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A LIFE CYCLE COST ANALYSIS FRAMEWORK FOR GEOLOGIC STORAGE OF HYDROGEN

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Abstract

Large scale geostorage options for fuels including natural gas and petroleum offer substantial buffer capacity to meet or hedge against supply disruptions. This same notion may be applied to large scale hydrogen storage to meet industrial or transportation sector needs. This study develops an assessment tool to calculate the potential 'gate-to-gate' life cycle costs for large scale hydrogen geostorage options in salt caverns, and continues to develop modules for depleted oil/gas reservoirs and aquifers. The U.S. Department of Energy has an interest in these types of storage to assess the geological, geomechanical and economic viability for this type of hydrogen storage. Understanding, and looking to quantify, the value of large-scale storage in a larger hydrogen supply and demand infrastructure may prove extremely beneficial for larger infrastructure modeling efforts when looking to identify the most efficient means to fuel a hydrogen demand (e.g., industrial or transportation-centric demand). Drawing from the knowledge gained in the underground large scale storage options for natural gas and petroleum in the U.S., the potential to store relatively large volumes of CO_2 in geological formations, the hydrogen storage assessment modeling will continue to build on these strengths while maintaining modeling transparency such that other modeling efforts may draw from this project.

Acknowledgments

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Introduction

The U.S. Department of Energy (DOE) Hydrogen Program has an interest in understanding geologic underground storage options in an effort to potentially develop an underground facility for the storage of hydrogen gas, as a low cost storage option, as part of the hydrogen delivery infrastructure. Sandia National Laboratories has assessed the potential for underground storage of hydrogen (H_2) from a systems perspective.

The initial methodology adopted was to examine the system by first assessing various geologic underground storage options from a performance and full life cycle perspective. Specifically, three general classes of underground storage are being considered at the conceptual level; salt caverns, depleted oil/gas reservoirs, and aquifers. These options hold substantial interest largely due to the lessons learned from moderate to large scale underground storage of natural gas already employed. Conceptually, storing natural gas is largely done in an effort to reduce or negate instances of short supplies and therefore difficult economic conditions in regional markets across the fluctuating seasonal demand. Understanding these various geologic storage types will help identify what geologic option would be best suited for the storage of hydrogen. Currently, there are only three locations worldwide, two of which are in the United States, which store hydrogen. All three sites store hydrogen within salt caverns.

Part one of the project study addressed the underground storage options by assessing the geological storage performance required to store hydrogen gas. This project phase is complete and consisted of a white paper (Lord, 2009) that gives an overview of the various types of geologic storage currently in use for the storage of natural gas. The intent is to give an understanding of geologic storage, to describe the different storage types, and to state the advantages and disadvantages of the underground facilities as they relate to natural gas and subsequently hydrogen gas within an integrated systems framework.

The second phase of the project, which is documented here, involved developing an economic analysis methodology that characterizes the costs entailed in developing and operating a hydrogen underground storage facility. The tool can be used to develop the costs, both capital and operational, of various geological underground storage facilities specific to hydrogen. The analysis can portray the probable costs entailed in developing and operating the most viable candidates for the underground storage of hydrogen.

Figure 1 depicts the assessment methodology and model framework. The storage cost model calculates the construction costs for a storage facility (e.g., solution mining, pipeline construction costs, etc.), working volume of hydrogen, the compression requirements (e.g., capital, electricity, other costs), cushion gas requirements, and additional site characteristics. Additionally, the framework addresses ongoing valuation assessment (e.g., seasonal and options-based value) by developing case studies of feasible, unfeasible, and plausible storage option scenarios to bound the options analysis when considering potential hydrogen geostorage locations. The model framework is modular by design, allowing it to be used in other larger hydrogen infrastructure assessment models.

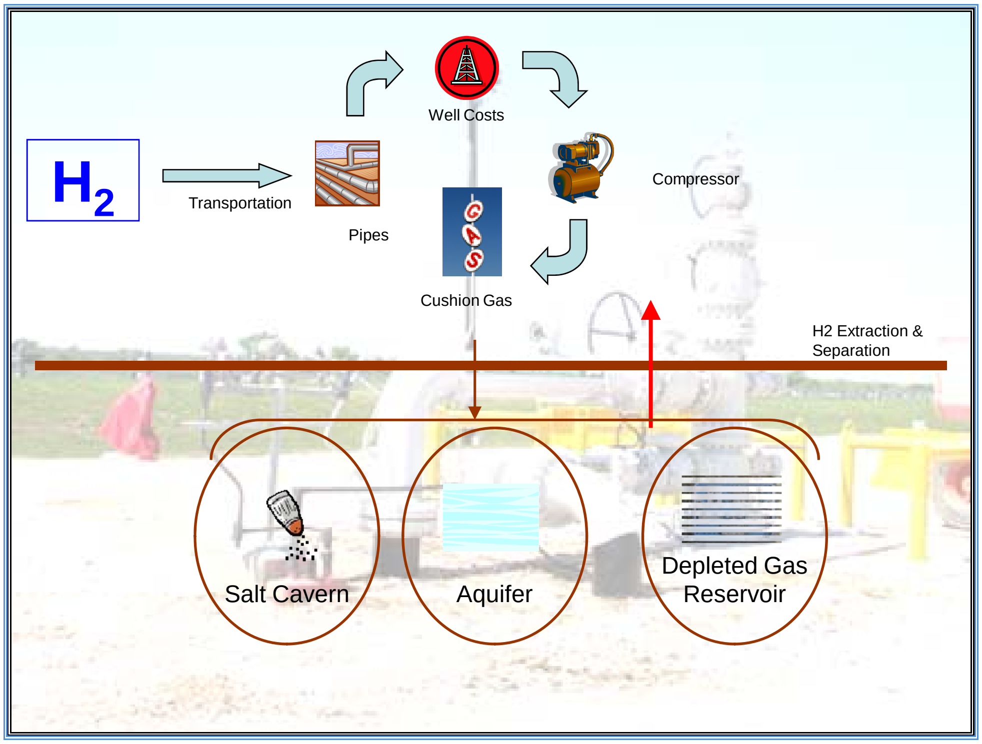

Figure 1: The Assessment Methodology and Model Framework.

Potential Geologic Storage Options

In phase one the project identified the suitability and availability of underground geologic storage for hydrogen by developing a white paper (Lord, 2009) that presents an understanding of the various geologic storage types available, the advantages and disadvantages of each type, as well as possible operational issues that may be specific to hydrogen. Presented here is a summary of our work.

The concept of storing natural gas underground in geologic formations arose from the need to supply gas to consumers during periods of high seasonal demand. The storage of natural gas is also an insurance policy against accidents and natural disasters. Currently, depleted oil/gas reservoirs, aquifers, and salt caverns are the three main types of underground natural gas storage in use today. The other storage options available currently and in the near future, such as abandoned coal mines, lined hard rock caverns, and refrigerated mined caverns, will become more popular as the demand for natural gas storage grows, especially in regions were depleted reservoirs, aquifers, and salt deposits are not available.

Underground storage must have adequate capacity and containment of gas. The storage formation must have high permeability in order for gas to be injected and extracted at adequate rates. Porous reservoirs such as depleted gas/oil reservoirs and aquifers must possess an impermeable caprock along with a geologic structure to contain and trap gas. Mined caverns such as salt caverns contain gas by the impermeability of the surrounding host rock.

Depleted oil/gas reservoirs and aquifers possess the largest capacity and require the greatest volume of cushion gas. Cushion gas is unrecoverable gas needed to sustain a minimum reservoir pressure and ensure adequate withdrawal rates. The reservoirs are typically cycled once annually and are used to meet base load demand. Unlike depleted oil/gas reservoirs, aquifers must be proven to trap and contain gas.

Depleted gas and oil reservoirs have been the most prominent and commonly used reservoir for natural gas storage to date. Depleted reservoirs are old gas and oil fields, located thousands of feet underground, where most of the recoverable product has been extracted. Geologically, the reservoirs have proven capable of holding gas, since the reservoirs once trapped hydrocarbons that migrated up from the underlying source rock. (Foh et al, 1979; www.naturalgas.org)

In regions where depleted reservoirs are not available, such as the Midwestern United States, aquifers can be developed for natural gas storage. Aquifers are water-bearing porous rocks, such as sandstone, typically located thousands of feet underground (EIA, www.eia.doe.gov; Beckman et al., 1995). A suitable aquifer for storage will have geology similar to depleted gas reservoirs. Aquifers are more expensive to develop than depleted reservoirs due to uncertain geology and lack of infrastructure. Geologic characteristics are uncertain and data must be acquired to determine that the formation can trap and seal in gas (naturalgas.org; Beckman et al., 1995).

Salt caverns are solution mined and hold a fraction of the gas volume than that of depleted reservoirs and aquifers. Salt caverns are typically used to meet peak load demands by possessing multi-cycle capabilities and providing high delivery rates. Salt caverns are solution mined by leaching out large cavities by injecting fresh water. Caverns can be created within salt domes or within bedded salt deposits. The salt surrounding the caverns is highly impermeable and virtually leak proof (www.naturalgas.org).

Excavated caverns within rocks such as coal and granite contain volumes less than aquifers and depleted reservoirs and are generally developed in regions where reservoirs are not available. Excavated caverns by nature are not completely impervious to gas loss. Several techniques have been developed to insure gas containment, such as lining caverns with steel and increasing the hydraulic pressure surrounding the caverns.

The storage of hydrogen within the same type of facilities, currently used for natural gas, may add new operational challenges to the existing cavern storage industry. Hydrogen is a small, light molecule that reacts with other elements and steel at high pressures and temperatures possibly creating geological, geomechanical, and operational issues.

The Hydrogen Geological Storage Model

The Hydrogen Geological Storage Model is a prototype systems model developed in order to highlight the major components of a 'gate-to-gate' (the analysis focuses on the storage infrastructure only), large-scale hydrogen storage facility. In order to illustrate each of the systems' components, submodules were developed based on existing industry knowledge, literature research, and in the absence of explicit data, conceptually analogous systems (e.g., natural gas and carbon sequestration storage systems). A dynamic system's level model was developed in Powersim Studio (www.powersim.com) to incorporate all of the flows and stocks associated with the system (e.g., flow of H_2, electricity for pumping, other metrics on cost, engineering and storage type, etc.) in order to more fully illustrate the results of various build out and scale up scenarios. For example, the model can address questions such as, 'What if the requirement for cushion gas increases from 30 to 80%?' How do the costs and overall system's flows change? Figure 2 introduces the tool developed for this prototype analysis.

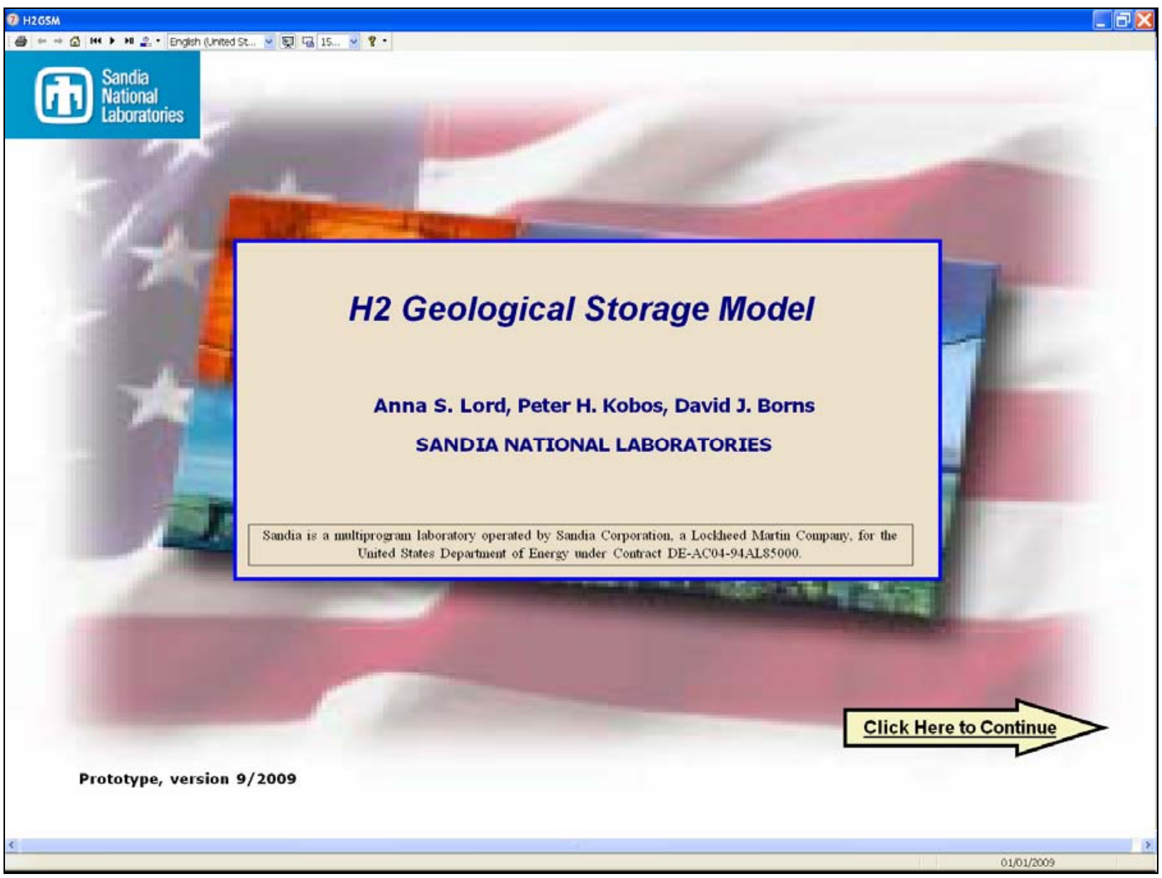

Figure 2. The Hydrogen Geologic Storage Model (H2GSM) Main Introduction Screenshot.

Figure 3 illustrates the overarching conceptual framework of the model. The concept of H2GSM is to augument already existing, detailed models to allow alternative flow, cost, scientific and engineering constraints for large-scale geostorage of hydrogen. The model develops in such a way that numerous submodules are developed and then integrated to form the overall 'gate-to-gate' systems model illustrated in Figures 1 and 3. The initial portion of Figure 3 begins with a flow (e.g., required supply to meet a given demand) of hydrogen gas for a given use. The model begins with a given hydrogen demand, and is a working inventory model based on the work of Yang and Ogden (2007). Their initial assumptions addressing a hypothetical case look to meet the potential demand for hydrogen-based vehicles, where a city the size of San Jose, CA would realize a market penetration level of 15% (e.g., 15% of all vehicles would require H_2) on up to a 100% level, cooresponding to 100,000 kg/day and 630,000 kg/day, respectively. This gives a baseline demand for a cyclic H_2 inventory model with delays for orders, fill rates, etc.

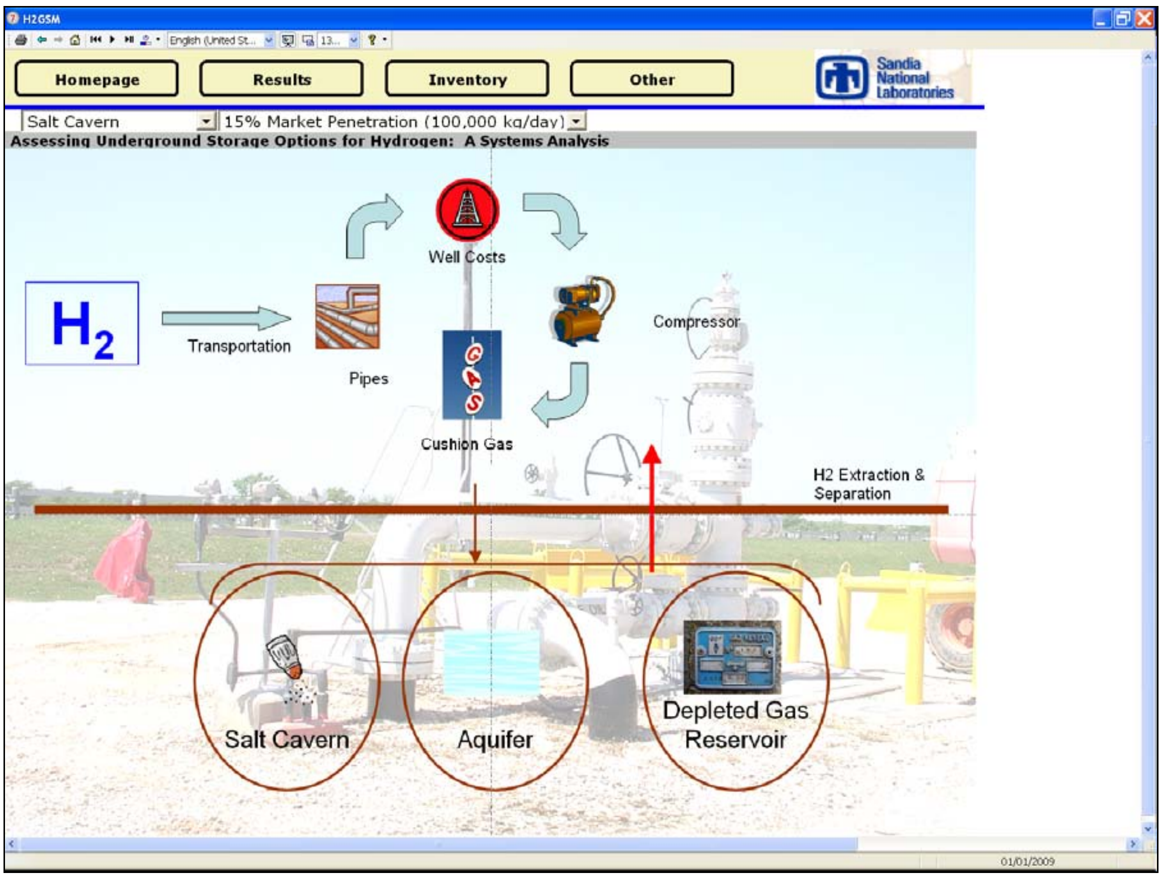

Figure 3. H2GSM Conceptual Layout for Geostorage Options of H_2.

A large-scale geostorage facility may provide the necessary days of coverage (supply) should a H_2 supply disruption occur in the face of a demand requirement. From the demand module, H2GSM then calculates any transportation costs and infrastructure build-up requirements. The initial assumptions, however, are set such that H2GSM is a 'gate-to-gate' model so that while it includes considerations for longer transportation lines within its cost calculations, they are set to zero under the base case. From this, the model then includes the cost of well drilling and operations based initially on the work of Ogden (2002). Using these assumptions allows the model to develop a literature-based base case set of results. From this set of baseline assumptions, model users have the ability to adjust these parameters to address site-specific needs.

The parameters used in the compressors module, those required to move the hydrogen through the overall system, are initially based on Amos (1998). The geostorage options initially include salt caverns, depleted oil/gas reservoirs, aquifers, and there is a category for other future options. Each of these types of geostorage options have their own unique attributes and the model's initial prototype either includes these attributes through assumptions, or leaves the modules open for future information to be included in the underlying calculations associated with these formations. For additional detail, Appendix 1 lists the underlying equations for each submodule illustrated in Figure 1, and described here.

In an effort to understand the sensitivities throughout the model's calculations and how they affect the overarching results, several representative scenarios were developed. While these results are very preliminary due to the prototype stage of the model, they are a proof-of-concept output to illustrate the model's abilities, and potential future research efforts. Figure 4 illustrates the high-level results of the base case scenario for the salt cavern storage option. A few of the key points to highlight are the capital cost, levelized cost and mass of H_2 results calculated for the base case. For example, using a cavern with a 50% cushion gas requirement may return up to 3.1 million kg of working H_2. The results interface allows analysts to adjust the variables that affect the levelized cost calculations (e.g., the discount rate, equipment lifetime and capacity factor for the facility) as well as other salient variables such as the cost of electricity, the cost of the cushion gas, and the relative amount of cushion gas the cavern must contain for a given scenario.

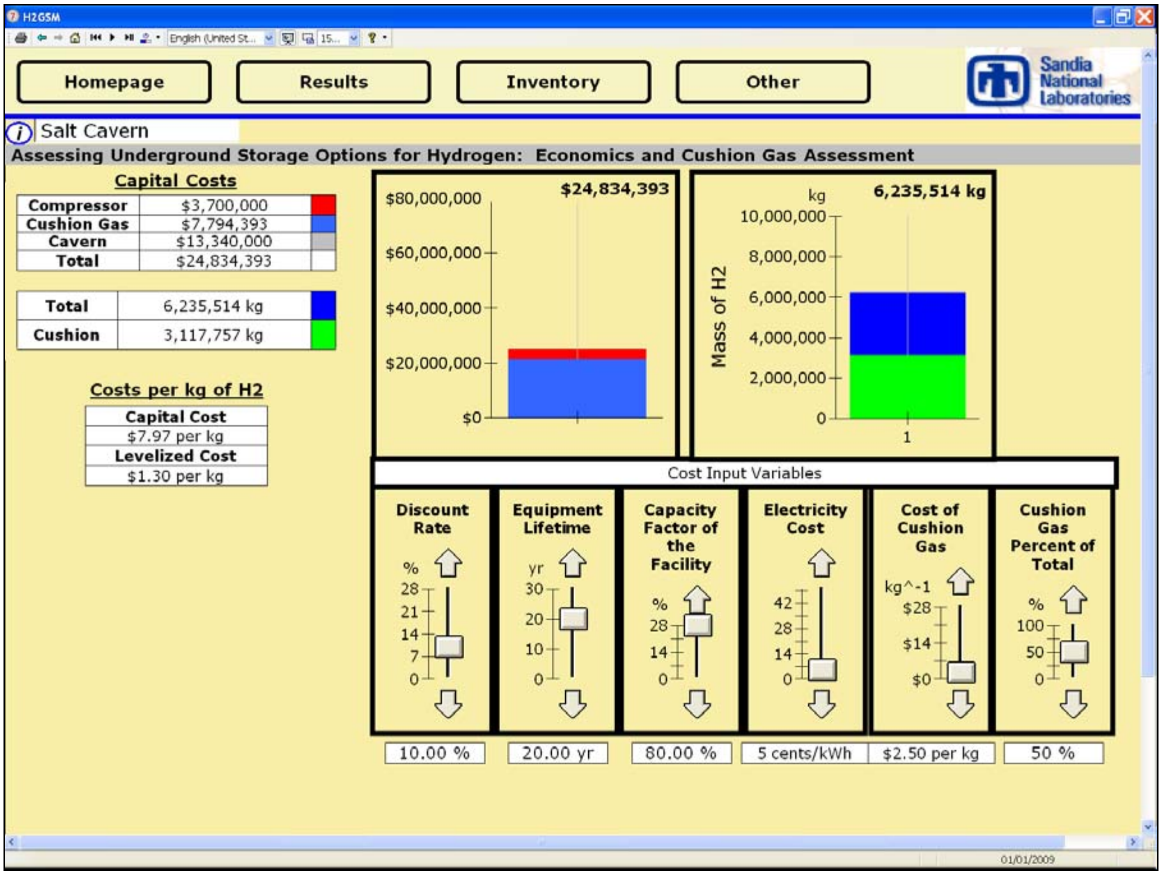

Figure 4. The High-Level Results Page of H2GSM.

In one deviation from the baseline scenario for a salt cavern, the cost of electricity changes from $0.05/kWh to $0.25/kWh. The overarching levelized cost of hydrogen ($/kg) does not change from $1.84/kg assuming a base case assumption for 50% cushion gas by volume within the cavern. This is largely due to the underlying assumptions regarding the majority of the initial (and future) payments on the large amounts of financial capital required to purchase and install the compressors, cushion gas, and cavern itself. The cost of electricity is, however, important within the operations and maintenance costs for running the compressors.

Changing the size of the cushion gas requirement also affects the overarching capital and levelized cost of hydrogen. By changing the cushion gas percent of the total cavern volume from 30 to 80%, the cushion gas requirements for a cavern holding a total of 6.2 million kg of hydrogen increase from 1.9 million kg to 5 million kg of H_2. Additionally, the change in the cushion gas volume leads to the capital and levelized costs of hydrogen for a large salt cavern increases from approximately $5/kg ($0.9/kg levelized cost) to $24/kg ($3.6/kg). While these results are preliminary, they do indicate the substantial cost of the *working* hydrogen gas available to meet demand increases dramatically when the cushion gas requirements increase (or analogously, the efficiency to meet demand decreases).

Figure 5 illustrates the well cost calculator module interface that can be used to assess cost component contributions for cavern, aquifer and/or reservoir wells. For the aquifers, depleted oil & gas reservoirs and other potential storage options, the model allows for a custom number of wells, depths and types (e.g., new and existing recompleted wells) to calculate their overall contribution to the system's costs.

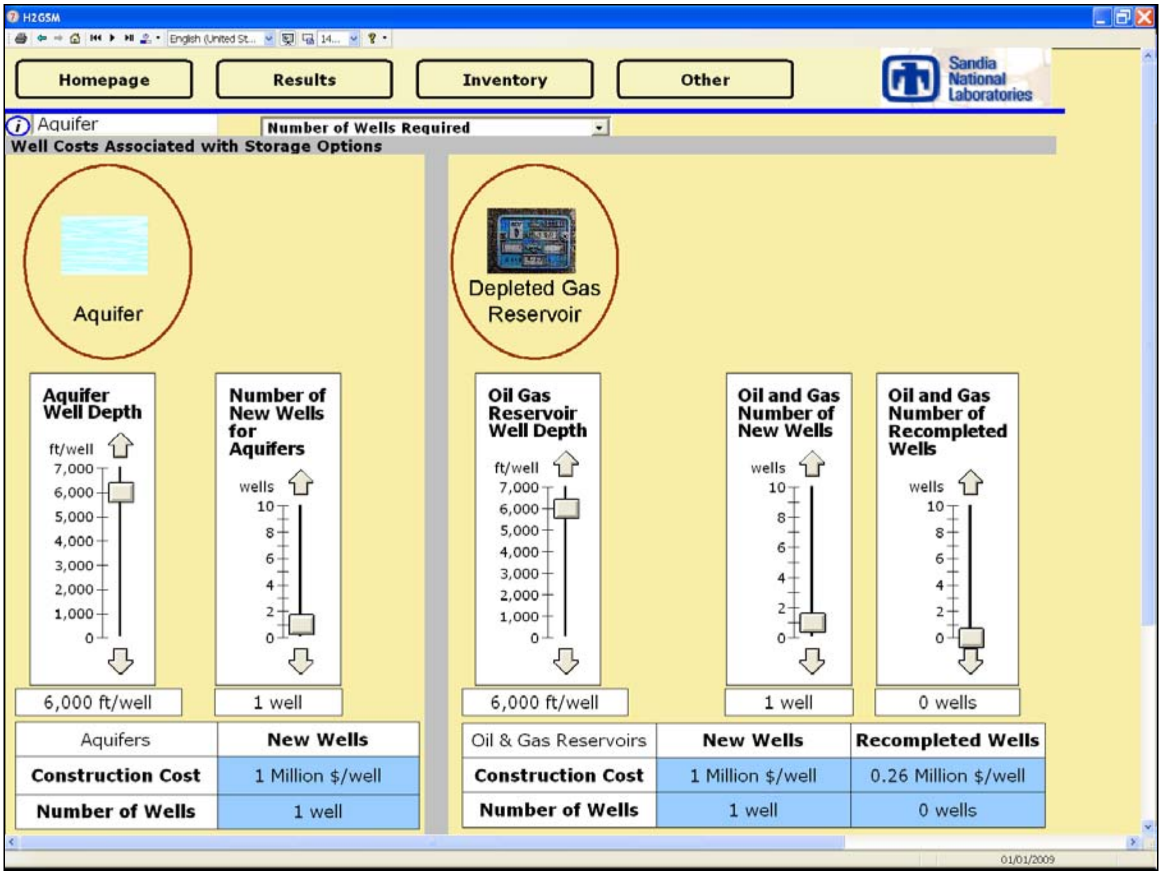

Figure 5. Custom Well Cost Calculator (Aquifer and Depleted Oil & Gas Reservoirs).

Figure 6 illustrates a base case analysis for the prototype inventory model. One example where this model and future more sophisticated versions of this model may prove useful may be to help calculate the accurate size and number of storage caverns. Additionally, a future version of the analysis may offer more storage options. Figure 6 indicates that after an initial fill up rate fluctuation, the supply meets demand for one given year. However, assuming the storage system may need to cover 60 day's worth of demand at 100,000 kg/day (Figure 7) this results in the need to build an additional cavern or series of storage facilities (e.g., may account for the H_2 stored in pipelines between the source/storage location and that of the H_2 demand).

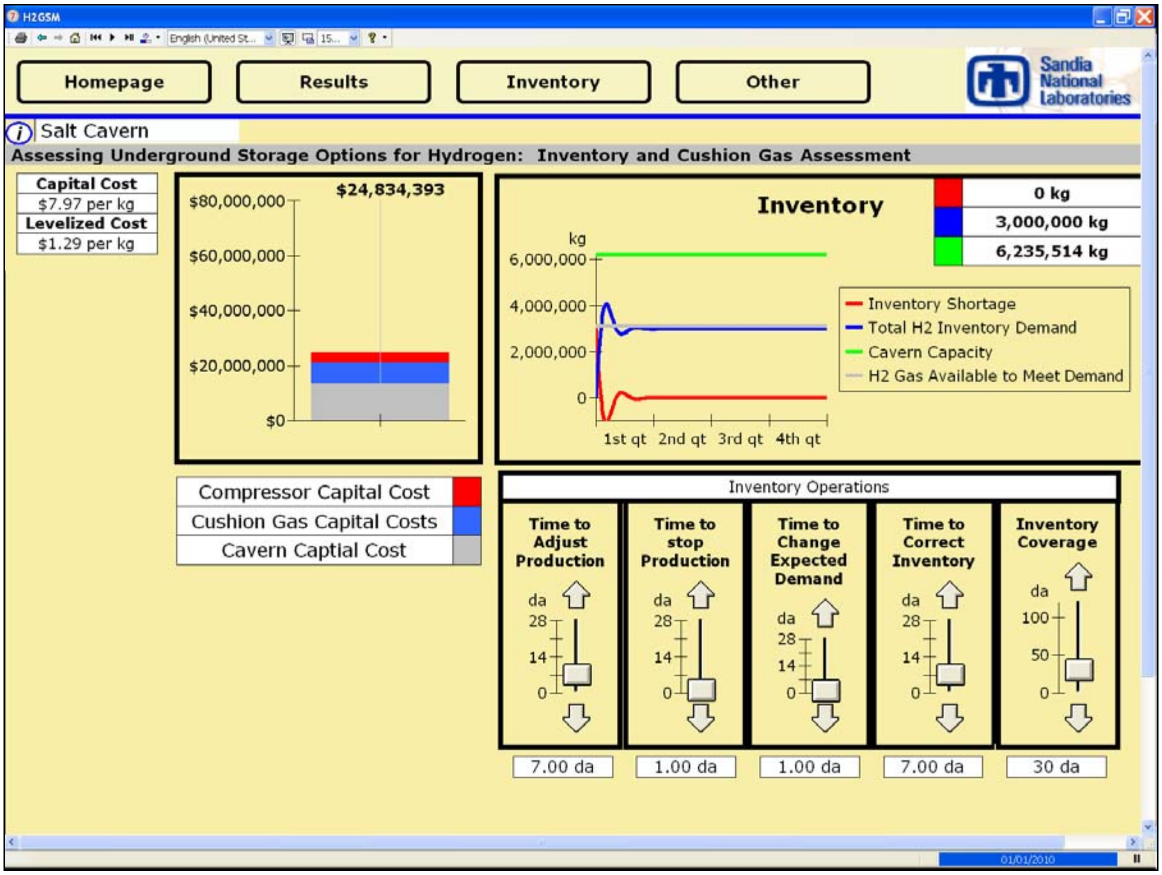

Figure 6. The Prototype Inventory and Cushion Gas Assessment of H2GSM.

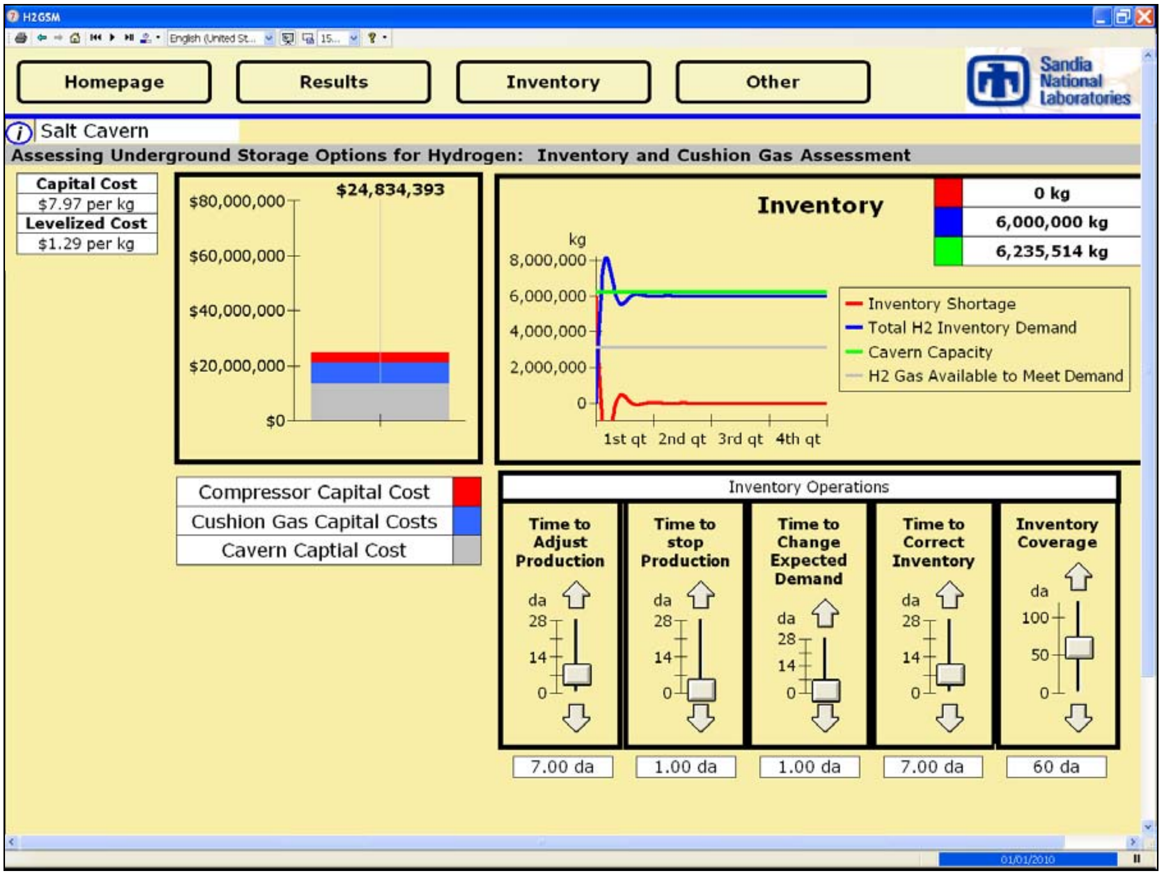

Figure 7. Sixty Day Inventory Coverage Scenario for the Inventory Module of H2GSM.

Summary

Fuel storage offers the ability to mitigate short-term supply shortages for natural gas and petroleum. Building on these and other case studies, an assessment tool was developed to calculate the potential for large-scale underground geologic storage options for hydrogen. Substantial potential exists for large-scale storage in salt domes and porous media (e.g., depleted oil and natural gas formations). The tool allows interested individuals and other modelers the ability to adapt the current model structure to calculate the value-added of storage within a developing hydrogen infrastructure.

Future Model Work and Suggestions

Future versions of the model may include additional details where available for the geological storage types (salt cavern, depleted oil/gas reservoir, aquifer and other). It may also include a more detailed inventory modeling module (e.g., demand fluctuations across a period of time). In an effort to refine the well drilling and completion costs for H_2, the analysis will likely include additional information as it becomes available in addition to developing a hydrogen extraction and separation module. These efforts will continue to build upon the suggestions received at presentations developed for this project (Lord, et al., 2008; Lord et al., 2009a).

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Appendix 1: Hydrogen Geological Storage Analysis Model Equations

The Hydrogen Geological Storage Model (H2GSM) was developed using several modules. The Hydrogen Supply, Transportation, Pipeline, Well Costs, Compressor, Cushion Gas, Geological Formation Type, and Hydrogen Extraction and Separation modules all contributed to the system's overarching results. The following table outlines the key assumptions, sources of data, and equations used in the working model framework. Additionally, a financial module allows for a transparent set of assumptions as they affect the underlying components, and therefore the overarching system's costs.

Table A1: Parameter Descriptions for H2GSM.

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
gH_2	grams of hydrogen	Calculated grams of hydrogen based on the ideal gas law equation	PV=nRT
P	kilopascals (kPa)	Pressure	Pressure measured in Kilopascals for each type of geological formation (gfp_i)
gfp_i	psi	Pounds per square inch of pressure	i = geological formation where; 1 = Salt Cavern (2,000 psi). Base case assumption based on Parks (2007). 2 = Oil / Gas Reservoir Pressure (3,600 psi). AGA (1996). 3 = Aquifer Pressure (psi). To be determined. 4 = Other Formation Type (psi). To be determined.
V_i	l	liters	V_i = volume of the reservoir where; 1 = Salt Cavern (580,000,000 l). Assumed base case (580,000 m^3), Parks (2007). 2 = Oil / Gas Reservoir (991,089,630,720 l). Assumed base case (35 bcf), AGA (1996) 3 = Aquifer. To be determined. 4 = Other Formation Type. To be determined.
n	grams/mol	Hydrogen molecular weight	2.016 grams/mol
R	kPa*l*(1/mol)*(1/K)	gas constant	8.314472 kPa*L*(1/mol)*(1/K)
T	Kelvin	Temperature	311 degrees Kelvin
cg%	% of Total H2 Storage Volume	Cushion Gas	Percent of the total Calculated Storage Volume of Hydrogen
cg	kg	kilograms of Hydrogen	The calculated mass of cushion gas: $cg = gH_2 * cg\%$

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
H_2a	Kg	kilograms of Hydrogen available	Kilograms of hydrogen available: $H_2a = gH_2 - cg$
\$cg	2009 \$US	Total Capital Cost of the Cushion Gas	$\$cg = cg * \$2.50 / kgH_2$ Where kgH_2 = \$2.50 base case assumption based on Yang and Ogden (2007) (0.10 to 4 \$/kg H_2) and HDSAM (\$2.50 / kg H_2).
TCC_i	2009 \$US	Total Capital Cost	Total Captial cost of the system. $TCC_i = \$gfcc_i + \$ccc + \$cg$ Where: $\$gfcc_i$ = geologic formation capital cost \$ccc = compressor capital cost
LTCC	2009 \$US	Levelized Total Capital Cost	$LTCC = TCC_i * CRF / CF$ Where: $CRF = \delta /(1-(1+\delta)^\wedge \lambda$ CRF = Capital Recovery Factor δ = discount rate (Assumed 10%) λ = Equipment Lifetime (Assumed 20 yrs) CF = Capacity Factor (Assumed 80%)
$L\$H_2$	2009 \$US / kg	Levelized Dollars per kg of hydrogen	$L\$H_{2,i} = (LTCC / H_2a) + COMC$ Where: $COMC = CLC + WCC * \chi$ Where: COMC = Compressor Operations and Maintanence Costs CLC = Compressor Levelized Cost WCC = Water and Cooling Costs χ = number of compressors
CLC	2009 \$US / tonne	Levelized Dollars per tonne of Hydrogen	$CLC = kWhc * EC * CCRF * (1/1yr / kWhco)$ kWhc = kilowatt hours required for the compressors EC = Electricity cost CCRF = compressor capital revovery factor kWhco = kWh per year for compressor operations

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
WCC	2009 US$ / kg	Water and Cooling Costs for the Compressors	WCC = WC * WRCC Where: WCC = Water and Cooling Costs WC = Water & Cooling (Assumed $0.02 per 1000 liters, Amos, 1998). WRCC = Water Requirements for Compressor Cooling (Assumed 50 liters / kg, Amos, 1998)
kWhc	kWh	Kilowatt hours	$kWhc = CP * IR * \varepsilon$ Where: CP = Compressor Power (Assumed base case 2.20 kWh/kg, Amos (1998)) IR = Injection Rate (Assumed 2960 kg/hr per compressor, Parks (2007)) ε = Compressor hours per year
ε	Hr/yr	Hours per year	$\varepsilon = 8760\, hrs / yr * CCF$ Where: CCF = Compressor Capacity Factor (Base Case Assumption 80%)
CS_i	m^3	Cavern size	CS_i = cavern size (base case assume 580,000 m^3) Where: 1 = 580,000 m^3 2 = 35 billion cubic feet (Base case assumption, AGA, 1996) = 991,089 m^3 3 = to be determined 4 = to be determined
P	2009 US$	Pipeline Costs	$P = \rho * \sigma$ $\rho = pipeline\ \cos t$ $\sigma = pipeline\, length\, (meter)$ (Base Case pipeline cost assumed $300/m, HDSAM, V2.0) (Base Case pipeline length assumed 100m) P = Pipeline costs Note: Pipelines not included in the final calculations, rather, they are built into the model as a placeholder until more detailed information becomes available.

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
ϕ	kg/day	Kilograms of H_2 demand per day	$\phi = \gamma * \eta$ $where:$ $\gamma = kg/day/station$ $\eta = number\ of\ stations$ Base Case Assumptions: γ = 500, 1800, or custom kg/day/station η = 200, 350, or custom number of stations Note: Yang and Ogden (2007) give two examples for the H_2 demands for a city the size of San Jose, CA at 15% and 100% market penetration (100,000 and 630,000 kg/day, respectively).
ι	kg	Desired kilograms of H_2 inventory to meet demand	$\iota = \phi * \kappa$ Where: κ=days worth of inventory coverage
φ	tonne / day	Expected Demand	$\varphi = \phi + ((\chi - \phi)/\mu))$ Where: μ = Time to Change Expected Demand (Days)
ν	tonne / day	Desired Production Rate	$\nu = \varphi + (\iota - o)/\varpi$ Where: ο = Total H_2 Inventory Demand ϖ = Time to Correct Inventory (Days)
o	tonne	Tonnes of H_2	$o = \sum(\chi * cp) - \phi$ Where: *cp* = compressor productivity (2,960 kg/hr/compressor) (Parks, 2007)
χ	Compressors	Number of Compressors	$\chi = \nu / cp$
I_j	% (based factor)	Inflation factor multiplier	$I_j = M_{2009} / N_{Year}$ Where: M_{2009} = inflation factor for the year 2009 N_{Year} = the inflation factor for the year of the base cost to be adjusted up to 2009 $US (e.g., 1998 $US to be converted to 2009 $US).

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