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A LIFE CYCLE COST ANALYSIS FRAMEWORK FOR GEOLOGIC STORAGE OF HYDROGEN: A USER'S TOOL

Anna S. Lord, Peter H. Kobos, Geoffrey T. Klise and David J. Borns

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

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Sandia National Laboratories
P.O. Box 5800
Albuquerque, NM 87185-0735

Abstract

The U.S. Department of Energy (DOE) has an interest in large scale hydrogen geostorage, which could offer substantial buffer capacity to meet possible disruptions in supply or changing seasonal demands. The geostorage site options being considered are salt caverns, depleted oil/gas reservoirs, aquifers and hard rock caverns. The DOE has an interest in assessing the geological, geomechanical and economic viability for these types of geologic hydrogen storage options. This study has developed an economic analysis methodology and subsequent spreadsheet analysis to address costs entailed in developing and operating an underground geologic storage facility. This year the tool was updated specifically to (1) incorporate more site-specific model input assumptions for the wells and storage site modules, (2) develop a version that matches the general format of the HDSAM model developed and maintained by Argonne National Laboratory, and (3) incorporate specific demand scenarios illustrating the model's capability.

Acknowledgments

The authors offer thanks to the ongoing support of Monterey Gardiner, Technology Development Manager in the Office of Hydrogen, Fuel Cells & Infrastructure Technologies within the U.S. Department of Energy for his valuable insight and feedback throughout the duration of this project. Additionally, the authors would like to thank Darlene Steward of the National Renewable Energy Laboratory, Marianne Mintz and particularly Amgad Elgowainy from Argonne National Laboratory for their insight and guidance. The authors also thank Jay Keller for his support, David Lord for his technical input using HYSIS, Stephen Bauer, and Len Malczynski for their ongoing technical review efforts.

Table of Contents

Figures

Tables

Introduction

The U.S. Department of Energy (DOE) Hydrogen Program and others throughout the research community have a renewed interest in understanding underground storage in geologic formations. Understanding these systems could allow for a relatively large, low-cost option to store hydrogen. Previous work as shown in Lord et al. (2008; 2009a, b, c; 2010a, b) developed initially a broader geologic understanding for the U.S. where opportunities may exist, and later a complementary economic analysis methodology. The analysis' modular design allows for relatively simple modification for the specific physical and economic model parameters and assumptions to test their influence as to the economic viability of specific types of geologic hydrogen storage sites.

The analysis' framework discussed in this report differs from that in Lord et al. (2010a, b) in a few key areas. First, the 2010 analysis framework version was the first time that the model was arrayed such that all four types of geologic storage options can be assessed at the same time. Second, the 2011 analysis framework was developed using several demand scenarios provided by colleagues at the Argonne National Laboratory (ANL) (Elgowainy, 2011). Third, additional effort was given to gathering more accurate model input assumptions for the aquifer and hard rock cavern storage site options. With this information, Argonne National Laboratory is working to incorporate this information into ongoing DOE-sponsored analyses including the Hydrogen Delivery Scenario Analysis Model (HDSAM, 2006; ANL, 2011). Therefore, the purpose of the study, and the analysis presented here, should be considered a starting point to link the geoscience reality of underground storage with higher-level systems modeling for policy insight (such as HDSAM).

Four general types of underground storage were analyzed: salt caverns, depleted oil/gas reservoirs, aquifers, and hard rock caverns/other custom sites. Due to the substantial lessons learned from the geological storage of natural gas already employed, these options present a potentially sizable storage option. Understanding and including these various geologic storage types in the analysis' physical and economic framework will help identify what geologic option would be best suited for the storage of hydrogen. It is important to note, however, that existing natural gas options may not translate to a hydrogen system where substantial engineering obstacles may be encountered. There are only three locations worldwide that currently store hydrogen underground and they are all in salt caverns. Two locations are in the U.S. (Texas), and are managed by ConocoPhillips and Praxair (Leighty, 2007). The third is in Teeside, U.K., managed by Sabic Petrochemicals (Crotogino et al., 2008; Panfilov et al., 2006). These existing H_2 facilities are quite small by natural gas storage standards.

The second stage of the analysis involved providing ANL with estimated geostorage costs of hydrogen within salt caverns for various market penetrations for four representative cities (Houston, Detroit, Pittsburgh and Los Angeles). Using these demand levels, the scale and cost of hydrogen storage necessary to meet 10%, 25% and 100% of vehicle summer demands was calculated.

Finally, a component of this year's work used Geographic Information System (GIS). A GIS tool was developed to identify and assess regions of the U.S. that may have potential for geologic hydrogen storage (e.g., regions with adequate salt deposits).

Background

Geologic storage is used extensively in the oil, natural gas, and compressed air energy industries. To understand the scale of this utilization, approximately 800 million barrels of oil (DOE, 2011) and 100's of billion cubic feet of natural gas (EIA, 2011) are stored geologically in the United States. The basic drive for geological storage is that the cost per volume-stored is 3 to 5 times less than surface storage. With this relatively inexpensive means to store large volumes, storage can be situated to buffer seasonal demands, provide continuity in case of disruption in the supply chain, and control congestion in the pipeline system.

Geologic cavern storage of hydrogen for industrial use already exists at two locations in Texas. In addition, a hydrogen economy and infrastructure raises similar needs as the natural gas and oil infrastructures. Analyses of the hydrogen infrastructure (Ogden, 2002; Williams, 2002; Simbeck and Chang, 2002) indicate that there may be an important role for geologic storage. This need, similar to fossil energy stocks, is to buffer seasonal demands, provide continuity in case of disruption in the supply chain, and control congestion in the pipeline system.

Argonne National Laboratory has developed a hydrogen transport and delivery model, which includes geologic storage of gaseous hydrogen as one of the model components. The Hydrogen Delivery Scenario Analysis Model (HDSAM) was developed to help determine the most cost effective hydrogen infrastructure from supply to demand (Chen, 2008).

The Hydrogen Geological Storage Model

The first goal of this project was to determine the suitability and availability of underground storage for hydrogen as described by Lord (2009). A white paper was developed to inform the DOE on underground natural gas storage in the U.S. and if geologic media may be suitable for hydrogen storage. The second goal of this project was to develop a basic modeling framework for the physical and economic attributes of underground geological storage options (Lord et al., 2009a). An initial analysis was developed to gather together a set of parameters believed to be necessary for a physical and economic analysis of geologic hydrogen storage. The third goal was to incorporate a scenario illustrating the model's capabilities in an integrated assessment-like framework (Lord et al., 2010b). A suite of scenarios were developed, with a specific focus on hydrogen storage for wind energy with the National Renewable Energy Laboratory (NREL). The following sections describe this year's work efforts and how they integrated into other research efforts at Argonne National Laboratory.

The Hydrogen Geological Storage Model (H2GSM) is a prototype analytical framework developed to highlight the major components of a ‘gate-to-gate’, large-scale hydrogen storage facility (the analysis focuses on the storage infrastructure only). This dynamic system’s level model was initially developed in Powersim Studio© (www.powersim.com) in order to illustrate the analysis from a physical infrastructure, hydrogen flow and cost perspective (Lord et al., 2010a, b). The analysis includes four storage options, namely salt caverns, depleted oil and gas reservoirs, aquifers, and hard rock caverns. The model has been re-written and updated in Microsoft® Excel to allow for a more collaborative development effort with Argonne National Laboratory[1] and now has the capability to address city demand scenarios. An additional component was created using GIS technology to help determine geographically-appropriate geologic formations and surrounding infrastructure that may present potential options for the storage of hydrogen. Figure 1 illustrates the overarching assessment methodology and analytical framework.

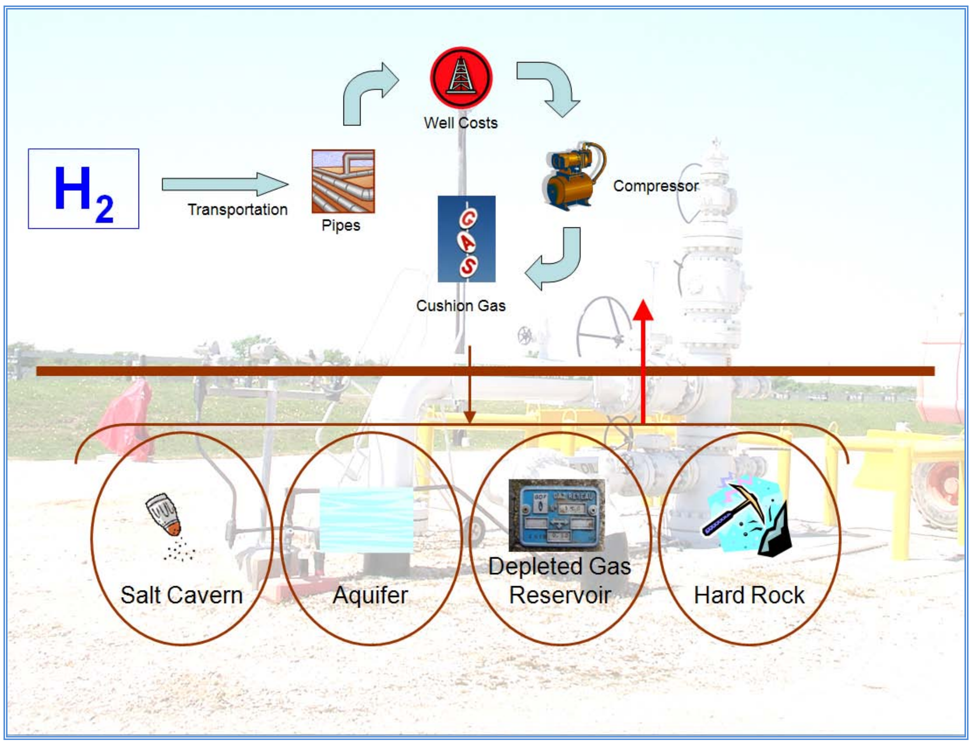

Figure 1. The Assessment Methodology and Model Framework.

[1] The version of H2GSM developed in Microsoft® Excel was developed to allow colleagues at the Argonne National Laboratory, and Amgad Elgowainy in particular, to utilize this information within the larger HDSAM model (ANL, 2011).

Four Geologic Storage Options

The type of rock formation under consideration to store hydrogen will have profound effects on the physical and economic viability to utilize that site. Four types of geological storage options have been examined for this analysis. Currently, depleted gas/oil reservoirs, aquifers, and salt caverns are the three main types of underground storage in use for natural gas today. The other storage options available currently and in the near future, such as lined hard rock caverns, will become more popular as the demand for natural gas storage grows, especially in regions where depleted reservoirs, aquifers, and salt deposits are not available. 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, such as the loss of hydrogen through chemical reactions and the occurrence of hydrogen embrittlement. Currently, there are only three locations worldwide, two of which are in the United States, that store hydrogen. All three sites store hydrogen within salt caverns. However, there have been successful cases of storing both town gas (50-60% hydrogen; Fasanio & Molinard, 1989; Panfilov et al., 2006) and helium (another small, light molecule; Tade, 1967) within aquifers successfully, thus possibly inferring the same media may be suitable for storage of hydrogen gas.

Salt caverns hold substantial promise due to the self-sealing nature of the salt, the ability to customize the size and often shape of the caverns, and the relatively close proximity of salt domes to the petroleum industry hubs along the Gulf Coast of the United States. Depleted oil and gas reservoirs have a known production history and thus are proven capable of holding gas. With this information, operators may have a good understanding of the potential rates of injection, withdrawal, and relative storage size of the formation. The reservoirs are easy to develop due to existing infrastructure. However, depleted oil and gas reservoirs may have a higher potential for gas loss through leaky wells and residual oil or gas within the reservoir may cause costly hydrogen contamination issues. Aquifers represent a very large potential storage option, yet also may represent the option with the least well-understood geology and therefore may require a large number of site surveys to more fully characterize the sites, which would add time and cost to site development. Even with this characterization, the potential for subsurface transport pathways in aquifers may preclude them from becoming an economically-viable storage site due to the high degree of uncertainty, and therefore, financial risk involved with developing and operating these types of sites. Lastly, hard rock caverns that require mining and impermeable liners represent more fully engineered storage systems that may be developed when other storage options are not available. However, this is a relatively new technology with only one site in the world that is fully operational to store natural gas.

The economic analysis developed for providing a cost comparison between the four types of underground storage studied used parameters collected from the literature and other known examples when possible. See Appendix A for a detailed compilation of these parameters and the subsequent costs. Table A1 presents the parameter equations used to create the model analysis, whereas Table A2 provides a comprehensive list of all the costs and parameters. Presented below are a set of tables listing a subset of the key parameters used in the analysis.

Table 1 illustrates the key storage conditions assumed for the base case scenarios for each of the four geologic storage options. The parameters used for the salt cavern and hard rock cavern examples are adapted from the ConocoPhillips salt cavern, which currently stores hydrogen in Texas (Parks, 2007). For the depleted oil and gas reservoir as well as the aquifer example, the geologic parameters listed in Table 1 were adapted from NatCarb (2008) and based on the Yeso Formation within the Estancia Basin in New Mexico. Cushion gas to working gas ratios were extracted from a 2004 report by the Federal Energy Regulatory Commission (FERC, 2004). The depleted oil and gas reservoirs and aquifers require higher percentages of cushion gas to keep the formation pressure high enough for successful operations (Beckman et al., 1995; FERC, 2004; NaturalGas.org, 2007). An aquifer system needs cushion gas volumes between 50 and 80% of the total volume depending on the nature of the formation. In Table 1, 50% cushion gas was assumed for the aquifer scenario, where in reality the cushion gas volume could be closer to 80% of the reservoir volume and the capital costs would then be significantly higher.

Table 1. Site Design Characteristics.

	Salt Cavern	**Depleted Oil & Gas Reservoir**	**Aquifer**	**Hard Rock Cavern**
Formation Pressure (psi)	2,000*	1,995	1,995	2,000*
Void Volume (m^3)	580,000	676,940	676,940	580,000
Formation Temp. (K)	310.9**	315.1	315.1	310.9**
Well Depth (ft)	3,800	4,604	4,604	3,800
Working Gas (tonnes H_2)	6,238	7,164	7,164	6,238
Cushion Gas (tonnes H_2)	1,871	3,582	3,582	1,871

* Assumed to be operating pressure. ** Assumed to be gas temperature.

Table 2 illustrates select compressor module results from the analysis framework. The base case assumptions for injection and withdrawal rates, power requirements and costs, operating and maintenance requirements and other related inputs illustrate the scale and scope of the compressor operations.

Table 2. Compressor Design and Cost Module.

	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Injection Rate (kg/hr)	2,960 [a]	2,487 [d]	2,487 [d]	2,960 [a]
Withdrawal Rate (kg/hr)	4,920 [a]	2,487 [d]	2,487 [d]	4,920 [a]
Compressor Power (kWh/kg)	2.2[c]	2.2 [c]	2.2 [c]	2.2 [c]
Compressor Size (kg/hr)	3,700 [a]	3,700 [a]	3,700 [a]	3,700 [a]
Cost per Compressor (2007 US$ / kW)	2,481 [b]	2,481 [b]	2,481 [b]	2,481 [b]
Compressor Costs Total (2007 US$)	27,539,480	18,359,654	18,359,654	27,539,480

Note: [a] Parks (2007); [b] Oil & Gas Journal (2009); [c] Amos (1998); [d] Steward (2010).

Table 3 presents a subset of the well and pipeline inputs used in the analysis. The difference in well costs noted between the various storage options is dictated by whether the well is new or recompleted and whether the well is drilled through sedimentary rock or igneous/metamorphic rock. Pipeline costs are negligible in the four storage site comparison analysis, since the analysis specifically concentrated on a 'gate-to-gate' scenario.

Table 3. Well and Pipeline Cost Module.

	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Full Pipeline Costs ($/tonne)	2.26	3.22	3.22	2.26
Full H_2 Wells Cost ($/tonne)	46.27	10.55	47.45	556
Full H_2 surface piping ($/tonne)	0	0	0	0
H_2 Transportation and Well Cost Total ($/tonne)	48.52	13.76	50.67	558.32

A few parameters have a larger uncertainty factor than others. For example, the number and even size of the compressors (and other equipment) required may vary considerably depending on site-specific factors, material costs, etc. The pipeline and well assessment presented here relies primarily on that in the CO_2 sequestration literature and H_2 pipeline costs may vary from these estimates (See Appendix B for differences in mass flow rates). Additionally, the steel liners required for the hard rock caverns are unknown at this time and their costs would be highly variable depending upon the price of steel.

For example, increases in steel prices lead to increases in the cost of wind turbine installations such that while installations may have occurred, it was at a higher marginal cost than before (Bloomberg, 2011). Indeed, the price of steel constitutes between 72 – 82% of the capital cost of certain wind farms (Qiu and Anadon, 2011; EWEA, 2009). Similar cost increases may be seen throughout these hydrogen storage cost estimates even while accounting for inflation (all costs have been adjusted to 2007 US$).

The central results for the overarching four storage options analysis are shown in Figure 2. According to strictly cost per kg of hydrogen stored, it may appear the depleted oil & gas reservoir or aquifers would be the economically-attractive options. Both these formations have an economy-of-scale advantage where they are able to hold several orders of magnitude (approximately 10 times as shown in Table 1) more hydrogen than a typical, proposed salt cavern or hard rock cavern. Figure 2 also displays levelized cost of hydrogen that accounts for the discounted capital costs across the lifetime of the project.

However, the current analysis does not yet quantify two very important criteria: the ability to cycle the caverns quickly and reliably, as well as the risk of not adequately characterizing the sites for potential leakage pathways. As mentioned earlier, salt caverns, once mined for operations, represent a 'self sealing' formation. Thus, if manageable leakage pathways were introduced or exist, the fracture pathways would likely heal due to salt's plastic properties. Additionally, salt caverns and hard rock caverns can be cycled multiple times per year for storage compared to depleted oil and gas reservoirs and aquifers that may only be able to be cycled once or twice yearly. However, aquifer delivery rates can be enhanced by an active water drive, using water to displace gas by filling previously gas-filled pores (EIA, 2007; Foh et al., 1979).

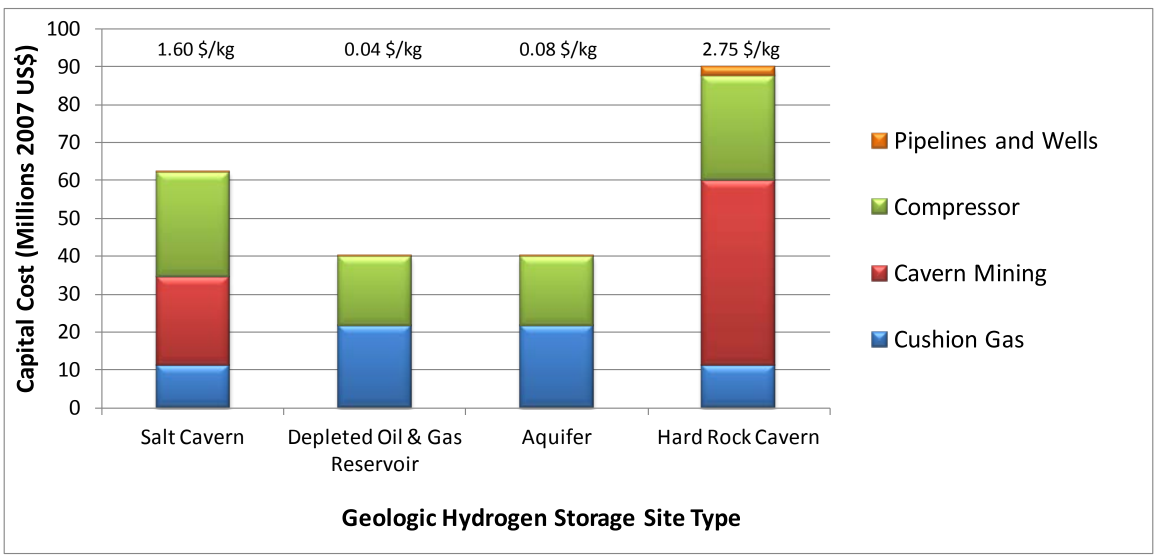

Figure 2. Cost Module (2007 US$). *(Note: Levelized cost of H_2 ($/kg) listed within chart; Hard Rock Cavern cost estimates do not yet include steel liners.)*

Site Development Scenarios to Meet Hydrogen Demand

To support the collaborative nature of the Hydrogen demand analysis, Sandia National Laboratories (SNL) and Argonne National Laboratories (ANL) developed several market demand scenarios to potentially include in HDSAM. Specifically, the four cities provided by Argonne National Laboratories (Elgowainy, 2011) were Houston, Detroit, Pittsburgh and Los Angeles.

The base case scenarios for each of the four cities vary greatly depending upon the total capital cost to install geological storage to meet 10%, 25% and 100% market penetration of each city's summer demand for its hydrogen transportation needs. To meet the summer demand for these cities, approximately 10% above the average daily demand for 120 days needs to be stored. Table 4 displays the mass of hydrogen required to meet the summer transportation needs for each city as both total capacity to be stored underground as well as the maximum production rate needed. Hydrogen summer storage needs were calculated for various market penetration levels by assuming 0.42 kg/day/person (based on Yang & Ogden, 2007).

Table 4. City Hydrogen Demand Assessment for Storage Size Scaling.

Market Penetration Level (%)	**Houston**	**Detroit**	**Pittsburgh**	**Los Angeles**
10%				
Desired Production Rate (kg H_2 /day)	15,929	16,263	7,304	49,121
kg stored for 120 days' supply	1,911,500	1,951,500	876,500	5,894,500
25%				
Desired Production Rate (kg H_2 /day)	39,823	40,656	18,260	122,802
kg stored for 120 days' supply	4,778,750	4,878,750	2,191,250	14,736,250
100%				
Desired Production Rate (kg H_2 /day)	159,292	162,625	73,042	491,208
kg stored for 120 days' supply	19,115,000	19,515,000	8,765,000	58,945,000

Each scenario assumed hydrogen storage in caverns leached within salt deposits. It is important to note that the extent and quantity of salt available differs from one region to the next, which can radically affect the overall cost of a project. Thick salt domes are available within the Houston region, whereas less massive bedded salts are present within the Detroit (Michigan Basin, Salina Salt Group) and Pittsburgh (Appalachian Basin, Salina Salt Group) regions. There is no salt near Los Angeles and transportation/pipeline costs are considered for storage within Arizona salt beds. The local geology dictates the size and at what depth a cavern can be constructed. Table 5 illustrates the difference in cavern size, which is dictated primarily by the characteristics of the salt formation present at each locality. Both levelized and capital costs are presented in Table 5 and capital costs are presented visually for each market penetration scenario in Figure 3. Table A1 presents the parameter equations used to create the model analysis, whereas Table A3 lists the actual costs and parameters used for the city demand analysis.

Table 5. City Hydrogen Demand Scenarios.

Cities	Population (persons)	Cavern Size (m^3)	Number of Caverns	Levelized Cost ($/kg)	Capital Cost (2007 US$)
Houston					
10%	38,230	580,000	1	1.61	19,384,471
25%	955,750	580,000	1	1.61	48,461,177
100%	3,823,000	580,000	4	1.61	193,844,709
Detroit					
10%	39,030	99,625	3	8.82	109,763,834
25%	975,750	99,625	7	8.82	274,409,585
100%	3,903,000	99,625	26	8.82	1,097,638,338
Pittsburgh					
10%	17,530	40,000	2	14.48	80,191,167
25%	438,250	40,000	5	14.48	200,477,916
100%	1,753,000	40,000	20	14.48	801,911,665
Los Angeles					
10%	117,890	580,000	1	1.67	63,254,547
25%	2,947,250	580,000	3	1.67	149,439,921
100%	11,789,000	580,000	10	1.67	597,759,684

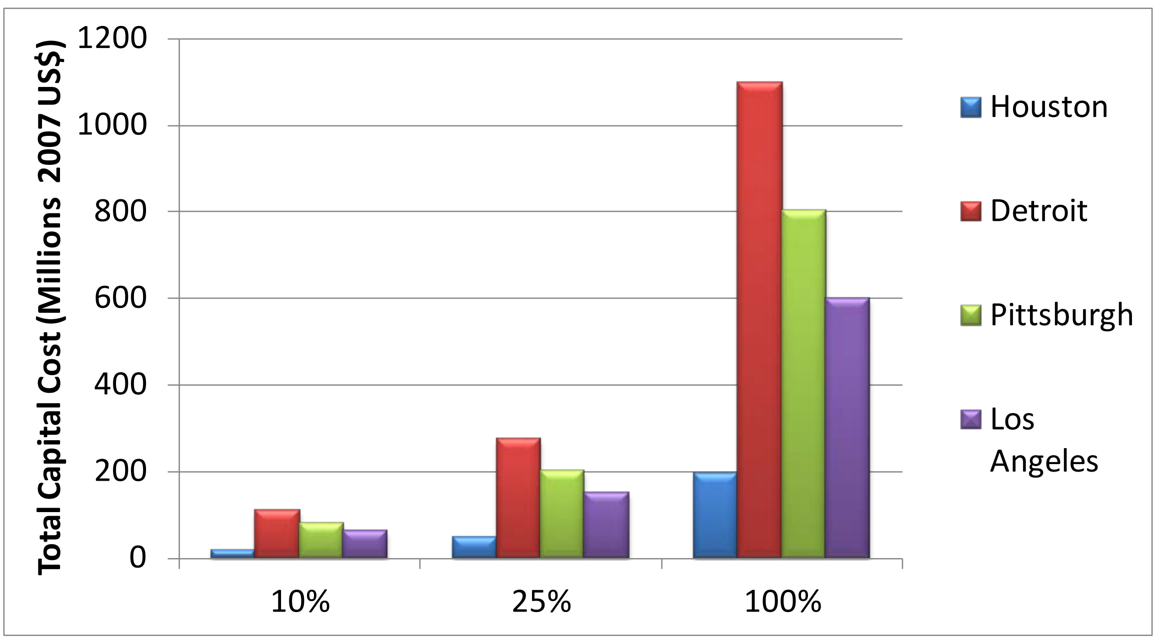

Figure 3. Total Capital Costs for four city demand scenarios (meeting 10, 25 or 100% of the city's summer vehicle demands).

The Storage Potential: Using Geographic Information System to Identify Sites in the U.S.

A GIS tool was developed to act as an upfront illustration to assist the economic analysis by allowing the user to conceptualize geographically the geology of the United States. The tool was developed using ESRI ArcGIS 10, for use in ArcReader10, a GIS software product available for free download from the ESRI website[2].

The tool was developed to identify not only the location of various rock types, but those regions with appropriate infrastructure, such as existing pipelines, to make geologic hydrogen storage more economically attractive than other regions lacking those components.

The file created for this application, once opened in ArcReader, displays as a map of the United States with the option for multiple layers to be activated either singularly or concurrently. The layers provide additional information that may be relevant to help assess the best location for proposing an underground geologic storage facility. The type of additional information that can be overlain on the U.S. map consists of such examples as, various geologic rock types that may have potential for storage, existing pipelines, existing natural gas storage facilities, cities, highways, federal lands, and surface topography. Figure 4 is an image of the ArcReader map displaying a subset of the attributes available for display; specifically note the colored polygons representing the locations of various geologic rock types that may possibly be suitable for underground storage.

[2] http://www.esri.com/software/arcgis/arcreader/download.html

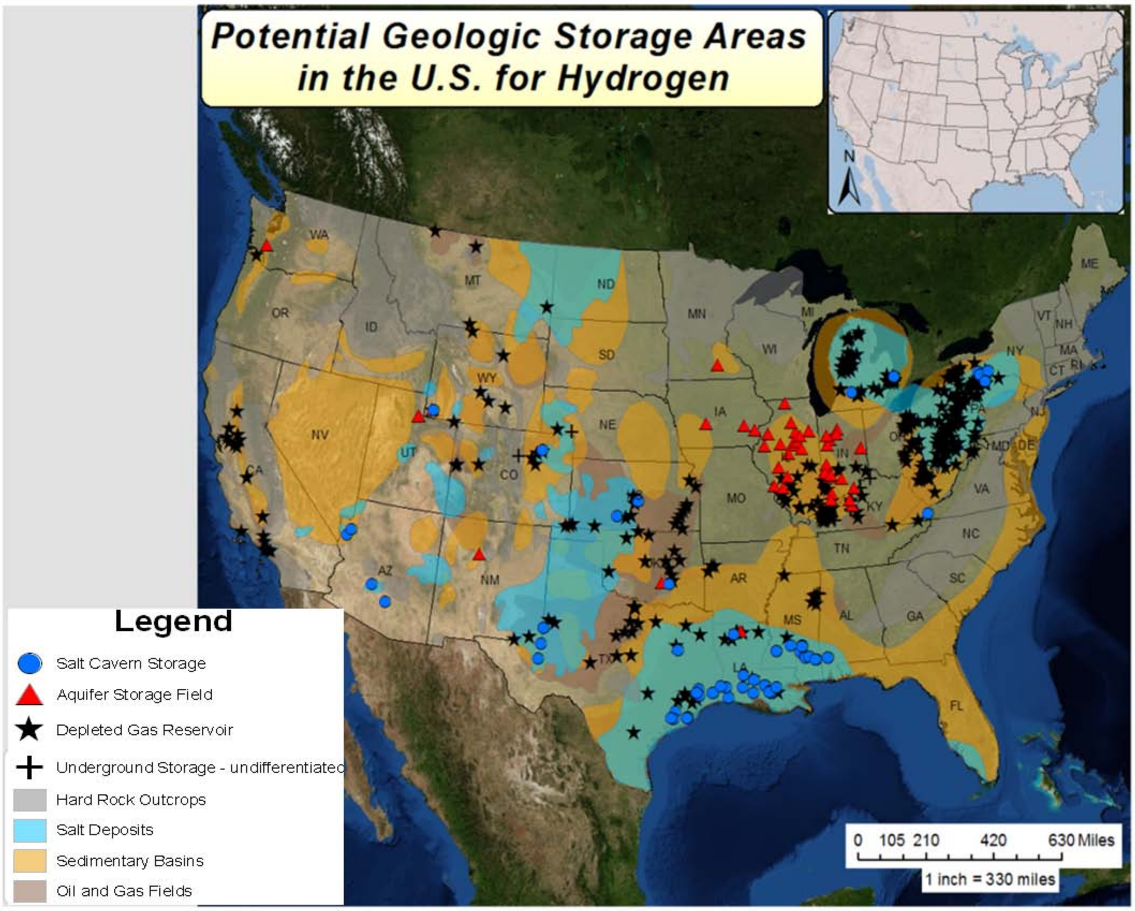

Figure 4. ArcReader map displaying U.S. geology that may have potential as underground storage as well as existing natural gas geologic storage facilities.

Summary

Large scale hydrogen storage offers hydrogen infrastructure systems the ability to mitigate short-term supply shortages. This study developed an economic spreadsheet analysis to address costs entailed in developing and operating an underground storage facility. The latest version was updated specifically to (1) incorporate more site-specific model input assumptions for the wells and storage site modules, (2) develop a version that matches the general format of the HDSAM model developed and maintained by Argonne National Laboratory, and (3) incorporate specific city demand scenarios illustrating the model's capability.

Salt caverns, depleted oil and gas reservoirs, aquifers, and mined hard rock caverns may offer potential geologic options for large-scale storage of hydrogen. It is important to note, however, that existing natural gas options may not translate to a hydrogen system where substantial engineering obstacles may be encountered. Possible new operational challenges include, but not limited to, the loss of hydrogen through chemical reactions and the occurrence of hydrogen embrittlement. The DOE has an interest in assessing the geological, geomechanical and economic viability for these types of geologic hydrogen storage options.

On a strictly cost per kg of hydrogen stored basis, it appears that depleted oil & gas reservoirs and aquifers would be the economically-attractive options. However, the current analysis does not yet quantify a very important criterion: a more complete analysis should have the ability to cycle the caverns quickly, allowing for a high annual throughput of gas. This may make salt caverns the most economical option.

The second thrust of the project supported ANL by Sandia developing several city market demand scenarios for geologic storage to potentially include in HDSAM. Cost estimates were developed for geologic storage with salt caverns to meet 10%, 25% and 100% market penetration of each city's summer demand for its hydrogen-based transportation needs. The type and quality of salt deposits present affect the differences in costs from one city to the next.

The final task included the development of a GIS tool to display the location of various rock types and their relation to major metropolitan regions and existing pipelines within the U.S.

Future Work and Suggestions

Driving further model refinements and expanding the scope are two key future work proposals. First, developing refinements to the geologic hydrogen storage cost parameters is an extension of the work completed in the geologic storage task in FY11 on the economic analysis work. This task could include additional storage cost parameters within the economic analysis to allow ANL and NREL the ability to refine their cost models and metrics of analysis. The main objective of this effort would be to continue working with Argonne National Laboratory to help refine the Hydrogen Delivery Scenario Analysis Model (HDSAM) with the latest hydrogen underground geologic storage parameters and cost estimates. Such updates to parameters would include brine disposal well costs, dehydration units, sales gas purification processes, and steel liner costs.

Second, expanding the scope of the initial analysis will help develop a full, U.S.-wide hydrogen storage resource profile and give a representative cost assessment. This would provide the basis to develop a national geologic storage of hydrogen supply curve. By doing so, this will allow for a more complete, collaborative scale-up analysis to be developed to understand how much economically-viable storage may be available in the U.S. This may include providing locations of preferable hydrogen and natural gas sites in an effort to help both ANL and NREL refine their full system analysis and site-specific work (e.g., using renewable energy resources to develop hydrogen storage facilities). By doing so, this will help further develop the economic analysis by illustrating regions of the U.S. that may have more favorable hydrogen storage for multiple uses (e.g., storing natural gas could be a dual-fuel system for a region by both using the natural gas directly for electricity and heating as well as using the natural gas as a feedstock for removing the hydrogen for transportation and other uses. This may affectively increase the value of storage by serving multiple uses. Additionally, this work will allow the analysis to develop a geologic hydrogen storage supply curve for the U.S.

Specific model refinements planned include (1) translating maximum flow rate per well from a CO_2 based system to H_2, (2) including a well calculator that would identify the number of wells required to meet demand, and (3) considering the affects of cyclicity on storage economics.

The maximum flow rate per day per well (tonne/day/well) currently used is based on a CO_2 system (Ogden, 2002). The Ogden model assumes CO_2 at 10-15 MPa and at 310K is under supercritical conditions, which means the gas has been compressed to a point that behaves like a liquid. Hydrogen is still a gas under the same conditions, and hence has a very low density. The mass flow rates will most likely need to be reduced by a factor of approximately 50 to 85 depending upon the well head and reservoir temperature and pressure conditions (See Appendix B).

Including a well calculator would account for the number of injection wells that will be needed to meet demand. Currently, the expected injection rates do not go beyond one well per formation type. In the city demand analysis, another cavern is built whenever more demand needs to be met and each one of those caverns has its own well.

Modeling cycle frequency would also affect the overall storage system cost. Salt caverns and hard rock caverns can generally be cycled multiple times per year for storage compared to depleted oil and gas reservoirs and aquifers that may only be able to be cycled once or twice yearly. The capability of a storage site to cycle product multiple times a year will decrease the levelized storage cost for that site. This may allow a previous costly storage option such as salt caverns to be more economically attractive.

Lastly, possible future work effort is to consider lined caverns within sedimentary rock (i.e., soft rocks), which would be easier and less expensive to mine. Lined caverns would ensure containment of the hydrogen, and could be operated in a similar fashion to salt caverns.

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Appendix A: Hydrogen Geological Storage Analysis Model Equations

The Hydrogen Geological Storage Model (H2GSM) was initially developed in 2009 and 2010 using several modules. The key assumptions, sources of data, and equations used in the model are given in the following table as well as updates regarding the representative hydrogen demand scenarios for cities the size of Houston, Detroit, Pittsburgh and Los Angeles.

A few of the key differences between the analyses of 2010 and 2011 involve adding more detailed city demand scenarios, as well as the more site-specific information across the four storage options (salt cavern, depleted oil/gas reservoir, aquifer and hard rock).

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 (1,011,011,428 l). Assumed base case (1,011,011 m^3), Steward (2010). 2 = Oil / Gas Reservoir (593,655,913 l). Steward (2010). 3 = Aquifer (6,814,619 m^3) (NatCarb, 2008). 4 = Hard Rock Cavern or Other Formation Type.
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 H_2 Storage Volume	Cushion Gas	Percent of the total Calculated Storage Volume of Hydrogen (30% for i=1, 4; 50% for i=2, 3).
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	2007 US\$	Total Capital Cost of the Cushion Gas	$\$cg = cg * \$6.00 / kgH_2$ Where kgH_2 = \$6.00 per kg of H_2 base case assumption derived from the range H_2 costs (Steward et al., 2009)
TCC_i	2007 US\$	Total Capital Cost	Total Capital cost of the system. $TCC_i = \$gfcc_i + \$ccc + \$cg$ Where: $\$gfcc_i$ = geologic formation capital cost \$ccc = compressor capital cost
LTCC	2007 US\$	Levelized Total Capital Cost	$LTCC = TCC_i * CRF / CF$ Where: $CRF_s = \delta /(1-(1+\delta)\wedge \lambda)$ CRF_s = Capital Recovery Factor δ_s = discount rate (Assumed 10%) for the site λ_s = Site Lifetime (Assumed 40 yrs) CF_s = Capacity Factor (Assumed 80%) for the site
$L\$H_2$	2007 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 Maintenance Costs CLC = Compressor Levelized Cost WCC = Water and Cooling Costs χ = number of compressors
CLC	2007 US\$ / tonne	Levelized Dollars per tonne of Hydrogen	$CLC = kWhc * EC * CRF_c * (1/1yr / kWhco)$ kWhc = kilowatt hours required for the compressors EC = Electricity cost CRF_c = compressor capital recovery factor Where: $CRF_c = \delta_c /(1-(1+\delta_c)\wedge \lambda_c)$ δ_c = discount rate (Assumed 10%) for the wells (identical to δ_s)

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
			λ_c = Compressor Lifetime (Assumed 20 yrs) kWhco = kWh per year for compressor operations
WCC	2007 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 2487 kg/hr per compressor) derived from Steward, 2010; Parks (2007) also reports 2960 kg/hr for comparison purposes. 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%)
VS_i	m^3	Void space	VS_i = void space Where: 1 = 1,011,011 m^3 2 = 6,814,619 m^3 3 = 6,814,619 m^3 4 = 100,000 m^3, to be determined
W	2007 US$	Well Costs	$W = (((wc + wv) * CRF_w) + ((w + v) * O\&M_w)) / gH_2$ wc = well capital cost wv = well variable cost CRF_w = capital recovery factor for wells Where: $CRF_w = \delta_w / (1 - (1 + \delta_w) \wedge \lambda_w)$ CRF_w = Capital Recovery Factor δ_w = discount rate (Assumed 10%) for the wells (identical to δ_s) λ_w = Well Lifetime (Assumed 30 yrs) $O\&M_w$ = operations and maintenance for wells

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
			gH_2 = mass (grams) of Hydrogen gas The well cost equation is based on the CO_2 well costs outlined in Ogden, 2002. Future versions of the H2GSM analysis will likely include additional considerations for Hydrogen well costs.
φ	tonne / day	Expected Demand	φ Where: φ = Expected demand
o	tonne	Tonnes of H_2	$o = \sum(\chi * cp_i) - \phi$ Where: cp_i = compressor productivity i = 1 (2,960 kg/hr, default derived from Parks, 2007, additional scenarios may include 2,487 kg/hr/compressor) (Steward, 2010) i = 2,3 (2,487 kg/hr, default derived from Steward, 2010, additional scenarios may include 6189.3 kg/hr/compressor) AGA, 1996 i = 4 (2,960 kg/yr, default derived from Parks, 2007)
χ	Compressors	Number of Compressors	$\chi = v / cp$ or user-defined custom # of compressors
I_j	% (based factor)	Inflation factor multiplier	$I_j = M_{2010} / N_{Year}$ Where: M_{2010} = inflation factor for the year 2010 N_{Year} = the inflation factor for the year of the base cost to be adjusted to 2007 US$ (e.g., 1998 US$ to be converted to 2007 US$).
Salt Formation Sizing Module			
Symbol or Abbreviation	**Units**	**Description**	**Equation, Assumption and/or source**
φ	tonne / day	Expected Demand	φ Where: φ = Expected demand
pop	Persons	City Population	pop = $\text{persons}_{\text{city (c)}}$ Where: city (c) = Houston, Detroit, Pittsburgh, Los Angeles $\text{persons}_{\text{Houston}}$ = 3,823,000 $\text{persons}_{\text{Detroit}}$ = 3,903,000 $\text{persons}_{\text{Pittsburgh}}$ = 1,753,000 $\text{persons}_{\text{Los Angeles}}$ = 11,789,000 Yang and Ogden, 2007

Symbol or Abbreviation	Units	Description	Equation, Assumption and/or source
cd	kg H_2 / day	City Demand	cd = (pcd*pop)*kdc Where: pcd = portion of city demand requiring H_2 (0.10 ,0.2, 0.50, 1.00) pop = City Population kdp = kg of H_2 required per day per person (Yang & Ogden, 2007) where 100% of 1.5 million people represents 630,000 kg/H_2 (1,800 kg/day for 350 stations) for 1,500,000 people or (630,000 kg/H_2/all cars)/(1,500,000) = 0.42 kg/day/person
scd	kg H_2 / day	Summer City Demand	Scd = (1+0.10)*cd 10% increase daily demand in summer
scc	kg H_2	Summer Cavern Capacity	scc = ((scd_{city} – cd_{city})* 120 days)*(1+asbc) Where: asbc = additional summer buffer capacity (base case = 0 days)
scccg	kg H_2	Summer Cavern Capacity + cushion gas	scccg = scc + cg
sss	tonnes H_2	Storage site size	sss = gH_2/10^6
dns	Storage sites	Desired number of Storage sites	dns = (scccg/(10^3))/sss

Table A2. H_2 Four Storage Options Details.

(1) Salt Cavern

(blue)	= Calculated Cells (do not change formulas)
(orange)	= Input Required; Input Used in Revenue Calculation
(green)	= Optional Input; Input NOT Used in Revenue Calculation
(yellow)	= Information Cells

Geologic Storage Volume Calculation		
Design Input, unit	**Value**	**Data Source**
PV = nRT		
Pressure (P), (psi)	**2000**	Parks, 2007
Pressure (P), (kPa)	13790	
Volume (V), (m^3)	**580,000**	Parks, 2007
Volume (V), (l)	580,000,000	
Temperature (T), (K)	**310.9**	Parks, 2007
Depth (ft)	**3800**	Parks, 2007
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	6,237,522,174	
mass (kg)	6,237,522	
mass (tonnes)	6,238	

Cushion Gas Module		
Design Input, unit	**Value**	**Data Source**
Percent Cushion Gas Desired (%)	**30%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	1,871	

Compressor Module		
Design Input, unit	**Value**	**Data Source**
Injection Rate (kg/hr)	**2960**	Parks, 2007
Withdrawal Rate (kg/hr)	**4920**	Parks, 2007
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.002	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.0144	
Compressor O&M Costs ($/kg)	**0.0144**	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**16**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	2.26	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**3800**	
Well Variable Cost (M$)	1.66	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	46.27	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002; Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0.00	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	48.52	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	Steward et al., 2009; Yang and Ogden, 2007
Cushion Gas Capital Cost ($)	$ 11,227,540	
Geologic Site Preparation		
mining costs ($/m^3)	23	Amos, 1998
Leaching Plant Costs ($ million)	10	Bauer, 2010
Total Salt Cavern Site Development ($)	23,340,000	
Dehydration Unit	TBD	Tannenhill, 2000
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	211,867	
Total Capital Costs	*$ 63,254,547*	
Levelized Total Capital Costs ($/kg)	*$ 1.54*	
Levelized Cost of H2 ($/kg)	***1.61***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,911,500**	Yang and Ogden, 2007
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,484,950	
Desired Production Rate (kg/day)	15,929	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**0.31**	
Desired Number of caverns (sites) (Rounded Up)	1	
Can the Desired Production Rate (kg/day) be met? (<1 = yes, >1 = no)	**0.13**	
Can daily production rate be met (hr/dy)?	**3**	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.02	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs	63,254,547	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.61	

(2) Depleted Oil and Gas Reservoir

	= Calculated Cells (do not change formulas)
	= Input Required; Input Used in Revenue Calculation
	= Optional Input; Input NOT Used in Revenue Calculation
	= Information Cells

Geologic Storage Volume Calculation

Design Input, unit	Value	Data Source
PV = nRT		
Pressure (P), (psi)	**1994.8**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Pressure (P), (kPa)	13754	
Volume (V), (m^3)	**676940.6**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Volume (V), (l)	676,940,600	
Temperature (T), (K)	**315.111**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Depth (ft)	**4604.4**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	7,164,092,637	
mass (kg)	7,164,093	
mass (tonnes)	7,164	

Cushion Gas Module

Design Input, unit	Value	Data Source
Percent Cushion Gas Desired (%)	**50%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	3,582	

Compressor Module

Design Input, unit	Value	Data Source
Injection Rate (kg/hr)	**2487**	Steward, 2010
Withdrawal Rate (kg/hr)	**2487**	Steward, 2010
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	499,836	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	2,499,179	
Levelized Cost per Compressor ($/kg)	0.001	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.0136	
Compressor O&M Costs ($/kg)	**0.0136**	
Number of Compressors (compressors)	2	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	18,359,654	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	20,891	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	2.42	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**16**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	3.22	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**0.26**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	0.26	
Well Variable Cost ($/km)	**318,757**	Ogden, 2002; Williams 2002
Well Depth (feet)	**4604.4**	
Well Variable Cost (M$)	0.45	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	10.55	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002; and Hendricks, 1994
Injection Rate (kg/hr)	238,479	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	0.26	
H2 Transportation and Well Costs ($/tonne)	13.76	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	
Cushion Gas Capital Cost ($)	$ 21,492,278	
Geologic Site Preparation		
mining costs ($/m^3)	0	Amos, 1998
Leaching Plant Costs ($ million)	0	Bauer, 2010
Total Cavern Site Development ($)	-	
Dehydration Unit	TBD	Tannenhill, 2000
Compressor Capital Costs	18,359,654	
Pipelines and Wells Capital Cost	49,297	
Total Capital Costs	*$ 40,106,938*	
Levelized Total Capital Costs ($/kg)	*$ 0.00*	
Levelized Cost of H2 ($/kg)	***0.04***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,911,500**	Yang and Ogden, 2007
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,867,250	
Desired Production Rate (kg/day)	15,929	
Storage Size (tonnes)	7,167,675	
Desired Number of sites	**1**	
Can the Desired Production Rate (kg/day) be met? (<1 = yes, >1 = no)	**0.27**	
Can daily production rate be met (hr/dy)?	**6**	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	277,778	Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	318,757	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	0.22	
Capital Cost per Well (2007 US M$)	0.26	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.02	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	
Recompleted Well Cost Multiplier	0.22	IEA, 2006, p. 7

Summary of Desired Inventory Modules		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs ($)	40,106,938	
Levelized Total Capital Costs ($/kg)	0.00	
Levelized Cost of H2 ($/kg)	0.04	

(3) Aquifers

(blue)	= Calculated Cells (do not change formulas)
(orange)	= Input Required; Input Used in Revenue Calculation
(green)	= Optional Input; Input NOT Used in Revenue Calculation
(yellow)	= Information Cells

Geologic Storage Volume Calculation

Design Input, unit	Value	Data Source
PV = nRT		
Pressure (P), (psi)	**1994.8**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Pressure (P), (kPa)	13754	
Volume (V), (m^3)	**676940.6**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Volume (V), (l)	676,940,600	
Temperature (T), (K)	**315.111**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Depth (ft)	**4604.4**	NatCarb, 2008, Estancia Yeso Formation; See Lord et al., 2010b
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	7,164,092,637	
mass (kg)	7,164,093	
mass (tonnes)	7,164	

Cushion Gas Module

Design Input, unit	Value	Data Source
Percent Cushion Gas Desired (%)	**50%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	3,582	

Compressor Module

Design Input, unit	Value	Data Source
Injection Rate (kg/hr)	**2487**	Steward, 2010
Withdrawal Rate (kg/hr)	**2487**	Steward, 2010
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	499,836	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	2,499,179	
Levelized Cost per Compressor ($/kg)	0.0012	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.0136	
Compressor O&M Costs ($/kg)	**0.0136**	
Number of Compressors (compressors)	2.00	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	18,359,654	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	20,891	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	2.42	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**16**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	3.22	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**4604.4**	
Well Variable Cost (M$)	2.01	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	47.45	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002; and Hendricks, 1994
Injection Rate (kg/hr)	238,479	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	50.67	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	
Cushion Gas Capital Cost ($)	$ 21,492,278	
Geologic Site Preparation		
mining costs ($/m^3)	0	Amos, 1998
Leaching Plant Costs ($ million)	0	Bauer, 2010
Total Salt Cavern Site Development ($)	-	
Compressor Capital Costs	18,359,654	
Pipelines and Wells Capital Cost	181,507	
Total Capital Costs	*$ 40,999,458*	
Levelized Total Capital Costs ($/kg)	*$ 0.00*	
Levelized Cost of H2 ($/kg)	***0.08***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,911,500**	Yang and Ogden, 2007
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,867,250	
Desired Production Rate (kg/day)	15,929	
Storage Size (tonnes)	7,167,675	
Desired Number of sites	**1**	
Can the Desired Production Rate (kg/day) be met? (<1 = yes, >1 = no)	**0.27**	
Can daily production rate be met (hr/dy)?	**6**	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.02	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs ($)	40,999,458	
Levelized Total Capital Costs ($/kg)	0.00	
Levelized Cost of H2 ($/kg)	0.08	

(4) Hard Rock Cavern

	= Calculated Cells (do not change formulas)
	= Input Required; Input Used in Revenue Calculation
	= Optional Input; Input NOT Used in Revenue Calculation
	= Information Cells

Geologic Storage Volume Calculation

Design Input, unit	Value	Data Source
PV = nRT		
Pressure (P), (psi)	**2000**	Parks, 2007
Pressure (P), (kPa)	13790	
Volume (V), (m^3)	**580,000**	Parks, 2007
Volume (V), (l)	580,000,000	
Temperature (T), (K)	**310.9**	Parks, 2007
Depth (ft)	**3800**	Parks, 2007
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	6,237,522,174	
mass (kg)	6,237,522	
mass (tonnes)	6,238	

Cushion Gas Module

Design Input, unit	Value	Data Source
Percent Cushion Gas Desired (%)	**30%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	1,871	

Compressor Module

Design Input, unit	Value	Data Source
Injection Rate (kg/hr)	**2960**	Parks, 2007
Withdrawal Rate (kg/hr)	**4920**	Parks, 2007
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.002	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.014	
Compressor O&M Costs ($/kg)	**0.014**	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**16**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	2.26	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**2.157**	Mansure & Blankenship, 2010; Mansure et al., 2006
Well Capital Cost (M$)	2.16	
Well Variable Cost (cofactor)	**0.00**	
Well Depth (feet)	**3800**	
Well Variable Cost (M$)	1.61	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	556	Mansure et al., 2006
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002, and Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	2.16	
H2 Transportation and Well Costs ($/tonne)	558.32	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	
Cushion Gas Capital Cost ($)	$ 11,227,540	
Geologic Site Preparation		
mining costs ($/m^3)	84	Amos, 1998
Cost of Steel Liner		TBD
Total Cavern Site Development ($)	48,720,000	
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	2,437,791	
Total Capital Costs	*$ 89,644,020*	
Levelized Total Capital Costs ($/kg)	*$ 2.18*	
Levelized Cost of H2 ($/kg)	***2.76***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,911,500**	Yang and Ogden, 2007
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,484,950	
Desired Production Rate (kg/day)	15,929	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**1**	
Can the Desired Production Rate (kg/day) be met? (<1 = yes, >1 = no)	**0.13**	
Can daily production rate be met (hr/dy)?	**3**	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)		
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)		
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.02	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs	89,644,020	
Levelized Total Capital Costs ($/kg)	2.18	
Levelized Cost of H2 ($/kg)	2.76	

Table A3. H_2 City Demand Analysis Details.

(1) Houston

(blue)	= Calculated Cells (do not change formulas)
(orange)	= Input Required; Input Used in Revenue Calculation
(green)	= Optional Input; Input NOT Used in Revenue Calculation
(yellow)	= Information Cells

Geologic Storage Volume Calculation

Design Input, unit	Value	Data Source
PV = nRT		
Pressure (P), (psi)	2000	Parks, 2007
Pressure (P), (kPa)	13790	
Volume (V), (m^3)	580,000	Parks, 2007
Volume (V), (l)	580,000,000	
Temperature (T), (K)	310.9	Parks, 2007
Depth (ft)	4800	Parks, 2007
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	6,237,522,174	
mass (kg)	6,237,522	
mass (tonnes)	6,238	

Cushion Gas Module

Design Input, unit	Value	Data Source
Percent Cushion Gas Desired (%)	30%	FERC, 2004
Cushion Gas of Total Volume (tonnes)	1,871	

Compressor Module

Design Input, unit	Value	Data Source
Injection Rate (kg/hr)	2960	Parks, 2007
Withdrawal Rate (kg/hr)	4920	Parks, 2007
Compressor Power (kWh/kg)	2.2	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	350	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.002	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.01	
Compressor O&M Costs ($/kg)	0.01	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	3,700	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2010 US$/kW)	2481	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**16**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	2.26	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**4800**	
Well Variable Cost (M$)	2.10	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	56.51	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002, and Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	58.76	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	Steward et al., 2009; Yang and Ogden, 2007
Cushion Gas Capital Cost ($)	$ 11,227,540	
Geologic Site Preparation		
mining costs ($/m^3)	23	Amos, 1998
Leaching Plant Costs ($ million)	10	Bauer, 2010
Total Salt Cavern Site Development ($)	23,340,000	
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	256,574	
Total Capital Costs	*$ 63,254,547*	
Levelized Total Capital Costs ($/kg)	*$ 1.54*	
Levelized Cost of H2 ($/kg)	***1.62***	

Note: The 'Max Flow Rate per day per well (tonne/day/well)' is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module (Houston)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,911,500**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,484,950	
Desired Production Rate (kg/day)	15,929	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**0.31**	
Desired Number of caverns (sites) (Rounded Up)	1	

Desired Inventory Module (Houston)		
Design Input, unit, (25% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**4,778,750**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	6,212,375	
Desired Production Rate (kg/day)	39,823	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**0.77**	
Desired Number of caverns (sites) (Rounded Up)	1	

Desired Inventory Module (Houston)		
Design Input, unit, (100% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**19,115,000**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	24,849,500	
Desired Production Rate (kg/day)	159,292	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**3.06**	
Desired Number of caverns (sites) (Rounded Up)	4	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Williams, 2002 & Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	Ogden, 2002
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.025	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules (Houston)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs	19,384,471	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.62	
Design Input, unit, (25% Market Demand)		
Total Capital Costs	48,461,177	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.62	
Design Input, unit, (100% Market Demand)		
Total Capital Costs	193,844,709	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.62	

(2) Detroit

	= Calculated Cells (do not change formulas)
	= Input Required; Input Used in Revenue Calculation
	= Optional Input; Input NOT Used in Revenue Calculation
	= Information Cells

Geologic Storage Volume Calculation		
Design Input, unit	**Value**	**Data Source**
PV = nRT		
Pressure (P), (psi)	**1400**	Based on 0.7 psi/ft *1988 ft, lithostatic pressure
Pressure (P), (kPa)	9653	
Volume (V), (m^3)	**99,625**	Gilhaus et al., 2006. Table 4, Consumer Power Company, MI
Volume (V), (l)	99,625,000	
Temperature (T), (K)	**309.8**	Gillhaus et al, 2006, Table 4, Consumer Power Company, MI
Depth (ft)	**2188**	Gilhaus et al., 2006
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	752,644,326	
mass (kg)	752,644	
mass (tonnes)	753	

Cushion Gas Module		
Design Input, unit	**Value**	**Data Source**
Percent Cushion Gas Desired (%)	**30%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	226	

Compressor Module		
Design Input, unit	**Value**	**Data Source**
Injection Rate (kg/hr)	**2960**	Parks, 2007
Withdrawal Rate (kg/hr)	**4920**	Parks, 2007
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.0020	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.01	
Compressor O&M Costs ($/kg)	**0.0144**	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**146**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	20.59	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**2188**	
Well Variable Cost (M$)	0.96	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	246.65	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002, and Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	267.24	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	Steward et al., 2009; Yang and Ogden, 2007
Cushion Gas Capital Cost ($)	$ 1,354,760	
Geologic Site Preparation		
mining costs ($/m^3)	23	Amos, 1998
Leaching Plant Costs ($ million)	10	Bauer, 2010
Total Salt Cavern Site Development ($)	12,291,375	
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	140,795	
Total Capital Costs	*$ 42,333,142*	
Levelized Total Capital Costs ($/kg)	*$ 8.52*	
Levelized Cost of H2 ($/kg)	***8.82***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module (Detroit)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**1,951,500**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,536,950	
Desired Production Rate (kg/day)	16,263	
Cavern Size (tonnes)	978	
Desired Number of caverns (sites)	**2.59**	
Desired Number of caverns (sites) (Rounded Up)	3	

Desired Inventory Module (Detroit)		
Design Input, unit, (25% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**4,878,750**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	6,342,375	
Desired Production Rate (kg/day)	40,656	
Cavern Size (tonnes)	978	
Desired Number of caverns (sites)	**6.48**	
Desired Number of caverns (sites) (Rounded Up)	7	

Desired Inventory Module (Detroit)		
Design Input, unit, (100% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**19,515,000**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	25,369,500	
Desired Production Rate (kg/day)	162,625	
Cavern Size (tonnes)	978	
Desired Number of caverns (sites)	**25.93**	
Desired Number of caverns (sites) (Rounded Up)	26	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Williams, 2002 & Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	Ogden, 2002
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.025	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules (Detroit)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs ($)	109,763,834	
Levelized Total Capital Costs ($/kg)	8.52	
Levelized Cost of H2 ($/kg)	8.82	
Design Input, unit, (25% Market Demand)		
Total Capital Costs ($)	274,409,585	
Levelized Total Capital Costs ($/kg)	8.52	
Levelized Cost of H2 ($/kg)	8.82	
Design Input, unit, (100% Market Demand)		
Total Capital Costs ($)	1,097,638,338	
Levelized Total Capital Costs ($/kg)	8.52	
Levelized Cost of H2 ($/kg)	8.82	

(3) Pittsburgh

	= Calculated Cells (do not change formulas)
	= Input Required; Input Used in Revenue Calculation
	= Optional Input; Input NOT Used in Revenue Calculation
	= Information Cells

Geologic Storage Volume Calculation		
Design Input, unit	**Value**	**Data Source**
PV = nRT		
Pressure (P), (psi)	**2100**	Based on 0.7 psi/ft *1988 ft, lithostatic pressure
Pressure (P), (kPa)	14479	
Volume (V), (m^3)	**40,000**	Gilhaus et al., 2006. Table 4, Consumer Power Company, MI
Volume (V), (l)	40,000,000	
Temperature (T), (K)	**318**	Gillhaus et al, 2006, Table 4, Consumer Power Company, MI
Depth (ft)	**3085**	Gilhaus et al., 2006
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	441,597,902	
mass (kg)	441,598	
mass (tonnes)	442	

Cushion Gas Module		
Design Input, unit	**Value**	**Data Source**
Percent Cushion Gas Desired (%)	**30%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	132	

Compressor Module		
Design Input, unit	**Value**	**Data Source**
Injection Rate (kg/hr)	**2960**	Parks, 2007
Withdrawal Rate (kg/hr)	**4920**	Parks, 2007
Compressor Power (kWh/kg)	**2.2**	Amos, W.A., 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.0020	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.01	
Compressor O&M Costs ($/kg)	**0.0144**	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2007 US$/kW)	**2481**	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**304**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	42.86	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**3085**	
Well Variable Cost (M$)	1.35	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	550.12	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002, and Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	592.98	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	Steward et al., 2009; Yang and Ogden, 2007
Cushion Gas Capital Cost ($)	$ 794,876	
Geologic Site Preparation		
mining costs ($/m^3)	23	Amos, 1998
Leaching Plant Costs ($ million)	10	Bauer, 2010
Total Salt Cavern Site Development ($)	10,920,000	
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	183,301	
Total Capital Costs	*$ 40,401,884*	
Levelized Total Capital Costs ($/kg)	*$ 13.86*	
Levelized Cost of H2 ($/kg)	***14.48***	

Note: The 'Max Flow Rate per day per well (tonne/day/well)' is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module (Pittsburgh)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**876,500**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	1,139,450	
Desired Production Rate (kg/day)	7,304	
Cavern Size (tonnes)	574	
Desired Number of caverns (sites)	**1.98**	
Desired Number of caverns (sites) (Rounded Up)	2	

Desired Inventory Module (Pittsburgh)		
Design Input, unit, (25% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**2,191,250**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	2,848,625	
Desired Production Rate (kg/day)	18,260	
Cavern Size (tonnes)	574	
Desired Number of caverns (sites)	**4.96**	
Desired Number of caverns (sites) (Rounded Up)	5	

Desired Inventory Module (Pittsburgh)		
Design Input, unit, (100% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**8,765,000**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	11,394,500	
Desired Production Rate (kg/day)	73,042	
Cavern Size (tonnes)	574	
Desired Number of caverns (sites)	**19.85**	
Desired Number of caverns (sites) (Rounded Up)	20	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Williams, 2002 & Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	Ogden, 2002
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.025	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules (Pittsburgh)		
Design Input, unit, (10% Market Demand)	**Value**	
Total Capital Costs ($)	80,191,167	
Levelized Total Capital Costs ($/kg)	13.86	
Levelized Cost of H2 ($/kg)	14.48	
Design Input, unit, (25% Market Demand)		
Total Capital Costs ($)	200,477,916	
Levelized Total Capital Costs ($/kg)	13.86	
Levelized Cost of H2 ($/kg)	14.48	
Design Input, unit, (100% Market Demand)		
Total Capital Costs ($)	801,911,665	
Levelized Total Capital Costs ($/kg)	13.86	
Levelized Cost of H2 ($/kg)	14.48	

(4) Los Angeles

	= Calculated Cells (do not change formulas)
	= Input Required; Input Used in Revenue Calculation
	= Optional Input; Input NOT Used in Revenue Calculation
	= Information Cells

Geologic Storage Volume Calculation		
Design Input, unit	**Value**	**Data Source**
PV = nRT		
Pressure (P), (psi)	**2000**	Parks, 2007
Pressure (P), (kPa)	13790	
Volume (V), (m^3)	**580,000**	Parks, 2007
Volume (V), (l)	580,000,000	
Temperature (T), (K)	**310.9**	Parks, 2007
Depth (ft)	**3800**	Parks, 2007
Gas Constant (R), (L*(1/mol)*(1/K))	8.314472	
Weight (gram/mol)	2.016	
mass (g)	6,237,522,174	
mass (kg)	6,237,522	
mass (tonnes)	6,238	

Cushion Gas Module		
Design Input, unit	**Value**	**Data Source**
Percent Cushion Gas Desired (%)	**30%**	FERC, 2004
Cushion Gas of Total Volume (tonnes)	1,871	

Compressor Module		
Design Input, unit	**Value**	**Data Source**
Injection Rate (kg/hr)	**2960**	Parks, 2007
Withdrawal Rate (kg/hr)	**4920**	Parks, 2007
Compressor Power (kWh/kg)	**2.2**	Amos, 1998, Appendix D, p D-2
Compressor kWh per year	988,819	
Days per year for Calculations	365	
Operating Days/yr (days/yr)	**350**	Amos, 1998, Appendix D, p D-2
Compressor Capacity Factor (%)	96	
Cost of Electricity (cents/kWh)	5	Amos, 1998, Appendix D, p D-2
Compressor Levelized Cost of Electricity ($)	4,944,094	
Levelized Cost per Compressor ($/kg)	0.0020	
Water & Cooling Costs for Compressors ($/100 liters)	$0.02	Amos, 1998, Appendix D.1
Water Requirements for Compressors (l/kg)	50	Amos, 1998, Appendix D.1
Water and Cooling Costs ($/kg)	0.012	Amos, 1998
Compressor O&M ($/kg)	0.014	
Compressor O&M Costs ($/kg)	**0.014**	
Number of Compressors (compressors)	3	
Compressor Size (kg/hr)	2,000	
Compressor Size (kW)	**3,700**	Parks, 2007
Cost per compressor (2009 US$/hp)	1824	Oil & Gas Journal, 2009
Cost per compressor (2010 US$/kW)	**2481**	
Compressor Costs Total ($)	27,539,480	
Hours per Year for Compressors (hrs)	8,760	
Compressor Capacity Factor and Hours	8,400	
Withdrawal Rate kW/hr/yr for Compressor Operations (tonne/yr)	41,328	

Wells & Surface Piping Module		
Design Input, unit	**Value**	**Data Source**
Initial Pipeline Fixed Costs ($/tonne)	4.03	Ogden, 2002; Williams 2002
H2 Pipeline cost, Initial Flow Rate (tonne/hr)	4.78	
Base Flow rate (tonne/hr)	445.9	Ogden, 2002; Williams 2002
Transport Distance of H2 (km)	**525**	
Base Transport Distance of H2 for Equation (km)	100	Ogden, 2002; Williams 2002
Full Pipeline Costs ($/tonne)	74.02	
Well O&M (%)	**4%**	Ogden, 2002; Williams 2002
Number of Brine Disposal Wells (wells)	**0**	
Number of Fresh Water Wells (wells)	**0**	
Number of Injection/Withdrawal Wells (wells)	**1**	
Capital Cost per Well (M$/well)	**1.15**	Ogden, 2002; Williams 2002
Well Capital Cost (M$)	1.15	
Fresh Water Well Depth (ft)	**0**	
Brine Disposal Well Depth (ft)	**0**	
Well Variable Cost ($/km)	**1,434,409**	Ogden, 2002; Williams 2002
Well Depth (feet)	**3800**	
Well Variable Cost (M$)	1.66	
Equipment lifetime (years)	30	
Discount Rate (%)	10%	
Capital Recovery Factor for Equipment	0.11	
Full H2 Wells Cost ($/tonne)	46.27	
Max Flow Rate per day per well (tonne/da/well)	2500	Ogden, 2002; Hendricks, 1994
Injection Rate (kg/hr)	283,836	
Full H2 surface piping ($/tonne)	0.0	
Wells Fixed Capital Cost (M$)	1.15	
H2 Transportation and Well Costs ($/tonne)	120.29	

Cost Module		
Design Input, unit	**Value**	**Data Source**
Cushion Gas		
Cost of Hydrogen Gas ($/kg of H2)	$ 6.00	Steward et al., 2009; Yang and Ogden, 2007
Cushion Gas Capital Cost ($)	$ 11,227,540	
Geologic Site Preparation		
mining costs ($/m^3)	23	Amos, 1998
Leaching Plant Costs ($ million)	10	Bauer, 2010
Total Salt Cavern Site Development ($)	23,340,000	
Compressor Capital Costs	27,539,480	
Pipelines and Wells Capital Cost	525,226	
Total Capital Costs	*$ 63,254,547*	
Levelized Total Capital Costs ($/kg)	*$ 1.54*	
Levelized Cost of H2 ($/kg)	***1.68***	

Note: The ‘Max Flow Rate per day per well (tonne/day/well)’ is based on CO_2-based system (Ogden, 2002). The density of hydrogen gas is less dense than CO_2. Thus, the mass of hydrogen flowing through these systems will differ from that of CO_2. The costs, therefore, may change according to these differences in future work.

Desired Inventory Module (Los Angeles)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**5,894,500**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	7,662,850	
Desired Production Rate (kg/day)	49,121	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**0.95**	
Desired Number of caverns (sites) (Rounded Up)	1	

Desired Inventory Module (Los Angeles)		
Design Input, unit, (25% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**14,736,250**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	19,157,125	
Desired Production Rate (kg/day)	122,802	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**2.36**	
Desired Number of caverns (sites) (Rounded Up)	3	

Desired Inventory Module (Los Angeles)		
Design Input, unit, (100% Market Demand)	**Value**	**Data Source**
Working Demand Capacity (kg)	**58,945,000**	
Desired Inventory to Cover Demand + Cushion Gas (kg)	76,628,500	
Desired Production Rate (kg/day)	491,208	
Cavern Size (tonnes)	8,109	
Desired Number of caverns (sites)	**9.45**	
Desired Number of caverns (sites) (Rounded Up)	10	

Economic Base Year Module		
Design Input, unit	**Value**	**Data Source**
Variable Cost Per Well Input (2002 US$/km)	1,250,000	Williams, 2002; Ogden, 2002
Inflation Factor	1.15	Whitehouse, 2009
Variable Cost Per Well Input (2007 US$/km)	1,434,409	
Pipeline Cost Equation Intercept (2002 US$/tonne)	3.51	Ogden, 2002
Pipeline Cost Equation Intercept (2007 US$/tonne)	4.03	Whitehouse, 2009
Capital Cost per Well (2002 US M$)	1	Williams, 2002; Ogden, 2002
Capital Cost per Well (2007 US M$)	1.15	
Water and Cooling for Compressors (1998 US$/100 liters)	0.02	Amos, 1998, Table 11
Inflation Factor	1.24	Whitehouse, 2009
Water and Cooling for Compressors (2007 US$/100 liters)	0.025	
Compressor Cost (2009 US$)	1895	Oil & Gas Journal, 2009
Inflation Factor	0.96	Whitehouse, 2009
Compressor Cost (2007 US$)	1824	
Electricity Cost (2007 US¢/kWh)	5	
Inflation Factor	1	
Electricity Cost (2007 US¢/kWh)	5	

Summary of Desired Inventory Modules (Los Angeles)		
Design Input, unit, (10% Market Demand)	**Value**	**Data Source**
Total Capital Costs	63,254,547	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.68	
Design Input, unit, (25% Market Demand)		
Total Capital Costs	149,439,921	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.68	
Design Input, unit, (100% Market Demand)		
Total Capital Costs	597,759,684	
Levelized Total Capital Costs ($/kg)	1.54	
Levelized Cost of H2 ($/kg)	1.68	

Appendix B: Comparison Between Carbon Dioxide and Hydrogen Injection Rates

Estimates for Hydrogen Injection Rates into Underground Storage Reservoir Compared to Carbon Dioxide Injection Baseline

David Lord
Geotechnology & Engineering Department
Sandia National Laboratories
dllord@sandia.gov

August, 2011

Problem statement

A current economic model for geologic storage of hydrogen under development at Sandia requires cost estimates for a large-scale system capable of injecting hydrogen into underground reservoirs. The model developers wish to utilize cost estimates from an existing economic model for CO_2 sequestration as a starting point. A question raised with this approach is what H_2 injection rate (metric tons/day) would be feasible if the baseline system can inject 2,500 t/day CO_2 into a given reservoir.

Background

Ogden (2003) describes a model CO_2 sequestration system with an injection rate of 2500t/day/well. This injection system is supplied by a 100 km pipeline with an outlet pressure of ~10 MPa. Fluid temperature is not explicitly given, but is assumed to be near ambient conditions given that the pipeline length is 100 km. Once received from the pipeline, the CO_2 must be injected into an underground reservoir. Ogden does not give specific parameters for the target reservoir, but Oldenburg (Oldenburg, Pruess et al. 2001) reported values of P = 122 bar (12,200 kPa), T = 65°C for a gas field in California that was modeled for possible CO_2 injection.

Fluid properties

Consideration for the critical properties of the two gases is required to estimate the relative mass flow rates. CO_2 and H_2 differ greatly as shown in Table 1.

Table 1. Critical constants for H_2 and CO_2 (from Sonntag and Van Wylen (1991)).

Substance	MW	T_c	P_c
		[K]	[MPa]
H_2	2.016	33.2	1.3
CO_2	44.01	304.1	7.38

The large disparities in critical constants have several implications for this analysis. First, CO_2 will exhibit higher density than H_2 at nearly any given P,T condition. At ideal gas conditions, CO_2 is 44/2 = 22 times more dense than H_2. Second, at pipeline and reservoir conditions relevant to this problem scenario (P = 10-13 MPa, T = 30-65°C), CO_2 transitions to supercritical conditions, and will exhibit a much more rapid increase in density with pressure than hydrogen in that region. The ratio of densities will therefore show a strong sensitivity to process stream pressure and temperature.

Literature data for CO_2 density near pipeline and reservoir conditions were taken from Wang, Cates et al. (1998) and Oldenburg, Pruess et al. (2001). There is a marked increase in CO_2 density as pressure is increased beyond 80 bar (~1200 psi) as the fluid transitions to supercritical. As such, any conversion from a CO_2 baseline mass flow rate to a H_2 mass flow rate will require a significant inverse multiplier. At the low end, this could be 1/22 for ideal gas conditions, while at the high end, this could approach 1/100 for T = 30°C and P = 14 MPa.

Approach

The CO_2 injection system of Ogden (2003) is taken as a baseline. This system injects supercritical CO_2 from a pipeline near 10 MPa downhole into a reservoir near 12 MPa at a mass flow rate of 2,500 t/day. Note that rigorously determining the effective injection rate into a reservoir requires knowledge of reservoir permeability and thickness, injection pressure, reservoir pressure, well depth, and fluid density and viscosity at pipeline and reservoir conditions. For the current exercise, the estimates of Ogden (2003) and Oldenburg, Pruess et al. (2001) will be used as a starting point, so that the full reservoir simulation will not be repeated. We will assume that the flowing pressure at the wellhead is 13 MPa in order to overcome flow resistance in the 12 MPa reservoir.

HYSYS process simulation

A simple process flow model was built with the chemical engineering process simulator software Aspen HYSYS v7.1 (see Appendix B1) in order to calculate the power requirement and volume flow rate associated with CO_2 injection in the above-mentioned conditions. Recall that the primary problem statement for this exercise was to determine the suitability of using existing cost estimates developed for a CO_2 injection system as a starting point for an H_2 injection system. The author assumes that power requirement is a driver for cost. Moreover, the limitations on fluid injection rate will be related to volume flow rate and pressure, which both directly relate to power requirements. Hence, an equivalent compression system was simulated in HYSYS for H_2 using selected input from the CO_2 system. The dependent variables in the H_2 system were the mass and volume flow rates assuming that the same power from the CO_2 system was drawn to compress H_2 from 10-13 MPa.

Selection of Equation of State

The equation of state (EOS) predicts the pressure-temperature-density relationship for the H_2 and CO_2 fluids within the process environment. While ideal gas law is sufficient for hydrogen in this problem scenario, the CO_2 system transitions through the supercritical region, and will require some consideration of EOS accuracy in this parameter space. The Soave-Redlich-Kwong (SRK) is a standard EOS used for petroleum process simulation, and was chosen as a starting point. A report by Oh, Lillo et al. (2004) states that in their experience, the Lee-Kesler-Plockman (LKP) EOS is the most accurate EOS defined in HYSYS for supercritical CO_2. Comparisons of CO_2 density calculated by HYSYS using the SRK and LKP EOS models with literature data are given in Figure 1 and Figure 2. The LKP model gives generally better agreement with the measured data, and a very good match in Figure at 40°C. The LKP model was therefore selected for the HYSYS simulations presented in the remainder of this report.

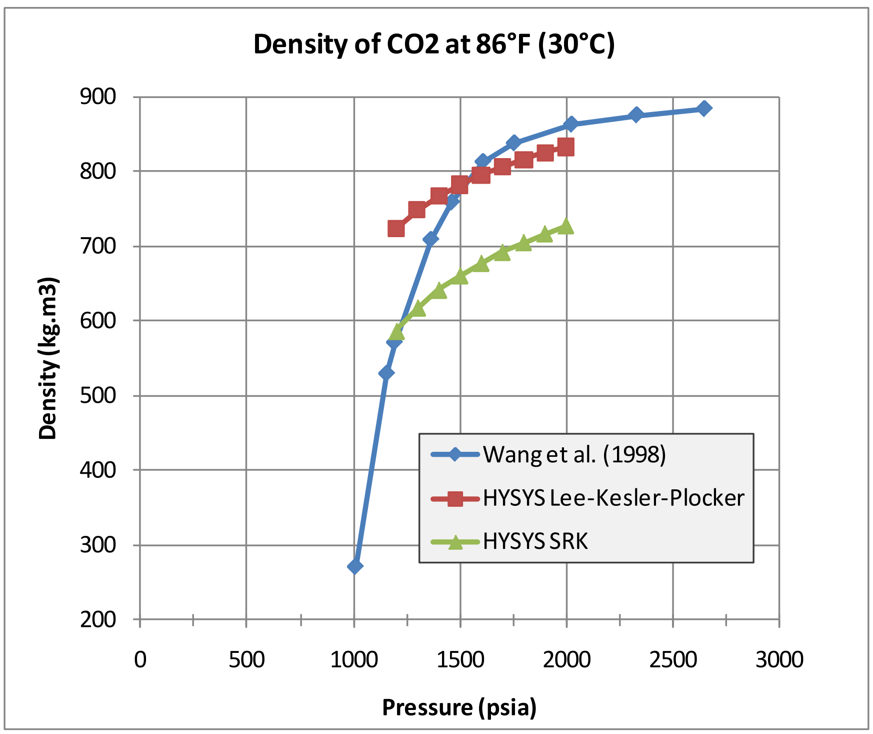

Figure 1. HYSYS-calculated CO2 density using the SRK and LKP equations of state overlaid with measured data from Wang, Cates et al. (1998) at T = 86°F (30°C).

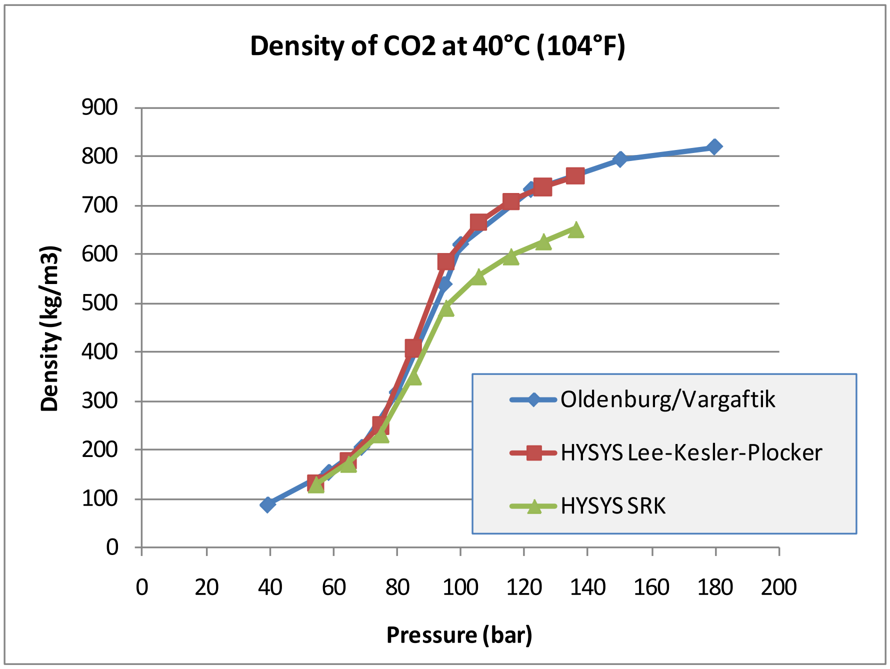

Figure 2. HYSYS-calculated CO_2 density using the SRK and LKP equations of state overlaid with data given in Oldenburg, Pruess et al. (2001) at T = 40°C (104°F).

Results

Results from HYSYS simulations are summarized in tables internal to the model as seen in Appendix B1 and are extracted, with unit conversions, in Table 2 for discussion. Reviewing the process flow, a feed stream of CO_2 was passed through a compressor at 104,200 kg/h (2,500 t/d) and compressed from 10 to 13 MPa, requiring a power input of 6.1E+05 kJ/h (170 kW). The mass density of CO_2 increased from 668 to 690 kg/m^3, and actual volume flow at the compressor outlet was 151 m^3/h (3,624 m^3/d). Mass flow rate (kg/hr) is constant across the compressor.

Moving to the H_2 system, a feed stream was compressed from 10-13 MPa using the same power as above, 170 kW, resulting in a compressed H_2 volume flow rate of 144.4 m^3/h (3,466 m^3/d) and a mass flow rate of 1,229 kg/h (29 t/d).

Table 2. Summary of results from HYSYS simulations of CO2 and H2 compression systems.

		Stream	*Stream*	*Unit Operation*
Parameter	*Units*	*CO_2 feed*	*CO_2 compressed*	*Compressor*
Temperature	[K]	311	318	
Pressure	[kPa]	10,000	13,000	
Mass Density	[kg/m^3]	668	690	
Mass flow	[t/d]	2,501	2,501	
Actual volume flow	[m^3/d]	3,744	3,624	
Power	[kW]			170
		Stream	*Stream*	*Unit Operation*
Parameter	*Units*	*H_2 feed*	*H_2 Compressed*	*Compressor*
Temperature	[K]	311	344	
Pressure	[kPa]	10,000	13,000	
Mass Density	[kg/m^3]	7.4	8.5	
Mass flow	[t/d]	29	29	
Actual volume flow	[m^3/d]	4,010	3,466	
Power	[kW]			170

As determined by the HYSYS simulation, for a ~170 kW compressor between the pipeline and a single wellhead, about 3,500 m^3/d fluid could be injected into a representative reservoir. Since CO_2 is about 85 times more dense than H_2 at the compressor outlet, the mass flow rate is also about 85 times higher. Hence, an injection system that could handle 2,500 t/d CO_2 would only be able to handle about 29 t/d H_2 with similar volume flow rates.

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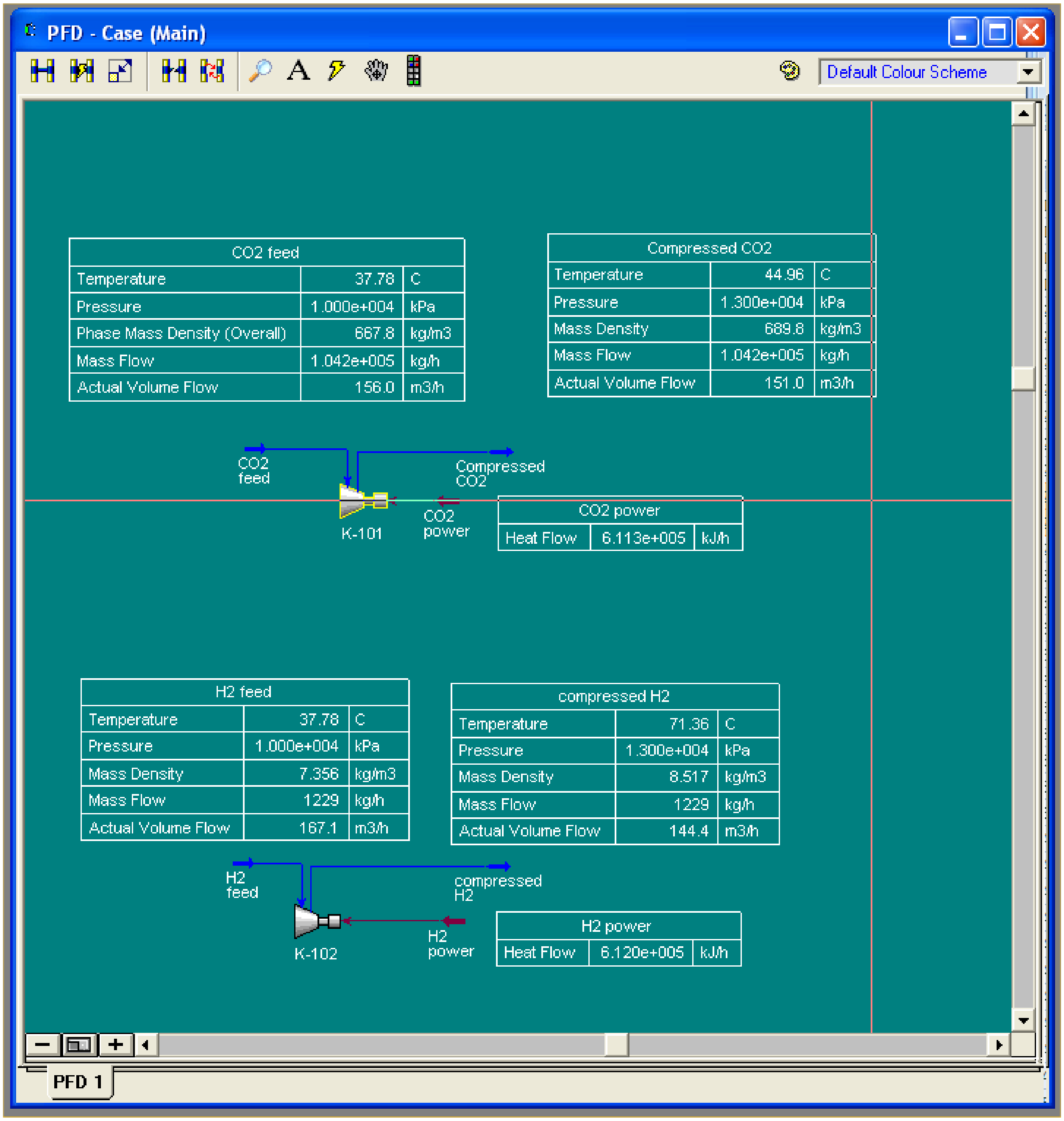
Appendix B1

Screen shot of HYSYS process flow diagram.



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