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Development of an Integrated Risk Management and Decision-Support System (IRMDSS) for Assuring the Integrity of Underground Natural Gas Storage Infrastructure in California

Gavin Newsom, Governor

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division manages the Natural Gas Research and Development Program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with research, development and demonstration (RD&D) entities, including individuals, businesses, utilities and public and private research institutions. This program promotes greater natural gas reliability, lower costs and increases safety for Californians and is focused in these areas:

- Buildings End-Use Energy Efficiency.
- Industrial, Agriculture and Water Efficiency.
- Renewable Energy and Advanced Generation.
- Natural Gas Infrastructure Safety and Integrity.
- Energy-Related Environmental Research.
- Natural Gas-Related Transportation.

Development of an Integrated Risk Management and Decision-Support System (IRMDSS) for Assuring the Integrity of Underground Natural Gas Storage Infrastructure in California is the final report for the, "An Integrated Risk Management and Decision-Support System (IRMDSS) for Assuring the Integrity of Underground Natural Gas Storage Infrastructure in California," project (PIR-16-027) conducted by Lawrence Berkeley National Laboratory. The information from this project contributes to the Energy Research and Development Division's Natural Gas Research and Development Program.

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ABSTRACT

Studies have concluded that underground natural gas storage (UGS) in California has served a critical role in meeting winter heating and summer cooling demands and will continue to serve this role for the foreseeable future. As a result, to guarantee energy reliability in California, it is crucial to ensure the safety and integrity of UGS infrastructure. The purpose of this project is to develop an Integrated Risk Management and Decision-Support System (IRMDSS) to improve loss of containment risk management for the subsurface components of UGS, specifically wells and caprock integrity. The risk management framework is built on a combination of advanced monitoring technologies and physics-based mechanistic simulation tools, taking advantage of the prediction capability of advanced mechanistic models, and (near) real-time monitoring data collected in the field to provide leading indicators of imminent risk, early leakage detection, or long-term assessment of potential risk. In addition, a supervisory interface is developed to integrate system components and to perform analyses using models and monitoring data, along with visualization of data and model results. The analysis is used to provide the key information needed to support evidence-based and defensible decision-making. The tools developed in the IRMDSS can be subsequently used in evaluating mitigation strategies. The IRMDSS is expected to provide greater energy reliability, lower costs from failure or incidents, and increased safety for underground gas storage. The project is in collaboration with Southern California Gas Company which provided its Honor Rancho Gas Storage Facility for the IRMDSS development and demonstration.

Keywords: Underground Natural Gas Storage, Risk Management, Mechanistic Models, Advanced Monitoring Technologies

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Introduction

Natural gas can be stored in underground reservoirs for later use when demand exceeds the overall pipeline transport supply rate. The underground natural gas storage system in California, with a total capacity of just under 400 billion cubic feet (Bcf) of natural gas, provides essential energy reliability services to meet energy demand during peak periods in winter and in summer. The report by the California Council on Science and Technology (CCST) (2018) concluded that although the need for underground gas storage (UGS) might be reduced in the coming decades, natural gas storage will be needed into the foreseeable future to meet California's large demand for natural gas for heating during peak periods in the winter. UGS can be carried out in caverns, aquifers, or depleted gas or oil reservoirs such as those used in California. Incidents of various kinds involving gas leakage and fires/explosions have been known to occur at UGS sites around the world (Evans, 2008, 2009; Folga et al., 2016).

The main hazard of UGS is that natural gas is highly flammable when mixed with air at certain concentrations, making gas leakage at the ground surface a severe safety hazard and threat to surface infrastructure (Miyazaki, 2009). At the same time, the tendency for gas to leak is ever-present because of the high pressure of the stored gas and the need to contain high-pressure gas over repeated injection and withdrawal cycles through wells. Loss-of-containment (LOC) happens when natural gas contained in the storage reservoir unintentionally leaks from the reservoir. Failure of a well to contain high pressure gas results in a LOC. This can occur anywhere along a failed well, but the most serious kind of LOC is the surface blowout such as the one that occurred at the Aliso Canyon UGS facility in California in October 2015 (e.g., Conley et al., 2016; Freifeld et al., 2016; Pan et al., 2017). LOC can also occur due to fracturing or faulting of the caprock (e.g., Evans and Schultz, 2017). Either leakage through a well or leakage through fractures can cause gas loss and/or potentially catastrophic damage to natural gas storage facilities at the ground surface, with potential injury to workers and the public, along with large emissions of CH_4, a potent greenhouse gas.

There are many surface (e.g., pipes, compressors, expanders, and gas-processing units) and subsurface (e.g., reservoir, caprock and wells) components of UGS systems relied upon to transport and contain high-pressure gas between the transmission pipeline and the storage reservoir. Failures of one or more of these components arising from any number of causes, e.g., accidents, poor maintenance, and/or errors in operation, can result in incidents with catastrophic consequences. UGS operators follow state regulations and their own internal risk management protocols and procedures to safely operate their UGS surface and subsurface infrastructure. In California, the surface infrastructure consisting of pipes, compressors, expanders, and gas-processing units is regulated by the California Public Utilities Commission (Interagency Task Force, 2016), while the wells which can extend up to two miles downward into the subsurface are regulated by the California Geologic Energy Management Division (CalGEM, formerly, the Department of Oil, Gas, and Geothermal Resources) (California Department of Conservation, 2021). All UGS reservoirs in California are in porous media in depleted oil or gas reservoirs. There are about 350 active wells in these fields. Many of them are re-purposed and aging wells built originally for gas or oil production. In contrast to surface infrastructure, wells at UGS sites are challenging to monitor and maintain because they are underground and many parts are not easily observable or accessible (e.g., the outer surface of casing and well cement that abuts the rock formation along the well). In addition to the risk from the engineered component, another failure scenario comes from failure of the natural system to contain gas (for example, leakage through caprock would occur if caprock integrity is compromised). Given that energy reliability especially during peak demand periods depends on natural gas in California, safety of UGS facilities is a key factor required to maintain the California energy system now and in the coming decade.

Currently, the standard overall risk management approach for UGS operation includes three steps: (1) threat (or hazard) identification, (2) development of risk mitigation activities, and (3) development of investment plans to reduce or mitigate risk. This approach focuses on hazard and threat identification using engineering methods and does not fully exploit mechanistic models that can potentially simulate and predict system failure and evaluate preventive measures (simulate what-if scenarios). Moreover, many of the subsurface monitoring programs at UGS sites rely on data collected at regular (infrequent) intervals (e.g., annual well-logging and well inspection). While annual noise and temperature logs can be used to identify wellbore leaks, they cannot indicate if a well failure is imminent, and it is possible for the well to leak the day after an inspection allowing the leak to evolve undetected and potentially growing in severity prior to the next logging run. Increasing well inspection frequency is not practical because well inspection operations carry their own risks, in addition to being costly.

Built on recent advances in monitoring technologies and physics-based mechanistic model simulation, an Integrated Risk Management and Decision-Support System (IRMDSS) was developed in this project to improve risk management for the subsurface components of UGS, specifically wells and geomechanical aspects controlling caprock integrity. The developed IRMDSS is a framework because the approach can be applied at various sites, even though the detailed components at each site will be different. The IRMDSS framework is designed to take advantage of continuous dynamic monitoring data available from new fiber-optic sensing approaches and the prediction capability of advanced mechanistic models. The combination of monitoring and modeling allows the operator to identify off-normal conditions and carry out what-if simulations to guide decision-making in preventing and mitigating LOC incidents.

Project Purpose

The purpose of this project was to develop a comprehensive and robust risk management framework (called the IRMDSS) that overcomes the limitations of current risk management approaches for UGS facilities in California to improve the safety of natural gas storage for energy reliability.

The IRMDSS aims at developing a number of tools that can be used to help operators identify potential risks (imminent or long-term evolving risks) and to help evaluate various safe operation and failure scenarios. If incidents have already happened, the tool can be used to analyze what happened and evaluate mitigation measures.

The specific goals of this project include:

- Develop a set of mechanistic models and analyses to estimate the risk and evaluate mitigation strategies for UGS under various operational and failure scenarios.
- Deploy advanced monitoring technologies and demonstrate how continuously updated monitoring data can be used to analyze scenarios.
- Provide a supervisory interface (SI) to integrate system components and help users to follow the workflow of the framework.

The framework was developed and demonstrated using the Honor Rancho site as the prototypical UGS site in close collaboration with the project partner, SoCalGas.

Project Approach

The approach of the IRMDSS is to merge mechanistic models with advanced monitoring technology for continuous reevaluation and assessment to provide indicators of potential threats. The three main components of the IRMDSS are:

1. Mechanistic models

The IRMDSS includes the following mechanistic models:

- Reservoir model, which is used to assess and predict the response of reservoir pressure to natural gas injection and withdrawal (I/W).
- Geomechanical model, which is used to simulate the stress change in the formation and deformation due to gas injection in the storage reservoir or other activities above the storage reservoir. The resulting stress state over years may affect both wellbore and caprock integrity, as well as fault stability.
- Wellbore model, which is used to simulate withdrawal, injection, and leakage (blowout) processes, and predict pressure and temperature response patterns under normal and/or abnormal (leaking) conditions within a wellbore. A wellbore model may be able to diagnose leakage at early stages through comparison of simulated results against observed pressure and temperature data, or analyze leakage incidents to estimate losses and impacts. It can also be used to simulate various pressure control procedures (aka well kills) for leaking wells and identify optimal procedures for each type of well configuration and gas storage system to minimize the impacts of well failure.
- Geohazard analysis, which can provide probabilistic seismic, fault displacement, and earthquake-induced landslide hazard analysis.

The models can be used to answer "what if" questions to help operators make decisions. Examples of such questions include, "What is the likelihood of fracturing the caprock if the reservoir is operated at a higher maximum pressure?" "What are the diagnostic signals (pressure and temperature changes) of leakage from tubing and from casing?" "What is the expected effectiveness of a given well leakage mitigation approach?"

2. Advanced monitoring technologies to provide indicators of risks
The advanced monitoring technologies considered in this project include:

- Downhole monitoring
  - Downhole quartz pressure/temperature sensors, which provide real-time measurements of pressure and temperature at the bottom of the instrumented well. These measurements are much more accurate than estimates made using wellhead measurements, which is the current practice.
  - Fiber-optic Distributed Temperature Sensing (DTS), which provides a continuous temperature measurement along the vertical wellbore. This profile could be different between normal and abnormal conditions and,therefore, such data can be very useful in leakage detection and analysis.
  - Fiber-optic Distributed Acoustic Sensing (DAS), which provides continuous acoustic signals. The signal is expected to be different in the presence of a gas leak allowing DAS to potentially provide quick leak detection.
- Surface monitoring
  - Unmanned Aerial System (UAS) or Unmanned Aerial Vehicle (UAV)/Drone gas leak monitoring, which provides CH_4 atmospheric concentrations at low elevation above the ground surface, and can be used for surface leakage detection.
  - Interferometric Synthetic Aperture Radar (InSAR) for ground deformation, which measures millimeter-scale changes in surface deformation over periods of days to years. The surface deformation can then be transformed to infer the volume changes within the reservoir associated with pressure changes due to natural gas storage operations.

The main advantages of these monitoring technologies (over current practices) are: the data are either continuous in time (downhole monitoring) or very frequent (e.g., surface monitoring); the technologies are either non-intrusive (surface monitoring) or non-intrusive after installation (downhole); data-streams can be automatically recorded (downhole and InSAR). The initial (capital) cost of the technologies (e.g., equipment and installation) is substantial, but the ongoing (operation and maintenance) costs (for example, data transmission and drone operation labor) and risks to integrity are low compared to those of well inspections and noise/temperature logs as currently required.

3. Supervisory interface

The purpose of the supervisory interface (SI) is to make it easy for users to apply the tools developed in the IRMDSS. The main utilities in the SI include:

- Facilitating IRMDSS users to run various scenarios for UGS operation using mechanistic models stored in the IRMDSS framework,

- Serving as a database for existing site information, model input/output, monitoring data, and data visualization
- Providing a platform to combine monitoring data with models to perform analysis for safe reservoir operations, anomaly detection and locate, quantify, and analyze functions.
- Providing use cases to demonstrate how to perform analysis using tools developed in the IRMDSS for UGS risk management and decision support.

A technical advisory committee , consisting of members from national laboratories and gas companies, was formed to provide guidance in project direction and feedback to the project findings and products.

Project Results

The aim of the project was to develop a framework, namely the IRMDSS, that can be used at various UGS sites. This means the IRMDSS approach is generic, i.e., how the monitoring data and models can be used together, e.g., for analyzing scenarios and evaluating impacts and mitigation strategies, is generic and can be applied to any UGS site. The models and data in the IRMDSS are unique for each UGS site, i.e., the mechanistic models – built based on site data and geological properties of the site, and the specific monitoring technologies and data, are site- and case-specific. Currently, the models were developed based on properties and conditions of the SoCalGas Honor Rancho UGS site and the advanced monitoring data were collected at the Honor Rancho site except the UAV survey, which was done at an analogue site due to Covid-19 restrictions at Honor Rancho. When the framework is applied to other sites, the site-specific models and data for that site should be used. If a different simulation software (i.e., other than the ones used in the project) is used when applying the IRMDSS framework, some parts of the SI related to the software application need to be modified.

A reservoir and a geomechanical model were developed for the Honor Rancho site, which can be run to provide pressure and stress predictions in the reservoir given actual operational injection and withdrawal (I/W) rates; geohazard analyses were performed for the Honor Rancho site, which provided the probabilistic seismic, fault displacement, and earthquake-induced landslide hazard analysis. A wellbore model was built for a particular well at the Honor Rancho facility where downhole monitoring instrumentation was installed as part of this project. The model was run to investigate what pressure and temperature signals are generated in various situations (for example, tubing leak compared to no tubing leak).

Most of the planned monitoring data were collected and analyzed. Downhole monitoring equipment was installed at an injection well at the Honor Rancho UGS site to demonstrate the use of real-time data. While the fiber-optic based sensors performed well, for unknown reasons the downhole quartz pressure-temperature sensors were never able to acquire data at the demonstration well. InSAR data were collected, and an approach to analyze the data was demonstrated. Due to Covid-related site restrictions, the planned UAS drone survey at the Honor Rancho site could not be performed during the project period. Instead, an analogue site with a known source of natural gas emission in Solano County, California was used for monitoring demonstration purposes.

Both the mechanistic models and the monitoring data are integrated in the IRMDSS framework through use cases. In general, a use case represents a list of actions that should be taken to achieve a goal. In the IRMDSS, a use case demonstrates how/when a model and/or a type of data can be used to handle a particular scenario or answer a particular question. Similar to the IRMDSS framework, the workflow in the use cases is generic. When it is applied for a specific site/well, it needs to use a site- or well-specific model. With the feedback from the TAC members, eight use cases were developed and are currently included in the IRDMSS. When needed, an IRMDSS user can follow the use case workflow, develop new use cases and add them into the IRMDSS. Through use-case demonstration, the mechanistic models including reservoir, geomechanical, wellbore models, and the geohazard analysis are shown to provide defensible answers to "what-if" questions, and to help with analyzing anomalies and evaluating mitigation strategies. Advanced monitoring technologies installed in the project well were demonstrated to provide near real-time monitoring data that can provide the input for early warning of abnormal behavior, and help identify potential threats that can allow operators to take preventive measures.

The developed SI was shown to provide a user-friendly environment for running models and performing analysis, and to provide use cases and related workflow and guidance for various UGS risk management scenarios. Although the development of the SI was based on the Honor Rancho site and models and data collected, the SI software is designed as a general framework so that it can be extended to include additional sites with the help of a software engineer.

Feedback on the IRMDSS was received from UGS operators. One issue raised is related to the huge data volume from the fiber optic monitoring. Even though an effort was made to pre-process data and reduce the volume while still providing insights into spatial and temporal changes in the borehole, the amount of processed data is still relatively large and training of staff in DAS data processing/analyzing would be beneficial to UGS facilities. Another point of feedback related to how fiber optic monitoring fits into current regulations. Currently, tubing removal is required for metal loss inspection with a frequency of every 24 months. Such tubing removal would be cost-prohibitive if fiber optic monitoring were deployed because of the cost of replacing fiber every 24 months. Applications of the IRMDSS would require comprehensive evaluations and acceptance of results by regulatory agencies as well.

Non-technical lessons learned in the project include:

1. Plan fieldwork and test equipment as early as possible, to mitigate delays arising from the many uncertainties inherent in fieldwork;
2. Plan sufficient out-of-state funds.

To summarize, the achievement of the IRMDSS is that it integrates a collection of tools, along with data intake and analysis capabilities to provide the most up-to-date site information for risk assessment, early detection/prevention, and mitigation evaluation.

Knowledge Transfer

To communicate the methods, technologies, and learnings developed in this project, a number of knowledge transfer activities have been carried out. These activities include writing technical reports and journal publications; preparing presentation material and video material; Creating a project website (https://irmdss.lbl.gov/); organizing meetings with project partner

SoCalGas and obtaining their advice and feedback on the project; and demonstrating the project to other interested parties.

We have presented some material at TAC meetings, as well as at meetings with a variety of entities. Both the TAC members and personnel from these meetings are potential messengers to help get the word out to industry about the benefits of using the IRMDSS framework.

Benefits to California

The IRMDSS is intended to improve the safety, lower the cost, and increase the reliability of natural gas supply in California through improved risk management of UGS, as detailed below:

Safety

Real-time monitoring and risk assessment, as well as early leakage detection, can be used to indicate preventative and corrective measures that can be taken before leaks happen, and inform decisions on mitigation measures before large leaks occur. Non-intrusive monitoring technologies also reduce risk associated with traditional well inspections. These advances can increase the safety of individual wells throughout the UGS sites in California.

Costs

The quantitative predictive methodology developed by the project will inform changes in operations and/or early preventative engineering measures to avoid failure or damage, thus lowering mitigation costs through risk-based maintenanc

Reliability

Improving gas storage integrity, which includes avoiding down-time for repairs and leakage mitigation, will provide greater reliability for the gas supply from UGS.

As a result, increased safety, lower costs, and greater reliability will allow continued inclusion of UGS as one of the approaches available to meet the demand for heating during winter, and provide fuel for smooth operations of electricity generation during periods of high power demand, e.g., hot summer day air-conditioning demand and. therefore, contribute to energy security.

CHAPTER 1: Introduction

Project Background

The main purpose of underground gas storage (UGS) is to meet varying demand for natural gas (predominantly methane, CH_4) over daily to seasonal time scales. In 2017, the California UGS system comprised 12 UGS facilities with a total capacity to store just under 400 Bcf of natural gas. These facilities provide storage of natural gas to meet the demand for heating during winter, and they provide fuel for smooth operations of electricity generation during periods of high demand, e.g., hot summer day air-conditioning demand. Based on a previous study (CCST Report, 2018), although the need for underground gas storage might be reduced in the coming decades, no immediate alternatives are available to meet California's demand for natural gas during peak periods in the winter—a demand that currently exceeds the state's pipeline capacity to import gas.

A schematic of the main components of a UGS site is shown in Figure 1 for storage in porous media reservoirs which could be aquifers or depleted oil or gas reservoirs. In California, the surface infrastructure components consisting of pipes, compressors, expanders, and gas-processing units are regulated by the California Public Utilities Commission (Interagency Task Force, 2016), while the wells which can extend up to two miles downward into the subsurface are regulated by CalGEM (formerly, the Department of Oil, Gas, and Geothermal Resources) (California Department of Conservation, 2021). All UGS reservoirs in California are in porous media in depleted oil or gas reservoirs. Failures of one or more of these gas-storage components arising from any number of causes, e.g., accidents, poor maintenance, and/or errors in operation, can result in incidents with catastrophic consequences. UGS operators follow state regulations and their own internal risk management protocols and procedures to safely operate their UGS surface and subsurface infrastructure.

Whether UGS is carried out in caverns, aquifers, or depleted gas or oil reservoirs such as those used in California, incidents of various kinds involving gas leakage and fires/explosions have been known to occur around the world over the many decades that UGS has been carried out (Evans, 2008, 2009; Folga et al., 2016; Evans and Schultz, 2017). The main hazard of UGS is that natural gas is highly flammable when mixed with air at certain concentrations, making gas leakage at the ground surface a severe safety hazard and threat to surface infrastructure. At the same time, the tendency for gas leakage is ever-present because of the high pressure of the stored gas (typically >1000 psi (~7 MPa)) and the need to contain high-pressure gas over repeated injection and withdrawal cycles through wells.

Loss of containment (LOC) of natural gas refers to natural gas leakage from the storage system consisting of the reservoir, wells, and surface infrastructure, not due to normal operational gas withdrawal. LOC can occur due to failure of the natural system to contain gas, e.g., fracturing or faulting of the caprock (e.g., Evans and Schultz, 2017), or due to failures of an engineered component, i.e, a well. Well failure can occur anywhere along a well, but the most serious kind of well failure from a health and safety perspective is the surface blowout such as the one that occurred at the Aliso Canyon UGS facility in California in October 2015 (e.g., Conley et al., 2016; Pan et al., 2017). Either leakage through a well or leakage through fractures can cause gas loss and/or potentially catastrophic damage to natural gas storage facilities at the ground surface. By California regulations, a leak is reportable if it results in total hydrocarbon concentration in air near the leak of more than 50,000 ppmv at any time, or more than 10,000 ppmv continuously for more than five days.

There are about 350 active (i.e., non-idle) wells at any given time in California UGS sites. Many of these wells are re-purposed and aging wells originally used for oil or gas production. In contrast to surface infrastructure, wells at UGS sites are challenging to monitor and maintain because they are underground and are not easily observable or accessible (e.g., the outer surface of casing and well cement that abuts the rock formation along the well). In addition to the risk from the engineered component, another failure scenario comes from failure of the natural system (e.g., caprock of the reservoir as part of the naturally occurring geological formation as opposed to man-made components) to contain gas (e.g., leakage through caprock would occur if caprock integrity is compromised). Given the energy reliability still depends on natural gas supply in California, safety of UGS facilities is a key factor required to maintain the California energy system now and in the coming decade.

Figure 1-1. Schematic of UGS system components

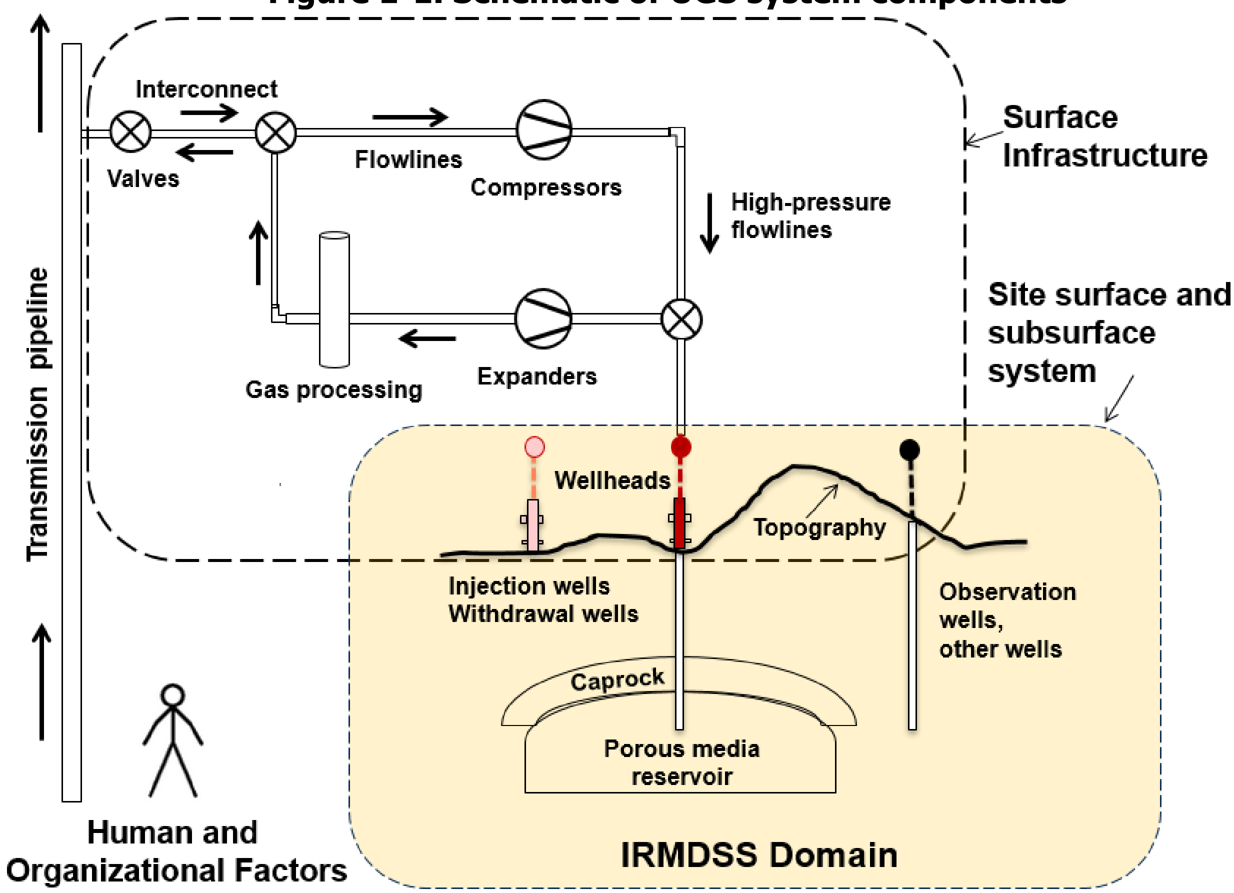


Figure 1-1 owing surface infrastructure (enclosed by upper long-dashed boundary) and the site surface and subsurface system components (enclosed by lower short-dashed boundary). The IRMDSS focuses on the subsurface components but includes the wellheads and topography that are at the intersection of the surface and subsurface domains (modified after Oldenburg et al., 2018 (Chap. 1.0)).

Current Risk Management Approaches for UGS Facilities

This section provides a review of the current risk management practices that are common in the UGS industry, including the role played by monitoring technologies and engineering and mechanistic models.

Definitions

In the context of UGS, a *failure scenario* is a single event or process, or a sequence of events or processes, that involves the failure of one or more components relied upon in a UGS system to contain high-pressure gas. The result of many kinds of UGS failure scenarios is LOC. The risk that we address in the IRMDSS can be defined as the product of the likelihood (e.g., probability of occurrence) and the consequences (e.g., severity) of a specific failure scenario (e.g., for UGS, a large-scale well blowout).

Risk assessment is the quantitative or semi-quantitative evaluation of the likelihood (e.g., annual average frequency of occurrence) and the severity (e.g., loss of natural gas, potential loss of use of the facility) of various failure scenarios, the product of which is used to estimate risk. Risk can be reduced by reducing the likelihood of the failure scenario from happening, an activity known as risk prevention. And risk can also be reduced by decreasing the potential consequences of the failure scenario, an activity known as risk mitigation.

Risk management can be thought of as a collection of all of the activities including hazard identification, risk assessment, prevention, and mitigation all aimed at reducing risk to acceptable levels within the context of the overall objectives of the industrial operation (NRC, 2009). Evidence-based and data-informed decision-making are essential for effective risk management.

Well logging is a practice of making a detailed record, referred to as a well log, of the geologic formations penetrated by a borehole, either using samples brought to surface, or direct measurements using geophysical methods at depth.

Standard monitoring practice at UGS sites

The current standard monitoring programs employed at UGS sites include wellhead pressure (tubing and casing) measurements, surface leakage monitoring and detection, and well logging and well inspections. Downhole pressure measurements require installation of pressure sensors at the bottom of the well, which is not the current practice. A typical practice for pressure monitoring is to monitor wellhead pressure and then compute the corresponding bottomhole (reservoir) pressure using gas thermodynamic models. While the gauges are fairly common in oil & gas operations, because UGS has traditionally operated with monobore construction (no tubing), gauge installation has not been practical. As UGS shifts to double barriers and tubing, gauges could be considered for permanent monitoring. The problem with this approach is that variable or unknown temperature of the column of gas in the wellbore leads to a significant uncertainty in the density of the wellbore fluid which then gets carried over into the estimate of the bottomhole pressure. These uncertain pressure estimates may lead to erroneous estimates of gas inventory (i.e., the amount of gas stored in the storage reservoir), which may mask detection of even moderate leaks when using gas inventory approaches.

Various logging tools are applied to wells periodically to evaluate and characterize properties like cement bond quality, casing wall thickness, and mechanical integrity (i.e., does the well hold pressure). In California, the required method for identifying leaks (DOGGR, now CalGEM) Requirements for California Underground Gas Storage Projects, §1726.6) in a gas storage well is to perform annual noise and temperature logs. The year-long interval between these logs creates the possibility of a leakage incident evading detection for as long as a year, during which time it could grow into a much more serious incident. On the other hand, increasing the well logging frequency may not be a solution because the very act of doing the logging carries with it LOC risk associated with shutting in the well and installing pressure control equipment to facilitate logging. In addition, logging surveys require operators to be present onsite to lower the logging tool down the borehole, which is expensive and time-consuming.

Depending on the results of well logging and mechanical integrity testing, the well may be assessed to have a higher or lower likelihood of failing in one way or another. Other data points operators can use for assessing likelihood of failure come from statistics of historical failures of UGS facilities themselves (Evans, 2008, 2009; Folga et al., 2016; Evans and Schultz, 2017).

Changing role of models for UGS risk assessment

Traditionally, reservoir experience and reservoir engineering methods (e.g., Katz and Tek, 1981) have been used in the UGS industry to predict behavior of the system to aid in interpretation of measurements. Recently, advanced mechanistic models have begun to gain favor in understanding certain aspects of a natural gas storage facility, e.g., to understand the leakage processes and pathways at the Leroy UGS facility (Chen et al., 2013). A wellbore simulator was used in 2015-2016 to understand the failure of several kill attempts at the Aliso Canyon UGS facility well blowout in California (Pan et al., 2018)). In the study by Pan et al., (2018), different scenarios of killing the SS-25 well were simulated using the T2Well simulator (Pan and Oldenburg, 2016) as constrained by well and gas release data to understand why various kill approaches were not working. Another example use of an advanced model is the TOUGH-FLAC simulator, developed at LBNL by coupling TOUGH2 and FLAC3D (Rutqvist, 2011). TOUGH-FLAC was used to analyze if caprock integrity might be compromised using the proposed increased operation pressure at two Canadian gas storage facilities (Walsh et al., 2015). The few examples of mechanistic modeling applications to UGS have demonstrated their usefulness and effectiveness in risk management, e.g., in evaluating mitigation strategies and supporting decision-making regarding adjustments in operations to mitigate risk.

The main advantage of mechanistic models is that they can provide more accurate predictions. As a result, they can be used to assess consequence of events/incidents as well as various operational strategies, and also of mitigation strategies. The resistance to using mechanistic models usually come from lack of data to constrain and build the models, as well as lack of staff with expertise in modeling (e.g., lack of reservoir engineers)

Current risk management approach for UGS facilities

In the past, most risk management approaches for UGS operation focus on hazard and threat identification using engineering methods and does not fully exploit mechanistic models that can potentially predict system failure and evaluate preventative measures (simulate “what if” scenarios). Moreover, this risk-evaluation approach relies on static or periodically collected data and does not usually have, or take advantage of, continuously updated monitoring data. As a result, it may not capture the dynamics of system risks that can change rapidly, leading to risk assessment results that are not updated effectively to give the operator the most current information for decision-making. It is important to note that continuously updated data not only allow the risk assessment to reflect current conditions, but continuous data also allow the operator to understand how conditions are changing over time which may reveal or provide evidence for various hypotheses for what processes and trends are occurring.

Recently, a more comprehensive risk-based approach to well integrity management was developed and advocated by a team that included federal and state regulators along with natural gas storage operators to address the need for better and more consistent risk management within the UGS industry. This approach is referred to the American Petroleum Institute Recommended Practice 1171 (API RP 1171): *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*. The approach includes five steps: (1) data collection, documentation, and review, (2) hazard and threat identification, (3) risk assessment, (4) risk treatment – developing preventive and mitigative measures, and (5) periodic review and reassessment. As described in API RP 1171, dynamic monitoring data can play a significant role in helping identify potential risks, developing preventive measures before catastrophic events happen, and in guiding mitigative measures when such catastrophic events happen.

The approach developed (IRMDSS framework) in this project as fully described below is aligned with the API 1171 approach in that the IRMDSS merges mechanistic process models with continuously collected real-time data to evaluate site scenarios and provide indicators of potential threats.

Project Objectives

Built on recent advances in monitoring technologies and physics-based mechanistic model simulation, an Integrated Risk Management and Decision-Support System (IRMDSS) was developed to improve LOC risk management for the subsurface components of UGS, specifically wells and geomechanical aspects controlling caprock integrity. The underlying concept of the IRMDSS framework is to take advantage of continuous dynamic monitoring data available from new fiber-optic sensing approaches and the prediction capability of advanced mechanistic models. The combination of monitoring and modeling allows the operator to identify off-normal conditions and carry out what-if simulations to guide decision-making in preventing and mitigating LOC incidents.

The overall goal of the IRMDSS was to develop a risk management approach emphasizing early damage detection and leak prevention. The specific objectives were:

- To develop a set of analytical tools specifically designed to estimate the risk and evaluate mitigation strategies for UGS infrastructure under various failure scenarios that are most relevant to UGS in California.
- To demonstrate how real-time monitoring data from the advanced monitoring technologies can help threat identification and hazard prevention.
- To provide a platform, called the Supervisory Interface (SI), to integrate data and analysis and provide information for risk management.

The general IRMDSS framework can be applied to any UGS site, but the focus during development of the framework has been on subsurface UGS facilities developed in porous reservoirs in California which comprise depleted hydrocarbon reservoirs. The components of the IRMDSS, i.e., the mechanistic models and the specific monitoring technologies and data, are site- and case-specific, i.e., mechanistic models are built based on site data and geological properties of the site. However, the workflow, i.e., how the monitoring data and models can be used together for analyzing scenarios and evaluating impacts and mitigation strategies, is generic and can be applied to any UGS site.

The framework is demonstrated at the Honor Rancho Gas Storage Facility owned by SoCalGas).

Project Team

The lead project team is from Lawrence Berkeley National Laboratory (LBNL) who provides expertise in risk management, underground injection, reservoir modeling, geomechanics, wellbore modeling, and InSAR data and downhole monitoring data analysis. Six subcontractors are Regents of the University of California, Berkeley, to support activities in InSAR data analysis, Lettis Consultants International Inc. to support geohazard analysis, Class VI Solutions to support advanced downhole monitoring technologies, Mokaena, LLC and Michael B. Kowalsky Consulting to support SI GUI development, and ABB, Inc. to support UAV/drone survey. The project is in collaboration with SoCalGas which is providing its Honor Rancho Gas Storage Facility for the purposes of IRMDSS development and demonstration.

Technical Advisory Committee

A technical advisory committee (TAC) containing nine members from national laboratories and natural gas companies was formed. Two TAC meetings were held. In the first TAC meeting, the TAC members provided guidance in project direction, and feedback in the project approach. Specific feedback from gas companies on how to handle situations in the presented use cases was received. In the second TAC meeting, preliminary product (IRMDSS SI) and model analysis were demonstrated.

CHAPTER 2: Project Approach

IRMDSS Framework Overview

The IRMDSS is designed for: real-time warning of imminent risks, long-term assessment of evolving risks, and early leakage/damage detection. The approach of the IRMDSS is to compare mechanistic model predications with continuously or frequently monitored data to detect and evaluate indicators of potential threats. The models in the IRMDSS are built based on existing site characteristics and data. They can be used to predict pressures and stresses in the reservoir, pressures and temperatures along the wellbores. The inconsistency between the measurements and observed data could indicate potential risks. In the meantime, the IRMDSS implements a platform called Supervisory Interface, to run its risk models, to analyze and plot data collected in the field, and to compare the model output with the monitoring data.

To be able to achieve the goals defined in the previous chapter, the IRMDSS was designed to have the following components:

- Mechanistic models, based on site-specific information
    - A reservoir model, to predict pressures in the storage reservoir.
    - A geomechanical model, to predict stresses inside and above the reservoir.
    - A wellbore model, to predict pressures and temperatures inside a well.
    - geohazard analysis, to provide probabilistic analysis of geohazards.
- Advanced monitoring technologies
    - Downhole monitoring technologies, for well integrity issues.
        - Distributed temperature sensing (DTS), for vertical well temperature.
        - Distributed acoustic sensing (DAS), for acoustic signals along the wellbore.
        - Downhole quartz temperature/pressure sensors, for downhole temperature and pressure measurements.
    - Interferometric synthetic aperture radar (InSAR) data, for monitoring ground deformation.
    - Surface CH_4 survey, for CH_4 leakage detection in ambient air (above the ground surface at the site).
- IRMDSS framework and use cases for facilitating the IRMDSS integration and field demonstration.

Figure 2-1: IRMDSS components and workflows

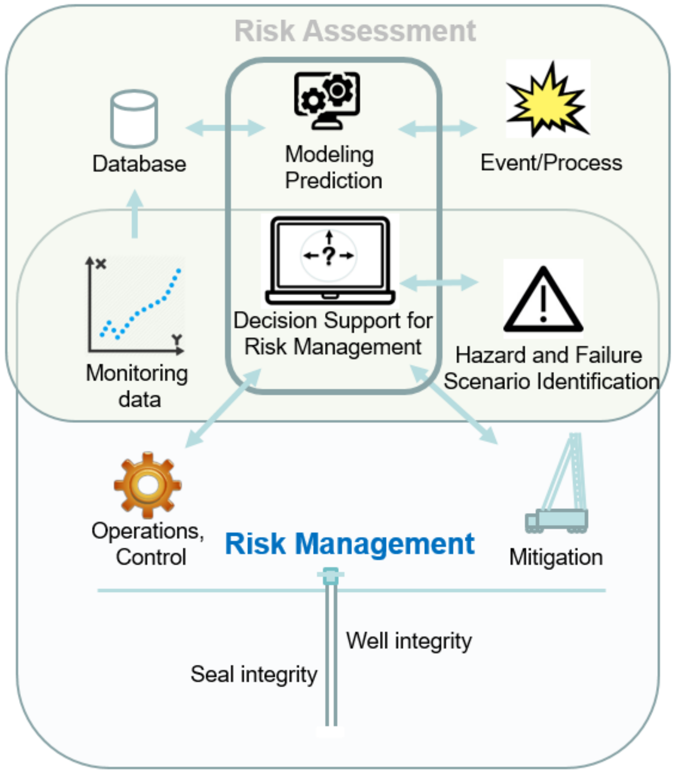


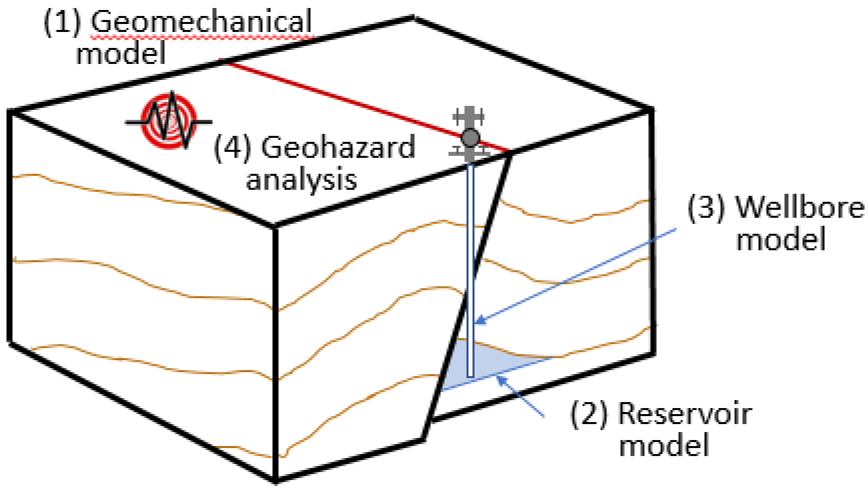
Figure 2-1 shows the main functionalities of the IRMDSS and how components are connected and information flows. In the risk assessment part, IRMDSS provides model prediction based on site and operational data; results are then compared to the monitoring data to evaluate risk; the model can also be used to simulate a particular event/process and results are compared to monitoring data to understand what could have happened for hazard/failure identification. Risk management contains additional components including using models for operation and mitigation strategies for risk reduction. The evaluation results will be used for basis to support further decisions.

Each component will be explained in the sub-sections of this report. All the models are built on site-specific information such as stratigraphy and lithology, and they generally cannot be used for other sites. The demonstration site used to build the IRMDSS framework is the Honor Rancho Gas storage site owned by SoCalGas. Therefore, the models and monitoring data presented in this report are for the Honor Ranch site.

Mechanistic Models

The models considered essential for managing UGS risk are shown in Figure 2-2 and include the mechanistic reservoir, geomechanical, and wellbore models. We also include the geohazard analysis in the figure because it estimates a critical component of risk, namely geotechnical hazard. It is important to note that the geohazard analysis is not based on any single set of equations and inputs like the mechanistic models, but rather is based on multiple inputs related to seismic hazard, slope, soil, and climate parameters synthesized by geotechnical engineers. Nevertheless, we include it with the models because it is an important part of UGS risk management.

Figure 2-2: Schematic of the Models in the IRMDSS



Schematic of the (1) large-scale geomechanical model that includes the reservoir and overburden, (2) the reservoir model, and (3) the wellbore model. The Geohazard analysis comprises induced seismicity and landslide hazard analysis.

Reservoir Model

A reservoir model is a computer model used to assess and predict the response of reservoir pressure to natural gas injection and withdrawal (I/W). In the IRMDSS, the reservoir model is built based on the site-specific geological conditions (natural containment features such as caprock and sealing faults), engineered components (wells), and rock properties of the storage reservoir (porosity, permeability, pore fluids). The main purpose of the reservoir model is to predict reservoir response to ongoing normal operations (i.e., making sure the maximum reservoir pressure is not exceeded), and to evaluate various operational conditions, such as removing well(s) or adding well(s), which provides a tool for safely managing UGS operations.

As mentioned previously, the 3-D reservoir model currently in the IRMDSS is built upon the site-specific Honor Rancho geological model containing detailed stratigraphy and lithology information, provided by SoCalGas. Reservoir model properties such as effective porosity and permeability (i.e., the capacity of the reservoir to rapidly store/produce large amounts of gas through wells in response to I/W demands) are calibrated by matching historical bottomhole pressure response calculated from monthly wellhead pressure data to those as driven by monthly reported gas injection and withdrawal over a 10-year period from January 1, 2008 to December 31, 2017. History matching using the 3-D reservoir model produced a good match between simulated and measured reservoir pressures in the gas cap including effects of the production of oil/condensate and water on enlarging the volume available for gas storage.

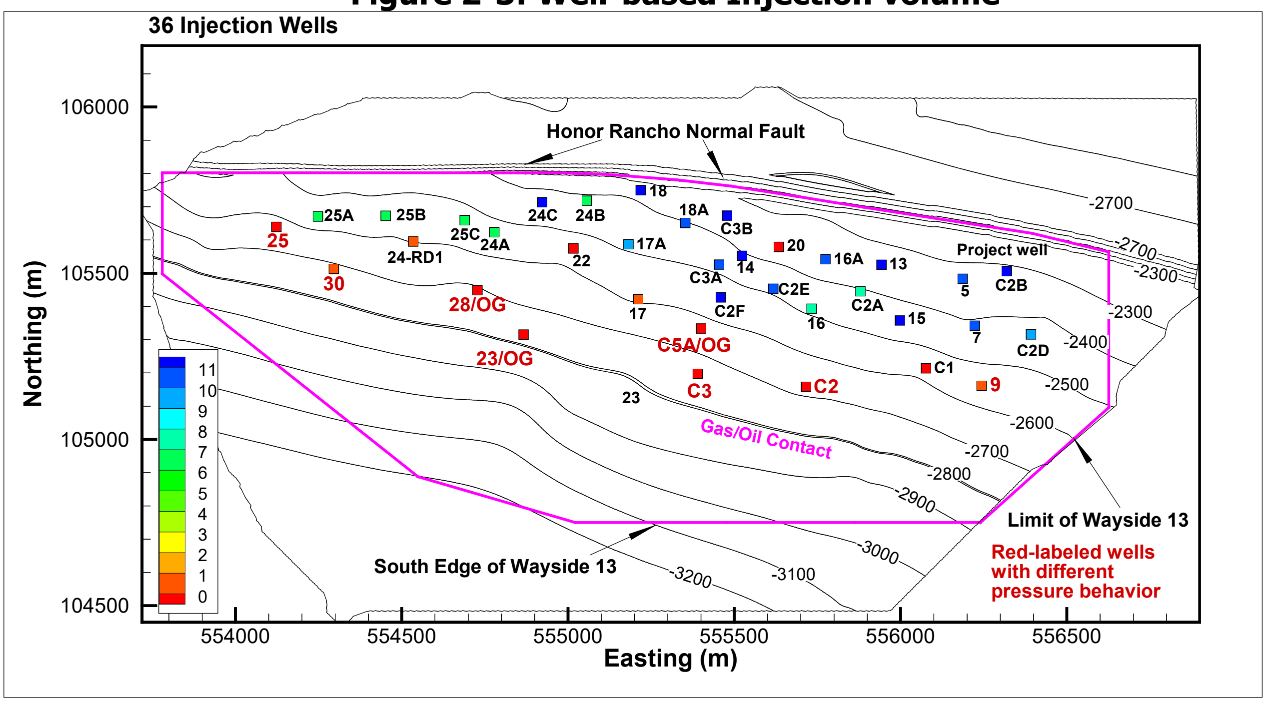
The numerical simulator iTOUGH2 (Finsterle, 2004) with a fluid module appropriate for water and CH_4 (EOSCH4) was used for the 3-D reservoir modeling. EOSCH4 models fluid properties for two components (water and CH_4) and two phases (aqueous phase and gas phase).

Site Information

The key geological map surfaces for the 3-D modeling of the Honor Rancho underground gas storage reservoir, the reservoir top and base of the Wayside 13, were provided by high-resolution geological surfaces contributed to LBNL by SoCalGas[1]. The geological features (e.g., the Honor Rancho normal fault, the F1 fault, and the San Gabriel fault, as well as reservoir pinch-out) were taken from the literature. The monthly standard volumes of injected and withdrawn natural gas, as well as stored gas, were downloaded for 36 wells in the gas storage field from the CalGEM (nee DOGGR) website (https://secure.conservation.ca.gov/WellSearch/?ActiveWell=True&ActiveOp=True&Field=308&Operator=S4700&Command=Search&PgStart=0&PgLength=10&SortCol=6&SortDir=asc#). Figure 2-3 shows the well-based total injected volume over the 10-year period with the true vertical depths from sea level (TVDSS) contour lines of the Wayside 13 top elevation in the background. For reservoir modeling, the volumes of injected and withdrawn gas were converted into monthly average injection and withdrawal rates for each well during the 10-year period.

A preliminary single grid block model of the closed gas reservoir volume suggests that the free-phase gas volume that supports reservoir pressure, referred to as free-phase gas volume (FPGV) for simplicity for the rest of the chapter, is on the order of 11 billion cubic feet (BCF).

Figure 2-3: Well-based Injection volume



Well-based total injected volume (BCF) color-coded (see legend bar) for the wells (square symbols) over the 10-year period. The background shows TVDSS contour lines of the Wayside 13 top elevation (m). The model boundaries are shown by the pink lines.

3D Reservoir Model

The model domain was determined by following the natural boundaries of the Wayside 13 reservoir, which is bounded by the relatively large-offset Honor Rancho normal fault on the north shown in Figure 2-3 by the large gradient in the Wayside 13 surface, by the F1 fault on the south (implicit in the model as the southern boundary of the domain), and by the pinch-out on the southwest. The eastern boundary of the model domain, located somewhere

[1] Personal communication with SoCalGas.\\\

between the gas reservoir and the regional San Gabriel Fault, is arbitrarily positioned to reduce the size of the model domain. The model domain covers all 36 active injection and withdrawal wells (see Figure 2-3), all of which are located more than 100 from the southern, western, and eastern boundaries. The northern, southern, and eastern boundaries are specified as no-flow boundaries, while the western boundary is a constant-pressure boundary. The geometry of the determined model domain is shown in Table 2-1.

Table 2-1: Properties of the 3-D reservoir model

Model Feature	Values
Model size east-west	0 to 2,846 m
Model size north-south	0 to 1,052 m
Formation thickness	60 to 200 m
Formation top elevation	-3,170 m to -2,255 m
Formation bottom elevation	-3,200 m to -2,400 m
Gas-oil contact elevation	-2,804 m
Oil-water contact elevation	-2,972 m
Permeability of the water-filled region	1.0×10^{-13} m^2
Porosity of the water-filled region	0.12
Permeability of the gas cap	1.0×10^{-12} m^2
Porosity of the gas cap	0.040, 0.044, 0.0475, 0.0506
Permeability of the western boundary	10^{-13}, 10^{-15},10^{-18}, 10^{-21} m^2
Pore compressibility for the model domain	1.0×10^{-10} Pa^{-1}
van Genuchten m parameter for the model domain	0.457
Residual water saturation for the model domain	0.35
Residual gas saturation for the model domain	0.05
Reservoir temperature	87.8 °C

The reservoir model has 13 vertical layers, which is considered a good balance between computational cost and desired vertical resolution. Each layer contains 3,892 grid blocks. The grid size changes from 0.2 m near the wells to 45 m far away from the wells (discretized in the form of a spider web). The initial elevation of the gas-oil contact and the oil-water contact were provided by SoCalGas through personal communication. Reservoir temperature is assumed constant at 87.8 °C[2]. For simplicity and fast simulation, oil and water were combined

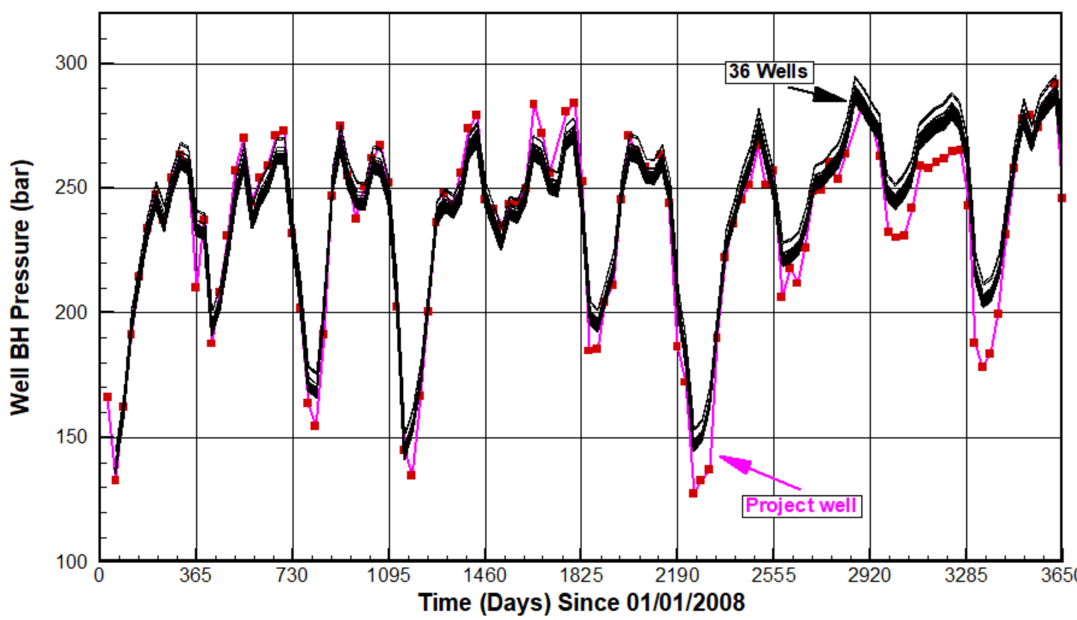
[2] See page 176 of "California Oil & Gas Fields Volume II – Southern, Central Coastal, and Offshore California Oil and Gas Fields" by California Department of Conservation, Division of Oil, Gas and Geothermal Resources.

into a single liquid phase with water properties for the 3-D reservoir modeling. The total gas-cap pore volume (the top part of the reservoir where the pore space is filled with gas. and residual liquid) is filled by free-phase natural gas. This volume of natural gas is the key parameter for matching the modeled pressure response to monthly reported gas I/W to the reported monthly pressure changes.

Model Results and Conclusions

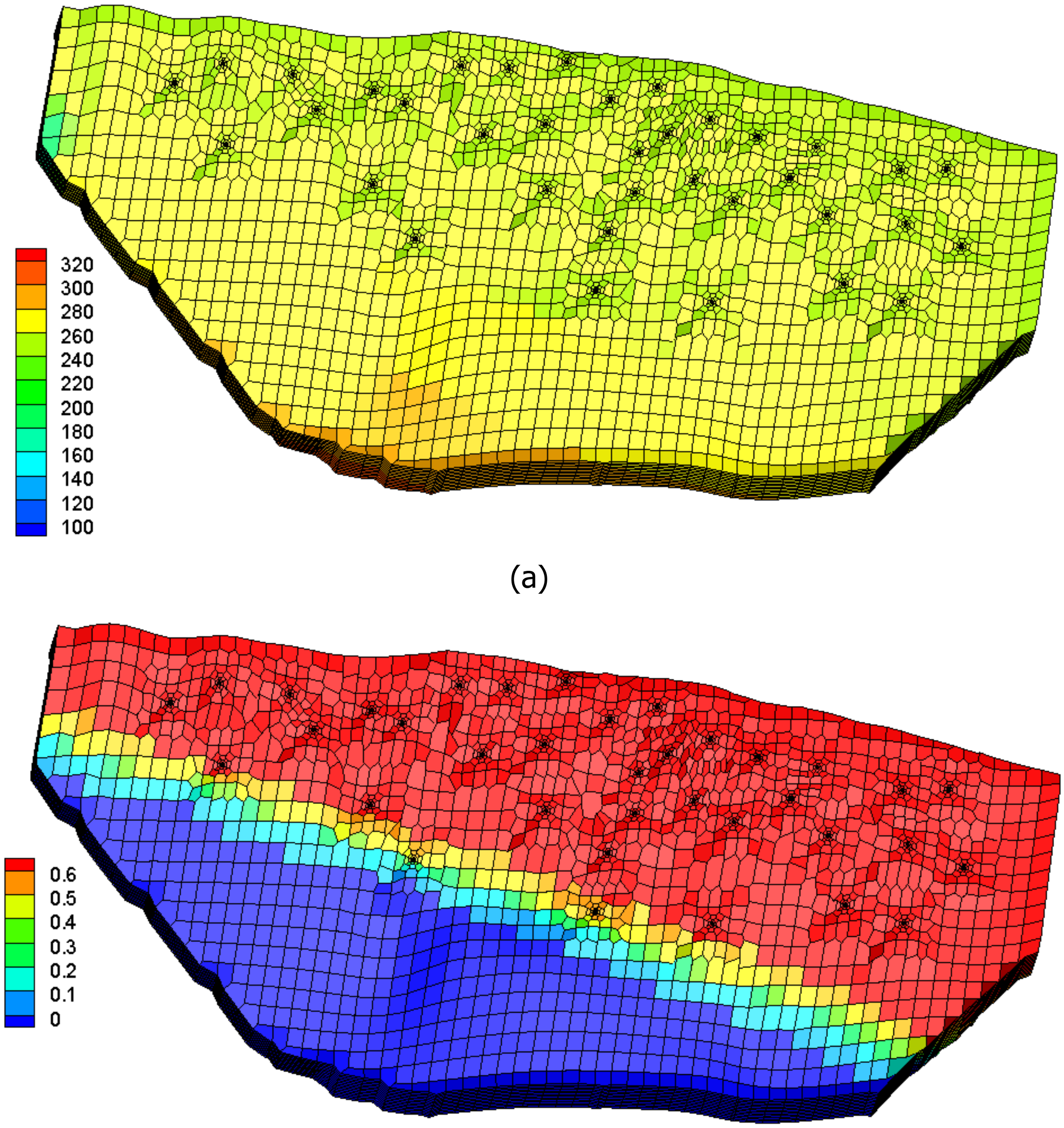
A good match between the simulated and measured pressures as shown in Figure 2-4 is obtained for the effective porosities and permeabilities used in the model. The match is obtained for a relatively closed system (i.e., the permeability at the boundary is eight orders of magnitude smaller than it in the reservoir) that is bounded by faults and reservoir pinch-outs for the period of simulation. This suggests that for the length of the period modeled (i.e., 10 years) the gas reservoir can be considered a closed system. The simulated fluid pressure and gas saturation in the 3-D reservoir model at the end of the 10-year period (i.e., 12/31/2017) are shown in Figure 2-5. These pressures and saturations can be used as the initial conditions for the simulations that start on 01/01/2018. The calibrated model parameters are stored in the IRMDSS and can be used in the simulations to predict pressures and saturations for planned gas injections and withdrawals. The boundary between the gas cap (red) and water-filled region (dark blue) is clearly shown in Figure 2-5(b).

Figure 2-4: Simulated Pressures vs. Measured Pressures



The pink line shows the measured pressures at the project well. The black lines show the simulated pressures at 36 wells using the best-fit parameters.

Figure 2-5: Model grid and simulated results at the end of the 10-year period



(a)

(b)

The top figure (a) shows simulated pressure in bar; The bottom figure (b) shows gas saturation.

The specific conclusions of the 3-D reservoir modeling include:

- A free-phase gas volume of approximately 11 BCF matches the local pressure response to monthly injected, withdrawn, and stored natural gas; this FPGV (or mass) does not include dissolved natural gas in oil and water in the formation which would increase the total amount of natural gas from a total-inventory perspective.
- The natural gas storage reservoir, including the gas-filled gas cap and the water-filled region, is a relatively closed system, as numerically verified; this conclusion is consistent with the presence of faults and formation pinch-outs that bound the reservoir.
- The effective porosity of the gas cap for free-phase gas storage is less than the total porosity derived from geophysical logs and core measurements, reflecting the effects of

natural heterogeneity; this small effective porosity only accounts for the gas-filled pore volume, excluding the liquid-filled pore volume (liquid saturation) in the gas cap.

- The very good match between the measured and simulated pressures at wells indicates the accurate capture of the FPGV to support pressure, initial stored gas, and the history of injected and withdrawn gas, as well as the history of produced liquids. With the produced liquids accounted for, the 3-D reservoir modeling maintains the mass and volume balances over the 10-year period from 3/1/2008 to 12/31/2017 without a significant trend of increasing reservoir pressure with time;
- The calibrated 3-D reservoir model can be used to simulate pressure and gas saturations under normal gas storage operations and the effects of variations such as removal or addition of wells in the IRMDSS.

Geomechanical Model

A geomechanical model is a computer model that is used to simulate the stress change and deformation in the formation rocks due to activities within or above the reservoir (e.g., gas injection or withdrawal in this project). The integrity of the UGS reservoir and associated seals could be compromised if certain limits to the pressure are exceeded. This maximum operating pressure depends on the in-situ state of stress that determines the fracture gradient (a function of in situ stress and rock tensile strength) and the stability of nearby faults (a function of stress, fault orientation and frictional strength). A starting point for maximum operating pressure analysis is the field discovery pressure (original formation pressure prior to hydrocarbon production and reservoir depletion). If an operator chooses to operate the facility above the discovery pressure then additional reservoir and caprock analyses are required to be able to justify safe operations at that pressure level[3]. Even if the operator decides to keep reservoir pressure at or below discovery pressure, field evidence has suggested that caprock can still be compromised (Lynch et al. 2013). The reason, as pointed out by Santarelli, et al. (1998, 2008), is that the stress state usually follows a different path during the production-induced reservoir depletion from the path during subsequent gas storage operations, and this hysteresis in the stress path may lead to erroneous calculation of the maximum reservoir pressure, which could potentially compromise the sealing capacity (Lynch, et al., 2013). In general, sealing capacity can be compromised by fracturing of the caprock which could lead to subsurface leakage, or sealing capacity can be compromised by induced earthquakes (reactivation of existing faults) that could severely impact the caprock or well integrity.

A 3D geomechanical model of the Honor Rancho gas storage field is developed to evaluate stress conditions during 20 years of production-induced reservoir depletion followed by 40 years of gas storage operations. Specifically, the investigation focuses on the potential impact on the caprock integrity and on the stability of the reservoir bounding faults, considering impact of irreversible geomechanical behavior during the initial reservoir depletion and subsequent pressure cycling. To investigate the impact of irreversible behavior, two modeling approaches, one using a linear elastic model as a reference case for the non-hysteretic stress path (ignoring irreversible behavior), and another one using a plastic cap mechanical model for hysteretic stress path (considering irreversible behavior), are used and compared.

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[3] Ground Water Protection Council and Interstate Oil and Gas Compact Commission, 2017.

The software used in this project for the geomechanical model is TOUGH-FLAC, which is a coupling of TOUGH and FLAC3D (Rutqvist, 2011). FLAC3D is a commercial numerical modeling software for geotechnical analyses of soil, rock, groundwater, man-made structures, and ground support[4].

Site Information

The geologic structure underlying the Honor Rancho UGS facility is a southwest-dipping monocline (Schlaefer, 1978). The gas storage reservoir is within the Wayside 13 sand, a coarse-grained turbidite deposit, and corresponds to the basal unit in the upper Miocene and lower Pliocene Towsley formation. The reservoir is capped by the shale beds of the Towsley formation. The formations above the caprock are the Pico formation which consists of marine sandstone and conglomerate (Schlaefer, 1978) and the Saugus formation composed of coarse to fine-grained, unconsolidated to loosely consolidated sand and silt (Schlaefer, 1978). The upper part of the Pico formation is called the Yule sand and is utilized for wastewater disposal. The surface elevations of these different rock formations[5] are used to build our 3D geomechanical model.

3D Geomechanical Model

The 3D geomechanical model extends to a depth of 6.3 km, and laterally ~10 km in the eastern and ~11 km in the northern direction (Figure 2-6a). The model is composed of 53,130 cells, with 4,830 cells for the Wayside 13 sand formation. The Wayside 13 sand formation is represented by two layers (2,415 cells per layer) with constant thickness totaling 170 m. The reservoir is bounded on the north by a normal fault oriented N090°-to-N100° dipping 80°N and on the south by a reverse fault oriented N090 dipping 58°N. These faults are 30 m wide and do not intersect the geological formations above the caprock. On the east and west, the reservoir boundaries are represented by a change in the hydraulic properties (lower porosity and lower permeability). Also on the east, the San Gabriel Fault is present. It is a subvertical right-lateral strike-slip fault oriented ~N140 (Schlaefer, 1978) (Figure 2-6b).

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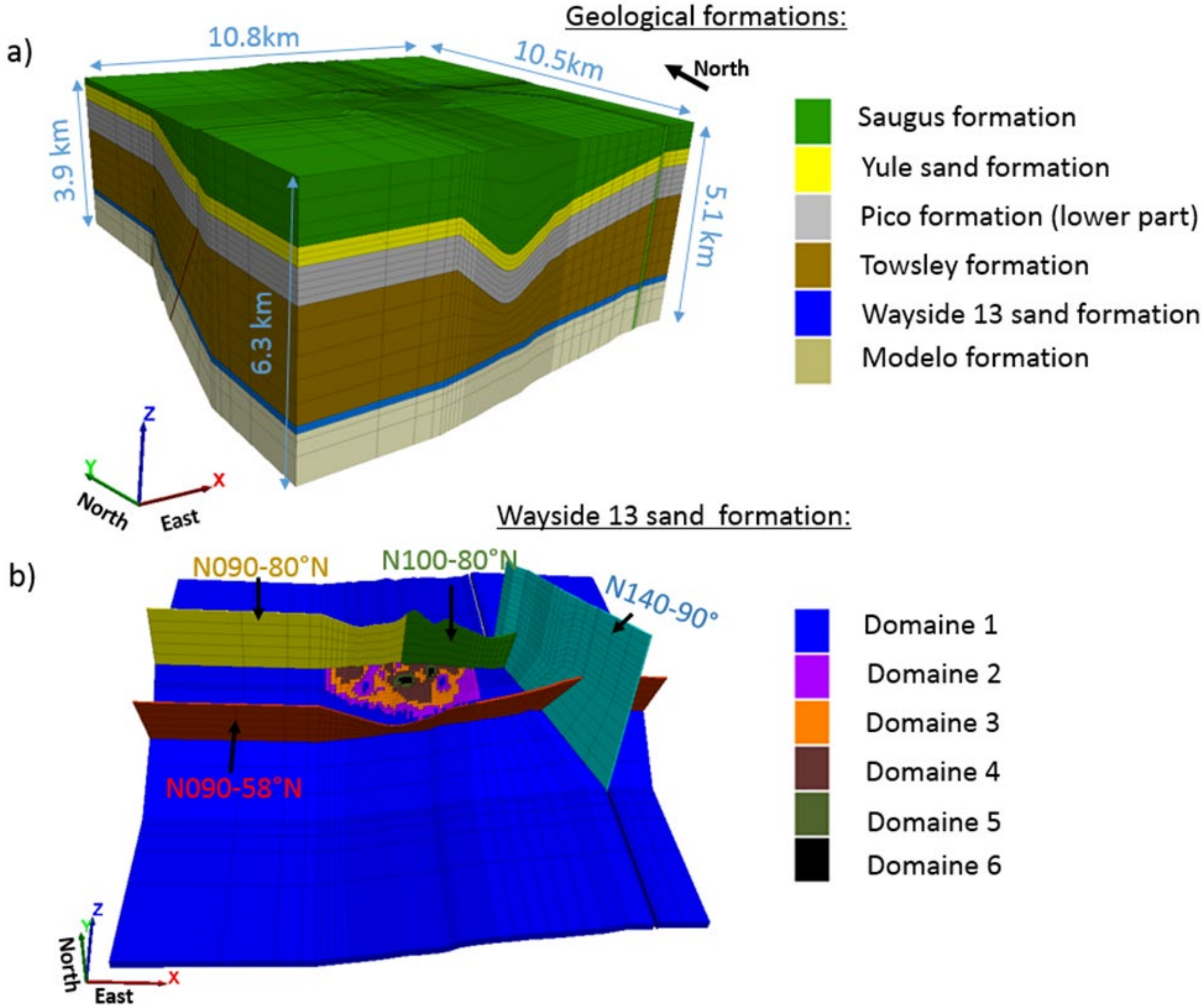
[4] https://www.itascacg.com/software/flac3d.

[5] Personal communication with SoCalGas.

Figure 2-6: 3D Geomechanical Model Domain



(a) 3D geomechanical model showing the different geological formations. (b) Layer forming the 'Wayside 13 sand' formation divided into six domains to consider the anisotropic distribution of the hydraulic properties within the turbiditie deposit and faults bounding the reservoir.

Geomechanical simulations are performed to analyze (1) the likelihood of a failure of the caprock by examining the critical pressures that could induce hydraulic fracturing (P_{FRAC}) or induce slip along existing fractures critically oriented for shear reactivation (P_{SHEAR}), and (2) the stability of the faults bounding the reservoir. Using the pressure measurements and injection/withdraw records from CalGEM, the geomechanical simulation period includes 20 years of reservoir depletion from 1955 to 1975, and 40 years of gas storage operation from 1977 to 2017 (no data are available from 1975 to 1977). The hydrological and geomechanical properties used in the simulation are listed in Table 2-2.

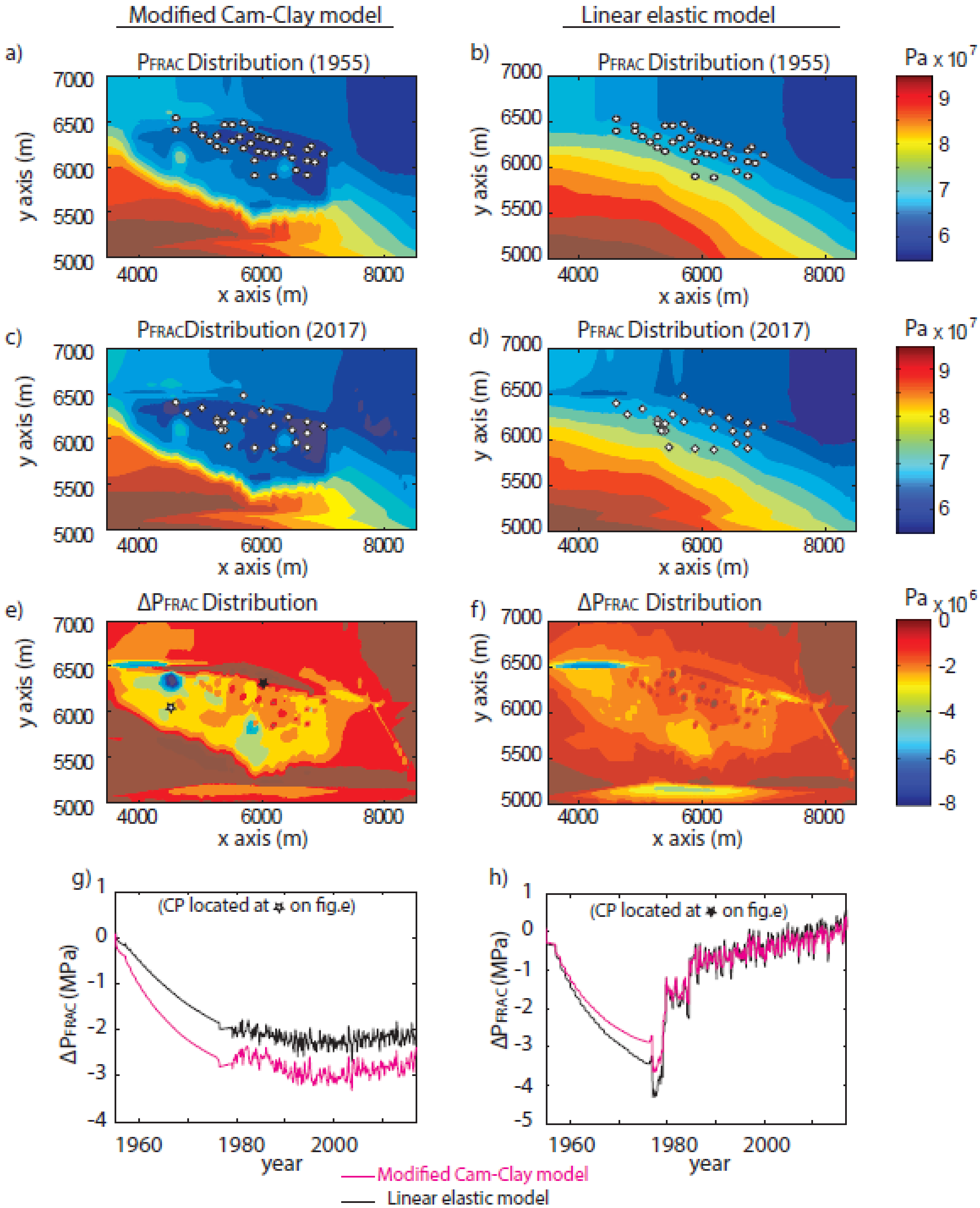
Table 2-2: Properties Used in the Geomechanical Model

Formations and Faults	Permeability (m^2)	Porosity (%)	Young's modulus (GPa)	Poisson's ratio (-)
Saugus	1.0E-12	20	7.66	0.3
Yule sand	1.0E-13	26	11	0.34
Lower Pico	1.0E-14	20	12	0.34
Towsley	1.0E-19	13	10	0.41
Wayside domain 1	8.0E-16	3	9.9	0.25
Wayside domain 2	5.0E-15	6	9.9	0.25
Wayside domain 3	1.0E-14	9	9.9	0.25
Wayside domain 4	4.0E-14	12	9.9	0.25
Wayside domain 5	8.5E-14	15	9.9	0.25
Wayside domain 6	1.0E-13	20	9.9	0.25
Modelo	1.0E-16	17	13.0	0.34
Normal fault N090-80N	1.00E-17	5	4.00	0.25
Normal fault N100-80N	1.00E-17	5	4.00	0.25
Reverse fault F1 N140-80N	1.00E-17	5	4.00	0.25
San Gabriel fault	1.00E-17	5	4.00	0.25

Model Results and Conclusions

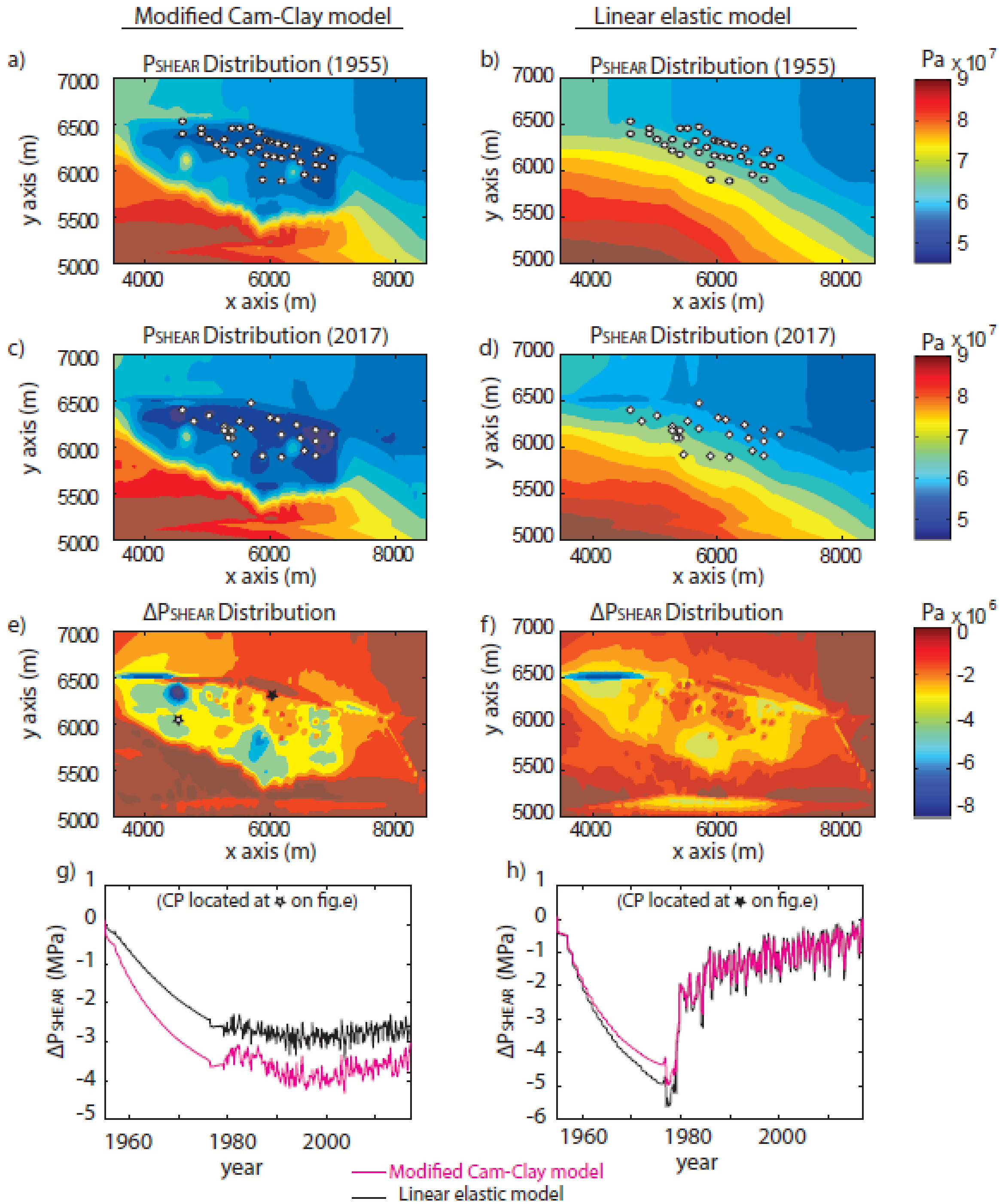
To understand if the model choice may affect results (i.e., impact of UGS operation on caprock integrity), simulations are performed for both models (a linear elastic model with non-hysteretic stress and strain change, and a plastic cap mode–modified Cam-Clay model–for simulating the hysteretic stress path). Figures 2-7 and 2-8 show the distribution and evolution of P_{SHEAR} and P_{FRAC} in the caprock (just above the reservoir) before oil production (1955), after 20 years of oil production and 43 years of gas storage operations (2017), as well as the changes between 1955 and 2017 for both models. Results show that the nonreversible deformations caused by plastic reservoir compaction can have important consequences for the calculation of the maximum working reservoir pressure on the seal integrity. The calculation of the maximum reservoir pressure to avoid the creation of a hydrofracture or the reactivation of fractures favorably oriented for shear reactivation in the seal formation tend to be over-estimated when irreversible deformations are ignored. For the Honor Rancho site, considering a hysteric stress path behavior, the calculated changes in P_{SHEAR} and P_{FRAC} at the end of the reservoir depletion are a few MPa higher than the calculated changes for a non-hysteretic stress path.

Figure 2-7: Distribution of P_{FRAC} in the Caprock



Distribution of P_{FRAC} and ΔP_{FRAC} (P_{FRAC} in 2017 - P_{FRAC} in 1955) before reservoir depletion and after 20 years of production and 43 years of gas storage operations (2018) in the caprock, calculated with the Modified Cam-Clay model (a, c, and e) and with the isotropic elastic model (b, d, f). (g) and (h) Evolution of ΔP_{FRAC} at two control points (located on fig. e) calculated with the Modified Cam-Clay model and with the isotropic elastic model.

Figure 2-8: Distribution of P_{SHEAR} in the caprock



Distribution of P_{SHEAR} and ΔP_{SHEAR} (P_{FRAC} in 2017 - P_{FRAC} in 1955) before reservoir depletion and after 20 years of production and 43 years of gas storage operations (2018) in the caprock calculated with the Modified Cam-Clay model (a, c, and e) and with the isotropic elastic model (b ,d, f). (g) and (h) Evolution of ΔP_{SHEAR} at two control points (located on fig. e) calculated with the Modified Cam-Clay model and with the isotropic elastic model.

Nevertheless, regardless of the two models applied, the geomechanical simulations show that under the estimated stress conditions applied here, the Honor Rancho Underground Storage Facility is being safely operated at reservoir pressure much below what would be required to compromise seal integrity.

Finally, the constructed geomechanical model is stored in the IRMDSS and can be used in the future for prediction purpose.

Wellbore Model

A wellbore model is a computer model that is used to simulate pressure and temperature response patterns under normal and/or abnormal (leaking) flow conditions within wellbores, and can, therefore, be used to identify abnormal conditions based these pressure and temperature data.

A wellbore model was built for the project well, defined as the well that was used in the project to install advanced downhole monitoring device and to demonstrate the IRMDSS framework. The wellbore model is used to simulate the pressure and temperature signals using various injection/withdrawal scenarios. In addition, it can simulate various pressure control procedures (aka well kills) for leaking wells and identify optimal kill procedures for each type of well configuration and gas storage system to minimize the impacts of well failure.

A coupled wellbore-reservoir simulator, T2Well with EOS7Cma, is used for the wellbore simulations. The software was successfully used to simulate the Aliso Canyon blowout and following kill attempts (Pan et al., 2017). Despite the original target application being geologic carbon sequestration, T2Well is a general coupled well-reservoir simulator that can be used for a variety of applications. For example, the code was slightly modified in 2010 to simulate the Macondo well oil and gas blowout in the Gulf of Mexico in response to the urgent need for flow-rate estimation (Oldenburg et al., 2012). T2Well is also used in geothermal reservoir modeling studies (e.g., Pan et al., 2015; Vasini, 2016) and aquifer-based compressed air energy storage studies (Oldenburg and Pan, 2013a & b; Guo et al., 2016). Applications of T2Well in various areas have confirmed the importance of modeling the coupling between the well and the reservoir, which can limit the supply of fluid to the well. In a leakage scenario, the shallow formation often provides pore space for the leaking fluid as well as complicated resistance to the leakage flow. Therefore, a coupled well-reservoir model instead of a well-only model is needed to capture the physics and dynamics of the processes.

Well Model Setup

A sketch of the project well diagram is shown in Figure 2-9. Honoring the size of each component in the diagram, a radially symmetric (around the center of tubing) grid is developed to simulate the complex configuration in the well and its coupling to the surrounding reservoir, caprock, and shallow formations (Figure 2-10). The tubing wall is explicitly described in the grid as special grid cells from the top of the well down to the packer which separates the A-annulus from the tubing. Tubing walls are impermeable to the fluid (i.e., only conductive to heat flow). The B-annulus casing wall is modeled as impermeable with connections between the annulus cells and the surrounding formation cells allowing only for conductive heat flow while the casing wall is simulated as a part of cement. The A-annulus is filled with gas at the top and liquid at the bottom. Below the depth where the well started to be inclined, the grid is tilted so that the correct gravity direction is assigned to the grid. The formations are assumed to be homogeneous in this model.

Figure 2-9: A Well Diagram Sketch and Demonstrated Leak Scenarios

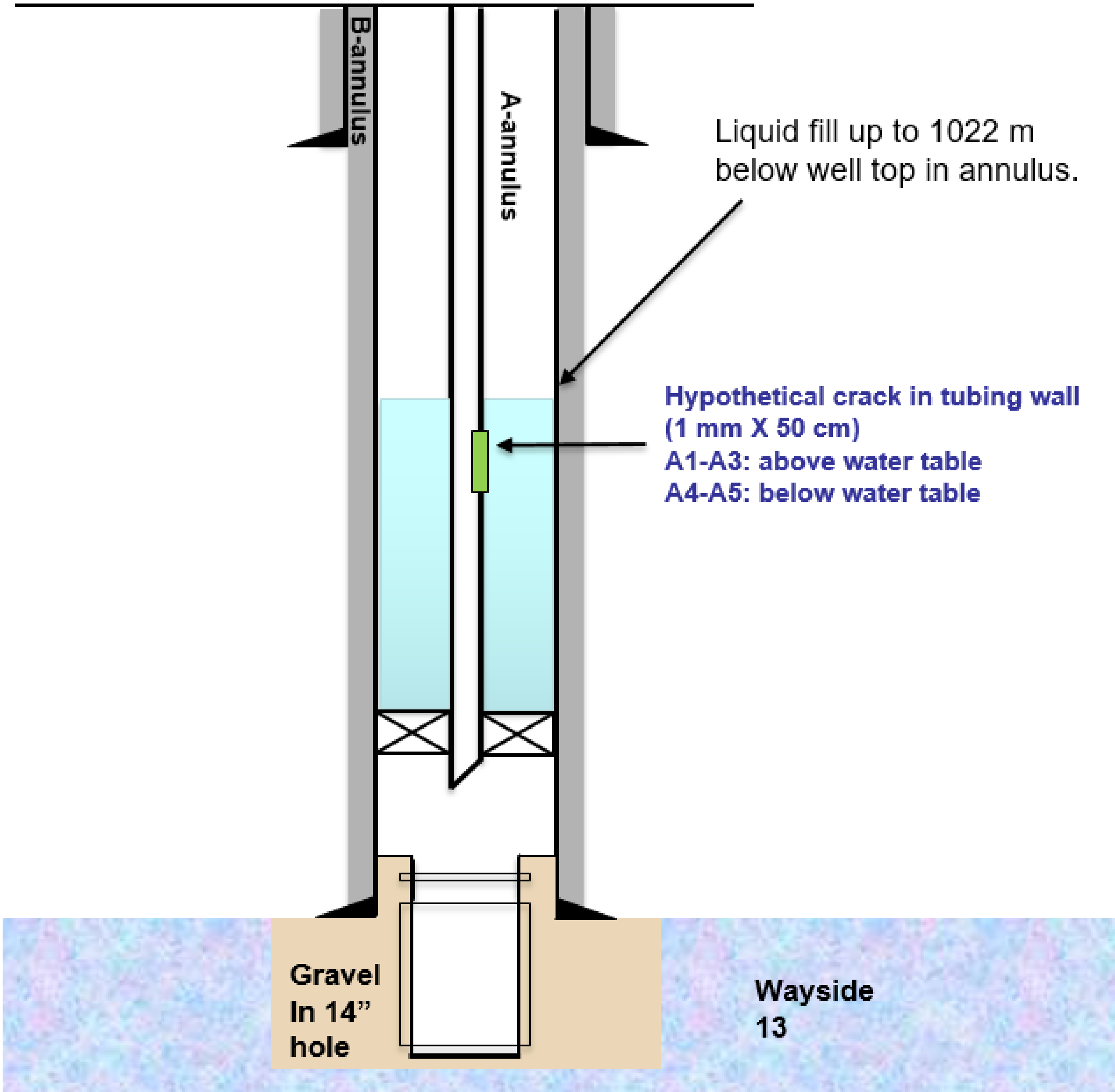
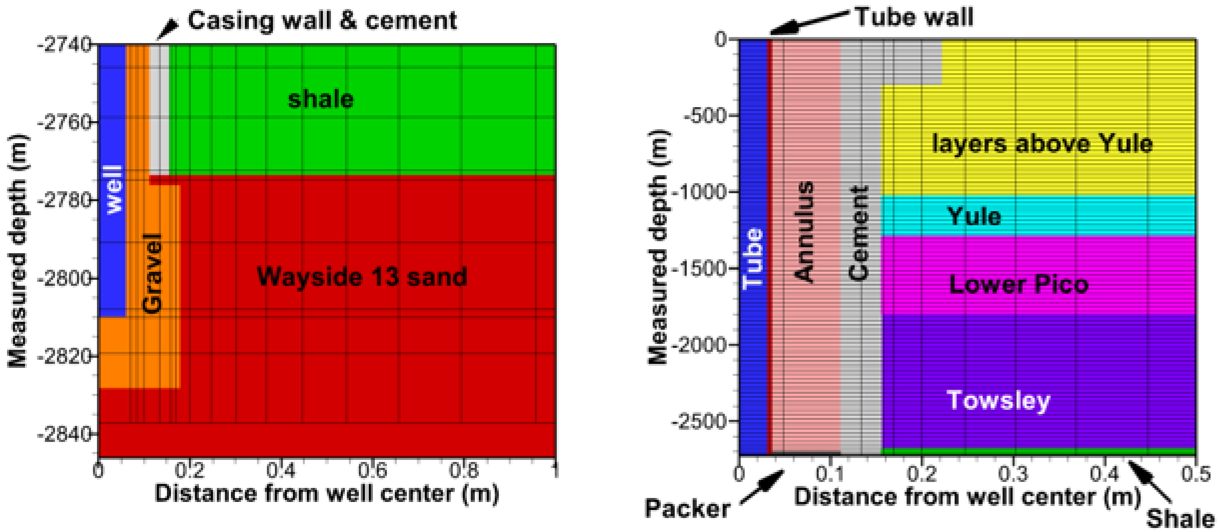


Figure 2-10: Detailed Numerical Grids Near the Well



Leakage Scenarios

To demonstrate how the developed well model is applied to understand abnormal situations, a base-case scenario without leakage and five tubing-leak scenarios at different leakage depth, as listed in Table 2-3 are simulated and compared. The five cases are selected to cover the entire depth of the well: A1 at the top; A5 at the bottom; A3 right above the liquid-gas interface in the annulus; A2 between A1 and A3; and A4 between A3 and A5. Simulation of leakage at various depths can help understand how leakage characteristics may change along the well, eventually help understand what leakage signals could be used to help identify leakage location if a tubing leak happened.

Table 2-3: Leak Depth for Leakage Scenarios

Case	A1	A2	A3	A4	A5
Measured depth (m)	109.7	496.2	1013.7	1544.2	2575.0

Simulation Results

The injection/withdrawal rates used for the simulation scenarios are listed in Table 2-4, and also on the second Y-axis in Figure 2-10 (shown as the flow rate in the legend).

Table 2-4: Injection/Withdrawal Rates Used in the Simulations

Duration (hr)	0-12	12-24	24-36	36-48	48-60	60-72	72-84	84-100
Flow rate (kg/s)	-6.0	-4.0	-2.0	0	2.0	4.0	6.0	4.0

Injection is shown as negative and withdrawal as positive.

Figure 2-11: WHP for the Simulated Scenarios

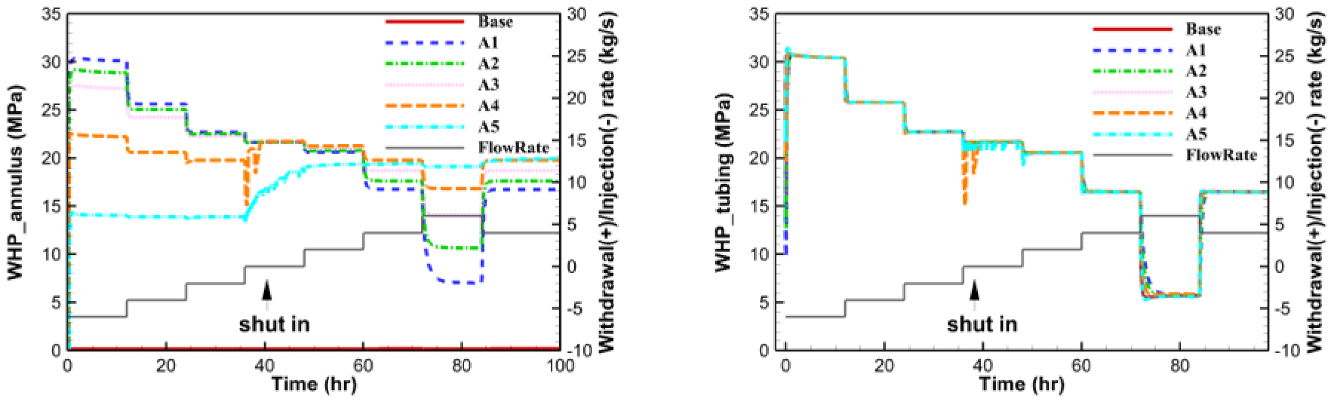
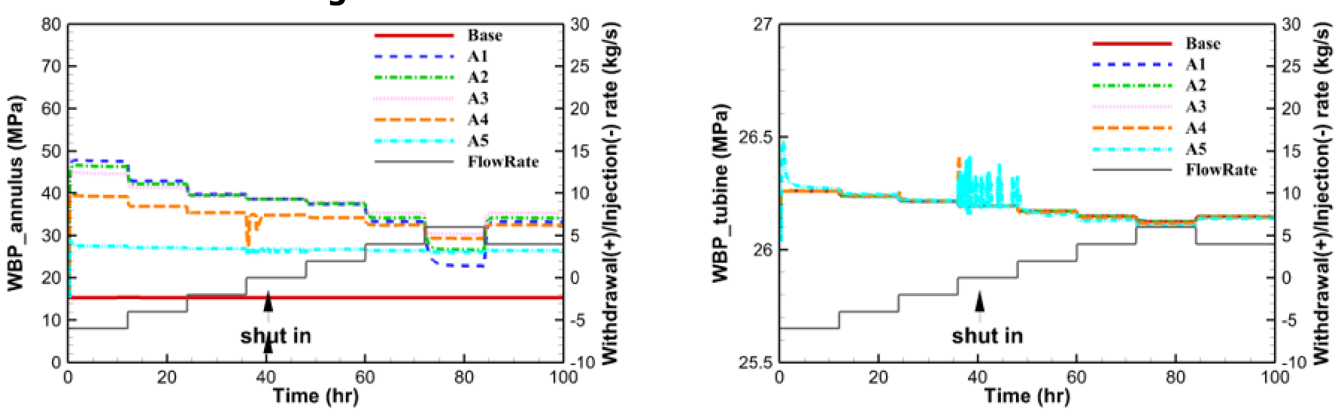


Figure 2-11 shows the wellhead pressure (WHP) responses to the injection/withdrawal operations for all the scenarios, in both the annulus and in tubing. All WHPs in the annulus experience a drastic increase for all the leakage scenarios, compared to a constant wellhead pressure expected in the base case. The magnitude of the pressure increase depends on injection/withdrawal rate. In addition, this pressure increase appears to be related to the leakage location. The difference in pressure increase between the leakage depths is more pronounced in Cases A4 and A5, in which the leaky locations are below the annulus gas-liquid interface, compared to the difference between the shallower leaky locations. Moreover, the magnitude of the annulus pressure decreases with the depth of the tubing failure in general except for the Cases A4 and A5 at later time when gas bubbles displace the water in the top portion of the annulus.

The WHP curves in the tubing from most cases in Figure 2-11 are overlapping, except for deeper Cases A4 and A5 during shut-in when strong oscillation occurs in tubing WHP. This shows that the WHP, dominated by the injection/withdrawal rate, is not so much affected by the small leakage amount that happens mostly in the first minute after the leak starts. Therefore, WHP does not contain much information in leakage locations or leakage amount.

In summary, an increase in annulus WHP is a signal indicating leakage. The amount of increase contains information of leakage location.

Figure 2-12: WBP for the Simulated Scenarios

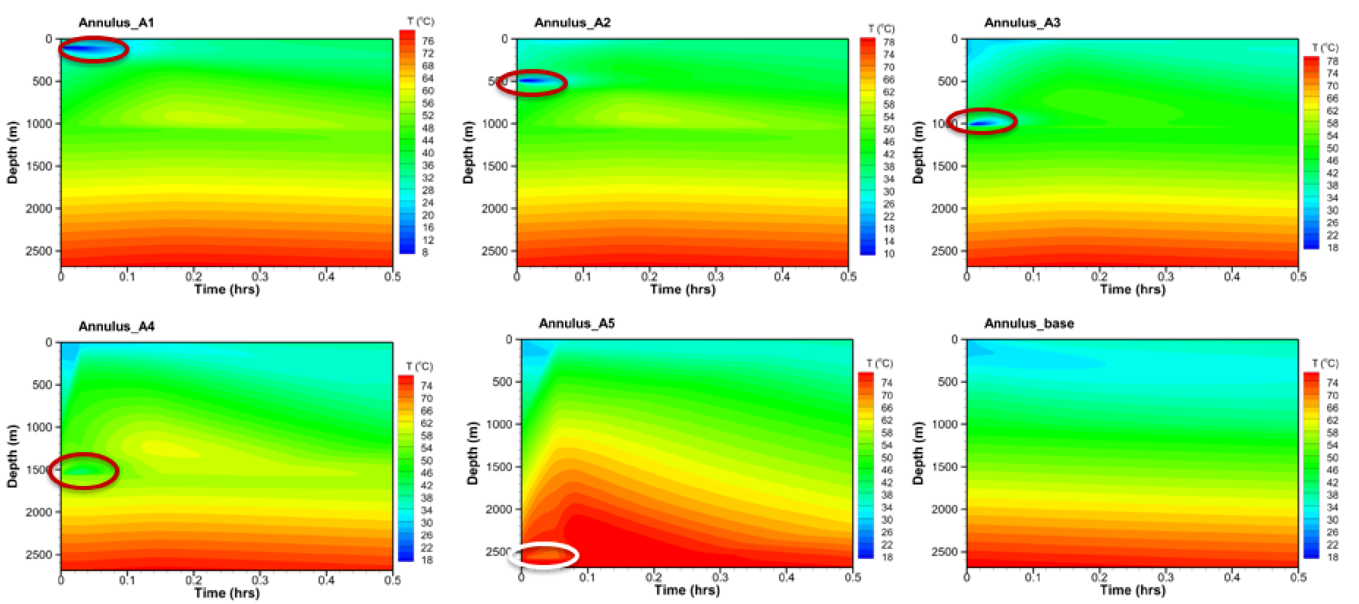


Similar observations are made for the well bottom pressure. As shown in Figure 2-12, annulus WBP increases significantly as a result of leakage and the magnitude of increase depends on the injection/production rate. The results indicate WBP measurements could provide another signal for leakage detection. WBP can be measured using downhole pressure/temperature quartz sensors discussed in the Advanced Monitoring section.

Temperature Reponses

Figure 2-13 shows the vertical temperature profile in the annulus for the first half-hour of gas injection. All five leakage scenarios show a local cooling at the leakage depth. This local cooling is caused by gas going through the crack, resulting in Joule-Thomson cooling. The cooling is more pronounced in Cases A1, A2, and A3, in which the leak location resides in the gas region of the annulus. It is less obvious in Cases A4 and A5, in which the cooling trend is immediately reduced by the warm water in the annulus. The cooling could be captured or missed, depending on both the strength of the signal (how long the cooling may last) and the frequency of temperature sampling (In this project the DTS sampling frequency for vertical temperature profile is set at 10 minutes. It is possible to be more frequent but will result in a larger data set). If the cooling is captured in real-time, it can provide an immediate warning of the leakage threat and estimate of leakage depth. This real-time vertical temperature measurement can be made by the distributed temperature sensing (DTS) method as described in the Advanced Monitoring section.

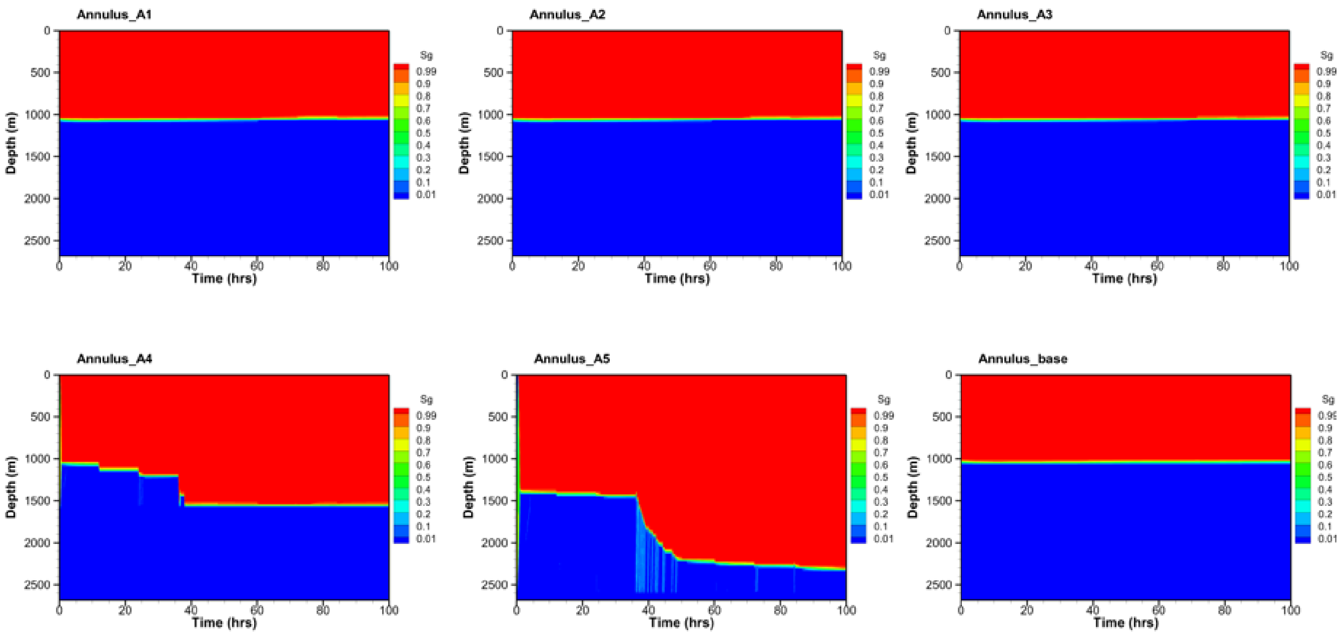
Figure 2-13: Vertical Temperature Profile in the Annulus



Gas-Liquid Interface in the Annulus

Figure 2-14 shows the gas saturation in the annulus for the simulated period. The purpose of the plot is to demonstrate that in the Cases A1-A3, the gas-liquid interface stays constant because the leak location is above this interface. As a result, there is only gas flow from inside tubing to the annulus due to the crack but there is no liquid flow from annulus to the tubing. On the other hand, in the Cases A4 and A5, the gas-liquid interface gets lowered to the leakage location during the shut-in or withdrawal periods due to significant liquid flow from the annulus to the tubing during the shut-in period. If the interface is monitored (as discussed in the DTS monitoring section later), for cases in which the leak happens below the original gas-liquid interface, the depth of the new gas-liquid interface provides a good estimate of leak location.

Figure 2-14: Gas Saturation (Gas-Liquid Interface) in the Annulus



Summary and Conclusions

A wellbore model was built based on the project well diagram. The model has been demonstrated to be able to simulate operations under normal conditions and tubing leak scenarios with a few leak depths. The results show:

- Both WHP and WBP are elevated if there is a crack in the tubing wall, as opposed to staying constant if there is no integrity issue. The magnitude of the pressure increase depends on injection/withdrawal rate, as well as the location of the tubing wall.
- Tubing leakage also produces a notable cooling at the depth of leakage. The signal is stronger if the depth is above the gas-liquid interface. Real-time vertical temperature measurement along the tubing wall (i.e., DTS measurements) can provide a real-time detection of leakage and a good estimate of leakage location. However, if the leakage location is below the gas-liquid interface and the signal does not last long enough for the DTS measurement to capture it (i.e., cooling duration is less than DTS sample frequency), the leakage location can be identified by the new gas-liquid interface after the leak. This interface location can be monitored using DTS measurements, as discussed in the Advanced Monitoring Technology section.

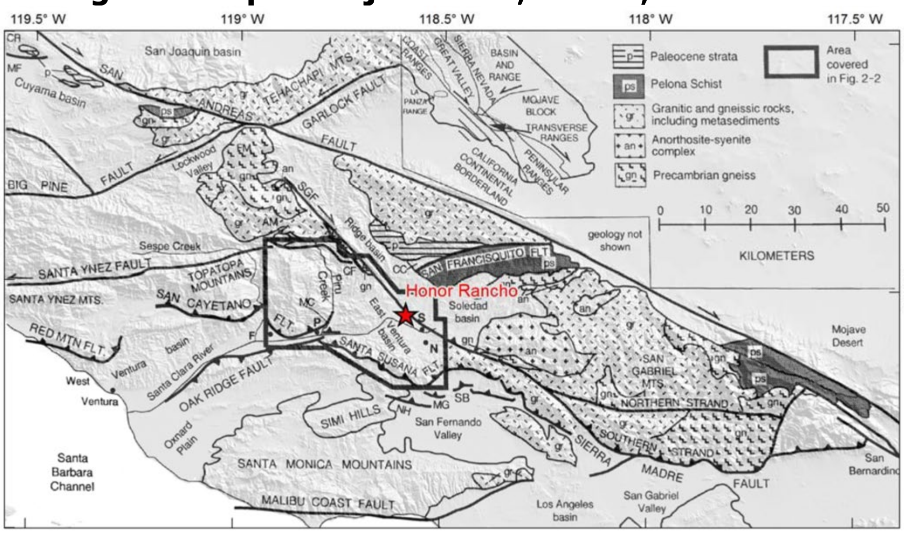
The developed model can also be used to simulate operations under other abnormal conditions, and potential mitigation scenarios. The model is stored in the IRMDSS and can be run under the SI and compared to the DTS measurements.

Geohazard Analysis

A geohazard analysis compiles site-specific information, such as applicable earthquake ground motion models, local and regional fault characteristics and landslide maps to provide probabilistic seismic, fault displacement, and earthquake-induced landslide hazard analysis. The main purpose of the analysis in the IRMDSS system is to help diagnose if a certain condition (e.g., unexpected LOC with resulting natural gas plume at the surface) could be caused by a geohazard (e.g., fault displacement, or landslide).

In order to incorporate earthquake hazards into the framework of the Integrated Risk Management and Decision-Support System (IRMDSS) for the Honor Rancho Gas Storage Facility, three geohazard analyses were performed: a probabilistic seismic hazard analysis (PSHA), a probabilistic fault displacement hazard analysis (PFDHA), and a pseudo-probabilistic earthquake-induced landslide hazard analysis. Regional map of major faults in the vicinity of the Honor Rancho site is shown in Figure 2-15. The results of these three analyses are summarized below.

Figure 2-15: Regional Map of Major Faults, Basins, and Basements Outcrops



Thick black outline indicates area of East Ventura Basin. Abbreviations include: AM, Alamo Mountain; CF, Canton fault; CR, Caliente Range; F, Fillmore; FM, Frazier Mountain; MC, Modelo Canyon; MF, Morales fault; MG, Mission Hills–Granada Hills fault; N, Newhall; NH, Northridge Hills fault; P, Piru; S, Saugus; SB, Sylmar basin; SGF, San Gabriel fault. Modified from Yeats et al. (1994)

Probabilistic Seismic Hazard Analysis (PSHA)

A probabilistic seismic hazard analysis (PSHA) provides the mean, median (50th percentile), 5th, 15th, 85th, and 95th percentile hazard curves for peak ground acceleration, as shown in Figure 2-16. Peak ground acceleration values of 0.66 g, 0.85 g, and 1.14 g correspond to return periods of 475, 975, and 2,475 years, respectively. A summary of probabilistic ground motions is provided in Table 2-5. At amplitudes of peak ground acceleration of about 0.4 g, the two most hazard-significant sources are the Northridge Hills fault and the Sierra Madre fault system, which includes the Santa Susana fault.

Figure 2-16: Seismic Hazard Curves for Peak Horizontal Acceleration

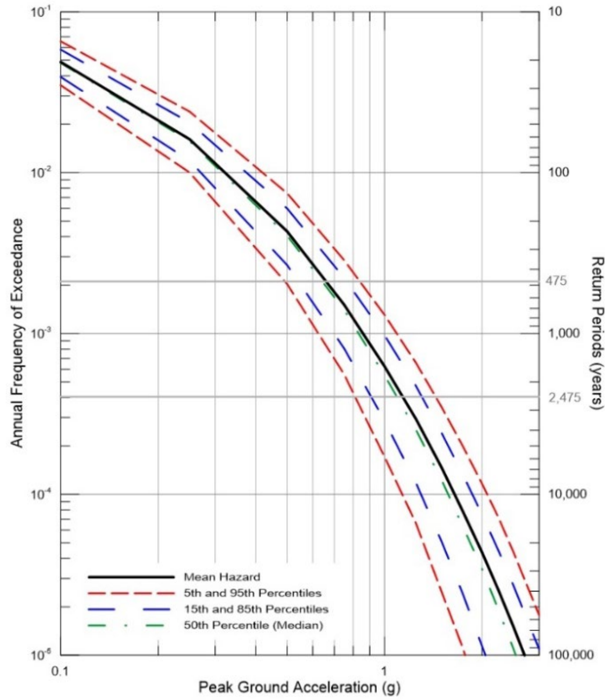


Table 2-5: Summary of probabilistic ground motions

Return Period (years)	PGA (g) Mean [5th, 95th percentiles]	0.2 Sec SA (g) Mean [5th, 95th percentiles]	1.0 Sec SA (g) Mean [5th, 95th percentiles]	3.0 Sec SA (g) Mean [5th, 95th percentiles]
475	0.66 [0.49, 0.84]	1.64 [1.14, 2.13]	0.66 [0.50, 0.85]	0.16 [0.11, 0.22]
975	0.85 [0.62, 1.08]	2.12 [1.47, 2.75]	0.89 [0.67, 1.153]	0.22 [0.15, 0.29]
2,475	1.14 [0.81, 1.44]	2.85 [1.93, 3.67]	1.270 [0.93, 1.62]	0.31 [0.21, 0.40]

Peak ground acceleration (PGA) and spectral acceleration (SA) values corresponding to 475, 975, and 2,475 year return periods.

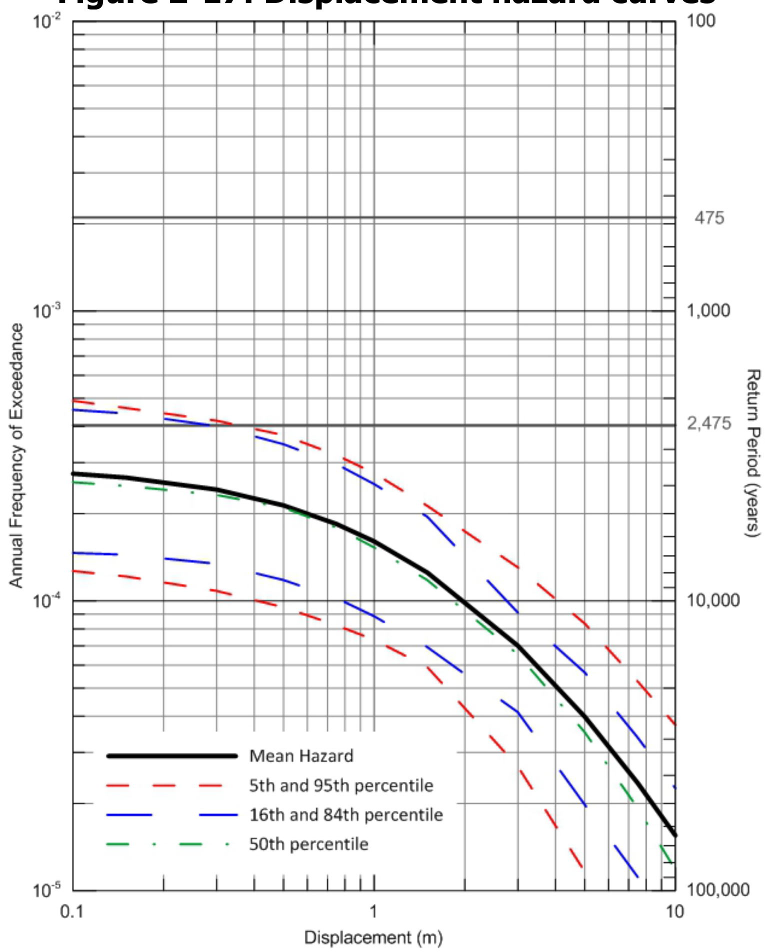
Probabilistic Fault Displacement Hazard Analysis (PFDHA)

A probabilistic fault displacement hazard analysis (PFDHA) was performed for the San Gabriel fault. This fault does not intersect any active wells within the Honor Rancho Gas Storage Field. However, for the purpose of demonstrating PFDHA methodology the location of the fault was hypothetically assumed to intersect well WEZU-7 near the ground surface in the northeast margin of the field.

There is not clear evidence that a fault displacement hazard exists for wells within the Honor Rancho Gas Storage Facility. However, there are several conflicting interpretations regarding the potential for fault displacement hazard in the storage field. These range from undeformed Quaternary and Pliocene strata across the oil field suggesting an absence of Quaternary fault displacement hazard (Schlaefer, 1978; Stitt and Yeats, 1983; Yeats, et al., 1994; Yeats and Stitt, 2003) to displacement on the base of the Quaternary Saugus Formation (Walrond, 2004; Davis and Namson, 2004) suggesting wells in the Honor Rancho Gas Storage Facility are exposed to a fault rupture hazard (Davis and Kuncir, 2004, and Davis, 2018). Workers that interpret Quaternary faulting within the Honor Rancho field also differ in their interpretations. Given the limited scope for this demonstration project, the various conflicting interpretations were not resolved by re-evaluating oil well data or modeled for the PFDHA.

Mean and fractile displacement hazard curves are provided for the San Gabriel fault in Figure 2-17.

Figure 2-17: Displacement hazard curves

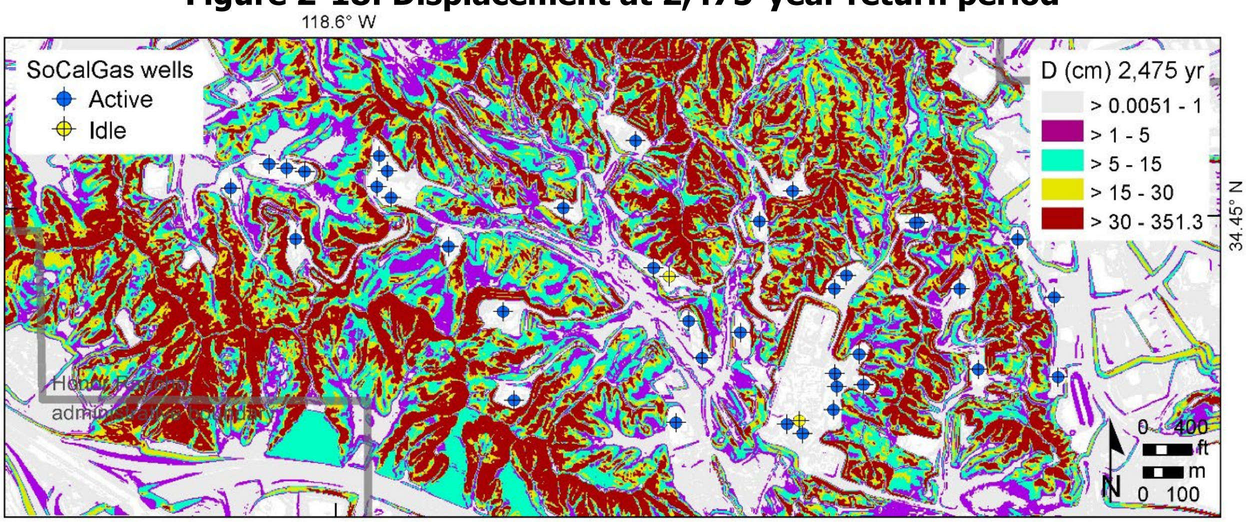


Pseudo-Probabilistic Earthquake-Induced Landslide Hazard Assessment

To model landslide hazard at the Honor Rancho Gas Storage Facility, a pseudo-probabilistic earthquake-induced landslide analysis was performed. This approach used high resolution digital lidar data to model slopes and the empirical prediction model of Rathje and Saygili (2009). The maps shown in Figure 2-18 present computed displacement for the 2,475-year return periods. In order to better understand the 2,475-year earthquake-induced landslide hazard to each well shown in Figure 2-18, a simple spatial analysis was performed in ArcGIS to quantify the percent area exceeding a threshold displacement within both 50-ft and 100-ft radii of each well. The percent area classified with D >5 cm were calculated for the 50-ft and 100-ft buffers. Observations regarding the 2,475-yea earthquake induced landslide hazard made from Figure 2-18 include:

- No well is located on ground predicted to experience displacements. This is largely due to the large, relatively horizontal well pads.
- For a majority of the wells, D >5 cm does not occur within 50 ft. Only 10 of the 39 wells include D >5 cm within 50 ft. Harp and Jibson's (1996) observation that most of the slides triggered in the 1994 Northridge earthquake were only about 1–5 m (~3–16 ft) thick, and the 50 ft distance to D >5 cm for most wells, suggests that the earthquake-induced landslide hazard to wells within the Honor Rancho Gas Storage field is not significant.

Figure 2-18: Displacement at 2,475-year return period



Landslide displacement triggered from 2,475-year peak ground acceleration of 1.14g.

Latitude/longitude coordinates of wells obtained from CalGEM (DOGGR) database downloaded on 11/26/18.

Advanced Monitoring Technologies

The monitoring technologies considered for this project include:

- Downhole quartz pressure-temperature sensors, which provide pressure and temperature real-time measurements at the bottom of the instrumented well. These measurements are much more accurate than estimates made using wellhead measurements, which is the current practice.
- Fiber-optic Distributed Temperature Sensing (DTS), which provides a continuous temperature measurement along the vertical wellbore. This profile could be different between normal and abnormal conditions and, therefore, such data can be very useful in leakage detection and analysis.
- Fiber-optic Distributed Acoustic Sensing (DAS), which is a technology that can quickly detect and locate the acoustic signal generated by a gas leak in a well.

- Unmanned Aerial System (UAS)/Drone Gas leak monitoring, which is used to monitor CH_4 atmospheric concentrations at low elevations above the ground surface for surface leakage detection.
- Interferometric Synthetic Aperture Radar (InSAR) for ground deformation, which measures millimeter-scale changes in surface deformation over spans of days to years. The surface deformation can then be transformed to infer the volume changes within the reservoir associated with pressure changes due to natural gas storage operations.

The WEZU C2B well (API 0403721475) at the Honor Rancho UGS site was identified for deploying downhole monitoring technologies, which include downhole quartz pressure-temperature sensors, DTS and DAS. Unlike the current practice for noise and temperature logging which is done annually at UGS sites in California, fiber optic measurements can be made continuously in an unsupervised manner, as long as the instrument can be connected to a source of power and there is an adequate data storage system in place. Unfortunately, for unknown reasons the downhole quartz pressure-temperature sensors were never able to acquire data, therefore, not discussed here. But DTS and DAS data for over half a year were successfully collected.

DTS Monitoring and Data

Introduction

The temperature along the length of a well is a fundamental diagnostic parameter that can be used to assess well integrity issues. When a well is under shut-in conditions, the vertical temperature profile of a well follows the natural geothermal gradient once it reaches thermal-equilibrium with its surroundings. This vertical temperature profile will change when there are injection/withdrawal activities. It is recognized that integrity issues along the well may cause the temperature to depart from the normal trend. As a result, thermal logging has long been used for well-leakage detection. In addition, the current regulator-required method for identifying leaks (CalGEM (nee DOGGR) Requirements for California Underground Gas Storage Projects, §1726.6) in a gas storage well is to perform annual noise and temperature logs. Given that a leak can be initiated at any time in the life of a well, annual thermal logging may give an incipient casing integrity issue time to grow more serious in the time between logging runs. While increasing the well logging frequency increases the chance of catching a leak early, it has its own downside because the logging intervention itself increases other risks associated with shutting in the well and installing pressure control equipment to facilitate logging.

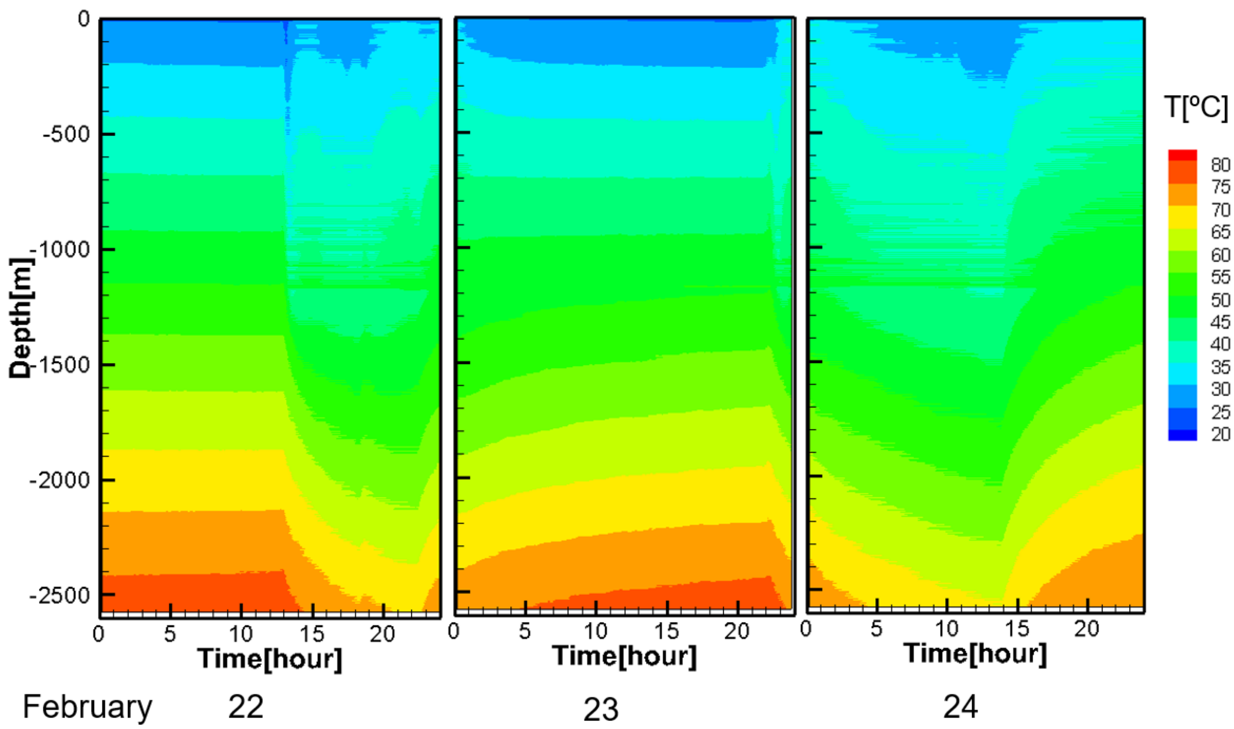
Distributed temperature sensing (DTS) comprises optoelectronic devices that measure temperatures by means of optical fibers. Temperatures are recorded along the optical sensor cable, thereby forming a continuous temperature profile. A DTS interrogator is the size of a standard personal computer and the sensing cable can measure along an optical fiber up to several kilometers in length. DTS temperature resolution is about 0.02 °C for a 1-hour integration time, or 0.1°C for 5 minutes integration time. Spatial resolution can be as high as 25 cm.

DTS Data Demonstration

For demonstration, the temperature profile at the project well is recorded about every 10 minutes, amounting to ~144 profiles per day. The temperature profiles are text-based files that can be open by any standard text editor. The downhole cable length is about 2500 m, and samples are taken every 25 cm (i.e., a total of 10,000 data points per profile) leading to a file size on the order of 500 KB per file.

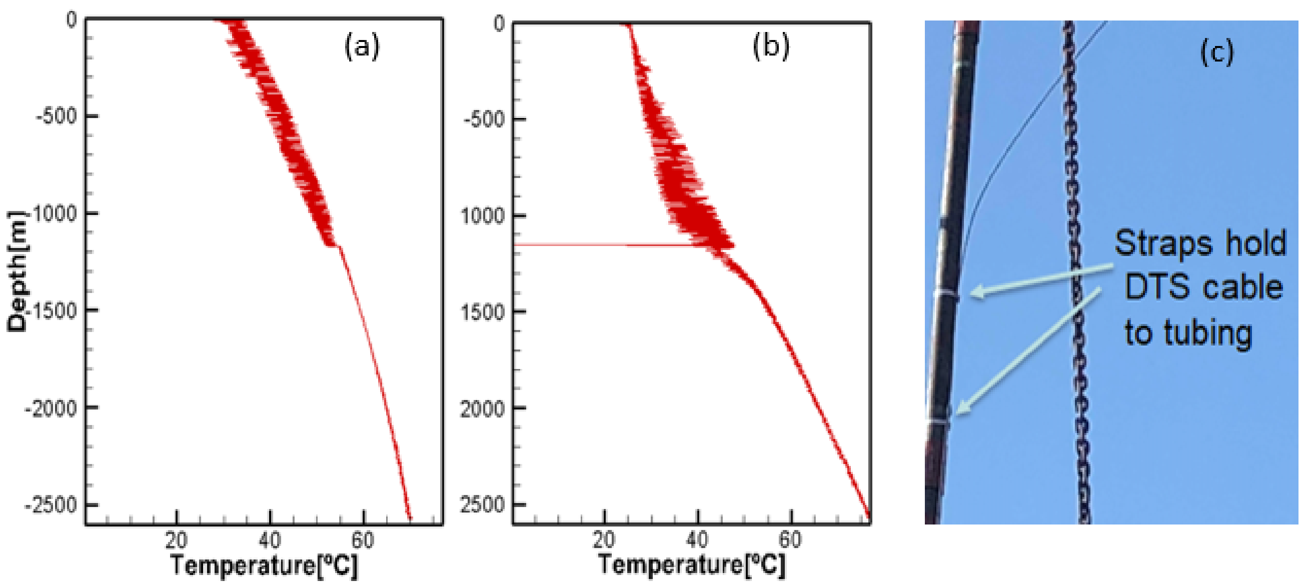
As an example, Figure 2-19 shows the vertical temperature profile of the project well for February 22-24, 2020. The profile clearly shows initially (at the beginning on February 22nd) the temperature was equilibrated with the formation geothermal gradient. The first injection started on the 13th hour of February 22nd, and lasted for about 10 hours. This is indicated by the cooler temperatures due to the cold gas injection. The temperature profile on February 23rd shows a long recovery from the cold gas injection, then this is followed by another injection, which started at around 10 pm. The temperature starts to cool down again. The injection lasted for about 16 hours. Then the temperature started to recover when the injection stopped.

Figure 2-19: Example of DTS profile During Injection and Shut-In



A distinct feature of these DTS profiles is that the measured temperature shows more noise in the upper part of the profile during operations (injection and withdrawal). This can be seen more clearly by focusing on a single temperature profile, as shown in Figures 2-20(a) and (b). The reason for this increase in "noise" is that the annulus of the well is filled with both gas (upper part) and treated brine (lower part), which is liquid. The treated brine in the annulus is used to stabilize the packer, by providing force to counteract the pressure in the reservoir. Maintenance of the brine height is a critical component of well integrity. The fiber optic cable is clamped to the tubing at discrete points along the tubing, as shown in a photograph taken in the field during installation as shown in Figure 2-20(c). The lower part of the cable is in the brine, which has higher thermal conductivity than the gas in the shallower section of the annulus. While it appears that the oscillations are "noise," in fact, the thermal signature reflects that the cable is clamped to the, and in between the clamps, the cable sits entirely surrounded by fluid. The DTS cable thus reflects both the tubing temperature (where it is clamped) and the ambient annular fluid temperature through which it runs between clamps. Therefore, the DTS cable shows that there is a strong thermal gradient under transient conditions between the inside of the tubing and the annulus and surrounding formation. The oscillations observed are real reflections of the gradient given the very small variations in cable position. The stronger oscillations at shallower depth reflect the lower thermal conductivity of annular gas as compared to the higher thermal conductivity of the liquid-filled annulus below the gas-liquid contact.

Figure 2-20: DTS Profiles and a Fiber Cable on the Tubing



Figures show (a) a DTS profile when withdrawal started; (b) a DTS profile when injection started; and (c) how the fiber optic cable is clapped onto the tubing.

Summary and Conclusion

Examples of DTS data of the project well are presented here. Clear signals due to gas injection/withdrawal were observed and expected. DTS measurements during normal operation provide a good baseline for integrity issues. The main advantage of DTS is that it can provide temperature profiles 24/7 in an unsupervised manner to ensure temperature anomalies are identified rapidly. In addition, the DTS measurements can provide the gas-liquid contact location in the annulus on a regular basis, which provides an important piece of information for operating the well and potentially for identifying integrity issues. The DTS data were collected for the project well between November 2019 to August 2020. No anomalies have been observed for the project well.

The DTS data can be combined with the T2Well model to analyze integrity issues, which will be demonstrated in the next Chapter.

DAS Monitoring and Data

Introduction

One way of detecting abnormal and potentially threatening conditions of wells is by analyzing acoustic noise passively generated by fluid or gas flow in the well. Turbulence generated by channelized flow across/through perforations or leakage pathways generates high-amplitude, characteristic acoustic signals that deviate from background noise generated during injection or withdrawal operations, enabling identification of anomalous behavior in the system. The most common technique used to listen to this noise and detect well leaks and other well integrity issues is spectral noise logging (e.g., Maslennikova et al., 2012). This method, used in industry since the 1970's, consists of lowering a noise logging tool down the borehole and recording acoustic noise at different frequency channels, either as a continuous reading along the borehole or as stationary measurements at different depths. Although this technique has been proven successful in leak detection, a major drawback of its application is that these tools are not designed to be permanently deployed in the well for continuous monitoring. Every time a survey is performed, the well has to be shut in for some time until the well is completely quiet and then the survey can be performed. The survey requires operators to lower the logging tool down the borehole to a certain depth, wait three-four minutes before the tool takes a reading. Then the tool is moved to the next measurement depth. This procedure is very time-consuming and, therefore, results in expensive surveys. Thus, current practice is limited to one noise logging survey per year, which limits the ability to detect leaks or other well-integrity issues before they represent a hazard to the system.

Distributed Acoustic Sensing (DAS) is an attractive alternative to the current approach. Similar to DTS data, DAS data are unsupervised and continuously collected. Examples of DAS data and analysis are provided below.

DAS Data Demonstration

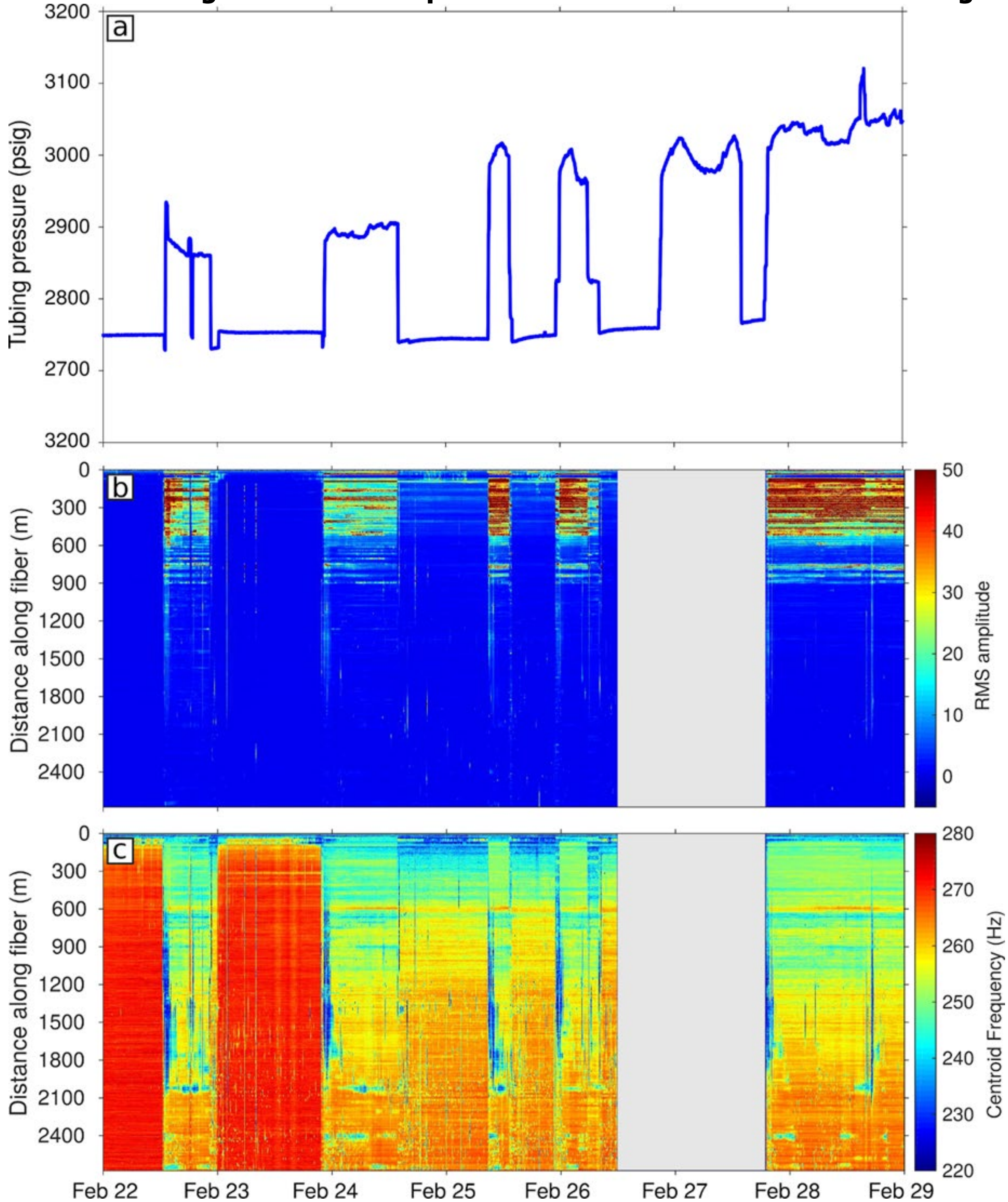
DAS sampling frequency was set to 1 kHz (1e-3 s) for demonstration, since the acoustic signals generated by fluid or gas flow in the well tend to be characterized by frequencies in the order of 100's of Hz. Spatial sampling was initially set as 0.25 m, resulting in a data volume of 1.2 TB per day. The sample spacing was later changed to 1 m to reduce data volume. Data were recorded in 30-seconds-long files and streamed continuously to external hard drives.

The DAS noise generated in the well at different stages of operations can be recorded at high resolution using this technology, and it has revealed that changes in amplitude and frequency content are good indicators of changing conditions. However, visual inspection of the amplitude and frequency content of each recorded 30-second-long file is very time consuming and inefficient. Moreover, the high density of measurements provided by DAS results in large data volumes that can be challenging to store and process. A simpler way of detecting changes in noise characteristics is by reducing each noise file to simple data metrics at each measurement channel that describe the main characteristics of the acoustic signal. The attributes chosen in Figure 2-21 provides an estimate of the average signal amplitude (Root-Mean-Square amplitude, Figure 2-21b) and the "center of mass" of the frequency spectrum (centroid frequency Figure 2-21c), which inform on the characteristics of the source of acoustic noise. These attributes can be calculated in a few minutes for each 30-seconds-long file, and it significantly reduces the size of the data. In addition, they still contain critical information that describes the acoustic signal and enable fast identification of changing conditions in the system.

Summary and Conclusion

This preliminary analysis of DAS data demonstrates that the analysis of acoustic noise recorded by DAS can provide critical information about changes occurring in the borehole at different stages of system operation. These different stages can be characterized with the objective of setting background characteristics that describe the acoustic behavior of the system during normal operations. This knowledge will enable establishing what "normal behavior" is, so that anomalies are quickly identified and analyzed to search for malfunctions such as a leak. In addition, data attributes were used to reduce DAS data volume while still provide insights into spatial and temporal changes in the borehole.

Figure 2-21: Example of Data Attributes for DAS Recording



(a**) Tubing pressure for period between February 22nd and February 29th. (b) Root-Mean-Square (RMS) amplitude for all data recorded during this period. Note how high amplitude periods correspond to times at which the well is flowing. Gray band indicates period with no data (c) Same as panel b, but showing centroid frequency. As in b), gray band indicates a gap in the data record. Note a shift in centroid frequency to lower frequencies during flowing conditions.**

InSAR Monitoring and Data

InSAR is a low-cost technology to measure ground deformation for hazard identification. The ground deformation may be due to many causes, such as groundwater pumping and excavation, but well leaks and reservoir leaks and fault motion can also produce detectible surface movements. InSAR technology is included in the IRMDSS as one of the long-term monitoring technologies for UGS safety.

Introduction

InSAR has emerged as an effective tool to measure the ground deformation associated with a wide variety of geophysical and geotechnical processes at high spatio-temporal resolution. By differencing the phase of two InSAR images acquired at different times, it can reveal surface deformation of any pixel within the scene coverage at the accuracy of a fraction of the radar wavelength (~ a few cm). A time series of surface deformation can be obtained with a temporal resolution of the images used. Compared to other geodetic tools, InSAR does not need to deploy any physical instruments in the field, so it is quite cost-effective. InSAR has proven useful in detecting and monitoring landslides, and as a surveillance tool over geothermal fields, oil fields, and carbon sequestration sites (Vasco et al. 2010). While the approach has been shown to resolve surface deformation due to gas storage (Teatini et al. 2011), it has not been routinely used as a monitoring technique for such facilities.

InSAR Data Workflow

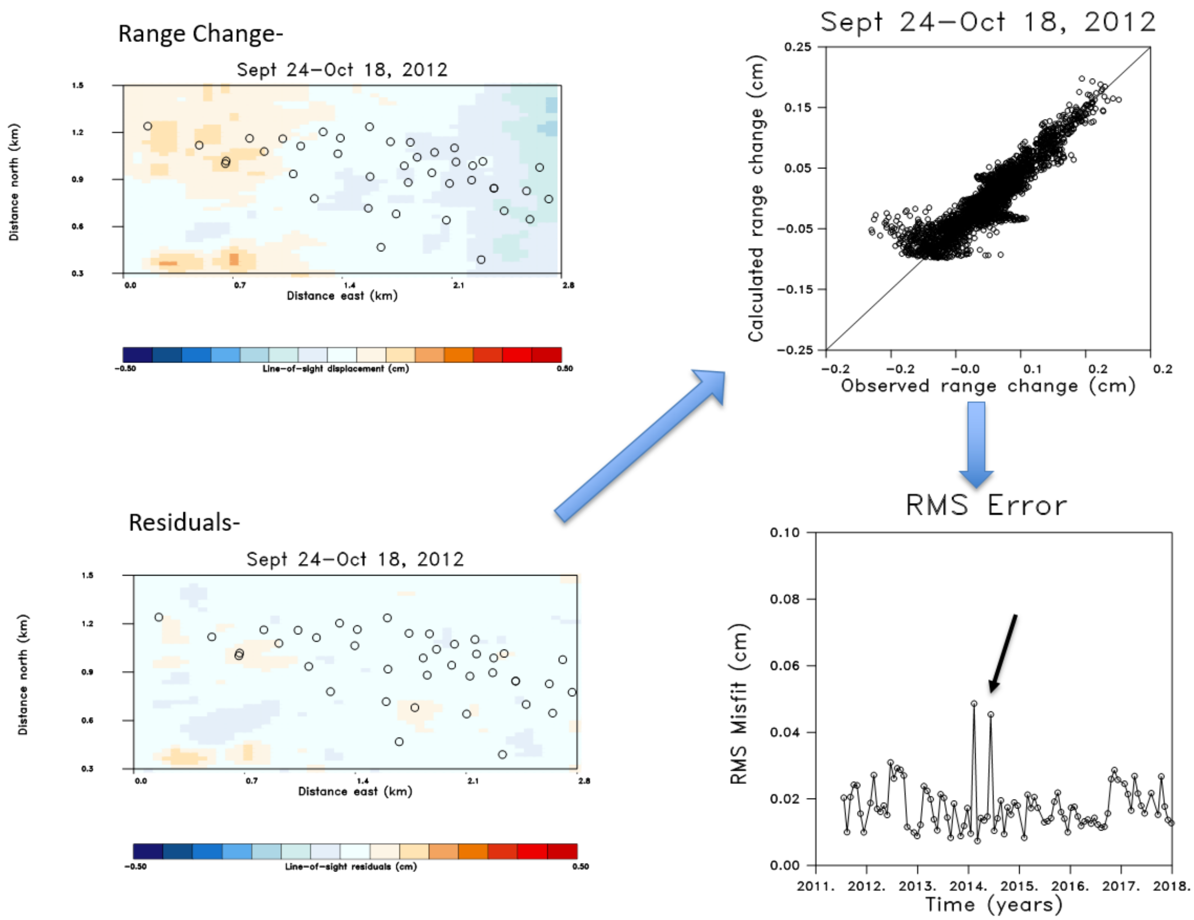
For demonstration, observations from the RadarSat-2 system operated by the Canadian government were used for the Honor Rancho site analysis. The repeat time of 24 days allows for nearly monthly observations. The accuracy of the estimates of surface displacement, in this case in the direction of the satellite position as it samples the area, is of the order of a few milli-meters relative to a nearby stable base point.

A workflow was developed to identity anomalous events. The main idea is to use observations of the deformation of the overburden to estimate volume change within the reservoir over time. Anomalous events are identified by identifying an event with a large total residual, i.e., time intervals during which it is difficult or impossible to fit the observed range changes with volume changes solely within the reservoir. Notice anomalous event does not signify any particular event, but it suggests further examination. For example, the unusual event that was detected could be the interaction of regional tectonics or the operation of the reservoir, or water injection into the above storage zone. This essential idea is presented in Figure 2-22.

Test Using Synthetic Data

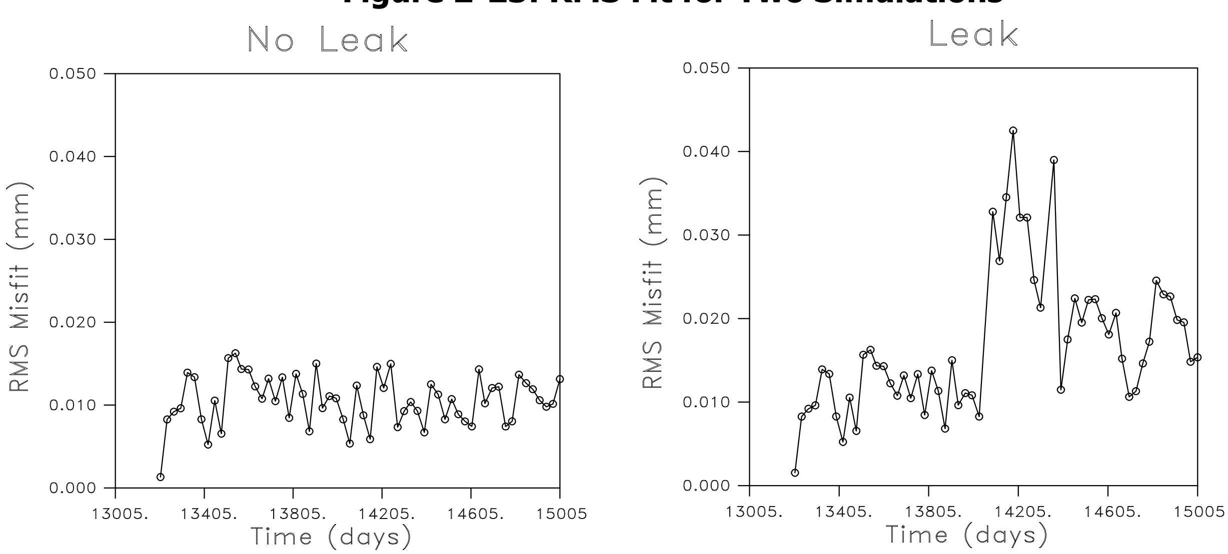
To test the above approach, synthetic range changes were generated using the Honor Rancho geomechanical model described previously. Two scenarios were considered: normal operation with no leak and anomalous behavior due to the occurrence of a hypothetical leak at a depth above the reservoir. The RMS history of the two scenarios is shown in Figure 2-23. The RMS values randomly fluctuate around 0.01 mm RMS misfit when there is no leakage; compared to a rapid increase in the level of misfit around 14,000 days in the scenario with leak. This test demonstrates that it is possible to detect leakage using InSAR monitoring data.

Figure 2-22: Calculation of Misfit to Identify Anomalous Events



Figures demonstrate a workflow for anomalous events using the InSAR data collected for the Honor Rancho site. Two anomalous events are identified related to the low inventory at the time.

Figure 2-23: RMS Fit for Two Simulations



Left-hand side figure shows RMS misfit as a function of calendar time for a simulation of the Honor Rancho gas storage facility; Right-hand side figure shows RMS misfit history associated with a simulation in which a synthetic leak started at around 14,000 days

Summary

InSAR observations provide a cost-effective method for monitoring an operating gas storage facility, even one as deep as Honor Rancho. While the surface deformation due to activities within the reservoir is small and can be accounted for through inversions for reservoir volume changes, processes above the reservoir such as slip on shallow faults, leaks from wells above the reservoir, and landslides lead to larger signals that can be identified through their large residuals in a given observation interval. Synthetic testing indicates that well leaks of sufficient size can be identified due to anomalous residuals. Similarly, two events in the actual InSAR data from Honor Rancho indicated unusual surface deformation that warrants further investigation (which in this case, was caused by low gas inventory). Known activities, such as shallow water injection, need to be accounted for in order to improve the monitoring reliability and to reduce the possible misinterpretation of increased InSAR residuals. Anomalous events only signify a time interval where the residuals should be examined and interpreted. They do not necessarily signify an event within the gas storage facility or within the reservoir.

UAV Drone Survey

Monitoring of CH_4 concentrations in air within the UGS infrastructure site footprint can significantly improve efforts to manage risks associated with leaks. Unmanned Aerial System (UAS)/Drone, or Unmanned Aerial Vehicle (UAV)/Drone technology has been developed for gas-leak detection. Due to Covid-related restrictions, the previously planned UAV drone survey at the Honor Rancho site could not be performed. Instead, demonstrations of UAV and other CH_4-monitoring techniques were done at an analogue site in Solano County, California in the vicinity of an artesian well that bubbles CH_4. ABB, the company under subcontract from LBNL, visited and surveyed the site twice, each time with three systems for methane concentration measurement: MobileGuard (vehicle based, mobile survey), HoverGuard (UAV based, mobile survey) and MicroGuard (next generation handheld detection). Unlike systems that rely on path-averaged measurements (based on laser scattering or satellite), these systems record local (point) gas concentrations and wind velocity while flying, thus, resolve the plume and wind vectors as a function of time. From these multi-parameter measurements, the local flux rate at the source is estimated (from turbulent fluid dynamics models).

The goal of the first visit was to demonstrate the capabilities of the three technologies in identifying and locating CH_4 leak source and estimating the emission rate. Four flights were taken to cover an altitude from 3-30 m Above Ground Level (AGL). However, in addition to the targeted known source at the "artesian well," the survey performed by HoverGuard suggested the presence of a larger, previously unknown source farther out in the marsh (See Figure 2-24). The separation between the indications from the "artesian well" and the newly identified source is noticeable and sufficient to conclude that the CH_4 detected from the "artesian well" is distinct and not propagated from the newly identified source. The second visit to the site was able to confirm the source and pinpoint the source location. Although the goal of the field survey was simply to validate the monitoring approaches using the known "artesian well" source, the survey ended up accomplishing something more significant, namely the demonstration that the UAS can detect and locate an unknown source, which is the ultimate goal of such a monitoring technology for UGS risk management.

Figure 2-24: Plot of the Measured CH_4 Concentrations From HoverGuard

Units are not provided for confidentiality. Color scale from blue to red indicates concentration from low to high.

Results

The source location estimate error and leak rate estimate from the HoverGuard and MobileGuard surveys are summarized in Table 2-6. Because the location of the "artesian well" is known, the error in positional estimation of the gas emission source can be calculated. Both MobileGuard and HoverGuard were readily able to detect the source to within 35 and 27 meters and were able to quantify the leak rate with a measurement error of 56 percent and 53 percent, respectively, using the leak rate measured from flux chamber as reference.

Table 2-6: Summary of Survey Results

System	Location accuracy (m)	Leak rate Measurement	
		Volumetric flow (cfh)	Relative error
Flux chamber[1]	NA	5.9 ± 0.5	Reference
HoverGuard	27.3 ± 6.3	9 ± 3.7	53%
MobileGuard	35	2.6 ± 1.8	56%

[1]Location has to be known to use flux chamber.

Conclusions

ABB visited and surveyed on two separate occasions the vicinity of an ”artesian well” located in Solano County, California with three different leak detection systems: HoverGuard (UAV-based), MobileGuard (vehicle-based) and MicroGuard (handheld). The gas flow rate out of the well was measured using the chamber method to provide an actual leak rate value for comparison with the remote mobile measurements. Source localization for both HoverGuard and MobileGuard was within the error bounds. The MicroGuard is capable of rapidly pinpointing the source while walking. Estimated flow rates determined by HoverGuard and MobileGuard were in excellent agreement with the chamber flux measurement and well within the error bounds.

The survey was in a marshy area that allowed the UAV-based gas leak detection system to show its advantage in ability to cover areas that may be inaccessible to conventional vehicles. Although unplanned, the first visit to the site also showed that HoverGuard can detect and locate an unknown leak, which was further confirmed during the second visit to the site

Supervisory Interface

The IRMDSS evaluates scenarios and assesses risks based on process models that are updated with advanced monitoring data to provide indicators of potential threats. The supervisory interface (SI) provides a graphical user interface (GUI) to prepare input files for model analysis; a database for site characterization and advanced monitoring data, and a platform to integrate data and analysis to risk management support. In addition, the SI includes use cases that are served as a guideline/workflows for UGS.

SI Design and Structure

The goal of building a SI for the IRMDSS is to make it possible for a broad audience to use the tools in IRMDSS and perform analysis for UGS operations. The main functionalities of the supervisory interface include:

- Database: data include static data, maps, model figures, model input/output, monitoring data, and use case collections.
- Model analysis: Preparation and execution of geomechanical model, reservoir model and wellbore model.
- Data and results visualization: Visualizing monitoring data and model results.
    - Model/data integration: Providing a platform to combining monitoring data with analytical models to perform analysis for safe reservoir operations, anomaly detection and locate, quantify, analyze issues; Providing use cases to demonstrate how to perform analysis using tools developed in IRMDSS for UGS risk management and decision support.

Figure 2-25: A Screenshot of SI Showing one set of InSAR observed range change

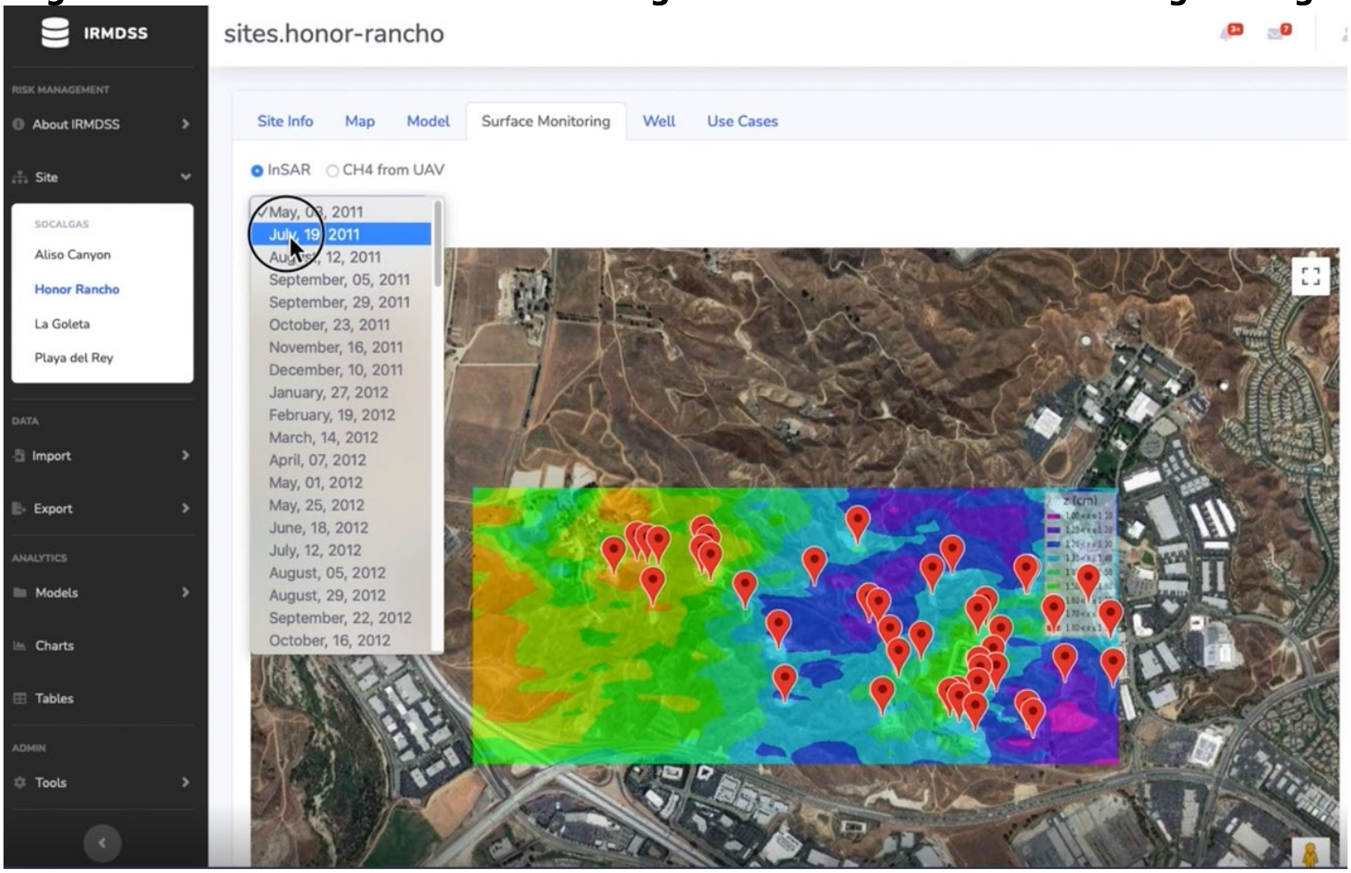


Figure 2-25 is an example showing a set of InSAR observed range change, taking from a screenshot of the SI.

Summary

Monitoring data and model capabilities are integrated in the IRMDSS framework through SI so that UGS operators can detect off-normal behaviors and simulate and evaluate "what if" scenarios for risk prevention (lowering the likelihood of incidents) and mitigation (lowering the consequences of incidents). Use cases are used to guide workflows within the IRMDSS. The SI provides a GUI to prepare input files for model analysis; a database for site characterization and advanced monitoring data, and a platform to integrate data and analysis for risk management support.

CHAPTER 3: Use Cases and Demonstration

IRMDSS Use Cases

In the IRMDSS framework, use cases–lists of actions that should be performed using IRMDSS components under specified conditionsare used to demonstrate the interactions among the system components, and later for field demonstration of the IRMDSS framework. Most of the IRMDSS use cases consist of the following general activities or steps:

1. Monitor (data collection).
2. Detect (is there an anomaly?).
3. Locate (where is it?).
4. Quantify (how bad is it?).
5. Analyze (what could be the cause, how is it evolving, how can it be fixed?).
6. Inform the decision (what are the indicated potential risk management actions?).

In this workflow, typical suggestion is that final decision should be made based on analysis results and utility emergency response procedure together.

Two use cases initially developed by the LBNL team and were presented and discussed at the first TAC meeting. Feedbacks on these two cases and potential new use cases were suggested by the TAC members who came from UGS facilities. Currently, eight use cases are included in the IRMDSS framework. These use cases, presented in Appendix A are based on most common scenarios. They are:

1. Safe reservoir management.
2. Subsurface well leak – tubing.
3. Ground deformation observed by InSAR.
4. Non-specific surface leakage.
5. Gas present on well pad.
6. Subsurface leak outside of but adjacent to the wellbore tubulars..
7. Compensating for P&A'ing a well.
8. Well blowout flow-rate management.

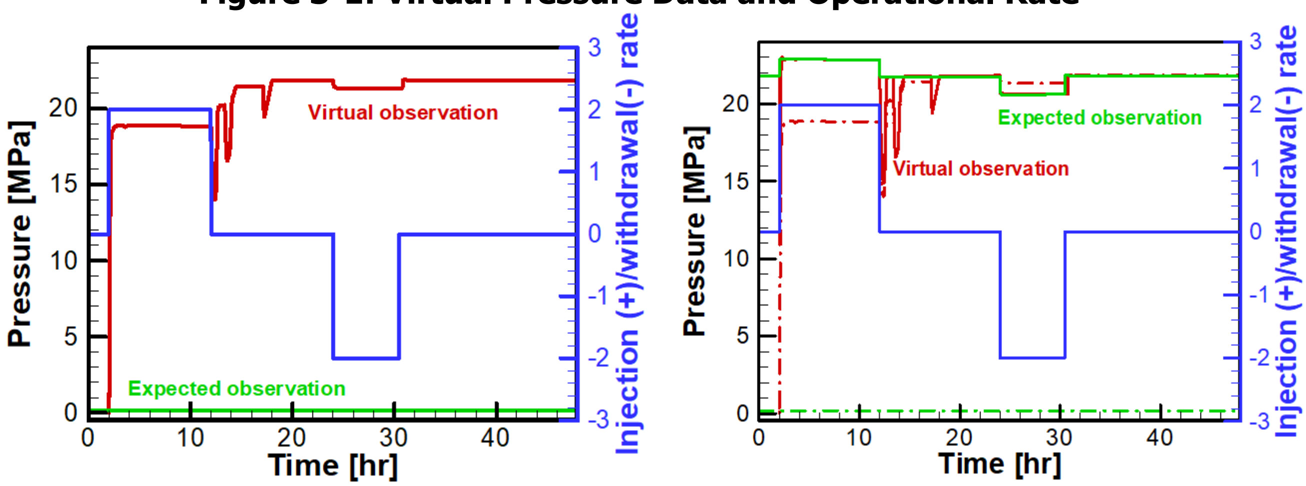
Two of them are discussed in detail here as part of the field demonstration.

Demonstration 1: Monitoring and Modeling of Well Flow

This first demonstration of the integration of data and mechanistic modeling in the IRMDSS arises from the UGS challenge of interpreting downhole temperature data in the context of a flowing well with possible LOC occurring (see Use Case 2 in Appendix A). The general workflow is shown in Table A-3 and follows the general steps 1-6 outlined above.

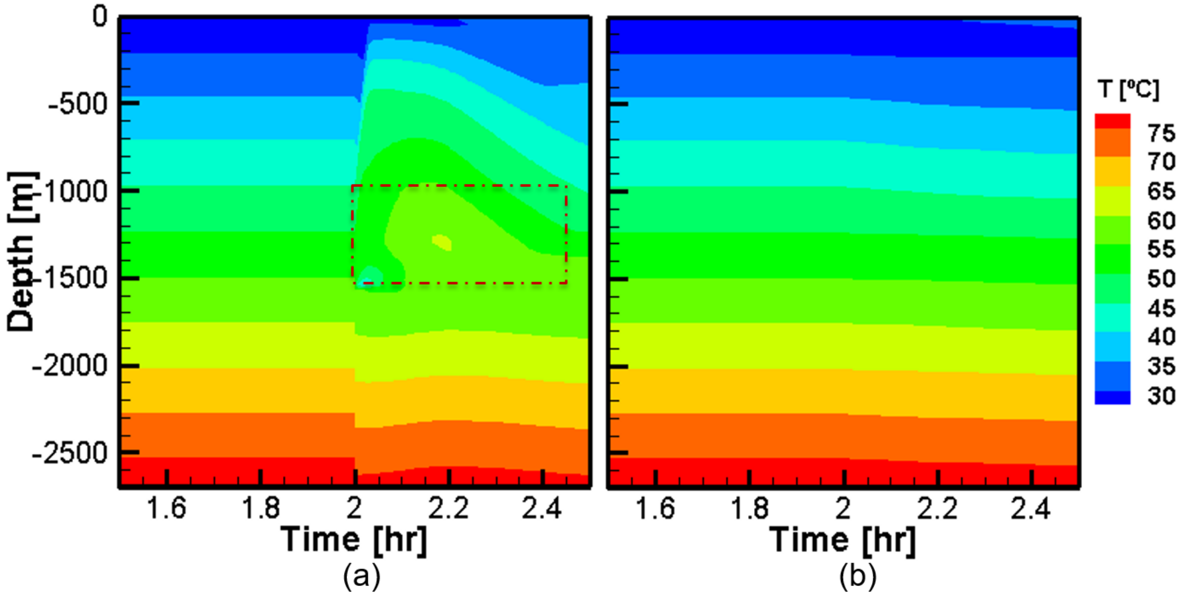
The scenario begins with use of the IRMDSS at a UGS site to plot monitoring data being collected including vertical DTS and DAS profiles over time along with pressures at the wellhead. The observations as shown in Figure 3-1 are that during a CH_4 injection event (2 kg/s or 104 cf/s) starting at time 2 hr (see Figure 3-1, second Y axis), wellhead pressure in the annulus (Figure 3-1a) was elevated indicating an off-normal tubing-annulus connection (something wrong in the well). Wellhead pressure in the tubing (Figure 3-1b) experienced a spike but typically the wellhead tubing pressure could be noisy when injection starts making the signal hard to interpret. In addition, real time DTS indicates a sudden heating and cooling at a depth of 3,700-5,000 ft (~1,100-1,500 m) as shown in Figure 3-2a, as compared to an expected smooth temperature transition at those depths without leakage (Figure 3-2b). The temperature anomaly indicates the potential leakage could be in that depth range. Wellhead and well bottom temperatures can be extracted as a time series to clearly demonstrate abnormal temperatures at the two locations, as shown in Figure 3-3. In summary, there are at least two independent measurements, annulus wellhead pressure and DTS temperature profiles over time, that can be used together to point to the existence of a tubing leak. This description so far comprises steps 1 and 2 (monitor and detect anomaly). Note that all of the data shown in Figures 3-1 to 3-3 are virtual data, i.e., these virtual data were generated using a UGS well model and the mechanistic simulator T2Well for demonstration purposes.

Figure 3-1: Virtual Pressure Data and Operational Rate



First Y-axis shows virtual pressure measurements and expected measurements under normal conditions (i.e., no leakage) in the annulus at wellhead (left), and in the tubing at wellhead (right). Second Y axis shows the injection (+) and withdrawal rates (-) in units of kg/s.

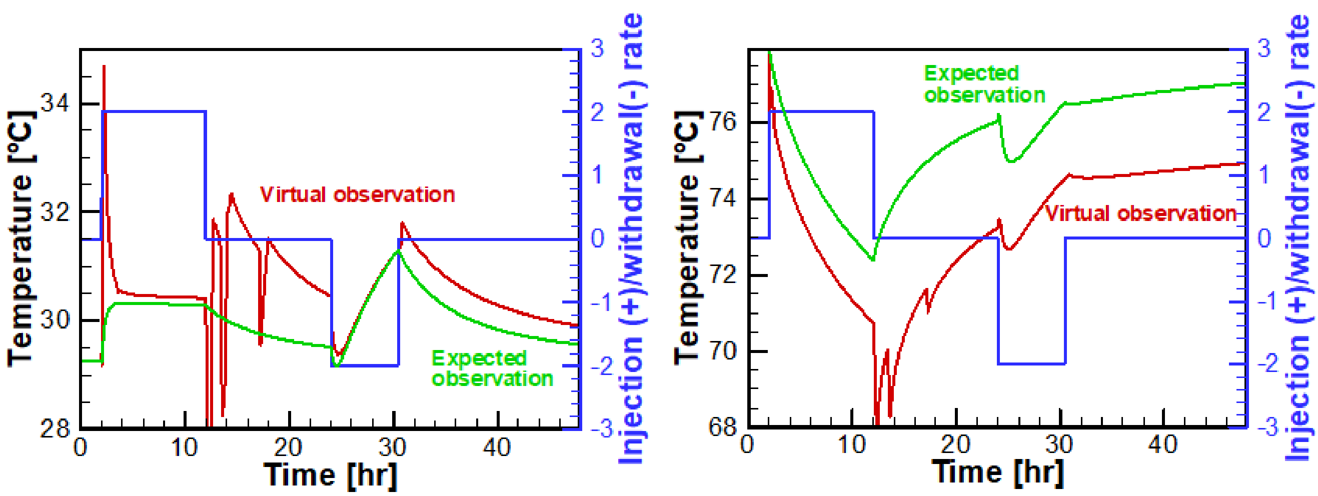
Figure 3-2: Virtual DTS Data and Expected Temperature Profile



Temperature profile (a) from a virtual DTS measurement; and (b) expected if there were no leakage. Assuming the injection and well leak start at time 2 hr.

Step 3 is to locate the leak. The local cooling shown by the virtual DTS data plotted in Figure 3-2 provides an approximate range of depth where the tubing hole is, but the duration of the cooling depends on the size of the crack; if it does not last long and the DTS sample is not frequent enough (every 10 minutes at the demonstration well), the exact location may be hard to pinpoint. However, the exact location can be inferred from careful investigations of DTS profiles when the injection/withdrawal starts as discussed in Chapter 2 (DTS Data Demonstration).

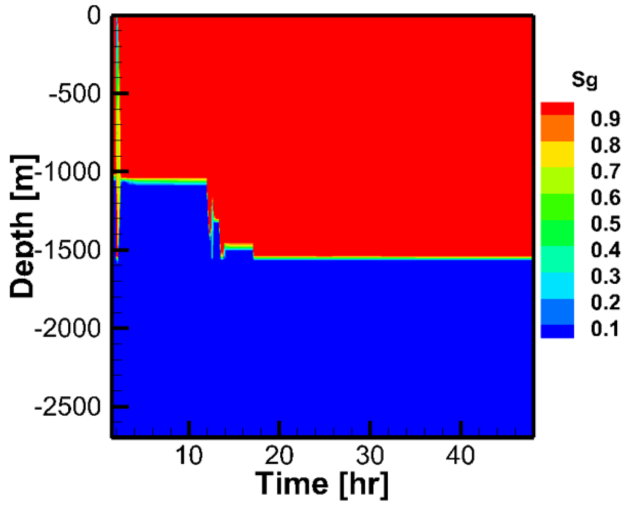
Figure 3-3: Well Head/Bottom Temperatures



Wellhead temperature (left) and well bottom temperature (right) over time.

Figure 3-4 shows virtual data on how the liquid-gas contact changes over time for the analyzed scenario. The liquid-gas contact was initially at 1,100 m, and then in the scenario the liquid in the annulus started to leak into the tubing until the liquid-gas contact eventually stabilized at around 1,500 m (which can be found based on DTS profiles). This indicates the hole in the tubing is at a depth of 1,500 m as shown in Figure 3-4.

Figure 3-4: Liquid-gas Interface Location Over Time for the Assumed Scenario

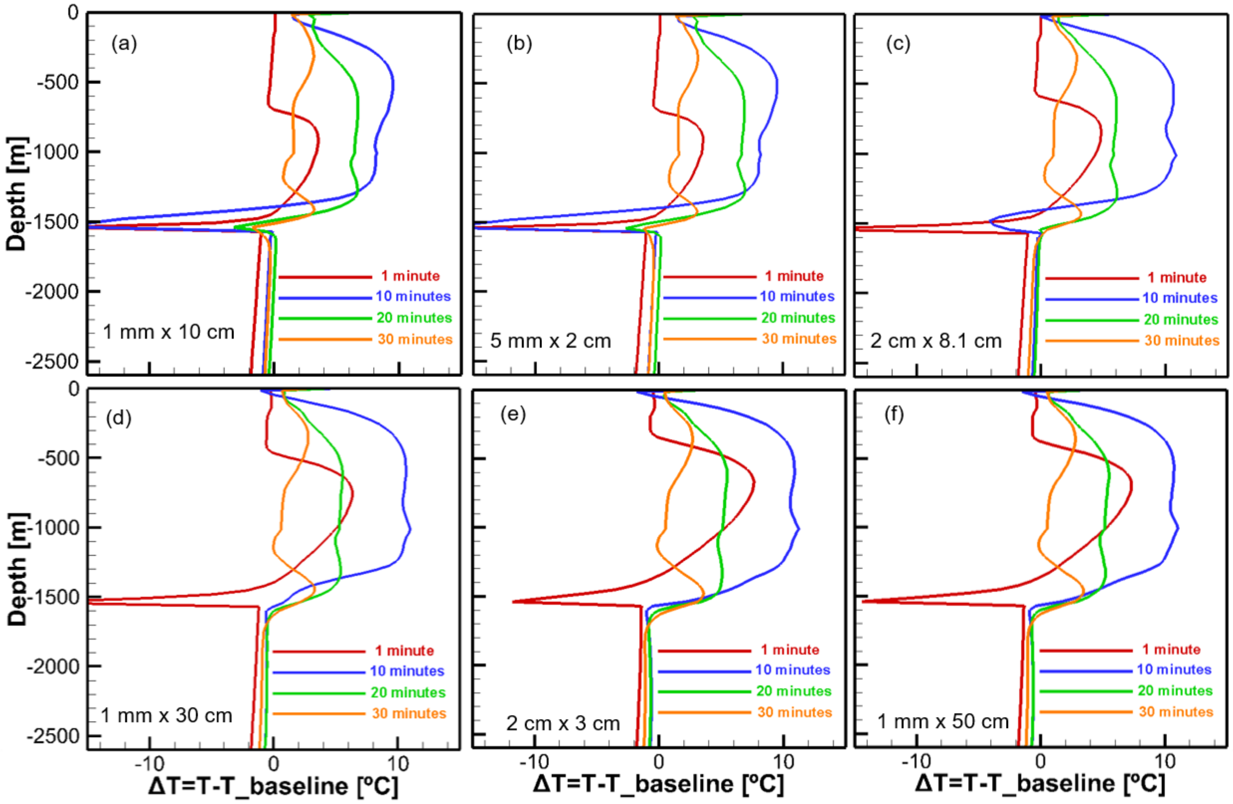


Step 4 is to quantify the size of a leakage orifice, or crack in tubing in this scenario. In the T2Well model, the size of the crack is quantified by the area and the perimeter of the opening. Quantification of crack size and shape can be determined by carrying out a number of simulations with a variety of crack sizes (Table 3-1) to compare to DTS measurements. Figure 3-5 shows the temperature deviation from the baseline (temperature if there were no leakage) for a few examples. Notice the crack in Figure 3-5(a) and 3-5(b) have the same area, but different perimeters; the hole in Figure 3-5(a) and 3-5(c) have the same perimeter, but different area. The general observation from these simulations is the temperature deviation due to leakage is mostly determined by the area of the crack rather than the shape, i.e., the smaller the area is, the stronger the local cooling is. The perimeter of the crack at constant area (an indicator of elongation of the crack) does not seem to have much impact on the local cooling. By comparing the simulated and the observed (virtual) temperature deviation, especially the cooling at 1,599 m depth, it can be determined the area of the crack is about 5.e-4 - 6.e-4 m^2 (for reference, if this hole were circular, the diameter would be ~1 inch).

Table 3-1: List of the Size of the Holes Used in the Simulations

Case	A	b	c	d	E	f
Area (m^2)	1.0e-4	1.0e-4	1.62e-4	3.0e-4	6.0e-4	5.0e-4
Perimeter (m)	0.202	0.05	0.202	0.602	0.100	1.002

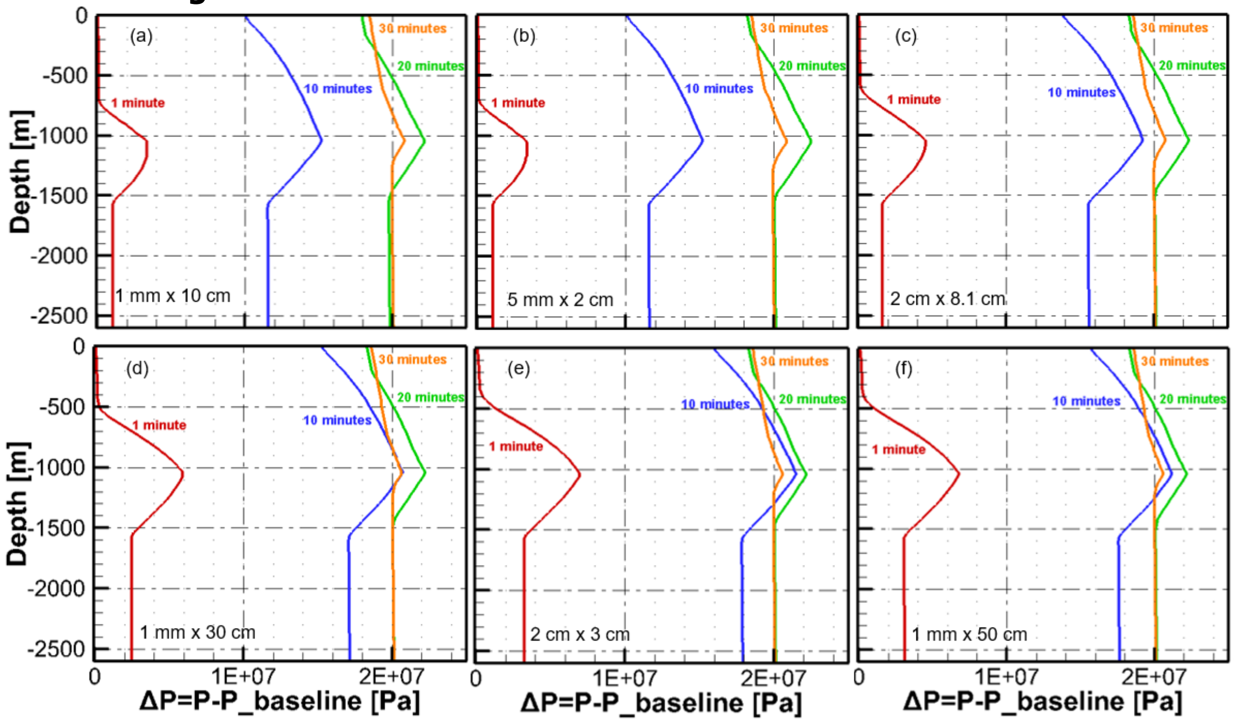
Figure 3-5: Temperature Deviation From the Baseline



Temperature deviation from the baseline for the size of the hole listed in Table 3-1.

In addition, pressure deviations in the annulus from the baseline values are calculated (Figure 3-6) and compared to the observed (virtual) pressure deviation (wellhead pressures can be measured in both annulus and tubing). The conclusions are similar to those for the temperature deviation. The area of the crack is an influential parameter affecting annulus pressure and temperature change due to leakage. The perimeter does not have much influence. This means the area of the crack can be estimated but the shape of the crack is uncertain.

Figure 3-6: Pressure Deviation in the Annulus From the Baseline



Pressure deviation in the annulus relative to the no-leak baseline for the sizes of hole listed in Table 3-1.

In addition to the size (area) of the crack, dynamic flow and temperature data over time along with well-flow modeling can be used to estimate the changes in the size of the tubing crack (or hole) over time. This information may be useful in evaluating possible causes of the hole, e.g., corrosion at a threaded junction, result of prior damage noted in well record, etc.. Moreover, if plugging the hole is determined to be a path forward, estimates of hole size can be used to design the plugging strategy, e.g., sizes of materials in a junk shot[6]. In summary, this Use Case 2 demonstrates how a tool in the IRMDSS can be applied to analyze a tubing leak and help support risk management decisions related to this leak.

Demonstration 2: Mitigating blowout flow rate

The goal of this demonstration is to show how to apply a site-specific reservoir model to mitigate an ongoing surface well blowout, i.e., to moderate and/or reduce the blowout flow rate through rapid withdrawal of gas from surrounding wells. Several mitigation strategies are listed and evaluated. Although some of the listed scenarios (e.g., no mitigations or withdrawing for 50 days for blowout release) may not be practical, the simulations and results do provide a solid understanding on what could happen in each scenario, and how effective each strategy is in case of a well blowout. The information can then be combined with practicality to support a final decision.

In this scenario referred to as Use Case 8 (see Appendix A), a leaky well (marked as the "project well" in Figure 3-7) is identified to be leaking to ground surface by operators by the

[6] Junk shot is a procedure used for stemming the flow of oil from a leaking well in which debris (such as shredded tyres, golf balls, etc) is pumped into the well at high pressure (from TheFreeDictionary.com, 2021).

smell of odorant, sound of escaping gas, and off-normal wellhead pressure. Before decisions are made about how to kill the well blowout, there are emergency actions that can be taken to mitigate the consequences/impacts of the incident. In order to select mitigation options, the operator needs information to answer several questions:

- How is the blowout flow rate (unmitigated) from a single well evolving with time?
- To what degree can withdrawing gas from surrounding wells decrease the blowout flow rate from the leaking well?
- What is the relative importance of withdrawal from nearby wells vs. wells that are farther away?
- How important is it for leakage rate reduction to maintain maximum withdrawal rate from surrounding wells over time?

The answers to these questions can help the operator decide if and how withdrawal wells should be used to reduce the blowout flow rate.

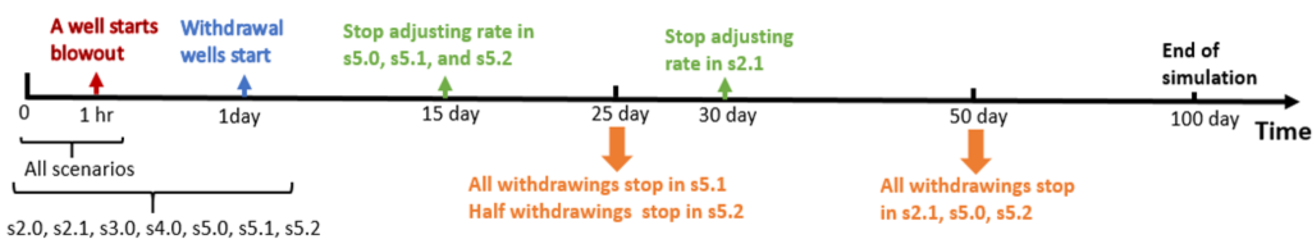
The model used for performing this analysis is the 3-D reservoir model for the Honor Rancho site described in Chapter 2. Recall the model contains a total of 36 active wells as shown in Figure 2-2. Twenty-eight of the active wells are located in the gas cap above the gas-oil contact, with similar pressure behavior (i.e., pressures going up and down together) during reservoir operation. The remaining eight wells (labeled by the last characters of their well names in red in Figure 2-2) are located in the water leg, a deeper part of the reservoir. Because the wells penetrate deeper than the water-gas contact, the pressure behaviors for these eight wells are different during gas injection and withdrawal relative to the other 28 wells.

The tested scenarios are listed in Table 3-2. These scenarios may not all be realistic within the actual operating ranges of the wells at Honor Rancho, but are designed to answer the questions listed above. Figure 3-7 (not scaled) shows all relevant time points for these scenarios. In Base Case s1, no withdrawal wells are used. This example of a variety of scenarios shows the range of "what if" questions an operator can ask and answer using the IRMDSS.

Table 3-2: Scenario Description for Use Case 8

Scenario abbreviation	Scenario description.
Scenario 1 (s1)	Well blowout (the project well on Figure 2-2) happens at t = 1 hr, assuming no mitigative measures are taken (base case).
Scenario 2.0 (s2.0)	12 adjacent wells (5, 7, C2D, 13, 15, 16A, C2A, C2E, 20, 16, C1 and 9) start withdrawal at t = 1 day, withdrawal pressure is adjusted for the first 30 days, and stays the same afterwards.
Scenario 2.1 (s2.1)	s2.0 setup, but all withdrawal wells stop withdrawing at 50 days.
Scenario 3.0 (s3.0)	12 far-away wells (22, 24, 24A, 24B, 24C, 25A, 25B, 25C, 17A, 18, 30 and 28) start withdrawal at 1 day, withdrawal pressure is adjusted for the first 30 days, and stays the same afterwards.
Scenario 4.0 (s4.0)	12 wells that are close to gas/liquid contact (C1, 9, 30, 28, 25, 23, C2, C3, 17,C5A, 22 and 20) start withdrawal at 1 day, withdrawal pressure is adjusted for the first 30 days, and stays the same afterwards.
Scenario 5.0 (s5.0)	All wells from s2.0 and s3.0 start withdrawal at 1 day, withdrawal pressure adjusted for the first 15 days, withdrawal stops at 50 day.
Scenario 5.1 (s5.1)	Almost the same as s5.0, except all wells stop withdrawing at day 25.
Scenario 5.2 (s5.2)	Almost the same as s5.0, except half of the wells stop withdrawing at day 25.

Figure 3-7: Operational Timeline



Timeline of the scenarios listed in Table 3-2 (not scaled).

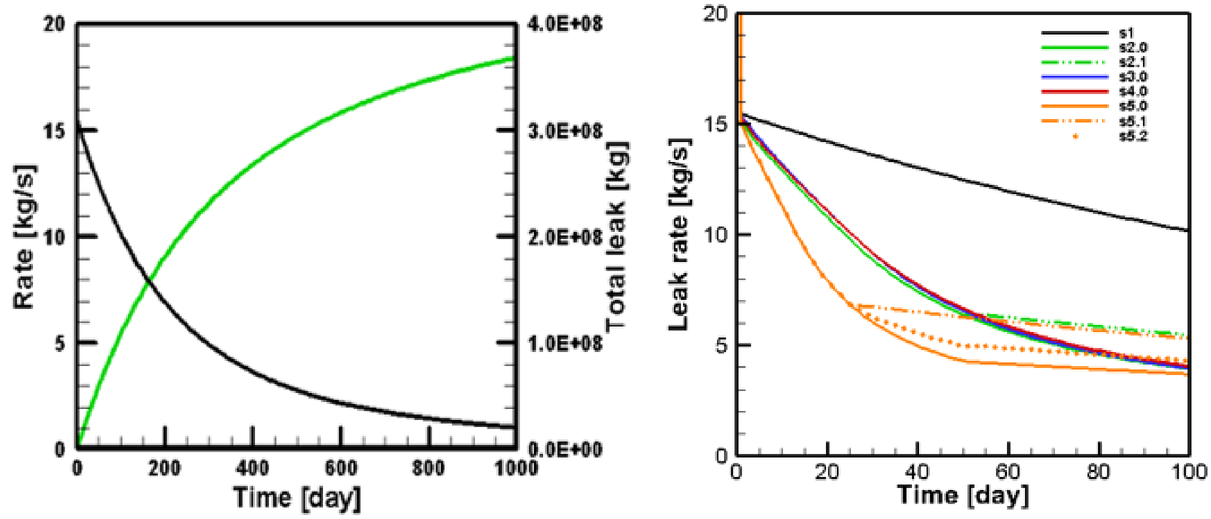
How the blowout rate and the total amount of leaked gas evolve over time for s1 is shown in Figure 3-8(a). The simulation results show clearly that the blowout flow rate declines quickly for the first 400 days, but slows down at later time. In reality, a blowout will probably not last this long because mitigative actions (well kill, relief well, etc.) will be successfully implemented. Figure 3-8(b) shows the leak rates for all scenarios compared to s1 for the first 100 days of simulation. From the figure we can observe the following:

- The withdrawal wells help to reduce the leak rate of the blowout well, the more the better, as each well is constrained by how much gas it can withdraw. The total emission reduction for the simulated period ranges from 30 percent - 52 percent, with s5.0 having the highest reduction. The reason the blowout flow rate declines is that reservoir pressure declines as gas is withdrawn by surrounding wells.

- The difference in s2.0, s3.0, and s4.0 is in the location of the withdrawal wells. The blowout flow rate curves for these scenarios are more or less on top of each other. This suggests that the reservoir is well connected (not compartmentalized) and the withdrawal locations used for reducing the blowout rate are not very significant. Note that because this reservoir is not highly compartmentalized, it is possible to use the overall UGS reservoir practice of injecting into one sector of the reservoir and withdrawing from another. However, this feature could also potentially cause whole-reservoir depressurization due to a single well failure. The Aliso Canyon reservoir has similar characteristics, which can be seen by the blowout rate from the Sesnon Standard-25 well (SS-25; API 03700776) failure (Figure 14, Conley et al., 2016).
- The difference between s2.0 and s2.1 is that in s2.1 the wells stop withdrawing at day 50, whereas in s2.0 those wells continue withdrawing to the end of the simulation (100 days). The figure shows that at later time additional withdrawal still helps reduce blowout rate, but less effectively (i.e., the total emission reduction is 40 percent for s2.0 vs. 36 percebt for s2.1, with only 4 percent of emission reduction increase by withdrawing for another 50 days).
- In simulation s5.0, the withdrawal wells are the combinations of all wells in s2.0 and s3.0, i.e., twice as many wells as in s2.0. But all wells stop withdrawing at day 50 compared to wells continue withdrawing to day 100. The blowout rate is reduced much faster at the beginning when twice as many wells are used, but the final rates are close because the wells stop withdrawing half of the end time. The total emission reduction is 52 percent for s5.0. Similarly, twice as many wells are used in s5.1 (as in s2.1) but wells stop withdrawing at day 25, compared to day 50 in s2.1. Again, even though the final rates are about the same at day 100, the blowout rate is reduced much more when twice of the wells are used at the beginning but withdrawing only half of the time (emission reduction is 43 percent for s5.1, with 9 percent difference compared to s5.0). This shows withdrawing at early time is more effective than withdrawing at later time.
- The difference between s5.0 and s5.2 is that in s5.1 all wells stop withdrawing at day 50 whereas in s5.2, half stop withdrawing at day 25 and the other half stop withdrawing at day 50. The emission reduction is 49 percent for s5.2 (compared to 52 percent for s5.0). The difference between the blowout rates in the two cases is not significant, indicating that even though a higher withdrawal rate at the beginning of the blowout helps reduce blowout rate, maintaining that high withdrawal rate may not be necessary.
- The leak rates in s2.1, s5.1, s5.2 where some withdrawal wells are used and stopped later look similar to the leak rate of the SS-25 at Aliso Canyon, as shown in Figure 3-9. During the 2015-2016 incident at Aliso Canyon, the facility withdrew gas daily through other non-leaking wells to deliver to their customers to reduce reservoir pressure and leak rate. The withdrawal was later stopped because the facility is mandated by the California Public Utilities Commission to maintain a working volume of 15 billion cubic feet (Bcf)of gas in the underground storage reservoir.

Based on observations of the simulation results, the IRMDSS user can conclude that maximizing daily withdrawal from the storage facility is important to reduce pressure and thereby reduce the blowout flow rate. However, at some point in time, maintaining such a high withdrawal rate may lead to the depletion of the reservoir in violation of contractual agreements. The location of the emergency withdrawal wells (far vs. close to the blowout well) is not important for reservoirs that are well connected (not compartmentalized). Although some of these conclusions may seem to be obvious, this example demonstrates how the reservoir model developed in the IRMDSS can be used. It can be further used to find a withdrawal rate to balance between emission and gas pressure in the reservoir.

Figure 3-8: Leak Rate for Simulated Scenarios



(a) Leak rate and total mass of leak amount for scenario s1; and (b) comparison of leak rates for all scenarios.

Figure 3-9: CH_4 Leak Rate of the 2015 Aliso Canyon incident

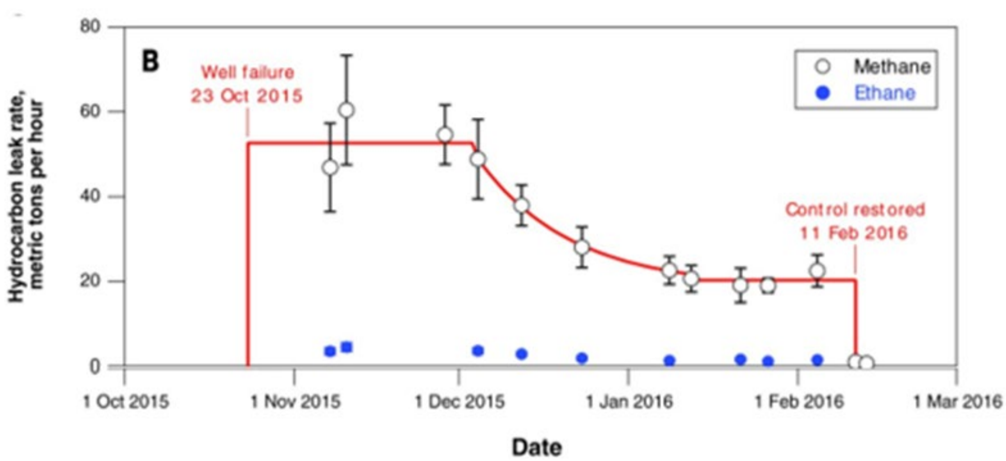


Figure showing CH_4 (open circle) and C_2H_6 (closed circles) leak rates from airborne measurements of the 2015 Aliso Canyon incident, with a red line as a fitting curve assuming an average leak rate from day 0 to 43, an exponentially decreased rate between day 43 to 80 and a constant rate thereafter to day 112 (From Conley et al., 2016).

Summary

The two demonstration examples show that advances in modeling and monitoring can be used to improve UGS safety and manage risk. The examples show that:

- Unexpected changes in the location of the gas-liquid interface in the annulus are an indication of a potential well integrity issue. Current practice is to identify the interface based on the use of a sonic water-level monitoring system. The sonic measurements are highly inaccurate, and could result in a level determination accurate to only ±20 m. In comparison, the DTS measurement that is part of the IRMDSS provides for continuous monitoring of the annulus fluid level and with an accuracy of ±50 cm.
- Determining the size of a casing or tubing hole could be important for understanding what type of leak and/or where the leak is, and the evolution of the leakage rate. The wellbore model combined with downhole monitoring data as integrated in the IRMDSS provide a way to estimate hole size.
- In the unexpected situation of a well blowout not killable by direct fluid injection, gas withdrawal from surrounding wells can be used to decrease blowout flow rate while waiting for the relief well to kill the blowout. Often this has to be done on an ad hoc basis, and because blowouts are rare and each one is different, it is not possible to know how effective the approach is. The reservoir model in the IRMDSS can provide a quick evaluation of effectiveness and allow the operator to experiments with different designs (i.e., what wells should be used for withdrawal and what rate should be used) to carry out the mitigation as effectively as possible.

CHAPTER 4: Knowledge Transfer Activities

The IRMDSS framework can be adopted by each gas company for their storage facility. However, the setup of the mechanistic models is site-specific (i.e., each model is built based on each site's geological conditions), therefore, new models with site specific input need to be constructed for each new site. The use cases provide a general workflow for various scenarios.

To communicate the methods, technologies, and learnings developed in this project, a number of knowledge transfer activities were planned and carried out, as described below.

Written Documents

Written documents include technical reports and published papers. So far, the project has generated a number of reports (Zhang et al., 2019, Zhang et al., 2020) for general audience, and Users/Technical Guide (Zhang and Kowalsky, 2021; Kowalsky and Tadic, 2021) for potential users, but also produced peer-reviewed journal articles to communicate the results with the scientific community. These articles are:

- Jeanne P., Y. Zhang, J. Rutqvist, 2020. Influence of hysteretic stress path behavior on seal integrity during gas storage operation in a depleted reservoir Journal of Rock Mechanics and Geotechnical Engineering. https://doi.org/10.1016/j.jrmge.2020.06.002
- Zhang, Y., C. M. Oldenburg, Q. Zhou, L. Pan, B. M. Freifeld, P. Jeanne, V. Rodríguez Tribaldos, and D. W. Vasco, Advanced Monitoring and Simulation for Underground Gas Storage Risk Management. Submitted to Journal of Petroleum Science and Engineering.
- Vasco, D. W. , S. V. Samsonov, K. Wang, R. Burgmann, P. Jeanne, W. Foxall, and Y. Zhang, Monitoring natural gas storage using Synthetic Aperture Radar: Are the residuals informative? Submitted to Geophysical Journal International.

Website

A website containing key information was created for the project: https://irmdss.lbl.gov. The main targeted audience are UGS facilities, and stakeholders (e.g., CalGEM) and public agencies (e.g., DOE).

Video Material

A few videos were made for a quick IRMDSS tour and some detailed components. They provide straightforward information on the contents and usage of the IRMDSS tool. The video material can be found on the project website.

Demonstrations and Talks

Discussions and meetings have been carried out with the project partner SoCalGas on a regular basis. A number of demonstrations and discussions were carried out with natural gas utilities and stakeholders, as summarized below.

Table 4-1: Summary of Meetings for Knowledge Transfer

Date	Topic	Audience
10/31/2019	Current practice of UGS risk management and needs	PG&E
11/14/2019	Current practice of UGS risk management and needs	SoCalGas
05/21/2020	DTS/DAS monitoring data demo	SoCalGas
8/31/2020	DTS/DAS monitoring data demo	Paulsson Inc; PG&E, C-FER, Schlumberger, LBNL; UC Berkeley; and CEC
01/29/2021	IRMDSS demo	CEC staff
3/5/2021	IRMDSS demo	SoCalGas; CEC
6/3/2021	IRMDSS demo	Paulsson Inc; C-FER; Schlumberger; LBNL; UC Berkeley; and CEC

These meetings have served an effective way to understand the need to communicate the IRMDSS with the natural gas industry.

Conferences

The findings from the wellbore simulations and the DTS monitoring was communicated in a presentation with the title, "Mechanistic Simulations of Well Flow for Well Integrity Risk Management," to a broader audience (~200) at the NETL Wellbore Integrity Workshop (Videoconference) in June 2021.

CHAPTER 5: Conclusions and Recommendations

UGS has played and will continue to play a critical role in the near future to meet energy demand during the peak winter heating period in California. Because many UGS facilities utilize wells that were installed decades ago and then were re-purposed for UGS, it is essential to have rigorous monitoring programs and up-to-date risk management approaches to address the safety concerns related to containment of high-pressure flammable natural gas at these facilities.

Conclusions

The IRMDSS risk management framework developed in this project for UGS facilities integrates three main components: (1) mechanistic models and analyses, (2) advanced monitoring technologies, and () supervisory interface built around pre-defined use cases that cover common risk management needs at California UGS sites. The main conclusions are:

- The reservoir model in the IRMDSS framework can be used to predict reservoir pressure for supporting decisions to ensure safe operations. The model is built based on the site-specific geological conditions (natural containment features), engineered components (man-made features, i.e., wells), and hydrogeologic properties of the storage reservoir. The reservoir model can be used in the IRMDSS to simulate normal gas storage operations and to simulate off-normal behaviors, the simulated reservoir responses to which (e.g., variations in bottomhole pressure over space and time) can be compared to monitoring data to support early detection of off-normal behaviors in the actual reservoir. In addition, the reservoir model can be used to answer "what if" questions to help make operational decisions.
- In the unexpected situation of a well blowout not killable by direct fluid injection, gas withdrawal from surrounding wells can be used to decrease blowout flow rate while waiting for the drilling of the relief well to kill the blowout. Often such emergency withdrawal operations have to be done on an ad hoc basis, and because blowouts are rare and each one is different, it is not possible to know a priori how effective the approach will be. The reservoir model in the IRMDSS can provide a quick evaluation of effectiveness and allow the operator to experiment with different designs (i.e., what wells should be used for withdrawal and what rate should be used) to carry out the mitigation (reservoir pressure and blowout flow rate reduction) as effectively as possible.
- The geomechanical model in the IRMDSS can be used to simulate stress changes and deformation in the reservoir and overburden due to gas injection in the storage reservoir or other fluid injection/withdrawal activities above the storage reservoir. The stress changes and deformation have an impact on the maximum working pressure above which the seal integrity may be compromised. It is essential to have such a model to understand the geomechanical state of UGS site and help avoid the creation of a hydrofracture or the reactivation of faults or fractures during long-term UGS operations. Application of the geomechanical model can help ensure that the UGS

facility is being safely operated within a margin below the pressure limit that could compromise reservoir integrity.

- The well model in the IRMDSS is used to simulate withdrawal, injection, and leakage (blowout) processes UGS wells. It can be used to predict pressure and temperature response patterns under normal and/or abnormal (leaking) conditions within a wellbore. The simulation results can be compared to the actual pressure and temperature measurements conducted in a well to identify discrepancies that might indicate well integrity problems. The model can also be used to estimate the size of a tubing crack/hole and rate of a leak. The analysis and estimates can then be used as the basis for making risk management decisions. In addition, a well model can be used to simulate various well-killing strategies and identify the most effective strategy in a catastrophic situation.
- Geohazard analysis is performed to provide probabilistic seismic, fault displacement, and earthquake-induced landslide hazard analysis to complement the mechanistic models in the IRMDSS. The main purpose of the geohazard analysis in the IRMDSS framework is to help diagnose if an anomaly (e.g., unexpected LOC with resulting natural gas plume at the surface) could be caused by a geohazard (e.g., fault displacement, or landslide).
- DTS for well monitoring provides a well temperature profile along the entire well in real-time. Unexpected local cooling or heating could indicate an anomaly (e.g., gas leakage) that needs further investigation. In addition, unexpected changes in the location of the gas-liquid interface in the annulus indicated by the DTS measurements are an indication of a potential well integrity issue. The DTS measurement provides continuous monitoring of the annulus fluid level with an accuracy of ±3 ft, much more accurate than that of the current practice, which uses a sonic water-level monitoring system and typically has an accuracy of ±30 ft.
- Determining the size of a hole/crack in casing or tubing could be important for understanding what type of leak and/or where the leak is, and the evolution of the leakage rate. The wellbore model combined with downhole monitoring data as integrated in the IRMDSS provide a way to estimate hole size.
- DAS provides a continuous acoustic measurement of noise along the entire length of the well at spatial resolution of a few meters. The observations from DAS monitoring indicate that the analysis of acoustic noise recorded by DAS can provide critical information about changes occurring in the borehole at different stages of system operation. Data attributes derived from the continuous raw data can be used to provide insights into spatial and temporal changes in the amplitude and spectral content characteristics of the acoustic noise passively being generated in the well before, during, and after injection/withdrawal. These changes and the deviation of these values from background conditions can be used as a diagnostic feature in the IRMDSS framework.
- A common challenge when working with monitoring data from fiber optics is data management. Because of the high spatial density of the measurements (< 1 m), large length of the cables (several km) and high temporal sampling (ten minutes for DTS, 1,000 samples/s for DAS), data volumes can amount to ~100 MB/day for DTS and over

1 TB/day for DAS. Thus, effective “big data” management and processing approaches are necessary for these monitoring data to be fully integrated into the IRMDSS. Our preliminary data evaluation indicates that acquisition parameters can be optimized to reduce the size of the raw datasets without significantly impacting the results. Moreover, data produced by post-processing consistently with data attributes or use of extracted signals provide ways to further reduce the volume of data that needs to be kept and integrated into the IRMDSS framework. Edge-based processing and machine learning capabilities could further alleviate the data management issue.

- In terms of the downhole monitoring technologies demonstrated, the fiber-optic monitoring technologies provide continuous, high-resolution measurements of the temperature and acoustic fields within the borehole, which enable an in-situ and accurate assessment of the wellbore conditions at a level not possible with any other monitoring technologies. With the cost of fiber optic sensing instruments rapidly decreasing,they promise to become cost-efficient tools for long-term monitoring in UGS. In addition, recent advances in array processing techniques and machine learning approaches promise to alleviate big-data challenges and will ease the extraction of meaningful information from these datasets.
- InSAR observations provide a non-intrusive, cost-effective method for monitoring the ground deformation around an operating UGS facility. While the surface deformation due to activities within the reservoir is small and can be accounted for through inversions for reservoir volume changes, events above the reservoir such as slip on shallow faults, leaks from wells above the reservoir, and landslides lead to larger signals that can be identified through their large residuals in a given observation interval. Synthetic testing indicates that well leaks of sufficient size can be identified due to anomalous residuals. Similarly, two events in the actual InSAR data from Honor Rancho indicated unusual surface deformation that warrants further investigation. Known activities, such as shallow water injection, need to be accounted for in order to improve the monitoring reliability and to reduce the possible misinterpretation of increased InSAR residuals. Anomalous events only signify a time interval when the residuals should be examined and interpreted. They do not necessarily signify an event within the UGS facility or within the reservoir.
- UAV surveys are a straightforward method for gas leak detection. Such surveys are non-intrusive and can be done as frequently as needed. Compared to vehicle-based and handheld CH_4 leak detection systems, the UAV-based gas leak detection system has the advantage of covering areas that may be inaccessible to conventional vehicles. Furthermore, the leak flow rate can be estimated accurately by established methods following the survey. When the UAV is combined with a handheld device, the leak source can be pinpointed quickly. The algorithm/analysis methods demonstrated for the IRMDSS can be done easily with minimum training.

Recommendations

The feedback received after the IRMDSS presentations to the UGS operators showed great interest in the fiber optic monitoring from the UGS facility managers. The facility representatives report say the non-intrusive (once installed) aspect and ability to provide continuous data in time are the main advantages of fiber optic monitoring. The fiber optic cables need to be installed in each well that is being monitored, with the possibility of sharing some of the data acquisition units at the surface. For potential applications of the technologies, the following investigations are recommended:

- Evaluate the long-term cost and benefit of fiber optic monitoring technologies against the annual logging which is required in current regulations.
- Build infrastructure for fiber optic sensing data storage and processing.
- Regulatory agencies are recommended to investigate the roles of the current requirement of tubing removal for metal loss inspection vs. fiber optic monitoring, because the tubing removal frequency of every 24 months, which is currently required, would make fiber optic monitoring cost-prohibitive because of the cost of replacing fiber every 24 months.

The value of the IRMDSS resides in the integration of models and monitoring data. Comparing model prediction to monitoring data can improve our understanding of the underground part of the UGS facility; Using models to answer "what if " questions can help evaluate scenarios and provide the basis for making decisions. One way to encourage UGS facilities to use advanced mechanistic models is to make simpler user interfaces and provide training for using them.

Future work on automatic data processing and transfer could make it easier to apply the IRMDSS framework. Once more fiber optic monitoring data (under both normal and abnormal conditions) are collected, machine learning algorithms can be used to make the anomaly detection automatic.

Lessons Learned

A few non-technical challenges were encountered in this project and lessons were learned, as described below.

- *Drone survey*

The drone survey demonstrated in the project was initially planned to be performed by an LBNL scientist with an LBNL drone. Right before the survey, the drone failed the safety test, with no repair dates provided. The project team had to look for a subcontractor with a matching technology and expertise within California (due to constrains in out-of-state funds available), and within the project duration for the task. Eventually, a suitable company, namely, ABB agreed to work on this task. However, due to Covid-related restrictions, the previously planned UAV drone survey at the Honor Rancho site could not be performed. Instead, demonstrations of UAV and other CH_4-monitoring techniques were done at an analogue site in Solano County, California in the vicinity of an artesian well that was known to emit bubbles of CH_4.

Eventually, the task was finished successfully. Lessons learned here are:

1. Plan and test as early as possible. The drone safety test could have been done earlier even though the survey was scheduled at a much later time. In that way, the failure of the drone could have been discovered earlier, which would have allowed a backup plan to be made earlier, leaving more time for handling unexpected events such as the Covid pandemic in the later stage of the project;

2. The challenge of finding a qualified subcontractor within California has shown that if additional out-of-state funds were made available during project planning period, it would have helped to obtain expertise in the area when needed.

- *Subcontractor in database and SI GUI development*

This task was initially planned for a student. A student with needed expertise was found but he requested his tuition to be paid. The approval process took a long time and eventually the request was denied. Although the student still agreed to work on the task, he eventually had to give it up because the approval process took too long. This caused a delay in this task. Again, the lessons learned here were:

1. A good understanding of what can be paid and what cannot be paid before a formal approval process is initiated would have been helpful. This could save time and help avoid losing the person with the right expertise due to the expert's own time constraints.
2. Again, additional out-of-state funds could have eased the challenge in finding the right expertise.

CHAPTER 6: Benefits to Ratepayers

The IRMDSS framework merges advanced mechanistic models with continuous reevaluation and assessment to provide leading indicators of potential threats. The IRMDSS is specifically designed for (1) real-time detection of imminent risks, (2) long-term risk assessment, and (3) early leakage/damage detection. The IRMDSS allows the user to build models based on existing site characteristics and data to predict potential risks. In the meantime, the IRMDSS provides a framework to perform risk assessment based on real-time data collected in the field. The tools developed in the IRMDSS can be subsequently used in evaluating and monitoring mitigation strategies. Through its ability to improve LOC risk management, the IRMDSS is expected to provide greater reliability, lower costs, and increased safety for the gas supply system.

It is generally difficult to quantify performance of the IRMDSS for long-term risk assessment because failure incidents are inherently rare (unlikely), and beyond that the likelihood is uncertain, so we cannot say for sure even if and when the IRMDSS were to be applied for a period of time that failures have been avoided.

In terms of providing alarms of imminent risks, and/or early leakage/damage detection, this function is made possible by the DTS monitoring system and UAV-based (combined with handheld device) gas leak detection system, which are integral parts of the IRMDSS. Specifically, DTS replaces and vastly improves upon periodic temperature logging which is the standard approach for detecting leaks in wells involving escape of high-pressure gas and associated expansion cooling. The DTS system costs $30-60K per well and provides high-frequency temporal and spatial profiles of temperature throughout the depth of the well. This cost can be roughly compared to the traditional temperature logging activity carried out, typically, annually. However, the performance, in terms of frequency and high-resolution of the DTS data, is far superior to the traditional approach. UAV-based gas leak detection system has the advantage of covering areas that may be inaccessible to conventional vehicles. This was demonstrated by the unplanned detection of the unknown leakage. The quick pinpoint to the source of the leak can help to decide what the next step could be.

Table 6-1 is a list of technical benefit of IRMDSS.

Table 6-1: Performance Metrics of the Technologies in the IRMDSS Compared to Some Traditional Methods

	Feature	Current methods	IRMDSS
Real-time risk assessment and early leakage detection	Frequency of temperature monitoring	Logging annually	DTS every 10 minutes[1]
	Accuracy of locating annulus gas/liquid interface[2]	~ 30 ft	~ 3 ft
	Surface leak detection	Daily inspection of individual wells by staff	UAV/Drone survey could provide site-wide leak detection; when it's combined with handheld device, leak location can be identified accurately and quickly. In addition, it provides a leak rate as an initial estimate for further investigation.
	Normal reservoir operations	Wellhead pressure monitoring, bottomhole pressure is estimated at well locations	Bottomhole pressures are monitored (planned in the project). Pressure at other reservoir locations are calculated using TOUGH model of the gas storage reservoir.
	Interpretation of well temperature data	Specialized effort (e.g., using Prosper)	Built-in well model T2Well
	Capable of detecting leakage in real time during storage operations	None (logging involves shutting in the well)	Yes (can detect thermal anomalies during injection/withdrawal or shut in periods).
	Capable of locating leak	Difficult	Easier compared to the current methods.
	Risk due to monitoring/inspection	Potential to cause unexpected problems due to workover	InSAR and UAV/drone survey are non-intrusive; DTS is non-intrusive once installed.

[1]This is an example, can be set differently.[2]Change of annulus gas/liquid interface could be indicative of leaks, providing useful information on leak locations.

Broadly speaking, the IRMDSS is expected to provide increased safety, lower costs, and greater reliability for the gas supply system, as detailed below:

Increased safety

Real-time monitoring and risk assessment, as well as early leakage detection allow implementation of preventive and corrective measures that can be done before leaks happen, and inform decisions on mitigation measures before large leaks occur. Non-intrusive monitoring technologies also reduce risk associated with traditional well inspections. These will increase the safety of the gas supply.

Lower costs

The quantitative predictive methodology developed by the project will enable short/long-term safety evaluation and potential change of operations (for example, schedules, capacity) if needed, or early preventative engineering measures to avoid failures or damage from happening, thus, lowering mitigation costs through condition-based maintenance.

Greater reliability

Improving gas storage integrity which implies avoiding down-time for repairs and leakage mitigation will provide greater reliability for the gas supply from UGS. For example, the unavailability of the Aliso Canyon gas storage facility due to the well blowout in 2015 has caused insufficient delivery of gas to power plants. Applying IRMDSS tools for risk monitoring, safety evaluation and corrective measure evaluation can lead to increased safety, and less down-time.

As a result, increased safety, lower costs, and greater reliability will allow continued inclusion of gas storage as one of the energy supplies available to meet the demand in California for heating during winter, and provide fuel for smooth operations of electric generation during periods of high demand (e.g., hot summer day air-conditioning demand), therefore, contributing to energy security.

GLOSSARY OR LIST OF ACRONYMS

Term	Definition
ABB	ASEA Brown Boveri
AGL	Above Ground Level
CCST	California Council on Science and Technology
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
DOE	Department of Energy
FPGV	Free-Phase Gas Volume
GMPE	Ground Motion Prediction Equation
InSAR	Interferometric Synthetic Aperture Radar
IRMDSS	Integrated Risk Management and Decision-Support System
LBNL	Lawrence Berkeley National Laboratory
LCI	Lettis Consultants International, Inc.
LOC	Loss of Containment
NETL	National Energy Technology Laboratory
P&A	Plug and Abandon (a well)
PEER	Pacific Earthquake Engineering Research
PFDHA	Probabilistic Fault Displacement Hazard Analysis
PSHA	Probabilistic Seismic Hazard Analysis
SI	Supervisory Interface
SoCalGas	Southern California Gas Company
TAC	Technical Advisory Committee
UAS	Unmanned Aerial System
UAV	Unmanned Aerial Vehicle
UGS	Underground natural Gas Storage

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APPENDIX A:
User Cases

A use case is a written description of the use of a computational tool or system, specifically here a workflow (list of actions or steps) that should be followed to achieve a defined goal with the IRMDSS. Most of the IRMDSS use cases consist of the following activities/goals:

- Monitor (data collection).
- Detect (is there an anomaly?).
- Locate (where is it?).
- Quantify (how bad is it?).
- Analyze (what could be the cause, how is it evolving, how can it be fixed?).
- Inform the decision (what are the potential actions and what are the potential results after the actions are taken?).

The eight use cases developed in this project are detailed in the Appendix A Tables:

1. Safe reservoir management.
2. Subsurface well leak–tubing.
3. Ground deformation observed by InSAR.
4. Non-specific surface leakage.
5. Gas present on well pad.
6. Subsurface leak outside of but adjacent to the wellbore tubulars.
7. Compensating for P&A'ing a well.
8. Well blowout flow-rate management.

Table A-1: Use Case 1

Title	Use Case 1	Safe reservoir management
Goal		Demonstrate how to use the IRMDSS to co-optimize reservoir storage management and integrity.
Scenario		Several wells are slated for workovers (and, therefore, will be unavailable for gas injection/withdrawal (I/W)) during a time with demand when reservoir-wide gas I/W is needed. Use the IRMDSS to explore various operational scenarios to accommodate I/W with fewer available wells.
Questions / Decisions		How to assign optimal I/W rates among wells while minimizing loss-of-containment (LOC) risk and other environmental hazards (e.g., induced seismicity). What is the uncertainty in the results of a simulation-based analysis using the reservoir model?
Analysis		
UC 1.1. Perform analysis	Workflow	Reservoir property and well data are used to create/edit an input file for the reservoir model. Run reservoir model to simulate reservoir pressure (and bottom hole pressure in wells) for various I/W scenarios.
	Dataflow	Model outputs are transferred to IRMDSS database (IRMDSSdb) for plotting/visualization.
UC 1.2. Correlate with well pressure operational limits	Workflow	Cross-check reservoir modeling results with maximum allowable reservoir and well pressures to ensure maximums are not exceeded. Cross-check reservoir modeling results with geomechanical analysis to ensure that fracturing pressure is not reached.
	Dataflow	Information on maximum pressures stored in the IRMDSSdb need to be queried along with modeling results for user to compare and flag exceedance of maximums. Geomechanical analysis results stored in the IRMDSSdb need to be queried along with modeling results for user to compare and flag overlaps between high pressure and low fracturing pressure.
UC 1.3. Perform uncertainty quantification on BHP and reservoir pressure prediction	Workflow	Carry out multiple forward model reservoir simulations to quantify the uncertainty of bottom-hole pressure (BHP) and reservoir pressure.
	Dataflow	Model outputs are transferred to IRMDSSdb for plotting/visualization.
Decision		
Determine an operation		Use model results and estimated uncertainty to determine an optimal operational strategy (change of I/W rates) with low potential of exceeding maximum reservoir pressure.

Table A-2: Use Case 2

Title	Use Case 2	Subsurface well leak, tubing.
Goal		Demonstrate how to address a subsurface tubing gas leak.
Scenario		Assuming injection and withdrawal (I/W) are through tubing only, real-time **DTS** indicates a thermal anomaly at a depth of 3700-5000 ft (~1100-1500 m) in a 10,000 ft (~3000 m) well. There is an **increase in casing pressure**. Decisions need to be made to address the leak.
Questions / Decisions		Where is the gas leak (depth)? What caused the leak (failed joint, weld, corrosion, etc.)? What is the leakage rate? What should be done to address the leakage?
Analysis		
UC 2.1. Locate leak	Workflow	Note the thermal anomaly location (depth) from DTS.
	Dataflow	Extract temperature data from IRMDSSdb, and plot T vs. length along well. If available, plot data from multiple times to look at time-evolution of the temperature profile along the well.
UC 2.2. Correlate with well construction record	Workflow	Correlate leakage location with well construction logs (joint locations, age of tubing) to understand potential cause/reason/type of leakage.
	Dataflow	Extract well construction logs and plot them at the same scale as the temperature along the well.
UC 2.3. Estimate leakage rate	Workflow	Shut-in the well. Vent flow and then allow pressure (P) build-up in the annulus. Continue to monitor casing P and analyze the rate of P build-up; increase DTS data collection frequency to analyze temperature (T) change; eventually estimate the leakage rate.
	Dataflow	Measured annular casing pressure data, as well as DTS data are stored in the IRMDSSdb. Extract P vs. time and T vs. time data, and plot to estimate the leakage rate.
UC 2.4. Evaluate ways to fix/mitigate the leak	Workflow	Brainstorm (or extract from a handbook or an expert system) various potential mitigations for the leak given its character as evaluated above. What are the costs? What are the risks?
	Dataflow	Access and read operational guides and handbooks, or content at links thereto, to gather information on potential solutions.
Decision		
Standard fix		Leak rate > threshold Continue to monitor pressure buildup rate and trend. Monitor fluid level in casing (how). Pull tubing and diagnose failure cause. Replace tubing, bring well online. Leak rate < threshold Continue to monitor with vigilance.

Table A-3: Use Case 3

Title	Use Case 3	Ground deformation observed by InSAR.
Goal		Demonstrate how to address unexpected ground deformation
Scenario		InSAR ground-surface elevation data show subtle deviations from normal trends as observed historically or as predicted by the geomechanical model in the IRMDSS.
Questions / Decisions		Where is the anomalous ground deformation? What is causing it? What are potential impacts for UGS integrity of the deformation? What should be done to address the anomalous ground deformation?
Analysis		
UC 3.1. Analyze InSAR data	Workflow	Obtain data for a new period to calculate the volume change in the reservoir. Invert volume change and calculate the residual (i.e., the volume change that cannot be accounted for by I/W). If the residual cannot be explained by I/W, further investigation is warranted.
	Dataflow	IRMDSSdb IO of InSAR data, plotting of residuals on map and cross section(s).
UC 3.2. Locate anomalies	Workflow	Locate InSAR anomaly on the field map in IRMDSS.
	Dataflow	Add InSAR ground surface data into IRMDSSdb.
UC 3.3. Correlate with well location and activity	Workflow	Correlate the anomaly with adjacent wells and their injection/withdrawal (I/W) history.
	Dataflow	Extract well location data, along with I/W history, and plot data on map with InSAR anomaly data.
UC 3.4. Estimate leakage rate, if any	Workflow	• Inventory assessment: – Review the gas inventory vs. pressure of the reservoir. – Determine if the anomaly is caused by a reservoir leak.
	Dataflow	Extract and plot gas inventory vs. pressure to look for anomalous (leak-related) behavior.
UC 3.5. Measure related surface leakage, if any	Workflow	Perform drone/vehicle-mounted/hand-held/stationary soil-gas monitoring survey to identify potential surface leakage.
	Dataflow	Add collected data to IRMDSSdb.
UC 3.6. Geomechanical modeling	Workflow	Create/edit input files for geomechanical model. Perform simulations for potential causes of the anomaly.
	Dataflow	Store model outputs in IRMDSSdb.
UC 3.7. Determine cause of the anomaly	Workflow	External to the IRMDSS, synthesize all available data and modeling results to generate hypotheses about cause.
	Dataflow	Map and plot data from the IRMDSS, e.g., topography, InSAR anomaly, well locations and activity, etc.
UC 3.8. Look for alternative causes	Workflow	External to the IRMDSS, consider the potential that the anomaly comes from activities not associated with the gas storage field.
	Dataflow	From IRMDSS map, observe what else is a possible cause of apparent ground deformation? Landslide potential? Erosion? Excavation? Other fluid I/W? Collect data on other activities

		occurring in reservoirs shallower than the UGS reservoir (e.g., I/W activities above the UGS reservoir).
UC 3.9. Evaluate potential consequences of ground deformation	Workflow	External to the IRMDSS, consider the ground deformation and its potential impacts on: Well integrity (cement failure, casing shear, casing buckling). Slope failure, erosion, stream diversion. Seal integrity. Fault reactivation. Surface leakage. Groundwater impact.
	Dataflow	Various maps of activities need to be displayed and overlaid to compare locations of wells, slopes, streams, faults, etc.
UC 3.10. What are potential mitigation approaches	Workflow	Brainstorm or refer to handbooks etc. to consider potential mitigations for the type of anomalous ground deformation observed.
	Dataflow	Access IRMDSS-stored contents of operational guides and handbooks, or links thereto, to gather information on potential solutions.
UC 3.11. What additional data are needed?	Workflow	If the reasons for anomaly are not clear, determine what data need to be collected to determine cause.
	Dataflow	Add new data to IRMDSSdb.
Decision		
Assuming deformation only (no leakage)		Ground surface anomaly > threshold* Mitigate based on determined cause. Ground surface anomaly < threshold Continue to monitor with vigilance. If trend over time in ground surface anomaly is a concern, consider operational changes to mitigate deformation and to avoid future incident(s).
If leaking above threshold rate,		Mitigate leakage.

***threshold may be consequence-based rather than arbitrary displacement value.**

Table A-4: Use Case 4

Title	Use Case 4	Non-specific surface leak.
Goal		Demonstrate how to address a non-specific surface leak.
Scenario		Native vegetation or crops over or near the UGS site have unexplained color change coupled with declining health or dying plants compared to surrounding area or adjacent vegetation or crops. UAS detects anomalous methane emanating from the affected area.
Questions / Decisions		Where is the leak? What is the leakage rate? What is the source of the leaking gas? What should be done to address the leakage?
Analysis		
UC 4.1. Locate leak	Workflow	Analyze ambient air methane concentration in the area using mobile gas-sampling, e.g., by drone, car, on foot). Plot concentration data on map. Make contours of concentration including uncertainty.
	Dataflow	Methane concentration data, location, and date-time data uploaded to IRMDSSdb. Data from IRMDSSdb queried to create concentration maps of various kinds.
UC 4.2. Estimate leakage rate	Workflow	Pinpoint the source location using a handheld device and deploy flux-measuring equipment focused on location of the leak. Accumulation chamber and/or eddy covariance tower can be used. California ARB uses EPA Method 21 and correlations it has developed to estimate leakage flow rates.
	Dataflow	Gas leakage rate data, location, and date-time data uploaded to IRMDSSdb. Data from IRMDSSdb queried to create flow-rate maps of various kinds.
UC 4.3. Determine origin of the gas.	Workflow	Determine composition of the leaking gas, e.g., this may include stable and radiogenic carbon isotopic ratios. Determine if gas is from storage operations, from other fossil hydrocarbon source, or from biogenic sources.
	Dataflow	Gas compositional data uploaded to IRMDSSdb. Compositional data downloaded for analysis, calculating ratios etc., and plotting by geochemists.
UC 4.4. Evaluate alternative ways to fix/mitigate the leak	Workflow	Investigate what the source of the leakage might be and where the source is. Based on findings, evaluate remedies. If no source is found, is a tent feasible and needed to capture leaking gas? Are there other soil vapor extraction and recovery options? Is flaring an option?
	Dataflow	Access various remedy options stored in the IRMDSSdb or externally for evaluation. Similarly, access cost databases for various remediesfor evaluation of options.
Decision		
Standard remedies		If source is UGS, pursue identifying where and why leakage is occurring. Leak rate is UGS and > threshold. Pursue remedies to stop the leak at its source in the subsurface.

		Leak rate is UGS and < threshold. Continue to monitor with vigilance. If trend over time is showing increase in leakage rate, pursue remedies. If source is not UGS, assist responsible party with addressing the problem.
Alternate remedies		If standard remedies are not feasible, consider tenting, flaring, active extraction and recovery.

Table A-5: Use Case 5

Title	Use Case 5	Gas present on well-pad site.
Goal		Demonstrate how to address gas of unknown origin present on well-pad.
Scenario		UAS/operator detects methane/odorant on and near the well site. Well pad site leak detection equipment indicates methane presence but no leakage sources are found on the well pad site after detailed inspection.
Questions / Decisions		Where is the leak? What is the leakage rate? What should be done to address the leakage?
Analysis		
UC 5.1. Locate	Workflow	By the specification of the scenario, the source must be off-site of the well pad, i.e., gas must be blowing in from somewhere else. Deploy wind-direction and speed sensors. Correlate concentration anomaly with wind direction. Focus monitoring and sampling in direction of the source. Alternative is to use a UAV with the help of a handheld device to location the source and estimate the flux.
	Dataflow	Temporal wind speed and direction data along with concentration data uploaded to IRMDSSdb.
		See Use Case 4 (starting at UC 4.1) for remainder of use case.

Table A-6: Use Case 6

Title	Use Case 6	Subsurface leak outside of but adjacent to the wellbore tubulars.
Goal		Demonstrate how to address a subsurface gas leak outside of but adjacent to the wellbore tubulars.
Scenario		DTS and/or temperature log shows a broad change in temperature trend (i.e., a change in temperature gradient or an anomalously warmer or cooler wellbore section) in the wellbore above the storage zone with no DAS response, no increase in annular pressure and no surface methane leakage is detected.
Questions / Decisions		Where is the leak (depth)? What is causing the leak? What is the leakage rate? What should be done to address the leakage?
Analysis		
UC 6.1. Locate	Workflow	Note the thermal anomaly location (depth) from DTS and/or temperature log.
	Dataflow	Extract temperature data from IRMDSSdb, and plot it vs. length along well. If available, plot data from multiple times to look at time-evolution.
UC 6.2. Correlate with well construction record	Workflow	Correlate leakage location inferred from temperature log with well construction logs (joint locations, age of casing) to understand potential cause/reason/type of leakage.
	Dataflow	Extract well construction logs and plot them at the same scale as the temperature along the well.
UC 6.3. Estimate leakage rate	Workflow	Develop model for CH_4 and water flow in exo-casing annular region with cement if appropriate. Create/edit T2Well input file with properties of the well and formation. External to the SI, run inverse models varying exo-casing annulus aperture, and other relevant unknowns. Match leakage rate to observed thermal anomaly.
	Dataflow	Model results/output uploaded to IRMDSSdb.
UC 6.4. Evaluate alternative ways to fix the leakage	Workflow	Brainstorm (or extract from a handbook or an expert system) various potential mitigations for the leak given its character as evaluated above. What are the costs? What are the risks?
	Dataflow	Access internally from the IRMDSS or externally operational guides and handbooks, or links thereto, to access information on potential solutions.
Decision		
Standard fix		If leakage rate > threshold, consider alternatives for attempting to fix the leak (e.g., squeeze cement into exo-casing annulus). If leakage rate < threshold, continue to monitor with vigilance.
Alternate fix		

Table A-7: Use Case 7

Title	Use Case 7	Compensating for P&A'ing a well (permanent removal of a well).
Goal		Demonstrate how to use the IRMDSS to support decisions about how to operate remaining I/W wells or replace the well upon permanent removal (P&A) of a well.
Scenario		Risk assessment of wells has determined that an I/W well is above a threshold of concern for risk of leakage. If the risky well is taken out of service, other I/W well operations will need to be adjusted to compensate for removal of this well.
Questions / Decisions		How should the I/W rates of remaining wells be adjusted to compensate for the loss of the P&A'd well? What is the uncertainty in the result of the analysis?
Analysis		
UC 7.1. Perform baseline analysis	Workflow	Create/edit model input files. Run reservoir model to forecast reservoir pressure and bottom hole pressure for actual and anticipated ranges of I/W using all of the wells.
	Dataflow	Model outputs transferred to IRMDSSdb.
UC 7.2. Perform analysis for loss of the I/W well	Workflow	Run reservoir model to forecast reservoir pressure and bottom hole pressure for actual and anticipated ranges of I/W without the P&A'd well.
	Dataflow	Reservoir and well property data transfer from IRMDSSdb to reservoir model. Model outputs transferred to IRMDSSdb.
UC 7.3. Perform analysis to optimize I/W of remaining wells.	Workflow	Optimize I/W operations while maintaining all required pressure and other operating requirements. This can be by manual optimization or done automatically if appropriate software tool is available.
	Dataflow	Reservoir model outputs transferred to IRMDSSdb for analysis.
UC 7.4. Perform uncertainty quantification	Workflow	Carry out multiple forward models to quantify the uncertainty of bottom-hole pressure (BHP), given future gas I/W demand is uncertain.
	Dataflow	Multiple IRMDSSdb I/O operations to obtain reservoir and well data for the modeling, and to store model results.
Decision		
Determine an operation		Use model results and estimated uncertainty to determine an optimal operational strategy for compensating for loss of an I/W well.

Table A-8: Use Case 8

Title	Use Case 8	Well blowout flow-rate management.
Goal		Demonstrate use of reservoir model to evaluate I/W strategies to reduce a well blowout flow rate.
Scenario		There is a well blowout underway with large measurable flow rate of natural gas into the atmosphere. During well blowout impact mitigation and kill planning, interim strategies are needed to reduce the leakage rate to the environment prior to successfully killing the well, e.g., by means of a relief well bottom kill. One approach is to lower reservoir pressure by means of gas withdrawal from surrounding wells.
Questions / Decisions		To what degree can withdrawing gas from surrounding wells help reduce the well blowout rate? How does the blowout rate evolve over time? How important is the proximity of gas withdrawal well(s) to the reduction in well blowout flow rate? How many withdrawal wells are needed to reduce the leakage rate to a certain level?
Analysis		
UC 8.1. Locate potential withdrawal wells	Workflow	Identify wells that can be used for withdrawal at various distances.
	Dataflow	Extract reservoir model with well locations.
UC 8.2. Perform Analysis	Workflow	Run simulations with the reservoir model.
	Dataflow	Extract and plot results of how the well blowout rate decreases with each set of withdrawal wells.
UC 8.3. Decisions temporary solution to reduce the CH4 release rate	Workflow	Compare the various withdrawal scenarios and the blowout leak rate, withdrawal amount, and reservoir pressure to optimize this approach until the well blowout is remedied.
	Dataflow	Store the results and suggested solution in the IRMDSS SI.