Illinois Compressed Air Energy Storage

Final Report

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Executive Summary

Compressed Air Storage Energy (CAES) is one of the few mid- technology readiness level (TRL) energy storage technologies that can address the long-duration infrastructure needed for dealing with variable electric output from renewable energy sources and be reliable backup source for replacing natural gas during supply interruptions. In CAES the goal is to capture and store compressed air in subsurface sedimentary strata when off-peak power is available, or there is a need for grid balancing. The stored high-pressure air is returned to the surface and used to power turbines during reductions in either renewable energy or supply issues with fossil fuels. The Illinois CAES project evaluates the feasibility of capturing surplus electrical energy from renewable sources and off-peak energy at a fossil fuel power plant at the University of Illinois Urbana - Champaign (UIUC) campus. The UIUC Abbott Power Plant uses natural gas and coal to generate electricity (capacity: 35 MWe by coal and 49 MWe by NG). UIUC receives additional electricity from on campus solar farm, and off-campus wind farm. Also, UIUC offsets electricity usage by integrating geothermal energy systems into building heating Also, UIUC offsets steam, hot and chilled water usage by integrating geothermal energy systems into building heating and cooling systems. Furthermore, the two UIUC solar farms (Solar Farm 1 is 21 acres and Solar Farm 2 is 54 acres) to generate 4.68 megawatts (MW) and 12.1 MW, respectively. Campus receives 8.6% of the wind-generated electricity from the Rail Splitter Wind Farm. The project objectives were to design an integrated system to 1) capture surplus electrical energy from renewable sources and the Abbott Power Plant using a CAES system, 2) store both the compressed air and the thermal heat generated by compression in the subsurface as part of an adiabatic system, 3) simulate the movement of the air and heat in the subsurface, 4) recover the compressed air and stored thermal heat to rotate turbine generators during sustained interruption due to weather events or fossil fuel disruptions.

Project Objectives

Compressed Air Energy Storage (CAES) is one of the few mid-technology readiness level (TRL) energy storage technologies that can address the long-duration infrastructure needed for dealing with variable electric output from renewable energy sources, as a means to keep fossil-fueled electrical systems base loaded when electricity demand is low, and as a reliable backup source for replacing natural gas during supply interruptions. The Illinois CAES project goal is to capture, and store compressed air and part of the heat from compression in subsurface sedimentary strata either when off-peak power is available or there is a need for grid balancing. The DOE Energy Storage Grand Challenge 2020 stated that CAES has been geographically limited to areas with caverns created from subsurface salt deposits. The Illinois CAES project designed a compressed air storage using subsurface porous reservoirs without the need for caverns. The stored high-pressure air is returned to the surface and used to power turbines when additional electricity is needed, and during reductions in either renewable energy or supply issues with fossil fuels. The Illinois CAES project will design surplus electricity generated by renewable sources and off-peak energy at a fossil fuel power plant at the University of Illinois Urbana - Champaign (UIUC) campus The UIUC Abbott Power Plant burns natural gas and coal to generate electricity (capacity: 49 MWe by NG and 35 MWe by coal and). UIUC receives additional electricity from on-campus solar farms, and an off-campus wind farm. Also, UIUC offsets steam, hot and chilled water usage by integrating geothermal energy systems into building heating and cooling systems. Furthermore, the two UIUC solar farms (Solar Farm 1 is 21 acres and Solar Farm 2 is 54 acres) to generate 4.68 megawatts (MW) and 12.1 MW, respectively. Also, the UIUC campus receives 8.6% of the wind-generated electricity from the Rail Splitter Wind Farm that the University owns.

The Illinois CAES project objectives were to design an integrated energy storage system to 1) capture surplus electrical energy from the fossil-fueled Abbott Power Plant and the renewable sources using a CAES system, 2) store both the compressed air and the thermal heat generated by compression in the subsurface as part of an adiabatic system), 3) recover the compressed air and stored thermal heat to rotate turbine generators when additional electricity is needed during sustained interruption due to weather events or fossil fuel disruptions. This project simulated the movement of air and heat in the subsurface.

Project Results

Technology Maturation Plan

The Technology Maturation Plan (Appendix 1 Part 1) details the improvement on technology readiness level (TRL) the resulted from this project. The Illinois CAES project simulated injection of compressed air into a clastic geologic formation (the Cambrian Mt. Simon Sandstone) without the need for salt caverns or geologic structures. The high-pressure, stored air will be returned to the surface and used to power turbines when additional electricity is needed, and during reductions in either renewable energy or supply issues with fossil fuels or fossil fuel energy generation.

Instead of using a cavern or anticline we studied the injection of compressed air into subsurface porous strata that is structurally flat. This should significantly increase are areas that can be used for air storage. However, CAES in flat lying subsurface porous reservoirs has never been attempted. Appendix part 2 shows the current TRL of the surface infrastructure to be 9. Our research suggested that the overall project TRL will remain at 5 because there is considerable uncertainty on subsurface air compression as a storage option without a field text.

At this point we would need to complete a demonstration test of the actual system prototype within the Abbott Power Plant system. This would include drilling a well into the Mt. Simon Sandstone and testing compression, heat storage capacity, and deliverability that would then be used to fine tune the infrastructure needs of a CAES system.

The post project plan at the next stage is to have two budget periods. The first budget period is to drill a well, get accurate permeability and porosity values, and attach compressors to pressure the Mt. Simon Sandstone reservoir. We would then monitor the pressure declines after injection. This would help us to refine the surface infrastructure. We would also attain core from the upper Mt. Simon to measure the thermal storage capacity of the sandstone to hold the heat from compression. At the end of the field test of the CAES system integrated with the power plant, the TRL of our proposed CAES system will be increased to 7.

Conceptual Study

Appendix 2 discusses the subsurface geology and reservoir flow simulations of compressed air under reservoir conditions. The surface infrastructure will be discussed in the Technoeconomic study (Appendix 3). Reservoir simulations were performed to assess the compressed air cycling performance of the Upper Mt Simon. A single injection/production well is assumed. This project requires a working gas volume of 1.57 MMscf, which is cycled in and out of the reservoir on a daily basis. Compressed air is injected at a rate of 2.09 MMscf/d for 18 hours, and then compressed air is produced at a rate of 6.28 MMscf/d for 6 hours. The cycle repeats daily.

Due to the relatively flat structure of the Mt Simon at UIUC, water coning during the production cycle is observed. Optimal vertical and horizontal wells were identified to minimize water production during cycling operations. The optimal vertical well has a perforation length of 6 ft, starting at the top of the Upper Mt Simon. The optimal horizontal well is located 4.5 ft below the top of Upper Mt Simon and has a perforation length of 100 ft. The simulation show that a horizontal well is more effective at reducing water production during compressed air cycling in the Upper Mt Simon at UIUC.

In gas storage projects, there are three volumes of gas that can be defined: fill gas (or total gas), working gas and cushion gas. Fill gas is the volume of gas injected into the storage reservoir before the first production cycle commences. Working gas is the gas volume that is cycled in and out of the reservoir during each fill/drain cycle. Cushion gas is gas that is permanently stored in the storage reservoir. Cushion gas is the difference between fill gas and working gas. Cushion gas helps to maintain deliverability and wellhead pressure during the drain cycle. For gas storage in aquifers, cushion gas also helps to push water away from the well to reduce water production during the drain cycle.

The simulation model was used to understand the impact of cushion gas on compressed air cycling performance of the Upper Mt Simon. A cushion gas volume of 90% of total gas was used to assess the performance of vertical and horizontal wells. Cushion gas has a significant impact on water production during compressed air cycling. Water production decreases as cushion gas increases.

Technoeconomic Study

The Technoeconomic Study (Appendix 3) discusses a proposed prototype process for Compressed Air Energy Storage (CAES) for the Abbott Power Plant. The TES covers process simulation, simulation results, estimated cost of electricity, and a comparison of the prototype facility with the existing Huntorf and McIntosh CAES plants and (where possible) the proposed commercial-scale CAES plant in Iceland. The purpose of the proposed prototype plant is to test how the storage component performs. The goal of the proposed prototype test is to demonstrate how well a CAES plant can operate when using a porous sandstone formation for compressed air storage. The two existing industrial scale CAES plants use salt caverns for compressed air storage. Demonstrating that CAES plants can successfully operate using porous stone formation storage will represent a substantial increase in the number of geographical regions where CAES plants can be implemented.

Surface equipment including compressors and turbines are not a primary focus of the study, therefore attempts to obtain optimum energy efficiency of surface equipment are beyond the scope of the present study. An effort has been made to minimize capital cost of the surface equipment for the prototype system due to the short-term, research nature of the project as compared to a commercial CAES application.

A comparison of the McIntosh plant tin Alabama with the proposed Abbot plant shows the normalized cost of power ($/kW) is much higher at the smaller scale. This is because the equipment power does not scale linearly with cost. This leads to a higher cost of electricity in $/kWh.

Gap Analysis

Appendix 4 Part 1 and 2 discusses the significant gap in our understanding the subsurface reservoirs. For example, geochemical reactions of injected air into subsurface sediments have been identified as a potential problem. For example, a CAES test facility injected air into St. Peter Sandstone at Pittsfield field in Pike County, Illinois and encountered problems. We currently have not completed adequate research on the reaction of the reservoir to short cycle times of injection and withdrawal of the compressed air. In natural gas storage, the cycling is annual and in CO_2 storage the injection is in one direction with no production of the CO_2. In the CAES reservoirs there is daily cycling of the air with corresponding changes in reservoir temperature and pressure. The geologic formations storing and overlying compressed air must remain hydraulically, mechanically, and seismically stable over decades of use. In addition, the subsurface storage of the heat generated has not been investigated at this point in time.

There are issues that relate to health and safety during compressed air energy storage. Cyclic changes in pressure and/or temperature could cause instability within the caprock. Reservoir heterogeneity may become critical in how much or how fast the air is moving through the reservoir. The response to the wellbore in cementation materials with this constant change in pressures and with the extraction of air during the expansion stage needs to be characterized. The limitations of the compression and turbine generators in the CAES application must be determined. It is going to be critical to understand the wellbore stability with frequent changes occurring including thermal expansion and dissolution of the cement because of the oxygen component of the compressed air and other chemical reactions. This could become a significant problem because it could eliminate the air coming to the surface instead increase the production of brine.

The largest technical risk associated with this project will be the storage component. There are still a lot of unknowns about how it will perform, both in terms of retaining pressure and heat. The McIntosh plant has air leaving the storage formation at 200F, while the predicted temperature of the air for the Abbott plant is 80F.

In terms of surface facility equipment, the turbines are the biggest risk. Not a lot of air turbines for this low amount of power exist. This project will require a microturbine with modifications made to the impellers.

Another risk of building a plant this scale, is that neither the turbines nor the compressors will be the same as a large-scale plant. The compressors for this plant will be reciprocating compressors, but large plants require centrifugal compressors to accommodate the higher air flow. Large plants also use existing gas turbines with only the expander portion being used, while this plant will use specific micro turbines.

There are key technology gaps in air turbines for this small of a cycle. R&D will need to be done for a CAES cycle of less than 2 MW, and with the cost of turbines and compressors not completely scaling based on power, building a 2 MW plant will result in a high cost in $/kWh.

Commercialization

The ISGS CAES project commercialization plan (appendix 5) demonstrates the use of porous rock for compressed air storage but will not create new types of applications for the CAES process nor alter the economics of the CAES process itself. Examples of applications for the CAES process can be found in the literature. Documented applications for CAES include:

- *Peak shaving / arbitrage***.** The business objective of peak shaving is to produce and store off-peak energy that can be used to meet on-peak demand. Peak shaving is focused on avoiding the need to generate the full on-peak demand during on-peak hours, instead meeting some of the on-peak demand by extracting previously stored energy. Making use of a peak shaving strategy can defer or even avoid expansion and load-levelling projects in transmission and distribution (T&D) systems. A closely related concept is arbitrage, which uses price hedging to generate profits from the "buy low / sell high" philosophy. Electricity can be purchased from the grid when it is less expensive (off-peak), then sold back to the grid when it is more expensive (on-peak). One of the key advantages of CAES plants over other energy storage technologies is that they have the storage capacity, flexibility and responsiveness needed to profit from an arbitrage operating strategy.
- *Energy imbalance / distributed generation.* In a system with distributed generation, local peak demand can exceed local instantaneous generation capacity. The use of CAES allows the storage of excess energy which can be extracted during demand peaks. This allows generation units to operate continuously at full power and accommodate higher demand peaks than would be possible without energy storage.

To generate market scenarios for a specific candidate CAES project, an economic model must be created. Input variables of the model (uptime, fuel cost, etc.) should be studied systematically to understand statistical economic risks for each project.

A unique benefit of a CAES plant is that it can serve as a synchronous condenser for the grid when not operating in storage or extraction modes. Other forms of energy storage, such as battery systems, do not provide this benefit to the grid. A synchronous condenser, also called a "spinning machine", is essentially a motor / generator connected to the grid where the shaft is allowed to freewheel without a load. Power companies sometimes install synchronous condensers as an alternative to capacitor banks to improve the electric power system's performance by storing kinetic energy in the rotor.

Benefits of the Project

Compressed Air Energy Storage (CAES) is one of the few mid-TRL energy storage technologies that can address the long-duration infrastructure needed for dealing with variable electric output from renewable energy sources, as a means to keep fossil-fueled electrical systems base loaded when electricity demand is low, and as a reliable backup source for replacing natural gas during supply interruptions. In CAES the goal is to capture and store compressed air in subsurface sedimentary strata when off-peak power is available or there is a need for grid balancing. The DOE Energy Storage Grand Challenge 2020 stated that CAES has been geographically limited to areas with caverns created from subsurface salt deposits. The Illinois CAES project will be evaluating using subsurface porous reservoirs without the need for caverns.

Natural gas (and to a lesser extent coal) may also be susceptible to supply issues. Early in the life of the natural gas industry it was recognized that individual natural gas wells can only produce at a certain rate, and the output from these wells could not be manipulated to supply the energy need for peak usage in cold winter diurnal and weekly demand for natural gas. For electricity generation, the need for natural gas would be high in the summer but would not be competing with individual homes. Most of the Midwestern United States does not have access to large natural gas fields and must use long-distance pipelines to transport the gas to consumers. However, these long-distance pipelines do not have the capability of transporting the gas in the volumes necessary to meet the needs during these peak usage events. Approximately 70 years ago, the utility industry began developing underground natural gas storage reservoirs (UNGS) located near major municipalities in order to meet these peak usage demands. With the increased rise of natural gas electricity generation, the utilities could lose both the capability of heating homes and generating electricity. New power plants will most likely use natural gas instead of coal because burning natural gas has almost a 50% reduction in carbon emissions compared to coal per Btu content.

The DOE Energy Storage Grand Challenge 2020 stated that CAES has been geographically limited to areas with caverns created from subsurface salt deposits. The Illinois CAES project will be evaluating using subsurface porous reservoirs without the need for caverns. The stored high-pressure air is returned to the surface and used to rotate turbines during reductions in energy or supply issues with fossil fuels. The CAES project will evaluate the feasibility capturing surplus electrical energy from renewable sources and at a university-owned fossil fuel power plant at the University of Illinois Urbana - Champaign (UIUC) campus. The project objectives are to design an integrated system to 1) capture surplus electrical energy from renewable sources and the Abbott Power Plant using a CAES system, 2) store both the compressed air and the thermal heat generated by compression will be stored in the subsurface as part of and adiabatic system, 3) simulate the movement of the air and heat in the subsurface, 4) recover the compressed air and stored thermal heat to rotate turbine generators during sustained interruption due to weather events or fossil fuel disruptions.

Summary

There has been significant research on the use of CAES applications, including two operational power plants, which use salt caverns to store the compressed air. Caverns have some unique advantages that include a known volume of air, easy retrieval of the air, and dry air with little moisture. However, there are significant limitations: 1) areas with thick salt deposits are limited geographically, 2) the creation of salt caverns is expensive, 3) the amount of compressed air storage capacity in caverns is limited, thereby restricting the duration of recoverable energy, and 4) salt is mobile, so compressed air and overlying sediments would cause the salt to flow and change the cavern volume.

Instead of using a cavern, our proposal would inject compressed air into subsurface porous strata. This should significantly increase the volume of potential storage and the duration of recovered energy. However, CAES in subsurface porous reservoirs has never been attempted. In addition, the speed of compressed air migration in the subsurface and the volume of formation water it would displace are unknown. Rapid migration of the compressed air would require an anticlinal structure to contain the gas. However, our research of a reservoir simulation of compressed air in the Cambrian Mt. Simon Sandstone in Illinois suggests that (with low regional dip) the compressed air will not travel very far from the injection well in a 30-year period.

Our research suggests that Compressed Air Energy Storage is feasible in Illinois but there must be a well drilled that we can use to test the interval in question. We need a demonstration project that can test the migration of air and its chemical reactions with the subsurface strata. The surface infrastructure is already at a TRL of 9 and would be integrated into the program at the subsurface testing. The project needs a field test before the validity of Compressed Air Energy Storage can be verified.

APPENDIX 1

Technology Maturation Plan (TMP) Part 1

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A. TECHNOLOGY READINESS LEVEL

Compressed Air Energy Storage (CAES) is one of the few mid- technology readiness level (TRL) energy storage technologies that can address the long-duration storage infrastructure needed for dealing with variable electric output from renewable energy sources and be a reliable backup energy source for replacing natural gas during supply interruptions. The current TRL of our proposed project is 5 because the only two CAES projects occur in salt caverns. The goal of the Illinois CAES is to compress and store high-pressure air in subsurface sedimentary strata when off-peak power is available, or there is a need for grid balancing. In addition, our Illinois project is planning to use the heat of compression to create a high temperature geothermal system that should significantly increase the efficiency of the system. In the Illinois CAES project the high-pressure stored air is returned to the surface and used to power turbines during reductions in renewable energy output (wind and solar) and supply issues with fossil fuels or fossil fuel energy generation.

Our project meets the objectives of the AOI. The Abbott Power Plant is already a case study of system integration of different energy sources to increase energy reliability due to the variability of renewable energy. CAES surface infrastructure needs such as compressors and gas turbines are mature technologies with a TRS of 9. The Illinois CAES project evaluated and designed a compressed air system that includes storing not only compressed air but the thermal energy from compression into the subsurface flat lying sedimentary layers. Illinois CAES is a case study of increasing the reliability of energy because of supply disruptions due to weather and natural disasters such has happened in Texas and United Kingdom in 2021. Our project could also increase revenue by providing energy when the price is most valuable during peak energy needs.

The use of storage in porous subsurface reservoirs has not been attempted and there are no projects investigating the utilization of subsurface reservoirs to store compressional thermal energy by creating a high-temperature geothermal resource in addition to compressional potential energy from the pressure of compressed air. Therefore, the pre-project TRL is 5 because it has not yet been implemented.

Renewable energy sources such as solar and wind are known as variable because they are dependent on the weather and need backup power supply to meet the needs of the community. Natural gas (and to a lesser extent coal) may also be susceptible to supply issues to generate electrical power. Early in the life of the natural gas industry it was recognized that gas production from individual natural gas wells could not be increased to meet peak demand for gas in cold winter seasons. Most of the Midwestern United States do not have access to large natural gas fields and must use interstate pipelines to transport the gas to consumers. However, these long-distance pipelines do not have the capability of transporting the gas in the volumes necessary to meet the needs during these peak usage events. Approximately 70 years ago, the utility industry began developing underground natural gas storage (UNGS) reservoirs located near major municipalities in order to meet these peak usage demands. With the increased rise of natural gas electricity generation, the utilities could lose both the capability of heating homes and generating electricity. There is a risk for transportation of natural gas in severe weather events. For example, in the winter of 2021 there were natural gas supply issues because of severe cold weather in Texas. CAES could have helped alleviate these supply problems by producing compressed air and generating electricity when natural gas was unavailable. New power plants will most likely use natural gas instead of coal because burning natural gas has almost 50% lower carbon emissions compared to coal per Btu content (U.S. Department of Energy Office of Fossil Energy, 2016). However, the dynamics of electricity generation may be changing. For example, Governor Pritzker of Illinois has proposed phasing out natural gas power plants by 2045 and coal fired power plants by 2035 (Hawthorne, 2021) and transition to renewables only.

The commercial applications are numerous. We have designed a prototype system that would be operational soon. The present CAES systems are limited geographically to specific areas with underlying large salt deposits where caverns can be created by dissolution. Our proposed technological advances will enable CAES systems to be implemented in any area underlain by porous rock formations with a seal above the reservoir. We may also significantly reduce the cost of the heating component of CAES by storing thermal energy from compression underground, creating a high-thermal energy storage system (HTES) in conjunction with CAES. The proposed CAES system could be implemented throughout large areas of the country with underlying sedimentary rock and suitable caprock formations.

B. Project WORK

Relate the proposed project work to the maturation of the proposed technology.

The surface infrastructure component of the proposed CAES project are already in use over a large variety of different energy projects and would have a TRL of nine. However, the application of Compressed Air Energy Storage with a high temperature geothermal component in a subsurface reservoir has never been attempted and has a current TRL of 5 or 6.

A significant challenge and limitation with Compressed Air Energy Storage (CAES) is that it is currently geographically limited to areas with subsurface salt deposits in which caverns are created by salt dissolution processes. (DOE, 2020)

There are two operational power plants using CAES, both of which use salt caverns to store the compressed air. Caverns have some unique advantages that include a known volume of stored air, easy withdrawal of the air via simple gas expansion, and dry air with little moisture. However, there are significant limitations: 1) areas with thick salt deposits are limited geographically, 2) the creation of salt caverns is expensive, 3) the amount of compressed air storage capacity in caverns is limited, thereby restricting the duration of generating recoverable energy, 4) salt caverns have an upper temperature limit for storing the compressed air by the temperature of the compressed air, and 5) salt is mobile, so compressed air and overlying sediments could cause the salt to flow and change the cavern volume. In addition, the number of salt domes is finite and in competition with other storage needs such as hydrogen and petroleum.

Many of the challenges in CAES are related to understanding the subsurface geology and fluid dynamics of the compressed air during injection and withdrawal. However, the design of surface infrastructure is also going to be challenging. The air compression and storage system must be able to not only compress the gas, but also store the heat of compression and include this thermal heat with the injected air. The compression equipment becomes less efficient with higher temperature and will increase the power costs. Air will expand and cool during the retrieval phase. The compressed air will have some water vapor and brine that has to be removed before passing through the turbines, which will require energy. The brine removal infrastructure will increase the cost, especially in the early phase of the project's operation.

A significant gap in the application of CAES is estimating the energy losses that are going to occur during compression, injection, expansion, and generation of electricity. Dissipation of heat following air compression is an important factor in CAES energy capture efficiency. The loss of heat limits the efficiency of CAES to 50% whereas recovering the heat using adiabatic recovery mechanisms could increase it to about 80%. Solutions include the use of molten salt to capture the heat of compression and utilize it during the power generation cycle, but this significantly limits the amount of thermal storage because of the finite heat capacity of the energy storage system and also increases system cost. One of the gaps is finding a way to combine compressed air and thermal energy storage in the same reservoir. This means that we need to determine the thermal capacity of the formation and to estimate the temperatures from compression and the heat loss from expansion during retrieval of the injected air.

Geochemical reactions of injected air into subsurface sediments have been identified as a potential problem. For example, a CAES test facility injected air into St. Peter Sandstone at Pittsfield field in Pike County Illinois and encountered problems. This CAES test began in 1982 and lasted almost 6 months with a goal of demonstrating the feasibility of CAES and understanding the continuous cycle of injection and retrieval of the air (Allen et al., 1985). The study found that the oxygen in the injected air had a chemical reaction with pyrite in the formation and this reduced the St. Peter reservoir porosity and permeability. However, the Pittsfield CAES study conclusion was that CAES is a viable method of storing both heat of compression and air in the subsurface.

One of the significant problems of using compressed air in saline reservoirs is the added cost of handling of brine produced when air is withdrawn, brine coning into air withdrawal wells, and the reduction of air withdrawal rates because of brine production. We evaluated the volume of brine that will be produced with compressed air to learn peak air withdrawal rate and estimate the number of withdrawal wells that might be necessary to meet a target air withdrawal rate.

We currently have not completed adequate research on the reaction of the reservoir to short cycle times of injection and withdrawal of the compressed air. In natural gas storage, the cycling is annual and in CO_2 storage the injection is in one direction with no production of the CO_2. In the CAES reservoirs there may be daily cycling of the air with corresponding changes in reservoir temperature and pressure. The geologic formations storing and overlying compressed air must remain hydraulically, mechanically, and seismically stable over decades of use. In addition, the subsurface storage of the heat generated from air compression has not been investigated now.

The Illinois CAES project evaluated the use clastic geologic formations on regional dip without the need for salt caverns or geologic structures. The high-pressure, stored air will be returned to the surface and used to power turbines when additional electricity is needed, and during reductions in either renewable energy or supply issues with fossil fuels or fossil fuel energy generation.

Instead of using a cavern, our proposal injects compressed air into subsurface porous strata. This should significantly increase the volume of air storage and therefore the duration of recovered energy generation. However, CAES in subsurface porous reservoirs has never been attempted. In addition, the extent of compressed air migration in the subsurface and the volume of formation water it would displace are unknown. Rapid migration of the compressed air would require an anticlinal structure to contain the gas. Reservoir simulation of compressed air in the Cambrian Mt. Simon Sandstone in Illinois suggests that (with low regional dip), the compressed air will not travel very far from the injection well in a 30-year period (i.e. outside of geologic structures).

Reservoir fluid simulation of subsurface strata in Illinois indicate that CAES in flat lying strata would be feasible. The simulation of CAES suggested that greater reservoir depths would lead to higher hydrostatic pressures and improve the recovery but will increase the compression costs. Their simulations also suggest that in homogenous reservoirs water coning (and subsequent water production) could be a problem as the rate of compressed air production increases. Reservoirs with lateral heterogeneity and with extensive vertical baffles may reduce the water coning problems. Using the Mt Simon Sandstone, we modeled the surface infrastructure and reservoir fluid migration in the subsurface. The Manlove Gas Storage Field is approximately 30 miles to the northeast of the University of Illinois campus and stores natural gas in the Mt. Simon. Reservoir characterization of the Mt. Simon at Manlove shows extensive baffles that would reduce the problem of water coning.

We evaluated capturing the heat of compression and storing it within the Mt Simon Sandstone during the injection phase. This combination of CAES with a high-thermal energy storage system (HTES) has the potential of significantly increasing the energy efficiency of air storage. The goal is to heat reservoir rocks above 100 ℃ to create a geothermal system in conjunction with compressed air. Initial analysis of the subsurface reservoirs in the project area, which is a few miles south of the University of Illinois Campus, suggest that, because of expected hydrostatic pressure, we could store the heat generated from compression up to 175 ℃ without formation water becoming steam. Nearby well data indicate that the Mt. Simon reservoir is already 49°C.CAES using salt caverns, gas storage in subsurface sandstone and carbonate reservoirs (such as natural gas projects for almost a century), and geothermal energy retrieval are all proven technologies. However, the integration of CAES and geothermal energy in flat lying sedimentary strata within a fossil power generation plant has not been done. In our proposed study we will evaluate the feasibility of injecting air in subsurface reservoirs without anticlines constraining the migration of the air, using the University of Illinois power system for powering air compression when load demand is low.

The Illinois CAES project will evaluate the feasibility of capturing surplus electrical energy from renewable sources and off-peak energy at a fossil fuel power plant at the University of Illinois Urbana - Champaign (UIUC) campus. The UIUC Abbott Power Plant uses natural gas and coal to generate electricity (capacity: 35 MWe by coal and 49 MWe by NG). UIUC receives additional electricity from an on-campus solar farm, and an off-campus wind farm. Also, UIUC offsets electricity usage by integrating geothermal energy systems into building heating. Furthermore, UIUC just completed a second 54- acre, 12.1 megawatt (MW) solar farm in addition to its current 21-acre, 4.68 MW solar farm. The UIUC campus receives 8.6% of the wind-generated electricity from the Rail Splitter Wind Farm. The Illinois CAES will include additional compressed air storage from the windfarm and usage of compressed air when wind energy is unavailable.

There are issues that relate to health and safety during compressed air energy storage. Cyclic changes in pressure and/or temperature could cause instability within the caprock. Reservoir heterogeneity may become critical in how much or how fast the air is moving through the reservoir. The response to the wellbore in cementation materials with this constant change in pressures and with the extraction of air during the expansion stage needs to be characterized. The limitations of the compression and turbine generators in the CAES application must be determined. It is going to be critical to understand the wellbore stability with frequent changes occurring including thermal expansion and dissolution of the cement because of the oxygen component of the compressed air and other chemical reactions. This could become a significant problem because it could eliminate the air coming to the surface instead increase the production of brine.

The project objectives have been organized into a logical progression of work that involves creating an integrated system to 1) design the best method to capture surplus electrical energy from renewable sources and the Abbott Power Plant using a CAES system, 2) design the well and equipment for injection of the compressed air and the thermal heat generated by compression as part of an adiabatic system, 3) simulate the movement of the air and heat in the subsurface, 4) evaluate the best method to maximize energy recovery from the compressed air and stored thermal heat to drive turbine generators during sustained shortages of other power sources due to weather events or fossil fuel disruptions.

The research evaluated how much of the injected air will remain in the formation during the recovery period. PNNL suggested that 59% of the injected air would remain in the reservoir and not be recoverable. There could also be technical issues with mitigating corrosion of the turbines during extraction of gas and formation water. This is a known issue in geothermal energy projects. Dehydration of the air may be required before it is fed to the turbine generators.

Expected Technology Readiness Level at end of project

CAES has only been used in two projects within salt caverns to store the compressed air. Site issues have limited the implementation even though compressors and gas turbines are mature technologies. Many of the individual components of the proposed project have a mid or mature TRL; however, an integrated CAES system has not been successfully demonstrated. The use of storage in porous subsurface reservoirs has not been attempted and there are no projects investigating the utilization of subsurface reservoirs to store compressional thermal energy by creating a high-temperature geothermal resource in addition to compressional potential energy from the pressure of compressed air. Therefore, the pre-project TRL is 5 because only two cavern storages CAES systems have been implemented.

At the end of the project, the TRL of the project will remain at 5 but the technical challenges associated with the subsurface geology and fluid dynamics of the compressed air during the cycle of injection and withdrawal, storage of the heat of compression in addition to compressional energy, design of surface infrastructure, and brine removal and treatment will be better understood and addressed. At this point we would need to complete a demonstration test of the actual system prototype within the Abbott Power Plant system. This would include drilling a well into the Mt. Simon Sandstone and testing compression, heat storage capacity, and deliverability that would then be used to fine tune the infrastructure needs of a CAES system.

C. POST-PROJECT PLANS

The plan at the next stage is to have two budget periods. The first budget period is to drill a well, get accurate permeability and porosity values, and attach compressors to pressure the Mt. Simon Sandstone reservoir. We would then monitor the pressure declines after injection. This would us to refine the surface infrastructure. We would also attain core from the upper Mt. Simon to measure the thermal storage capacity of the sandstone to hold the heat from compression. At the end of the field test of the CAES system integrated with the power plant, the TRL of our proposed CAES system will be increased to 7

Appendix 1 Part 2
TECHNOLOGY MATURATION PLAN (TMP)

by

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1. Introduction

This section contains a Technology Maturation Plan (TMP) that will focus on the critical Compressed Air Energy Storage technologies for the Illinois CAES project. This project aims to incorporate relatively established surface equipment for air compression, heating, and expansion with compressed, elevated temperature air storage in subsurface porous sandstone formations that have not been commercially used for this purpose. The TMP addresses the following topics:

- Key Technology Addressed
- Objective
- Current State of the Art
- Technology Development Approach
- Scope
- Schedule
- Budget

Since this project is at the most initial, conceptual phase, these items will necessarily be addressed at a very high level using general industry experience as a guide and reference.

2. Current Technology Readiness Level

The surface facility equipment for CAES is an early TRL9. During this work, two commercial plants in operation were identified as well as third planned in Iceland. Information on the two operational plants and a comparison to the proposed Abbott prototype plant is provided in the Technoeconomic Study Memo.

The subsurface storage component of the Illinois CAES concept is at TRL2. During this work, no CAES plants with this compressed air storage in porous subsurface formations were identified and research on the topic as part of this project does not yet include the analytical studies and laboratory-scale studies to physically validate the analytical predictions that are required for TRL3.

3. Key Technology Addressed

The work proposed for a Phase II Illinois CAES project would be one of the next steps needed to further advance the TRL of this concept. In Phase II, a Pre-FEED study would be performed with the help of an EPC engineering firm to further define the surface facility and injection/production well requirements for the proposed prototype scale facilities needed to experimentally test the subsurface storage aspects of the project as well as their integration with the Abbott Power Plant host site.

4. Current State of the Art

During this project, two Original Equipment Manufacturer (OEM) companies, Siemens Energy, who manufactured and designed the equipment for the McIntosh plant, and MAN Energy Solutions, who offers commercial solutions for CAES, were identified as having developed commercial-scale CAES surface facilities. As described further in the TES memo, these plants are on the 100+ MW scale. However, compressed air storage in these facilities is in salt caverns. These facilities have efficiency values on the order of 55%. The same efficiency may not be possible in a prototype-scale facility, but the goal of the prototype is to test and advance the subsurface component of the Illinois CAES concept while maximizing reliability and minimizing cost for the surface facilities.

Current state of the art technology in a flow diagram can be seen in the figure below.

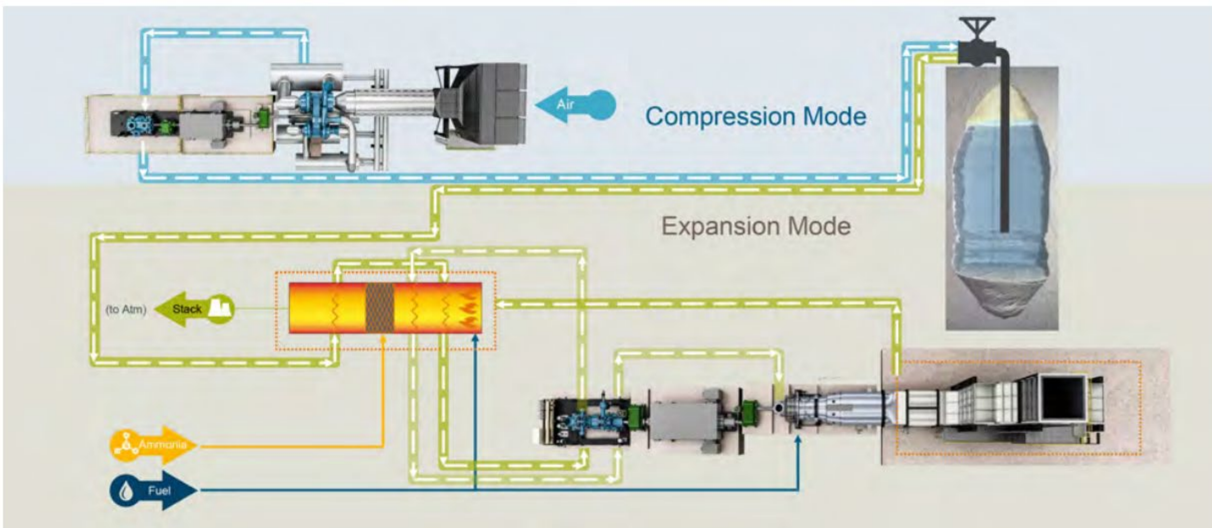

Figure 1: CAES Flow Diagram (Siemens)

5. Technology Development Approach

Some significant engineering effort will be needed to develop an air turbine at the proposed prototype scale. Different OEMs involved in CAES have different approaches to the expansion train. Siemens Energy uses two high pressure steam turbines to expand the high pressure air and to produce power before using combustion and direct heat at low pressures for the final stage of expansion. However, MAN energy uses turbines modified like turbo charger expanders. They're made for exhaust gasses, so direct heat is used before each stage of expansion.

The gas turbines used by Siemens can be seen below.

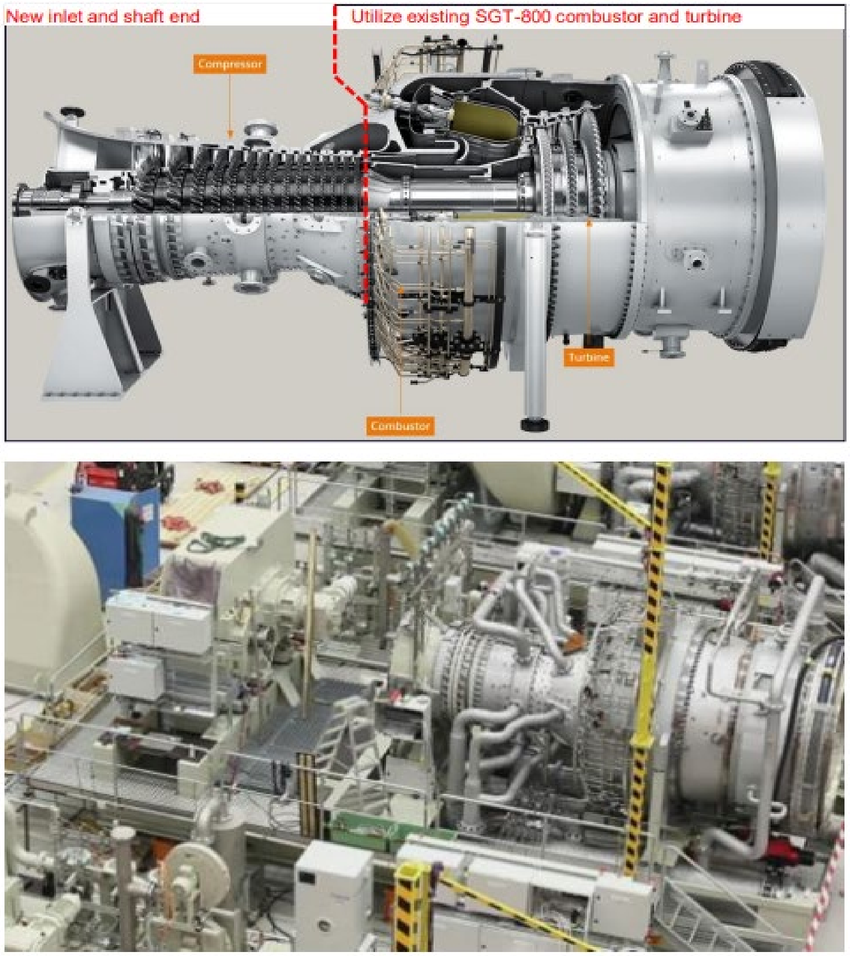

Figure 2: Siemens Gas Turbine

Smaller gas turbines referred to as microturbines would be needed for a prototype scale test. Development would likely include Computational Fluid Dynamics (CFD) analysis on the turbine blades to help determine the best shape for maximum efficiency, stress analysis on the turbine casing and blades to determine the Maximum Allowable Working Pressure (MAWP) at a given temperature, and heat maps of the turbine when running development tests. The turbine would then need to be tested to obtain operating curves. This type of work is usually done by the OEM.

6. Scope

Most of the prototype scale turbine development scope will fall on the OEM. Air compressors at the prototype scale are commercially available as is the heating and heat exchange equipment. Additional engineering development will be needed for the air injection/production well and any related subsurface gauges and/or equipment.

7. Schedule

A typical timeline from Pre-FEED to operation of a pilot scale prototype is three years.

8. Budget

A typical cost from Pre-FEED to operation of a pilot scale prototype is on the order of $ 13.4 MM. This includes all the engineering, construction, and equipment costs. However, this does not include the cost to drill the injection and production wells, as these numbers can vary and be difficult to predict.

Appendix 2

Conceptual Study

Technical Report

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9. Introduction

The objective of the reservoir modeling task is to assess the feasibility of using the Mt Simon Sandstone for injecting and producing heated air as part of a Compressed Air Storage Energy (CAES) project at the University of Illinois Urbana-Champaign (UIUC) campus in Champaign, Illinois.

The next section of this report describes the geologic model for the Mt Simon Sandstone that was used in this study. Later sections describe the dynamic simulation model that was constructed and used to assess the feasibility of cycling compressed air in and out of the Mt Simon Sandstone.

10.Static Reservoir Modeling

The static model for the Mt Simon sandstone was constructed, using Schlumberger's *Petrel* software, in a prior study that assessed the geothermal energy extraction capacity of the Mt Simon Sandstone at the University of Illinois at Urbana-Champaign (Okwen et al, 2020). The static model covers 36 square miles and is centered on the UIUC campus. The model structure is based on regional trends, and flow and heat transfer property arrays are based on all available data from the Illinois Basin – Decatur Project (IBDP).

The static model includes the overlying Eau Claire, three zones in the Mt Simon (upper, middle and lower), and underlying Argenta and Precambrian basement.

Figure **3** shows the distribution of porosity and permeability within the Mt Simon Sandstone. Additional details on the static model can be found in Lin et al. (2019).

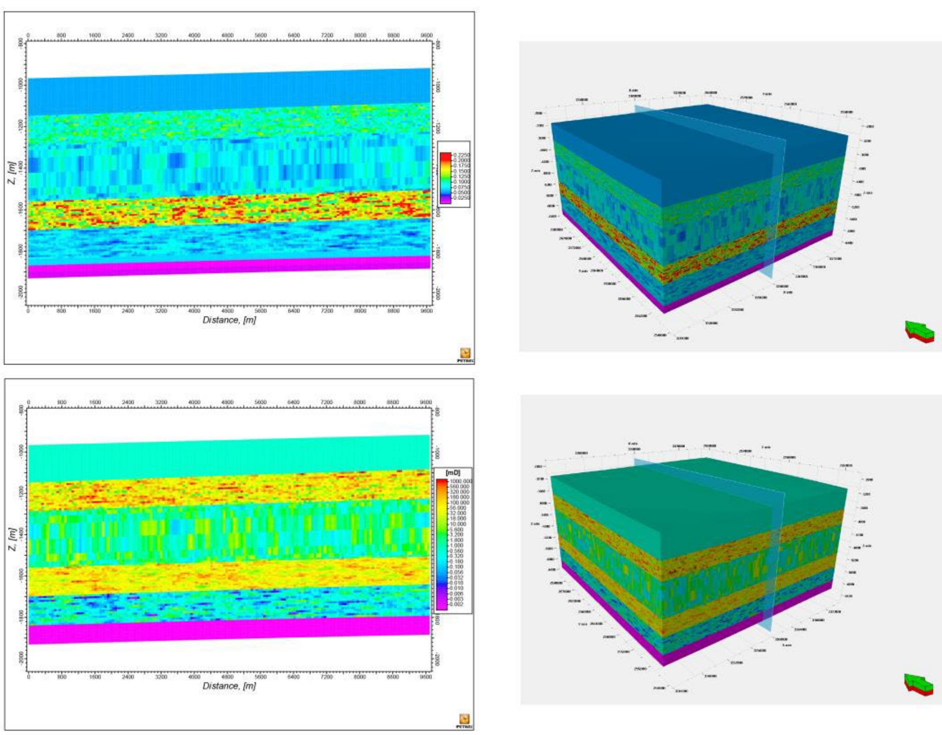

Figure 3. Porosity and permeability distribution in the Mt Simon Sandstone from the static model. (source: Lin et al., 2020).

11.Dynamic Reservoir Modeling

Dynamic reservoir simulations were performed to assess the feasibility of using the Mt Simon Sandstone for injecting and producing heated air as part of a CAES project at the University of Illinois Urbana-Champaign (UIUC) campus in Champaign, Illinois. Since this is a pilot project, only a small volume of gas (1.57 MMscf) is to be cycled in and out of the Mt Simon Sandstone on a daily basis. The daily cycle is 18 hours of injection at 2.09 MMscf/d followed by 6 hours of production at 6.28 MMscf/d.

The dynamic simulations were run using CMG's *STARS* reservoir simulation software. *STARS* is CMG's Thermal and Advanced Process Simulator. *STARS* was selected as the simulation software for this study for its thermal capabilities.

3.1 Model Input

This section describes the reservoir engineering data and assumptions used in building the Mt Simon *STARS* simulation model. The reservoir engineering data include:

- grid and property data,
- fluid PVT data,
- rock property data, and
- wellbore modeling data.

3.1.1 Grid and Property Arrays

A geological model for the Mt Simon Sandstone (Mt Simon) was created in *Petrel*, and the grid and property arrays were exported to *STARS* for dynamic reservoir simulation. The original static model was too large (36 × 36 miles) and the cells were too coarse in both the areal (200 × 200 ft) and vertical (layer thickness ranges from 30 to several hundred feet) directions for this study. The static model was re-gridded to have areal grid dimensions of 40 × 40 ft and a vertical cell thickness of 3 ft within the targeted injection zone; the Upper Mt Simon sandstone, and a one square mile sector model was exported for simulation (See Figure 4).

The exported sector model was further refined within *STARS* to have cells with areal dimensions of 20 × 20 ft in 0.25 sq mile area around the well, and formations below the Middle Mt Simon were removed from the model. The lower part of the Middle Mt Simon has low permeability and acts as a baffle/barrier. Therefore, the removal of the formations below the Middle Mt Simon has a negligible impact on the simulation results. Figure 5 shows the refined sector model that was used for dynamic simulation. The refined model has 168 layers and a total of 6.9 million cells.

The top and bottom surfaces of the model are sealed, no-flow boundaries. An infinitely-acting aquifer was attached and calibrated to the edges of the model to simulate open-boundaries as expected with laterally extensive formations. *STARS* allows the aquifer to transfer both fluid and heat to/from the reservoir. Figure 6 and Figure 7 show the porosity and permeability along a cross-section through the center of the model; respectively. An initial temperature array was also imported into the model, which was calculated from well data at IBDP in an earlier study (Okwen et al, 2020).

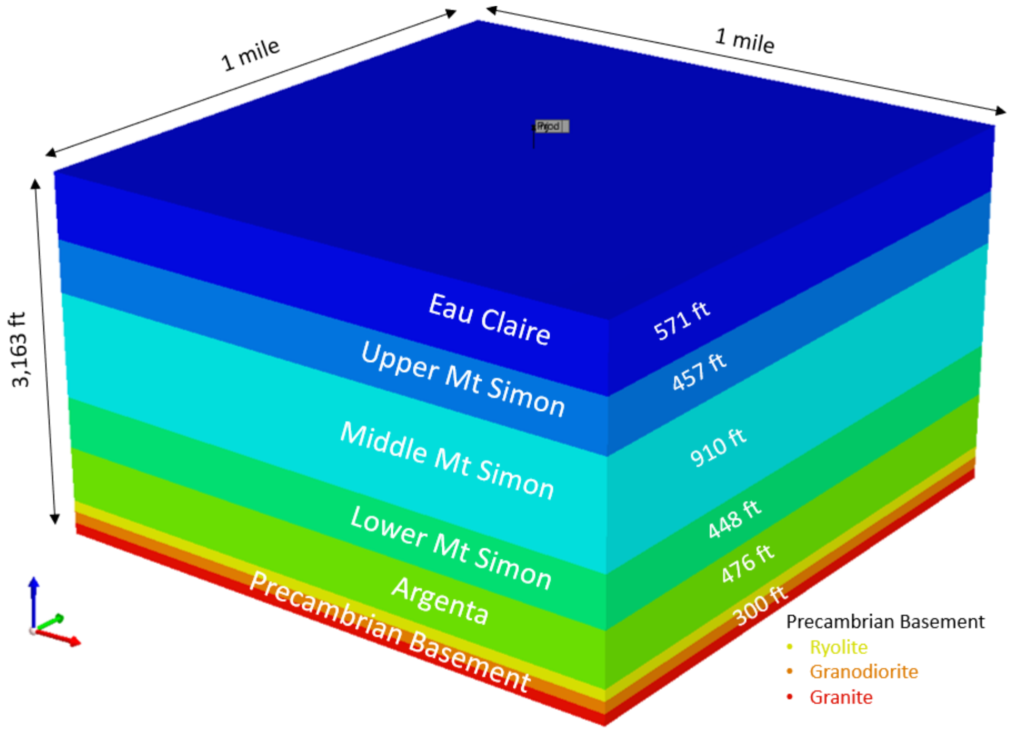

Figure 4*. One square mile sector model with refined vertical layering, showing the overlying Eau Claire, Mt Simon (Upper, Middle and Lower), and the underlying Argenta and Precambrian basement formations.*

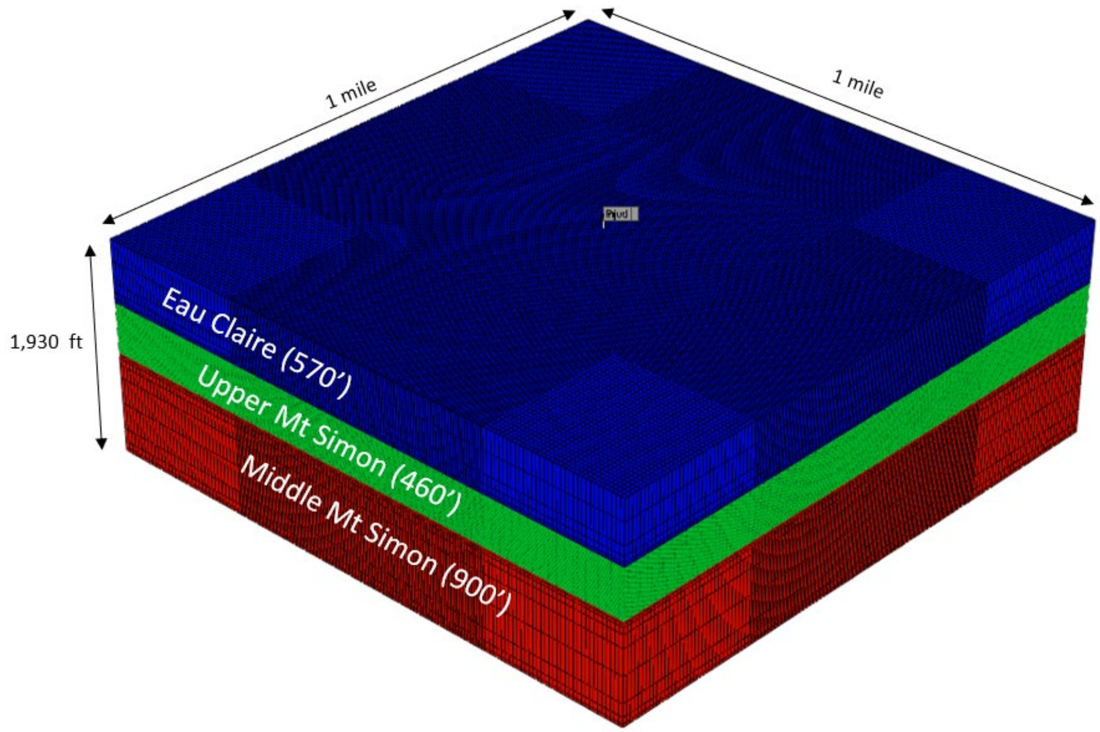

Figure 5*. Refined sector model used for the dynamic simulation; which includes 20 × 20 ft grid wells near the well and removal of the underlying Argenta and Precambrian basement formations.*

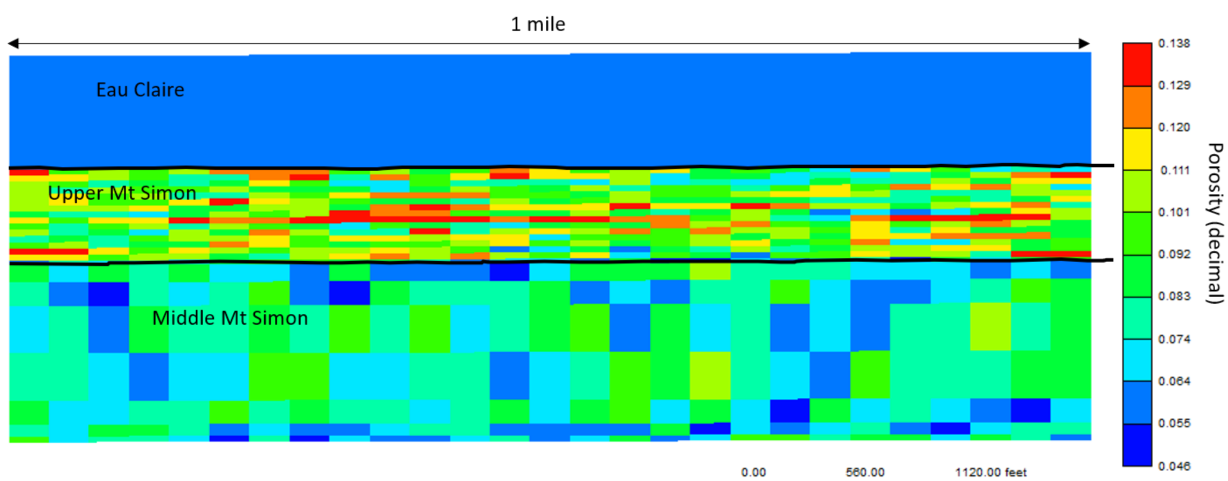

Figure 6. *Porosity distribution along a cross-section through the center of the model.*

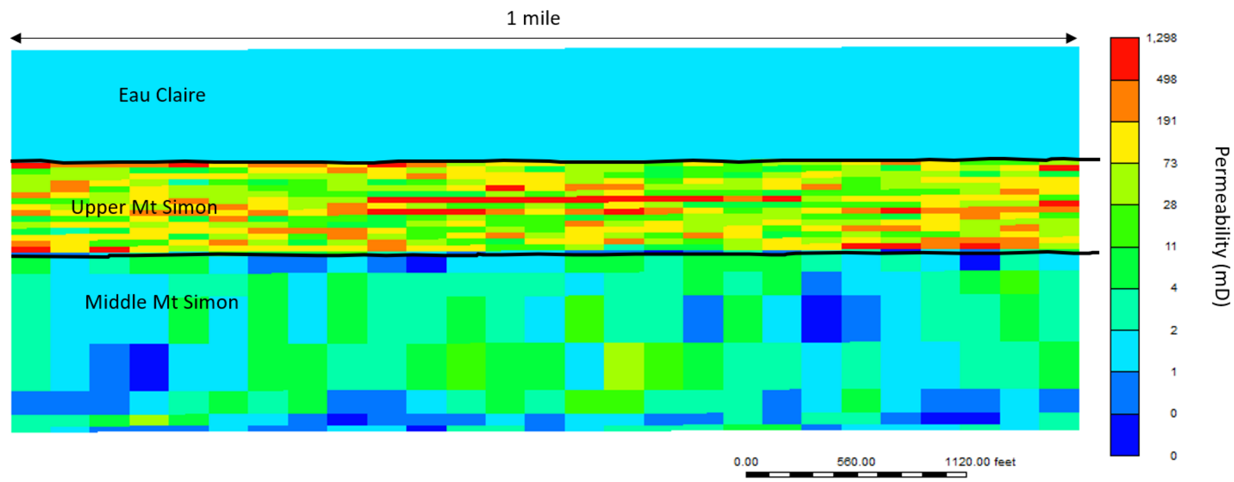

***Figure** 7. Permeability distribution along a cross-section through the center of the model.*

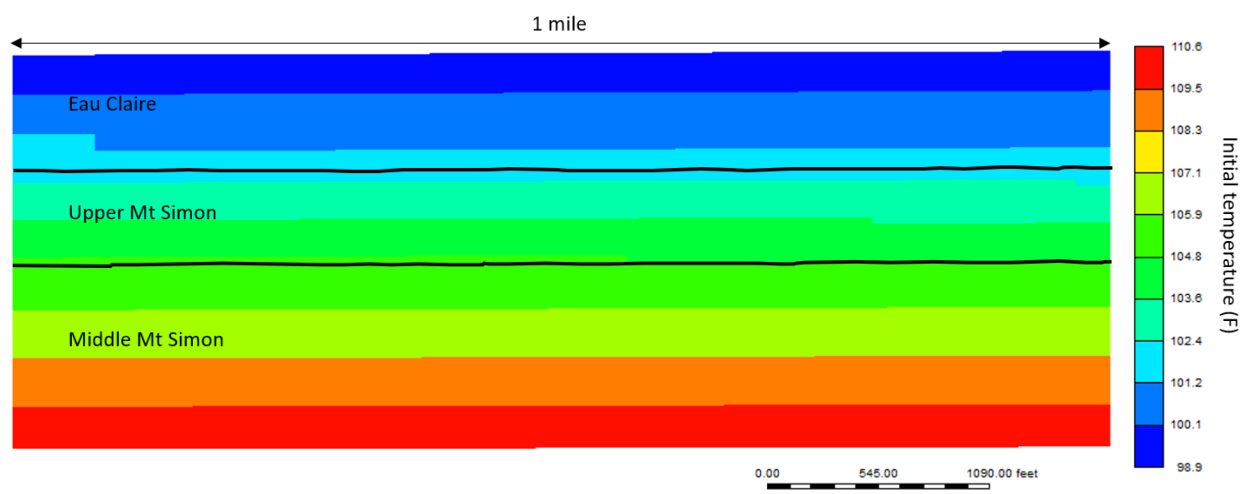

***Figure 8**. Initial temperature distribution along a cross-section through the center of the model.*

3.1.2 Fluid PVT Data

The Mt Simon *STARS* model is an air-brine model, and uses the compositional model internal to *STARS*. Air is assumed to be composed of only nitrogen (N_2) and oxygen (O_2); with a composition of 78.85% N_2 and 21.15 % O_2. The compositional model contains three components: nitrogen, oxygen and water; within 2 phases, water and gas. Nitrogen and oxygen gas viscosities were calibrated to viscosity data from the National Institute of Standards and Technology (NIST) Chemistry WebBook (Lemmon, 2021). The water density and compressibility used in the model are 63.889 lb/ft3 and 2.785×10^{-6} psia^{-1}, respectively.

The initial reservoir pressure was estimated using a hydrostatic gradient of 0.45 psi/ft (10.3 MPa/Km) determined from CCS1 and VW1 formation pressure monitoring data (Bauer et al., 2016); and interpreted to be 1,842 psia at 3,500 ft, TVDss (670 ft elevation).

3.1.3 Rock Properties

No site-specific laboratory measurements of relative permeability, capillary pressure and rock compressibility were available. Rock compressibility was estimated using Newman's correlation for sandstones (Newman, 1973), using the median porosity within the Mt Simon. The median porosity is 15.25%, which corresponds to a rock compressibility value of 3.9×10^{-6} psi^{-1}. No compressed air-brine relative permeability data were found in the literature, so CO_2-brine relative permeability was assumed. The relative permeability curves used in the simulations were generated based on general knowledge from the literature using Brooks-Corey functions (Krevor et.al., 2012), see Figure 9 and Figure 10.

Thermal simulations also require thermal properties for the rocks. The rock thermal properties were calculated in an earlier study (Okwen et al, 2020), and average values were assigned by formation, see Table 1. Thermal conductivities for water and air are 8.6 and 0.51 BTU-ft-day-^{O}F; respectively. The water value is typical, and the air value is a typical value for air at reservoir temperature and pressure.

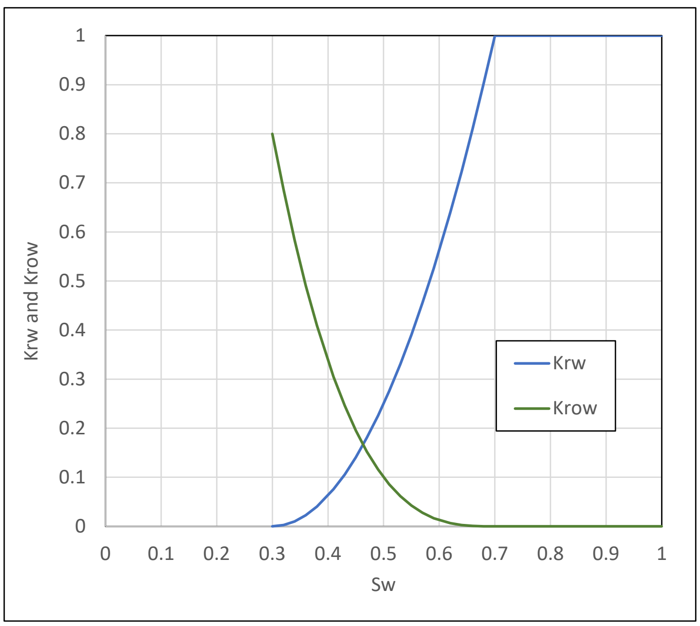

***Figure 9**. Oil-Water relative permeability curves used in the Mt Simon simulation model.*

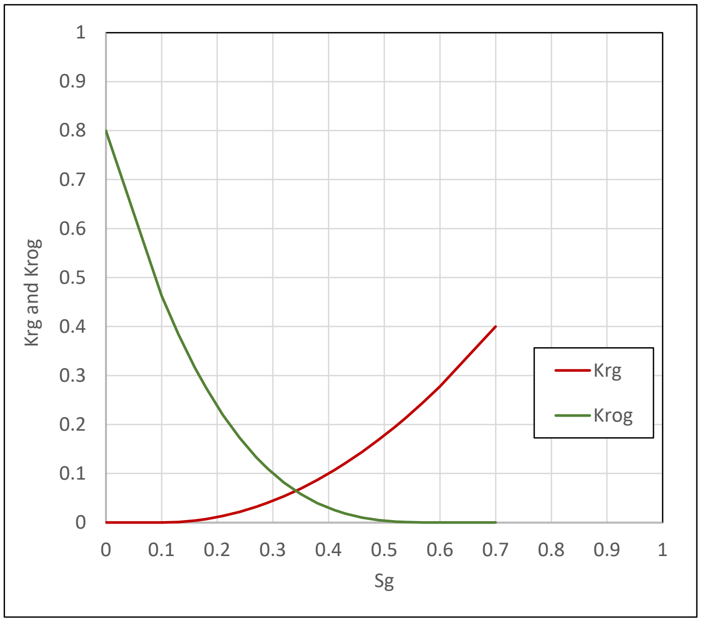

Figure 10. *Gas-Oil relative permeability curves used in the Mt Simon simulation model.*

Table 1. *Rock thermal properties used in the Mt Simon simulation model.*

Formation	Thermal Conductivity	Heat Capacity
	BTU/ft-day-F	BTU/ft3-F
Eau Claire	25.60	38.82
Upper Mt Simon	70.89	28.96
Middle Mt Simon	79.55	29.40

3.1.4 Wellbore Model

STARS includes a wellbore model to calculate frictional losses and heat transfer to/from the surrounding rock in the wellbore. The wellbore model was used to calculate well-head temperatures and pressures in the Mt Simon model. The schematic of the wellbore model, from the *STARS* manual is shown in Figure 11, and Table 2 details the parameters used in the simulation model. The wellbore assumes insulated pipe, and the wellbore properties are based on an earlier geothermal study (Okwen et al, 2020).

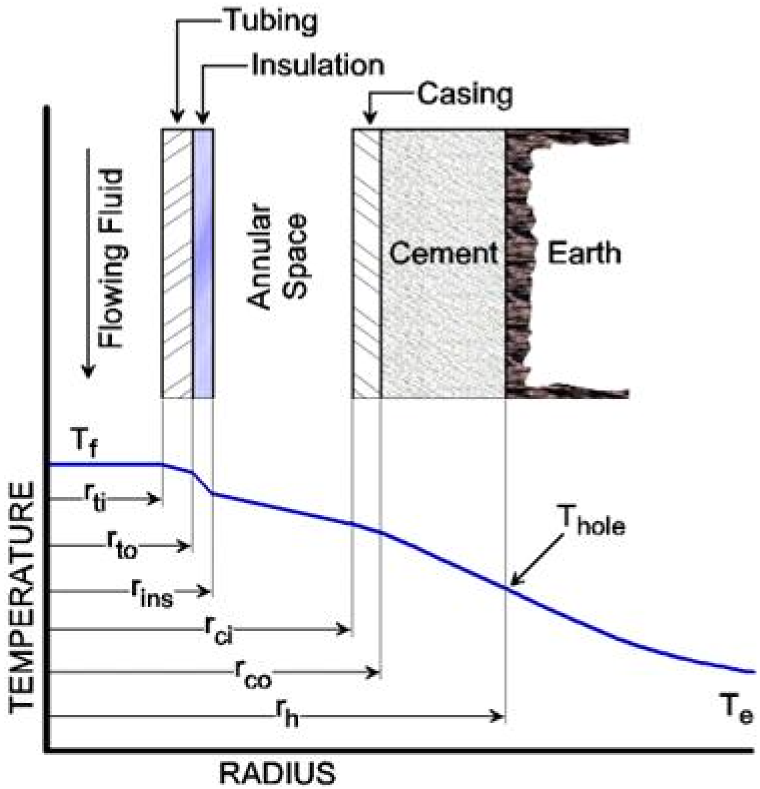

Figure 11. *Wellbore model schematic (STARS, 2021)*

Table 2. *Wellbore parameter values used in the Mt Simon simulation model.*

Variable	Description	Value	Units
Rti	Inner radius of 2-7/8" tubing	0.1018	ft
Rto	Outer radius of 2-7/8" tubing	0.1198	ft
Rins	Radius to outside of insulation	0.1615	ft
Rci	Inner radius of 7" casing	0.2577	ft
Rco	Outer radius of 7" casing	0.2917	ft
Rh	Hole radius	0.4375	ft
Contub	thermal conductivity of tubing	763.19	Btu/ft-day
Condins	thermal conductivity of insulation	1.44	Btu/ft-day
Condcas	thermal conductivity of casing	763.19	Btu/ft-day
Condcem	thernal conductivity of cement	11.1	Btu/ft-day
Geograd	Geothermal gradient	0.00936	°F/ft
Surface Temp	Surface Temperature	61	°F

3.2 Simulation Cases

Dynamic simulations were performed to assess the compressed air injectivity of the Upper Mt Simon, and to assess the performance of the Upper Mt Simon to compressed air cycling. The reservoir rock is an aquifer, with a water saturation of 100%. *STARS* requires both an oil-water and gas-oil contact and an initial pressure at a reference depth to initialize the simulation model. The simulation model is initialized with an oil-water and gas-oil contacts placed just above the top of the model and an initial pressure at datum depth of 1,842 psia at 3,500 ft TVDss.

3.2.1 Maximum Injectivity Assessment

Reservoir simulations were performed to assess compressed air injectivity into the Upper Mt Simon. Based on simulation results, three potential injection intervals were identified in the Upper Mt Simon; each with an overlying low-permeability interval to help trap the compressed air. Figure 12 shows the gas saturation along a cross-section through the center of the model after injecting 28 MMscf across the entire Upper Mt Simon. The three potential injection zones and the associated permeabilities are shown in the figure. The upper zone, denoted with a “1” in Figure 12 is located just below the Eau Claire which serves as a seal. This zone has an average permeability of 117 mD and is underlain by a lower permeability interval that will help contain the injected air. The middle zone, denoted with a ‘2” in Figure 12, is a thicker interval with slightly lower average permeability, 78 mD. In this zone the air bubble is elongated and there may be more water production due to the lower gas saturation values within the gas plume. The lower zone, denoted with a “3” in Figure 12, has a much higher average permeability of 1,045 mD. The high permeability results in a thinner air bubble with air being pushed further away from the wellbore laterally. This is not advantageous for an air cycling process, because the air will be pushed further away from the well with each drain/fill cycle and there is a greater risk of water coning from the bottom of the well. The overall injectivity of the Upper Mt Simon is large, with an injectivity of 170 MMscf/d of compressed air; constrained by 90% of the fracture gradient of 0.71 psi/ft. The upper zone of the Upper Mt Simon, interval “1” in Figure 12 was selected as the injection interval for the cycling assessment.

3.2.2 Compressed air cycling performance

Reservoir simulations were performed to assess the compressed air cycling performance of the Upper Mt Simon. A single injection/production well is assumed. This project requires a working gas volume of 1.57 MMscf, which is cycled in and out of the reservoir on a daily basis. Compressed air is injected at a rate of 2.09 MMscf/d for 18 hours, and then compressed air is produced at a rate of 6.28 MMscf/d for 6 hours. The cycle repeats daily.

In gas storage projects, there are three volumes of gas that can be defined: fill gas (or total gas), working gas and cushion gas. Fill gas is the volume of gas injected into the storage reservoir before the first production cycle commences. Working gas is the gas volume that is cycled in and out of the reservoir during each fill/drain cycle. Cushion gas is gas that is permanently stored in the storage reservoir. Cushion gas is the difference between fill gas and working gas. Cushion gas helps to maintain deliverability and wellhead pressure during the drain cycle. For gas storage in aquifers, cushion gas also helps to push water away from the well to reduce water production during the drain cycle. Cushion gas can range from 80 to 90% of the total gas volume for gas storage in aquifers (Vikara et al., 2019). The relationship between fill gas, cushion gas and working gas relative to a working gas volume of 1.57 MMscf is detailed in Table 3. The simulation model was used to understand the impact of cushion gas on compressed air cycling performance of the Upper Mt Simon. A cushion gas volume of 90% of total gas was used to assess the performance of vertical and horizontal wells; sensitivities to cushion gas were run for selected cases.

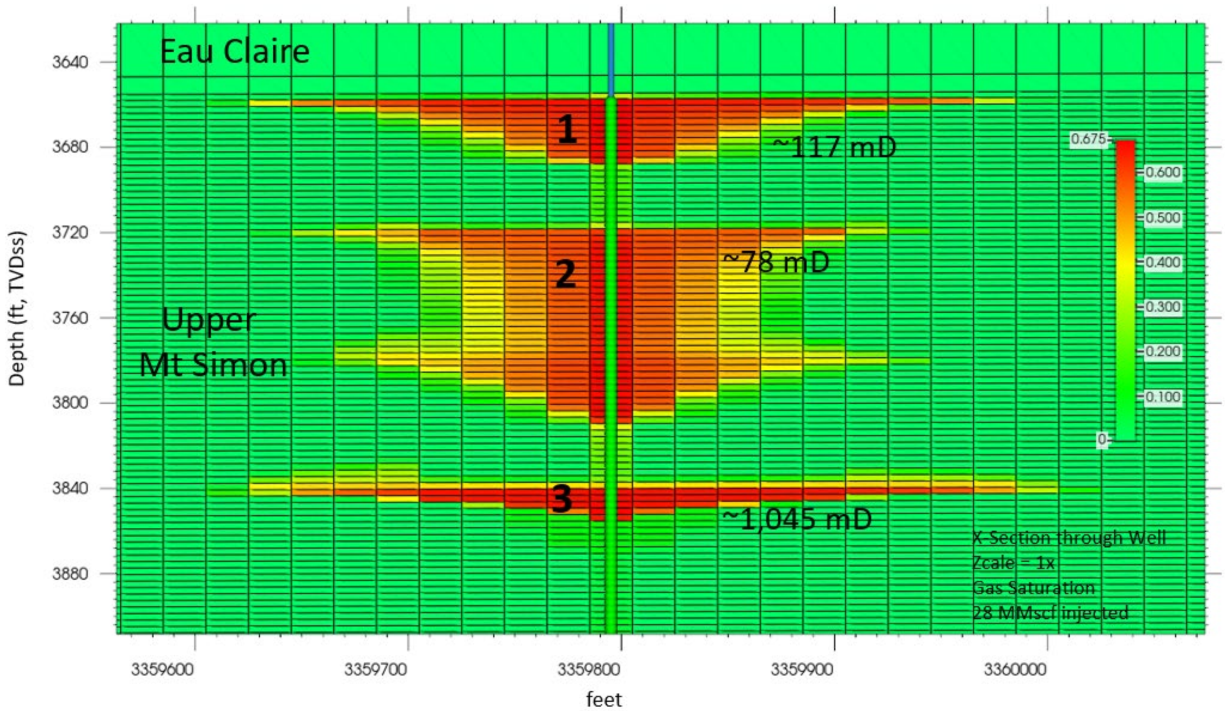

Figure 12. *Gas saturation along a cross-section through the center of the simulation model after injecting 28 MMscf of compressed air across the entire Upper Mt Simon. Compressed air enters the reservoir in three distinct zones, denoted as 1, 2 and 3 due to the heterogenous permeability.*

***Table 3**. Relationship between total gas, working gas, and cushion gas relative to a working gas volume of 1.57 MMscf.*

				Inj Hrs	Prod Hrs
				18	6
Working Gas	Cushion Gas	Fill Gas	Cushion Gas	Inj Rate	Prod Rate
MMscf	MMscf	MMscf	% of total	MMscf/d	MMscf/d
1.570	1.6	3.1	50%	2.09	6.28
1.570	4.7	6.3	75%	2.09	6.28
1.570	6.3	7.9	80%	2.09	6.28
1.570	8.6	10.2	85%	2.09	6.28
1.570	14.1	15.7	90%	2.09	6.28
1.570	29.8	31.4	95%	2.09	6.28
1.570	50.2	51.8	97%	2.09	6.28

3.2.2.1 Vertical Well Simulations

Vertical well sensitivities were run to optimize the completion length. The model was run for 10 drain/fill cycles, after fill gas injection. The vertical well is perforated from the top of the Upper Mt Simon downward (see Figure 13), the perforation length was varied to determine the optimal length for a vertical well. The perforation length was varied between 3 and 21 ft; in 3 ft increments as the cell thickness is 3 ft. Water production was used as the discriminating factor for optimizing the perforation length. Figure 14 shows the cumulative water production at the end of the 10th production cycle for a vertical well vs. perforation length from the top of the Upper Mt Simon. The minimum cumulative water production occurs at 6 ft, so 6 ft was selected as the optimal perforation length for a vertical well. Figure 15 and Figure 16 show cumulative water production and water production rate vs. time after initial fill for a vertical well with various perforation lengths; respectively. Water production increases significantly as perforation length is increased beyond 6 ft. Water production is a result of water coning into the well from below, and coning increases with perforation length. Figure 17 shows cumulative water production and water production rate vs. time after initial fill for the optimal perforation length of 6 ft. The water production rate increases with each drain/fill cycle because gas migrates to the top of the Upper Mt Simon and the water saturation below the well increases with each drain/fill cycle. Figure 18 shows the gas saturation vs. time along a cross-section through the center of the model for a vertical well with 6ft of perforations. The gas saturation images show the gas saturation decreasing and the water saturation increasing below the well as water cones into the well during each drain/fill cycle.

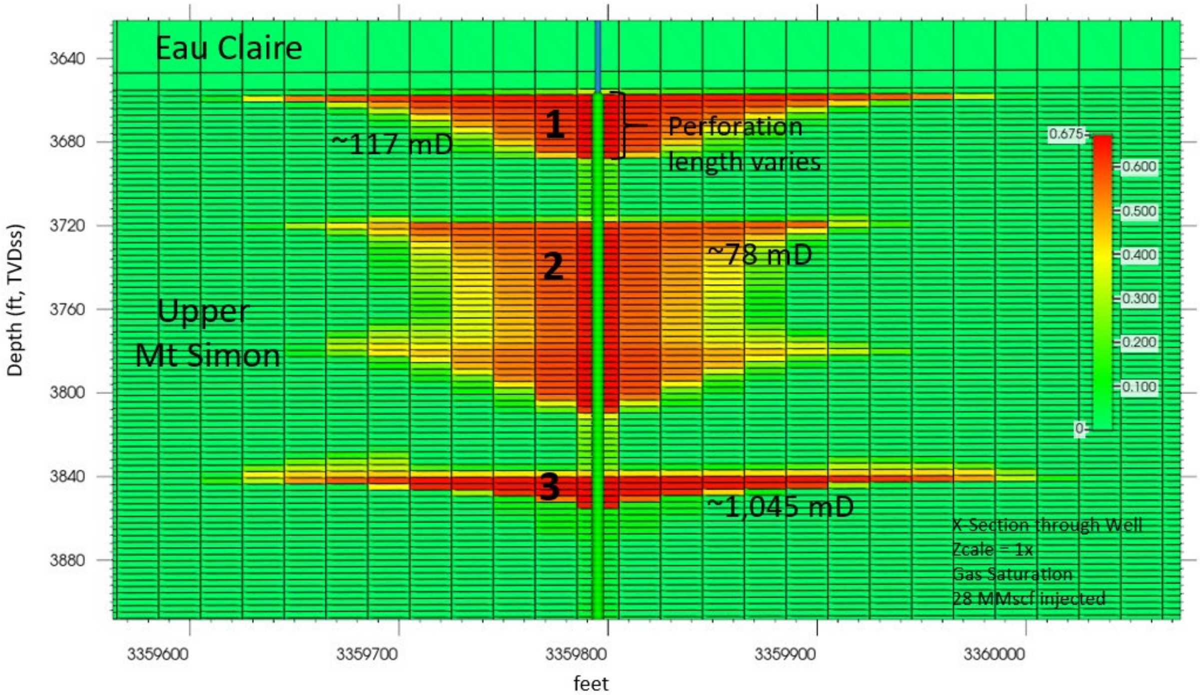

Figure 13. *Cross-section through the center of the model showing vertical well perforation length on a gas saturation map.*

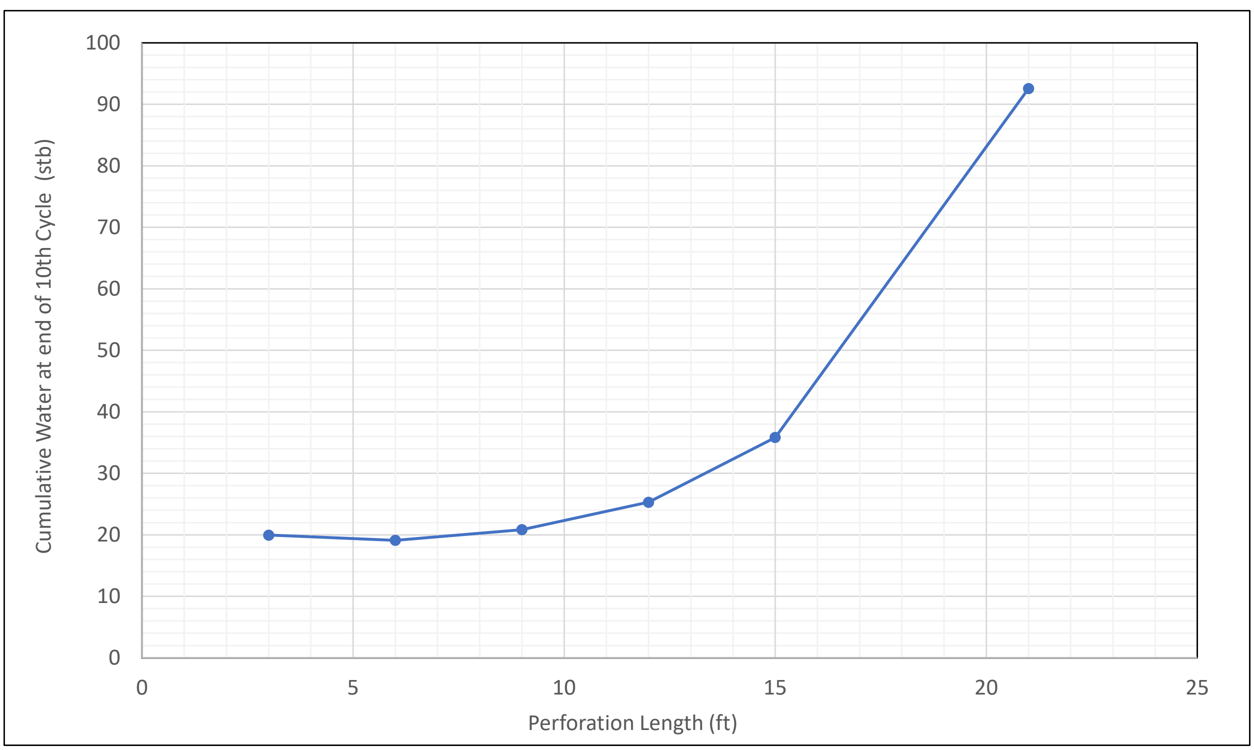

Figure 14. *Vertical well cumulative water production at the end of the 10th production cycle vs. perforation length from the top of the Upper Mt Simon.*

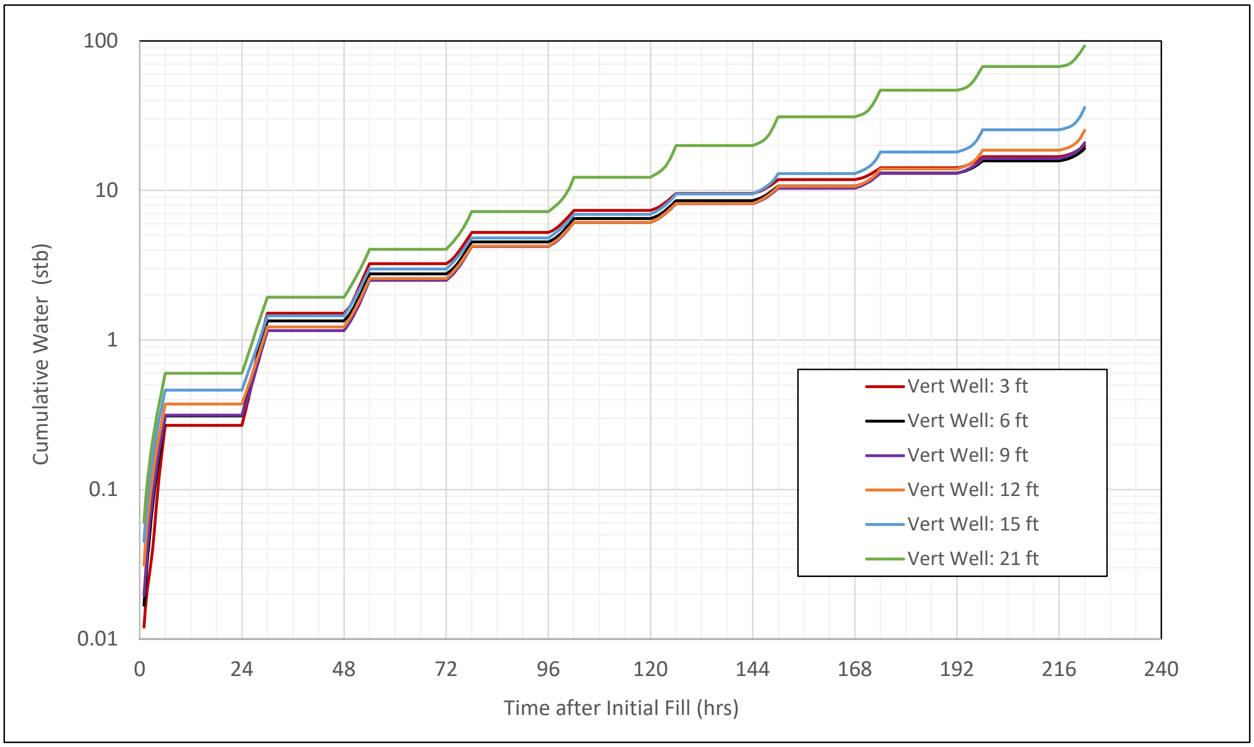

Figure 15*. Vertical well cumulative water production vs. time after initial fill for various perforation lengths.*

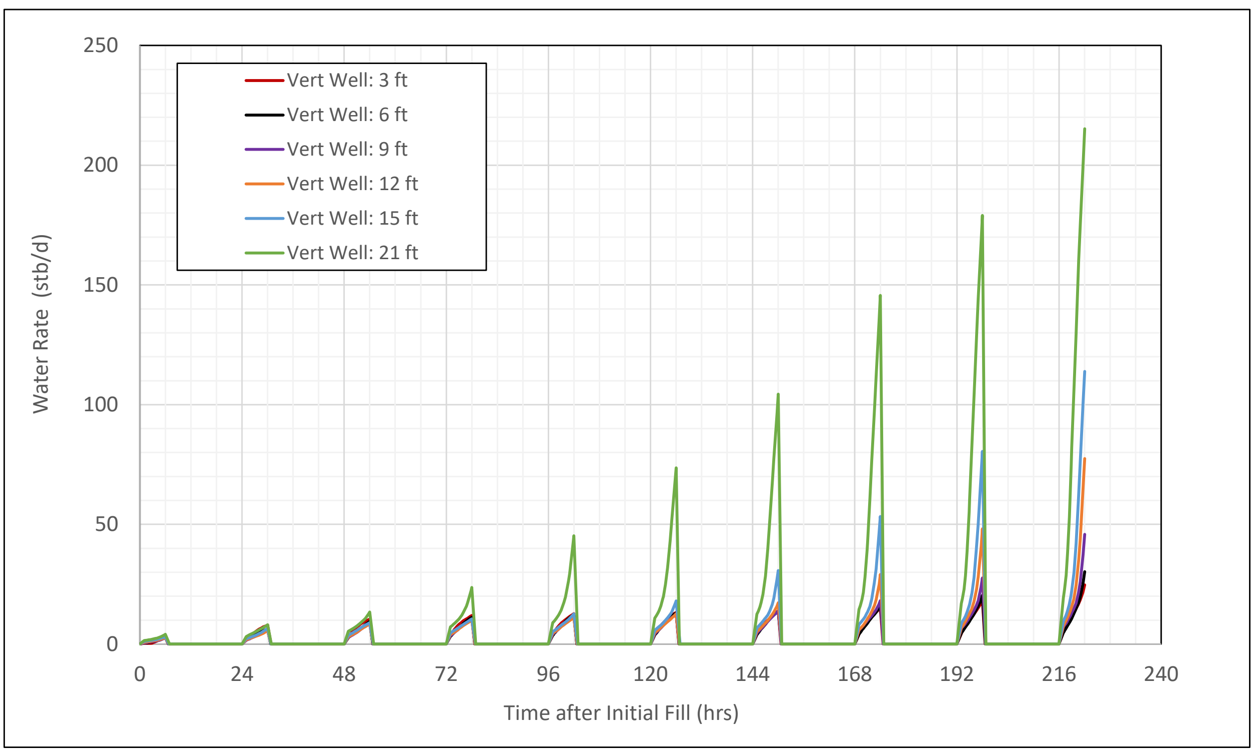

Figure 16. *Vertical well water rate vs. time after initial fill for various perforation lengths.*

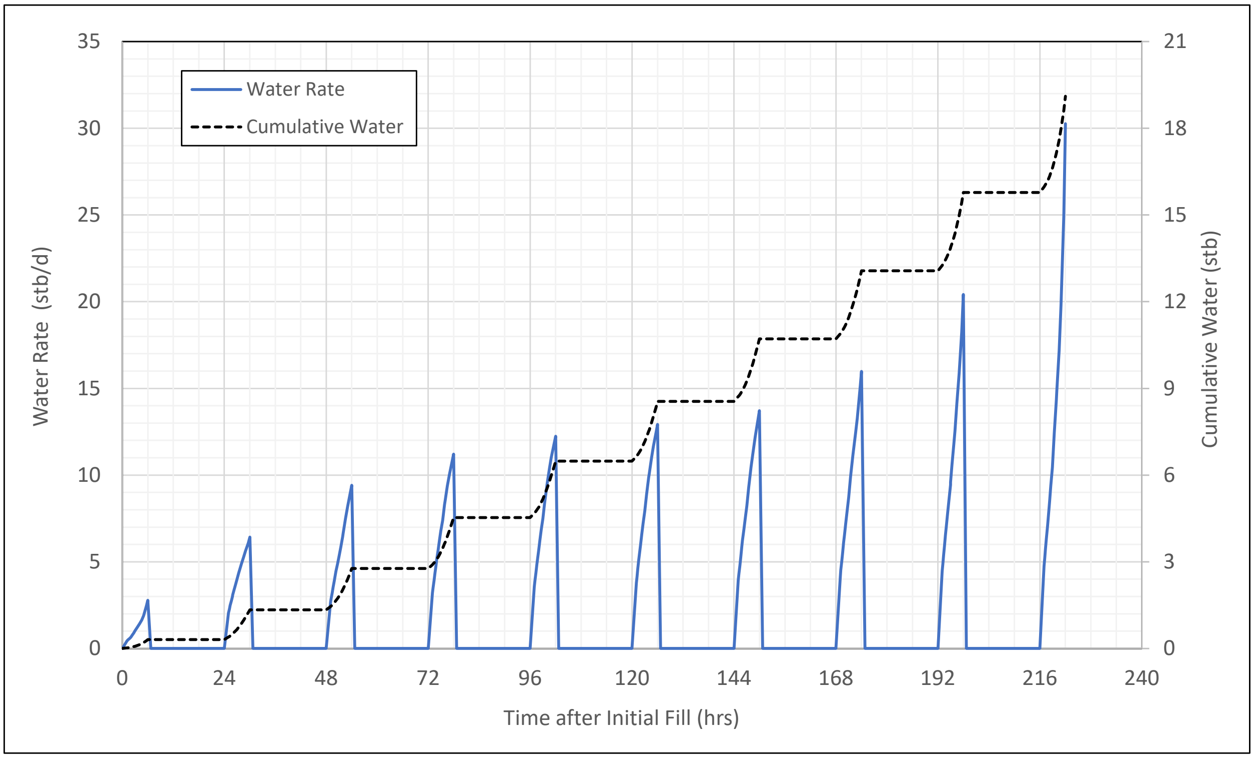

Figure 17. *Water production rate and cumulative water production vs. time after initial fill for a vertical well with the optimal perforation length of 6 ft.*

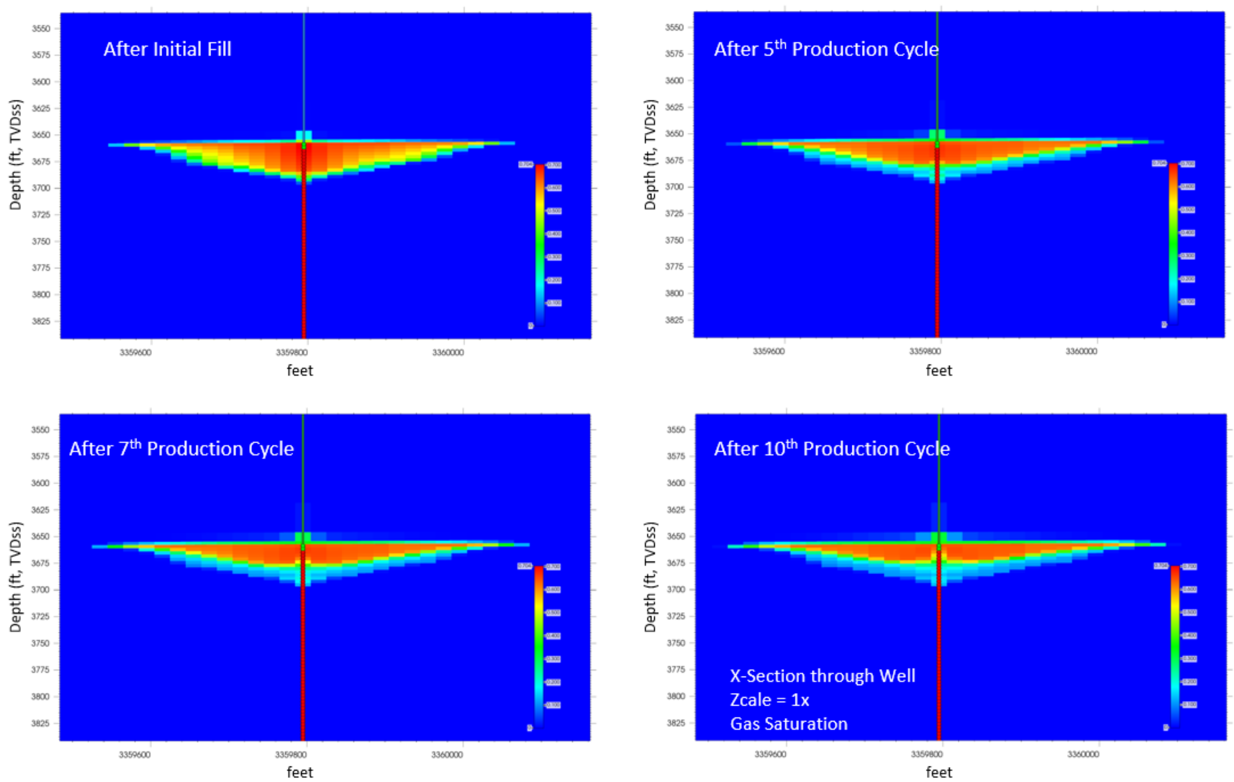

Figure 18. *Cross-section through the center of the model showing gas saturation vs. time for a the optimal vertical well with 6ft perforation length.*

3.2.2.2 Horizontal Well Simulations

Vertical well simulations show water coning issues, so horizontal well cases were simulated to determine if horizontal wells would reduce water coning. Multiple simulations were run to optimize both the horizontal well length and the depth below the top of the Upper Mt Simon. Figure 19 is a cross-section through the center of the model showing that horizontal wells are located at a variable depth below the top of Upper Mt Simon and that the perforation length varies. Horizontal well cases were run for 10 drain/fill cycles after fill gas injection and, similar to the vertical well cases, water production was used as the discriminator for both length and depth optimization.

Figure 20 shows cumulative water production at the end of the 10^{th} production cycle vs. layer for a horizontal well with lengths of 80 and 100 ft. The performance of a horizontal well of length 80 and 100 ft are very similar. Layer 8 is the first simulation cell in the Upper Mt Simon. A horizontal well in layer 8, 9, 10, 11 and 12 is 1.5, 4.5, 7.5, 10.5 and 13.5 ft below the top of the Upper Mt Simon; respectively. The results indicate that a horizontal well completed in layer 9 has the lowest cumulative water production after 10 drain/fill cycles. Layer 9 is selected as the optimal completion layer, which is 4.5 ft below the top of the Upper Mt. Simon. Figure 21 and Figure 22 show cumulative water production and water production rate vs. time after initial fill for a 100 ft horizontal well for various completion depths below the top of the Upper Mt Simon. Water production appears to stabilize after 6 drain/fill cycles for horizontal wells placed in layers 8 through 10; 1.5 ft to 7.5 ft below the top of the Upper Mt Simon.

Figure 23 and Figure 24 show cumulative water production and water production rate at the end of the 10th production cycle vs. horizontal well length for a well placed in layer 9; respectively. The results show that cumulative water production is minimum for a well that is 80 ft long. However, the water rate at the end of the 10th production cycle is minimum for a well that is 100 ft long. Since, water rate is a derivative of cumulative water production, the 100 ft long well would likely have slightly lower cumulative water production in later cycles. Figure 25 shows water production rate vs. time after initial fill for horizontal wells of length 80 and 100 ft, completed in layer 9. The results show that a 100 ft horizontal well has an initial water production rate higher than an 80 ft well. However, a 100 ft horizontal well has a lower water production rate than an 80 ft horizontal well after 6 drain/fill cycles. Hence, the optimal well length is selected to be 100 ft.

Figure 26 and Figure 27 show cumulative water production and water production rate vs. time after initial fill for a horizontal well of various lengths completed in layer 9; respectively. Figure 28 shows water production rate and cumulative water production vs. time after initial fill for the optimal horizontal, which is 100 ft long and located 4.5 ft below the top of the Upper Mt Simon. Figure 29 shows gas saturation on a cross-section through the center of the model vs. time for the optimal horizontal well. The gas saturation images show the gas saturation decreasing and water saturation increasing below the well as water cones into the well during each drain/fill cycle.

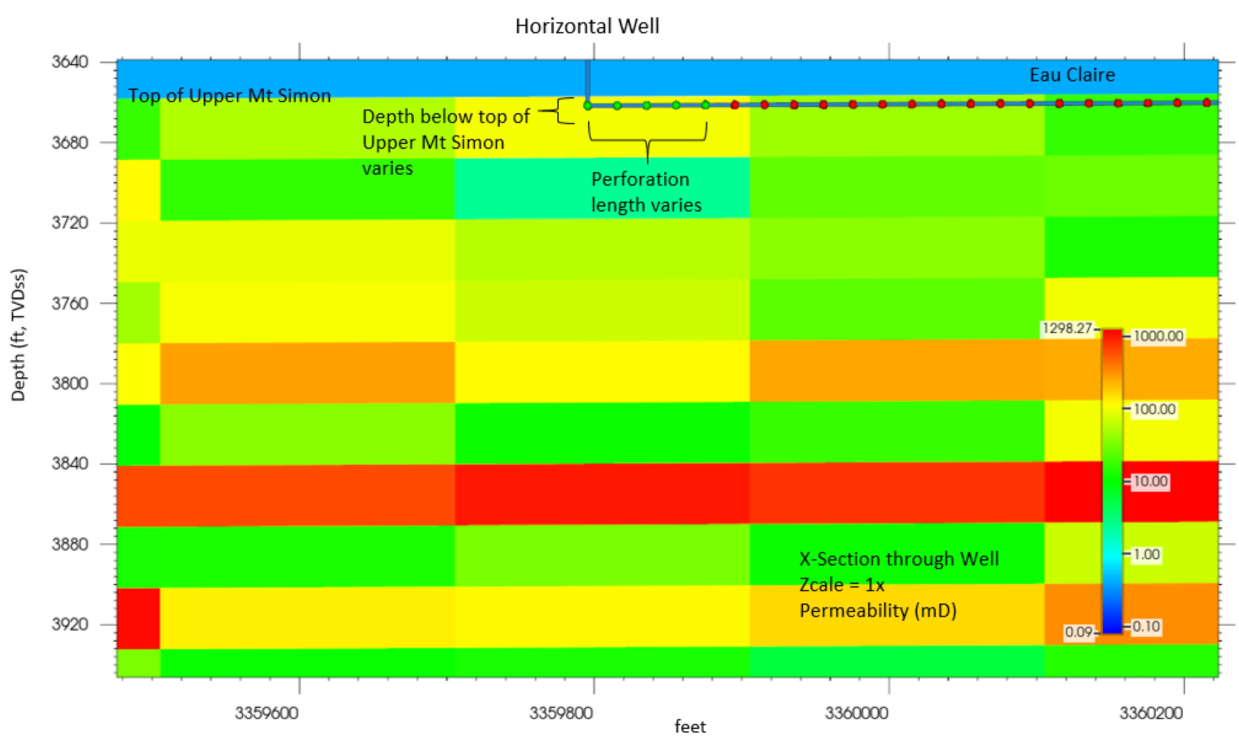

Figure 19. *Cross-section through the center of the model showing the location (depth) and perforation length of a horizontal well on a permeability map.*

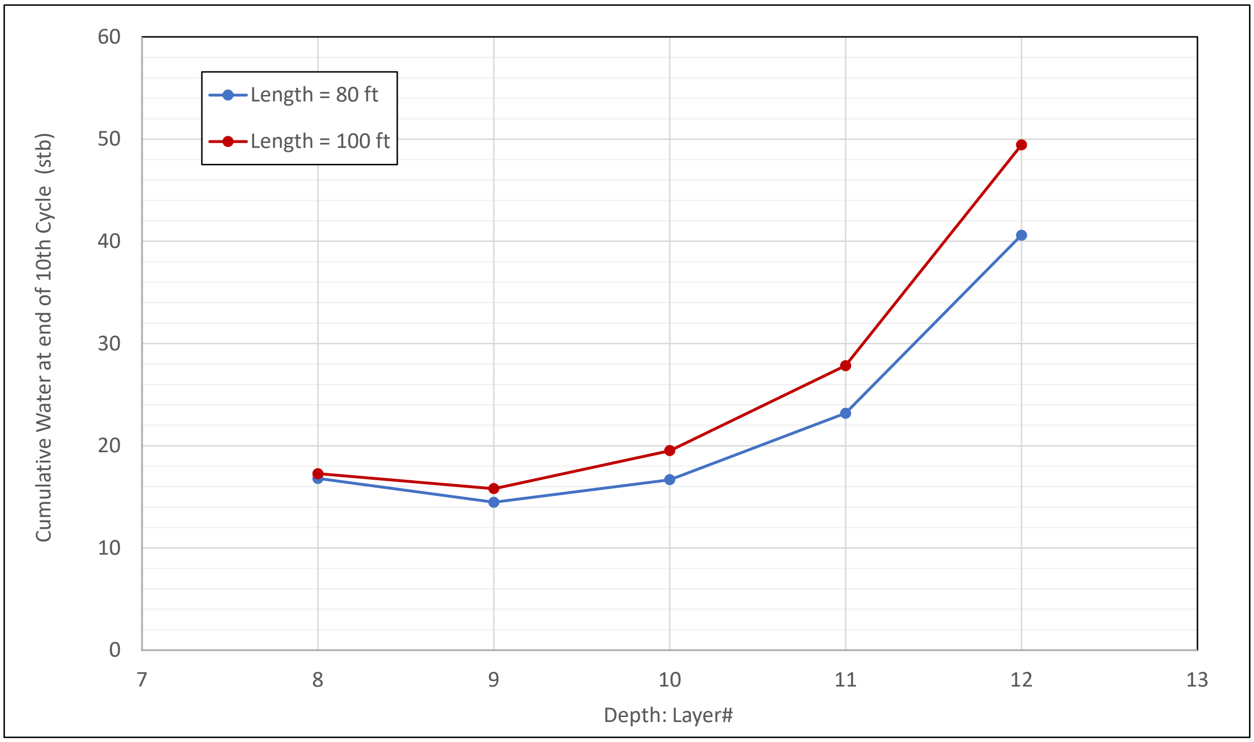

Figure 20. *Cumulative water production at the end of the 10th production cycle vs. layer for a horizontal well with lengths of 80 and 100 ft.*

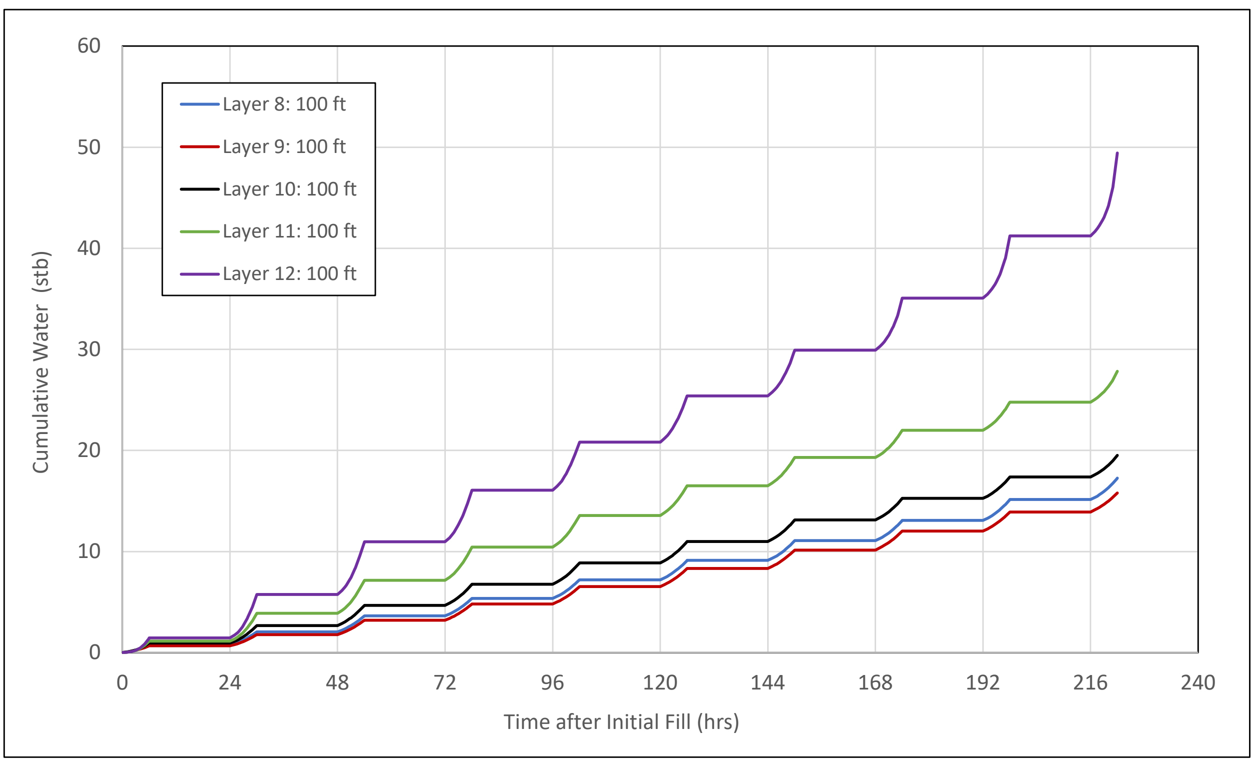

Figure 21. *Cumulative water production vs. time after initial fill for a 100 ft horizontal well completed in layer 8, 9 10, 11 or 12; which is 1.5, 4.5, 7.5, 10.5 or 13.5 ft below the top of the Upper Mt Simon; respectively.*

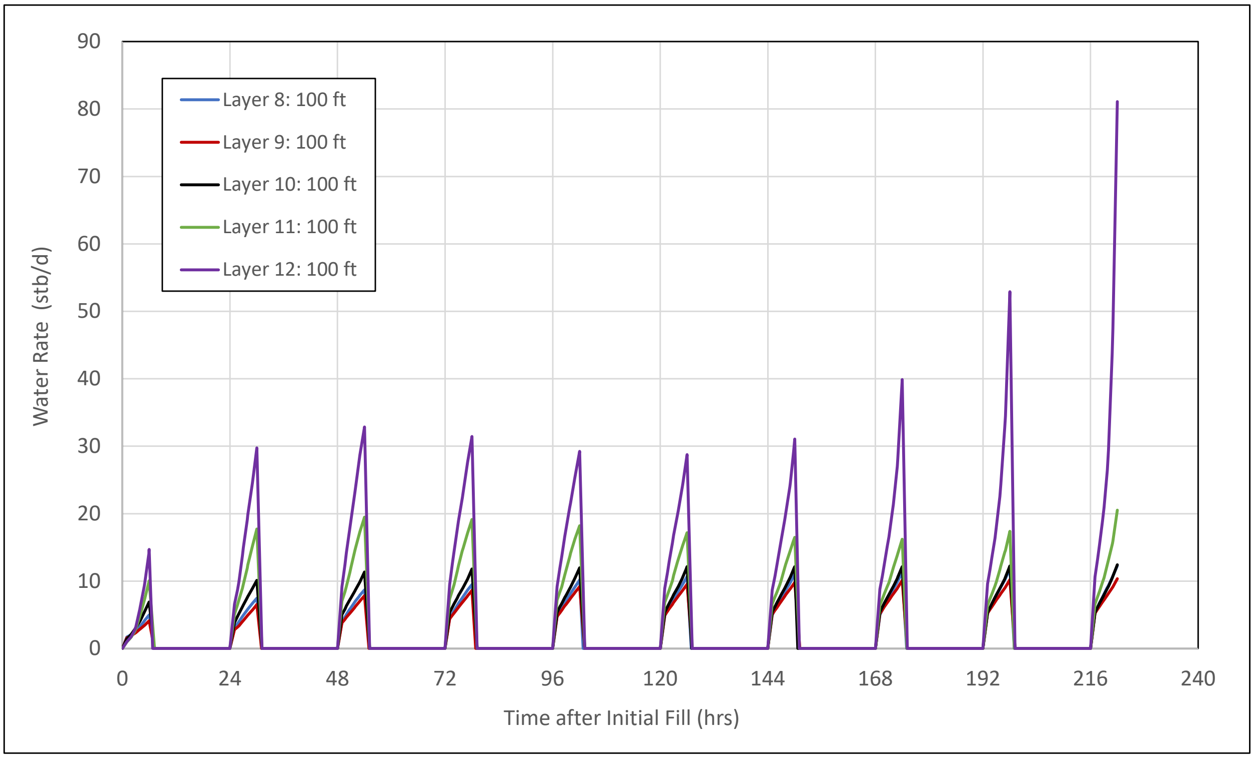

Figure 22. *Water production rate vs. time after initial fill for a 100 ft horizontal well completed in layer 8, 9 10, 11 or 12; which is 1.5, 4.5, 7.5, 10.5 or 13.5 ft below the top of the Upper Mt Simon; respectively.*

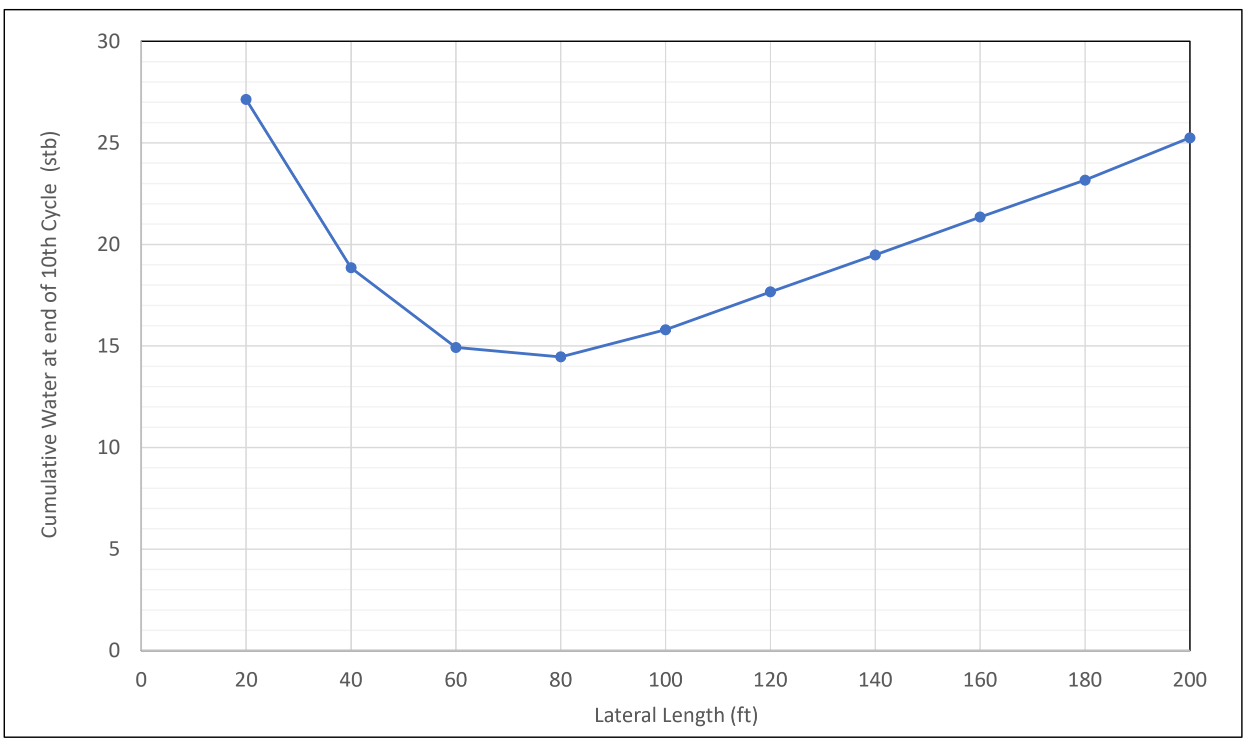

Figure 23. *Cumulative water production at the 10th production cycle vs. horizontal well length for a well placed in layer 9.*

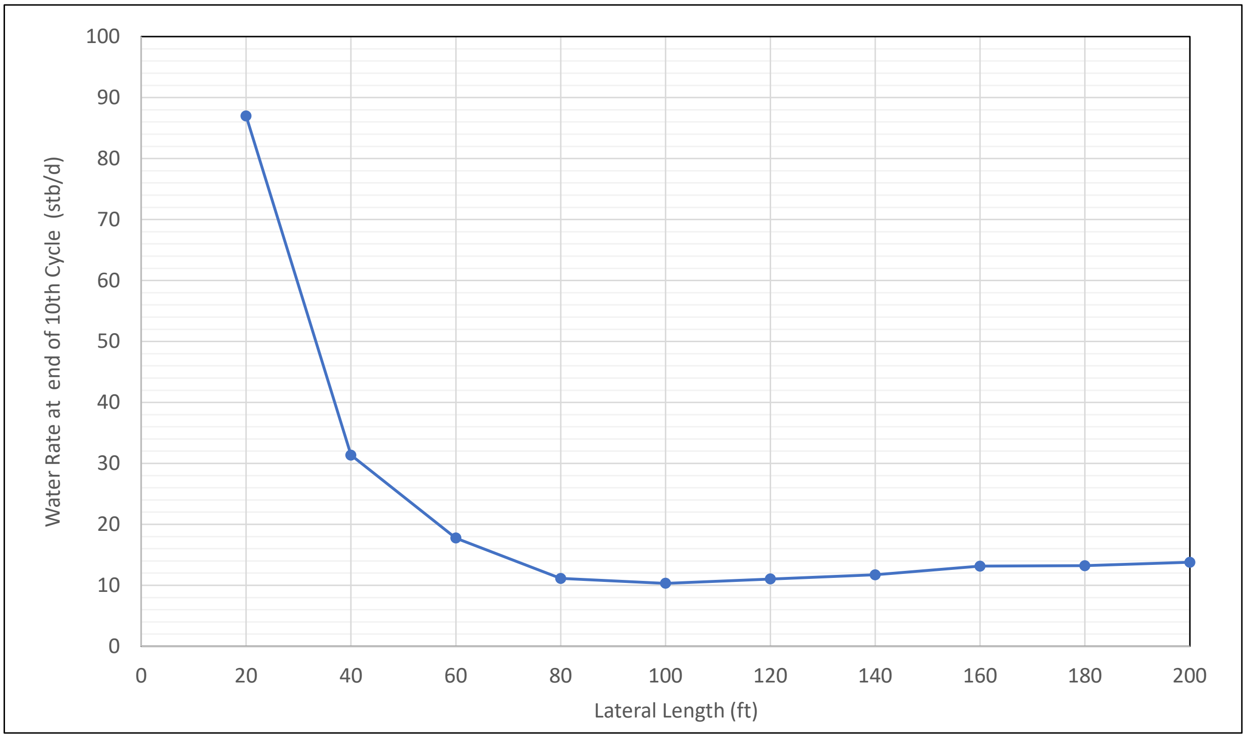

Figure 24. *Water production rate at the 10th production cycle vs. horizontal well length for a well placed in layer 9.*

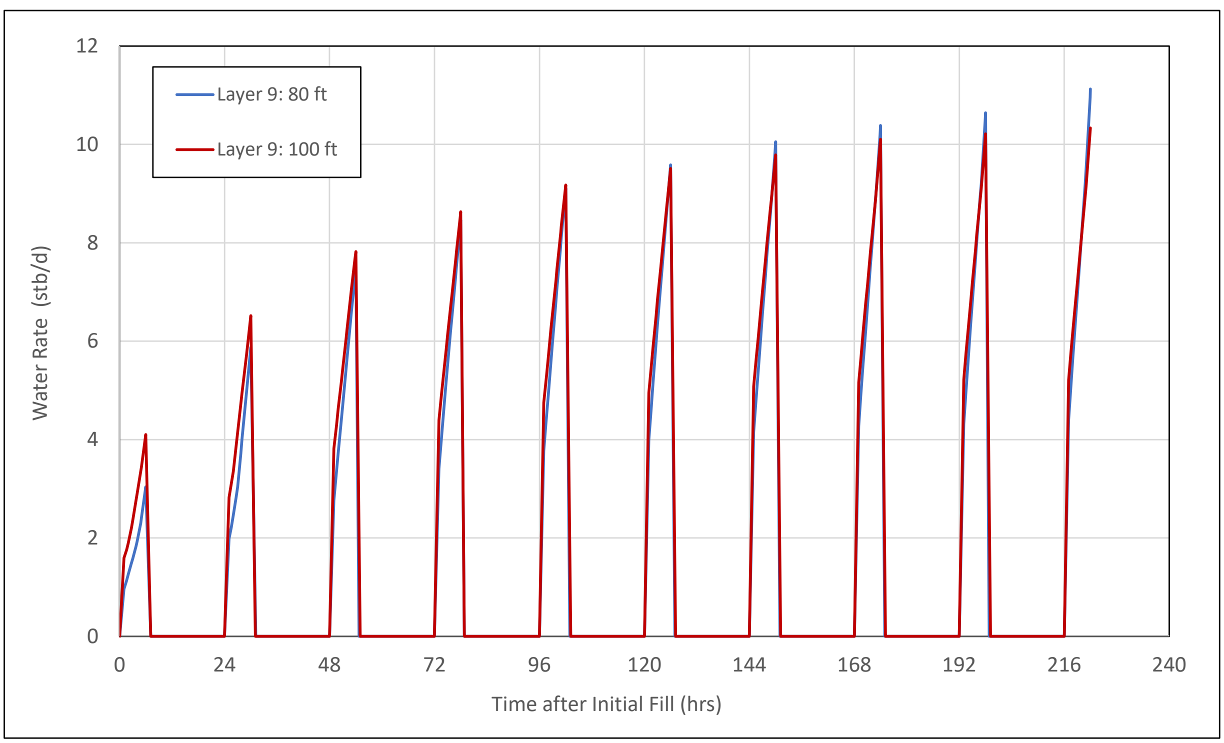

Figure 25. *Water production rate vs. time after initial fill for horizontal wells of length 80 and 100 ft completed in layer 9.*

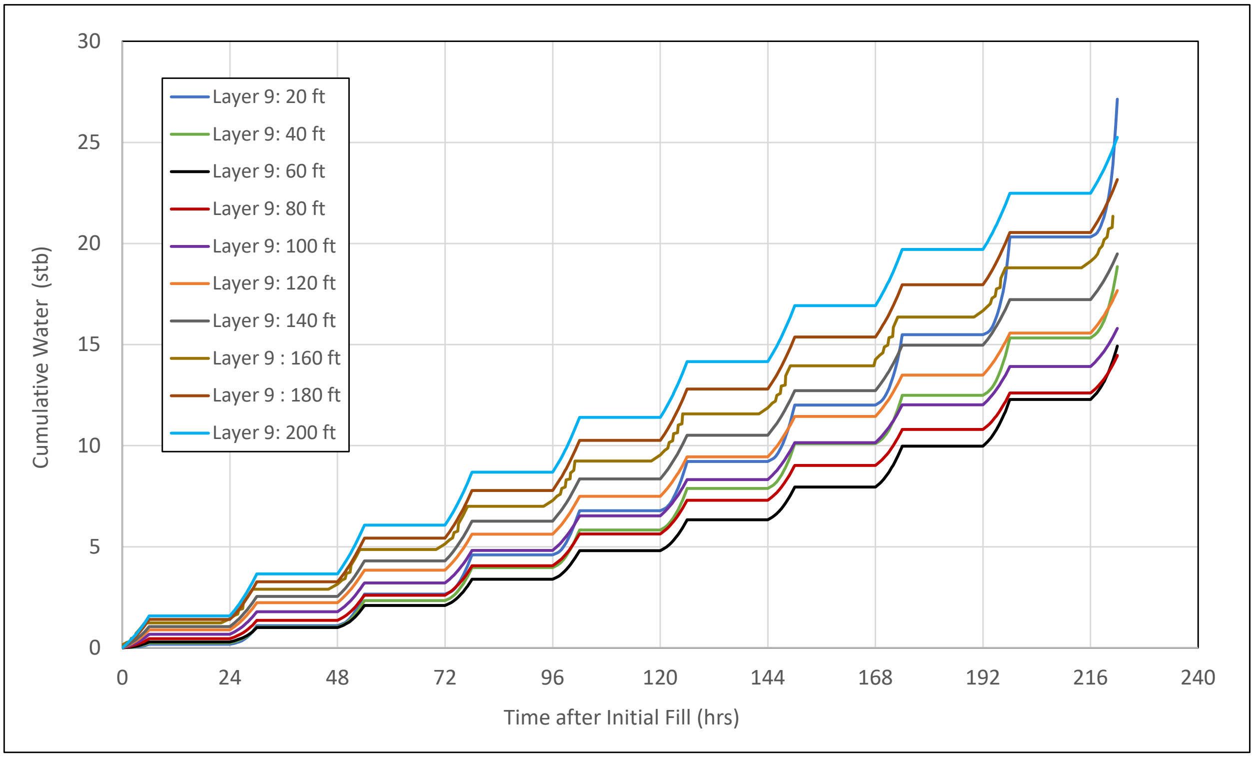

Figure 26. *Cumulative water production vs. time after initial fill for a horizontal well of different lengths completed in layer 9.*

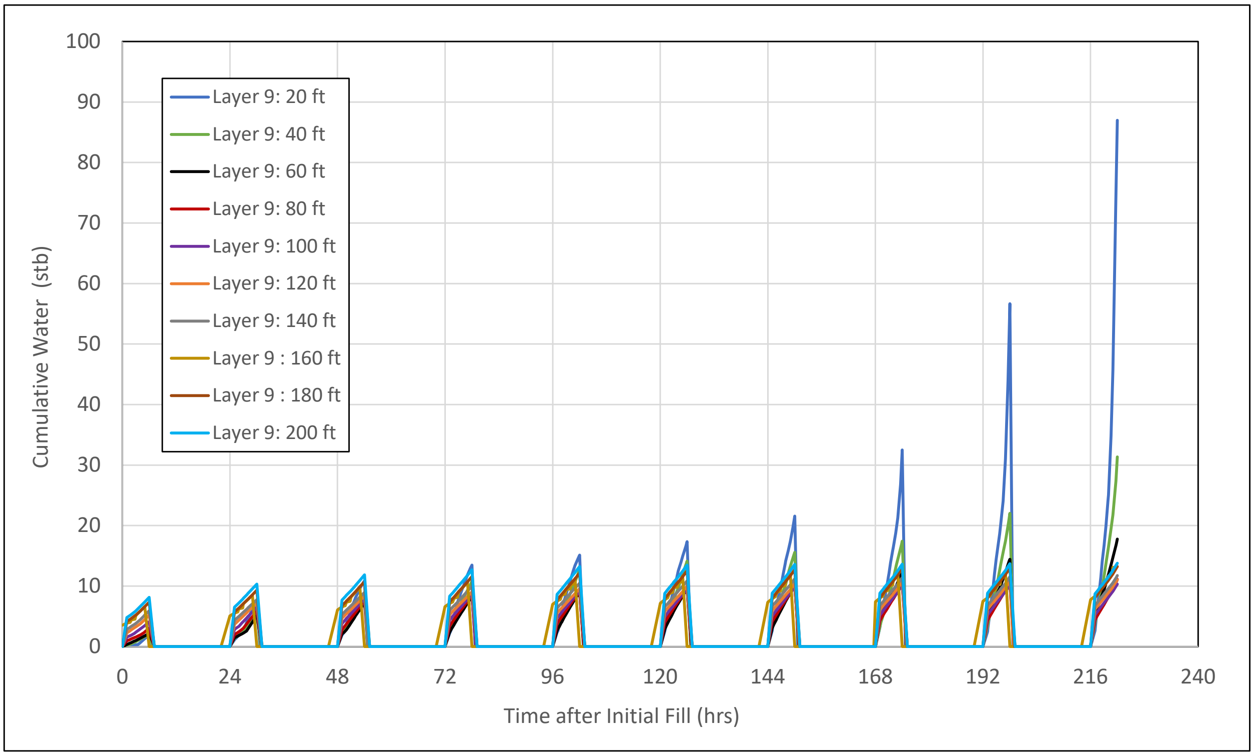

Figure 27. *Cumulative water production vs. time after initial fill for a horizontal well of different lengths completed in layer 9.*

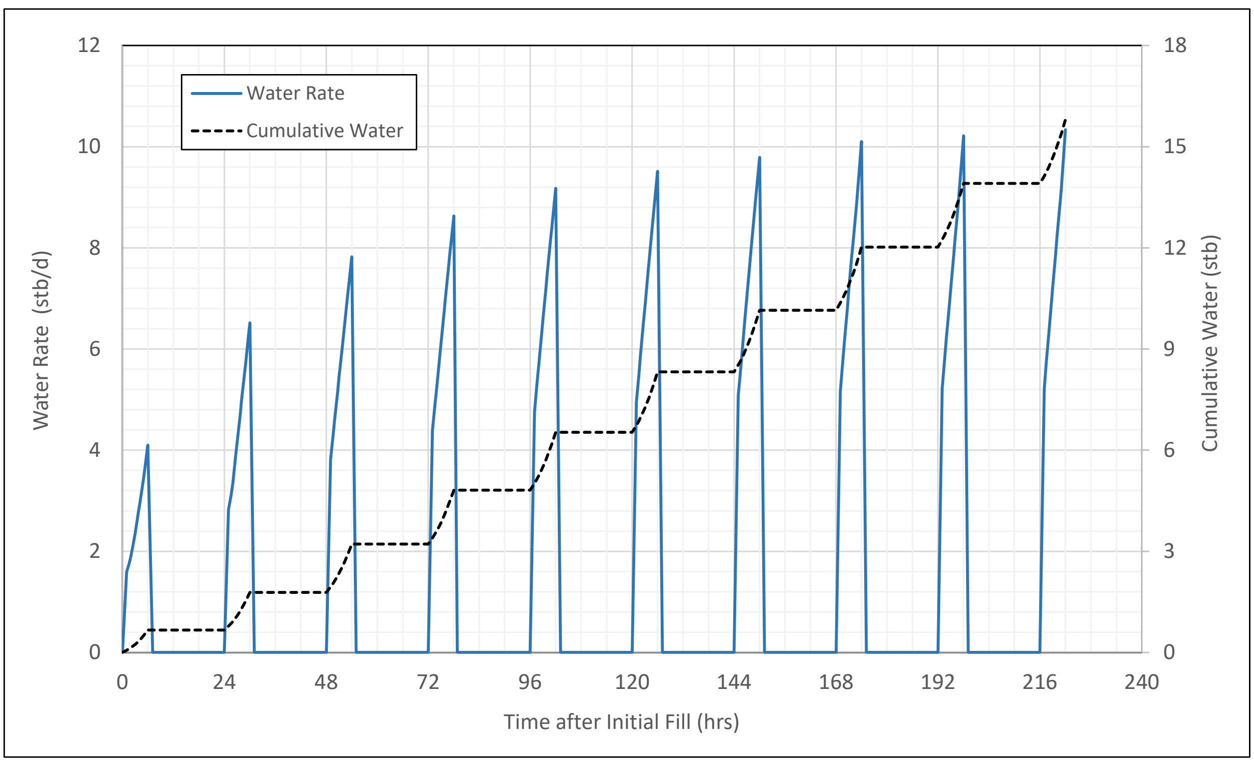

__Figure 28__. Water production rate and cumulative water production vs. time after initial fill for the optimal horizontal well, which is 100 ft long and located 4.5 ft below the top of the Upper Mt Simon.

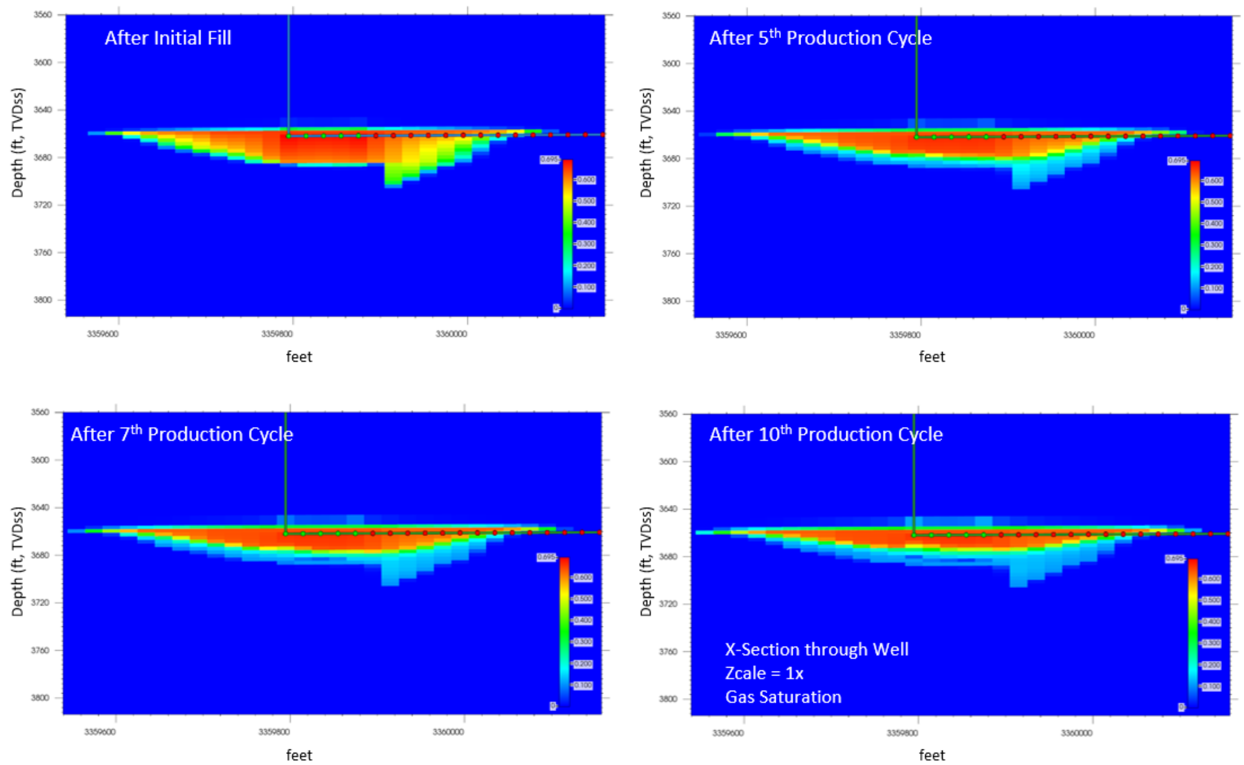

__Figure 29__. Cross-section through the center of the model showing gas saturation vs. time for the optimal horizontal well, which is 100 ft long and located 4.5 ft below the top of the Upper Mt Simon.

3.2.2.3 Cushion Gas Sensitivity

The simulations presented in the proceeding sections are based on 90% cushion gas (percent of total gas). Sensitivities were run to assess the impact of cushion gas on water production for both the optimal vertical and horizontal wells. The simulation cases were run for 10 drain/fill cycles.

Figure 30 through Figure 32 show the simulation results for a vertical well. Figure 30 shows that cushion gas has a significant impact on water production during gas cycling. Water production decreases as cushion gas increases. Figure 31 shows cumulative water production vs. time after initial fill for various amounts of cushion gas. There is a significant reduction in water production rate for cushion gas volumes greater than 85%. Figure 32 shows water production rate vs. time after initial fill for cushion gas volumes of 90, 95 and 97%. There is a significant reduction in water production rate at 95% cushion gas relative to 90% cushion gas. The reduction in water production rate is much smaller when cushion gas is increased from 95 to 97%. However, the rate of increase in water production with each cycle is lower with 97% cushion gas.

Figure 33 and Figure 34 show the simulation results for a horizontal well. Figure 33 shows that cushion gas has a significant impact on water production during gas cycling. Water production decreases as cushion gas increases. Figure 34 shows cumulative water production vs. time after initial fill for various amounts of cushion gas. There is a significant reduction in water production rate for cushion gas volumes greater than 80%.

Figure 35 and Figure 36 compare the impact of cushion gas volume on water production for vertical and horizontal wells. Figure 35 shows cumulative water production at the end of the 10th production cycle vs. cushion gas for both a vertical and horizontal well. Water production performance is similar for both vertical and horizontal wells for cushion gas ≥ 95%. Figure 36 shows water production rates vs. time after initial fill for 95% cushion gas for both a vertical and horizontal well. Initially, a vertical well produces less water but after two drain/fill cycles the vertical well produces more water than the horizontal well for all subsequent drain/fill cycles. The results indicate that a horizontal well is more effective at reducing water production during compressed air cycling in the Upper Mt Simon.

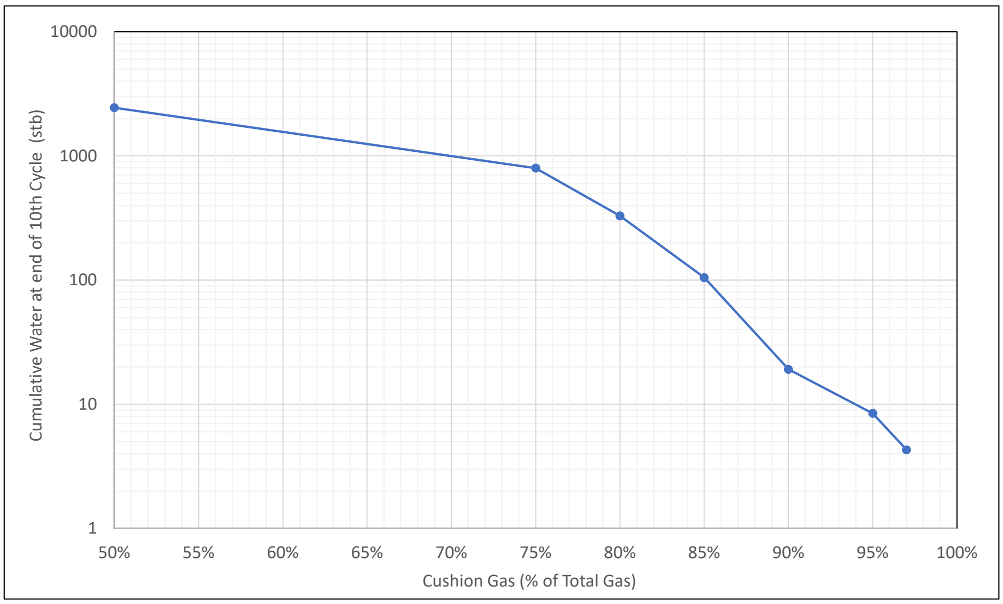

Figure 30. *Cumulative water production at the end of the 10th production cycle vs. cushion gas for a vertical well.*

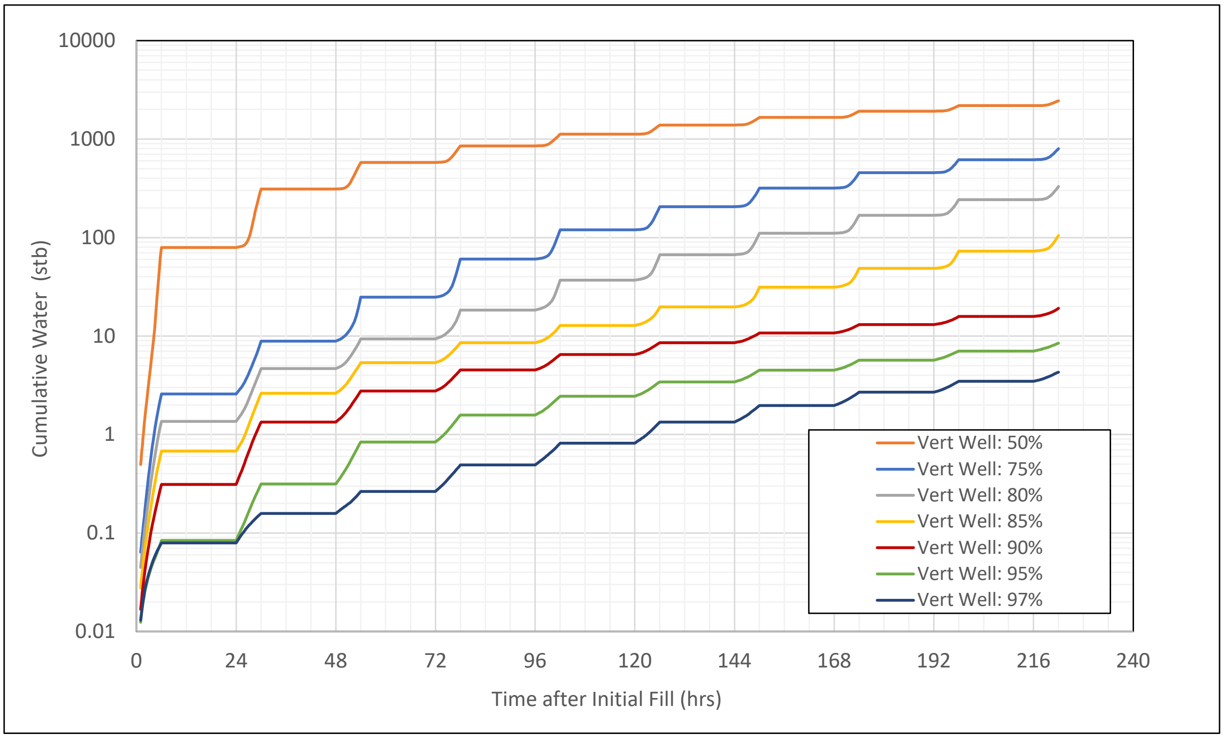

Figure 31. *Cumulative water production vs. time after initial fill for a vertical well for various cushion gas volumes.*

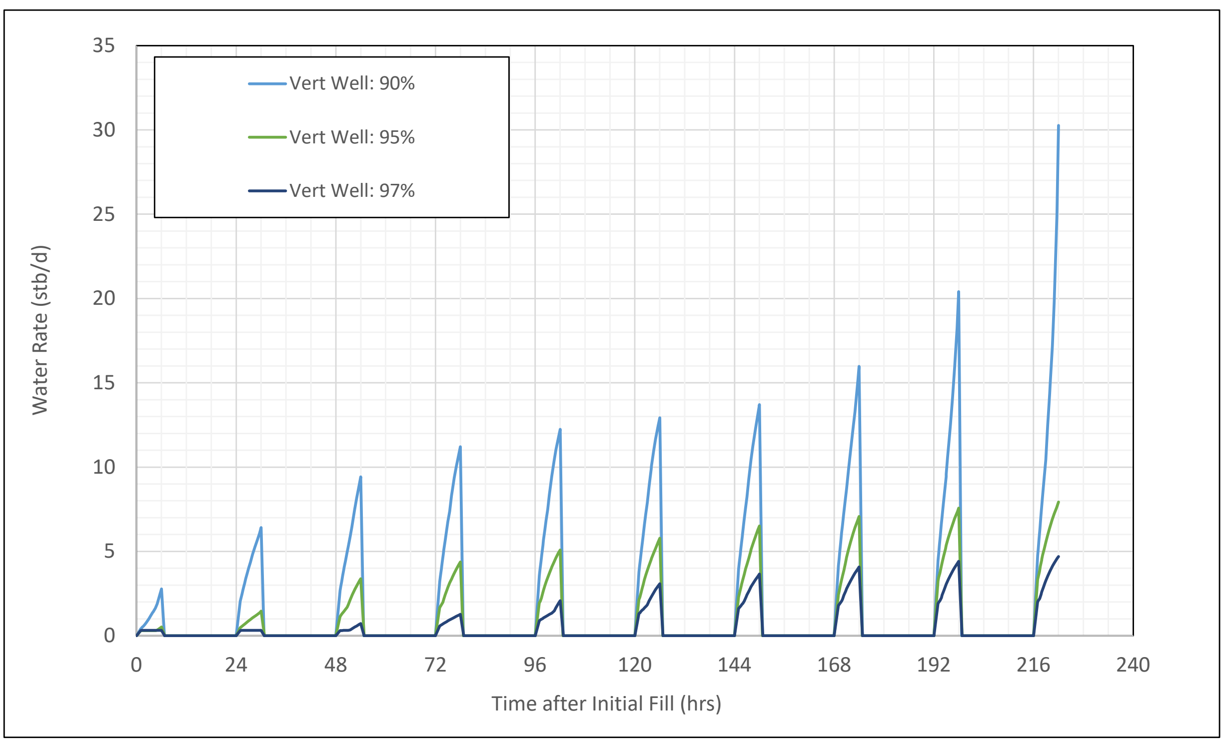

Figure 32. *Cumulative water production vs. time after initial fill for a vertical well for cushion gas volumes 90, 95, and 97%.*

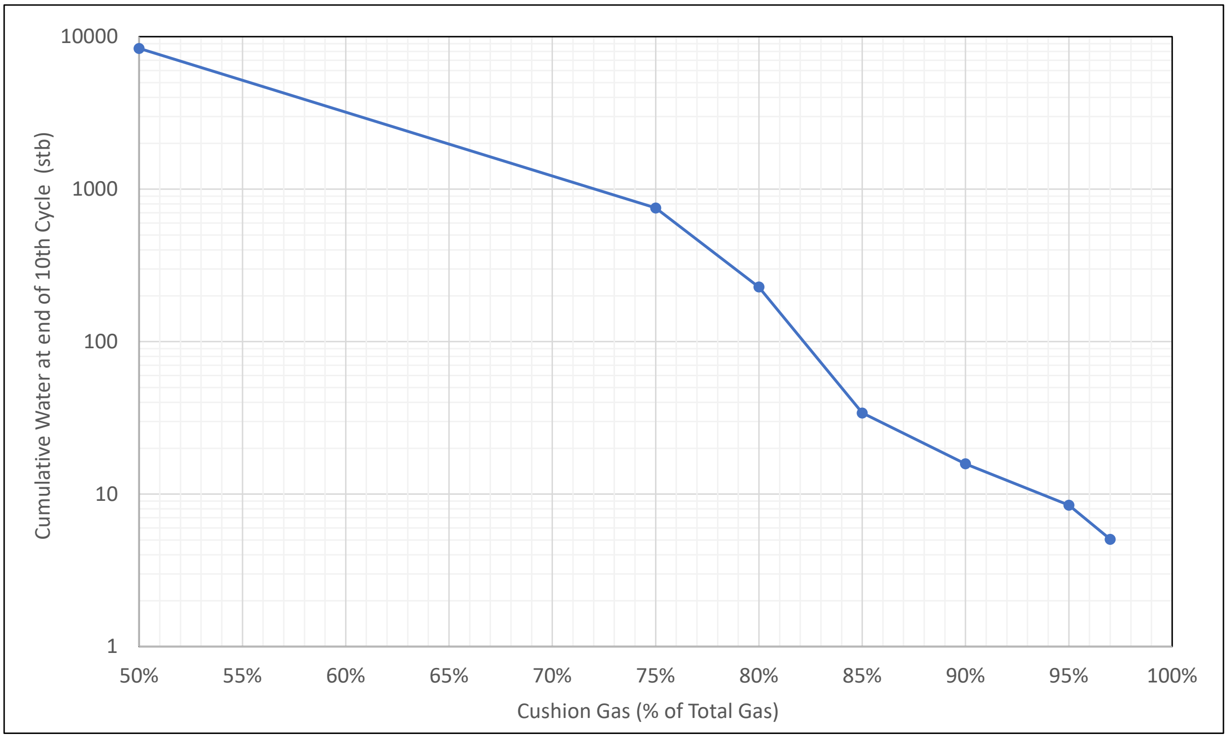

Figure 33. *Cumulative water production at the end of the 10th production cycle vs. cushion gas for a horizontal well.*

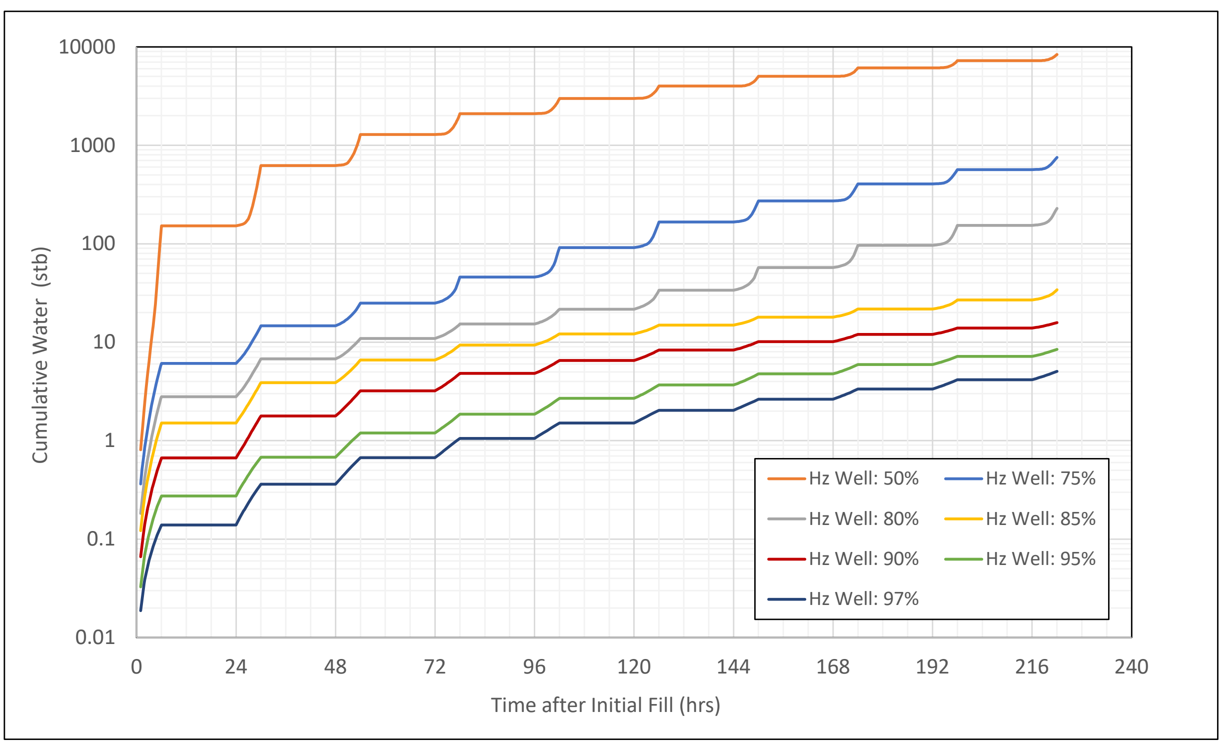

Figure 34. *Cumulative water production vs. time after initial fill for a horizontal well for various cushion gas volumes.*

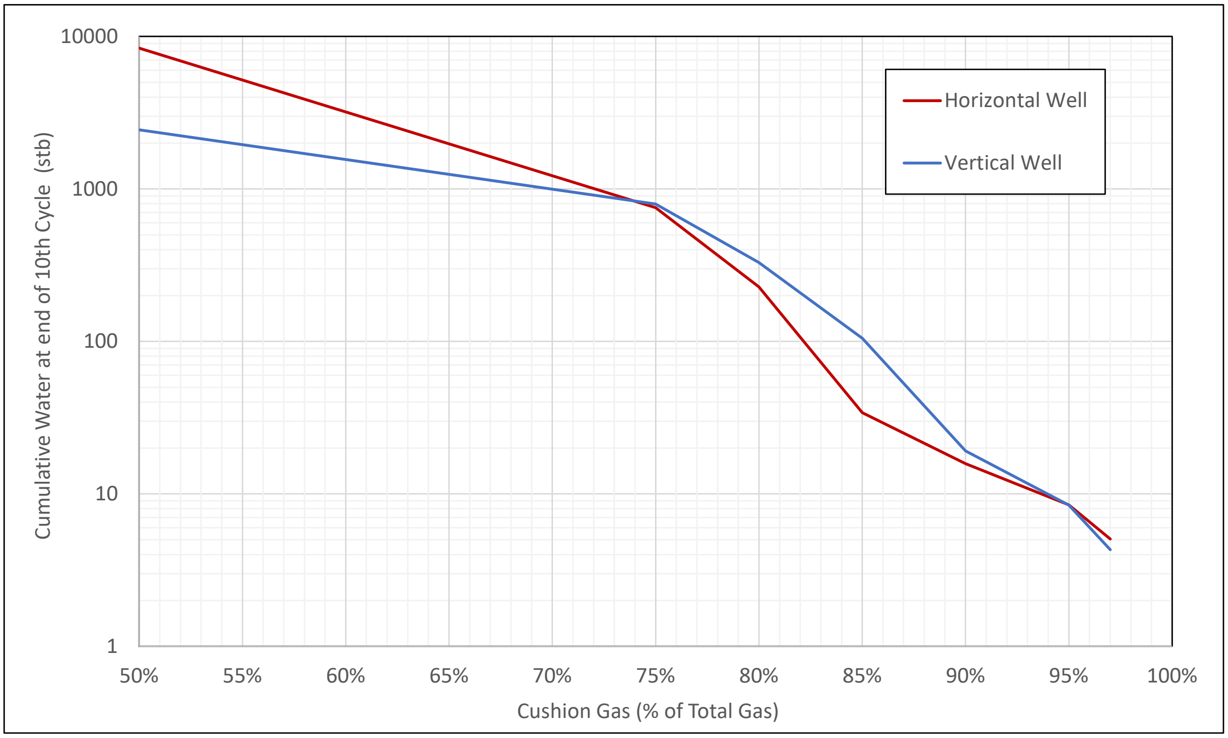

Figure 35. *Cumulative water production at the end of the 10th production cycle vs. cushion gas for both a vertical and horizontal well.*

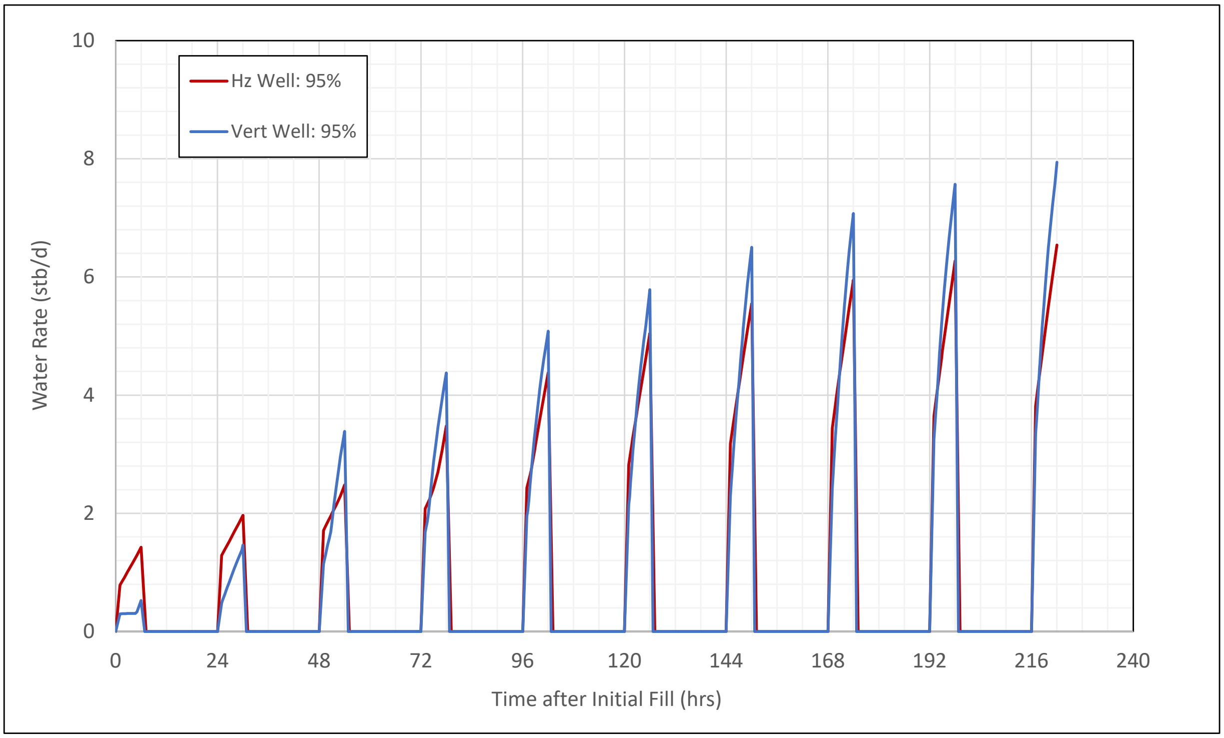

Figure 36. *Water production rate vs. time after initial fill with 95% cushion gas for both a vertical and horizontal well.*

12.Conclusions

A *STARS* dynamic simulation model for the Mt Simon sandstone was constructed using the geologic model exported from *Petrel*. Reservoir simulations were performed to assess the compressed air cycling performance of the Upper Mt Simon. A single injection/production well is assumed. This project requires a working gas volume of 1.57 MMscf, which is cycled in and out of the reservoir on a daily basis. Compressed air is injected at a rate of 2.09 MMscf/d for 18 hours, and then compressed air is produced at a rate of 6.28 MMscf/d for 6 hours. The cycle repeats daily.

Learnings from the Mt Simon simulation study are as follows:

- The overall injectivity of the Upper Mt Simon is large, with an injectivity of 170 MMscf/d of compressed air; constrained by 90% of the fracture gradient of 0.71 psi/ft.
- Three potential injection intervals were identified in the Upper Mt Simon; each with an overlying and underlying low permeability interval to help trap the compressed air.
- The upper zone of the Upper Mt Simon was selected as the injection interval for the compressed air cycling assessment. This zone has an average permeability of 117 mD and is overlain by the low-perm Eau Claire and underlain by low permeability intervals that help trap the injected compressed air.
- Due to the relatively flat structure of the Mt Simon at UIUC, water coning during the production cycle is observed. Optimal vertical and horizontal wells were identified to minimize water production during cycling operations.
- The optimal vertical well has a perforation length of 6 ft, starting at the top of the Upper Mt Simon.
- The optimal horizontal well is located 4.5 ft below the top of Upper Mt Simon and has a perforation length of 100 ft.
- Cushion gas has a significant impact on water production during compressed air cycling. Water production decreases as cushion gas increases.
- Water production performance is similar for both vertical and horizontal wells for cushion gas ≥ 95%.
- A horizontal well is more effective at reducing water production during compressed air cycling in the Upper Mt Simon at UIUC.
- Simulation results indicate that water production will continue to increase with each drain/fill cycle for both vertical and horizontal wells. Further studies should focus on how to minimize water production during a continuous operation. Options to reduce water production may include but should not be limited to:
    - 1). multiple gas injectors to reduce water saturation surrounding one producer,
    - 2). water extraction, and
    - 3). inject cross-linking polymer slugs ahead of the fill gas to create an artificial salt diapir that could reduce water coning and cushion gas.

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Appendix 3

TECHNOECONOMIC STUDY
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15.Introduction

This Technoeconomic Study (TES) document will discuss a proposed prototype process for Compressed Air Energy Storage (CAES) for the Abbott Power Plant. The TES covers process simulation, simulation results, estimated cost of electricity, and a comparison of the prototype facility with the existing Huntorf and McIntosh CAES plants and (where possible) the proposed commercial-scale CAES plant in Iceland.

The purpose of the proposed prototype plant is to test how the storage component performs. The goal of the proposed prototype test is to demonstrate how well a CAES plant can operate when using a porous sandstone formation for compressed air storage. The two existing industrial scale CAES plants use salt caverns for compressed air storage. Demonstrating that CAES plants can successfully operate using porous stone formation storage will represent a substantial increase in the number of geographical regions where CAES plants can be implemented.

Surface equipment including compressors and turbines are not a primary focus of the study, therefore attempts to obtain optimum energy efficiency of surface equipment are beyond the scope of the present study. An effort will be made to minimize capital cost of the surface equipment for the prototype system due to the short-term, research nature of the project as compared to a commercial CAES application.

To Trimeric's knowledge, a prototype CAES plant has not been built using the storage structure proposed for this project, so should this prototype be built and be successful in storing energy, it will increase the number of locations where CAES can be used.

16.Simulation Results

The process flow diagram (PFD) for the proposed CAES prototype cycle is shown in Figure 1. The simulation results used to develop the estimates in this section are provided in Appendix A. Figure 2 can also be seen below. This is a flow diagram that shows the surface facility equipment in more detail than the basic PFD seen in Figure 1.

Steady state simulations were used to specify the surface equipment. A study investigating the dynamic pressure swings of the storage formation, and the effects on surface equipment sizing / performance, should be part of future engineering activities.

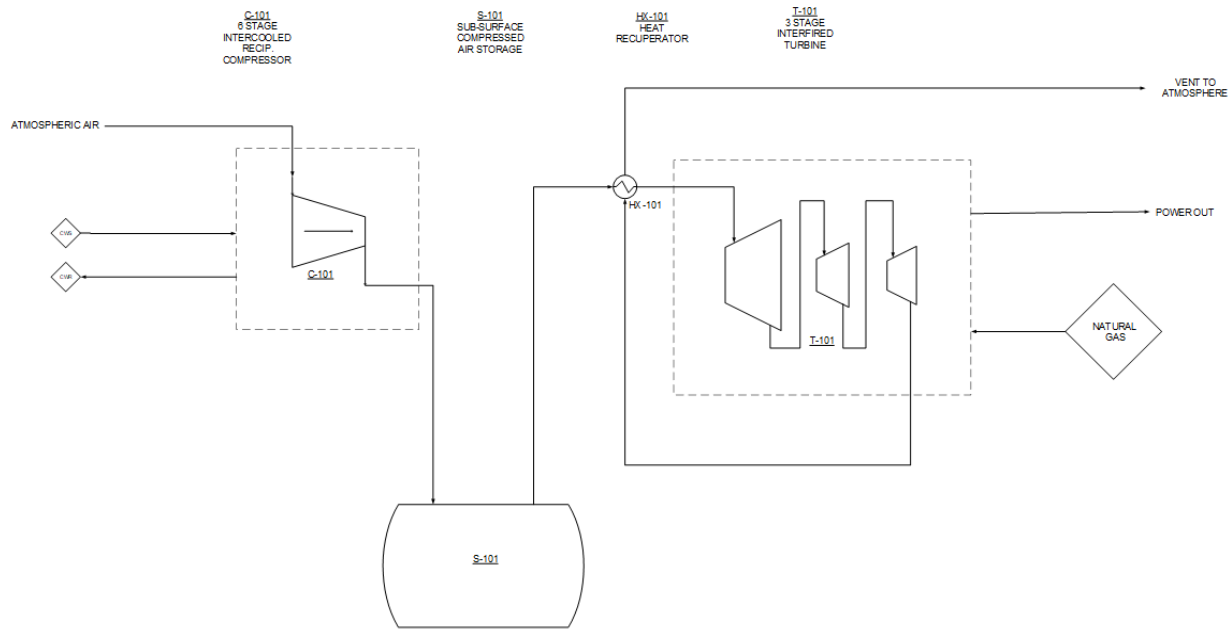


Figure 37: Abbott CAES Plant PFD

Like all CAES plants, this prototype will operate in one of two modes: energy storage and energy extraction. These modes are described below.

In energy storage mode, the proposed prototype process will use a 6-stage reciprocating compressor to compress 2.11 MMSCFD (1,465 scfm) of ambient air to 1,864 psig during an 18-hour storage period and direct the compressed air to an injection well for a subsurface porous stone formation. Estimated pressure in the porous stone formation is 2,150 psig. During this storage period, a total of 10 MWh of energy is stored in the porous rock formation in the form of compressed air. Reciprocating compressors were chosen for this prototype because, for the small flow rates used in this demonstration, they represent a smaller capital investment than centrifugal compressors.

In energy extraction mode, when energy is needed, compressed air is produced from the storage formation well at a flow rate equivalent to 6.34 MMSCFD (4,402 scfm) at 1,815 psig and 82.5 ^{o}F. The air from the well is heated first by recuperation (heat exchange with hot turbine exhaust gas) and then via direct heat from a burner using natural gas prior to each stage of expansion. The incorporation of the heat recuperation exchanger increases the total plant efficiency (defined below) from 35% to 44% according to the simulation, which represents a significant benefit. In the simulation, the turbine and compressor polytropic efficiencies were set to 86% to represent typical industry values. The results from the simulation are summarized in Table 1 and Table 2.

The plant efficiency is calculated by taking the output work of the turbines in MWh and dividing it by the sum of the input thermal energy in MWh and the input electrical energy in MWh. This is shown in the following equation: $\eta_{plant} = \frac{W_{turbine}}{W_{Compressor} + Q_{Burner}}$ [1]

This equation relates the energy output of the CAES plant to the total energy input into the CAES plant. The air compressors are powered by renewable energy and / or excess fossil-fuel energy received from the grid.

Fuel Rates	(Natural Gas)	
Burner 1	4101	SCFH
Burner 2	2355	SCFH
Burner 3	2968	SCFH
Total	9424	SCFH

Table 4: Burner Natural Gas Flow Rates

Efficiency Calculation		
Power In		
Compressor 1	0.11	MWe
Compressor 2	0.10	MWe
Compressor 3	0.10	MWe
Compressor 4	0.09	MWe
Compressor 5	0.09	MWe
Compressor 6	0.03	MWe
Total	0.52	MWe
Operating Time	18.00	Hours
MWh	9.29	MWh
Burner 1 LHV	1.11	MWth
Burner 2 LHV	0.64	MWth
Burner 3 LHV	0.80	MWth
Total	2.54	MWth
Operating Time	6.00	Hours
MWh	15.27	MWh
Total Energy In	24.55	MWh
Power Out		
Turbine 1	0.63	MWe
Turbine 2	0.58	MWe
Turbine 3	0.58	MWe
T[illegible]	[illegible]	[illegible]
Operating Time	6.00	Hours
MWh	10.70	MWh
Energy out / in	0.44	
Efficiency	44	%

Table 5: Abbott CAES Plant Efficiency Calculation – Based Off Steady State Simulations

MWe (megawatts of electric power) and MWth (megawatts of thermal power) are treated as equivalent units of measure for this calculation when each is multiplied by the cycle time to estimate the energy in MWh (megawatt-hours). As shown in Table 1, the predicted plant efficiency is approximately 44%. A burner efficiency of 75% was used in the simulation, meaning that 75% of heat released from

Table 6: Heat Rate Calculation for the Abott CAES Plant

Plant Power MW	Heat Rate in BTU/kWh
160	3,823
105	3,849
85	3,873
65	3,908
50	3,947
45	4,002
20	4,174

burning the natural gas (on a lower heating value basis) is transferred to the fluid (compressed air in this case).

Heat Rate in BTU/kWh		
LHV of Methane	900	BTU/scf
Fuel Flow Rate	9424	SCFH
Plant Power	1780	kW
Heat Rate	4760	BTU/kWh

Table 7: Heat Rates for CAES Plants of Varying Power Output

In Table 3, the heat rate of the 1.8 MW Abbott prototype CAES plant is calculated as 4,760 BTU of thermal energy required per kW of electrical output. This value is in general agreement with representative heat rates for larger power plants as shown in Table 4 [2]. It is important to note that the trend seen for CAES plants is that the heat rate is lower at larger power plants than it is at smaller power plants.

17.Cost of Electricity and Normalized Capital Cost

The cost of electricity is one method used to compare one CAES plant to another. Cost of electricity is calculated by dividing the sum of the total capital cost (annualized over an assumed service life of 30 years) and the annual operating cost by the total electricity output. The calculated cost of producing and storing electricity for the proposed prototype process is $0.29 / kWh as shown in Table 5. This calculation is based on continuous, year-round operation with 18 hours per day operating in storage mode, and 6 hours per day operating in extraction mode. The costs for incremental cooling water were not estimated. The cost of the air injection / production well was not included, due to limited availability of data. However, Trimeric believes this cost will be significant in the total capital cost of the plant.

Electricity Cost per Produced kWh ($/kWh)		
Total Capital Cost	13,460	USD /1000
Capital cost over 30 Years (capital cost/30)	449	USD /1000 per year
Natural Gas Cost (at $7.7 per 1000 cubic feet)	150	USD /1000 per year
Labor Cost (1 operator at 72k per year)	72	USD /1000 per year
Maintenance Cost (2% of total capital cost)	269	USD /1000 per year
Compressor Electricity Cost (assuming 0.07 $/kwh)	237	USD /1000 per year
Total Operating Cost + Annualized Capital Cost	1,177	USD /1000
kWh per year	3,898,200	kWh
Electricity Cost	0.30	$/kWh

Table 8: Abbott CAES Plant Cost of Electricity Calculation

The method used to compute the capital cost per year over 30 years was simply dividing the total capital cost by 30. This number can be expected to increase if a capital recovery factor is used, or if the period was changed from 30 years to a different amount of time. An increase in the capital cost per year

Another method to compare CAES plants is the cost per unit of power ($/MW), also called normalized capital cost. It is typically higher at the lower end of the power range. This can be seen in tables 6 and 8.

Natural Gas Cost (at $7.7 per 1000 cubic feet)	150	USD /1000 per year
Labor Cost (1 operator at 72k per year)	72	USD /1000 per year
Maintenance Cost (2% of total capital cost)	248	USD /1000 per year
Compressor Electricity Cost (assuming 0.07 $/kwh)	237	USD /1000 per year
Operating Cost per Year	707	USD /1000 per year

Table 10: Abbott CAES Plant Operating Cost

18.Plant Comparisons

There are currently two operating commercial scale CAES plants. These are the McIntosh plant in Alabama, and the Huntorf plant in Germany. Due to the limited availability of info on the Huntorf plant, the proposed Abbott plant will be compared to the McIntosh plant only. The methods of comparison are plant efficiency, total capital cost, cost of electricity in $/kWh, normalized cost in $/kW, and heat rates in BTU/kW. The comparisons are shown in Table 8.

Criteria	McIntosh	Abbott (Proposed)
Capital Cost (MMUSD)	195	12.4
Cost per kWh (USD)	0.06	0.3
Power Output (MW)	160	1.78
Efficiency	53%	44%
Normalized Cost $/kW	1,219	7,562
Heat Rate BTU/kWh	3,823	4,760

Table 11: CAES Plant Comparisons

As seen in the tables, the normalized cost of power ($/kW) is much higher at the smaller scale. This is because the equipment power does not scale linearly with cost. This leads to a higher cost of electricity in $/kWh.

The heat rates of the two CAES plants are comparable to each other. The heat rate is the amount of heat required to produce a kWh of electricity. Typically, commercial CAES plants have heat rates of approximately 4,000 BTU/kWh, however as the scale of the plant decreases, the heat rate increases.

Table 8 also shows that the estimated efficiency for the Abbott prototype plant is comparable to the commercial scale plants. Additional work is needed in the proposed Phase II Pre-FEED study and in subsequent project development to improve the accuracy of the estimated efficiency for the prototype plant. The primary goal this proposed project is to determine the effectiveness of the porous sandstone formation for compressed air energy (pressure and temperature) storage and its impact on the efficiency of the overall cycle. At the small scale of the prototype test, project economics often incentivize less energy efficient equipment in order to minimize capital costs. A commercial scale CAES unit based on the prototype process would achieve better energy efficiency than the prototype.

19.References

[1] Elmegaard, B., & Brix, W. (2011). Efficiency of Compressed Air Energy Storage. In The 24th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems: The 2011 conference motto: International Smart Energy Networks of Cooperation for Sustainable Development

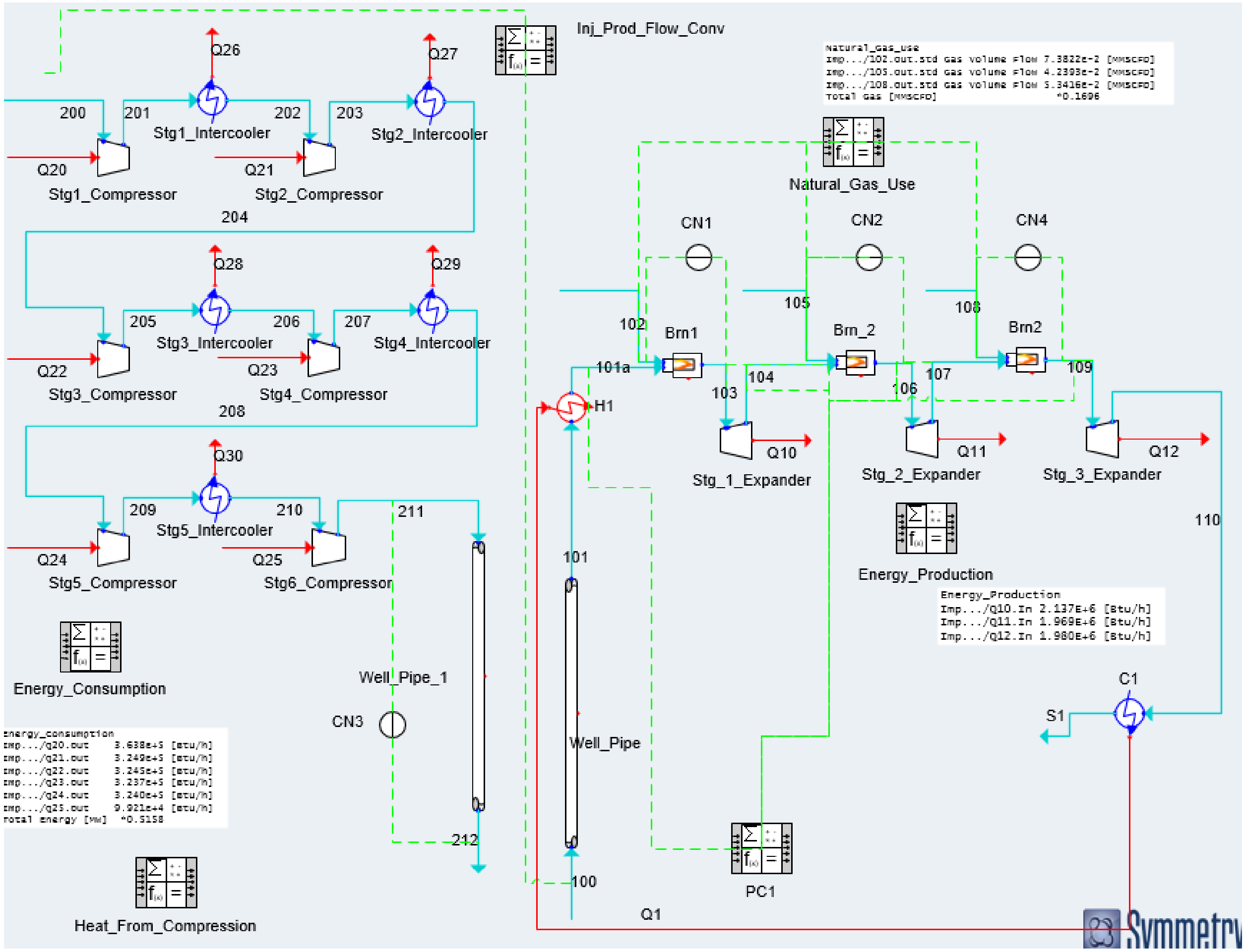
[2] Bailie, B., 2021. *Compressed Air Energy Storage*. [online] Netl.doe.gov. Available at: <https://netl.doe.gov/sites/default/files/netl-file/21TMCES_Bailie.pdf> [Accessed 10 February 2022].

[3] https://www.araner.com/blog/heat-rate-improvement

Appendix A – Process Simulation Results Summary

Back to Index	100	101	102	103	104	105	106	107	108	109	110	200	201	202
In.VapFrac	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
In.T [F]	**110.00**	82.48	**70.00**	1000.00	607.61	**70.00**	900.00	531.23	**70.00**	900.00	532.92	**76.00**	**300.00**	100.00
In.P [psia]	**2165.00**	1827.08	**1900.00**	1802.08	450.52	**500.00**	450.52	112.63	**100.00**	100.00	**25.00**	**14.70**	42.36	37.36
In.Energy [Btu/h]	2502949.75	2373320.01	26449.08	7434516.32	5297348.84	18529.92	6925818.68	4956508.91	24650.14	7009719.24	5029802.10	861595.01	1225409.05	899253.71
In.Mole Flow [lbmol/h]	696.52	696.52	8.11	704.62	704.62	4.65	709.28	709.28	5.87	715.14	715.14	232.17	232.17	232.17
In.Mass Flow [lb/h]	20174.60	20174.60	130.03	20304.63	20304.63	74.67	20379.30	20379.30	94.09	20473.39	20473.39	6724.87	6724.87	6724.87
In.Volume Flow [ft3/s]	0.55	0.61	0.01	1.76	5.02	0.01	6.43	18.64	0.09	29.03	84.67	25.21	12.42	10.36
In.Std Gas Volume Flow [MMSCFD]	6.34	6.34	0.07	6.42	6.42	0.04	6.46	6.46	0.05	6.51	6.51	2.11	2.11	2.11
In.Mass Density [lb/ft3]	10.18	9.20	6.70	3.20	1.12	1.52	0.88	0.30	0.29	0.20	0.07	0.07	0.15	0.18
In.MW	28.97	28.97	16.04	28.82	28.82	16.04	28.73	28.73	16.04	28.63	28.63	28.97	28.97	28.97
In.Mole Fraction [Fraction]														
NITROGEN	**0.78**	0.78	**0.00**	0.77	0.77	**0.00**	0.77	0.77	**0.00**	0.76	0.76	**0.78**	0.78	0.78
OXYGEN	**0.21**	0.21	**0.00**	0.18	0.18	**0.00**	0.17	0.17	**0.00**	0.15	0.15	**0.21**	0.21	0.21
ARGON	**0.01**	0.01	**0.00**	0.01	0.01	**0.00**	0.01	0.01	**0.00**	0.01	0.01	**0.01**	0.01	0.01
CARBON DIOXIDE	**0.00**	0.00	**0.00**	0.01	0.01	**0.00**	0.02	0.02	**0.00**	0.03	0.03	**0.00**	0.00	0.00
WATER	**0.00**	0.00	**0.00**	0.02	0.02	**0.00**	0.04	0.04	**0.00**	0.05	0.05	**0.00**	0.00	0.00
METHANE	**0.00**	0.00	**1.00**	0.00	0.00	**1.00**	0.00	0.00	**1.00**	0.00	0.00	**0.00**	0.00	0.00
In.MoleFlows [lbmol/h]														
NITROGEN	543.88	543.88	0.00	543.88	543.88	0.00	543.88	543.88	0.00	543.88	543.88	181.29	181.29	181.29
OXYGEN	145.90	145.90	0.00	129.69	129.69	0.00	120.38	120.38	0.00	108.65	108.65	48.63	48.63	48.63
ARGON	6.51	6.51	0.00	6.51	6.51	0.00	6.51	6.51	0.00	6.51	6.51	2.17	2.17	2.17
CARBON DIOXIDE	0.23	0.23	0.00	8.34	8.34	0.00	12.99	12.99	0.00	18.86	18.86	0.08	0.08	0.08
WATER	0.00	0.00	0.00	16.21	16.21	0.00	25.52	25.52	0.00	37.25	37.25	0.00	0.00	0.00
METHANE	0.00	0.00	8.11	0.00	0.00	4.65	0.00	0.00	5.87	0.00	0.00	0.00	0.00	0.00
In.Cp [Btu/lbmol-F]	8.37	8.36	12.77	7.48	7.41	9.65	7.58	7.34	8.88	7.67	7.37	6.96	7.07	6.99
In.Thermal Conductivity [Btu/h-ft-F]	0.02	0.02	0.03	0.04	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.01	0.02	0.01
In.Viscosity [cP]	0.02	0.02	0.01	0.04	0.03	0.01	0.04	0.03	0.01	0.04	0.03	0.02	0.02	0.02
In.Z Factor	1.00	0.98	0.80	1.03	1.01	0.92	1.01	1.00	0.98	1.00	1.00	1.00	1.00	1.00

Back to Index	203	204	205	206	207	208	209	210	211	212	101a	S1
In.VapFrac	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
In.T [F]	**300.00**	100.00	**300.00**	100.00	**300.00**	100.00	**300.00**	100.00	161.62	188.22	494.62	**100.00**
In.P [psia]	94.28	89.28	225.07	220.07	553.61	548.61	1377.03	1372.03	1879.47	2164.99	1802.08	10.00
In.Energy [Btu/h]	1224148.34	896601.10	1221051.96	890043.09	1213765.18	874378.28	1198409.77	840420.52	939634.51	982844.63	4604563.17	2798761.63
In.Mole Flow [lbmol/h]	232.17	232.17	232.17	232.17	232.17	232.17	232.17	232.17	232.17	232.17	696.52	715.14
In.Mass Flow [lb/h]	6724.87	6724.87	6724.87	6724.87	6724.87	6724.87	6724.87	6724.87	6724.87	6724.87	20174.60	20473.39
In.Volume Flow [ft3/s]	5.58	4.33	2.34	1.75	0.96	0.70	0.39	0.28	0.23	0.21	1.15	119.25
In.Std Gas Volume Flow [MMSCFD]	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	6.34	6.51
In.Mass Density [lb/ft3]	0.33	0.43	0.80	1.07	1.95	2.67	4.77	6.69	8.03	8.76	4.88	0.05
In.MW	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.63
In.Mole Fraction [Fraction]												
NITROGEN	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.76
OXYGEN	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.15
ARGON	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CARBON DIOXIDE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05
METHANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
In.MoleFlows [lbmol/h]												
NITROGEN	181.29	181.29	181.29	181.29	181.29	181.29	181.29	181.29	181.29	181.29	543.88	543.88
OXYGEN	48.63	48.63	48.63	48.63	48.63	48.63	48.63	48.63	48.63	48.63	145.90	108.65
ARGON	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	6.51	6.51
CARBON DIOXIDE	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.23	18.86
WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.25
METHANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
In.Cp [Btu/lbmol-F]	7.10	7.03	7.15	7.14	7.27	7.40	7.55	7.99	8.00	8.02	7.55	7.08
In.Thermal Conductivity [Btu/h-ft-F]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.01
In.Viscosity [cP]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02
In.Z Factor	1.00	1.00	1.00	0.99	1.01	0.99	1.02	0.98	1.01	1.02	1.04	1.00


Inj_Prod_Flow_Conv
Natural_Gas_Use
Imp.../102.out.std gas volume flow 7.3822e-2 [MMSCFD]
Imp.../105.out.std gas volume flow 4.2393e-2 [MMSCFD]
Imp.../108.out.std gas volume flow 5.3416e-2 [MMSCFD]
Total gas [MMSCFD] *0.1696
Natural_Gas_Use
Q26
Q27
200
201
202
203
Stg1_Intercooler
Stg2_Intercooler
Q20
Q21
Stg1_Compressor
Stg2_Compressor
204
Q28
Q29
205
206
207
Stg3_Intercooler
Stg4_Intercooler
Q22
Q23
Stg3_Compressor
Stg4_Compressor
208
Q30
209
210
211
Stg5_Intercooler
Q24
Q25
Stg5_Compressor
Stg6_Compressor
Energy_Consumption
Energy_consumption
Imp.../Q20.out 3.638e+5 [Btu/h]
Imp.../Q21.out 3.249e+5 [Btu/h]
Imp.../Q22.out 3.245e+5 [Btu/h]
Imp.../Q23.out 3.237e+5 [Btu/h]
Imp.../Q24.out 3.240e+5 [Btu/h]
Imp.../Q25.out 9.921e+4 [Btu/h]
Total energy [MW] *0.5158
Heat_From_Compression
Well_Pipe_1
CN3
212
CN1
CN2
CN4
102
105
108
Brn1
Brn_2
Brn2
101a
103
104
106
107
109
H1
Q10
Q11
Q12
Stg_1_Expander
Stg_2_Expander
Stg_3_Expander
110
Energy_Production
Energy_Production
Imp.../Q10.In 2.137E+6 [Btu/h]
Imp.../Q11.In 1.969E+6 [Btu/h]
Imp.../Q12.In 1.980E+6 [Btu/h]
101
Well_Pipe
C1
S1
PC1
100
Q1
Symmetry

Appendix B – Capital Cost Estimation

ISGS
Compressed Air Energy Storage
Revision: A
Date: 2/21/22

	Cost	Factor	Basis	Comments
Purchased Equipment & Skids (PE)	**$3,829,000**	N/A	Itemized	
Freight & Taxes	$382,900	0.10	PE	Manufactured in USA
Total Delivered Equipment (TDE)	**$4,212,000**			
Installation	$1,474,200	0.35	Itemized	30-60% of PE per reference
Insulation	$0	0.00	TDE	Estimated, hot piping around compressor touchable
Instrumentation & controls	$631,800	0.15	TDE	Skidded with instruments/controls provided, other control system items included in PE cost
Piping (installed)	$2,106,000	0.50	TDE	
Electrical	$421,200	0.10	TDE	15-30% of PE per reference
Structural/civil	$842,400	0.20	TDE	10-20% of PE per reference
Utilties and Site Infrastructure	$210,600	0.05	TDE	Lube oil storage and sumps
Total installation-related costs	$5,686,200			
Total Direct Cost (TDC)	**$9,898,200**		2.59	
Engineering & supervision	$989,820	0.10	TDC	8% of Fixed Capital Investment per reference
Construction expenses	$791,856	0.08	TDC	8% of Fixed Capital Investment per reference, but skidded construction should minimize construction
Demobilization Cost	$494,910	0.05	TDC	
Contractor's fee	$296,946	0.03	TDC	2-8% of TDC per reference
Contingencies	$989,820	0.10	TDC	8% of Fixed Capital Investment per reference
Total overhead costs	$3,563,352			
Fixed Capital Investment	**$13,462,000**		3.52	"Lang factor" (FCI / PE)

ISGS
Compressed Air Energy Storage
Revision: A
Date: 2/21/22

Purchased Equipment

Item	Cost	Notes	
Microturbine	$2,040,000	600-1200$ per kw, 1700 kw	(facilitiesnet.com)
Recip compressor	$1,500,000	Compressor Cost Curves	
Heat Recuperator	$289,000	ASPEN Cost Estimator	

Total Purchased Equipment	**$3,829,000**		

Aspen Exchanger Design and Rating   Shell & Tube V10

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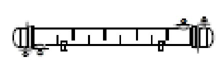
Costs/Weights

Weights	lb	**Cost data**	Dollar(US)
Shell	2539.9	Labor cost	222338
Front head	2069.8	Tube material cost	21256
Rear head	2086.6	Material cost (except tubes)	45448
Shell cover			
Bundle	6693.9		
Total weight - empty	13390.2	Total cost (1 shell)	72260
Total weight - filled with water	16363.8	Total cost (all shells)	289040

TEMA Sheet

Heat Exchanger Specification Sheet

1	Company:					
2	Location:					
3	Service of Unit: Our Reference:					
4	Item No.: Your Reference:					
5	Date: Rev No.: Job No.:					
6	Size 13.6221 - 224.409: in Type: BEM Horizontal Connected in: 1 parallel 4 series					
7	Surf/unit(eff.) 5467.8 ft² Shells/unit 4 Surf/shell(eff.) 1366.9 ft²					
8	**PERFORMANCE OF ONE UNIT**					
9	Fluid allocation		Shell Side		Tube Side	
10	Fluid name		3->4		1->2	
11	Fluid quantity, Total	lb/h	20473		20175	
12	Vapor (In/Out)	lb/h	20473	20473	20175	20175
13	Liquid	lb/h	0	0	0	0
14	Noncondensable	lb/h	0	0	0	0
15						
16	Temperature (In/Out)	°F	532.9	101.01	82.5	494.95
17	Bubble / Dew point	°F	-370.33 / 115.4	-377.63 / 88.35	/	/
18	Density Vapor/Liquid	lb/ft³	0.077 /	0.06 /	9.215 /	4.937 /
19	Viscosity	cp	0.0282 /	0.0186 /	0.0222 /	0.0299 /
20	Molecular wt, Vap		28.52	28.52	28.85	28.85
21	Molecular wt, NC					
22	Specific heat	BTU/(lb-F)	0.2625 /	0.2494 /	0.2896 /	0.2655 /
23	Thermal conductivity	BTU/(ft-h-F)	0.024 /	0.015 /	0.019 /	0.026 /
24	Latent heat	BTU/lb				
25	Pressure (abs)	psi	28.7	12.67	1826.7	1825.17
26	Velocity (Mean/Max)	ft/s	82.85 / 102.93		1.21 / 1.57	
27	Pressure drop, allow./calc.	psi	13	16.03	24	1.53
28	Fouling resistance (min)	ft²-h-F/BTU	0		0	0 Ao based
29	Heat exchanged 2261516 BTU/h MTD (corrected) 31.64 °F					
30	Transfer rate, Service 13.07 Dirty 13.45 Clean 13.45 BTU/(h-ft²-F)					
31	**CONSTRUCTION OF ONE SHELL**				**Sketch**	
32			Shell Side	Tube Side		
33	Design/Vacuum/test pressure	psi	43.51 / /	2016.02 / /		
34	Design temperature	°F	599	563		
35	Number passes per shell		1	1		
36	Corrosion allowance	in	0.125	0.125		
37	Connections In	in	1 12 / -	1 2.9 / -		
38	Size/Rating Out		1 10.02 / -	1 2.9 / -		
39	ID Intermediate		1 10.02 / -	1 2.9 / -		
40	Tube #: 388 OD: 0.75 Tks. Average 0.083 in Length:24.4095 in Pitch: 0.9375 in Tube pattern:30					
41	Tube type: Plain Insert:None Fin#: #/ft Material:Carbon Steel					
42	Shell Carbon Steel ID 23.622 OD 24.4095 in				Shell cover -	
43	Channel or bonnet Carbon Steel				Channel cover -	
44	Tubesheet-stationary Carbon Steel -				Tubesheet-floating -	
45	Floating head cover -				Impingement protection None	
46	Baffle-cross Carbon Steel Type Single segmental Cut(%d) 39.69 Horiz Spacing: c/c 21.6535 in					
47	Baffle-long - Seal Type				Inlet 31.8691 in	
48	Supports-tube U-bend 0 Type					
49	Bypass seal Tube-tubesheet joint Expanded only (2 grooves)(App.A 'i')					
50	Expansion joint - Type None					
51	RhoV2-Inlet nozzle 683 Bundle entrance 554 Bundle exit 909 lb/(ft-s²)					
52	Gaskets - Shell side - Tube side Flat Metal Jacket Fibe					
53	Floating head -					
54	Code requirements ASME Code Sec VIII Div 1 TEMA class R - refinery service					
55	Weight/Shell 13390.2 Filled with water 16363.8 Bundle 6693.9 lb					
56	Remarks					
57						
58						

Appendix 4 Part 1
Gap Analysis

Hannes E. Leetaru
Illinois State Geological Survey

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Technology Gap Assessment

Current state of the art for Compressed Air Energy Storage

Applications

Compressed Air Energy Storage (CAES) is one of the few mid- technology readiness level (TRL) energy storage technologies that can address the long-duration storage infrastructure needed for dealing with variable electric output from renewable energy sources and be a reliable backup energy source for replacing natural gas during supply interruptions. The current TRL of 5 is based on current geologic limitations of salt domes needed for storage. The goal of CAES is to compress and store high-pressure air in subsurface sedimentary strata when off-peak power is available, or there is a need for grid balancing. The high-pressure stored air is returned to the surface and used to power turbines during reductions in renewable energy output and supply issues with fossil fuels or fossil fuel energy generation.

The Illinois Compressed Air Energy Storage project will evaluate subsurface saline reservoirs for injection and withdrawal processes defining a CAES project. The Ordovician St. Peter Sandstone and the Mt. Simon Sandstone are porous and permeable reservoirs and have had a long history (over 50 years in Illinois) of being used for natural gas storage.

Natural gas (and to a lesser extent coal) may also be susceptible to supply issues to generate electrical power. Early in the life of the natural gas industry it was recognized that gas production from individual natural gas wells could not be increased to meet peak demand for gas in cold winter seasons. Most of the Midwestern United States do not have access to large natural gas fields and must use interstate pipelines to transport the gas to consumers. However, these long-distance pipelines do not have the capability of transporting the gas in the volumes necessary to meet the needs during these peak usage events. Approximately 70 years ago, the utility industry began developing underground natural gas storage (UNGS) reservoirs located near major municipalities in order to meet these peak usage demands. With the increased rise of natural gas electricity generation, the utilities could lose both the capability of heating homes and generating electricity. There is a risk for transportation of natural gas in severe weather events. For example, in the winter of 2021 there were natural gas supply issues because of severe cold weather in Texas. CAES could have helped alleviate these supply problems by producing compressed air and generating electricity when natural gas was unavailable. New power plants will most likely use natural gas instead of coal because burning natural gas has almost 50% lower carbon emissions compared to coal per Btu content (U.S. Department of Energy Office of Fossil Energy, 2016). However, the dynamics of electricity generation may be changing. For example, Governor Pritzker of Illinois has proposed phasing out natural gas power plants by 2045 and coal fired power plants by 2035 (Hawthorne, 2021) and transition to renewables only.

Shortcomings and limitations and challenges

A significant challenge and limitation with Compressed Air Energy Storage (CAES) is that it is currently geographically limited to areas with subsurface salt deposits in which caverns are created by salt dissolution processes (DOE, 2020).

There are two operational power plants using CAES (Yu et al., 2019), both of which use salt caverns to store the compressed air. Caverns have some unique advantages that include a known volume of stored air, easy withdrawal of the air via simple gas expansion, and dry air with little moisture. However, there are significant limitations: 1) areas with thick salt deposits are limited geographically, 2) the creation of salt caverns is expensive, 3) the amount of compressed air storage capacity in caverns is limited, thereby restricting the duration of generating recoverable energy, 4) salt caverns have and upper temperature limit for storing the compressed air by the temperature of the compressed air, and 5) salt is mobile, so compressed air and overlying sediments could cause the salt to flow and change the cavern volume. In addition, the number of salt domes is finite and in competition with other storage needs such as hydrogen and petroleum.

Many of the challenges in CAES are related to understanding the subsurface geology and fluid dynamics of the compressed air during injection and withdrawal. However, the design of surface infrastructure is also going to be challenging. The air compression and storage system must be able to not only compress the gas, but also store the heat of compression and include this thermal heat with the injected air. The compression equipment becomes less efficient with higher temperature and will increase the power costs. Air will expand and cool during the retrieval phase. The compressed air will have some water vapor and brine that has to be removed before passing through the turbines, which will require energy. The brine removal infrastructure will increase the cost, especially in the early phase of the project's operation.

A significant gap in the application of CAES is estimating the energy losses that are going to occur during compression, injection, expansion, and generation of electricity. Dissipation of heat following air compression is an important factor in CAES energy capture efficiency. The loss of heat limits the efficiency of CAES to 50% whereas recovering the heat using adiabatic recovery mechanisms could increase it to about 80%. Solutions include the use of molten salt to capture the heat of compression and utilize it during the power generation cycle, but this significantly limits the amount of thermal storage because of the finite heat capacity of the energy storage system and also increases system cost. One of the gaps is finding a way to combine compressed air and thermal energy storage in the same reservoir. This means that we need to determine the thermal capacity of the formation and to estimate the temperatures from compression and the heat loss from expansion during retrieval of the injected air.

Geochemical reactions of injected air into subsurface sediments have been identified as a potential problem. For example, a CAES test facility injected air into St. Peter Sandstone at Pittsfield field in Pike County Illinois and encountered problems. This CAES test began in 1982 and lasted almost 6 months with a goal of demonstrating the feasibility of CAES and understanding the continuous cycle of injection and retrieval of the air (Allen et al., 1985). The study found that the oxygen in the injected air had a chemical reaction with pyrite in the formation and this reduced the St. Peter reservoir porosity and permeability. However, the Pittsfield CAES study conclusion was that CAES is a viable method of storing both heat of compression and air in the subsurface.

One of the significant problems of using compressed air in saline reservoirs is the added cost of handling of brine produced when air is withdrawn, brine coning into air withdrawal wells, and the reduction of air withdrawal rates as a consequence of brine production. We need to evaluate the volume of brine that will be produced with compressed air to learn peak air withdrawal rate and estimate the number of withdrawal wells that might be necessary to meet a target air withdrawal rate. We need to estimate methods and costs for brine treatment and/or disposal.

We currently have not completed adequate research on the reaction of the reservoir to short cycle times of injection and withdrawal of the compressed air. In natural gas storage, the cycling is annual and in CO_2 storage the injection is in one direction with no production of the CO_2. In the CAES reservoirs there may be daily cycling of the air with corresponding changes in reservoir temperature and pressure. The geologic formations storing and overlying compressed air must remain hydraulically, mechanically, and seismically stable over decades of use. In addition, the subsurface storage of the heat generated from stored has not been investigated at this point in time.

How will our study overcome limitations and shortcomings?

The Illinois CAES project evaluate use clastic geologic formations on regional dip without the need for salt caverns or geologic structures. The high-pressure, stored air will be returned to the surface and used to power turbines when additional electricity is needed, and during reductions in either renewable energy or supply issues with fossil fuels or fossil fuel energy generation.

Instead of using a cavern, we modeled injecting compressed air into subsurface porous strata. This should significantly increase the volume of air storage and therefore the duration of recovered energy generation. However, CAES in subsurface porous reservoirs has never been attempted. In addition, the extent of compressed air migration in the subsurface and the volume of formation water it would displace are unknown. Rapid migration of the compressed air would require an anticlinal structure to contain the gas. However, research of a reservoir simulation of movement of compressed air in the Cambrian Mt. Simon Sandstone in Illinois suggests that (with low regional dip), the compressed air will not travel very far from the injection well in a 30-year period (i.e., outside of geologic structures).

Reservoir fluid simulation of subsurface strata in South Carolina indicate that CAES in flat lying strata would be feasible (Jarvis, 2015). The simulation of CAES suggested that greater reservoir depths would lead to higher hydrostatic pressures and improve the recovery but will increase the compression costs. Their simulations also suggest that in homogenous reservoirs water coning (and subsequent water production) could be a problem as the rate of compressed air production increases. Reservoirs with lateral heterogeneity and with extensive vertical baffles may reduce the water coning problems. Using the Mt Simon Sandstone, we modeled the surface infrastructure and reservoir fluid migration in the subsurface. The Manlove Gas Storage Field is approximately 30 miles to the northeast of the University of Illinois campus and stores natural gas in the Mt. Simon. Reservoir characterization of the Mt. Simon at Manlove shows extensive baffles that reduces the problem of water coning but definitely does not eliminate it (Morse and Leetaru, 2005).

We evaluated capturing the heat of compression and storing it within the Mt Simon Sandstone during the injection phase. This combination of CAES with a high-thermal energy storage system (HTES) has the potential of significantly increasing the energy efficiency of air storage. The goal is to heat reservoir rocks above 100 °C to create a geothermal system in conjunction with compressed air. Initial analysis of the subsurface reservoirs in the project area, which is a few miles south of the University of Illinois Campus, suggest that, because of expected hydrostatic pressure, we could store the heat generated from compression up to 175 °C without formation water becoming steam. Nearby well data indicate that the Mt. Simon reservoir is already 49°C.CAES using salt caverns, gas storage in subsurface sandstone and carbonate reservoirs (such as natural gas projects for almost a century), and geothermal energy retrieval are all proven technologies. However, the integration of CAES and geothermal energy in flat lying sedimentary strata within a fossil power generation plant has not been done. In our study we evaluated the feasibility of injecting air in subsurface reservoirs without anticlines constraining the migration of the air, using the University of Illinois power system for powering air compression when load demand is low.

The Illinois CAES project evaluated the feasibility of capturing surplus electrical energy from renewable sources and off-peak energy at a fossil fuel power plant at the University of Illinois Urbana - Champaign (UIUC) campus. The UIUC Abbott Power Plant uses natural gas and coal to generate electricity (capacity: 35 MWe by coal and 49 MWe by NG). UIUC receives additional electricity from an on-campus solar farm, and an off-campus wind farm. Also, UIUC offsets electricity usage by integrating geothermal energy systems into building heating. Furthermore, UIUC just completed a second 54- acre, 12.1 megawatt (MW) solar farm in addition to its current 21-acre, 4.68 MW solar farm. The UIUC campus receives 8.6% of the wind-generated electricity from the Rail Splitter Wind Farm. The Illinois CAES will include additional compressed air storage from the windfarm and usage of compressed air when wind energy is unavailable.

Key technical risks and issues associated with compressed air

There are issues that relate to health and safety during compressed air energy storage. Cyclic changes in pressure and/or temperature could cause instability within the caprock. Reservoir heterogeneity may become critical in how much or how fast the air is moving through the reservoir. The response to the wellbore in cementation materials with this constant change in pressures and with the extraction of air during the expansion stage needs to be characterized. The limitations of the compression and turbine generators in the CAES application must be determined. It is going to be critical to understand the wellbore stability with frequent changes occurring including thermal expansion and dissolution of the cement because of the oxygen component of the compressed air and other chemical reactions. This could become a significant problem because it could eliminate the air coming to the surface instead increase the production of brine. Field tested be injecting to air into to subsurface needs to be done.

Technological gaps needed for commercialization by 2030

The present CAES systems are limited geographically to specific areas with underlying large salt deposits where caverns can be created by dissolution. Our proposed technological advances will enable CAES systems to be implemented in any area underlain by porous rock formations with a seal above the reservoir. We may also significantly reduce the cost of the heating component of CAES by storing thermal energy from compression underground, creating a high-thermal energy storage system (HTES) in conjunction with CAES. The proposed CAES system could be implemented throughout large areas of the country with underlying sedimentary rock and suitable caprock formations. Excessive water production during the withdrawal phase must be reduced to ensure higher rates of air extraction and reduce brine handling at the surface. An assessment of the integration of CAES on regional dip using compressed air from fossil-fuel fired power plant and wind energy farms with CAES will close gaps on complete transition from fossil fuels using CAES. The high concentration of oxygen in air causes many known corrosion, precipitate, and biological growth challenges that will be prevalent in air storage in brine aquifers.

Workflow description to overcome key technical risks and issues

Although CAES using subsurface salt domes has been successfully demonstrated, salt deposits are not present in most areas of the world. There are no commercial CAES systems in porous sedimentary reservoirs employing the concepts proposed in this project. The two CAES-salt dome plants are based on the diabatic method, where heat of compression of combustion air is separate from the heat supplied to the turbine.

Our CAES would use an adiabatic system where the thermal compression heat is stored in the subsurface reservoir with the air. The major benefit in using Abbott Power Plant's cogeneration configuration in this proposed study is that Abbott is a natural gas and coal fueled electrical and steam generating plant that is integrated in an energy system with variable renewable electricity from wind and solar farms and geothermal energy systems that has demonstrated the ability to overcome the key technical risks and issues of engineering scale projects. Enhancing this existing system with CAES, will advance CAES usage and close many of the technological gaps identified.

The objectives have been organized into a logical progression of work that involves creating an integrated system to 1) design the best method to capture surplus electrical energy from renewable sources and the Abbott Power Plant using a CAES system, 2) design the well and equipment for injection of the compressed air and the thermal heat generated by compression as part of an adiabatic system, 3) simulate the movement of the air and heat in the subsurface, 4) evaluate the best method to maximize energy recovery from the compressed air and stored thermal heat to drive turbine generators during sustained shortages of other power sources due to weather events or fossil fuel disruptions, and 5) remove or treat subsurface formation water that was produced with the compressed air.

The proposed research evaluated how much of the injected air will remain in the formation during the recovery period. PNNL (McGrail, 2013) suggested that 59% of the injected air would remain in the reservoir and not be recoverable. There could also be technical issues with mitigating corrosion of the turbines during extraction of gas and formation water. This is a known issue in geothermal energy projects. Dehydration of the air may be required before it is fed to the turbine generators.

Expected Technology Readiness Level at end of project

CAES has only been used in two projects within salt caverns to store the compressed air. Site issues have limited the implementation even though compressors and gas turbines are mature technologies. Many of the individual components of the proposed project have a mid or mature TRL; however, an integrated CAES system has not been successfully demonstrated. The use of storage in porous subsurface reservoirs has not been attempted and there are no projects investigating the utilization of subsurface reservoirs to store compressional thermal energy by creating a high-temperature geothermal resource in addition to compressional potential energy from the pressure of compressed air. Therefore, the pre-project TRL is 5 because only two cavern storages CAES systems have been implemented.

At the end of the project, we tried to use the gap analysis to describe the necessary steps to increase to a TRL 6. The goal of a phase II project is the engineering development of the technology to create a prototype. This will involve developing the prototype including compressor limitations, turbines, and brine removal methods. The limitation to the increase in TRL is the need to drill a well to the top of the Mt. Simon and test the capability of storing compressed air.

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Appendix 4 Part 2
GAP ANALYSIS
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20.State of the Art Technology

The state-of-the-art technology can be seen in use in McIntosh, Alabama and Huntorf, Germany. These plants are large scale and the TRL of the surface technology is level 9. This is because of the two existing commercial scale plants currently in use, and a 3rd planned in Iceland.

See pictures below for detailed information on the McIntosh plant in Alabama.

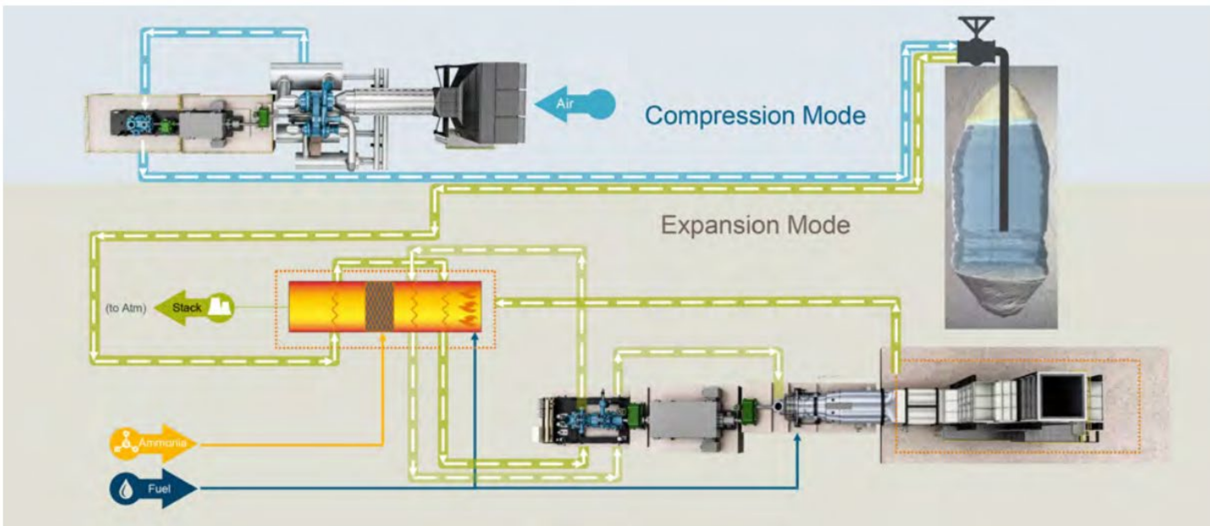

Figure 38: CAES Flow Diagram

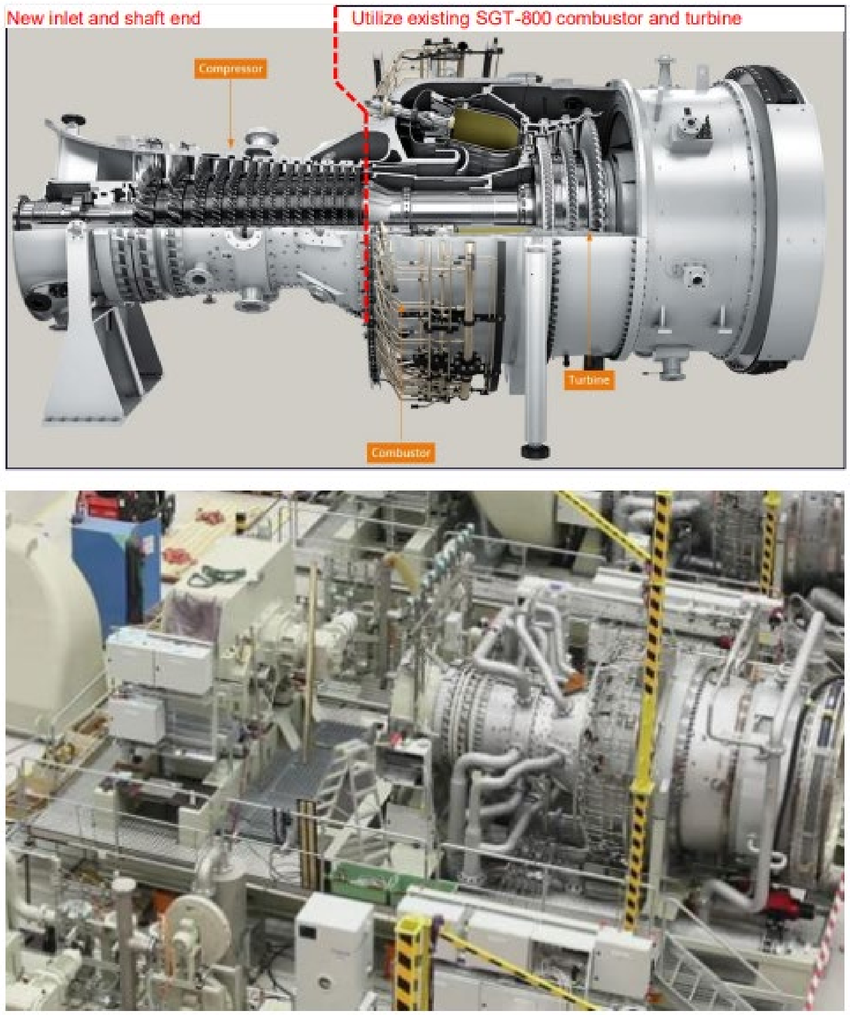

Figure 39: Current CAES Turbines

As seen in figure 2, siemens uses the expander and combustion portion of their existing gas turbines. The McIntosh plant currently runs at a reliability rate of 99%, after being designed and built more than 30 years ago.

21.Proposed System

The proposed Abbott CAES plant will use sub surface porous formations rather than salt caverns. The performance for this kind of storage is unknown. The overall efficiency of the plant will depend heavily on the storage component's ability to maintain pressure and temperature.

22.Technical Risks

The largest technical risk associated with this project will be the storage component. There are still a lot of unknowns about how it will perform, both in terms of retaining pressure and heat. The McIntosh plant has air leaving the storage formation at 200F, while the predicted temperature of the air for the Abbott plant is 80F.

In terms of surface facility equipment, the turbines are the biggest risk. Not a lot of air turbines for this low amount of power exist. This project will require a microturbine with modifications made to the impellers.

Another risk of building a plant this scale, is that neither the turbines nor the compressors will be the same as a large-scale plant. The compressors for this plant will be reciprocating compressors, but large plants require centrifugal compressors to accommodate the higher air flow. Large plants also use existing gas turbines with only the expander portion being used, while this plant will use specific micro turbines.

23.Technology Gaps

Like it was mentioned in the previous section, there are key technology gaps in air turbines for this small of a cycle. R&D will need to be done for a CAES cycle of less than 2 MW, and with the cost of turbines and compressors not completely scaling based on power, building a 2 MW plant will result in a high cost in $/kWh.

Appendix 5
COMMERCIALIZATION FACTORS

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24. SUMMARY

This report summarizes key considerations for commercializing the Compressed Air Energy Storage (CAES) process. The Illinois State Geological Survey (ISGS) CAES project at the University of Illinois seeks to demonstrate that CAES can be successfully operated using a porous rock formation for compressed air storage. If successful, this effort will significantly expand the geographic regions where CAES can be used beyond regions with available salt caverns. The ISGS investigation seeks to increase the range applicability for CAES, but does not otherwise alter the economics of the CAES process. Economic analysis results of CAES processes can be potentially quite favorable for a well-suited application.

25. BRIEF DESCRIPTION OF CAES

Compressed Air Energy Storage (CAES) is a method of energy storage that has been seriously investigated since the 1970s. Several innovative variations of the process have been proposed over time, but the basic process (as applied at the two existing commercial scale installations) consists of the following major pieces of equipment:

- Multi-stage air compressor with inter-stage cooling
- Multi-stage combustion / expansion turbine
- A motor / generator, a single piece of equipment which can operate as either a motor or a generator. When connected to the air compressor using a clutch mechanism, it operates as a motor drawing power from the grid to drive the compressor. When it is connected to the expansion turbine using a second clutch mechanism, it operates as a generator supplying electricity to the grid. If both clutches are released, the motor / generator can be attached to the grid as a synchronous condenser – an operating mode described below.
- High pressure air storage structure. For plants of industrial size, this storage structure is below ground. In the existing industrial plants, storage is in salt caverns though the use of a porous rock formation will be studied in the ISGS CAES project.

CAES units can be operated in one of two distinct modes: storage mode and extraction mode.

In storage mode, the motor / generator is engaged to the air compressor and disengaged from the expansion turbine. Electrical power is taken from the grid and used to compress ambient air into the storage structure, effectively storing the energy for later use.

In extraction mode, the motor / generator is disengaged from the air compressor and engaged to the expansion turbine. Compressed air is extracted from the storage structure, mixed with natural gas, and fed to the expansion turbine. There the hot, expanding gases turn the turbine generating electricity that can be supplied to the grid. Energy that was previously stored as compressed air is thereby recovered to the grid.

INNOVATIVE ASPECT OF THE ISGS CAES PROJECT

At the present time, there are two industrial scale CAES plants operating in the world: a 290 MW plant near Huntorf, Germany and a 110 MW plant near McIntosh, Alabama. [1]. Both existing plants use below ground salt caverns for compressed air storage. In contrast, the ISGS CAES project will make use of a porous rock structure in the subsurface of the University of Illinois campus for compressed air storage. A successful demonstration of CAES using porous rock storage will potentially remove one of the barriers to building additional CAES plants: future plants could be located in other areas where salt caverns are not available for compressed air storage.

26.INPUTS FOR MARKET SCENARIOS

To create market scenarios for the CAES process, site-specific factors and the business objectives must be defined for the project being studied. Site-specific factors will include local prices for on-peak and off-peak electricity, duration and magnitude of electricity demand cycle, etc. Business objectives for the CAES process depend on the specific applications for the plant.

The ISGS CAES project is expected to successfully demonstrate the use of porous rock for compressed air storage but will not create new types of applications for the CAES process nor alter the economics of the CAES process itself. Examples of applications for the CAES process can be found in the literature [1]. Documented applications for CAES include:

- **Peak shaving / arbitrage.** The business objective of peak shaving is to produce and store off-peak energy that can be used to meet on-peak demand. Peak shaving is focused on avoiding the need to generate the full on-peak demand during on-peak hours, instead meeting some of the on-peak demand by extracting previously stored energy. Making use of a peak shaving strategy can defer or even avoid expansion and load-levelling projects in transmission and distribution (T&D) systems. A closely related concept is arbitrage, which uses price hedging to generate profits from the "buy low / sell high" philosophy. Electricity can be purchased from the grid when it is less expensive (off-peak), then sold back to the grid when it is more expensive (on-peak). One of the key advantages of CAES plants over other energy storage technologies is that they have the storage capacity, flexibility and responsiveness needed to profit from an arbitrage operating strategy.
- **Energy imbalance / distributed generation.** In a system with distributed generation, local peak demand can exceed local instantaneous generation capacity.

> The use of CAES allows the storage of excess energy which can be extracted during demand peaks. This allows generation units to operate continuously at full power and accommodate higher demand peaks than would be possible without energy storage.

To generate market scenarios for a specific candidate CAES project, an economic model must be created. Input variables of the model (uptime, fuel cost, etc.) should be studied systematically to understand statistical economic risks for each project. Specific analysis methods for energy storage projects are documented in open literature [2].

Natural gas prices will affect conventional CAES units because natural gas is used in the combustion / expansion turbines when the unit is operating in extraction mode. A typical heat rate is 4,000 BTU (HHV) of natural gas per kWh generated [1].

Renewables penetration into the energy market is likely to generate additional opportunities for CAES. In particular, it has been noted that wind farms might create opportunities for CAES because it can operate on the time scale of daily production / demand cycles [3]. Renewable energy sources such as wind and solar can be implemented in a distributed generation scheme which could be complemented by CAES plants to store power when it is generated and deliver power when it is needed.

Because CAES plants are energy storage facilities, they could be justified anywhere in the world that a suitable compressed air storage structure exists and that a business case can be established. There is not expected to be any substantial difference in applicability of CAES technology between domestic and international markets. In fact, as discussed in Section 0, there are currently two existing industrial sized CAES plants: one is domestic and the other is international.

27.MARKET ADVANTAGE OF THE CONCEPT

The primary market advantage of energy storage technology is the ability to meet higher peak demands with smaller generation, transmission, and distribution equipment. Many electricity generation technologies have unpredictable output, slow ramping rates, or inefficient operation at turndown conditions. On the demand side, it is typical that electrical demands go through daily and seasonal cycles. Energy storage serves as a buffer between fluctuations in power generation and fluctuations in demand. Rather than sizing the generation, transmission, and distribution equipment to meet the *highest peak demand*, a robust energy storage system allows equipment to be sized closer to the *average demand*.

In a situation with ever-increasing demand, energy storage allows existing equipment to be used for a longer time before upgrades and improvements are required. Load-leveling through energy storage can defer the need for large new investments further into the future.

A benefit specific to the CAES process [1] is the ability to exploit on-peak vs off-peak energy prices to generate income through arbitrage / price hedging. The magnitude of energy that can be stored and the fast response time allows CAES plants to take advantage of short-term price fluctuations.

28.ADDITIONAL BENEFITS

SYNCHRONOUS CONDENSER

A unique benefit of a CAES plant is that it can serve as a synchronous condenser for the grid when not operating in storage or extraction modes. Other forms of energy storage, such as battery systems, do not provide this benefit to the grid. A synchronous condenser, also called a "spinning machine", is essentially a motor / generator connected to the grid where the shaft is allowed to freewheel without a load. Power companies sometimes install synchronous condensers as an alternative to capacitor banks to improve the electric power system's performance by storing kinetic energy in the rotor. A recent Australian project installing four synchronous condensers is described in [4]. The motor / generator of a CAES plant can be put into this mode by disengaging both the air compressor clutch and the combustion expander clutch. Both existing CAES plants are sometimes operated in this manner [1]. Since this operating mode does not involve stored air, the plant can operate in this mode for as long as desired.

UNQUANTIFIED BENEFITS

CAES is a technology that has been extensively studied. Key advantages which have been documented in literature [1] include:

- CAES technology can provide large capacity energy storage (thousands of MWh) with the flexibility to provide energy storage / extraction on small time scales (e.g., six-hour cycles). Plants have fast start-up times, fast ramping rates, and run efficiently at turn-down.
- Compressor and expander equipment is established and readily available industrial equipment that can be provided by multiple suppliers.

Additional benefits may include:

- Improved customer satisfaction with reduced outages and voltage sags.
- Improved equipment reliability due to less frequent operation at maximum possible rates.

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Appendix 6

Environmental Impact Assessment

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There were no environmental issues since this DOE funded project was a paper study.