was retested. Retested results are shown.

LAN ID:	BMRJ	J81M	NEP3	BMRJ	BMRJ	J81M	NEP3	J81M	J81M	BMRJ	NEP3	J81M	BMRJ	BMRJ	NEP3	J81M	J81M	JJAP
DATE:	7/24/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/25/13	7/26/13	7/25/13	7/25/13	7/25/13	7/26/13	7/26/13	11/15/13
WELL NUMBER:	1-AS	1-S	2-S	3-S	4-S	5-S	6-S	7-S	8-S	9-S	10-S	11-S	12-S	13-S	14-S	15-S	16-S	17-S
TYPE OF DHSV:	RC	RC	RC	RC-2	RC	RC	RC-2	RC	RC-2	RC	RC-2	RC-2	RC-2	RC	RC	RC	RC	RC
DATE INSTALLED:	1991	2002	2004	2010	2004	2004	2010	1993	2007	2002	2010	2009	2007	1998	1993	2004	2003	2004
CTRL LINE SHUT-IN PRESSURE:	3800	3700	4200	3700	3700	3850	3700	3800	3850	3900	3800	3900	3800	3900	3800	3900	3900	3800
Control Line Pressure :05	3800	3700	4200	3700	3700	3800	3700	3800	3850	2500	3800	3900	3800	3800	3750	3900	3900	3800
Control Line Pressure :10	3800	3700	4200	3700	3700	3700	3700	3800	3850	1800	3800	3900	3800	3800	3750	3900	3900	3800
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	WILL	0	0	0	0	0	0	1	0
GAS IN CONTROL LINE:	N	Y	N	N	N	N	N	Y	N	NOT	N	N	Y	Y	Y	N	N	N
OUNCES OF FLUID RETURNED:	16	10	16	18	14	8	22	10	8	B/D	8	8	20	30	80	6	8	8
Control Line Build-up :05	0	100	0	0	0	0	0	0	0	2500	0	0	0	0	1900	0	0	0
Control Line Build-up :10	0	450	0	0	0	0	0	0	0	1800	0	0	100	0	2000	0	0	0
Control Line Build-up :15	0	675	0	0	0	0	0	0	0	1600	0	0	180	0	2000	0	0	0
Control Line Build-up :30	0	990	0	0	0	0	0	0	0	1600	0	0	210	0	2000	0	0	0
Control Line Build-up :45	0	1300	0	0	0	0	0	0	0	1500	0	0	300	0	2000	0	0	0
TUBING SHUT-IN PRESSURE:	2035	1960	1963	1962	2040	1964	1966	1964	1960	1966	1964	1964	1962	1962	2039	1957	1955	2045
BLED TUBING PRESSURE TO:	1520	1340	1400	0	1651	980	0	840	0	1460	0	0	0	1442	1500	833	1449	1490
CONTROL LINE PRESSURE:	0	1300	0	0	0	0	0	0	0	1400	0	0	0	0	2000	0	0	0
Tubing pressure Build-up :05	1527	1350	1440		1710	985		857		1503				1462	2039	836	1529	1492
Control Line Pressure:	0	1350	0		0	0		0		1400				0	2000	0	0	0
Tubing pressure Build-up :10	1529	1360	1482		1755	993		893		1522				1475	2039	853	1554	1495
Control Line Pressure:	0	1385	0	2.0	0	0	0.8	0	24.5	1400	3.8	26.6	0.3	0	2000	0	0	0
Tubing pressure Build-up :15	1530	1394	1496	cu/ft	1790	1008	cu/ft	929	cu/ft	1532	cu/ft	cu/ft	cu/ft	1485	2039	864	1587	1496
Control Line Pressure:	0	1400	0	10 mins	0	0	10 mins	0	10 mins	1400	10 mins	10 mins	10 mins	0	2000	0	0	0
Tubing pressure Build-up :30	1532	1406	1585		1868	1010		949		1564				1512	2039	882	1743	1499
Control Line Pressure:	0	1400	0		0	0		0		1400				0	2000	0	0	0
Tubing pressure Build-up :45	1533	1431	1640		1975	1015		988		1594				1524	2039	890	1958	1502
Control Line Pressure:	0	1400	0		0	0		0		1400				0	2000	0	0	0
CASING SHUT-IN PRESSURE:	1957	1959	1964	2044	1964	1965	1965	1966	1962	1967	1964	1965	1964	1964	1962	1958	1954	2049
BLED CASING PRESSURE TO:	1450	1369	1560	0	1460	1480	5	1490	0	1460	0	0	0	1464	1455	1452	1505	1510
CONTROL LINE PRESSURE:	0	1350	0	0	0	0	0	0	0	1400	0	0	0	0	0	0	0	0
Casing pressure Build-up :05	1460	1375	1566		1473	1492		1495		1466				1518	1456	1455	1547	1513
Control Line Pressure:	0	1385	0		0	0		0		1400				0	0	0	0	0
Casing pressure Build-up :10	1463	1427	1572		1476	1499		1498		1480				1552	1457	1462	1614	1515
Control Line Pressure:	0	1385	0	0.5	0	0	2.5	0	10.1	1400	4.4	15.6	4.4	0	0	0	0	0
Casing pressure Build-up :15	1467	1480	1579	cu/ft	1480	1507	cu/ft	1502	cu/ft	1481	cu/ft	cu/ft	cu/ft	1585	1460	1476	1626	1516
Control Line Pressure:	0	1400	0	10 mins	0	0	10 mins	0	10 mins	1400	10 mins	10 mins	10 mins	0	0	0	0	0
Casing pressure Build-up :30	1477	1520	1581		1482	1512		1505		1483				1673	1463	1482	1635	1518
Control Line Pressure:	0	1400	0		0	0		0		1400				0	0	0	0	0
Casing pressure Build-up :45	1485	1645	1582		1489	1518		1507		1484				1741	1463	1485	1644	1521
Control Line Pressure:	0	1400	0		0	0		0		1400				0	0	0	0	0

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

Thick Black Border indicates a component that failed initial testing and was retested. Retested results are shown.

LAN ID:	J01Y	J01Y	J4K1	J4K1	S9SY	S9SY	J4K1	J4K1	J01Y	J01Y	S9SY	S9SY	J01Y	J01Y
DATE:	3/27/13	3/27/13	3/27/13	3/27/13	3/27/13	3/27/13	3/28/13	3/28/13	3/28/13	3/28/13	3/28/13	3/28/13	3/28/13	3/28/13
WELL NUMBER:	1-AE	1-E	2-E	3-E	4-E	5-E	6-E	7-E	8-E	9-E	11-E	12-E	13-E	14-E
TYPE OF DHSV:	RC-2	RC-2	RC	RC	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC
DATE INSTALLED:	2009	2005	2001	2001	2007	2012	2007	2012	2012	2007	2011	2012	2005	2005
CTRL LINE SHUT-IN PRESSURE:	4200	4200	4250	4250	4100	4100	4100	4500	4200	4400	4100	4500	4150	4300
Control Line Pressure :05	4200	4200	4250	4250	4100	4100	4100	4500	4200	4400	4100	4500	4150	4300
Control Line Pressure :10	4200	4200	4250	4250	4100	4100	4100	4500	4200	4400	4100	4500	4150	4300
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	Y	N	Y	N	N	N	Y	N	N	N	N	N	Y
OUNCES OF FLUID RETURNED:	16	12	6	0	4	4	8	10	2	2	3	2	2	6
Control Line Build-up :05	0	0	0	500	0	0	0	0	0	0	0	0	0	0
Control Line Build-up :10	0	0	0	1000	0	0	0	0	0	0	0	0	0	0
Control Line Build-up :15	0	0	0	1500	0	0	0	0	0	0	0	0	0	0
Control Line Build-up :30	0	0	0	1700	0	0	0	0	0	0	0	0	0	0
Control Line Build-up :45	**0**	**0**	**0**	**1800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1767	1770	1767	1770	1768	1767	1781	1793	1769	1776	1764	1768	1760	1777
BLED TUBING PRESSURE TO:	0	0	1267	1234	0	0	0	0	0	0	0	0	0	1262
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up :05			1335	1253										1288
Control Line Pressure:			0	0										0
Tubing pressure Build-up :10			1362	1259										1318
Control Line Pressure:	11.0	1.0	0	0	5.0	35.0	10.0	18.0	25.0	10.0	0.0	22.0	1.0	0
Tubing pressure Build-up :15	cu/ft	cu/ft	1383	1260	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	1357
Control Line Pressure:	10 mins	10 mins	0	0	10 mins	10 mins	10 mins	10 mins	10 mins	10 mins	10 mins	10 mins	10 mins	0
Tubing pressure Build-up :30			1443	1270										1420
Control Line Pressure:			0	0										0
Tubing pressure Build-up :45			1494	1274										1480
Control Line Pressure:			0	0										0
CASING SHUT-IN PRESSURE:	1767	1770	1767	1770	1769	1767	779	1801	1772	1774	1762	1769	1760	1776
BLED CASING PRESSURE TO:	0	0	1278	1270	0	0	33	0	0	0	0	0	0	1268
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up :05			1282	1300										1281
Control Line Pressure:			0	0										0
Casing pressure Build-up :10			1286	1307										1282
Control Line Pressure:	0.0	19.0	0	0	4.0	29.0		0.0	12.0	1.0	2.0	2.0	19.0	0
Casing pressure Build-up :15	cu/ft	cu/ft	1290	1308	cu/ft	cu/ft	CAS WILL	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	cu/ft	1285
Control Line Pressure:	10 mins	10 mins	0	0	10 mins	10 mins	NOT B/D	10 mins	10 mins	10 mins	10 mins	10 mins	10 mins	0
Casing pressure Build-up :30			1300	1309										1285
Control Line Pressure:			0	0										0
Casing pressure Build-up :45			1302	1314										1287
Control Line Pressure:			0	0										0

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

Thick Black Border indicates a component that failed initial testing and was retested. Retested results are shown.

LAN ID:	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J01Y	J81M	S9SY	J01Y	S9SY	J81M	JUK	JUK	S9SY	S9SY
DATE:	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/3/13	4/1/13	4/1/13	4/1/13	3/29/13	3/29/13	3/29/13	3/29/13	3/29/13
WELL NUMBER:	1A-W	1-W	2-W	3-W	4-W	5-W	6-W	7-W	8-W	9-W	10-W	11-W	12-W	13-W	15-W	16-W	17-W	18-W	19-W	20-W
TYPE OF DHSV:	RC	RC-2	RC-2	RC-2	RC-2	RC	RC-2	RC-2	RC-2	RC	RC	RC	RC-2	RC-2	RC-2	RC	RC-2	RC-2	RC-2	RC
DATE INSTALLED:	2001	2008	2009	2012	2008	1999	2009	2011	2011	1994	1990	1995	2009	2008	2011	2005	2009	2011	2008	1999
CTRL LINE SHUT-IN PRESSURE:	1000	4700	4700	4600	4600	4600	4300	4200	4200	4500	4450	4250	4400	4200	4100	4100	4100	4100	4100	4100
Control Line Pressure :05	1000	4700	4700	4600	4600	4600	4300	4200	4200	4500	4450	4250	4400	4200	4100	4100	4100	4100	4100	4100
Control Line Pressure :10	1000	4700	4700	4600	4600	4600	4300	4200	4200	4500	4450	4250	4400	4200	4100	4100	4100	4100	4100	4100
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	N	N	N	N	Y	Y	N	N	Y	N	N	Y	N	N	Y	Y	N	N	N
OUNCES OF FLUID RETURNED:	8	2	2	4	2	12	4	1	5	10	4	3	12	2	3	3	2	2	5	10
Control Line Build-up :05	0	0	0	0	0	0	0	0	0	0	0	0	1790	0	0	0	0	0	0	0
Control Line Build-up :10	0	0	0	0	0	0	0	0	0	0	0	0	1790	0	0	0	0	0	0	0
Control Line Build-up :15	0	0	0	0	0	0	0	0	0	0	0	0	1790	0	0	0	0	0	0	0
Control Line Build-up :30	0	0	0	0	0	0	0	0	0	0	0	0	1790	0	0	0	0	0	0	0
Control Line Build-up :45	0	0	0	0	0	0	0	0	0	0	0	0	1790	0	0	0	0	0	0	0
TUBING SHUT-IN PRESSURE:	1790	2033	1806	1820	1800	1806	1805	1814	1792	1798	1798	1802	1789	1797	1838	1776	1778	1766	2040	1803
BLED TUBING PRESSURE TO:	1250	0	0	0	2	1269	0	0	0	1200	1190	1094	0	0	0	1222	1	3	0	1300
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up :05	1256					1325				1228	1207	1107				1382				1380
Control Line Pressure:	0					0				0	0	0				0				0
Tubing pressure Build-up :10	1258					1380				1248	1209	1116				1519				1430
Control Line Pressure:	0	10 3	0 0	23 7	19 0	0	0 0	12 0	9 0	0	0	0	8 0	0 0	1 0	0	14 0	50 0	13 1	0
Tubing pressure Build-up :15	1270	cu/ft	cu/ft	cu/ft	cu/ft	1481	cu/ft	cu/ft	cu/ft	1257	1209	1121	cu/ft	cu/ft	cu/ft	1679	cu/ft	cu/ft	cu/ft	1465
Control Line Pressure:	0	10 mins	10 mins	10 mins	10 mins	0	10 mins	10 mins	10 mins	0	0	0	10 mins	10 mins	10 mins	0	10 mins	10 mins	10 mins	0
Tubing pressure Build-up :30	1301					1605				1269	1209	1128				1777				1520
Control Line Pressure:	0					0				0	0	0				0				0
Tubing pressure Build-up :45	1337					1637				1281	1210	1129				1778				1545
Control Line Pressure:	0					0				0	0	0				0				0
CASING SHUT-IN PRESSURE:	1792	1801	1805	1820	2040	1802	1799	1803	1792	1797	1795	1798	1795	1797	1835	1772	1773	1766	1812	1805
BLED CASING PRESSURE TO:	1290	5	6	0	N/A	1207	0	0	21	1294	1133	1227	0	3	0	1255	3	2	0	1160
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up :05	1450					1219				1310	1147	1238				1257				1160
Control Line Pressure:	0					0				0	0	0				0				0
Casing pressure Build-up :10	1512					1221				1313	1149	1242				1259				1160
Control Line Pressure:	0	44 0	18 0	38 5		0	10 0	3 0	10 0	0	0	0	2 0	11 0	21 0	0	30 0	19 0	3 0	0
Casing pressure Build-up :15	1572	cu/ft	cu/ft	cu/ft	CAS WILL	1224	cu/ft	cu/ft	cu/ft	1314	1151	1244	cu/ft	cu/ft	cu/ft	1265	cu/ft	cu/ft	cu/ft	1160
Control Line Pressure:	0	10 mins	10 mins	10 mins	NOT B/D	0	10 mins	10 mins	10 mins	0	0	0	10 mins	10 mins	10 mins	0	10 mins	10 mins	10 mins	0
Casing pressure Build-up :30	1648					1226				1315	1154	1248				1266				1160
Control Line Pressure:	0					0				0	0	0				0				0
Casing pressure Build-up :45	1720					1227				1315	1154	1249				1267				1160
Control Line Pressure:	0					0				0	0	0				0				0

2014 McDonald Island Downhole Safety Valve Testing

Turner Cut Station North Wells

LAN ID:	BMRj	BMRj	BMRj	BMRj	BMRj	BMRj	NEP3	REWORK	BMRj	NEP3	BMRj	BMRj	BMRj	NEP3	JIMR	REWORK
DATE:	7/21/14	7/24/14	7/24/14	7/24/14	7/24/14	11/4/14	11/4/14	8/11/14	11/4/14	11/4/14	7/23/14	7/23/14	7/22/14	11/6/14	11/10/14	8/25/14
WELL NUMBER:	1-N	2-N	3-N	4-N	5-N	6-N	7-N	8-N	9-N	10-N	11-N	12-N	13-N	15-N	16-N	17-N
BAKER MODEL DHSV:	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC	RC-2	RC-2	RC	RC-2	RC	RC	RC-2	RC-2	RC-2
DATE INSTALLED:	2013	2013	2010	2006	2013	2006	2003	2014	2006	2013	2013	2000	1985	2012	2010	2014
CTRL LINE SHUT-IN PRESSURE:	4100	4000	4100	3900	3900	3900	3850		4100	4000	3900	3900	4000	4100	3800	
Control Line Pressure **:05**	4100	4000	4100	3900	3900	3900	3850		4100	4000	3900	3800	3900	4100	3800	
Control Line Pressure **:10**	4100	4000	4100	3900	3900	3900	3850		4100	4000	3900	3800	3900	4100	3800	
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0		0	0	0	0	0	200	0	
GAS IN CONTROL LINE:	Y	N	N	N	Y	N	Y		Y	N	Y	N	N	N	N	
OUNCES OF FLUID RETURNED:	28	16	3	4	162	28	28		16	4	4	8	8	5	20	
Control Line Build-up **:05**	0	0	0	0	0	0	0		0	0	0	0	0	200	0	
Control Line Build-up **:10**	0	0	0	0	0	0	0		0	0	0	0	0	200	0	
Control Line Build-up **:15**	0	0	0	0	0	0	200		0	0	0	0	0	200	0	
Control Line Build-up **:30**	0	0	0	0	0	0	400		0	0	0	0	0	200	0	
Control Line Build-up **:45**	0	0	0	0	0	0	500		0	0	0	0	0	200	0	
TUBING SHUT-IN PRESSURE:	1668	1673	1675	1675	1673	1851	1856	1708	1854	1851	1665	1671	1668	1844	1825	1612
BLED TUBING PRESSURE TO:	1168	1173	1175	1175	1173	1350	1286	0	1350	1350	1165	1170	1168	1332	1340	0
CONTROL LINE PRESSURE:	0	0	0	0	0	0	1600	0	0	0	0	0	0	200	0	0
Tubing pressure Build-up **:05**	1227	1226	1243	1279	1198	1425	1319		1402	1428	1187	1197	1189	1347	1355	
Control Line Pressure:	0	0	0	0	0	0	1850		0	0	0	0	0	200	0	
Tubing pressure Build-up **:10**	1270	1257	1241	1349	1199	1482	1330		1426	1480	1194	1206	1193	1355	1370	
Control Line Pressure:	0	0	0	0	0	0	1850		0	0	0	0	0	200	0	
Tubing pressure Build-up **:15**	1313	1290	1325	1425	1200	1527	1334	0.43 cu/ft 10 mins	1444	1529	1199	1213	1196	1358	1380	0.10 cu/ft 10 mins
Control Line Pressure:	0	0	0	0	0	0	1850		0	0	0	0	0	200	0	
Tubing pressure Build-up **:30**	1441	1382	1425	1629	1200	1668	1344		1501	1667	1214	1225	1202	1362	1382	
Control Line Pressure:	0	0	0	0	0	0	1850		0	0	0	0	0	200	0	
Tubing pressure Build-up **:45**	1510	1469	1521	1675	1201	1792	1360		1558	1748	1227	1236	1207	1364	1385	
Control Line Pressure:	0	0	0	0	0	0	1850		0	0	0	0	0	200	0	
CASING SHUT-IN PRESSURE:	1669	1675	1675	1675	1673	1852	1856	1669	1854	1851	1667	1675	1668	1846	1847	1664
BLED CASING PRESSURE TO:	1150	N/A	N/A	1175	1173	1315	1360	0	N/A	1358	1167	1175	1168	1337	1370	0
CONTROL LINE PRESSURE:	0	0	0	0	0	0	1850	0	0	0	0	0	0	200	0	0
Casing pressure Build-up **:05**	1160			1183	1192	1320	1375			1386	1186	1212	1180	1344	1388	
Control Line Pressure:	0			0	0	0	1850			0	0	0	0	200	0	
Casing pressure Build-up **:10**	1161			1185	1194	1323	1380			1392	1187	1240	1183	1347	1391	
Control Line Pressure:	0			0	0	0	1850			0	0	0	0	200	0	
Casing pressure Build-up **:15**	1163	CAS WILL NOT BLOWDOWN	CAS WILL NOT BLOWDOWN	1188	1195	1325	1382	0.59 cu/ft 10 mins	CAS WILL NOT BLOWDOWN	1394	1189	1266	1185	1348	1392	1.04 cu/ft 10 mins
Control Line Pressure:	0			0	0	0	1850			0	0	0	0	200	0	
Casing pressure Build-up **:30**	1165			1188	1198	1330	1389			1397	1190	1351	1186	1350	1393	
Control Line Pressure:	0			0	0	0	1850			0	0	0	0	200	0	
Casing pressure Build-up **:45**	1167			1189	1200	1335	1395			1398	1192	1420	1186	1353	1395	
Control Line Pressure:	0			0	0	0	1850			0	0	0	0	200	0	

2014 McDonald Island Downhole Safety Valve Testing

Turner Cut Station North Wells

	DAO6	**DAO6**	**rbq1**	**DAO6**
RETEST- DATE:	1/12/15	1/16/15	1/15/15	1/14/15
WELL NUMBER:	**1-N**	**2-N**	**9-N**	**10-N**
BAKER MODEL DHSV:	**RC-2**	**RC-2**	**RC-2**	**RC-2**
DATE INSTALLED:	2013	2013	2006	2013
CTRL LINE SHUT-IN PRESSURE:	4100	4000	4100	4000
Control Line Pressure **:05**	4100	4000	4100	4000
Control Line Pressure **:10**	4100	4000	4100	4000
BLED CONTROL LINE PRESSURE TO:	0	0	0	0
GAS IN CONTROL LINE:	Y	N	Y	N
OUNCES OF FLUID RETURNED:	28	16	16	4
Control Line Build-up **:05**	0	0	0	0
Control Line Build-up **:10**	0	0	0	0
Control Line Build-up **:15**	0	0	0	0
Control Line Build-up **:30**	0	0	0	0
Control Line Build-up **:45**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1621	1673	1854	1618
BLED TUBING PRESSURE TO:	0	1173	1350	0
CONTROL LINE PRESSURE:	0	0	0	0
Tubing pressure Build-up **:05**	0.5	1226	1402	0.1
Control Line Pressure:	0	0	0	0
Tubing pressure Build-up **:10**	1.2	1257	1426	1.7
Control Line Pressure:	0	0	0	0
Tubing pressure Build-up **:15**	1.7	1290	1444	3.9
Control Line Pressure:	0	0	0	0
Tubing pressure Build-up **:30**	2.4	1382	1501	10.8
Control Line Pressure:	0	0	0	0
Tubing pressure Build-up **:45**	3	1469	1558	18
Control Line Pressure:	0	0	0	0
CASING SHUT-IN PRESSURE:	1669	1589	1597	1851
BLED CASING PRESSURE TO:	1150	1589	1087	1358
CONTROL LINE PRESSURE:	0	0	0	0
Casing pressure Build-up **:05**	1160		1091	1386
Control Line Pressure:	0		0	0
Casing pressure Build-up **:10**	1161		1092	1392
Control Line Pressure:	0		0	0
Casing pressure Build-up **:15**	1163	CAS WILL NOT BLOWDOWN	1093	1394
Control Line Pressure:	0		0	0
Casing pressure Build-up **:30**	1165		1094	1397
Control Line Pressure:	0		0	0
Casing pressure Build-up **:45**	1167		1094	1398
Control Line Pressure:	0		0	0

2014 McDonald Island Downhole Safety Valve Testing
Turner Cut Station Sou h Wells

LAN ID:	BMRj	NEP3	BMRj	NEP3	BMRj	BMRj	NEP3	JIMR	REWORK	REWORK	NEP3	JIMR	REWORK	REWORK	BMRj	NEP3	BMRj	NEP3
DATE:	8/1/14	8/1/14	8/1/14	7/31/14	7/31/14	7/31/14	7/31/14	11/6/14	9/5/14	9/18/14	11/6/14	11/6/14	9/30/14	10/16/14	7/30/14	7/30/14	7/29/14	7/29/14
WELL NUMBER:	**1-AS**	**1-S**	**2-S**	**3-S**	**4-S**	**5-S**	**6-S**	**7-S**	**8-S**	**9-S**	**10-S**	**11-S**	**12-S**	**13-S**	**14-S**	**15-S**	**16-S**	**17-S**
BAKER MODEL DHSV:	**RC**	**RC**	**RC**	**RC-2**	**RC**	**RC**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC**	**RC**	**RC**
DATE INSTALLED:	1991	2002	2004	2010	2004	2004	2010	1993	2014	2014	2010	2009	2014	2014	1993	2004	2003	2004
CTRL LINE SHUT-IN PRESSURE:	3700	3700	4000	3800	3600	3900	3900	3600			3850	3800			4100	4350	4200	4100
Control Line Pressure **:05**	3700	3700	4000	3800	3600	3900	3900	3600			3850	3800			4100	4350	4200	4100
Control Line Pressure **:10**	3700	3700	4000	3800	3600	3900	3900	3600			3850	3800			4100	4350	4200	4100
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0			0	0			0	0	0	0
GAS IN CONTROL LINE:	N	N	N	N	N	Y	N	N			N	N			Y	N	Y	N
OUNCES OF FLUID RETURNED:	16	30	30	20	6	16	50	21			22	22			48	10	30	32
Control Line Build-up **:05**	0	0	0	0	0	1700	0	0			0	0			0	0	0	0
Control Line Build-up **:10**	0	0	0	0	0	1700	0	0			0	0			0	0	0	0
Control Line Build-up **:15**	0	0	0	0	0	1700	0	0			0	0			0	0	0	0
Control Line Build-up **:30**	0	0	0	0	0	1700	0	0			0	0			0	0	0	0
Control Line Build-up **:45**	0	0	0	0	0	1700	0	0			0	0			0	0	0	0
TUBING SHUT-IN PRESSURE:	1676	1680	1680	1684	1681	1681	1682	1854	1550	1628	1851	1845	1486	1745	1678	1680	1678	1682
BLED TUBING PRESSURE TO:	1176	1170	1180	N/A	1181	1181	1140	1339	0	0	1328	1340	0	0	N/A	1035	1180	1170
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**	1198	1197	1215		1220	1210	1155	1387			1360	1359				1055	1240	1186
Control Line Pressure:	0	0	0		0	0	0	0			0	0				0	0	0
Tubing pressure Build-up **:10**	1223	1203	1227		1267	1215	1164	1427			1389	1420				1070	1262	1189
Control Line Pressure:	0	0	0		0	0	0	0	1 88	0 20	0	0	0 50	6 90		0	0	0
Tubing pressure Build-up **:15**	1242	1212	1236	TUB WILL NOT BLOWDOWN	1315	1217	1175	1453	cu/ft	cu/ft	1418	1490	cu/ft	cu/ft	TUB WILL NOT BLOWDOWN	1085	1281	1190
Control Line Pressure:	0	0	0		0	0	0	0	10 mins	10 mins	0	0	10 mins	10 mins		0	0	0
Tubing pressure Build-up **:30**	1300	1227	1257		1434	1220	1195	1535			1482	1655				1140	1329	1191
Control Line Pressure:	0	0	0		0	0	0	0			0	0				0	0	0
Tubing pressure Build-up **:45**	1350	1240	1277		1475	1222	1209	1584			1505	1821				1200	1378	1192
Control Line Pressure:	0	0	0		0	0	0	0			0	0				0	0	0
CASING SHUT-IN PRESSURE:	1678	1680	1681	1680	1681	1680	1681	1851	1592	1574	1851	1844	1599	1720	1675	1680	1676	1682
BLED CASING PRESSURE TO:	1178	1170	1180	1180	1181	1180	1138	1361	0	0	1350	1340	0	0	1175	1172	1175	1180
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:05**	1131	1219	1188	1203	1195	1194	1146	1373			1362	1351			1187	1181	1190	1190
Control Line Pressure:	0	0	0	0	0	0	0	0			0	0			0	0	0	0
Casing pressure Build-up **:10**	1133	1246	1190	1214	1197	1196	1155	1377			1365	1353			1189	1184	1200	1192
Control Line Pressure:	0	0	0	0	0	0	0	0	0 00	0 00	0	0	0 00	0 00	0	0	0	0
Casing pressure Build-up **:15**	1135	1272	1191	1221	1198	1198	1158	1379	cu/ft	cu/ft	1368	1355	cu/ft	cu/ft	1190	1185	1213	1194
Control Line Pressure:	0	0	0	0	0	0	0	0	10 mins	10 mins	0	0	10 mins	10 mins	0	0	0	0
Casing pressure Build-up **:30**	1141	1339	1194	1243	1199	1201	1159	1382			1372	1358			1191	1189	1237	1196
Control Line Pressure:	0	0	0	0	0	0	0	0			0	0			0	0	0	0
Casing pressure Build-up **:45**	1146	1398	1195	1263	1199	1204	1160	1387			1378	1362			1192	1192	1261	1198
Control Line Pressure:	0	0	0	0	0	0	0	0			0	0			0	0	0	0

	rbq1
RETEST- DATE:	1/14/15
WELL NUMBER:	**3-S**
BAKER MODEL DHSV:	**RC-2**
DATE INSTALLED:	2010
CTRL LINE SHUT-IN PRESSURE:	3800
Control Line Pressure **:05**	3800
Control Line Pressure **:10**	3800
BLED CONTROL LINE PRESSURE TO:	0
GAS IN CONTROL LINE:	N
OUNCES OF FLUID RETURNED:	20
Control Line Build-up **:05**	0
Control Line Build-up **:10**	0
Control Line Build-up **:15**	0
Control Line Build-up **:30**	0
Control Line Build-up **:45**	**0**
TUBING SHUT-IN PRESSURE:	1601
BLED TUBING PRESSURE TO:	1100
CONTROL LINE PRESSURE:	0
Tubing pressure Build-up **:05**	1102
Control Line Pressure:	0
Tubing pressure Build-up **:10**	1104
Control Line Pressure:	0
Tubing pressure Build-up **:15**	1108
Control Line Pressure:	0
Tubing pressure Build-up **:30**	1113
Control Line Pressure:	0
Tubing pressure Build-up **:45**	1119
Control Line Pressure:	0
CASING SHUT-IN PRESSURE:	1680
BLED CASING PRESSURE TO:	1180
CONTROL LINE PRESSURE:	0
Casing pressure Build-up **:05**	1203
Control Line Pressure:	0
Casing pressure Build-up **:10**	1214
Control Line Pressure:	0
Casing pressure Build-up **:15**	1221
Control Line Pressure:	0
Casing pressure Build-up **:30**	1243
Control Line Pressure:	0
Casing pressure Build-up **:45**	1263
Control Line Pressure:	0

2014 McDonald Island Downhole Safety Valve Testing
Whisky Slough Station East Wells

LAN ID:	NEP3	NEP3	NEP3	NOT TESTED	NEP3	BMRj	NEP3	NEP3	BMRj	BMRj	NEP3	BMRj	BMRj	NEP3
DATE:	8/5/14	8/5/14	8/8/14		8/6/14	8/6/14	8/6/14	8/7/14	8/7/14	8/7/14	8/7/14	8/7/14	8/8/14	8/8/14
WELL NUMBER:	1-AE	1-E	2-E	3-E	4-E	5-E	6-E	7-E	8-E	9-E	11-E	12-E	13-E	14-E
BAKER MODEL DHSV:	RC-2	RC-2	RC	RC	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC
DATE INSTALLED:	2009	2005	2001	2001	2007	2012	2007	2012	2012	2007	2011	2012	2005	2005
CTRL LINE SHUT-IN PRESSURE:	4100	4100	4350		4000	4100	4050	4150	4100	4500	4500	4350	4150	4150
Control Line Pressure **:05**	4100	4100	4500	WELL O/S	4000	4100	4050	4150	4100	4500	4500	4500	4150	4150
Control Line Pressure **:10**	4100	4100	4500		4000	4100	4050	4150	4100	4500	4500	4500	4150	4150
BLED CONTROL LINE PRESSURE TO:	0	0	0		0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	N	Y		Y	N	N	N	N	N	N	N	N	Y
OUNCES OF FLUID RETURNED:	20	16	2	CTRL LINE LEAKS DOWN HOLE	6	3	4	6	2	28	4	33	2	26
Control Line Build-up **:05**	0	0	0		0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:10**	0	0	500		0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:15**	0	0	500		0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:30**	0	0	500		0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:45**	0	0	500		0	0	0	0	0	0	0	0	0	0
TUBING SHUT-IN PRESSURE:	1696	1700	1707		1710	1703	1698	1700	1698	1703	1705	1706	1708	1700
BLED TUBING PRESSURE TO:	1550	1200	1200		1210	1203	1180	1218	1200	1200	1185	1200	1200	1185
CONTROL LINE PRESSURE:	0	0	500		0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**		1443	1248		1681	1457	1276	1405	1392	1490	1212	1295	1305	1240
Control Line Pressure:		0	500		0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:10**		1465	1211	WELL O/S DID NOT TEST	1693	1634	1380	1431	1412	1703	1231	1380	1370	1300
Control Line Pressure:		0	500		0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:15**	TUB WILL NOT BLOWDOWN	1508	1213		1701	1684	1468	1447	1427	1703	1245	1447	1427	1360
Control Line Pressure:		0	1000		0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:30**		1608	1216		1701	1697	1637	1489	1466	1703	1284	1604	1598	1480
Control Line Pressure:		0	1000		0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:45**		1665	1465		1701	1697	1682	1530	1498	1703	1306	1700	1696	1610
Control Line Pressure:		0	1000		0	0	0	0	0	0	0	0	0	0
CASING SHUT-IN PRESSURE:	1701	1702	1775		1710	1705	1708	1700	1700	1703	1710	1703	1709	1705
BLED CASING PRESSURE TO:	1200	1204	1200		1210	1205	1208	1215	N/A	1200	1200	1200	1200	1208
CONTROL LINE PRESSURE:	0	0	500		0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:05**	1240	1225	1209		1229	1221	1226	1226		1216	1212	1216	1210	1224
Control Line Pressure:	0	0	500		0	0	0	0		0	0	0	0	0
Casing pressure Build-up **:10**	1266	1227	1211	WELL O/S DID NOT TEST	1238	1226	1231	1229		1218	1215	1218	1212	1226
Control Line Pressure:	0	0	500		0	0	0	0		0	0	0	0	0
Casing pressure Build-up **:15**	1291	1230	1213		1240	1230	1236	1230	CAS WILL NOT B/D	1219	1218	1219	1213	1228
Control Line Pressure:	0	0	500		0	0	0	0		0	0	0	0	0
Casing pressure Build-up **:30**	1364	1238	1216		1252	1239	1249	1232		1223	1222	1221	1214	1230
Control Line Pressure:	0	0	500		0	0	0	0		0	0	0	0	0
Casing pressure Build-up **:45**	1436	1280	1218		1261	1241	1263	1234		1223	1228	1222	1213	1233
Control Line Pressure:	0	0	500		0	0	0	0		0	0	0	0	0

2014 McDonald Island Downhole Safety Valve Testing
Whisky Slough Station East Wells

	DAO6	DAO6	DAO6	JJAP	JJAP	DAO6	rbq1	rbq1	rbq1	rbq1	rbq1
RETEST- DATE:	12/10/14	12/10/14	12/16/14	12/16/14	12/18/14	12/24/14	12/18/14	12/18/14	12/16/14	12/10/14	12/10/14
WELL NUMBER:	1-AE	1-E	4-E	5-E	6-E	7-E	8-E	9-E	12-E	13-E	14-E
BAKER MODEL DHSV:	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC
DATE INSTALLED:	2009	2005	2007	2012	2007	2012	2012	2007	2012	2005	2005
CTRL LINE SHUT-IN PRESSURE:	4100	4100	4100	4100	4050	4150	4100	4500	4350	4150	4150
Control Line Pressure **:05**	4100	4100	4100	4100	4050	4150	4100	4500	4500	4150	4150
Control Line Pressure **:10**	4100	4100	4100	4100	4050	4150	4100	4500	4500	4150	4150
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	N	Y	N	N	N	N	N	N	N	Y
OUNCES OF FLUID RETURNED:	20	16	6	3	4	6	2	28	33	2	26
Control Line Build-up **:05**	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:10**	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:15**	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:30**	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:45**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1786	1805	1764	1750	1754	1783	1698	1756	1781	1802	1789
BLED TUBING PRESSURE TO:	1284	1270	1260	1245	1248	1279	1200	1250	1278	1300	1291
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**	1363	1287	1380	1292	1310	1322	1392	1338	1325	1401	1349
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:10**	1429	1295	1493	1356	1350	1361	1412	1393	1370	1510	1396
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:15**	1492	1303	1611	1420	1390	1397	1427	1455	1425	1603	1446
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:30**	1735	1318	1764	1612	1482	1492	1466	1756	1521	1769	1577
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:45**	1786	1336	1764	1750	1563	1578	1498	1756	1635	1790	1701
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
CASING SHUT-IN PRESSURE:	1701	1702	1710	1705	1708	1700	1757	1703	1703	1709	1705
BLED CASING PRESSURE TO:	1200	1204	1210	1205	1208	1215	1254	1200	1200	1200	1208
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:05**	1240	1225	1229	1221	1226	1226	1262	1216	1216	1210	1224
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:10**	1266	1227	1238	1226	1231	1229	1264	1218	1218	1212	1226
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:15**	1291	1230	1240	1230	1236	1230	1265	1219	1219	1213	1228
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:30**	1364	1238	1252	1239	1249	1232	1268	1223	1221	1214	1230
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:45**	1436	1280	1261	1241	1263	1234	1271	1223	1222	1213	1233
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0

2014 McDonald Island Downhole Safety Valve Testing
Whisky Slough Station West Wells

LAN ID:	BMRj	NEP3	BMRj	NEP3	BMRj	NEP3	BMRj	BMRj	NEP3	BMRj	BMRj	NEP3	BMRj	NEP3	BMRj	NEP3	NEP3	BMRj	NEP3	BMRj
DATE:	8/11/14	8/11/14	8/11/14	8/11/14	8/12/14	8/12/14	8/12/14	8/12/14	8/13/14	8/13/14	8/13/14	8/13/14	8/14/14	8/14/14	8/14/14	8/14/14	8/15/14	8/15/14	8/15/14	8/15/14
WELL NUMBER:	**1A-W**	**1-W**	**2-W**	**3-W**	**4-W**	**5-W**	**6-W**	**7-W**	**8-W**	**9-W**	**10-W**	**11-W**	**12-W**	**13-W**	**15-W**	**16-W**	**17-W**	**18-W**	**19-W**	**20-W**
BAKER MODEL DHSV:	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**
DATE INSTALLED:	2001	2008	2009	2012	2008	1999	2009	2011	2011	1994	1990	1995	2009	2008	2011	2005	2009	2011	2008	1999
CTRL LINE SHUT-IN PRESSURE:	4100	4200	4400	4400	4200	4300	4500	4500	4000	4100	4200	4250	4000	3900	4200	4200	3950	4000	0	4200
Control Line Pressure **:05**	3700	4200	4400	4400	4200	4300	4500	4500	4000	4100	4200	4250	4000	3900	4200	4200	3950	4000	0	4200
Control Line Pressure **:10**	3700	4200	4400	4400	4200	4300	4500	4500	4000	4100	4200	4250	4000	3900	4200	4200	3950	4000	0	4200
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	Y	Y	N	Y	Y	N	N	N	Y	N	N	N	N	N	Y	Y	N	N	N
OUNCES OF FLUID RETURNED:	32	4	30	5	16	32	4	3	16	30	28	6	30	12	2	12	16	13	0	2
Control Line Build-up :05	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0	0	0	0
Control Line Build-up :10	0	0	0	0	0	0	0	0	0	0	0	0	200	0	0	0	0	0	0	0
Control Line Build-up :15	0	0	0	0	0	0	0	0	0	0	0	0	600	0	0	0	0	0	0	0
Control Line Build-up :30	0	0	0	0	0	0	0	0	0	0	0	0	800	0	0	0	0	0	0	0
Control Line Build-up :45	0	0	0	0	0	0	0	0	0	0	0	0	1100	0	0	0	0	0	0	0
TUBING SHUT-IN PRESSURE:	1724	1682	1722	1725	1723	1720	1722	1720	1721	1721	1720	1720	1724	1724	1722	1722	1724	1722	1720	1720
BLED TUBING PRESSURE TO:	1224	1184	1152	1225	1220	1220	1222	1220	1220	1220	1220	1220	1224	1224	1222	1220	1190	1205	N/A	N/A
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	1100	0	0	0	0	0	0	0
Tubing pressure Build-up :05	1258	1360	1183	1249	1390	1306	1255	1389	1330	1265	1278	1242	1254	1470	1341	1302	1208	1220		
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	1400	0	0	0	0	0		
Tubing pressure Build-up :10	1268	1452	1208	1263	1563	1353	1263	1485	1450	1282	1315	1250	1258	1644	1405	1360	1227	1232		
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	1400	0	0	0	0	0		
Tubing pressure Build-up :15	1275	1535	1248	1270	1671	1398	1270	1497	1574	1297	1345	1257	1261	1719	1456	1397	1240	1246	TUB WILL NOT BLOWDOWN	TUB WILL NOT BLOWDOWN
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	1400	0	0	0	0	0		
Tubing pressure Build-up :30	1291	1625	1310	1286	1720	1482	1283	1512	1720	1335	1425	1274	1265	1722	1557	1457	1270	1270		
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
Tubing pressure Build-up :45	1315	1644	1369	1301	1720	1616	1295	1524	1720	1378	1496	1288	1269	1722	1640	1511	1298	1292		
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
CASING SHUT-IN PRESSURE:	1724	1720	1731	1725	1723	1720	1721	1717	1720	1719	1729	1722	1724	1722	1719	1722	1722	1721	1720	1717
BLED CASING PRESSURE TO:	1224	N/A	1231	N/A	1220	1220	1220	1217	1220	1220	1229	1222	1224	1222	1219	1222	1220	1221	N/A	N/A
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	1750	0	0	0	0	0	0	0
Casing pressure Build-up :05	1291		1242		1238	1234	1235	1246	1237	1236	1232	1238	1234	1240	1235	1240	1239	1238		
Control Line Pressure:	0		0		0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
Casing pressure Build-up :10	1341		1248		1240	1237	1238	1265	1239	1238	1234	1240	1234	1242	1237	1243	1243	1243		
Control Line Pressure:	0		0		0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
Casing pressure Build-up :15	1394	CAS WILL NOT BLOWDOWN	1254	CAS WILL NOT BLOWDOWN	1242	1238	1239	1283	1241	1239	1235	1242	1238	1244	1239	1245	1249	1247	CAS WILL NOT BLOWDOWN	CAS WILL NOT BLOWDOWN
Control Line Pressure:	0		0		0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
Casing pressure Build-up :30	1514		1270		1246	1241	1242	1328	1246	1241	1235	1245	1244	1247	1242	1247	1249	1255		
Control Line Pressure:	0		0		0	0	0	0	0	0	0	0	1750	0	0	0	0	0		
Casing pressure Build-up :45	1606		1281		1249	1244	1243	1370	1247	1241	1236	1247	1248	1249	1244	1248	1253	1263		
Control Line Pressure:	0		0		0	0	0	0	0	0	0	0	0	0	0	0	0	0		

	jjap	rbq1	rbq1	JJAP	JJAP
RETEST- DATE:	1/23/15	12/5/14	12/5/14	1/5/15	1/5/15
WELL NUMBER:	**3-W**	**12-W**	**13-W**	**19-W**	**20-W**
BAKER MODEL DHSV:	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**
DATE INSTALLED:	2012	2009	2008	2008	1999
CTRL LINE SHUT-IN PRESSURE:	4400	4150	3900	0	4200
Control Line Pressure **:05**	4400	4150	3900	0	4200
Control Line Pressure **:10**	4400	4150	3900	0	4200
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0
GAS IN CONTROL LINE:	N	Y	N	N	N
OUNCES OF FLUID RETURNED:	5	22	12	0	2
Control Line Build-up **:05**	0	0	0	0	0
Control Line Build-up **:10**	0	0	0	0	0
Control Line Build-up **:15**	0	0	0	0	0
Control Line Build-up **:30**	0	0	0	0	0
Control Line Build-up **:45**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1725	1724	1814	1684	1684
BLED TUBING PRESSURE TO:	1225	1224	1315	N/A	N/A
CONTROL LINE PRESSURE:	0	0	0	0	0
Tubing pressure Build-up **:05**	1249	1254	1396		
Control Line Pressure:	0	1400	0		
Tubing pressure Build-up **:10**	1263	1258	1485		
Control Line Pressure:	0	1400	0		
Tubing pressure Build-up **:15**	1270	1261	1566	TUB FAILED IN 5 MINS	TUB WILL NOT BLOWDOWN
Control Line Pressure:	0	1400	0		
Tubing pressure Build-up **:30**	1286	1265	1790		
Control Line Pressure:	0	1750	0		
Tubing pressure Build-up **:45**	1301	1269	1814		
Control Line Pressure:	0	1750	0		
CASING SHUT-IN PRESSURE:	1569	1724	1722	1684	1684
BLED CASING PRESSURE TO:	1039	1224	1222	N/A	N/A
CONTROL LINE PRESSURE:	0	1750	0	0	0
Casing pressure Build-up **:05**	1040	1234	1240		
Control Line Pressure:	0	1750	0		
Casing pressure Build-up **:10**	1041	1234	1242		
Control Line Pressure:	0	1750	0		
Casing pressure Build-up **:15**	1043	1238	1244	CAS WILL NOT BLOWDOWN	CAS WILL NOT BLOWDOWN
Control Line Pressure:	0	1750	0		
Casing pressure Build-up **:30**	1044	1244	1247		
Control Line Pressure:	0	1750	0		
Casing pressure Build-up **:45**	1046	1248	1249		
Control Line Pressure:	0	0	0		

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

LAN ID:	NAMD	BMRJ	NEP3	NEP3	BMRJ	NEP3	NAMD	BMRJ	NEP3	NAMD	NEP3	BMRJ	NEP3	BMRJ	NEP3	BMRJ
DATE:	7/13/15	7/13/15	7/13/15	7/13/15	7/13/15	7/21/15	7/14/15	7/14/15	7/14/15	7/14/15	7/14/15	7/14/15	7/15/15	7/15/15	7/15/15	7/15/15
WELL NUMBER:	1-N	2-N	3-N	4-N	5-N	6-N	7-N	8-N	9-N	10-N	11-N	12-N	13-N	15-N	16-N	17-N
TYPE OF DHSV:	RC-2	RC-2	RC-2	RC-2	RC-2	RC-2	RC	RC-2	RC-2	RC-2	RC-2	RC	RC	RC-2	RC-2	RC-2
DATE INSTALLED:	2013	2013	2010	2006	2013	2006	2003	2014	2006	2013	2013	2000	1985	2012	2010	2014
CTRL LINE SHUT-IN PRESSURE:	3800	3900	3950	3900	3800	3650	3800	4100	3950	4100	3850	4100	3900	4200	4100	4100
Control Line Pressure **:05**	3800	3900	3950	3900	3800	3600	3800	4150	3950	4100	3800	4100	3900	4200	4100	4100
Control Line Pressure **:10**	3800	3900	3950	3900	3800	3550	3800	4150	3950	4100	3800	4100	3900	4200	4100	4100
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y	N	Y	Y	N	Y	Y	Y	N	Y	Y	Y	Y	N	Y	N
OUNCES OF FLUID RETURNED:	20	1	12	10	2	14	6	3	8	4	16	5	18	1	20	4
Control Line Build-up **:05**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:15**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:30**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:45**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1927	1930	1930	1915	1933	1923		1900	1900	1914	1885	1915	1900	1915	1905	1887
BLED TUBING PRESSURE TO:	1427	1420	1390	1380	1410	1422		1400	1400	1410	1384	1400	1400	1384	1505	1280
CONTROL LINE PRESSURE:	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**	1463	1490	1372	1420	1458	1460		1425	1392	1471	1414	1433	1436	1399	1438	1289
Control Line Pressure:	0	200	0	0	0	0		0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:10**	1472	1526	1322	1448	1462	1500	NOT	1420	1393	1477	1418	1438	1440	1405	1441	1295
Control Line Pressure:	0	500	0	0	0	0	TESTED	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:15**	1478	1578	1356	1475	1463	1520		1410	1396	1480	1422	1441	1445	1409	1442	1302
Control Line Pressure:	0	1000	0	0	0	0	UHSV	0	0	0	100	0	0	0	0	0
Tubing pressure Build-up **:30**	1490	1675	1433	1537	1463	1644	STUCK	1368	1395	1482	1425	1445	1450	1411	1445	1310
Control Line Pressure:	0	1400	0	0	0	0	OPEN	0	0	0	200	0	0	0	0	0
Tubing pressure Build-up **:45**	1495	1758	1504	1594	1463	1740		1349	1392	1482	1426	1446	1454	1416	1444	1316
Control Line Pressure:	0	1400	0	0	0	0		0	0	0	250	0	0	0	0	0
CASING SHUT-IN PRESSURE:	1925	1933	1930	1945	1936	1933	1835	1902	1935	1929	1932	1888	1915	1923	1924	1925
BLED CASING PRESSURE TO:	1440	1933	1930	1440	1420	1430	1335	1400	1435	1429	1430	1380	1395	1420	1420	1425
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	300	0	0	0	0	0
Casing pressure Build-up **:05**	1450			1463	1444	1451	1353	1422	1460	1461	1455	1387	1409	1532	1447	1449
Control Line Pressure:	0			0	0	0	0	0	0	0	300	0	0	0	0	0
Casing pressure Build-up **:10**	1462			1479	1448	1455	1362	1426	1467	1464	1460	1387	1412	1600	1450	1451
Control Line Pressure:	0	WILL	WILL	0	0	0	0	0	0	0	350	0	0	0	0	0
Casing pressure Build-up **:15**	1472	NOT	NOT	1484	1451	1458	1370	1428	1470	1465	1461	1387	1414	1658	1452	1452
Control Line Pressure:	0	BLOW	BLOW	0	0	0	0	0	0	0	400	0	0	0	0	0
Casing pressure Build-up **:30**	1478	DOWN	DOWN	1492	1453	1463	1382	1429	1472	1465	1463	1383	1416	1787	1454	1454
Control Line Pressure:	0			0	0	0	0	0	0	0	400	0	0	0	0	0
Casing pressure Build-up **:45**	1489			1519	1455	1466	1403	1429	1476	1465	1471	1380	1420	1863	1456	1457
Control Line Pressure:	0			0	0	0	0	0	0	0	400	0	0	0	0	0

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
North Wells

LAN ID:	**JJAP**	**JJAP**
RETEST DATE:	1/5/16	1/5/16
WELL NUMBER:	**6-N**	**15-N**
TYPE OF DHSV:	**RC-2**	**RC-2**
DATE INSTALLED:	2006	2012
TUBING SHUT-IN PRESSURE:	1728	
BLED TUBING PRESSURE TO:	1173	
CONTROL LINE PRESSURE:	0	
Tubing pressure Build-up **:05**	1210	
Control Line Pressure:	0	
Tubing pressure Build-up **:10**	1245	
Control Line Pressure:	0	
Tubing pressure Build-up **:15**	1265	
Control Line Pressure:	0	
Tubing pressure Build-up **:30**	1347	
Control Line Pressure:	0	
Tubing pressure Build-up **:45**	1415	
Control Line Pressure:	0	

CASING SHUT-IN PRESSURE:		1730
BLED CASING PRESSURE TO:		1230
CONTROL LINE PRESSURE:		0
Casing pressure Build-up **:05**		1353
Control Line Pressure:		0
Casing pressure Build-up **:10**		1478
Control Line Pressure:		0
Casing pressure Build-up **:15**		1602
Control Line Pressure:		0
Casing pressure Build-up **:30**		1730
Control Line Pressure:		0
Casing pressure Build-up **:45**		1730
Control Line Pressure:		0

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
South Wells

LAN ID:	**NEP3**	**NEP3**	**NEP3**	**BMRJ**	**BMRJ**	**NEP3**	**S9SY**	**BMRJ**	**NEP3**	**S9SY**	**NEP3**	**NEP3**	**NEP3**	**NEP3**	**JJAP**	**DAO6**	**BMRJ**	**BMRJ**
DATE:	9/2/15	9/9/15	9/2/15	9/21/15	9/3/15	9/3/15	9/3/15	9/3/15	9/3/15	9/3/15	9/4/15	9/4/15	9/9/15	11/16/15	8/2/15	8/19/15	11/16/15	9/9/15
WELL NUMBER:	**1-AS**	**1-S**	**2-S**	**3-S**	**4-S**	**5-S**	**6-S**	**7-S**	**8-S**	**9-S**	**10-S**	**11-S**	**12-S**	**13-S**	**14-S**	**15-S**	**16-S**	**17-S**
TYPE OF DHSV:	**RC**	**RC**	**RC**	**RC-2**	**RC**	**RC**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC**
DATE INSTALLED:	1991	2002	2004	2010	2004	2004	2010	1993	2014	2014	2010	2009	2014	2014	2015	2015	2003	2004
CTRL LINE SHUT-IN PRESSURE:	3850	3800	4200	3850	3900	3000	3850	3850	3800	3915	3900	3750	3900	4300	REWRK	REWRK	4300	4000
Control Line Pressure **:05**	3850	3800	4200	3850	3850	2700	3850	3600	3750	3915	3900	3700	3900	4300	WELL	WELL	4300	3900
Control Line Pressure **:10**	3850	3800	4200	3850	3800	2600	3850	3350	3750	3915	3900	3700	3900	4250			4300	3900
BLED CONTROL LINE PRESSURE TO:	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
GAS IN CONTROL LINE:	Y	N	N	N	N	N	N	Y	N	N	Y	N	N	0			Y	Y
OUNCES OF FLUID RETURNED:	30	12	10	2	5	8	30	26	4	7	15	20	12	3			16	8
Control Line Build-up **:05**	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Control Line Build-up **:10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Control Line Build-up **:15**	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Control Line Build-up **:30**	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Control Line Build-up **:45**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**			**0**	**0**
TUBING SHUT-IN PRESSURE:	1939	1950	1946	1944	1944	1944	1947	1944	1943	1945	1947	1949	1953	2003			1944	1954
BLED TUBING PRESSURE TO:	1435	1450	1440	1475	1475	1435	1200	1445	1440	1281	1448	1450	1453	1500			1490	1460
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Tubing pressure Build-up **:05**	1532	1476	1946	1944	1488	1468	1947	1497	1476	1290	1508	1568	1953	1944			1547	1492
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	100
Tubing pressure Build-up **:10**	1581	1484	1491	1525	1542	1471	1230	1527	1493	1303	1531	1651	1953	1983			1580	1497
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2	0.0	0	300
Tubing pressure Build-up **:15**	1628	1491	1500	1529	1597	1472	1245	1593	1506	1308	1552	1810	1953	2002	cu/ft	cu/ft	1613	1500
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 mins	10 mins	0	500
Tubing pressure Build-up **:30**	1730	1504	1522	1537	1681	1472	1290	1602	1537	1313	1607	1909	1953	2002			1649	1507
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	500
Tubing pressure Build-up **:45**	1823	1517	1541	1543	1776	1472	1347	1655	1560	1316	1657	1946	1953	2002			1690	1507
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0				500
CASING SHUT-IN PRESSURE:	1934	1954	1946	1945	1945	1948	1948	1946	1946	1947	1949	1950	1956	2003			2002	1956
BLED CASING PRESSURE TO:	1430	1454	1426	1444	1440	1450	1375	1444	1435	1424	1449	1450	1454	1503			2002	1455
CONTROL LINE PRESSURE:	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
Casing pressure Build-up **:05**	1445	1483	1452	1468	1448	1458	1398	1460	1454	1443	1455	1464	1463	1560				1470
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0				300
Casing pressure Build-up **:10**	1446	1494	1463	1478	1455	1469	1402	1466	1457	1447	1457	1467	1466	1590				1473
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.5	1.3	WILL	500
Casing pressure Build-up **:15**	1448	1503	1475	1484	1457	1470	1406	1469	1459	1452	1459	1468	1468	1622	cu/ft	cu/ft	NOT	1475
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 mins	10 mins	BLOW	500
Casing pressure Build-up **:30**	1451	1522	1502	1501	1460	1475	1415	1480	1436	1461	1463	1472	1471	1706			DOWN	1478
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0				500
Casing pressure Build-up **:45**	1453	1539	1526	1517	1462	1477	1420	1488	1467	1467	1465	1475	1474	1783				1480
Control Line Pressure:	0	0	0	0	0	0	0	0	0	0	0	0	0	0				500

McDonald Island Downhole Safety Valve Testing
Turner Cut Station
South Wells

LAN ID:	**RBQ1**	**RBQ1**	**DAO6**	**JJAP**	**JJAP**	**JJAP**
RETEST DATE:	1/11/16	1/11/16	1/19/16	1/11/16	1/11/16	1/5/16
WELL NUMBER:	**1-AS**	**4-S**	**11-S**	**12-S**	**13-S**	**16-S**
TYPE OF DHSV:	**RC**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**
DATE INSTALLED:	1991	2004	2009	2014	2014	2003
TUBING SHUT-IN PRESSURE:	1720	1722	1722	1721	1725	
BLED TUBING PRESSURE TO:	1220	1221	1189	1138	1225	
CONTROL LINE PRESSURE:	0	0	0	0	0	
Tubing pressure Build-up **:05**	1235	1263	1206	1205	1535	
Control Line Pressure:	0	0	0	0	0	
Tubing pressure Build-up **:10**	1240	1300	1238	1292	1571	
Control Line Pressure:	0	0	0	0	0	
Tubing pressure Build-up **:15**	1257	1352	1273	1410	1600	
Control Line Pressure:	0	0	0	0	0	
Tubing pressure Build-up **:30**	1286	1431	1372	1721	1657	
Control Line Pressure:	0	0	0	0	0	
Tubing pressure Build-up **:45**	1310	1493	1467	1721	1725	
Control Line Pressure:	0	0	0	0	0	
CASING SHUT-IN PRESSURE:						1730
BLED CASING PRESSURE TO:						1230
CONTROL LINE PRESSURE:						0
Casing pressure Build-up **:05**						1238
Control Line Pressure:						0
Casing pressure Build-up **:10**						1247
Control Line Pressure:						0
Casing pressure Build-up **:15**						1259
Control Line Pressure:						0
Casing pressure Build-up **:30**						1285
Control Line Pressure:						0
Casing pressure Build-up **:45**						1306
Control Line Pressure:						0

McDonald Island Downhole Safety Valve Testing
Whisky Slough Station
East Wells

LAN ID:	BMRJ	NEP3	BMRJ	JJAP	NAMD	NAMD	NEP3	BMRJ	BMRJ	NEP3	BMRJ	NEP3	BMRJ	NEP3
DATE:	6/29/15	6/29/15	6/30/15	9/8/15	6/30/15	6/30/15	6/30/15	6/30/15	6/30/15	6/29/15	6/29/15	6/29/15	6/29/15	6/29/15
WELL NUMBER:	**1-AE**	**1-E**	**2-E**	**3-E**	**4-E**	**5-E**	**6-E**	**7-E**	**8-E**	**9-E**	**11-E**	**12-E**	**13-E**	**14-E**
TYPE OF DHSV:	**RC-2**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**
DATE INSTALLED:	2009	2005	2001	2015	2007	2012	2007	2012	2012	2007	2011	2012	2005	2005
CTRL LINE SHUT-IN PRESSURE:	4100	4200	LEAKY	REWRK	4000	4050	4000	4200	4100	4000	4200	4000	4300	4000
Control Line Pressure **:05**	4000	4100	CTRL	WELL	3850	4000	3950	4200	4000	3900	4100	3900	4100	4000
Control Line Pressure **:10**	3800	4000	LINE		3800	4000	3900	4200	4000	3750	4000	3900	4100	4000
BLED CONTROL LINE PRESSURE TO:	0	0			0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	N	N			Y	N	N	N	N	N	N	N	Y	N
OUNCES OF FLUID RETURNED:	18	10			2	2	2	8	3	8	10	6	12	12
Control Line Build-up **:05**	0	0			0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:10**	0	0			0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:15**	0	0			0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:30**	0	0			0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:45**	**0**	**0**			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1899	1906			1900	1847	1904	1902	1904	1908	1906	1907	1900	1902
BLED TUBING PRESSURE TO:	1400	1400			1400	1390	1400	1375	1400	1408	1400	1400	1400	1400
CONTROL LINE PRESSURE:	0	0			0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**	1528	1457			1650	1897	1535	1400	1424	1526	1415	1498	1590	1465
Control Line Pressure:	0	0			0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:10**	1595	1404			1900	1897	1595	1339	1431	1645	1420	1542	1660	1510
Control Line Pressure:	0	0		0.0	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:15**	1666	1333	NOT	cu/ft	1900	1897	1652	1355	1440	1800	1423	1578	1742	1540
Control Line Pressure:	100	0	TESTED	10 mins	0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:30**	1823	1187			1900	1897	1802	1418	1452	1908	1427	1677	1882	1626
Control Line Pressure:	200	0			0	0	0	0	0	0	0	0	0	0
Tubing pressure Build-up **:45**	1899	920			1900	1897	1890	1533	1463	1908	1430	1754	1890	1670
Control Line Pressure:	200	0			0	0	0	0	0	0	0	0	0	0
CASING SHUT-IN PRESSURE:	1901	1902			1900	1904	1904	1900	1906	1903	1906	1902	1903	1908
BLED CASING PRESSURE TO:	1386	1400			1400	1400	1904	1395	1400	1903	1400	1408	1400	1400
CONTROL LINE PRESSURE:	0	0			0	0	0	0	0	0	0	0	0	0
Casing pressure Build-up **:05**	1408	1428			1420	1416		1405	1415		1417	1422	1412	1415
Control Line Pressure:	200	0			0	0		0	0		0	0	0	0
Casing pressure Build-up **:10**	1414	1431			1435	1420		1407	1418		1420	1425	1415	1417
Control Line Pressure:	200	0		1.7	0	0	WILL	0	0	WILL	0	0	0	0
Casing pressure Build-up **:15**	1421	1433		cu/ft	1442	1427	NOT	1409	1420	NOT	1422	1426	1418	1419
Control Line Pressure:	300	0		10 mins	0	0	BLOW	0	0	BLOW	0	0	0	0
Casing pressure Build-up **:30**	1437	1448			1450	1435	DOWN	1413	1424	DOWN	1426	1428	1423	1423
Control Line Pressure:	800	0			0	0		0	0		0	0	0	0
Casing pressure Build-up **:45**	1447	1457			1460	1440		1414	1426		1429	1436	1428	1425
Control Line Pressure:	800	0			0	0		0	0		0	0	0	0

McDonald Island Downhole Safety Valve Testing
Whisky Slough Station
East Wells

LAN ID:	JJAP	RBQ1	JJAP
RETEST DATE:	1/19/16	11/19/15	Jan-16
WELL NUMBER:	6-E	9-E	12-E
TYPE OF DHSV:	RC-2	RC-2	RC-2
DATE INSTALLED:	2007	2007	2012
TUBING SHUT-IN PRESSURE:	1716	1980	1994
BLED TUBING PRESSURE TO:	1200	1460	1395
CONTROL LINE PRESSURE:	0	0	0
Tubing pressure Build-up **:05**	1245	1588	1415
Control Line Pressure:	0	0	0
Tubing pressure Build-up **:10**	1276	1754	1425
Control Line Pressure:	0	0	0
Tubing pressure Build-up **:15**	1329	1980	1440
Control Line Pressure:	0	0	0
Tubing pressure Build-up **:30**	1475	1980	1482
Control Line Pressure:	0	0	0
Tubing pressure Build-up **:45**	1597	1980	1523
Control Line Pressure:	0	0	0

CASING SHUT-IN PRESSURE:	1717	1979
BLED CASING PRESSURE TO:	1193	1979
CONTROL LINE PRESSURE:	0	0
Casing pressure Build-up **:05**	1195	
Control Line Pressure:	0	
Casing pressure Build-up **:10**	1196	
Control Line Pressure:	0	WILL
Casing pressure Build-up **:15**	1197	NOT
Control Line Pressure:	0	BLOW
Casing pressure Build-up **:30**	1199	DOWN
Control Line Pressure:	0	
Casing pressure Build-up **:45**	1202	
Control Line Pressure:	0	

McDonald Island Downhole Safety Valve Testing
Whisky Slough Station
West Wells

LAN ID:	BMRJ		BMRJ	NEP3	BMRJ	NEP3	S9SY	BMRJ	NEP3	S9SY	BMRJ	S9SY	S9SY	JIMR	BMRJ	S9SY	JIMR	BMRJ	SYS9	JIMR
DATE:	6/25/15		6/26/15	6/26/15	6/26/15	6/26/15	6/26/15	6/26/15	6/26/15	6/26/15	6/27/15	6/26/15	6/27/15	6/27/15	6/27/15	6/27/15	6/27/15	6/27/15	6/27/15	6/27/15
WELL NUMBER:	**1A-W**	**1-W**	**2-W**	**3-W**	**4-W**	**5-W**	**6-W**	**7-W**	**8-W**	**9-W**	**10-W**	**11-W**	**12-W**	**13-W**	**15-W**	**16-W**	**17-W**	**18-W**	**19-W**	**20-W**
TYPE OF DHSV:	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**	**RC-2**	**RC-2**	**RC-2**	**RC**
DATE INSTALLED:	2001	2015	2009	2012	2008	1999	2009	2011	2011	1994	1990	1995	2009	2008	2011	2005	2009	2011	2008	1999
CTRL LINE SHUT-IN PRESSURE:	4200	REWRK	4000	3900	4000	4300	4000	4200	4000	4100	4200	4000	4000	4200	4050	4300	4100	4600	4000	4300
Control Line Pressure **:05**	4200	WELL	4000	3800	3850	4200	2600	4200	3900	4020	4200	3700	3700	4200	4000	4100	4050	4500	4000	4300
Control Line Pressure **:10**	4200		4000	3800	3850	4200	2500	4200	3800	4000	4200	3600	3600	4150	4000	4000	4000	4500	4000	4300
BLED CONTROL LINE PRESSURE TO:	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GAS IN CONTROL LINE:	Y		Y	N	N	N	N	N	N	Y	N	N	Y	N	N	N	N	N	N	N
OUNCES OF FLUID RETURNED:	14		12	8	5	12	4	2	16	12	4	8	15	6	4	4	10	6	4	8
Control Line Build-up **:05**	800		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Line Build-up **:10**	1100		0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0
Control Line Build-up **:15**	1800		0	0	0	0	0	0	0	0	0	0	150	0	0	0	0	0	0	0
Control Line Build-up **:30**	1800		0	0	0	0	0	0	0	0	0	0	300	0	0	0	0	0	0	0
Control Line Build-up **:45**	**1800**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TUBING SHUT-IN PRESSURE:	1886		1863	1902	1893	1904	1907	1896	1904	1878	1896	1887	1907	1897	1897	1893	1881	1856	1903	1900
BLED TUBING PRESSURE TO:	1386		1025	1150	1340	1400	1350	1310	1400	1000	1400	1312	1250	1400	1398	1330	1400	1400	1310	1400
CONTROL LINE PRESSURE:	1200		0	0	0	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0
Tubing pressure Build-up **:05**	1414		1059	1156	1510	1550	1355	1343	1694	1030	1400	1366	1283	1556	1506	1362	1436	1480	1761	1810
Control Line Pressure:	1200		0	0	0	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0
Tubing pressure Build-up **:10**	1463		1072	1159	1636	1632	1360	1349	1722	1048	1402	1371	1295	1660	1575	1394	1452	1502	1902	1900
Control Line Pressure:	1350	0 0	0	0	0	0	0	0	0	0	0	0	750	0	0	0	0	0	0	0
Tubing pressure Build-up **:15**	1473	cu/ft	1088	1159	1744	1698	1360	1353	1818	1073	1402	1392	1296	1770	1642	1416	1471	1514	1903	1901
Control Line Pressure:	1500	10 mins	0	0	0	0	0	0	0	0	0	0	1000	0	0	0	0	0	0	0
Tubing pressure Build-up **:30**	1487		1115	1160	1887	1860	1360	1350	1902	1126	1399	1401	1296	1889	1741	1478	1492	1547	1903	1901
Control Line Pressure:	1500		0	0	0	0	0	0	0	0	0	0	1200	0	0	0	0	0	0	0
Tubing pressure Build-up **:45**	1492		1143	1160	1894	1894	1371	1343	1902	1173	1394	1404	1299	1898	1852	1567	1517	1576	1903	1901
Control Line Pressure:	1500		0	0	0	0	0	0	0	0	0	0	1500	0	0	0	0	0	0	0
CASING SHUT-IN PRESSURE:	1896		1893	1900	1896	1900	1911	1894	1902	1892	1898	1883	1894	1900	1896	1894	1900	1898	1904	1889
BLED CASING PRESSURE TO:	1396		1390	1400	1394	1400	1410	1400	1402	1378	1400	1380	1390	1393	1400	1390	1900	1400	1904	1889
CONTROL LINE PRESSURE:	1500		0	0	0	0	0	0	0	0	0	0	1500	0	0	0	0	0	0	0
Casing pressure Build-up **:05**	1400		1401	1409	1413	1422	1420	1408	1422	1389	1415	1400	1406	1406	1416	1401		1416		
Control Line Pressure:	1500		0	0	0	0	0	0	0	0	0	0	1600	0	0	0		0		
Casing pressure Build-up **:10**	1469		1404	1411	1416	1425	1420	1409	1424	1392	1416	1408	1409	1408	1419	1406		1420		
Control Line Pressure:	1500	0 0	0	0	0	0	0	0	0	0	0	0	1600	0	0	0	WILL	0	WILL	WILL
Casing pressure Build-up **:15**	1519	cu/ft	1405	1412	1418	1426	1428	1409	1424	1395	1417	1410	1411	1410	1421	1408	NOT	1425	NOT	NOT
Control Line Pressure:	1500	10 mins	0	0	0	0	0	0	0	0	0	0	1600	0	0	0	BLOW	0	BLOW	BLOW
Casing pressure Build-up **:30**	1590		1407	1413	1422	1429		1408	1425	1395	1417	1410	1416	1412	1424	1410	DOWN	1433	DOWN	DOWN
Control Line Pressure:	1500		0	0	0	0		0	0	0	0	0	1600	0	0	0		0		
Casing pressure Build-up **:45**	1709		1407	1415	1424	1430		1405	1423	1398	1417	1411		1415	1427	1400		1439		
Control Line Pressure:	1500		0	0	0	0		0	0	0	0	0		0	0	0		0		

McDonald Island Downhole Safety Valve Testing
Whisky Slough Station
West Wells

LAN ID:	RBQ1	JJAP	JJAP
RETEST DATE:	1/19/16		
WELL NUMBER:	1A-W	12-W	17-W
TYPE OF DHSV:	RC	RC-2	RC-2
DATE INSTALLED:	2001	2009	2009
CTRL LINE SHUT-IN PRESSURE:	4200	4000	
Control Line Pressure **:05**	4200	4000	
Control Line Pressure **:10**	4200	4000	
BLED CONTROL LINE PRESSURE TO:	0	0	
GAS IN CONTROL LINE:	Y	Y	
OUNCES OF FLUID RETURNED:	20	10	
Control Line Build-up **:05**	250	0	
Control Line Build-up **:10**	850	0	
Control Line Build-up **:15**	1200	0	
Control Line Build-up **:30**	1700	0	
Control Line Build-up **:45**		0	
CASING SHUT-IN PRESSURE:	1716		1994
BLED CASING PRESSURE TO:	1214		1463
CONTROL LINE PRESSURE:	0		0
Casing pressure Build-up **:05**	1289		1467
Control Line Pressure:	0		0
Casing pressure Build-up **:10**	1344		1474
Control Line Pressure:	0		0
Casing pressure Build-up **:15**	1391		1477
Control Line Pressure:	0		0
Casing pressure Build-up **:30**	1507		1487
Control Line Pressure:	0		0
Casing pressure Build-up **:45**	1595		1497
Control Line Pressure:	0		0

LOS MEDANOS (LM) DOWNHOLE SAFETY VALVE TEST RESULTS

WELL NUMBER :	LM 1A	LM 1A	LM 1A
DATE :	10/08/13	10/30/2014	10/20/2015
HYD. LINE S.I.	4200	4200	4200
HYD. :05	4200	4200	4200
HYD. :10	4200	4200	4200
Amount of fluid back. (OZ)	24	12	20
GAS in control line. (Y / N)	Y	Y	Y
Bled down pressure to :	0	0	0
* BUILD UP *			
:05			
:10			
:15			
:30			
:45	1100	1300	900
SAFETY VALVE TEST			
TUBING SHUT - IN	1349	1328	1370
Bled down tubing to :	0	810	855
		814	866
10 Min			
	1.5 cu/ft	818	870
		823	875
		838	880
		852	886
CASING SHUT - IN	1349	1327	1370
Bled down casing to :		810	855
		812	859
10 Min		813	860
	1.6 cu/ft		
		814	862
		816	864
		818	866

WELL NUMBER :	LM 2A	LM 2A	LM 2A
DATE	10/29/13	10/28/14	10/21/15
CONTROL LINE TEST			
HYD. LINE S.I.	4300	4200	4400
HYD. :05	4300	4200	4400
HYD. :10	4300	4200	4400
Amount of fluid back. (OZ)	4	4	2
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0		0
:10	0		0
:15	0		0
:30	0		0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1577	1547	1558
Bled down tubing to :	1013	1026	1019
Control Line	0		0
* Build Up * TUBING :05	1018	1045	1023
Control Line --	0		0
* Build Up * TUBING :10	1020	1065	1028
Control Line --	0		0
* Build Up * TUBING :15	1022	1088	1030
Control Line --	0		0
* Build Up * TUBING :30	1025	1166	1032
Control Line --	0		0
* Build Up * TUBING :45	1027	1228	1035
Control Line --	0		0
CASING SHUT - IN	1577	1547	1559
Bled down casing to :	1012	1025	1026
Control Line --	0		0
* Build Up * CASING :05	1015	1027	1030
Control Line --	0		0
* Build Up * CASING :10	1016	1028	1032
Control Line --	0		0
* Build Up * CASING :15	1017	1029	1033
Control Line --	0		0
* Build Up * CASING :30	1019	1030	1034
Control Line --	0		0
* Build Up * CASING :45	1020	1032	1036
Control Line --	0		0

WELL NUMBER:	LM 3A	LM 3A	LM 3A
DATE	10/29/13	10/28/14	10/21/15
CONTROL LINE TEST			DAO6
HYD. LINE S.I.	4300	4400	4300
HYD. :05	4300	4400	4300
HYD. :10	4300	4400	4300
Amount of fluid back. (OZ)	4	6	8
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0		0
:10	0		0
:15	0		0
:30	0		0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1578	1544	1562
Bled down tubing to :	1018	1025	1043
Control Line	0		0
* Build Up * TUBING :05	1025	1031	1048
Control Line --	0		0
* Build Up * TUBING :10	1029	1035	1051
Control Line --	0		0
* Build Up * TUBING :15	1032	1037	1054
Control Line --	0		0
* Build Up * TUBING :30	1035	1039	1057
Control Line --	0		0
* Build Up * TUBING :45	1037	1039	1058
Control Line --	0		0
CASING SHUT - IN	1578	1544	1562
Bled down casing to :	1018	1025	1042
Control Line --	0		0
* Build Up * CASING :05	1019	1027	1044
Control Line --	0		0
* Build Up * CASING :10	1021	1028	1046
Control Line --	0		0
* Build Up * CASING :15	1022	1029	1046
Control Line --	0		0
* Build Up * CASING :30	1023	1029	1048
Control Line --	0		0
* Build Up * CASING :45	1024	1029	1048
Control Line --	0		0

WELL NUMBER:	LM 4B	LM 4B	LM 4B
DATE	05/08/13	11/06/14	12/29/15
CONTROL LINE TEST	RC-2		k2s2
HYD. LINE S.I.		4200	4200
HYD. :05		4200	4000
HYD. :10		4200	3900
Amount of fluid back. (OZ)		2	2
GAS in control line. (Y / N)		N	N
Bled down pressure to :		0	
* BUILD UP *			
:05		0	
:10		0	
:15		0	
:30		0	
:45		0	0
SAFETY VALVE TEST			
TUBING SHUT - IN		1529	1465
Bled down tubing to :		1020	1000
Control Line			
* Build Up * TUBING :05		1050	1075
Control Line --	.14 cu/ft		
* Build Up * TUBING :10		1076	1120
Control Line --			
* Build Up * TUBING :15	Rework	1140	1162
Control Line --			
* Build Up * TUBING :30		1275	1272
Control Line --			
* Build Up * TUBING :45		1382	1360
Control Line --			
CASING SHUT - IN		1529	1464
Bled down casing to :		1023	1000
Control Line --			
* Build Up * CASING :05		1025	1006
Control Line --	1.2 cu/ft		
* Build Up * CASING :10		1026	1008
Control Line --	Rework		
* Build Up * CASING :15		1028	1010
Control Line --			
* Build Up * CASING :30		1029	1015
Control Line --			
* Build Up * CASING :45		1029	1016
Control Line --			

WELL NUMBER:	LM 5B	LM 5B	LM 5B
DATE	05/22/13	11/06/14	12/29/15
CONTROL LINE TEST	RC-2		k2s2
HYD. LINE S.I.		4200	4200
HYD. :05		6000	4100
HYD. :10		6000	4100
Amount of fluid back. (OZ)		2	2
GAS in control line. (Y / N)		N	N
Bled down pressure to :		0	0
* BUILD UP *			
:05		0	
:10		0	
:15		0	
:30		0	
:45		0	0
SAFETY VALVE TEST			
TUBING SHUT - IN		1530	1465
Bled down tubing to :		1025	1002
Control Line			
* Build Up * TUBING :05		1026	1024
Control Line --			
* Build Up * TUBING :10	.14 cu/ft	1026	1035
Control Line --			
* Build Up * TUBING :15	Rework	1026	1045
Control Line --			
* Build Up * TUBING :30		1027	1067
Control Line --			
* Build Up * TUBING :45		1027	1085
Control Line --			
CASING SHUT - IN			1465
Bled down casing to :			1002
Control Line --			
* Build Up * CASING :05		Casing	1014
Control Line --		wont	
* Build Up * CASING :10	.29 cu/ft	blowdown	1019
Control Line --			
* Build Up * CASING :15	Rework		1023
Control Line --			
* Build Up * CASING :30			1031
Control Line --			
* Build Up * CASING :45			1038
Control Line --			

WELL NUMBER:	LM 6B	LM 6B	LM 6B
DATE	09/25/13	09/29/14	09/09/15
CONTROL LINE TEST		DAO6	rbq1
HYD. LINE S.I.	4200	4100	4200
HYD. :05	4200	4100	4200
HYD. :10	4200	4100	4200
Amount of fluid back. (OZ)	2	2	2
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	0
:10	0	0	0
:15	0	0	0
:30	0	0	0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1558	1433	1559
Bled down tubing to :	0	1433	1059
Control Line	0	0	0
* Build Up * TUBING :05			1059
Control Line --			0
* Build Up * TUBING :10			1066
Control Line --		Would	0
* Build Up * TUBING :15	3 cu/ft	not	1068
Control Line --		blowdown	0
* Build Up * TUBING :30			1068
Control Line --			0
* Build Up * TUBING :45			1069
Control Line --			0
CASING SHUT - IN	1559	1433	1559
Bled down casing to :	0	930	1008
Control Line --	0	0	0
* Build Up * CASING :05		935	1011
Control Line --		0	0
* Build Up * CASING :10		939	1012
Control Line --		0	0
* Build Up * CASING :15	2 cu/ft	941	1013
Control Line --		0	0
* Build Up * CASING :30		942	1014
Control Line --		0	0
* Build Up * CASING :45		944	1014
Control Line --		0	

WELL NUMBER:	LM 7C	LM 7C	LM 7C
DATE	11/07/13	11/18/14	12/30/15
CONTROL LINE TEST	JJAP	dao6	k2s2
HYD. LINE S.I.	4300	4000	4300
HYD. :05	4300	4000	4300
HYD. :10	4300	4000	4300
Amount of fluid back. (OZ)	8	5	5
GAS in control line. (Y / N)	Y	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	
:10	0	0	
:15	0	0	
:30	0	0	
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1586	1529	1426
Bled down tubing to :	1005	1010	1000
Control Line	0	0	
* Build Up * TUBING :05	1009	1017	1036
Control Line --	0	0	
* Build Up * TUBING :10	1014	1020	1036
Control Line --	0	0	
* Build Up * TUBING :15	1017	1023	1035
Control Line --	0	0	
* Build Up * TUBING :30	1020	1026	1034
Control Line --	0	0	
* Build Up * TUBING :45	1021	1027	1034
Control Line --	0	0	
CASING SHUT - IN	1587	1528	1425
Bled down casing to :	1005	1010	stuck
Control Line --	0	0	open
* Build Up * CASING :05	1007	1014	
Control Line --	0	0	
* Build Up * CASING :10	1009	1016	
Control Line --	0	0	
* Build Up * CASING :15	1011	1018	
Control Line --	0	0	
* Build Up * CASING :30	1015	1020	
Control Line --	0	0	
* Build Up * CASING :45	1018	1022	
Control Line --	0	0	

WELL NUMBER:	LM 8C	LM 8C	LM 8C
DATE	11/06/13	11/18/14	12/30/15
CONTROL LINE TEST	JJAP	dao6	k2s2
HYD. LINE S.I.	4300	4300	4300
HYD. :05	4300	4300	4300
HYD. :10	4300	4300	4300
Amount of fluid back. (OZ)	2	3	1
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	
:10	0	0	
:15	0	0	
:30	0	0	
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1587	1529	1451
Bled down tubing to :	1000	1012	900
Control Line	0	0	
* Build Up * TUBING :05	1587	1163	900
Control Line --	0	0	
* Build Up * TUBING :10	1587	1334	965
Control Line --	0	0	
* Build Up * TUBING :15	1587	1529	983
Control Line --	0	0	
* Build Up * TUBING :30	1587	1529	1006
Control Line --	0	0	
* Build Up * TUBING :45	1587	1529	1075
Control Line --	0	0	
CASING SHUT - IN	N/A	N/A	
Bled down casing to :	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a
* Build Up * CASING :05	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a
* Build Up * CASING :10	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a
* Build Up * CASING :15	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a
* Build Up * CASING :30	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a
* Build Up * CASING :45	N/A	N/A	n/a
Control Line --	N/A	N/A	n/a

WELL NUMBER:	LM 9C	LM 9C	LM 9C
DATE	09/30/13	09/29/14	09/09/15
CONTROL LINE TEST			rbq1
HYD. LINE S.I.	4200	4200	4200
HYD. :05	4200	4200	4200
HYD. :10	4200	4200	4200
Amount of fluid back. (OZ)	16	2	2
GAS in control line. (Y / N)	Y	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05			0
:10			0
:15			0
:30			0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1578	1438	1551
Bled down tubing to :	0	926	1052
Control Line		0	0
* Build Up * TUBING :05		936	1058
Control Line --		0	0
* Build Up * TUBING :10	0.4	945	1061
Control Line --	cu. Ft	0	0
* Build Up * TUBING :15	10 mins	950	1063
Control Line --		0	0
* Build Up * TUBING :30		962	1063
Control Line --		0	0
* Build Up * TUBING :45		972	1062
Control Line --		0	0
CASING SHUT - IN	1578	1437	1551
Bled down casing to :	0	924	1048
Control Line --		0	0
* Build Up * CASING :05		927	1051
Control Line --		0	0
* Build Up * CASING :10	1.2	930	1051
Control Line --	cu. Ft.	0	0
* Build Up * CASING :15	10 mins	931	1052
Control Line --		0	0
* Build Up * CASING :30		935	1053
Control Line --		0	0
* Build Up * CASING :45		939	1054
Control Line --		0	0

WELL NUMBER:	LM 10C	LM 10C	LM 10C
DATE	11/7/13	11/18/14	12/16/15
CONTROL LINE TEST	JJAP		k2s2
HYD. LINE S.I.	4300	4300	4200
HYD. :05	4300	4300	4200
HYD. :10	4300	4300	4200
Amount of fluid back. (OZ)	4	4	12
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	0
:10	0	0	0
:15	0	0	0
:30	0	0	0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1587	1530	1511
Bled down tubing to :	1017	980	1000
Control Line	0	0	
* Build Up * TUBING :05	1018	984	1067
Control Line --	0	0	
* Build Up * TUBING :10	1025	994	1075
Control Line --	0	0	
* Build Up * TUBING :15	1030	998	1078
Control Line --	0	0	
* Build Up * TUBING :30	1043	1003	1080
Control Line --	0	0	
* Build Up * TUBING :45	1045	1007	1079
Control Line --	0	0	
CASING SHUT - IN	1588	1530	1511
Bled down casing to :	1017	981	1000
Control Line --	0	0	
* Build Up * CASING :05	1050	1040	1230
Control Line --	0	0	
* Build Up * CASING :10	1106	1190	1364
Control Line --	0	0	
* Build Up * CASING :15	1200	1294	1456
Control Line --	0	0	
* Build Up * CASING :30	1480	1525	1506
Control Line --	0	0	
* Build Up * CASING :45	1588	1525	1506
Control Line --	0		

WELL NUMBER:	LM 11C	LM 11C	LM 11C
DATE	09/25/13	09/29/14	09/25/15
CONTROL LINE TEST			
HYD. LINE S.I.	4500	4200	
HYD. :05	4500	4200	
HYD. :10	4500	4200	
Amount of fluid back. (OZ)	2	8	
GAS in control line. (Y / N)	N	y	
Bled down pressure to :	0	0	2015
* BUILD UP *			Rework
:05	4		Well
:10	5		New
:15	6		DHSV
:30	8		Installed
:45	10	250	6/24/2015
SAFETY VALVE TEST			
TUBING SHUT - IN	1561	1438	
Bled down tubing to :	1005	855	
Control Line	0		
* Build Up * TUBING :05	1039	863	
Control Line --	0		
* Build Up * TUBING :10	1094	871	
Control Line --	0		
* Build Up * TUBING :15	1145	880	
Control Line --	0		
* Build Up * TUBING :30	1244	896	
Control Line --	0		
* Build Up * TUBING :45	1361	911	
Control Line --	0		
CASING SHUT - IN	1561	1438	
Bled down casing to :	989	1438	
Control Line --	0		
* Build Up * CASING :05	990	would	
Control Line --	0	not	
* Build Up * CASING :10	991	blow	
Control Line --	0	down	
* Build Up * CASING :15	992		
Control Line --	0		
* Build Up * CASING :30	992		
Control Line --	0		
* Build Up * CASING :45	992		
Control Line --	0		

WELL NUMBER:	LM 12C	LM 12C	LM 12C
DATE	09/25/13	09/29/14	09/08/15
CONTROL LINE TEST			rbq1
HYD. LINE S.I.	4200	4200	4200
HYD. :05	4200	4200	4200
HYD. :10	4200	4200	4200
Amount of fluid back. (OZ)	24	26	26
GAS in control line. (Y / N)	Y	Y	Y
Bled down pressure to :	0	0	0
* BUILD UP *			
:05			100
:10			200
:15			350
:30			700
:45	1000	200	1000
SAFETY VALVE TEST			
TUBING SHUT - IN	1558	1438	1545
Bled down tubing to :	1010	928	1044
Control Line		0	
* Build Up * TUBING :05	1015	934	1056
Control Line --		0	
* Build Up * TUBING :10	1016	938	1058
Control Line --		0	
* Build Up * TUBING :15	1017	940	1058
Control Line --		0	
* Build Up * TUBING :30	1017	942	1056
Control Line --		0	
* Build Up * TUBING :45	1017	944	1055
Control Line --		0	
CASING SHUT - IN	1558	1437	1546
Bled down casing to :	1010	926	will not
Control Line --		0	blowdown
* Build Up * CASING :05	1012	929	
Control Line --		0	
* Build Up * CASING :10	1012	930	
Control Line --		0	
* Build Up * CASING :15	1012	931	
Control Line --		0	
* Build Up * CASING :30	1012	932	
Control Line --		0	
* Build Up * CASING :45	1012	934	
Control Line --		0	

WELL NUMBER:	LM 13C	LM 13C	LM 13C
DATE	09/25/13	09/29/14	09/08/15
CONTROL LINE TEST	DAO6	DAO6	rbq1
HYD. LINE S.I.	4200	4200	4200
HYD. :05	4200	4200	4200
HYD. :10	4200	4200	4200
Amount of fluid back. (OZ)	6	2	3
GAS in control line. (Y / N)	Y	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	0
:10	0	0	0
:15	0	0	0
:30	0	0	0
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1561	1439	1547
Bled down tubing to :	1039	925	1048
Control Line	0	0	0
* Build Up * TUBING :05	1042	928	1057
Control Line --	0	0	0
* Build Up * TUBING :10	1045	931	1058
Control Line --	0	0	0
* Build Up * TUBING :15	1047	934	1059
Control Line --	0	0	0
* Build Up * TUBING :30	1049	937	1059
Control Line --	0	0	0
* Build Up * TUBING :45	1050	939	1058
Control Line --	0	0	0
CASING SHUT - IN	1566	1439	1549
Bled down casing to :	1037	925	1030
Control Line --	0	0	0
* Build Up * CASING :05	1039	927	1032
Control Line --	0	0	0
* Build Up * CASING :10	1040	928	1032
Control Line --	0	0	0
* Build Up * CASING :15	1040	930	1032
Control Line --	0	0	0
* Build Up * CASING :30	1042	932	1031
Control Line --	0	0	0
* Build Up * CASING :45	1042	934	1029
Control Line --	0	0	0

WELL NUMBER:	LM 14C	LM 14C	LM 14C
DATE	10/29/13	10/29/14	10/21/15
CONTROL LINE TEST			
HYD. LINE S.I.	4500	4400	440
HYD. :05	4500	4400	4400
HYD. :10	4500	4400	4400
Amount of fluid back. (OZ)	28	14	6
GAS in control line. (Y / N)	Y	Y	Y
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	3		0
:10	4		1
:15	6		2
:30	10		3
:45	16	0	3
SAFETY VALVE TEST			
TUBING SHUT - IN	1588	1553	1563
Bled down tubing to :	1075	928	998
Control Line	0	0	0
* Build Up * TUBING :05	1076	930	1002
Control Line --	0	0	0
* Build Up * TUBING :10	1080	931	1005
Control Line --	0	0	0
* Build Up * TUBING :15	1083	931	1008
Control Line --	0	0	0
* Build Up * TUBING :30	1086	931	1012
Control Line --	0	0	0
* Build Up * TUBING :45	1088	931	1013
Control Line --	0	0	0
CASING SHUT - IN	1588	1555	1565
Bled down casing to :	1077	1007	998
Control Line --	0	0	0
* Build Up * CASING :05	1081	1008	999
Control Line --	0	0	0
* Build Up * CASING :10	1083	1009	1000
Control Line --	0	0	0
* Build Up * CASING :15	1084	1010	1002
Control Line --	0	0	0
* Build Up * CASING :30	1085	1010	1004
Control Line --	0	0	0
* Build Up * CASING :45	1086	1010	1005
Control Line --	0	0	0

WELL NUMBER:	LM 15C	LM 15C	LM 15C
DATE	10/29/13	10/29/14	10/21/15
CONTROL LINE TEST	DAO6		DAO6
HYD. LINE S.I.	4300	4300	4400
HYD. :05	4300	4300	4400
HYD. :10	4300	4300	4400
Amount of fluid back. (OZ)	24	24	22
GAS in control line. (Y / N)	Y	Y	Y
Bled down pressure to :	0		0
* BUILD UP *			
:05	0		0
:10	0		0
:15	0		0
:30	0		0
:45	0	1400	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1580	1545	1561
Bled down tubing to :	1060	1033	1043
Control Line	0		0
* Build Up * TUBING :05	1072	1035	1046
Control Line --	0		0
* Build Up * TUBING :10	1074	1039	1047
Control Line --	0		0
* Build Up * TUBING :15	1076	1041	1050
Control Line --	0		0
* Build Up * TUBING :30	1080	1046	1054
Control Line --	0		0
* Build Up * TUBING :45	1084	1046	1057
Control Line --	0		0
CASING SHUT - IN	1383	1369	1393
Bled down casing to :	873	853	867
Control Line --	0		0
* Build Up * CASING :05	876	854	868
Control Line --	0		0
* Build Up * CASING :10	878	855	870
Control Line --	0		0
* Build Up * CASING :15	880	856	871
Control Line --	0		0
* Build Up * CASING :30	882	857	872
Control Line --	0		0
* Build Up * CASING :45	885	858	872
Control Line --	0		0

WELL NUMBER:	LM 16D	LM 16D	LM 16D
DATE	12/16/13	11/18/14	12/28/15
CONTROL LINE TEST			k2s2
HYD. LINE S.I.	4500	4500	4300
HYD. :05	4500	4500	4300
HYD. :10	4500	4500	4300
Amount of fluid back. (OZ)	12	4	3
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	
* BUILD UP *			
:05		0	
:10		0	
:15		0	
:30		0	
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1437	1535	1493
Bled down tubing to :	1084	971	1000
Control Line		0	
* Build Up * TUBING :05	1103	989	1051
Control Line --		0	
* Build Up * TUBING :10	1131	1012	1068
Control Line --		0	
* Build Up * TUBING :15	1148	1038	1081
Control Line --		0	
* Build Up * TUBING :30	1183	1089	1109
Control Line --		0	
* Build Up * TUBING :45	1241	1137	1134
Control Line --		0	
CASING SHUT - IN	1437	1534	1494
Bled down casing to :	1110	1030	1000
Control Line --		0	
* Build Up * CASING :05	1250	1161	1246
Control Line --		0	
* Build Up * CASING :10	1352	1306	1384
Control Line --		0	
* Build Up * CASING :15	1406	1451	1466
Control Line --		0	
* Build Up * CASING :30	1437	1534	1494
Control Line --		0	
* Build Up * CASING :45	1437	1534	1494
Control Line --		0	

WELL NUMBER:	LM 17D	LM 17D	LM 17D
DATE	12/16/13	11/04/14	12/16/15
CONTROL LINE TEST			k2s2
HYD. LINE S.I.	4500	4300	4200
HYD. :05	4500	4300	4200
HYD. :10	4500	4300	4200
Amount of fluid back. (OZ)	2	2	8
GAS in control line. (Y / N)	N	Y	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0		0
:10	0		0
:15	0		0
:30	0		0
:45	0	1200	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1445	1535	1511
Bled down tubing to :	916	947	1020
Control Line	0		
* Build Up * TUBING :05	928	1014	1034
Control Line --	0		
* Build Up * TUBING :10	932	1031	1044
Control Line --	0		
* Build Up * TUBING :15	939	1045	1054
Control Line --	0		
* Build Up * TUBING :30	951	1087	1085
Control Line --	0		
* Build Up * TUBING :45	959	1124	1111
Control Line --	0		
CASING SHUT - IN	1444	1535	1511
Bled down casing to :	914	Would	1020
Control Line --	0	not	
* Build Up * CASING :05	919	blow	1032
Control Line --	0	down	
* Build Up * CASING :10	921		1042
Control Line --	0		
* Build Up * CASING :15	924		1051
Control Line --	0		
* Build Up * CASING :30	931		1079
Control Line --	0		
* Build Up * CASING :45	943		1108
Control Line --	0		

WELL NUMBER:	LM 18D	LM 18D	LM 18D
DATE	11/06/13	11/18/14	12/28/15
CONTROL LINE TEST	JJAP		k2s2
HYD. LINE S.I.	4300	4400	4300
HYD. :05	4300	4400	4300
HYD. :10	4300	4400	4300
Amount of fluid back. (OZ)	2	2	8
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0	0	
:10	0	0	
:15	0	0	
:30	0	0	
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1591	1535	1495
Bled down tubing to :	999	965	1020
Control Line	0	0	
* Build Up * TUBING :05	1006	969	1037
Control Line --	0	0	
* Build Up * TUBING :10	1010	971	1038
Control Line --	0	0	
* Build Up * TUBING :15	1017	972	1040
Control Line --	0	0	
* Build Up * TUBING :30	1025	974	1042
Control Line --	0	0	
* Build Up * TUBING :45	1033	974	1043
Control Line --	0	0	
CASING SHUT - IN	1591	1535	1495
Bled down casing to :	999	963	1020
Control Line --	0	0	
* Build Up * CASING :05	1000	964	1033
Control Line --	0	0	
* Build Up * CASING :10	1001	965	1034
Control Line --	0	0	
* Build Up * CASING :15	1002	965	1034
Control Line --	0	0	
* Build Up * CASING :30	1004	966	1034
Control Line --	0	0	
* Build Up * CASING :45	1006	966	1033
Control Line --	0	0	

WELL NUMBER:	LM 19D	LM 19D	LM 19D
DATE :	10/29/13	10/30/2014	10/29/2015
MODEL DHSV :	DAO6		slmf
HYD. LINE S.I.	4100	4300	4200
HYD. :05	4100	4300	4200
HYD. :10	4100	4300	4200
Amount of fluid back. (OZ)	10	4	4
GAS in control line. (Y / N)	N	N	N
Bled down pressure to :	0		
* BUILD UP *			
:05	0		
:10	0		
:15	0		
:30	0		
:45	0	0	0
SAFETY VALVE TEST			
TUBING SHUT - IN	1590	1560	1572
Bled down tubing to :	0	1015	1009
		1019	1017
10 Min			
	.19 cu ft	1022	1020
		1024	1022
		1026	1025
		1026	1025
CASING SHUT - IN	1589	1560	1572
Bled down casing to :	0	1014	1009
		1016	1011
10 Min			
	.65 cu ft	1017	1012
		1019	1013
		1021	1014
		1022	1014

WELL NUMBER:	LM 20D	LM 20D	LM 20D
DATE	12/16/13	11/20/14	12/28/15
CONTROL LINE TEST			k2s2
HYD. LINE S.I.	4500	4300	4300
HYD. :05	4500	4300	4300
HYD. :10	4500	4300	4300
Amount of fluid back. (OZ)	24	24	28
GAS in control line. (Y / N)	Y	Y	Y
Bled down pressure to :	0	0	0
* BUILD UP *			
:05	0		400
:10	0		600
:15	0		800
:30	0		1000
:45	0	1000	1000
SAFETY VALVE TEST			
TUBING SHUT - IN	1444	1531	1496
Bled down tubing to :	940	1005	1004
Control Line	0		
* Build Up * TUBING :05	942	1012	1014
Control Line --	0		
* Build Up * TUBING :10	944	1017	1016
Control Line --	0		
* Build Up * TUBING :15	945	1021	1018
Control Line --	0		
* Build Up * TUBING :30	947	1028	1022
Control Line --	0		
* Build Up * TUBING :45	948	1035	1024
Control Line --	0		
CASING SHUT - IN	1444	1531	1493
Bled down casing to :	940	1005	1004
Control Line --	0		
* Build Up * CASING :05	943	1008	1009
Control Line --	0		
* Build Up * CASING :10	945	1011	1010
Control Line --	0		
* Build Up * CASING :15	946	1012	1011
Control Line --	0		
* Build Up * CASING :30	948	1014	1013
Control Line --	0		
* Build Up * CASING :45	949	1016	1013
Control Line --	0		

WELL NUMBER:	LM 21D	LM 21D	LM 21D
DATE	10/17/13	10/29/14	10/29/15
CONTROL LINE TEST	RC-2	RC-2	RC-2
HYD. LINE S.I.	4200	4400	
HYD. :05	4200	4400	
HYD. :10	4200	4400	
Amount of fluid back. (OZ)	6	2	
GAS in control line. (Y / N)	N	N	
Bled down pressure to :	0	0	
* BUILD UP *			
:05			Accepted
:10			upon
:15			rework
:30			complete
:45	0	0	6/2/2015
SAFETY VALVE TEST			
TUBING SHUT - IN	1590	1566	
Bled down tubing to :		1063	
Control Line		0	
* Build Up * TUBING :05		1140	
Control Line --		0	
* Build Up * TUBING :10	33.1cu/ft	1198	
Control Line --		0	
* Build Up * TUBING :15		1269	
Control Line --		0	
* Build Up * TUBING :30		1500	
Control Line --		0	
* Build Up * TUBING :45		1566/FAIL	
Control Line --		0	
CASING SHUT - IN	1590	1567	
Bled down casing to :	will not	will not	
Control Line --	blowdown	blowdown	
* Build Up * CASING :05			
Control Line --			
* Build Up * CASING :10			
Control Line --			
* Build Up * CASING :15			
Control Line --			
* Build Up * CASING :30			
Control Line --			
* Build Up * CASING :45			
Control Line --			

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX J

2013-2015 DHSV TEST RESULTS:

MCDONALD ISLAND & LOS MEDANOS

2013 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

Field Name	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
Los Medanos	**1A**	4	1	1	2007	RC-2
Los Medanos	**2A**	OK	1	1	2005	RC
Los Medanos	**3A**	OK	1	1	2000	RC
Los Medanos	**4B**	Rework well			2013	RC-2
Los Medanos	**5B**	Rework well			2013	RC-2
Los Medanos	**6B**	OK	1	1	2006	RC-2
Los Medanos	**7C**	OK	1	1	1992	RC
Los Medanos	**8C**	OK	4	N/A	2012	T5 only
Los Medanos	**9C**	OK	1	1	2011	RC-2
Los Medanos	**10C**	OK	1	4	2003	RC
Los Medanos	**11C**	OK	4	1	1992	RC
Los Medanos	**12C**	OK	1	1	1991	RC
Los Medanos	**13C**	1	1	1	1990	RC
Los Medanos	**14C**	1	1	1	1990	RC
Los Medanos	**15C**	0	1	1	1999	RC
Los Medanos	**16D**	0	2	4	2004	RC
Los Medanos	**17D**	0	1	1	1997	RC
Los Medanos	**18D**	OK	1	1	1992	RC
Los Medanos	**19D**	0	1	1	2007	RC-2
Los Medanos	**20D**	0	1	1	1990	RC
Los Medanos	**21D**	1	1	4	2008	RC-2
McDonald Island	**1N**	0	1	1	2013	Baker RC-2
McDonald Island	**2N**	0	1	1	2013	Baker RC-2
McDonald Island	**3N**	0	4*	4*	2010	Baker RC-2
McDonald Island	**4N**	0	1	0	2006	Baker RC-2
McDonald Island	**5N**	0	1	1	2013	Baker RC-2
McDonald Island	**6N**	0	1	1	2006	Baker RC-2
McDonald Island	**7N**	0	2	1	2003	Baker RC
McDonald Island	**8N**	0	4	4	2000	Baker RC
McDonald Island	**9N**	0	1	1	2006	Baker RC-2
McDonald Island	**10N**	0	1	1	2013	Baker RC-2
McDonald Island	**11N**	0	1	1	2013	Baker RC-2
McDonald Island	**12N**	0	1	2	2000	Baker RC
McDonald Island	**13N**	0	1	1	1985	Baker RC
McDonald Island	**15N**	0	1	1	2012	Baker RC-2
McDonald Island	**16N**	0	1	1	2010	Baker RC-2
McDonald Island	**17N**	0	4	4	2000	Baker RC
McDonald Island	**1AS**	0	1	1	1991	Baker RC
McDonald Island	**1S**	4	1	3	2002	Baker RC
McDonald Island	**2S**	0	3	1	2004	Baker RC
McDonald Island	**3S**	0	1	1	2010	Baker RC-2
McDonald Island	**4S**	0	4	1	2004	Baker RC
McDonald Island	**5S**	0	1	1	2004	Baker RC
McDonald Island	**6S**	0	1	1	2010	Baker RC-2
McDonald Island	**7S**	0	2	1	1993	Baker RC
McDonald Island	**8S**	0	1	1	2007	Baker RC-2
McDonald Island	**9S**	4 *	2	1	2002	Baker RC
McDonald Island	**10S**	0	1	1	2010	Baker RC-2

2013 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

Field Name	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
McDonald Island	**11S**	0	1	1	2009	Baker RC-2
McDonald Island	**12S**	3	1	1	2007	Baker RC-2
McDonald Island	**13S**	0	3	3	1998	Baker RC
McDonald Island	**14S**	4 *	4	1	1993	Baker RC
McDonald Island	**15S**	0	1	1	2004	Baker RC
McDonald Island	**16S**	0	2	2	2003	Baker RC
McDonald Island	**17S**	0	0	0	2004	Baker RC
McDonald Island	**1AE**	0	1	0	2009	Baker RC-2
McDonald Island	**1E**	0	1	1	2005	Baker RC-2
McDonald Island	**2E**	0	3	1	2001	Baker RC
McDonald Island	**3E**	4	1	1	2001	Baker RC
McDonald Island	**4E**	0	1	1	2007	Baker RC-2
McDonald Island	**5E**	0	1	1	2012	Baker RC-2
McDonald Island	**6E**	0	1	4*	2007	Baker RC-2
McDonald Island	**7E**	0	1	0	2012	Baker RC-2
McDonald Island	**8E**	0	1	1	2012	Baker RC-2
McDonald Island	**9E**	0	1	1	2007	Baker RC-2
McDonald Island	**11E**	0	0	1	2011	Baker RC-2
McDonald Island	**12E**	0	1	1	2012	Baker RC-2
McDonald Island	**13E**	0	1	1	2005	Baker RC-2
McDonald Island	**14E**	0	3	1	2005	Baker RC
McDonald Island	**1AW**	4	1	4	2001	Baker RC
McDonald Island	**1W**	0	1	1	2008	Baker RC-2
McDonald Island	**2W**	0	0	1	2009	Baker RC-2
McDonald Island	**3W**	0	1	1	2012	Baker RC-2
McDonald Island	**4W**	0	1	4*	2008	Baker RC-2
McDonald Island	**5W**	0	4	1	1999	Baker RC
McDonald Island	**6W**	0	0	1	2009	Baker RC-2
McDonald Island	**7W**	0	1	1	2011	Baker RC-2
McDonald Island	**8W**	0	1	1	2011	Baker RC-2
McDonald Island	**9W**	0	1	1	1994	Baker RC
McDonald Island	**10W**	0	1	1	1990	Baker RC
McDonald Island	**11W**	0	1	1	1995	Baker RC
McDonald Island	**12W**	4	1	1	2009	Baker RC-2
McDonald Island	**13W**	0	0	1	2008	Baker RC-2
McDonald Island	**15W**	0	1	1	2011	Baker RC-2
McDonald Island	**16W**	0	4	1	2005	Baker RC
McDonald Island	**17W**	0	1	1	2009	Baker RC-2
McDonald Island	**18W**	0	1	1	2011	Baker RC-2
McDonald Island	**19W**	0	1	1	2008	Baker RC-2
McDonald Island	**20W**	0	3	0	1999	Baker RC

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

* Will not blowdown

2014 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

FIELD NAME	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
Los Medanos	**1A**	4	1	1	2007	RC-2
Los Medanos	**2A**	1	3	1	2005	RC
Los Medanos	**3A**	1	1	1	2000	RC
Los Medanos	**4B**	0	4	1	2013	RC-2
Los Medanos	**5B**	0	1	4*	2013	RC-2
Los Medanos	**6B**	1	4	1	2006	RC-2
Los Medanos	**7C**	1	1	1	1992	RC
Los Medanos	**8C**	1	4	N/A	2012	T5 only
Los Medanos	**9C**	0	1	1	2011	RC-2
Los Medanos	**10C**	0	1	4	2003	RC
Los Medanos	**11C**	1	1	4	1992	RC
Los Medanos	**12C**	1	1	1	1991	RC
Los Medanos	**13C**	1	1	1	1990	RC
Los Medanos	**14C**	1	1	1	1990	RC
Los Medanos	**15C**	4	1	1	1999	RC
Los Medanos	**16D**	0	2	4	2004	RC
Los Medanos	**17D**	4	2	4*	1997	RC
Los Medanos	**18D**	0	1	1	1992	RC
Los Medanos	**19D**	1	1	1	2007	RC-2
Los Medanos	**20D**	4	1	1	1990	RC
Los Medanos	**21D**	0	4	4	2008	RC-2
McDonald Island	**1N**	0	1	1	2013	Baker RC-2
McDonald Island	**2N**	0	3	4*	2013	Baker RC-2
McDonald Island	**3N**	0	4	4*	2010	Baker RC-2
McDonald Island	**4N**	0	4	1	2006	Baker RC-2
McDonald Island	**5N**	0	1	1	2013	Baker RC-2
McDonald Island	**6N**	0	4	1	2006	Baker RC-2
McDonald Island	**7N**	4	1	1	2003	Baker RC
McDonald Island	**8N**	Rework	1	1	2014	Baker RC-2
McDonald Island	**9N**	0	2	4*	2006	Baker RC-2
McDonald Island	**10N**	0	1	1	2013	Baker RC-2
McDonald Island	**11N**	0	1	1	2013	Baker RC-2
McDonald Island	**12N**	0	1	3	2000	Baker RC
McDonald Island	**13N**	0	1	1	1985	Baker RC
McDonald Island	**15N**	0	1	1	2012	Baker RC-2
McDonald Island	**16N**	0	1	1	2010	Baker RC-2
McDonald Island	**17N**	Rework	1	1	2014	Baker RC-2
McDonald Island	**1AS**	0	2	1	1991	Baker RC
McDonald Island	**1S**	0	1	3	2002	Baker RC
McDonald Island	**2S**	0	1	1	2004	Baker RC
McDonald Island	**3S**	0	1	1	2010	Baker RC-2
McDonald Island	**4S**	0	3	1	2004	Baker RC
McDonald Island	**5S**	0	1	1	2004	Baker RC
McDonald Island	**6S**	0	1	1	2010	Baker RC-2
McDonald Island	**7S**	4	3	1	1993	Baker RC
McDonald Island	**8S**	Rework	1	1	2014	Baker RC-2
McDonald Island	**9S**	Rework	1	1	2014	Baker RC-2
McDonald Island	**10S**	0	2	1	2010	Baker RC-2
McDonald Island	**11S**	0	4	1	2009	Baker RC-2

2014 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

FIELD NAME	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
McDonald Island	**12S**	Rework	1	1	2014	Baker RC-2
McDonald Island	**13S**	Rework	1	1	2014	Baker RC-2
McDonald Island	**14S**	0	4*	1	1993	Baker RC
McDonald Island	**15S**	0	2	1	2004	Baker RC
McDonald Island	**16S**	0	2	1	2003	Baker RC
McDonald Island	**17S**	0	1	1	2004	Baker RC
McDonald Island	**1AE**	0	4*	3	2009	Baker RC-2
McDonald Island	**1E**	0	1	1	2005	Baker RC-2
McDonald Island	**2E**	4	3	1	2001	Baker RC
McDonald Island	**3E**	Well Out Of Service			2001	Baker RC
McDonald Island	**4E**	0	4	1	2007	Baker RC-2
McDonald Island	**5E**	0	4	1	2012	Baker RC-2
McDonald Island	**6E**	0	4	1	2007	Baker RC-2
McDonald Island	**7E**	0	3	1	2012	Baker RC-2
McDonald Island	**8E**	0	3	1	2012	Baker RC-2
McDonald Island	**9E**	0	4	1	2007	Baker RC-2
McDonald Island	**11E**	0	2	1	2011	Baker RC-2
McDonald Island	**12E**	0	4	1	2012	Baker RC-2
McDonald Island	**13E**	0	4	1	2005	Baker RC-2
McDonald Island	**14E**	0	4	1	2005	Baker RC
McDonald Island	**1AW**	0	1	4	2001	Baker RC
McDonald Island	**1W**	0	4	4*	2008	Baker RC-2
McDonald Island	**2W**	0	3	1	2009	Baker RC-2
McDonald Island	**3W**	0	1	4*	2012	Baker RC-2
McDonald Island	**4W**	0	4	1	2008	Baker RC-2
McDonald Island	**5W**	0	4	1	1999	Baker RC
McDonald Island	**6W**	0	1	1	2009	Baker RC-2
McDonald Island	**7W**	0	4	2	2011	Baker RC-2
McDonald Island	**8W**	0	4	1	2011	Baker RC-2
McDonald Island	**9W**	0	2	1	1994	Baker RC
McDonald Island	**10W**	0	3	1	1990	Baker RC
McDonald Island	**11W**	0	1	1	1995	Baker RC
McDonald Island	**12W**	0	1	1	2009	Baker RC-2
McDonald Island	**13W**	0	4	1	2008	Baker RC-2
McDonald Island	**15W**	0	4	1	2011	Baker RC-2
McDonald Island	**16W**	0	3	1	2005	Baker RC
McDonald Island	**17W**	0	2	1	2009	Baker RC-2
McDonald Island	**18W**	0	1	1	2011	Baker RC-2
McDonald Island	**19W**	0	4*	4*	2008	Baker RC-2
McDonald Island	**20W**	0	4*	4*	1999	Baker RC

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

0: No leakage
1: 1 to 100 psig
2: 101 to 200 psig
3: 201 to 300 psig
4: 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

* Will not blowdown

2015 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

FIELD NAME	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
Los Medanos	**1A**	4	1	1	2007	RC-2
Los Medanos	**2A**	4	1	1	2005	RC
Los Medanos	**3A**	1	1	1	2000	RC
Los Medanos	**4B**	0	4	1	2013	RC-2
Los Medanos	**5B**	0	1	1	2013	RC-2
Los Medanos	**6B**	0	1	1	2006	RC-2
Los Medanos	**7C**	0	1	4*	1992	RC
Los Medanos	**8C**	0	2		2012	T5 only
Los Medanos	**9C**	0	1	1	2011	RC-2
Los Medanos	**10C**	0	1	4	2003	RC
Los Medanos	**11C**	New on 2015 rework			2015	RC-2
Los Medanos	**12C**	4	1	4*	1991	RC
Los Medanos	**13C**	1	1	1	1990	RC
Los Medanos	**14C**	1	1	1	1990	RC
Los Medanos	**15C**	1	1	1	1999	RC
Los Medanos	**16D**	0	1	4	2004	RC
Los Medanos	**17D**	1	1	1	1997	RC
Los Medanos	**18D**	0	1	1	1992	RC
Los Medanos	**19D**	1	1	1	2007	RC-2
Los Medanos	**20D**	4	1	1	1990	RC
Los Medanos	**21D**	New on 2015 rework			2015	RC-2
McDonald Island	**1N**	0	1	1	2013	Baker RC-2
McDonald Island	**2N**	0	4	4*	2013	Baker RC-2
McDonald Island	**3N**	0	2	4*	2010	Baker RC-2
McDonald Island	**4N**	0	3	1	2006	Baker RC-2
McDonald Island	**5N**	0	1	1	2013	Baker RC-2
McDonald Island	**6N**	0	3	1	2006	Baker RC-2
McDonald Island	**7N**	0	O/S	1	2003	Baker RC
McDonald Island	**8N**	0	1	1	2014	Baker RC-2
McDonald Island	**9N**	0	1	1	2006	Baker RC-2
McDonald Island	**10N**	0	1	1	2013	Baker RC-2
McDonald Island	**11N**	0	1	1	2013	Baker RC-2
McDonald Island	**12N**	0	1	0	2000	Baker RC
McDonald Island	**13N**	0	1	1	1985	Baker RC
McDonald Island	**15N**	0	1	4	2012	Baker RC-2
McDonald Island	**16N**	0	1	1	2010	Baker RC-2
McDonald Island	**17N**	0	1	1	2014	Baker RC-2
McDonald Island	**1AS**	0	1	1	1991	Baker RC
McDonald Island	**1S**	0	1	1	2002	Baker RC
McDonald Island	**2S**	0	2	2	2004	Baker RC
McDonald Island	**3S**	0	1	1	2010	Baker RC-2
McDonald Island	**4S**	0	3	1	2004	Baker RC
McDonald Island	**5S**	0	1	1	2004	Baker RC
McDonald Island	**6S**	0	2	1	2010	Baker RC-2
McDonald Island	**7S**	0	3	1	1993	Baker RC
McDonald Island	**8S**	0	2	1	2014	Baker RC-2
McDonald Island	**9S**	0	1	1	2014	Baker RC-2
McDonald Island	**10S**	0	3	1	2010	Baker RC-2

2015 DOWNHOLE SAFETY VALVE (DHSV) TESTING RESULTS

FIELD NAME	WELL	CONTROL LINE	TUBING DHSV	CASING DHSV	INSTALL DATE	TYPE
McDonald Island	**11S**	0	4	1	2009	Baker RC-2
McDonald Island	**12S**	0	4	1	2014	Baker RC-2
McDonald Island	**13S**	0	4	3	2014	Baker RC-2
McDonald Island	**14S**	Rework	1	1	2015	Baker RC-2
McDonald Island	**15S**	Rework	1	1	2015	Baker RC-2
McDonald Island	**16S**	0	2	1	2003	Baker RC
McDonald Island	**17S**	0	1	1	2004	Baker RC
McDonald Island	**1AE**	0	4	1	2009	Baker RC-2
McDonald Island	**1E**	0	1	1	2005	Baker RC-2
McDonald Island	**2E**	4*	1	1	2001	Baker RC
McDonald Island	**3E**	Rework	1	1	2015	Baker RC-2
McDonald Island	**4E**	0	4	1	2007	Baker RC-2
McDonald Island	**5E**	0	4	1	2012	Baker RC-2
McDonald Island	**6E**	0	4	1	2007	Baker RC-2
McDonald Island	**7E**	0	2	1	2012	Baker RC-2
McDonald Island	**8E**	0	1	1	2012	Baker RC-2
McDonald Island	**9E**	0	4	4*	2007	Baker RC-2
McDonald Island	**11E**	0	1	1	2011	Baker RC-2
McDonald Island	**12E**	0	2	1	2012	Baker RC-2
McDonald Island	**13E**	0	4	1	2005	Baker RC-2
McDonald Island	**14E**	0	3	1	2005	Baker RC
McDonald Island	**1AW**	4	2	4	2001	Baker RC
McDonald Island	**1W**	Rework	1	1	2015	Baker RC-2
McDonald Island	**2W**	0	2	1	2009	Baker RC-2
McDonald Island	**3W**	0	1	1	2012	Baker RC-2
McDonald Island	**4W**	0	4	1	2008	Baker RC-2
McDonald Island	**5W**	0	4	1	1999	Baker RC
McDonald Island	**6W**	0	1	1	2009	Baker RC-2
McDonald Island	**7W**	0	1	1	2011	Baker RC-2
McDonald Island	**8W**	0	4	1	2011	Baker RC-2
McDonald Island	**9W**	0	2	1	1994	Baker RC
McDonald Island	**10W**	0	1	1	1990	Baker RC
McDonald Island	**11W**	0	1	1	1995	Baker RC
McDonald Island	**12W**	1	1	1	2009	Baker RC-2
McDonald Island	**13W**	0	4	1	2008	Baker RC-2
McDonald Island	**15W**	0	4	1	2011	Baker RC-2
McDonald Island	**16W**	0	3	1	2005	Baker RC
McDonald Island	**17W**	0	2	1	2009	Baker RC-2
McDonald Island	**18W**	0	2	1	2011	Baker RC-2
McDonald Island	**19W**	0	4	4*	2008	Baker RC-2
McDonald Island	**20W**	0	4	4*	1999	Baker RC

RC Dhsv/ Control Line Rating *(Pressure Build-up/ 45 mins)*

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1: 1 to 100 psig
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3: 201 to 300 psig
4: 301 or higher

RC-2 Dhsv Rating *(Flow test/ 10 mins)*

1: ≤ 50.0 cu/ft
4: > 50.0 cu/ft

* Will not blowdown

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX K

2012-2015 STORAGE COMPRESSOR SAFETY BROCHURES

APPENDIX K

2012 STORAGE COMPRESSOR SAFETY BROCHURE

Natural Gas

Compression and Storage Facilities

There's safety in knowledge.

Pacific Gas and Electric Company
PO Box 2478
Austin, TX 78768-9912

Natural gas is one of the most efficient, reliable, and affordable sources of energy, and pipelines are the safest way of transporting it to our communities. Delivering safe and reliable service is PG&E's highest priority.

You are receiving this material because you live or work near one of the many PG&E facilities that help ensure reliable gas service across California. PG&E has a rigorous maintenance and monitoring schedule to ensure that these facilities keep our system operating smoothly and provide the safest possible service to your community.

In addition to underground pipelines, PG&E relies on several types of gas facilities to deliver reliable gas service. As natural gas flows through the pipelines, it slowly loses pressure and slows down. To assist in moving the gas through the system, compressor stations are placed along PG&E's transmission pipelines. The gas is compressed, which increases the pressure and the speed of the flow of gas, ultimately pushing the gas further down the pipeline. Compressor stations assist with regulating the flow and pressure of a pipeline system, ensuring that gas can be delivered to even the most distant points on the system.

PG&E also relies on storage facilities such as above ground holding tanks and underground gas reservoirs. These storage facilities permit natural gas to be safely stored until it is needed. This helps ensure an adequate supply of natural gas is available to our community during times of high demand, such as cold winter days.

Know the location of PG&E facilities

You can learn where the nearest PG&E gas transmission pipelines are by using our interactive online map at www.pge.com/pipelinelocations.

Natural gas safety tips

Natural gas leaks and accidents are rare, but there's safety in knowing how to respond. Using your senses will help you recognize a leak and respond safely.

To recognize a natural gas leak or emergency:

Sight	Discolored vegetation in an otherwise green or moist area, dust or dirt blowing from an unexpected area, or flames
Sound	A whistle, roaring or hissing sound
Smell	A sulfur-like odor similar to rotten eggs
To respond safely, **DO:**	1 **Immediately** leave the area 2 **Call 911** - Then call PG&E at **1-800-743-5000** 3 **Keep others away** from the area
To respond safely, **DO NOT:**	• Do anything that could cause a fire or create a spark including: - Starting an engine; - Turning switches on or off; or, - Using a phone or cell phone, unless in a safe area • Attempt to stop the gas from leaking, turn off a valve or put out a fire • Remain near the suspected gas leak

How PG&E keeps you safe

PG&E takes significant steps to keep our natural gas facilities safe by using the latest technology and maintenance programs. We prepare and practice emergency response protocols and work closely with emergency responders to be prepared to coordinate in the event an emergency occurs. We also take additional steps to ensure the integrity of pipelines that are located in sensitive or highly populated areas. We actively patrol our pipelines, perform leak surveys and conduct pipeline inspections. For more information on how PG&E maintains the safety of our natural gas system, please visit: www.pge.com/gas.

Know what's below. Call 811 before you dig

Planting a tree, installing sprinklers, building a fence, or planning other digging? In most situations, California law requires you or others doing excavation work to call 811 at least two working days before digging. Homeowners, workers, contractors and professional excavators need to know where gas and electric lines lie underground to prevent injuries, property damage and outages. After you call 811, utility operators like PG&E will send a representative to mark the location of their underground facilities, free of charge.

811 Know what's **below.** **Call** before you dig.

Three steps to a safe digging project

1. Survey proposed excavation areas, and mark the dig site with white chalk, paint or flour.
2. Call 811 before you dig, and allow utilities such as PG&E the required two working days to mark any nearby underground lines.
3. Dig with care. Determine the exact location of the underground line by using hand tools to excavate within 24 inches of the underground line.

To report an emergency or unsafe digging around a pipeline, call 1-800-743-5000 24 hours a day.

Pipeline markers

Pipeline markers designate the general route of a pipeline and include emergency contact information. However, pipelines may not follow a straight path between pipeline markers, so please call 811 before digging near a pipeline marker.

And most importantly, know where to find more information

For assistance in English please call
1-888-743-7431.

Para ayuda en español por favor llame al
1-800-660-6789.

要用粵語/國語請求協助，請致電
1-800-893-9555.

Kung kailangang makipag-usap sa nakakasalita ng Tagalog, tumawag sa
1-888-743-7431.

Để được giúp đỡ bằng tiếng Việt, xin gọi
1-800-298-8438.

PG&E

APPENDIX K

2013 STORAGE COMPRESSOR SAFETY BROCHURE

Pacific Gas and Electric Company
551 East Street
Hollister, CA 95023

Important safety information about PG&E compressor stations and storage facilities

If you have additional questions or would like more information, visit pge.com/pipelinesafety or contact us at the numbers below:

For assistance in English, please call............................**1-888-743-7431**

Para ayuda en español, por favor llame al...................**1-800-660-6789**

要用粵語/國語請求協助，請致電...............................**1-800-893-9555**

Để được giúp đỡ bằng tiếng Việt, xin gọi........................**1-800-298-8438**

811. It's Easy. It's Free. Call Before You Dig.

You live or work near a PG&E Compressor Station or Storage Facility

We monitor our gas pipeline operations 24 hours a day, 7 days a week and conduct regular inspections and surveys on pipelines and facilities. Learn about the projects PG&E is undertaking to improve the safety and reliability of our gas system at **pge.com/pipelinesafety.**

Important Safety Information

There's safety in knowledge. Your safety is our top priority. PG&E is committed to becoming the safest, most reliable gas system in the nation. We operate natural gas distribution and transmission pipeline systems across California. Compressor stations and storage facilities are an important part of these systems.

You are receiving this safety information because our records indicate that you live or work within approximately 1,000 feet of a PG&E compressor station or underground storage facility. For more information, call us at **1-888-743-7431.**

Compressor Stations

Above-ground compressor station facilities are located at regular intervals along the pipeline route. They assist with regulating the flow and pressure of natural gas in the pipeline system so that gas can be transported from one area to another. This helps us ensure that gas is delivered to even the most distant point along the gas system.

Gas enters the compressor station from connecting pipelines. The gas is then compressed and cooled. This provides the gas enough energy to move through the pipeline until it is delivered to our customers or reaches the next compressor station.

Storage Facilities

Underground gas storage facilities are connected to pipeline systems and safely store natural gas until it is needed. The ability to store gas helps ensure we have an adequate supply of natural gas available to our customers during times of high demand, such as cold winter days.

Emergency Response Procedures

We have gas detection, fire detection and emergency shutdown systems in place at PG&E compressor stations and storage facilities to protect neighbors, staff and our gas system. Our personnel are trained to respond to emergency situations and to work directly with local emergency response officials.

In the event of an emergency, you will be notified by local emergency response officials with instructions for evacuation or shelter-in-place procedures. Call our Gas Help Line at **1-888-743-7431** if you have questions about our emergency response procedures.

Safety Is a Shared Responsibility

We monitor our gas pipeline operations 24 hours a day, 7 days a week and conduct regular inspections and surveys on pipelines and facilities. Learn about the projects PG&E is undertaking to improve the safety and reliability of our gas system at pge.com/pipelinesafety.

You play a critical role in natural gas safety. Your awareness and actions can increase the safety of your home and community. Together, we can make gas safety a priority every day.

Know the Signs of a Gas Pipeline Leak

Both compressor stations and underground storage facilities connect to natural gas pipelines. Know the signs of a gas pipeline leak and how to respond.

Signs of a gas leak can include:

- A "rotten egg" odor
- Hissing, whistling or roaring sounds outside near the pipeline or inside near an appliance
- Dirt spraying into the air, continuous bubbling in a pond or creek
- Dead or dying vegetation in an otherwise moist area near the line

If you smell, hear or see signs of a gas pipeline leak, **leave the area** in an upwind direction, **warn others** to stay away and from a safe place **call 911 and PG&E at 1-800-743-5000.**

Do not light a match, operate a vehicle or use any electronic device near a gas pipeline leak.

APPENDIX K

2014 STORAGE COMPRESSOR SAFETY BROCHURE

Safety information for customers near PG&E's gas facilities

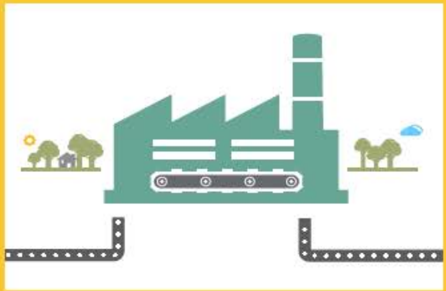
You live or work within approximately 1,000 feet of a compressor station and/or a storage facility.

Look inside for more gas safety tips

K-8

Together, Building a Better California

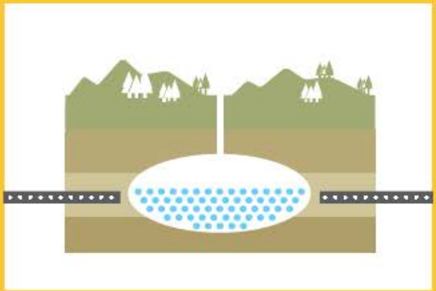
Safety information on facilities near you



Compressor Stations

Above-ground facilities are located at regular intervals along the transmission pipeline route.

They assist with regulating the flow and pressure of natural gas in the pipeline system ensuring the transportation of gas from one area to another. This helps us deliver gas to even the most distant point in our gas system.



Storage Facilities

Underground gas storage facilities connect to pipeline systems and safely store natural gas.

The ability to store gas helps ensure we have an adequate supply of natural gas available to our customers during times of high demand, such as cold winter days.

To learn which natural gas facility is near you, visit pge.com/gasfacilities.

Emergency Response Procedures

We have gas detection, fire detection and emergency shutdown systems in place at PG&E compressor stations and storage facilities to protect our neighbors, employees and our gas system.

Our employees respond quickly and coordinate directly with local emergency response officials. In the event of an emergency, local emergency response officials will notify you with instructions for evacuation or shelter-in-place procedures.

You can learn more by calling our Gas Help Line at 1-888-743-7431.

Safety is at the heart of everything we do

We operate, monitor and maintain natural gas distribution and transmission pipelines across California.

Our larger transmission pipelines carry gas from one part of the state to another and connect to our **distribution system**. These smaller lines deliver natural gas for heating and cooking to your home and business. We monitor our gas pipeline system 24 hours a day, 7 days a week. We maintain a comprehensive safety and monitoring program and regularly inspect all of our pipelines for possible leaks or other signs of damage to ensure natural gas safety.

Learn about the projects PG&E is undertaking as part of our commitment to provide safe, reliable and affordable natural gas service for our customers—visit pge.com/seeourprogress.

Locate PG&E natural gas pipelines near you

You can spot PG&E's larger transmission pipelines near you by looking for pipeline markers. Markers include an emergency contact number and indicate the need for extra care when digging in the area. These markers specify the approximate or offset location; however, not all pipelines follow a straight path between markers.

Use our interactive online map
Visit pge.com/pipelinelocations to learn more about the transmission pipelines in your neighborhood. You can view any location in our service area—including your home—to see if transmission pipelines run nearby.

Protect pipeline right-of-ways

We conduct regular maintenance within the right-of-way that often includes mowing, trimming or removing shrubs, trees or other items near the pipeline. This clear access allows us to safely maintain, inspect and operate our system.

Learn more online at
pge.com/rightofway

Prevent accidentally digging into underground pipelines

Damage from digging is a common cause of pipeline accidents. PG&E is committed to reducing accidental dig-ins to our underground gas and electric lines.

When you call **811**, this free program notifies local utility companies to mark the location of underground lines. PG&E will locate and mark the horizontal location of underground facilities by painting stripes on surface streets and sidewalks or placing colored flags in landscaped areas so you can dig safely.

Always call 811 at least two working days before **any** digging to have gas pipelines and other underground utility lines located and marked for **FREE**.

Safe digging tips

California law requires contractors to practice safe excavation by calling 811 two working days before digging projects.

Use hand held digging tools when digging within 24 inches of the outside edge of any underground lines.

PG&E and other utilities will use colored utility flags, stakes or paint to mark underground lines. Leave these in place until you have finished digging.

Learn more at pge.com/digsafely.

Spot a natural gas leak

You play a critical role in natural gas safety and should report any signs of a gas leak. Your awareness and actions can increase the safety of your home and community. Together, we can make gas safety a priority every day.

Smell: We add a distinctive, sulfur-like "rotten egg" odor, so you can detect even small amounts of natural gas.

Sound: Pay attention to hissing, whistling or roaring sounds coming from underground or from a gas appliance.

Sight: Be aware of dirt spraying into the air, continual bubbling in a pond or creek and dead or dying vegetation in an otherwise moist area.

Respond if there is a gas leak.

If you suspect a gas leak or if you or your contractor accidentally dent, scrape, or hit a gas pipeline, **alert others and leave the area immediately** for a safe, upwind location. Then call 911 to notify local police and fire and contact PG&E at 1-800-743-5000.

Do not use anything that could be a source of ignition until you are a safe distance away. Devices that might create a spark include vehicles, cell phones, matches, electric switches, doorbells and garage door openers.

K-15

Pacific Gas and Electric Company
P.O. Box 997315
Sacramento, CA 95899

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Learn about the projects PG&E is undertaking to provide safe, reliable and affordable natural gas service for our customers—visit pge.com/seeourprogress or contact us at the numbers below.

For assistance in English please call
1-888-743-7431

Para ayuda en español, por favor llame al
1-800-660-6789

要用粵語/國語請求協助，請致電
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Kung kailangang makipag-usap sa nakakasalita ng Tagalog, tumawag sa
1-888-743-7431

Đ c giúp b ng ti ng Vi t, xin g i
1-800-298-8438

Call 811 two working days before you dig. It's FREE!

APPENDIX K

2015 STORAGE COMPRESSOR SAFETY BROCHURE

Living or working near a PG&E facility

You live or work near a PG&E compressor or storage facility—see inside for more info and gas safety tips.

Together, Building
a Better California

Safety is at the heart of everything we do

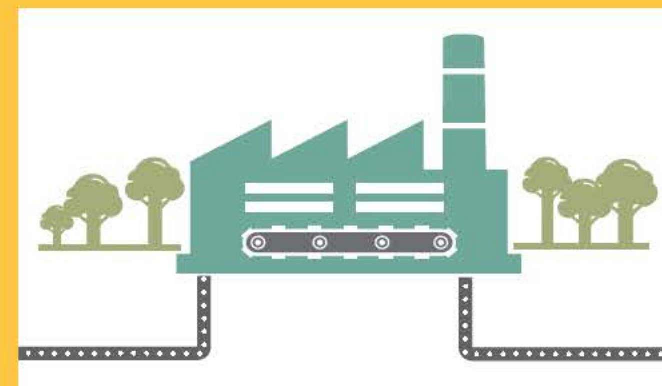
We operate, monitor and maintain natural gas pipelines across California. Our larger transmission pipelines carry gas from one part of the state to another and connect to our distribution system. The smaller distribution pipelines deliver natural gas for heating and cooking to your home or business.

We monitor our pipeline system 24 hours a day, 7 days a week, and maintain a comprehensive safety program. We regularly inspect all of our pipelines for possible leaks or other signs of damage to ensure natural gas safety. Safety is at the heart of everything we do, and this work is all part of our system-wide commitment toward providing safe, reliable, clean and affordable natural gas to all of our customers across the state of California.

PG&E's natural gas system serves millions of California homes and businesses, and includes more than 45,000 miles of pipelines, all working together to provide service to approximately 4.2 million customers from Bakersfield to the Oregon border.

Essential to the integrity of the system are compressor and storage facilities. Located throughout the service territory, these facilities help ensure that the pressure within the pipelines is regulated and that our customers receive consistent and reliable service, no matter how high the demand.

Your home or office is near a compressor station or storage facility. Learn more about our facilities, what living near one means for you, and how you can help prevent damage to facilities and help keep members of your community safe.



Compressor stations

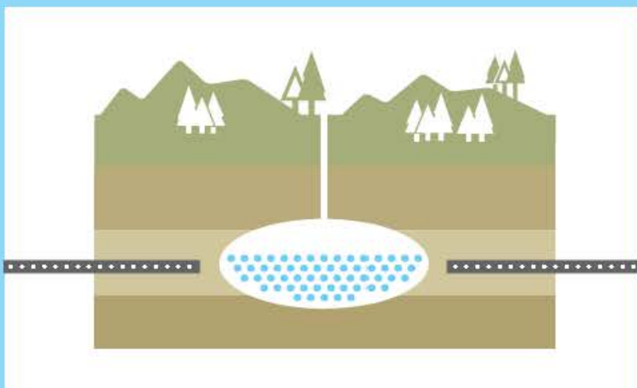
Above-ground compressor stations are located at regular intervals along the transmission pipeline system, helping regulate the flow and pressure of natural gas throughout our service area. There are eight compressor stations in our system that enable us to safely deliver natural gas to every corner of our gas system.

Emergency response procedures

We have gas detection, fire detection and emergency shutdown systems in place at PG&E compressor stations and storage facilities to protect our neighbors, employees and our gas system.

Our employees respond quickly and coordinate directly with local emergency response officials. In the event of an emergency, local emergency response officials will notify you with instructions for evacuation or shelter-in-place procedures.

Safety is paramount and we're all in this together.



Storage facilities

Underground storage facilities connect to pipeline systems and safely store natural gas. The ability to store gas helps balance costs and provide savings for our customers and helps ensure that we have an adequate supply of natural gas available to our customers during times of high demand, such as cold winter days.

Is there a compressor or a storage station near you?

Find out.

Just visit **pge.com/gasfacilities** and enter your home or office address to see where our facilities are located.

Spread the knowledge

How can you help? One way you can help keep your community safe and your gas service reliable is by learning where pipelines are located. Visit **pge.com/pipelinelocations** to find the pipelines in your community.

Locate pipelines near you

A pipeline right-of-way is a strip of land in which a pipeline is installed either above or beneath the ground. Maintaining clear access to the pipeline allows us to safely maintain, inspect and operate our pipeline system.

Help protect these rights-of-ways by learning if pipelines exist on or near your property, practicing safe digging in those areas, and knowing how to plant the right tree in the right place by visiting **pge.com/righttreerightplace**.

Pipeline markers

Spot PG&E's larger transmission pipelines by looking for pipeline markers like the one pictured, which specify the approximate location of an underground pipeline. Markers include an emergency contact number and indicate the need for extra care when digging in the area.

No project is too small to call

From hiring a landscaper to planting a garden, always call 811 before you dig. Utilities will mark the location of lines so you can exercise safe digging. It's free and it's the law.

Use hand-held tools when digging within 24 inches of marked lines.

Leave markings in place until your project is complete. PG&E and other utilities will use colored utility flags, stakes, or paint to mark your underground lines.

Don't forget to backfill and compact the soil when your project is done.

Gas safety tips

Spot a gas leak

Your awareness and actions can increase the safety of your home and community—always report signs of a gas leak.

Smell: Be aware of a distinctive, sulfur-like "rotten egg" odor—added to normally odorless natural gas, to help you detect even small amounts of natural gas.

Sound: Pay attention to hissing, whistling or roaring sounds coming from underground or from a gas appliance.

Sight: Take notice of your usual surroundings—watch for dirt spraying into the air, continual bubbling in a pond or creek, and dead or dying vegetation in an otherwise moist area.

Respond to a gas leak

If you suspect a leak, or if you or your contractor accidentally damages a pipeline, alert others and immediately walk to a safe, upwind location.

- **Call 911** to notify emergency responders.
- Call PG&E at **1-800-743-5000**.

Don't use anything that could be a source of ignition until you've evacuated the area. Devices that could create a spark include vehicles, cell phones, matches, electric switches, doorbells or garage door openers.

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PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX L

GOVERNOR'S EMERGENCY PROCLAMATION

Governor's Emergency Proclamation

Directive #	Brief Description
1	All state agencies to provide necessary support during response to incident.
2	Office of Emergency Services to coordinate state agencies and provide updates to affected residents.
3	CPUC and CEC to ensure SoCal Gas maximizes withdrawals from Aliso Canyon.
4	DOGGR to direct SoCal Gas to capture leaking gas and odorant while relief wells being completed.
5	DOGGR to require SoCal Gas to identify how to stop leak if pumping through relief wells fails or leak worsens.
6	Ensure SoCal Gas' proposals to Directives 4 and 5 are evaluated by panel of experts from Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories.
7	DOGGR continue to prohibit injection into Aliso Canyon until comprehensive review completed.
8	ARB and other agencies to monitor emissions and provide public updates on air quality.

ARB = California Air Resources Board
CAISO = California Independent System Operator
CEC = California Energy Commission
DOGGR = Division of Oil, Gas, and Geothermal Resources

Governor's Emergency Proclamation (cont.)

Directive #	Brief Description
9	Office of Environmental Health Hazard Assessment convene independent panel to evaluate if additional measures needed to protect public health.
10	CPUC, CEC, and CAISO to ensure continued reliability of gas and electricity supplies during Aliso Canyon injection moratoriums.
11	CPUC to ensure SoCal Gas covers costs related to leak and response.
12	ARB and state agencies to develop program funded by SoCal Gas to mitigate leak's emissions of methane by March 31, 2016.
13	DOGGR to promulgate emergency regulations for California's storage operators.
14	DOGGR, CPUC, ARB, and CEC submit report that assesses long-term viability of storage in California, operational safety, potential health risks, emissions, supply reliability for gas and electric demand, and role of storage and natural gas infrastructure in the State's long-term greenhouse gas reduction strategy. Report due to Governor's office six months after completion of investigation of cause of Aliso Canyon leak.

ARB = California Air Resources Board
CAISO = California Independent System Operator

CEC = California Energy Commission
DOGGR = Division of Oil, Gas, and Geothermal Resources