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An Integrated Analytical Technique to Screen Depleted Reservoirs for Underground Gas Storage Suitability

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Abstract

Underground gas storage (UGS) technique is gaining impetus and is widely implemented due to the global gas demand and consequent variation of gas prices. Due to the upfront investment involved in UGS projects, thorough screening of potential candidate reservoirs followed by economic feasibility analysis is essential to ensure the functionality of the project.

A range of technical factors like reservoir containment, gas recovery, pressure regimes throughout the operation, well integrity, available surface equipment, presence of contaminants in the fluid and project safety are considered as a part of the reservoir screening and UGS design workflow. Cushion gas requirement, working gas capacity, and maximum gas injection/ withdrawal requirements are the key operating elements that drive the feasibility and design of a UGS project. Finally, risk evaluation, economic feasibility and policy factors are reviewed to assess the feasibility of the candidate reservoir for a UGS project.

The study encompassed evaluation of three depleted fields for UGS candidacy. The two smaller fields offer very limited storage volumes and were deemed as unsuitable due to target extraction and storage rates. The bigger structure was delineated as a potential candidate. Geological investigation affirmed the caprock seal integrity. Formation pressure data confirmed hydraulic connectivity of the reservoir that was continuous to an adjacent structure. However, this connectivity was constrained by a gas-water contact (GWC) that acted as the bottom boundary for the containment. After calibrating the model with a fit-for-purpose objective, the reservoir modelling identified opportunities for maximizing working gas capacity through sensitivity analysis. Well engineering and completion assessments qualified existing wells for conversion to injectors, identify potential workover requirements and propose upgrades to existing equipment. Overall, the reservoir was qualified as good candidate for UGS requiring an additional investment circa $200Mn towards UGS specific surface facility with 30% uncertainty.

Based on the meticulous review and integration of outcomes from multiple disciplines, a quick analytical technique based on material balance and production performance prediction was developed. This workflow was carefully implemented to assess the UGS candidacy of a similar reservoir in a nearby field. Further

development of the workflow has the potential to serve as quick-look tool and precursor to the detail oriented integrated approach described earlier.

Introduction

UGS is a critical technique in the energy sector, providing a means to balance the seasonal and operational fluctuations in natural gas supply and demand. With the global energy landscape experiencing dynamic shifts, the role of UGS has become increasingly significant. The global demand for natural gas has seen a steady rise, driven by its relatively lower carbon footprint compared to other fossil fuels and its versatility in power generation, heating, and industrial applications. This growing demand, coupled with the inherent volatility in gas prices, necessitates robust storage solutions to ensure supply reliability and economic stability. UGS facilities serve multiple purposes: they act as a buffer against supply disruptions, enable the efficient management of pipeline operations, and provide a mechanism for trading and arbitrage in gas markets. By storing excess gas during periods of low demand (typically summer) and withdrawing it during peak demand (winter), UGS helps in maintaining a stable supply, mitigating price spikes, and ensuring the energy security of regions dependent on natural gas.

Given the substantial upfront investment and long-term commitment required for UGS projects, it is imperative to undertake a comprehensive and meticulous screening process to identify suitable candidate reservoirs. The screening process must include the following:

1. **Technical Evaluation:** Assess the technical feasibility of potential UGS sites by examining key factors such as working gas capacity, injection and withdrawal rates, reservoir containment, and well integrity.
2. **Economic Feasibility:** Conduct a thorough economic analysis, evaluating the cost implications and potential returns on investment for the selected reservoirs.
3. **Risk and Policy Assessment**: Identify and evaluate the risks associated with UGS projects and to understand the policy and regulatory environment that could impact the feasibility and operation of these projects.

To achieve these objectives, the study employs a multi-disciplinary approach, integrating geoscientific, engineering, and economic analyses. The outcome is a streamlined workflow that can be applied to screen and evaluate UGS candidates efficiently, reducing the time and resources required for preliminary assessments. This paper is structured to provide a comprehensive overview of the screening process adopted, with a focus on the technical screening elements. It also highlights key aspects from economic feasibility and risk evaluation, culminating in a detailed case study of the most suited field. Finally, the development of a quick-look analytical workflow will be discussed, highlighting its potential application in similar reservoir evaluations. By adopting this integrated approach, the study aims to contribute to the optimization of UGS project planning and execution, ultimately supporting the broader objective of energy security and economic efficiency in the natural gas sector.

UGS Strategy in Egypt

Egypt has seen a rapid increase in domestic gas consumption due to economic growth and industrial expansion. Despite significant natural gas reserves and recent discoveries in the Mediterranean, Egypt faces challenges in balancing domestic consumption with export commitments. Growing urbanization and industrial activities have increased the domestic demand for natural gas, stressing the supply infrastructure.

Natural gas demand for heating in Europe has seen significant fluctuations, particularly influenced by seasonal changes and weather conditions. In Europe, gas consumption varies significantly between seasons, averaging 8 TWh per day in summer and 22 TWh per day in winter. This surge in demand during the winter

months is driven by the need for heating, which highlights the importance of having reliable underground gas storage (UGS) facilities to manage these fluctuations effectively.

Europe's energy landscape is characterized by high natural gas consumption, with significant reliance on imports to meet domestic demand. The region's dependence on imported gas, particularly from geopolitically unstable areas, poses a risk to energy security. This vulnerability is highlighted during political conflicts and supply disruptions, which can lead to significant economic and social impacts.

Out of the numerous case studies highlighting the impact of unforeseen disruptions in gas supply, the European Union (EU) has been focusing on diversifying its energy sources and enhancing its energy security through the development of UGS facilities. Geopolitical tensions and conflicts in gas-producing regions can severely impact gas supply stability. The presence of conflicts and unstable regimes can lead to frequent disruptions, making it imperative for countries to have reliable UGS solutions to buffer against these uncertainties.

Growing demand for natural gas storage capacity is evident, with the EU reaching its target of filling gas storage facilities to 90% of capacity well ahead of the winter season1. This highlights the ongoing need to expand storage capacity to manage variable demand, especially during peak periods such as winter when heating needs surge. Clean energy initiatives have been a focus since 1915 in Canada, addressing variable demand. In the USA, half of gas consumption during peak demand seasons is provided through storage facilities.

Egypt aims to become a regional gas hub, exporting LNG to Europe and other markets. However, fluctuating domestic demand can impact its ability to meet export targets. In this case, UGS can be a game changer where Egypt can import and store the imported gas and export this gas in the peak demand season. Additionally, Egypt is strategically located with relatively easier access to Europe, allowing it to capitalize on buying and storing cheap gas and selling it during times of high demand in Europe.

UGS not only enhances energy security but also contributes to environmental sustainability. By optimizing gas storage and reducing flaring, it can help in lowering greenhouse gas emissions. It allows for the capture and storage of excess gas that might otherwise be flared, reducing methane and CO2 emissions. Utilizing the existing infrastructure in depleted fields for UGS applications reduces the carbon footprint by avoiding drilling new wells. By managing supply and demand more effectively, UGS facilities help in the efficient utilization of natural gas and also minimize wastage.

Challenges

UGS appears like a effective solution which yields multiple benefits from balancing gas supply and demand cycles to reducing hydrocarbon footprints. However, the uncertainties involved in selecting potential candidates and the high capital expenditure make it a challenging operation. Some of the key risk metrics in a UGS operation are as follows:

a. *Identifying Suitable Reservoirs*: Identifying a suitable reservoir requires extensive geological and engineering studies to evaluate parameters such as porosity, permeability, and caprock integrity.
b. *Reducing Uncertainty in Containment*: Ensuring the reservoir's ability to contain gas without leakage is crucial. Failure to maintain containment can lead to gas losses, environmental hazards, safety risks, financial losses, and legal liabilities. This underscores the importance of thorough geoscientific assessments and surveillance.
c. *Well Integrity and Workover Costs*: Ensuring the integrity of existing wells and performing necessary workover activities to convert production wells to injection and withdrawal wells can be costly. This includes inspections, repairs, and upgrades to maintain safety and functionality.
d. *Infrastructure Setup*: Building the necessary infrastructure, including pipelines, compressors, and surface facilities, involves substantial capital investment.

e. *Equipment Life Cycle and Maintenance*: The life cycle of UGS equipment, including maintenance, upgrades, and replacements, adds to the operational costs. Ensuring the reliability and longevity of this equipment is critical for continuous operations. A thorough economic analysis is required to evaluate the feasibility and return on investment, considering the long-term operational costs and potential revenue from gas storage.

Technical Screening Requirements

The underground storage of natural gas (UGS) is an essential technique for managing global gas demand and price fluctuations. Given the significant investments required for UGS projects, a comprehensive evaluation of potential candidate reservoirs is crucial to ensure their viability. In evaluating potential UGS candidates, it is crucial to conduct a thorough technical screening to ensure the suitability and effectiveness of the reservoir for gas storage. The following are the key technical elements that drive the screening process.

a. **Working Gas Capacity:** Working gas capacity refers to the volume of gas that can be cycled in and out of the storage reservoir, as opposed to the base gas or cushion gas, which remains in the reservoir to maintain minimum pressure and ensure deliverability. The working gas capacity is a critical factor as it determines the volume of gas that can be stored and utilized/traded to meet market demands. The working gas capacity is calculated based on the reservoir's pore volume, the efficiency of gas recovery, and the reservoir pressure. Accurate estimation of this capacity involves detailed geological and reservoir engineering studies, including core sampling, well logging, and pressure testing.
b. **Maximum Injection and Withdrawal Requirements:** The maximum gas injection and withdrawal rates are essential to ensure the reservoir can meet the operational demands on timely basis. These rates are influenced by the reservoir's permeability, porosity, and the design of the well completions. High injection and withdrawal rates are desirable to manage peak demand periods effectively.
c. **Daily and Seasonal Requirements**: UGS facilities must be able to accommodate daily and seasonal fluctuations in gas demand. This requires a detailed understanding of the market dynamics and the ability to adjust injection and withdrawal schedules accordingly. Seasonal storage typically involves injecting gas during off-peak periods (summer) and withdrawing it during peak periods (winter).
d. **Reservoir Containment:** Ensuring the reservoir's containment is crucial to prevent gas leakage and maintain storage integrity. This involves evaluating the caprock, pre-existing faults and surrounding formations to ensure they can effectively seal the gas within the reservoir. Geological surveys and seismic studies are commonly used to assess containment.
e. **Gas Recovery Potential:** The ability to recover the injected gas efficiently is a key consideration. This depends on the reservoir's porosity, permeability, and pressure maintenance. High recovery rates ensure that the stored gas can be effectively utilized when needed.
f. **Pressure Regimes and Management:** Maintaining optimal pressure regimes throughout the operation is essential for efficient gas storage and withdrawal. This involves continuous monitoring and management of reservoir pressure to prevent issues such as gas migration or reservoir compaction.
g. **Well Integrity and Surface Equipment:** The integrity of existing legacy wells and the availability of suitable surface equipment are critical factors. Well integrity ensures safe and effective gas injection and withdrawal, while surface equipment must be capable of handling the operational requirements. This may involve upgrading existing infrastructure or installing new equipment.
h. **Presence of Contaminants and Safety Concerns:** The presence of contaminants such as water, sulfur compounds, or other impurities can impact the quality of the stored gas and the operation of the UGS facility. Safety concerns related to gas storage, including the risk of leaks or blowouts, must be thoroughly assessed, and mitigated. Additionally, consideration of increased effective stress and fatigue on well integrity with repeated production-injection cycles must be reviewed.

UGS Workflow

The UGS workflow described in Fig. 1, divides the study into four main phases as follows:

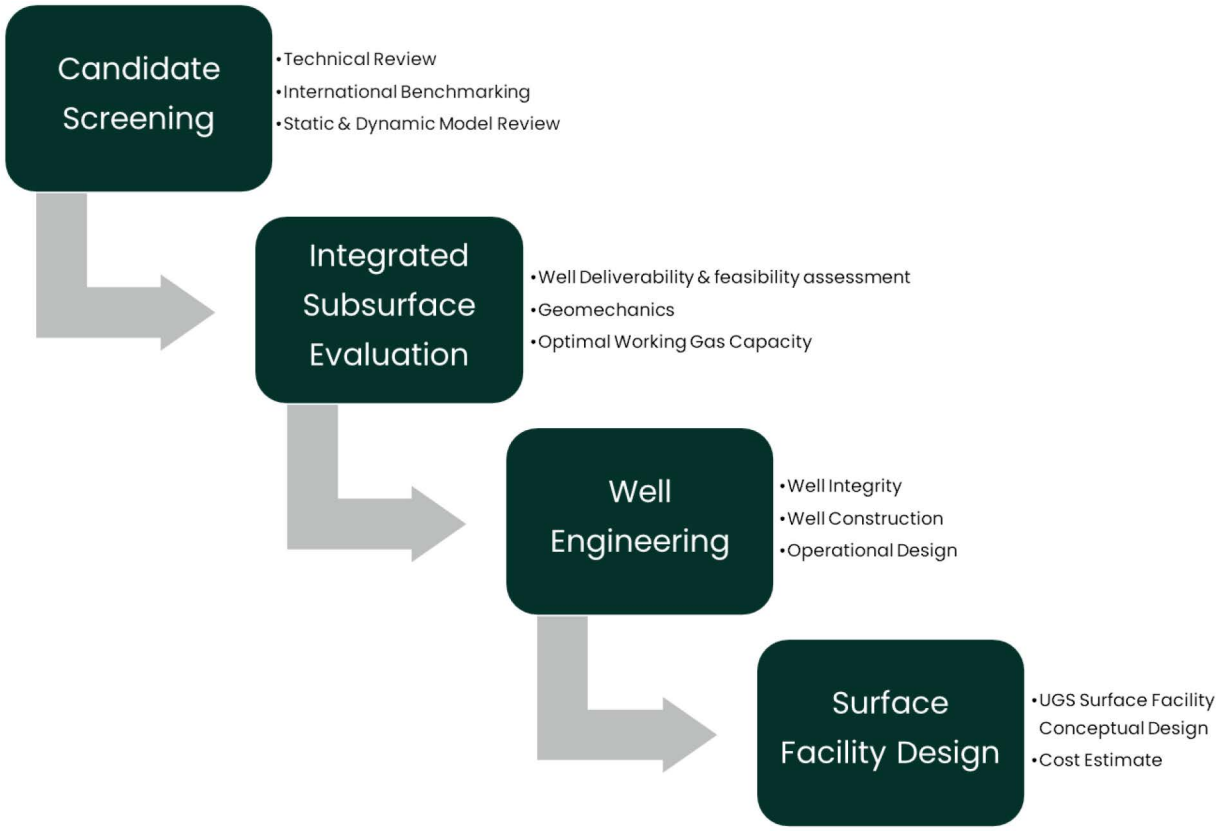


Figure 1—Schematic of the UGS Workflow developed and utilized for the case history described in this paper.

a. **Candidate Screening:** This phase involved a comprehensive audit of the subsurface characteristics of the field, identifying inconsistencies in previous modelling approaches and suggesting improvements. It also includes an international benchmarking process which compared the field A to UGS projects in depleted gas field within 50-200% of its working gas capacity. The review covered surface facility installations, petrophysical evaluations, and geological/geomechanical models. Key tasks included analyzing drilling experiences, reviewing rock mechanical properties, validating facies models, and performing a preliminary well performance analysis. The observations and inferences from the screening are evaluated against the desired objectives to modify the approach and/ or strategy if necessary.
b. **Integrated Subsurface Evaluation:** This phase focuses on a detailed static and dynamic assessment of the subsurface conditions to ensure the feasibility of the UGS project. It includes evaluating the mechanical properties of the reservoir rock to ensure it can withstand the pressures involved in gas injection and withdrawal, assessing the ability of the wells to deliver the required volumes of gas, and determining the optimal amount of working gas that can be stored and withdrawn efficiently.
c. **Well Engineering:** This phase encompasses well construction and integrity analysis. Primary cement evaluation and identification of leakage pathways are assessed for wells with reservoir access, along with offset wells analysis using existing daily drilling reports, end-of-well reports, and mud logs. To check the feasibility of repurposing existing wells for UGS, a detailed corrosion analysis of production tubing and existing completions' barrier elements is conducted to evaluate their current integrity.

Injection and production simulations and related load cases and stresses are simulated considering the existing well completions. A single infill well plan and completions design are also proposed.

d. **Surface Facility Design:** A critical component to judge the feasibility for the development of the UGS project is understanding existing surface facility and development needed to ensure smooth gas injection and withdrawal. The objectives of this analysis were to perform a desktop review of the existing surface facilities and infrastructure in the field, develop the surface facility conceptual design for gas injection and extraction, and develop a Class 5 level capital cost estimate in accordance with Association for the Advancement of Cost Engineering (AACE) for the new facilities to be installed.

Case Study

Background

The case study focuses on the evaluation of three depleted gas fields (Fields A, B and C) located in the onshore Nile Delta. The primary objective of this study was to assess the feasibility of converting these fields into UGS sites followed by detailed deep-dive analysis of the most suited UGS candidate. Through a high-level screening process, each field was analyzed for its unique advantages and potential challenges. This involved a preliminary investigation of geological conditions for UGS, volumetric estimations to evaluate the storage capacity based on available gas and extraction plans, and a review of the status of assets and wells to inform potential pilot projects and future expansion.

The high-level screening revealed that all three fields possess potential for gas storage, each with its unique advantages and challenges. Field C showed promise due to its rich gas content, which could aid in condensate recovery but also presented some uncertainty regarding the aquifer, introducing additional risks. Field B was identified as a promising site, particularly for small to medium-sized storage, due to its optimal balance of available capacity and quick extraction turnaround time. However, Fields B and C, due to their limited storage volumes, were ultimately deemed unsuitable for the desired storage and extraction rates. Conversely, Field A, characterized by the absence of aquifer support and the presence of native dry gas, emerged as the strongest candidate for UGS. The next phase of the study involves a detailed study of field A for UGS evaluation from a multi-disciplinary approach using the UGS workflow.

Field A is a primarily a gas field producing primarily producing from a Late Miocene sandstone reservoir. The reservoir is characterized by an average porosity of ~26% and has a high permeability. The original gas in place is 100x bscf. The field was discovered in 2005 and production started in 2007 and has been produced until 2020 through 7 wells. The reservoir is producing mainly using its depletion drive mechanism. Additionally, there is a presence of a very weak water drive that provides very little pressure support. Field A was selected as the best candidate for UGS and the following section details the analysis and inferences derived from the study.

Engineering Analysis

The main objectives of the engineering analysis were to perform iterative feasibility assessment, estimating working gas capacity, well deliverability and sub-surface containment assurance by updating the static and dynamic reservoir models along with geomechanical assessment.

a. **Geological and Geomechanical Constraints:**

A robust, and fully integrated 3D static model that provides a more accurate representation of the structure, reservoir properties, and initial fluid saturations was developed. Analysis of the formation pressure testing data over time revealed that the gas-water contact has risen approximately 100ft above the initial conditions. As shown in Fig. 2, the target reservoir for UGS in field A is very likely the same sand unit in the offset field, and the published pressure data suggests a strong communication with field A at the initial condition. To minimize the risk of injected gas reaching the spill point to the

offset field, it was recommended to slowly fill the structure (storage volume) while safely pushing the water back. Geomechanical analysis was carried out to understand the existing in-situ stress regime and potential geomechanical impacts of gas injection/withdrawal on storage reservoir-caprock system integrity. Two main risks assessed under the current geomechanical analysis were potential tensile breach of reservoir and cap rock due to gas injection and stability assessment of pre-existing faults/fractures. While the initial pressures were mainly hydrostatic, the field has experienced significant depletion over the course of its production history. The geomechanical effects on the associated faults and cap rock integrity were analyzed at the depleted reservoir pressure condition and after injection back to the initial reservoir pressure. The maximum injection reservoir pressure is planned to be 90% of the original reservoir pressure to ensure that the expected bottomhole pressure does not exceed the fracture gradient (Shmin) of reservoir-caprock system. Also, fault stability analysis suggested that none of the faults are expected to be critically stressed for the planned UGS pressure envelope.

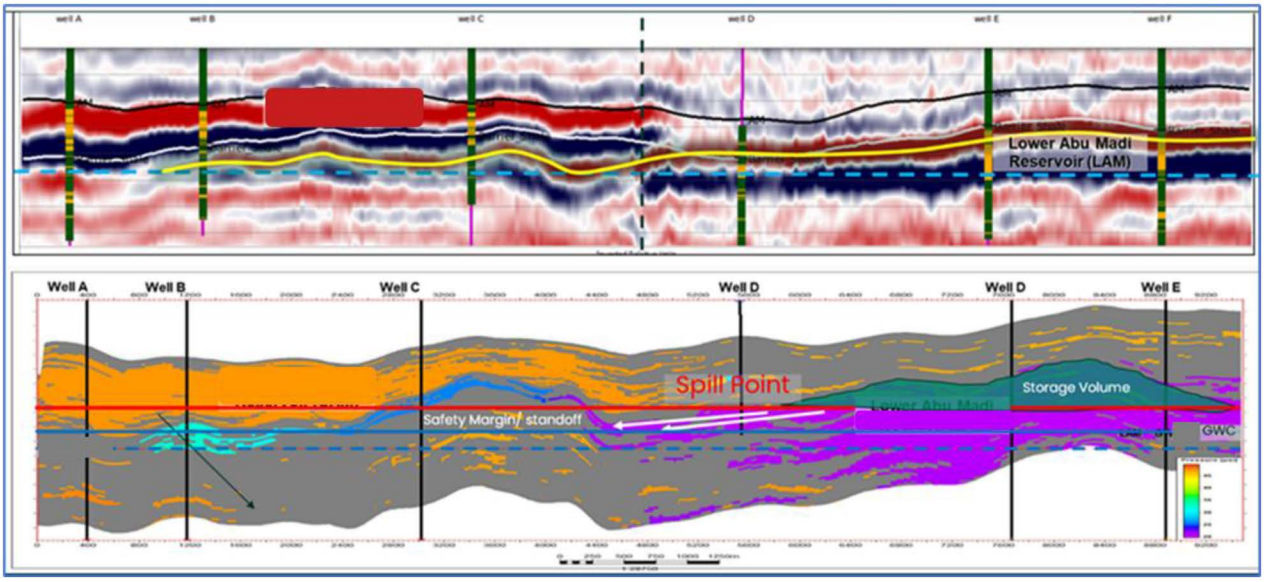


Figure 2—Seismic and stratigraphic section of the target reservoir for UGS in field A extending into an offset field through a spill point.

b. **Dynamic Model and History Match**

The dynamic model was successfully constructed and initialized based on the static model grid and reservoir engineering inputs. A history matching approach involved achieving a fit-for-purpose field level match by modifying existing dynamic parameters. Next, the well level match was achieved to adequately condition the model to qualify for UGS simulations based on the history match for the last six months.

The aquifer, modelled as a weak aquifer, was a critical parameter to match water production. Material balance analysis conducted in the screening phase indicated depletion as dominant drive mechanism along with a weak aquifer. Different sensitivities were tried by adding bottom and side aquifers on south, west, and north areas. It was observed that the aquifer strength and location are very sensitive for water production on the crestal wells. Finally, a weak side and bottom aquifer showed a better water production match.

Fault transmissibility were modified iteratively to analyze the effect of sealed, open, and partially sealed faults on well production rates and pressures. Two faults were sealed to improve the history match. Permeability, NTG, relative permeability and pore volume modifications were done at well and reservoir levels to enhance the history match. The final history match was achieved with good

match on gas rate and pressure as shown in table. Water production was very difficult to match on crestal wells and fit for purpose match was achieved on water production. The final history matched model shown in Fig. 3 was used for prediction phase to estimate UGS capacity.

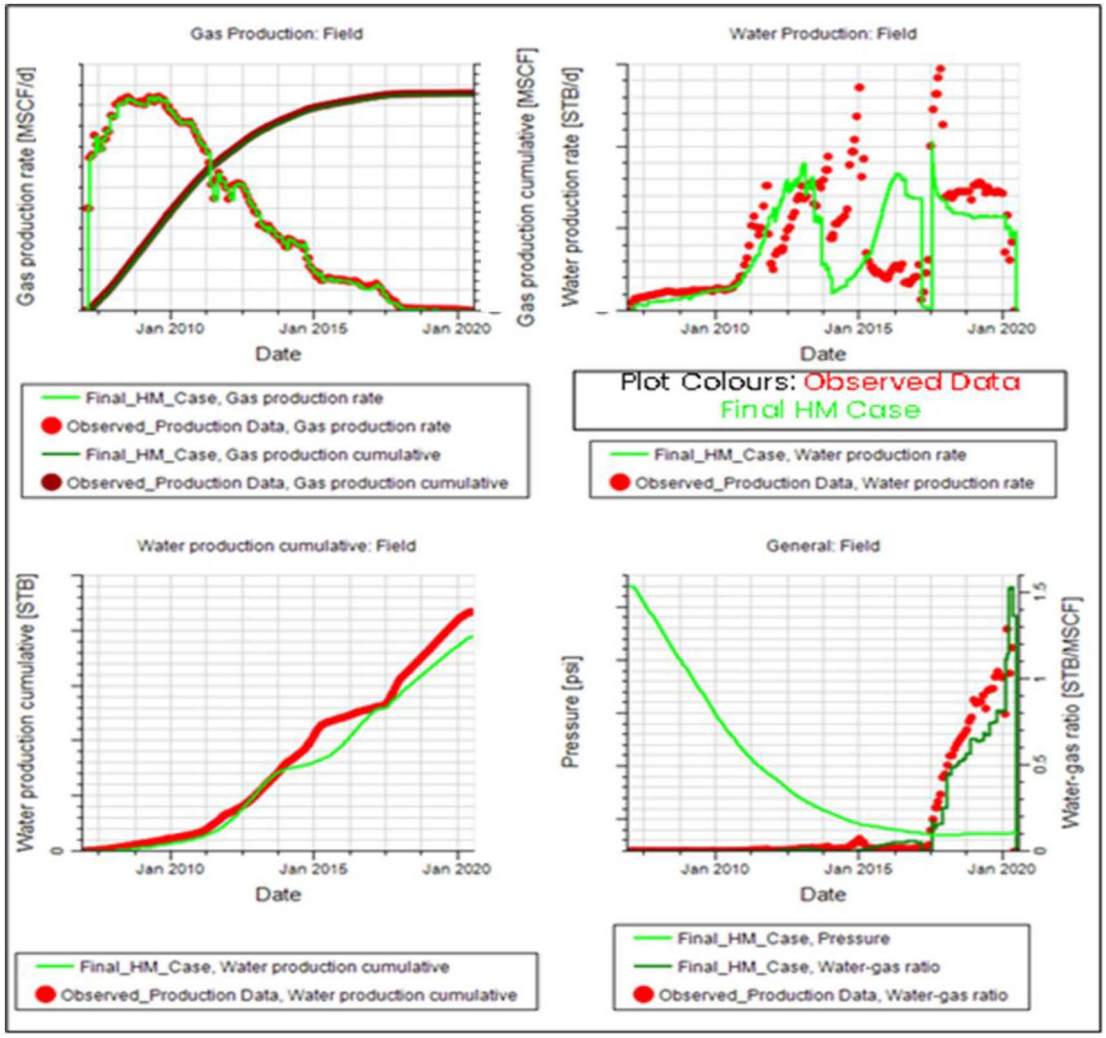


Figure 3—Results from fit-for-purpose history match at field level.

c. **Prediction and Optimization:**

A total of 5 wells were selected as UGS candidates during the prediction cases from June 2023 till March 2029. For prediction purposes, the first injection cycle commences in June 2023 with injection rate constraints at the well and field levels. Injection continues till March 2026 and to include both cushion gas and working gas volumes. 15 days of stabilization period is implemented before starting the summer withdrawal period with production rate control. The summer withdrawal is terminated on September 15, 2026 before another 15 days stabilization. Once stabilization period is finished, winter injection stage starts from October 2026 till March 15, 2027. Similar withdrawal and injection cycles are continued till March 2029 as shown in Fig. 4.

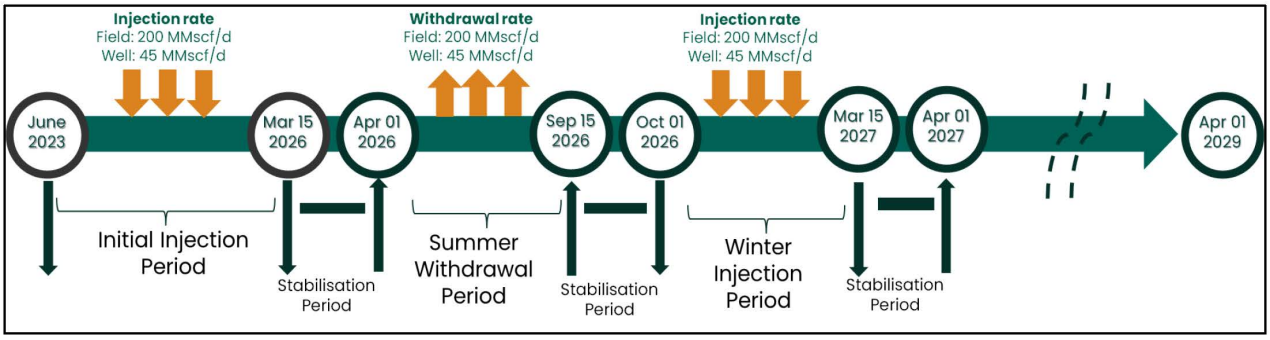


Figure 4—Injection and production/ extraction schedule developed based on the seasonal gas demand and availability of gas for storage.

A systematic optimization workflow was adopted to effectively organize the prediction cases at each stage and study the effect of each sensitivity scenario included in the workflow. Fig. 5 shows the workflow commencing from a base case with sensitivities on injection pressure, tubing head pressure during production, infill wells, workovers in existing wells and tubing size.

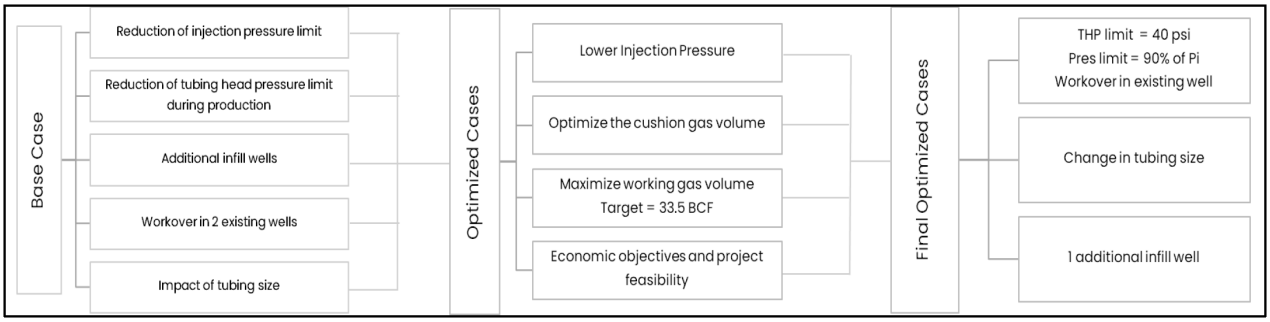


Figure 5—A systematic optimization workflow to effectively organize the prediction cases at each stage and study the effect of each sensitivity scenario included in the workflow.

The following observations were recorded from the sensitivity scenarios of base case:

- **Scenario -1: Decreasing the injection pressure by 10% - 20%**
  - Working gas capacity is decreased by 10% - 23%
  - Incremental of 20 BCF cushion gas is observed.
  - Overall injection gas volume is decreased by 24%
- **Scenario -2: Reducing the Tubing Head pressure during the production cycle.**
  - Negligible impact of working gas capacity and cushion gas volume is observed.
  - Increment of 13% in cumulative gas production by reducing the THP to limiting value viz. approximately half of the base case value.
- **Scenario -3: By adding Infill Wells**
  - Adding 1 infill well has greater impact as compared to adding 2 or 3 infill wells.
  - Working gas capacity and cushion gas volume are increased by 10% and 2% respectively.
  - Total gas production is enhanced by 30%.

- **Scenario -4: Perform Workover in the existing UGS wells**.
  - Injection gas volumes, working gas volume and cushion gas volumes has an increment of 4%, 2% and 6 %, respectively.
- **Scenario -5: Increase the Tubing Size from 3.5″ to 4.5″**
  - No change is observed Injection gas volumes.
  - Working gas volume and cushion gas volumes has an increment of 11% and 4%, respectively.

Based on the scenarios and sensitivities, optimization performed at lower pressures aim to optimize the injection cushion gas volume and maximize the working (production) gas volume during each withdrawal cycle. In this scenario, the sensitivities were performed at an varied injection BHP limits. The following inference were drawn from the results (Fig. 6) of the optimized cases.

- Injection cushion gas volumes for various cases are reduced by approx. 67 – 124 BCF from the base prediction case.
- Working gas and stored gas volumes for various cases are in the range of 49-90% BCF appx. This infers that the reduction of the cushion gas volume can be achieved while maintaining the average cyclic target rates (33.5 BCF) during summer withdrawal and winter injection periods.
- This sensitivity of the optimized cases provided the options to further optimize the CAPEX and project feasibility.

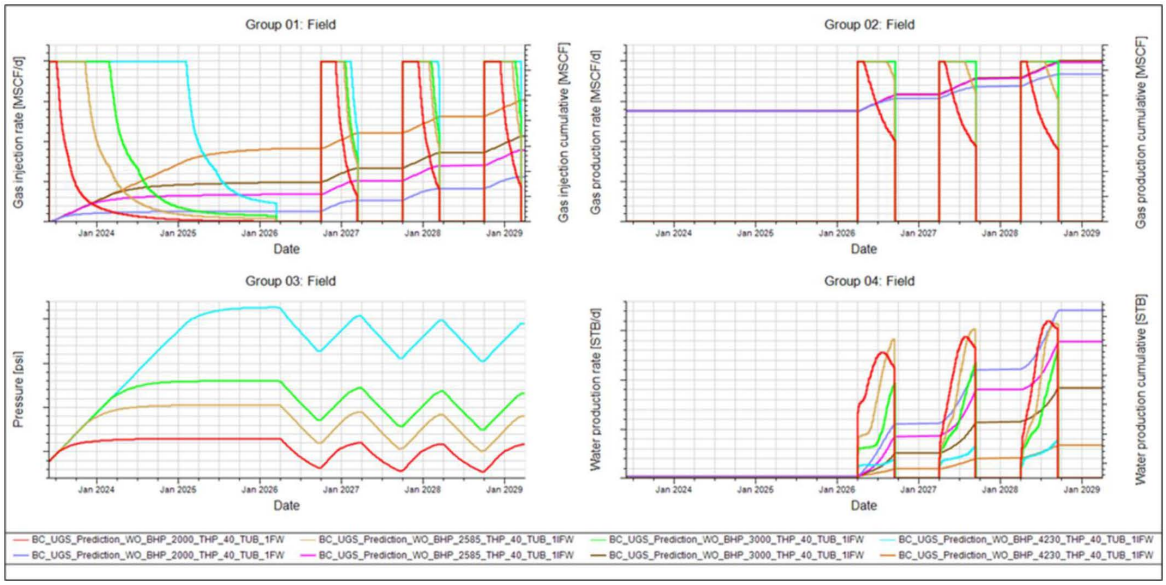


Figure 6—Field-scale result profiles of the optimized cases.

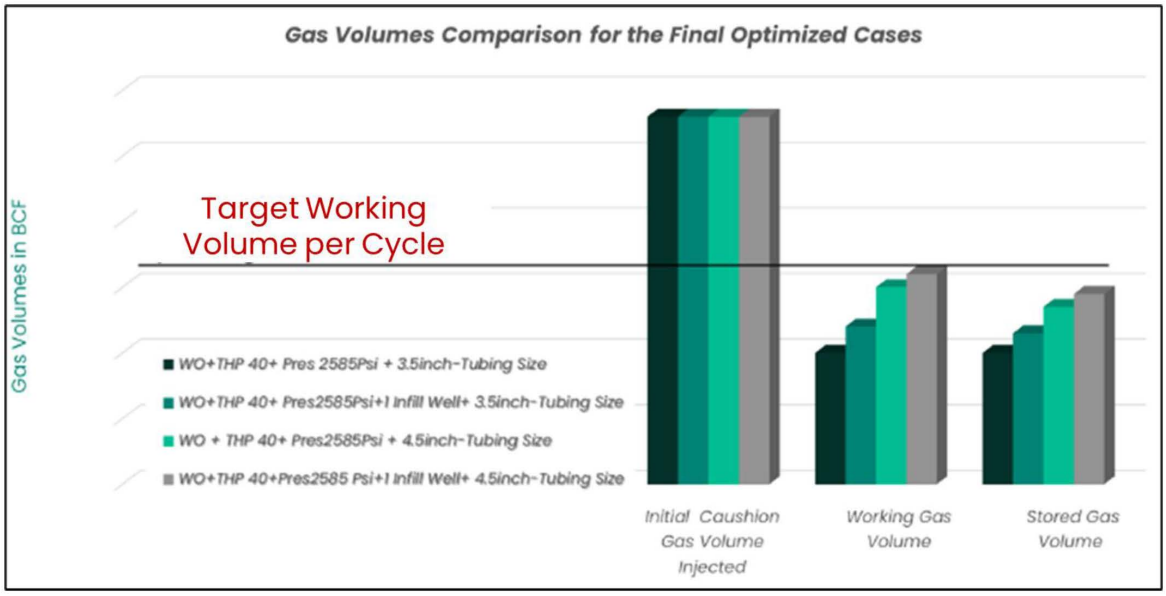


Figure 6—Bar chart representation of the final optimized cases.

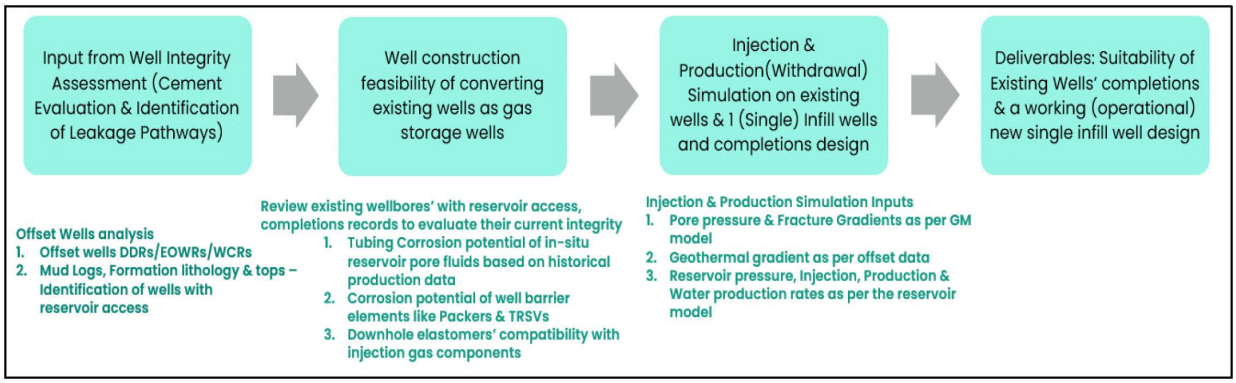


Figure 6—Well Engineering Workflow for Repurposing Existing Wells

Finally, three more sensitivities were run to assess the impact of tubing size and additional one infill well performance at the lower reservoir pressure for further optimization and economics. (Fig. 7)

- Impact on the initial cushion gas volume is negligible as the injection constraints are not altered, like the optimized cases.
- Significant improvements in the cushion and stored gas volumes can be achieved by modifying the completions and adding one infill well.

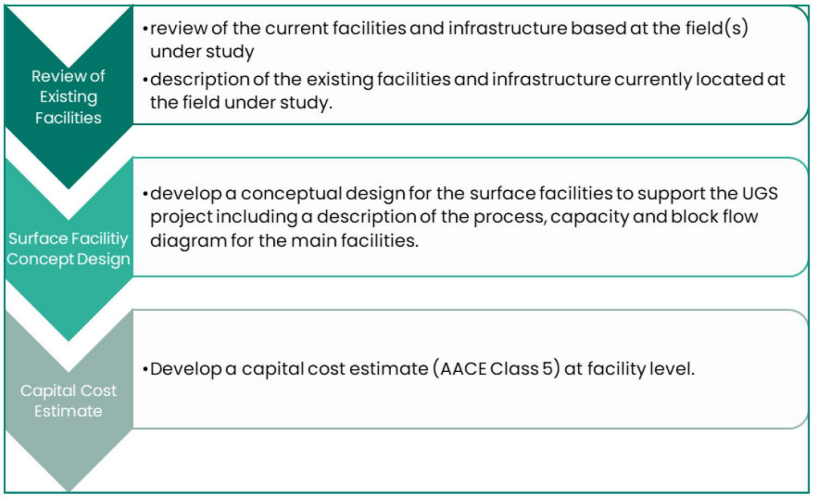


Figure 7—Surface facility review and design workflow.

d. **Key Findings and Development Plan**

Sensitivity studies indicated that an optimal reservoir charge-up pressure, which optimizes the amount of cushion gas and enhances the efficiency of the working gas capacity. This pressure was within the bounds of geomechanics and surface facility constraints and adheres to the limitation on gas contact with water to avoid spillover. The cushion gas requirement is 25% of GIIP and the optimal working gas capacity was determined to be between 40 to 60% of the cushion gas volume. This plan involves converting five wells to 4 ½ tubing and adding one infill well. The injection volume is set, with four-month production and injection cycles. The injection strategy must include monitoring to avoid invading the critical contact for spillover into the northern compartment. This will involve frequent saturation logs and production logging tests (PLTs) to monitor injection efficiency and plume movement.

Well Engineering Recommendations

As a part of UGS studies, the existing wells and completions design penetrating the target reservoir were reviewed for containment assurance for the design storage operation volumes, pressure, injection, and withdrawal rates. Fig. 6 shows the workflow adopted for well engineering studies.

The existing wells were checked for well integrity by examining the condition of the cement in place through available cement bond logs (CBL) and the type of cement used, which is Class G. The application of Class G cement was found suitable, supported by the available offset wells' documentation, such as the end-of-well reports, which mentioned that the intermediate casing cement is good. The wells, currently in a shut-in condition, have no recorded events of any sustained casing pressure, with the surface wellhead Annulus A and Annulus B pressure at zero, indicating that no leakage pathways exist behind the casing in the cement. Following the well integrity assessment, based on the available cement bond logs, the reviewed wells were deemed fit to be converted to injectors.

Based on the results of the integrated subsurface evaluation, five candidate wells penetrating the target reservoir were selected for a detailed well engineering study to repurpose them as UGS injection wells. Additionally, to meet the injection volume and envisaged injection rate of the project, a single infill well was proposed and planned. Hence, a total of six wells targeting the reservoir were subjected to detailed well engineering feasibility analysis for UGS purposes.

Based on historical production data, related reservoir fluids, and the natural gas injectate components' maximum molar percentage, a detailed corrosion analysis was performed. Results showed that after some cycles of injection and withdrawal, oxygen in the presence of water, existing downhole either as

dissolved oxygen in water and/or in vapor-liquid phase, along with the presence of elemental sulfur and mercaptans, may potentially induce corrosion on the martensitic 9% Cr and 13% Cr stainless steel completion components. Likewise, non-rapid gas decompression (RGD) resistant elastomers, such as nitrile, are at risk of explosive failure if a sudden drop in pressure occurs. For this reason, it was recommended that elastomeric components be made of RGD-resistant materials, such as HNBR (Hydrogenated Acrylonitrile Butadiene Rubber). 25Cr Duplex Stainless-Steel material was recommended for injection wells' flow-wetted primary pressure barrier elements like packer and tubing retrievable safety valve (TRSV).

Wall thickness reduction of the existing production tubing was calculated considering historical production rates and periods, shut-in periods, and produced hydrocarbon and water components as part of the corrosion studies. Dry gas with a maximum water concentration of 76 ppmv has been considered for injection. This water concentration is based on assuming the dew point at −10°C at a pressure of 70 barg, with the injected gas maximum characteristics specifying that the injection gas should have a water dew point below 0°C at a pressure of 70 barg. Since with decreasing temperature the relative concentration of water in the gas decreases, the assumed dew point at −10°C giving a water concentration of 76 ppmv is the worst-case scenario.

All five existing candidate wells have different completions installed downhole. Based on reservoir simulations, apart from the existing 3-1/2″ production tubing, an optimized case of 4-1/2″ tubing is also considered for one of the candidate wells. The new infill well and completions design was run considering 4-1/2″ tubing and completions. A total of three pressure scenarios were considered across the target reservoir to model the surface injection and withdrawal rates, pressures, stress, and loads on production tubing: Depleted (pre-injection), Optimized (Injection), and Maximum (for production). Based on the extensive reservoir modeling, different injection rates, production/withdrawal rates, and water production rates were derived for each of the existing five well candidates and the new proposed infill well. The different pressure scenarios were then taken as a reference to model the respective wells' injection and production rates for a detailed tubing stress analysis.

Per well models were created; different load cases comprising injection, production, shut-in, and failure loads, tubing stress analysis including tubing-to-packer forces, and packer load envelopes were considered in the simulation models of each of the wells. Moreover, annular fluid expansion loads on the tubing and casing strings were modeled, considering the stipulated injection and production rates. The simulation models have the 3-1/2″ production tubing for each of the wells, with respective wall thickness reduction as per the individual wells' corrosion analysis performed based on historical production. The 9-5/8″ production casing string and the 7″ production liner string were considered for modeling, with a 12.5% reduction of the critical strength parameters of burst and triaxial, to account for the manufacturing wall thickness eccentricity, as per the maximum permissible tolerance of wall thickness reduction due to internal and external imperfections.

Surface Facility Requirements

A vital part of the gas storage project was to perform a desktop review of the existing surface facilities and infrastructure in the field, develop the surface facility conceptual design for gas injection and extraction and develop a Class 5 level capital cost estimate. Fig. 7 shows the existing surface facility review and facility design workflow that was followed. Desktop review of the existing surface infrastructure made it clear that very limited remaining facilities were available for the planned design. Most of the facilities were either removed or were not suitable for re-use considering the required maximum injection and withdrawal rates and pressures. To support an underground storage project at the target field, a new greenfield gas processing plant will be required based on the existing facilities review. The underground storage surface facility and infrastructure design is driven by the maximum rate of injection and withdrawal required to support the seasonal swing in energy storage. Based on the wells-stock and the reservoir description, wellhead equipment and valves can be reused for the storage facility, which will suffice for planned gas injection

pressure below ~350 bar. To ensure this limit is not exceeded, and to provide an allowance for the main layers of overpressure protection the control, trips and relief, the maximum injection pressure at the tubing head was set at a maximum of 275 bar. For the gas withdrawal from the reservoir, the initial pressure at the wellhead will be 275 bar, with the final pressure a minimum of 40 bar in line with the optimized operating case. Fig. 8 shows conceptual block diagram for the planned gas storage surface facility. For injection mode of operation, after gas filtering, metering will be performed in a custody metering system including pressure and temperature compensation and chromatography to confirm gas quality. Subsequently gas compression up to the required pressure and cooling will be done before sending to manifolds. The manifold will then distribute injection gas via the new flow lines to each of the injection wells. Control of the injection flow rates will be managed at the well sites via the appropriate chokes. For gas withdrawal mode of operation, the plant will produce wet gas from the wells via the flow lines into the production manifold. The gas will be withdrawn initially at a pressure suitable to allow export without compression. Gas withdrawal will be via the wells and their flow lines, with fluids gathered at the main inlet manifold at the new processing facility. The wet gas will then be processed in a gas-liquid separator to remove any bulk water, after which it will be heated, and the pressure further reduced to a suitable pressure for export. To ensure the gas is suitable for transfer into the gas transmission network, once its pressure is reduced, it will be dehydrated using a glycol dehydration unit before it is custody metered and filtered.

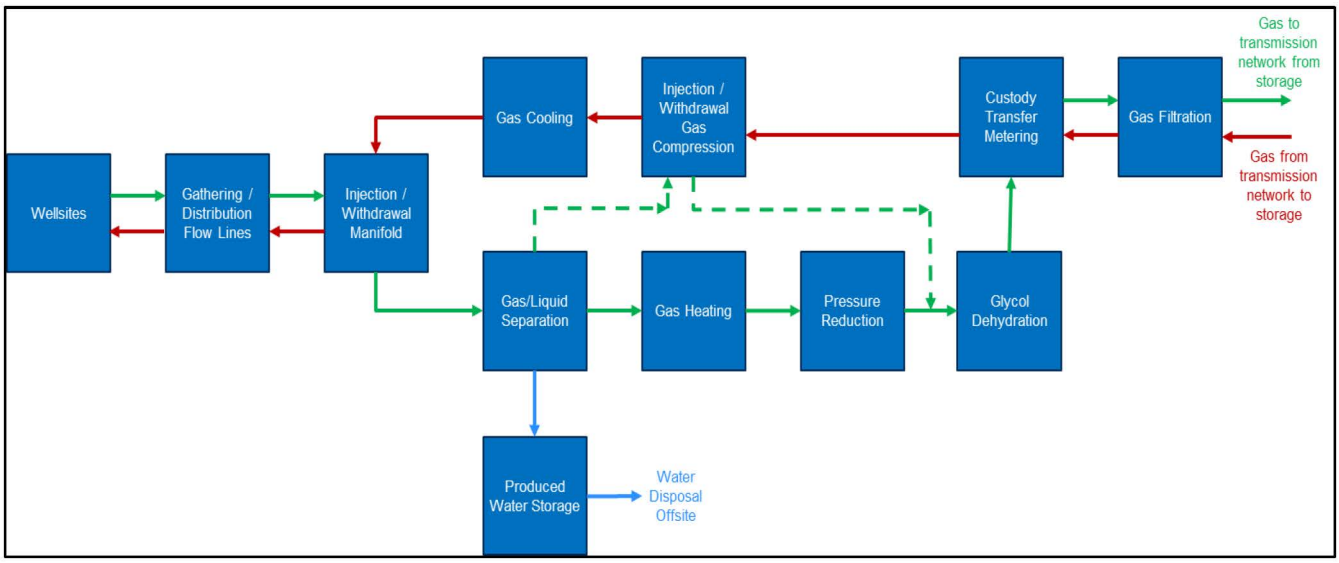


Figure 8—Block Flow Schematic of Surface Facilities

To develop a Class 5 cost estimate for the new UGS development, a combination of in-house data and commercial software was used. The Class 5 estimate has an expected accuracy range of +/-50% and has been developed based on using top-down estimating techniques as its basis. This cost estimate provided a good benchmark for the gas storage feasibility assessment and further refinements were suggested before the final investment decision (FID).

Economic Estimates

The selected reservoir, identified as a potential candidate for UGS, requires a detailed economic analysis to ensure the project's feasibility. The following estimates provide a comprehensive overview of the anticipated costs and investments necessary for the successful implementation of the UGS project. The total capital expenditure for the UGS project is estimated to be approximately $200 million. This estimate encompasses several key components as shown in Fig 9:

- **Surface Facilities:** The construction and installation of UGS-specific surface facilities, including the processing plant and flowlines, are projected to cost approximately 50% of the CAPEX. This includes the necessary infrastructure to handle gas injection and withdrawal operations efficiently.
- **Wellsite Facilities:** The conversion of existing wells to injectors, along with any required workovers, is estimated to cost 12% of the CAPEX. This includes the assessment and upgrading of well integrity to ensure safe and effective gas storage operations.
- **Pipeline Infrastructure:** The development of pipeline infrastructure for gas transportation is estimated at 8% of the CAPEX. This includes the costs associated with laying new pipelines and connecting the storage site to the existing gas network.
- **Contingency:** A 30% contingency has been added to account for uncertainties in development maturity and scope definition. This contingency ensures that any unforeseen costs or project scope changes can be accommodated without jeopardizing the project's financial stability.

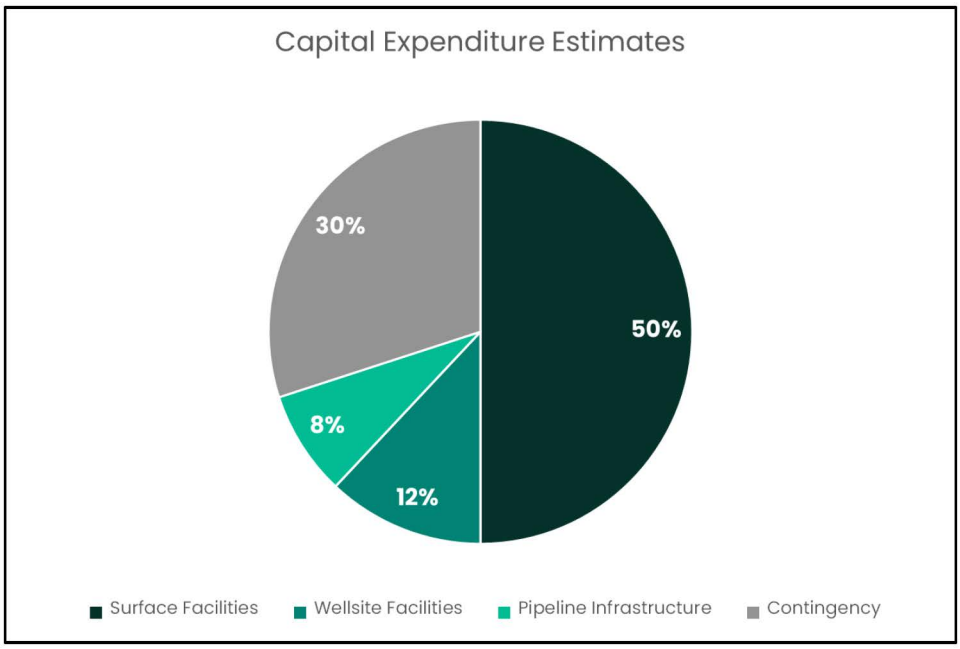


Figure 9—Distribution of the estimated capital expenditure.

Need for a Quick Analytical Technique for Screening

Traditional methods for evaluating UGS suitability, like the detailed workflow described so far in this paper, are often time-consuming and resource-intensive, requiring detailed geological, geophysical, and engineering analyses. While these comprehensive assessments are indispensable for final project approval, there is a pressing need for a quicker, yet reliable, preliminary screening technique. Such a technique would enable stakeholders to rapidly identify promising candidates and focus detailed studies on the most viable options, thereby optimizing resource allocation and reducing the overall project timeline. A quick analytical technique for screening depleted reservoirs for UGS suitability offers several advantages:

- **Efficiency in Decision-Making:** By providing a rapid assessment of reservoir potential, decision-makers can quickly eliminate unsuitable candidates and prioritize those with the highest potential. This accelerates the project initiation phase and ensures that resources are directed towards the most promising reservoirs.
- **Cost-Effectiveness:** Early identification of viable reservoirs reduces the need for extensive and costly detailed studies on multiple candidates. This targeted approach minimizes unnecessary expenditures and allows for more efficient use of financial and technical resources.

- **Risk Mitigation:** Preliminary screening helps in identifying potential risks and challenges at an early stage. By understanding the key factors that influence UGS feasibility, such as reservoir containment, pressure regimes, and well integrity, stakeholders can make informed decisions and develop strategies to mitigate risks before committing to full-scale evaluations.
- **Flexibility and Adaptability:** A quick-look analytical workflow can be adapted and refined based on initial findings, allowing for iterative improvements and customization to specific project requirements. This flexibility ensures that the screening process remains relevant and effective across different reservoir types and geological settings.
- **Strategic Planning:** Rapid screening supports strategic planning by providing a clear overview of potential UGS sites within a region. This enables better coordination with existing infrastructure, regulatory frameworks, and market dynamics, facilitating smoother project development and integration.

Hence, the development and implementation of a quick analytical technique for screening depleted reservoirs is essential for the efficient and effective advancement of UGS projects. By streamlining the initial evaluation process, such a technique not only enhances decision-making and cost management but also contributes to the overall success and sustainability of UGS initiatives.

Application of Material Balance based Analytical Technique for UGS Screening

The material balance approach is a fundamental reservoir engineering tool used to estimate original gas in place (OGIP), predict reservoir performance, and evaluate reservoir drive mechanisms. Its application in the context of UGS screening provides a robust and efficient method for assessing the feasibility of depleted reservoirs for gas storage purposes. Material balance equations are derived from the conservation of mass principle, which states that the total mass of gas in a reservoir must equal the sum of the mass of gas produced, the mass of gas remaining in the reservoir, and any changes in the mass of gas due to pressure and volume changes. This technique involves plotting production data against pressure data to create diagnostic plots that can reveal key reservoir characteristics. The following are the advantages of material balance for UGS screening:

- **Simplicity and Speed:** Material balance calculations are relatively straightforward and can be performed quickly using available production and pressure data. This makes it an ideal preliminary screening tool that can provide rapid insights into reservoir potential without the need for extensive data collection and complex simulations.
- **Basic Data Requirement:** The technique leverages existing production and pressure data, which are typically available for depleted reservoirs. This reduces the need for additional data acquisition and allows for immediate application to candidate reservoirs.
- **Reservoir Characterization:** Material balance analysis helps in understanding reservoir drive mechanisms, such as depletion drive, water drive, or gas cap drive. This information is crucial for evaluating the suitability of a reservoir for gas storage, as it influences gas recovery efficiency and storage capacity.
- **Estimation of Storage Capacity:** By applying material balance equations, engineers can estimate the original gas in place and the remaining gas volumes. This provides a basis for calculating the working gas capacity and cushion gas requirements, which are key parameters for UGS design.
- **Identification of Reservoir Connectivity:** The technique can also help identify hydraulic connectivity within the reservoir and between adjacent structures. This is important for ensuring that the gas storage operation will be contained within the target reservoir and will not migrate to undesired areas.

In addition to providing critical reservoir characterization and volumetric insights in the history matching phase, a history-matched material balance-based model can be a quick and accurate prediction tool to estimate the cushion gas and working gas volumes. This can be done before moving on to the complex and detail-oriented dynamic modeling phase. Since this is a quick analytical technique with minimal data requirements, it can easily be implemented in the initial technical screening phase where the best candidate field is chosen among potential candidates. Implementing this novel approach for screening potential UGS candidates improves the screening process, provides estimates of the gas volumes involved, and facilitates quick estimates of the revenue cycle.

Implementation in Offset Field

The detailed assessment and study of Field A as a UGS candidate indicated that the target working gas capacity could be achieved. However, the project involved a significant capital investment of approximately $200 million. Given the degree of uncertainty involved, specifically with reference to the spill-point linking the target reservoir to a neighbouring structure, and the size of the investment, it was decided to test the feasibility of the UGS on a smaller scale through a pilot project. Field B, which was earlier screened out during the high-level screening process due to its limited storage volumes resulting in lower storage and extraction rates, was considered as a possible candidate for this pilot. To aid this decision and understand the scale of the operation, it was essential to calculate the estimated cushion gas and working gas volumes. Performing a detailed study covering all aspects of UGS planning as done for Field A was not feasible due to the limited time available for the decision. Hence, it was decided to use material balance as a prediction tool to estimate the cushion gas and working gas volumes, evaluate the scale of the operation, and thereby assess whether a detailed study was required to cover all aspects of UGS planning to proceed with the pilot operation.

Field B is characterized by similar reservoir properties as Field A but is significantly smaller. The GIIP in Field B is only 1% of the GIIP for Field A. It was produced through two active wells. A material balance history matching exercise was already performed in the high-level screening phase to understand the dominant reservoir drive mechanism, estimate original gas in place and remaining gas volume, and to identify hydraulic connectivity of the target reservoir with offset fields.

Fig. 10 (a) shows the material balance history match with fluid expansion as the dominant reservoir drive mechanism, without the presence of an aquifer. It can be observed that the simulated reservoir pressure trend matches well with the available pressure history. Additionally, the P/Z function plotted against the cumulative volume follows a straight line, and the corresponding GIIP is within 1% of the expected GIIP. However, the final reservoir pressure from this model did not match the expected reservoir pressure calculated from the shut-in tubing head pressure (SITHP). The simulated pressure was approximately 50% lower than the expected reservoir pressure. This indicated that the additional energy in the system could possibly be a result of the presence of a weak aquifer.

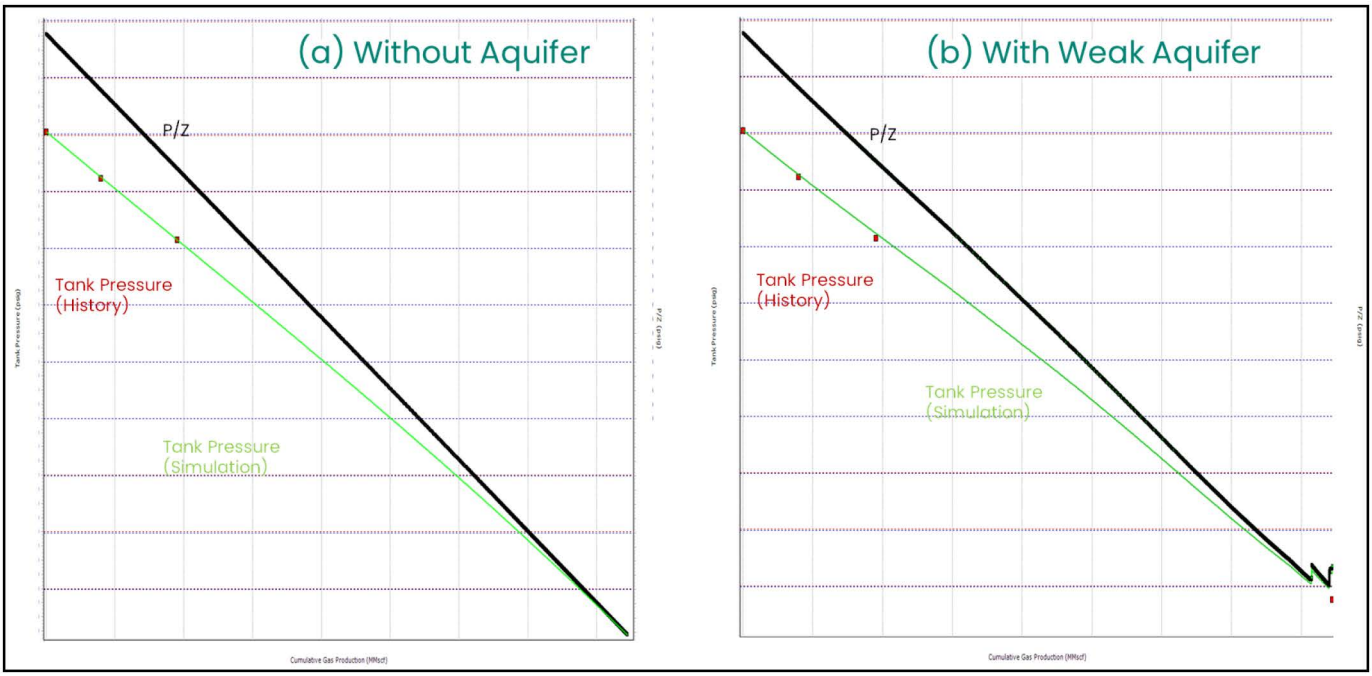


Figure 10—(a) History match using material balance without the presence of an aquifer. (b) History match using material balance with presence of a weak aquifer.

Fig. 10 (b) shows the history match on updating the model with a weak aquifer. The simulated reservoir pressure matches well with the available pressure history, and the final/depleted reservoir pressure is higher than that without the aquifer and is in agreement with the estimated reservoir pressure from the SITHP. Additionally, detailed analysis of the production history of the two wells in this field shows that one of the wells had experienced a gradual increase in water cut with a simultaneous decline in gas production. This confirms the presence of an aquifer in addition to the dominant fluid expansion drive mechanism (Fig. 11). In the case of the model with the weak aquifer, the GIIP still continues to match the expected GIIP within a 1% margin of error as earlier. As the GIIP and simulated pressure and rates adequately match the historical data using a single tank model, it was safe to assume that the reservoir was not influenced or connected to its offset fields as the mass and energy balance in the field is adequately represented by the single tank model. However, the risk of geological connectivity with offset fields needs to be carefully assessed through detailed geological assessment, which would be part of a detailed study to be undertaken based on the results of this quick analytical assessment for volume estimates. The history-matched material balance model with a weak aquifer was used to predict the estimated cushion gas and working gas volumes. The base case (Case 1) was developed under existing conditions with no further actions or investments, utilizing a single well in operation with the existing 3.5-inch tubing. The reservoir pressure was constrained between the maximum injection limit (90% of virgin reservoir pressure) and the minimum bottom hole pressure calculated from the minimum tubing-head pressure required for production. The injection and production cycles were set to 6 months each for simplicity of calculation. However, these cycles can be accurately designed to represent the seasonal nature of injection and production based on the demand for gas and the availability of gas for storage. Since the volumes involved in this case are much smaller compared to Field A, the cushion gas injection was included in the regular injection cycles instead of having a dedicated cycle to recharge the cushion gas before injecting the storage volume. The prediction tenure was set to 10 years.

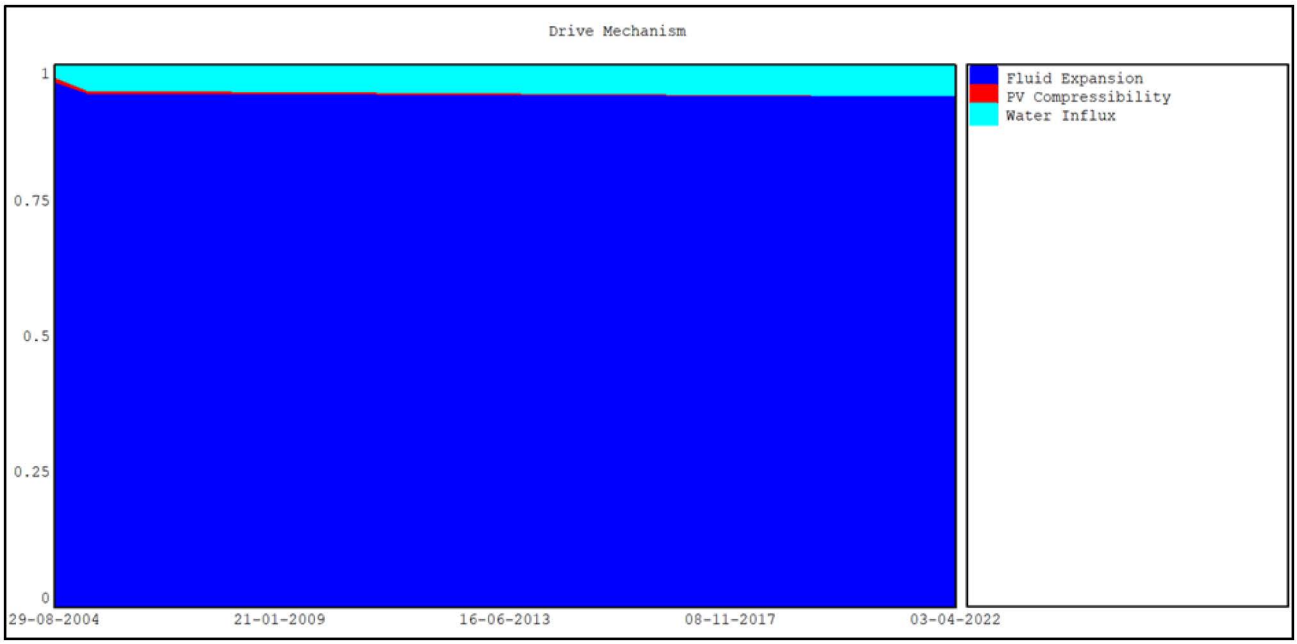


Figure 11—Plot showing the contribution of each reservoir drive mechanism involved in producing from the target formation. Fluid expansion is the dominant drive mechanism with a presence of weak aquifer indicated by the water influx.

Fig. 12 shows the material balance-based prediction results from the base case. The results indicated that approximately 20% of the GIIP volume would be required to be injected as cushion gas. However, the entire cushion gas volume wouldn't be injected in a single 6-month injection cycle given the assumptions and constraints. Therefore, in the base case, it is recommended to inject the cushion gas and working gas volume over the span of the first year and thereafter begin the first production cycle. The base case yields a working gas volume that is 1.5 times the cushion gas volume required for this case. Once the base case was defined, optimized sensitivity scenarios were run to estimate the change in working gas volumes by simulating changes to tubing size and the addition of wells.

Changing the existing 3.5in tubing to a 4.5in tubing was the first sensitivity scenario analyzed (Fig. 12; Case 2). This simple workover alone was observed to improve the injection and production by rates by 40% above the base case results. An infill well, assumed to be identical to the existing well, was added to the model for the next sensitivity (Fig. 13; Case 3). In this case, both existing well and the infill well were assumed to be completed using the existing 3.5in tubing. As expected, this scenario shows that the cushion gas can be filled along with the working volume in a single 6-month injection cycle. However, the injection-extraction cycle stabilizes at a working gas volume twice of the base case. It is evident that adding an infill well substantially improves the throughput and should be considered in case of higher working gas volume requirements. Finally, Case 4 was run to evaluate the effect adding an infill well and change the existing 3.5in tubing to 4.5in in both wells. This case shows a 17% improvement in results in comparison to case 3- and 2.15-times improvement in the working gas capacity. Case 3 and Case 4 are seen to utilize the entire bandwidth of the reservoir pressure between the two constraining values as seen in Fig. 13.

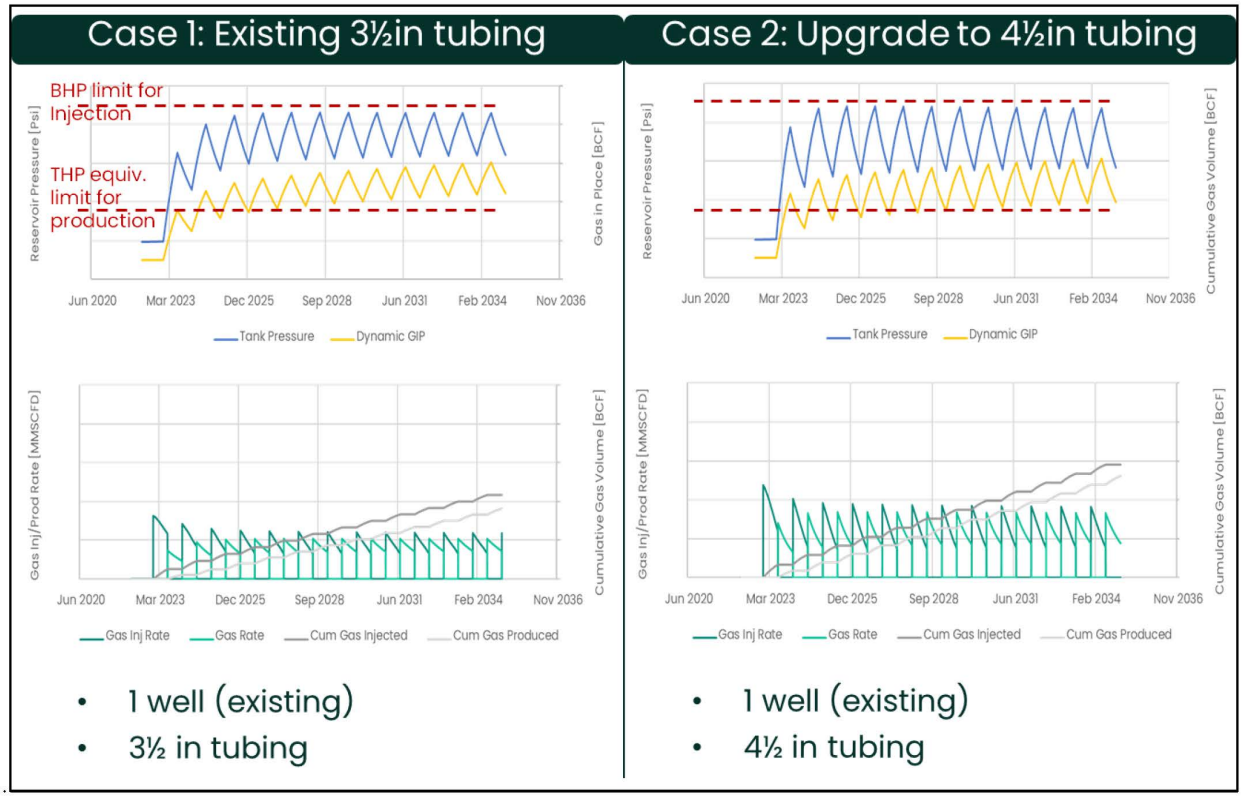


Figure 12—Results from analytical prediction using material balance for the base case (Case 1) and optimized sensitivity scenario including a workover operation to replace the existing 3.5in tubing with a 4.5in tubing.

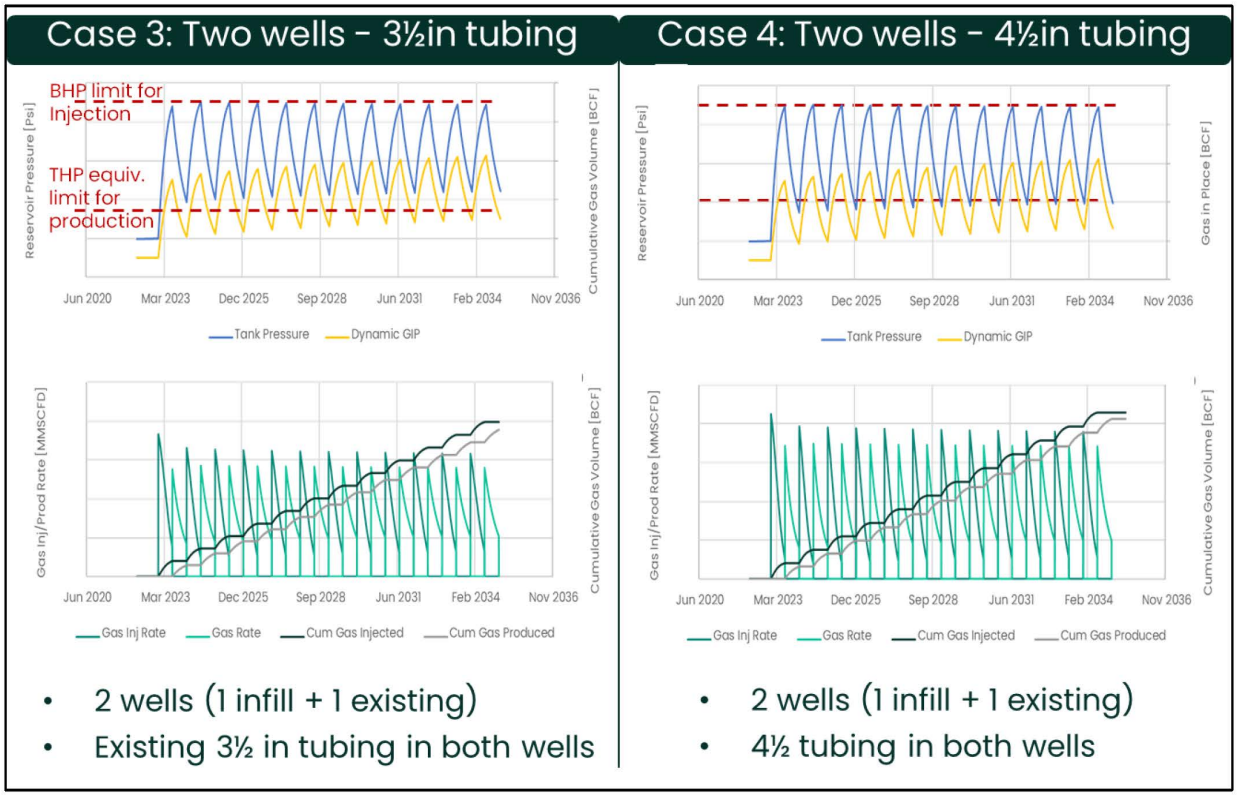


Figure 13—Results from analytical prediction using material balance for optimized cases involved one infill well where both wells are completed with the existing 3.5in tubing (Case 3) and 4.5in tubing (Case4).

Concluions

The study emphasizes the importance of a comprehensive approach to evaluating depleted reservoirs for UGS suitability. The UGS screening workflow developed and utilized in the case history described in this paper demonstrates how UGS operations, which are riddled with complexities, uncertainties, and significant capital investments, can be evaluated and qualified against key risk metrics and technical elements driving the final investment decision (FID).

The analysis of three candidate fields in the case study highlighted the necessity of considering technical factors such as reservoir containment, gas recovery, pressure regimes, well integrity, and contaminants. The successful identification of a suitable reservoir underscores the value of thorough geological investigations and formation pressure data in confirming hydraulic connectivity and caprock seal integrity. Well engineering and completion assessments provided insights into converting existing wells into injectors and identifying necessary upgrades. Corrosion analysis and material selection ensured the long-term integrity and safety of UGS operations, emphasizing the use of RGD-resistant materials and appropriate stainless-steel grades.

The surface facility review revealed that most existing facilities were unsuitable for reuse, necessitating a fit-for-purpose gas processing plant. The design of the surface facility and infrastructure is driven by the maximum rates of injection and withdrawal needed to support seasonal energy storage swings. Key steps include gas filtering, metering, compression, cooling, and distribution for injection, as well as gas-liquid separation, heating, pressure reduction, dehydration, and metering for withdrawal. Economic estimates indicate that the total capital expenditure for the UGS project is approximately $200 million. This includes costs for surface facilities (50% of CAPEX), wellsite facilities (12% of CAPEX), and pipeline infrastructure (8% of CAPEX). A 30% contingency has been added to account for uncertainties, ensuring financial stability.

The assessment of an alternative field B to conduct a pilot UGS operation on a small scale before proceeding with the large-scale, investment-intensive operation in field A led to the formulation of a fit-for-purpose analytical screening technique. The development of this quick analytical technique, based on material balance and production performance prediction, represents a significant value addition to the UGS screening process. This technique offers a streamlined method for assessing the UGS candidacy of similar reservoirs, serving as a precursor to more detailed evaluations. Since the assessment requires minimal data that is easily available for most depleted fields, the technique can be included in the high-level screening process. It serves as a quick and reliable solution to quantify the cushion gas and working gas capacity and aid in evaluating the economic feasibility of the UGS candidate. The successful application of this workflow to a nearby field demonstrates its potential to expedite the screening process and enhance decision-making efficiency.

It should be noted that although the analytical technique can be fairly accurate in predicting the cushion gas and injection/extraction volumes, material balance assumes a tank model and cannot replace the accuracy of results and clarity of insights provided by meticulous geological investigations and dynamic modelling. Hence, it is recommended to use this tool as a high-level screening technique wisely to delineate those candidates that cannot meet the desired volumetric requirement for storage and production. The FID and all related decisions must be based on the findings of a detailed study covering all aspects of UGS as described for field A.

Overall, the study highlights the necessity of integrating multidisciplinary insights and leveraging advanced modelling techniques to ensure the successful implementation of UGS projects. The findings and methodologies presented offer valuable guidance for future UGS projects, contributing to the broader goal of meeting global gas demand and stabilizing gas prices through effective storage solutions.

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