Conceptual Design of Optimized Fossil Energy Systems with Capture and Sequestration of Carbon Dioxide

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Conceptual Design of Optimized Fossil Energy Systems with Capture and Sequestration of Carbon Dioxide

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ABSTRACT

In this final progress report, we describe research results from Phase I of a technical/economic study of fossil hydrogen energy systems with CO_2 sequestration. This work was performed under NETL Award No. DE-FC26-02NT41623, during the period September 2002 through August 2005

The primary objective of the study is to better understand system design issues and economics for a large-scale fossil energy system co-producing H_2 and electricity with CO_2 sequestration. This is accomplished by developing analytic and simulation methods for studying the entire system in an integrated way. We examine the relationships among the different parts of a hydrogen energy system, and identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We carried out a geographically specific case study of development of a fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread.

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EXECUTIVE SUMMARY

In this final report, we present results from Phase I of a technical and economic assessment of fossil H_2 energy systems with CO_2 sequestration. This work was performed during the period September 2002-August 2005 under NETL Award No. DE-FC26-02NT41623.

The primary objective of the study is to better understand system design issues and economics for a large-scale fossil energy system co-producing hydrogen (H_2) and electricity with carbon dioxide (CO_2) sequestration. This is accomplished by developing new analytic and simulation tools for studying the entire system in an integrated way. We examine the relationships among the various parts of a fossil hydrogen energy system, and attempt to identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We are carrying out a geographically specific case study of development of a fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread.

We consider fossil energy complexes producing both H_2 and electricity from either natural gas or coal, with sequestration of CO_2 in geological formations such as deep saline aquifers. The design and economics of the system depend on a number of parameters that determine the cost and performance of the system "components", as a function of scale and geography (components include: the fossil energy complex, H_2 pipelines and refueling stations, CO_2 pipelines, CO_2 sequestration sites, and H_2 energy demand centers). If we know the cost and performance characteristics of the components, designing the system can be posed as a problem of cost minimization. The goal is to minimize the delivered H_2 cost with CO_2 disposal by co-optimizing the design of the fossil energy conversion facility and the CO_2 disposal and H_2 distribution networks. Research to perform this cost minimization has two parts: 1) implement technical and economic models for each "component" in the system, and 2) develop optimization algorithms to size various the system components and connect them via pipelines into the lowest cost network serving a particular energy demand. Finally, to study transition issues, we use these system models to carry out a case study of developing a large-scale fossil energy system in the Midwestern United States.

The research consisted of three tasks.

Task 1.0 Implement Technical and Economic Models of the System Components

We utilize data and component models of fossil energy complexes with H_2 production, and CO_2 sequestration developed by the principal investigator as part of the Carbon Mitigation

Initiative (CMI) at Princeton University.[1] Models for H_2 distribution systems and refueling stations were adapted from the principal investigator's previous studies of H_2 infrastructure for the US Department of Energy Hydrogen R&D Program (Ogden 1998, Ogden 1999a, Ogden 1999b), studies at UC Davis under the Hydrogen Pathways program (Yang and Ogden 2004), and those of other researchers (Mintz et al. 2003, Amos 1998, Thomas et al. 1998). During the past year the principal investigator worked with the "H2A", a group of hydrogen analysts convened by the USDOE to develop cost and performance estimates for hydrogen technologies. The H2A is developing an EXCEL-based spreadsheet database, for hydrogen production, refueling and delivery systems.[2] In addition the National Academy of Engineering recently released an assessment of the Hydrogen Economy, including data on hydrogen technologies (NAE 2004). In Phase II, we propose to update our models to reflect the new information contained in these studies.

Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Network

As a first step, we developed a simple analytical model linking the components of the system. We consider single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center. We developed "cost functions" for the CO_2 disposal cost and the delivered H_2 cost with explicit dependence on important input parameters (e.g. size of demand, fossil energy complex process design, aquifer physical characteristics, distances, pressures etc.). Analytic sensitivity studies of this "simple system" are used to provide us with insights on which parameters are most important in determining costs.

As a next step, we extended this simple model, by designing the supply to meet a specified level of demand. Results were derived for the cost of fossil hydrogen production with CO_2 sequestration as a function of geographic factors (geographic density of demand, location of fossil energy complexes and sequestration sites), level of hydrogen use (e.g. size of the market, market penetration of hydrogen vehicles), and technology (type of supply technology, hydrogen vehicle fuel economy). We developed an idealized model of a city as a basis for designing and costing hydrogen distribution infrastructure (e.g. a hydrogen pipeline network or truck delivery routes in cities).

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we explored use mathematical programming methods to find the lowest cost system design. From our system modeling, we seek to distill "rules for thumb" for developing H_2 and CO_2 infrastructures.

Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

[1] Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor Company to find solutions to global warming and climate change.

[2] During the period February 2003-August 2004, the principal investigator took part in developing the H2A database, and led the team looking at hydrogen delivery systems. The H2A spreadsheets should become available in October of 2004, and we plan to include these results as part of Phase II.

In this task, the goal is to explore transition strategies: how H_2 and CO_2 infrastructures might develop in time, in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

To better visualize our results, we use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks. We plan to coordinate with other ongoing GIS based studies of CO_2 sequestration potential such as the NATCARB project. Input from these projects will be used to estimate the best options for sequestration. Optimization tools available in the ARCView GIS software are used to identify the lowest cost pipeline network for supplying hydrogen to users.

1.0 INTRODUCTION

In this final report, we present results from Phase I of a technical and economic assessment of fossil H_2 energy systems with CO_2 sequestration. This research was performed under NETL Award No. DE-FC26-02NT41623, between September 2002 and August 2005.

1.1. Background and Motivation

Production of hydrogen from fossil sources with capture and sequestration of CO_2 offers a route toward near-zero emissions in production and use of fuels. Implementing such an energy system on a large scale would require building two new infrastructures: one for producing and delivering H_2 to users (such as vehicles) and one for transmitting CO_2 to disposal sites and securely sequestering it.

In Figure 1.1.1, we show a fossil hydrogen energy system with CO_2 sequestration. A fossil feedstock (natural gas or coal) is input to a fossil energy complex producing hydrogen and electricity. CO_2 is captured, compressed to supercritical pressures for pipeline transport to a sequestration site, and injected into an aquifer or other underground geological formation. Hydrogen is delivered to users via a pipeline distribution system that includes compression and storage at the hydrogen production plant, pipelines (possibly with booster compressors) and hydrogen refueling stations. The design and economics of a fossil H_2 energy system with CO_2 sequestration depend on a host of factors, many of which are regionally specific and change over time. (Variable considered in this study are shown in Figure 1.1.1 in italics.) These include:

- The size, type, location, time variation and geographic density of the H_2 demands.
- Cost and performance of component technologies making up the system. Key components are: the fossil energy conversion plant [design variables include the scale, feedstock: (coal vs. natural gas), process design, electricity co-production, separation technology, pressures and purity of H_2 and CO_2 products, sulfur removal options including co-sequestration of sulfur compounds and CO_2, location (distance from demand centers and sequestration sites)], H_2 and CO_2 pipelines and H_2 refueling stations.
- The location and characteristics of the CO_2 sequestration sites (storage capacity, permeability, reservoir thickness),
- Cost, location and availability of primary resources for H_2 production.
- Location of existing energy infrastructure and rights of way (that could be used for siting hydrogen transmission pipelines).

For simplicity, in Figure 1.1.1, we have shown a single fossil energy complex, serving a single demand, and one CO_2 sequestration site. However, a future fossil hydrogen system could be more complex, linking multiple H_2 demand centers (cities), fossil energy complexes and sites for CO_2 sequestration (Figure 1.1.2).

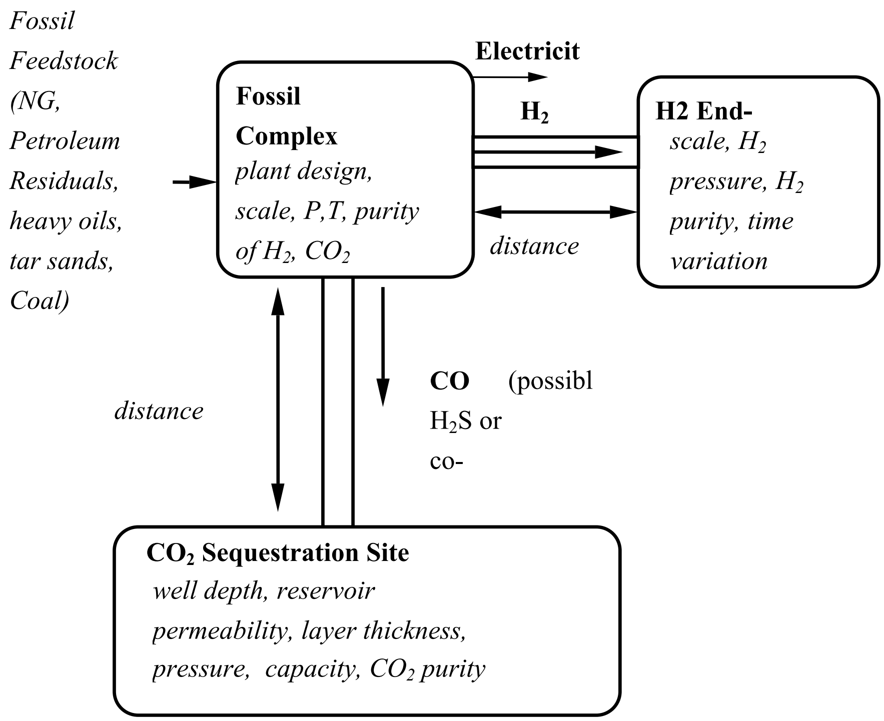

Figure 1.1.1. A Fossil Energy System for Production of Hydrogen and Electricity with CO_2 Sequestration. (Variables for the Study are Shown in Italics)

Several detailed technical and economic studies have been carried out for various parts of the system, including CO_2 capture from electric power plants (Hendriks 1994; Foster Wheeler 1998; Simbeck 1999), or H_2 plants (Foster Wheeler 1996; Doctor et al. 1999; Spath and Amos 1999; Kreutz et al. 2002), CO_2 transmission (Skovholt 1993) and storage (Holloway 1996), and H_2 infrastructure (Directed Technologies et al. 1997, Ogden 1999; Thomas et al. 1998, Mintz et al 2002). However, relatively little work has been done assessing complete fossil hydrogen systems with CO_2 sequestration in an integrated way. An integrated viewpoint is important for understanding the design and economics of these systems. For example, the scale of the fossil hydrogen plant can have a large impact on the design and cost of both the hydrogen distribution system, and the system for transporting and sequestering CO_2.

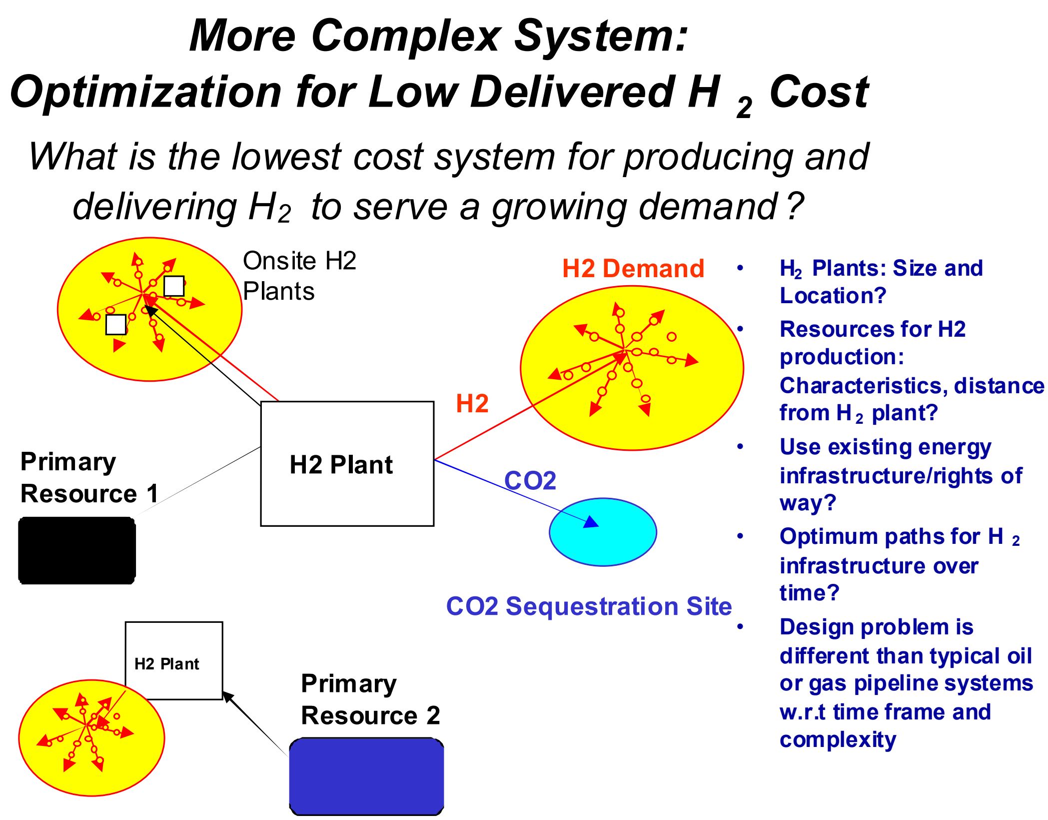

Figure 1.1.2. Schematic of More Complex Hydrogen System

1.2. Scope of this Study

The primary objective of this study is to better understand total system design issues and economics for a large-scale fossil energy system co-producing hydrogen (H_2) and electricity with CO_2 sequestration. We consider fossil energy complexes producing both H_2 and electricity from either natural gas or coal, with sequestration of CO_2 in geological formations such as deep saline aquifers. We apply various analytic and simulation methods to study the entire system in an integrated way. We attempt to identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2. We examine the relationships among the system components (e.g. fossil energy complexes, H_2 and CO_2 pipelines, H_2 demand centers, and CO_2 sequestration sites), and apply new simulation tools to studying these systems, and optimizing their design.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We focus on understanding how H_2 and CO_2 infrastructures might evolve to meet a growing H_2 demand under different regional conditions. If we know the location, size, cost and performance characteristics of the system components, designing the system can be posed as a problem of cost minimization. The goal is to minimize the delivered H_2 cost with CO_2 disposal by co-optimizing the design of the fossil energy conversion facility and the CO_2 and H_2 pipeline networks. Research to perform this cost minimization has two parts: 1) implement technical and economic models for each component in the system (Task 1), and 2) explore use of optimization algorithms to size various the system components and connect them via pipelines into the lowest cost network serving a particular energy demand (Task 2). Techniques for studying regional H_2 and CO_2 infrastructure development and transition strategies are described, based on use of Geographic Information System (GIS) data and network optimization techniques.

To understand the impact of geographic factors, we carried out a case study of development of a large scale fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread (Task 3).

Three tasks were completed.[3]

1.2.1. Task 1.0 Implement Technical and Economic Models of the System Components

Before developing a total system model, we developed technical/economic models for the various parts (or "components") of the system. Performance and cost of each "component" of the system is characterized as a function of scale and other relevant parameters. We utilize data and models of fossil energy complexes with H_2 production, and CO_2 sequestration developed as part of the Carbon Mitigation Initiative (CMI) at Princeton University.[4] Models for H_2 distribution systems and refueling stations were adapted from the principal investigator's previous studies of H_2 infrastructure for the US Department of Energy (Ogden 1998, Ogden 1999a, Ogden 1999b), work at UC Davis under the Hydrogen Pathways Program (Yang and Ogden 2004), and those of other researchers (Mintz et al. 2003, Amos 1999, Thomas et al. 1998, NAE 2004). [5]

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[3] Results are given for each task in the "Results and Discussion" section below. Earlier results were described in previous progress reports for this contract (Ogden 2003a, Ogden 2003b, Ogden 2003c).

[4] Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor Company to find solutions to global warming and climate change.

[5] During the past year the author worked with the "H2A", a group of hydrogen analysts convened by the USDOE to develop cost and performance estimates for hydrogen technologies. The H2A data should become available in October 2004. In addition the National Academy of Engineering recently released an assessment of the Hydrogen Economy (NAE 2004). In Phase II of this project, propose to update our models to reflect the new information contained in these studies.

1.2.2. Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Network

As a first step, we developed a simple analytical model linking the components of the system. We consider a single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center (see Figure 1.1.1). We developed "cost functions" for the CO_2 disposal cost and the delivered H_2 cost with explicit dependence on the many input parameters described above (e.g. size of demand, fossil energy complex process design, aquifer physical characteristics, distances, pressures etc.). Sensitivity studies of this "simple system" provided insights on which parameters are most important in determining hydrogen costs.

Later, we expanded this simple model to include better models of hydrogen demand and hydrogen distribution systems. To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we explored use mathematical programming methods to find the lowest cost system design. To facilitate regionally specific case studies, we developed an interface between our cost models and the Geographic Information System (GIS) database developed in Task 3. This allows us to make hydrogen system design and cost calculations based on quantities easily derived from GIS maps.

Through system modeling, we seek to distill "rules for thumb" for developing H_2 and CO_2 infrastructures.

1.2.3. Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

In this task, we explore how H_2 and CO_2 infrastructures might develop, in the context of a geographically specific regional case study. We focussed on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. We consider how fossil energy systems might develop over time to meet an evolving energy demand. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

To better visualize our results, use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks. First, a survey of relevant GIS data sets was conducted, and a database was built including hydrogen supply, demand and existing infrastructure. Network optimization methods were combined with the "Network analyst" capabilities of GIS software (ARCView) to find low cost hydrogen distribution networks. We used this database to make preliminary design and cost studies of fossil energy systems with CO_2 sequestration.

2.0 RESULTS AND DISCUSSION

2.1. Task 1.0. Implement Technical And Economic Models Of The System Components

In this Task we implement technical/economic models of various parts of a fossil hydrogen system with CO_2 sequestration. These include:

Task 1.1. The fossil energy complex for producing hydrogen and electricity from natural gas or coal (Appendix A)

Task 1.2. CO_2 compression and pipeline transport (Appendices B,C)

Task 1.3. CO_2 injection into underground geological formations (Appendix D)

Task 1.4. Hydrogen demand for vehicles

Task 1.5. Hydrogen fuel delivery infrastructure (including hydrogen compression, storage, pipeline transmission and refueling stations) (Appendix E)

Key results from the technical/economic models for each part of the system are summarized below.[6]

2.1.1. Task 1.1. Modeling the Fossil Energy Complex

In the fossil energy complex, a synthetic gas (or syngas) is produced via gasification of coal or steam reforming of methane. The syngas undergoes a water gas shift reaction to increase the hydrogen content. CO_2 is removed from the syngas using a separation system (such as an amine scrubber, a physical adsorption system like Selexol or a pressure swing adsorption system or PSA) and is available at near atmospheric pressure. CO_2 is then compressed from capture pressure to a supercritical state and pumped to pipeline transmission pressures of 15-20 MPa (150-200 bar). In some cases, electricity is co-produced with hydrogen. Simplified diagrams of the processes for producing hydrogen from natural gas and coal shown in Figure 2.1.1 and Figure 2.1.2.

As a basis for modeling natural gas-based hydrogen plants, we use a recent study by Foster Wheeler (1996) and data from Air Products and Chemicals (Ogden 1999). As part of the CMI, researchers at Princeton have developed ASPEN-plus process and cost models for a variety of coal-based systems co-producing H_2 and electricity with CO_2 capture (Kreutz, Williams, Socolow and Chiesa 2002), that include alternative options for sulfur removal and disposal. We use the results of these detailed process design

[6] Base case economic assumptions are given in Appendix 0. Model details are given in Appendices A-E.

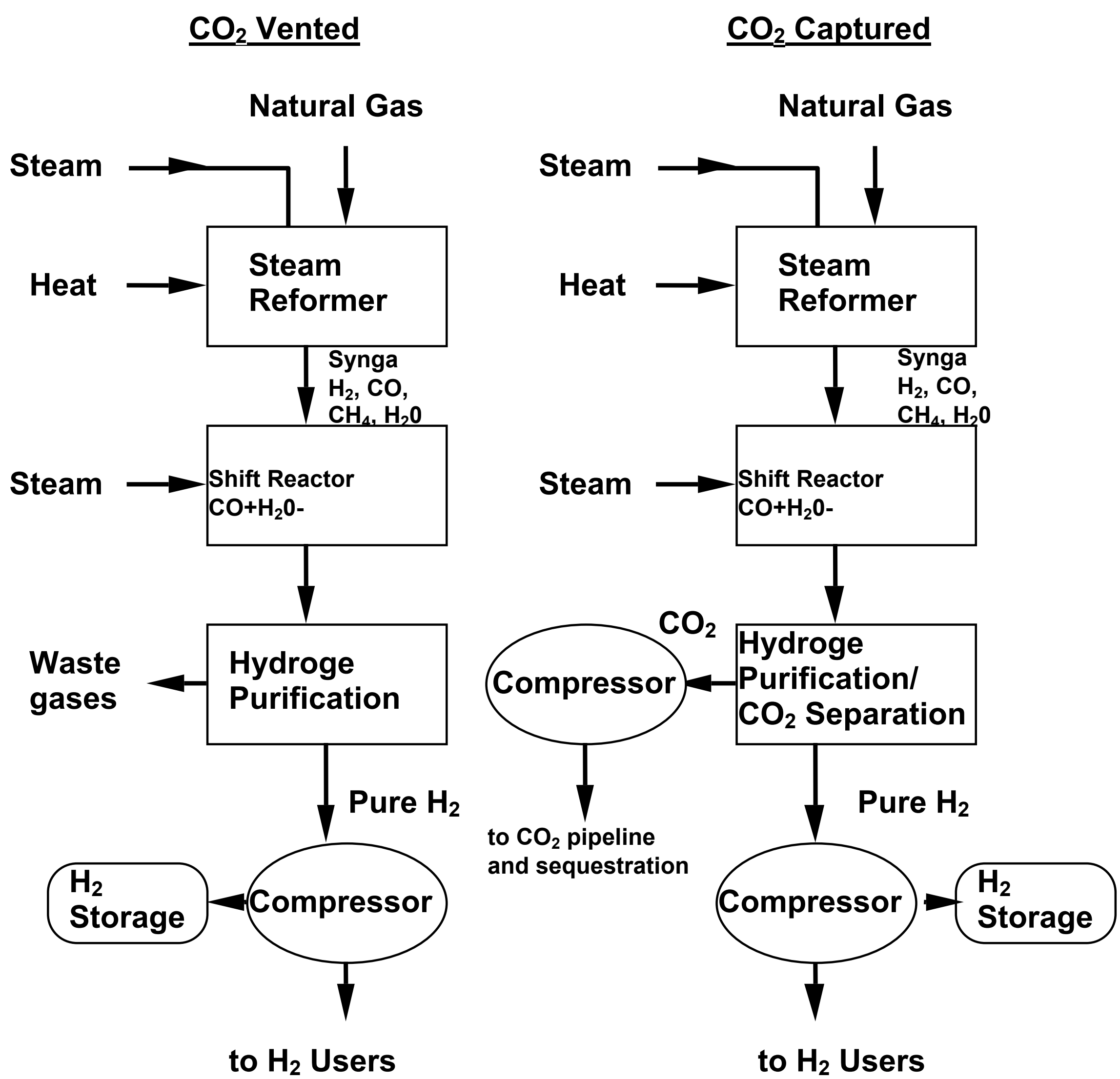


Figure 2.1.1. Hydrogen Production from Natural Gas with and without CO_2 Capture

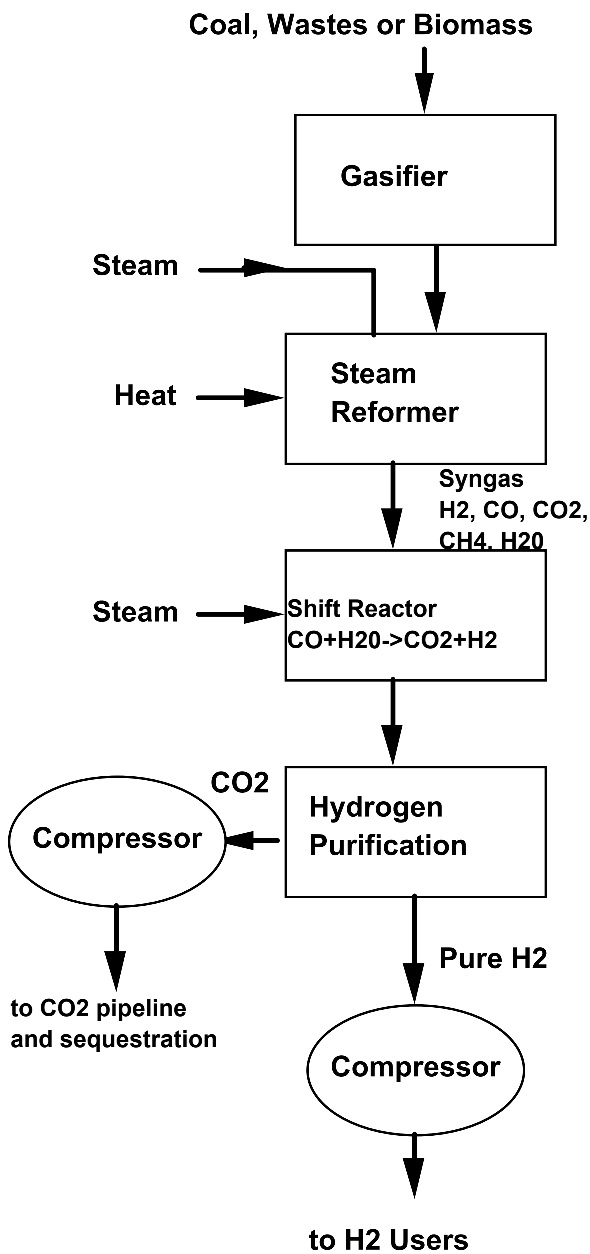


Figure 2.1.2. Production of Electricity and H_2 from Coal with CO_2 Capture

studies to produce a simplified model for the cost and performance of fossil H_2 plants as a function of scale, feedstock and process design. Summary costs for natural gas and coal-based hydrogen production systems are given in Table 2.1.1 through Table 2.1.3.

For each coal-to-hydrogen case in **Error! Reference source not found.**, the sizes, capital costs and O&M costs of the various fossil energy plant components were estimated, along with the energy consumption, hydrogen and electricity production, and carbon emissions (Kreutz 2002). From these studies, we can examine the impact of plant design on the economics of H_2 production and CO_2 capture (Table 2.1.3). This is complicated, because the plant design changes in several ways, depending on whether CO_2 is captured, and whether sulfur compounds are separated.

CO_2 capture and compression add ~ 10-25% to the hydrogen production cost depending on the plant design. In Figure 2.1.3, we plot the levelized cost of hydrogen production from natural gas and coal as a function of plant size, assuming the CO_2 is either vented or captured. Fossil hydrogen plants exhibit strong scale economies. Because coal plants are more capital intensive than natural gas plants, the hydrogen cost is slightly more sensitive to scale for coal.

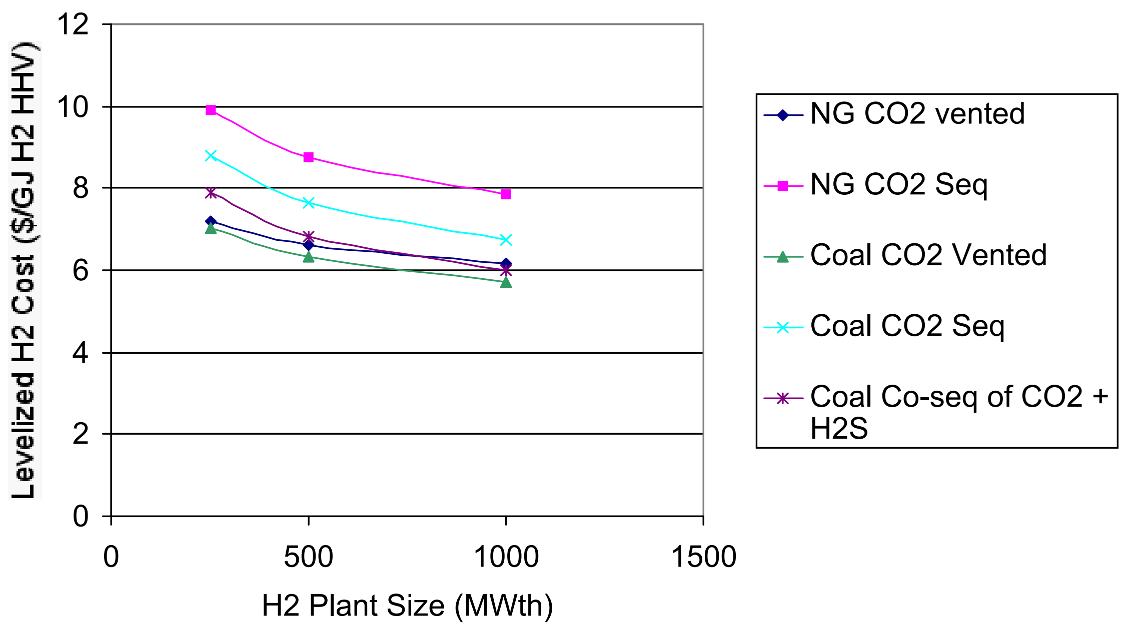


Figure 2.1.3. Cost of Hydrogen Production from Coal and Natural Gas with CO_2 Separation and Compression versus Hydrogen Plant Size

Table 2.1.1. Cost and Performance of Natural Gas Based Hydrogen Production Plants

w/ and w/o CO_2 Capture (Foster Wheeler 1996)

	CO_2 vented	**CO_2 captured**
Hydrogen Production MWth (at 60 bar output pressure)	1000	1000
First law efficiency HHV basis	81%	78%
CO_2 emission rate (kgC/GJ H_2)	17.56	2.74
CO_2 Sequestration Rate (tonne/h)	0	204
Capital Investment (million $)		
Reformer	48.65	67.90
Purification	23.65	58.08
CO_2 Compression	0	35.67 (for an estimated CO_2 compressor power of 18.6 MWe)
Other	123.95	174.67
Subtotal	**196.25**	**336.32**
Subtotal (excluding CO_2 compressor)	196.25	300.65
Added costs		
Engineering, construction management, commissioning, training	9.13	16.94
Catalysts and chemical	8.75	9.00
Clients costs	24.00	28.00
Contingency	23.81	39.03
TOTAL INSTALLED CAPITAL COST (million $)	**261.94**	**429.3**
Incremental Installed Capital Cost for CO_2 Capture (million $)		167.36

Table 2.1.2. Levelized cost of hydrogen production from natural gas with and without CO_2 separation and compression

Levelized Cost of H_2 Production with CO_2 separation, excluding CO_2 compression ($/GJ H_2) HHV	**CO_2 vented**	**CO_2 captured**
Capital (excluding CO_2 compression)	1.56	2.28
Natural Gas Feedstock	4.20	4.36
Non-fuel O&M	0.42	0.61
CO_2 Compressor Capital and O&M	n.a.	0.34
CO_2 Compressor Electricity	n.a	0.27
Total	6.17	7.86
Incremental cost of CO_2 separation and compression	**n.a.**	
$/GJ H2 HHV		1.69
$/tonne CO_2		29.8

Table 2.1.3. Cost and Performance for Hydrogen and Electricity Production from Coal (70 bar gasifier) (Kreutz 2002)

	CO_2 Vented, sulfur removal	CO_2 Capture, sulfur removal	CO_2 capture, co-sequestration of CO_2 and H_2S
H2 Production MWth	1000	1000	1000
Electricity production (net power out) MWe	52.2	30.9	30.9
First law efficiency HHV	0.736	0.705	0.705
CO_2 emission rate (kgC/GJ H2 HHV)	35.6	2.61	2.61
CO_2 captured (tonne/h)	0	437.4	437.4
Installed Capital Cost of Fossil Energy Complex (million $) = 1.16 x Bare Capital Equipment Cost			
H2 Plant excluding CO_2 compressor	658.6	707.2	612.6
CO_2 Compressor	0	51.7 (36.6 MWe)	51.7 (36.6 MWe)
H2 Plant including CO_2 Compressor	658.6	758.9	663.4
Incremental plant cost for CO_2 capture including CO_2 compression	0	100.3	4.8
Incremental plant cost for CO_2 separation excluding CO_2 compression	0	48.7	-46.0
Levelized Cost of H2 Production ($/GJ HHV)			
Plant capital except CO_2 Compressor	3.92	4.20	3.64
Non-fuel O&M	1.04	1.12	0.97
Feedstock cost	1.26	1.32	1.32
CO_2 compression capital + O&M		0.39	0.39
CO_2 compressor power		0.37	0.37
Electricity credit incl comp pwr	-0.52	-0.675	-0.675
Total without CO_2 compression	5.70	5.97	5.23
Total with CO_2 compression		6.73	6.01
Incremental Cost of CO_2 Capture, excluding CO_2 compression			
$/GJ H2 (HHV)		0.27	-0.44
$/tonne CO_2		2.22	-3.56
Incremental Cost of CO_2 Capture, including CO_2 compression			
$/GJ H2 (HHV)		1.02	0.31
$/tonne CO_2		8.43	2.56

2.1.2. *Task 1.2.Modeling CO_2 Compression and Pipeline Transport*

Once CO_2 has been captured at the fossil energy complex, it must be compressed to supercritical pressures and transported by pipeline to a suitable sequestration site.

CO_2 Compression

Equations for compressor power requirements and cost models for CO_2 compressors are developed in Appendix B. The electric power required for compression of CO_2 to supercritical pressures (15 MPa) is modest, perhaps 6% of the total hydrogen power output (in MW thermal, based on the higher heat value of hydrogen). The levelized cost of compression is found to be about $4-6/tonne CO_2, for compressor electricity costing 3.6 cents/kwh.

CO_2 compression costs show the following sensitivities to varying parameters:

- The cost of electricity dominates the levelized cost of compression. For our base case assumptions, about $3-3.5/tonne CO_2 is due to power costs, the remainder to capital costs.

- Compressor capital costs are sensitive to scale.

- Compression costs are somewhat sensitive to the compressor outlet pressure. This pressure is typically at least 15 MPa, to assure that the CO_2 stays above the critical pressure throughout the pipeline. There is a modest incremental cost of about $1/tonne CO_2 to increase the CO_2 outlet pressure from 80 to 150 bar for pipeline transmission.

CO_2 *Pipeline Transmission*

We use a technical/economic model for supercritical CO_2 pipeline transmission developed by the principal investigator under the CMI program. Our model is based on pipeline flow equations developed in (Farris 1983) and (Mohitpour 2000). [Details of CO_2 pipeline flow and cost calculations are given in Appendix C.] This model has been benchmarked with existing CO_2 pipeline models in the literature (Farris 1983, Skovholt 1993), and with industry practice through conversations with engineers at BP.

One of the issues in estimating CO_2 pipeline costs is the wide variation in published estimates. This is shown in Figure 2.1.4**,** where installed CO_2 pipeline costs (in $/m of pipeline length) according to various studies are plotted versus pipeline diameter (Doctor 1999; Skovholt 1993; Holloway 1996; Fisher, Sloan and Mortensen 2002). We have selected a mid-range value for our studies, recognizing that published estimates of capital costs for CO_2 pipelines vary over more than a factor of two above and below the midrange value. The wide variation is probably due to differences in local terrain,

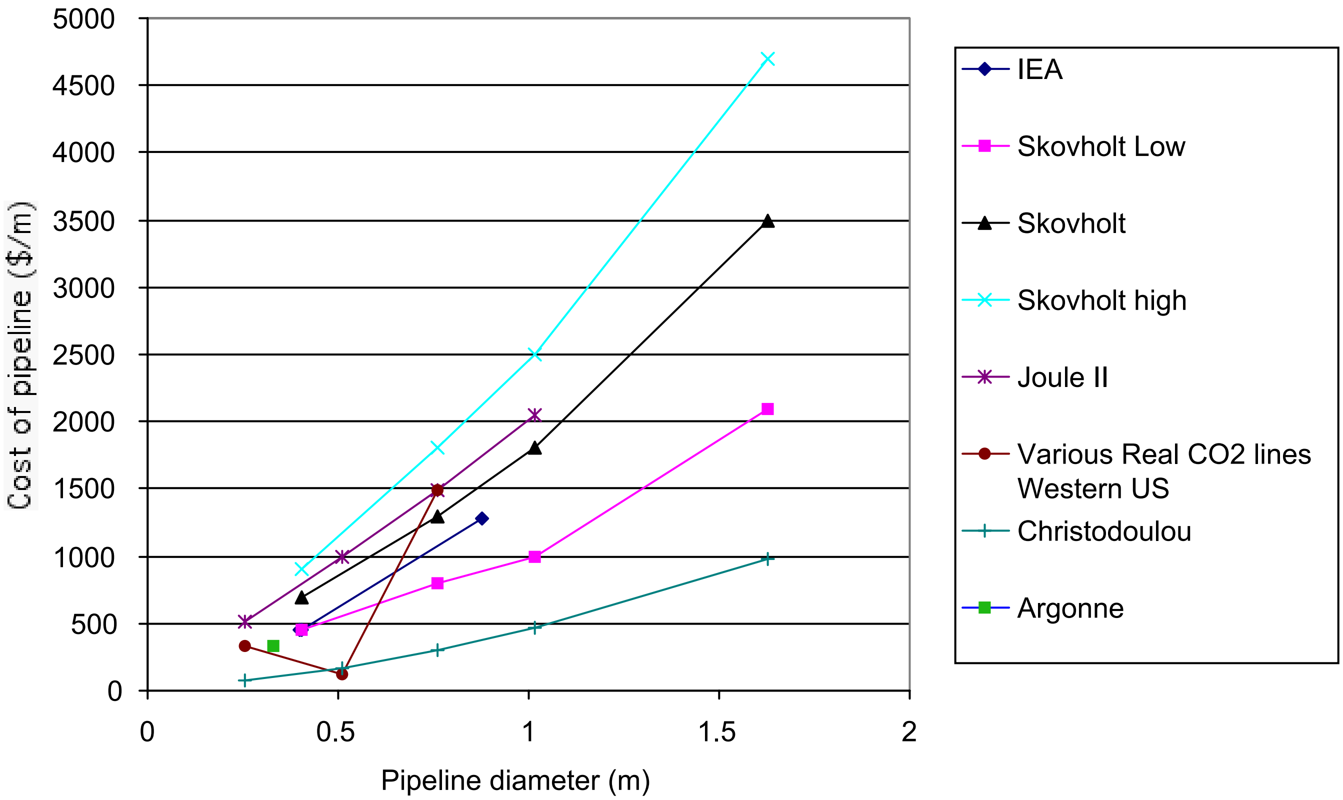


Figure 2.1.4. Installed Capital Cost of CO_2 Pipelines

construction costs and rights of way, all of which are important variables in determining the actual installed pipeline cost.

Using a cost function fit to published pipeline data, and inlet and outlet pressure of 15 MPa and 10 MPa, respectively, we find a pipeline capital cost per unit length ($/m), in terms of the flow rate Q and the pipeline length L:

$$Cost(Q,L) = (\$700/m)\left(\frac{Q}{Q_0}\right)^{0.48}\left(\frac{L}{L_0}\right)^{0.24} \qquad [1]$$

Where Qo = 16,000 tonnes CO_2 /day and Lo = 100 km.

Figure 2.1.5 and Figure 2.1.6 show the cost of CO_2 pipeline transmission as a function of pipeline flow rate and pipeline length.

The levelized cost of pipeline transmission ($/t CO_2) scales approximately as

$(CO_2 \text{ flow rate})^{-0.52} \times (\text{pipeline length})^{1.24}$

The cost per tonne of CO_2 is lower for the coal hydrogen plant than the natural gas hydrogen plant, because of its larger CO_2 flow rate. However, the cost per GJ of hydrogen produced is higher for the coal plant, because more CO_2 is produced per unit of hydrogen (Figure 2.1.7).

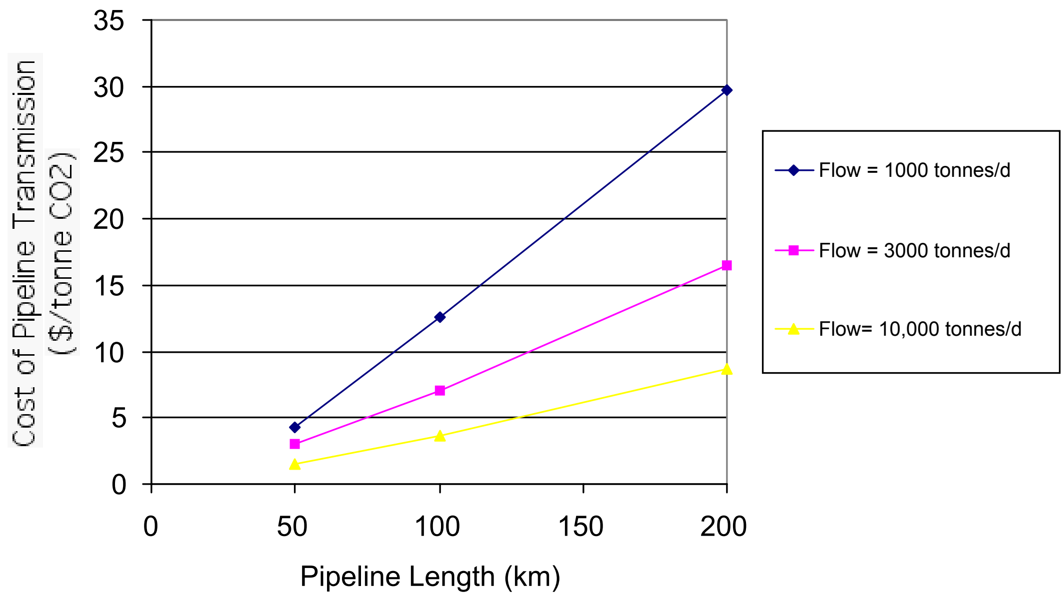


Figure 2.1.5. Levelized Cost of Pipeline Transmission ($/tonne CO_2) vs. Pipeline Length and Flow Rate

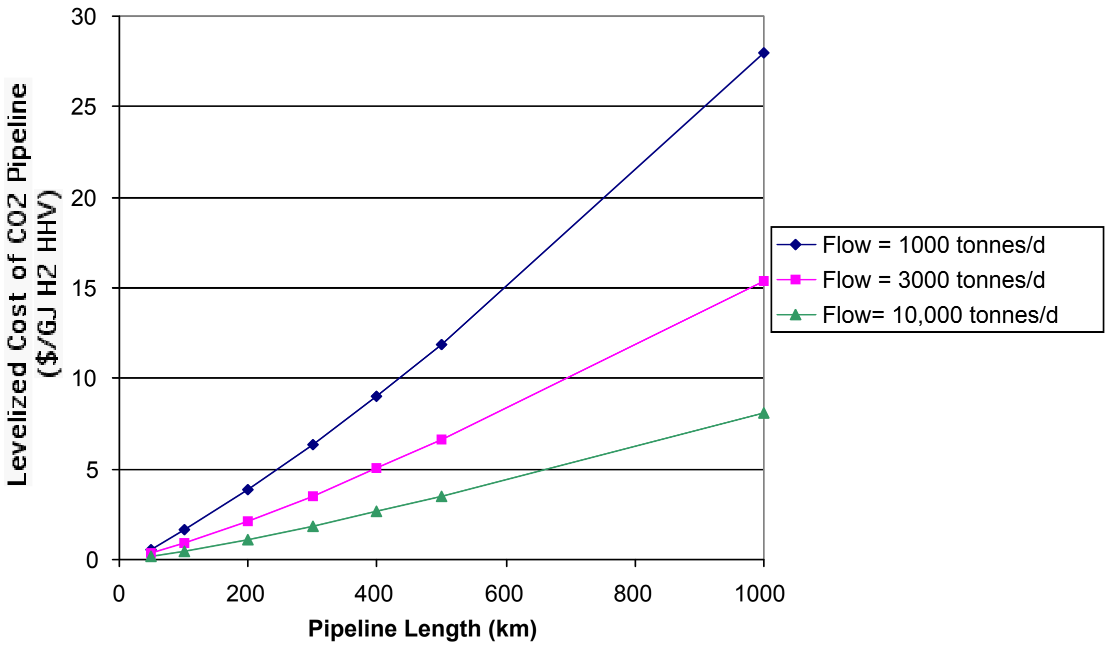


Figure 2.1.6. Levelized Cost of CO_2 Pipeline for Coal-Based H_2 Plant ($/GJ H_2 HHV) vs. Pipeline Length and CO_2 Flow Rate

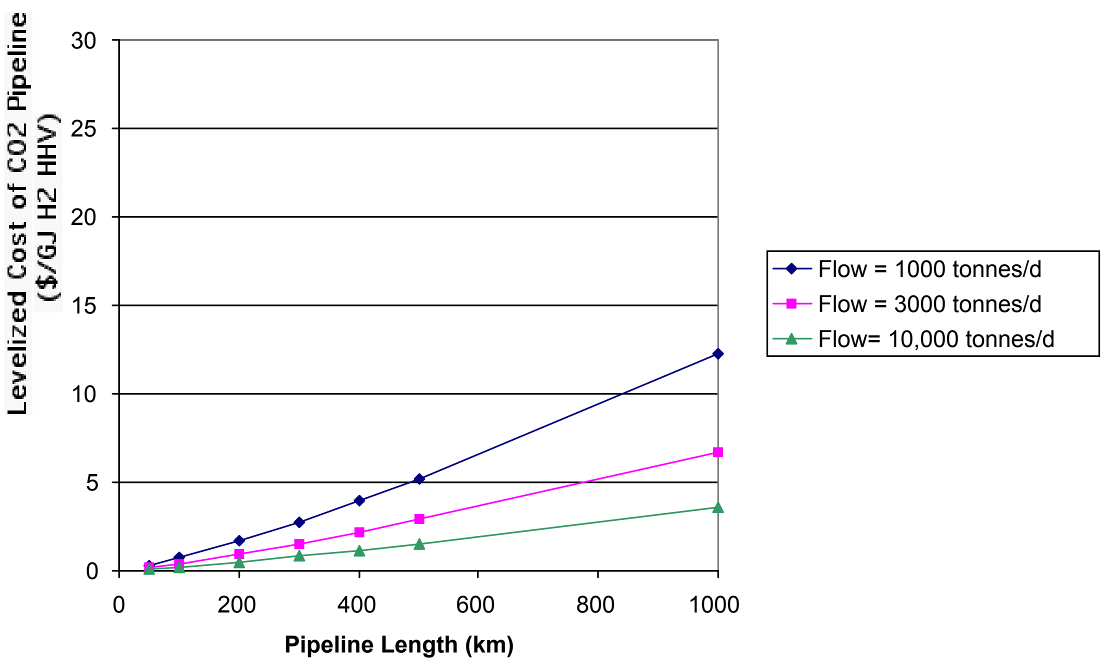


Figure 2.1.7. Levelized Cost of CO_2 Pipeline ($/GJ H_2 HHV) for Natural Gas to H_2 Plant vs. Length and CO_2 Flow Rate

2.1.3. Task 1.3. Modeling CO_2 Sequestration sites

At the CO_2 sequestration site, CO_2 is injected into an underground geological formation such as a deep saline aquifer or depleted hydrocarbon reservoir. A CO_2 booster compressor might be needed at the injection well-head depending on the well depth and the aquifer pressure. Several injection wells might be needed, which would be connected via above ground piping. Models for injection rate and capacity of underground geological formations are described based on fundamental reservoir parameters (see Appendix D for details). The injection rate of CO_2 into an underground reservoir depends on the permeability and thickness of the reservoir, the injection pressure, the reservoir pressure, the well depth, and the viscosity of CO_2 at the injection pressure. A practical upper limit on the injection rate per well is taken to be 2500 tonnes per day, limited by pressure drop due to friction in the well at higher flow rates, assuming practical well diameters (Hendriks 1994). Using a standard equation for flow into an injection well (Hendriks 1994), this upper limit implies that for a layer thickness above 50 m and permeabilities above 40 milliDarcy , the flow rate is limited not by the reservoir characteristics, but by the pipe friction flow constraints. For the base case 1000 MW natural gas (coal) to H_2 plant, producing about 5,000 (10,000) tonnes CO_2 per day, 2 (4) wells are needed. The installed capital cost of each well is (Hendriks 1994):

Capital ($/well) = $1.56 million x well depth (km) + $1.25 million.

In our base case, we assume a well depth of 2 km. CO_2 is distributed by surface piping at the injection site from well to well. We require each reservoir to store 20 years of CO_2 production from the H_2 plant. For our base case (reservoir thickness of 50 m), the length of surface piping required at the injection site is found to be 12 (37) km for the natural gas (coal) based H_2 plant. This implies a cost of $3.2 (9.2) million, based on a piping cost from Equation [1], but assuming that the minimum cost is $155,000/km ($250,000/mile) (Ogden 1999). As long as the aquifer characteristics allow such a relatively high injection rate, the cost of injection wells and associated piping is quite small, less than $2/tonne CO_2.

The total levelized cost of CO_2 pipeline transmission and storage is shown in Table 2.1.4, for hydrogen plants producing 1000 MW of hydrogen per day from natural gas and coal. Per tonne of CO_2, the cost of CO_2 disposal is higher for natural gas, but because the coal plant produces about twice as much CO_2 as the natural gas H_2 plant, the contribution to the levelized cost of H_2 ($/GJ) is higher for coal.

Table 2.1.4. CO_2 Pipeline Transmission and Storage System for Base Case H2 Plants Producing 1000 MW of hydrogen output from Natural Gas and Coal

	H_2 from natural gas	**H_2 from coal**
CO_2 captured (tonne/h) at full capacity	204	406
CO_2 Disposal System (100 km pipeline, 2 km well depth, injection rate = 2500 t CO_2/day/well)		
CO_2 100 km Pipeline Diameter (m)	0.25	0.34
Number of CO_2 Injection Wells	2	4
Injection Site Piping length (km)	12.2	37
System Capital Cost (million $)		
CO_2 100 km Pipeline	40.5	55.7
CO_2 Injection Wells	8.8	17.5
CO_2 Injection Site Piping	3.2	9.2
Total CO_2 Pipeline Transmission and Storage System	*52.5*	*82.4*
Levelized Cost of CO_2 Disposal ($/t$CO_2$)		
CO_2 100 km Pipeline	5.26	3.45
CO_2 Injection Wells	1.16	1.17
CO_2 Injection Site Piping	0.44	0.61
Total CO_2 Pipeline Transmission and Storage System	*6.87*	*5.23*
Total CO_2 Pipeline Transmission and Storage System ($/GJ H_2)	**0.39**	**0.59**

2.1.4. Task 1.4. Modeling H2 Demand Centers

Designing a hydrogen fuel delivery infrastructure depends on the characteristics of the hydrogen demand. We model the magnitude, spatial distribution, and time dependence of hydrogen demand, based on Geographic information system (GIS) data on populations, estimates of vehicles per person, and projections for energy use in hydrogen vehicles, and market penetration rates. Our method for calculating a hydrogen demand map is described below (see Figure 2.1.8).

- First, population density is mapped as a function of location. This information is available in GIS format from US Census data.
- On average in the US there are about three light duty vehicles for every four people (Davis 2000). From this, we can approximate the numbers of light duty vehicles as a function of location (vehicles/km^2). This obviously a simplification, as numbers of vehicles will not exactly track population. If more detailed information is known about the locations of vehicles, this could be shown as well. In addition, early markets for hydrogen might be found in heavy duty applications, such as fleets. If information is known about these vehicles, this could be added as well.
- Next, a market penetration rate for hydrogen is estimated (fraction of new vehicles using hydrogen). This could be done in various ways. For example, one could assume that a “ZEV mandate” is put in place, so that a fixed fraction of new vehicles sold must use hydrogen. Alternatively, one could devise other criteria for estimating

how many new hydrogen vehicles are sold each year, based on projections of when they become competitive with competing technologies like gasoline internal combustion engine technologies. From the market penetration rate, the number of hydrogen vehicles can be found as a function of location and time (H_2 vehicles/km^2 versus time).

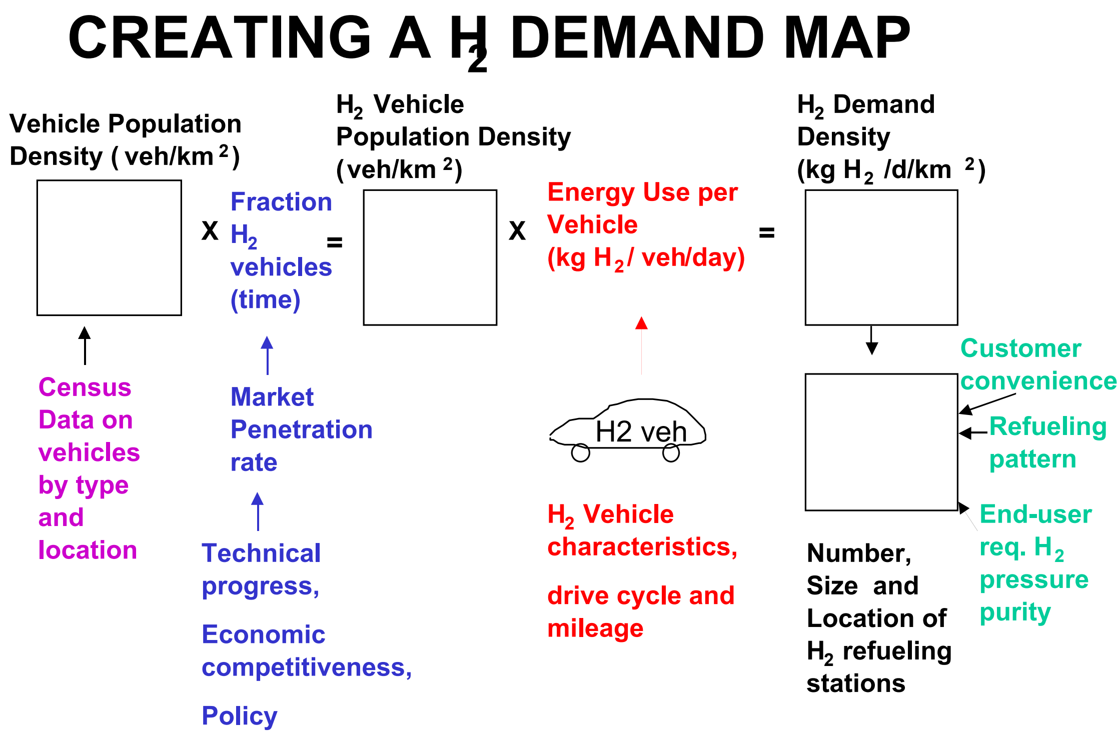


Figure 2.1.8. Mapping Hydrogen Demand Density

- The hydrogen use per vehicle (kg H_2/d/vehicle) is estimated from assumptions about hydrogen vehicle fuel economy and miles traveled. A map of hydrogen demand density versus location and time can be calculated (kg/d/km^2). This is shown in Figure 2.1.9, for the state of Ohio. The lighter colors are low demand density, the darker colors higher density. The cities of Cleveland, Columbus and Cincinnati are obvious areas of high demand.
- Once the hydrogen demand density is known, one has to decide how many refueling stations are required and where they should be sited. The number, location and size of refueling stations have a major effect of the cost of infrastructure. In the United States, on average, there is one gasoline refueling station for every 2000 light duty vehicles (Davis 2000). For several cities we examined, stations tend to cluster along major roads in “spoke” or “ring” like patterns. Often, more than one station is found at major intersections or at freeway exits. Recent analyses suggest that today’s convenience level could be preserved, if perhaps 10-30% of current gasoline stations

offered hydrogen (Nicholas 2003). Methods for siting and sizing stations are discussed further in section 1.5 and in Appendix H.

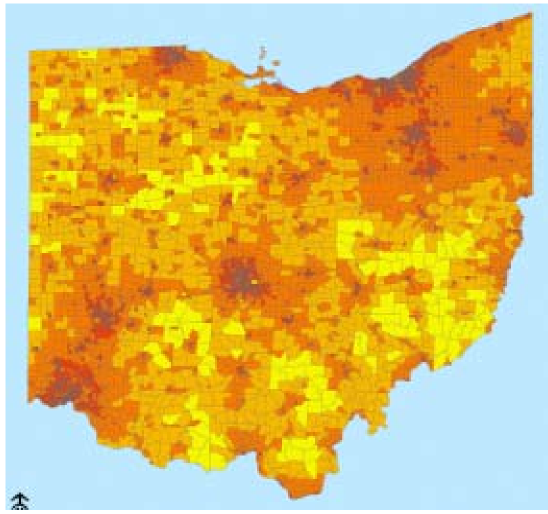


Figure 2.1.9. Hydrogen Demand Density in Ohio

An application of this hydrogen demand model is described for a case study of Ohio (Task 3).

2.1.5. Task 1.5. Modeling H_2 Delivery Infrastructure

There are many options for producing and delivering hydrogen to users. These include centralized production options (e.g. fossil energy complexes with CO_2 capture), and decentralized options (such as small reformers or electrolyzers located at refueling stations). We have developed cost and performance estimates for a variety of possible hydrogen supply and delivery options, which are likely to be important in future hydrogen energy systems:

Centralized, large-scale production of hydrogen from:
- Steam reforming of natural gas with and without CO_2 sequestration
- Coal gasification with and without CO_2 sequestration
- Large scale electrolysis

Distributed production of hydrogen at refueling sites from:
- Natural gas reforming
- Electrolysis using off-peak power

For centralized production, we consider hydrogen delivery via truck (compressed gas tube trailer or liquid tank truck), or via gas pipeline.

At refueling stations, we assume that hydrogen is dispensed to vehicles as a compressed gas for onboard storage at 5000 psi.

2.1.5.1. Modeling Hydrogen Distribution System Components

Models for hydrogen delivery infrastructure components are described in detail in Appendix E. These include:

- Hydrogen compressors
- Gaseous hydrogen bulk storage
    - Above ground pressure vessels
    - Underground storage
- Compressed gas tube trailer trucks
- Hydrogen gas pipelines
    - Long distance transmission lines
    - Local pipeline distribution networks
- Liquefiers
- Liquid hydrogen bulk storage
- Liquid hydrogen trucks
- Hydrogen refueling stations
    - LH2 truck delivery
    - Gas pipeline delivery
    - Onsite small steam methane reformers at station
    - Onsite small electrolyzers at station

Hydrogen compression

Electricity needed for compression is about 5-10% of the energy content of the hydrogen (on a higher heat value basis), depending on the inlet and outlet pressures.[7] Compression typically adds less than $1/GJ ($0.14/kg) to the cost of hydrogen. Most of this cost is due to the electricity cost. (See Appendix E for details.)

Gaseous Hydrogen Storage

In the case of large centralized fossil hydrogen production, it is desirable to run the hydrogen production plant continuously. However, the system-wide demand profile for transportation fuel will vary over the day, weekly and even seasonally, so that some storage capacity (ranging from ½ day to several days plant output) will be needed in the system.

Hydrogen can be compressed and storage as a high-pressure gas. For a gaseous hydrogen pipeline distribution system, several options are available. Hydrogen could be

[7] Compression energy requirements are higher for hydrogen as compared to natural gas, by roughly a factor of three.

stored: 1) in the pipeline, 2) at the refueling station, 3) at the production site. We assume the last option is used, although some storage is also located at the refueling station.

Bulk gaseous storage at the central plant can be accomplished in several ways (Taylor et.al 1986). First hydrogen is compressed from production pressure (typically 200 psi for steam reforming or gasification systems) to storage pressure of perhaps 1000 psi (assuming that the pipeline will be fed from storage). For very large quantities (on the order of 100 million scf or more), underground gas storage might be used.

Hydrogen Liquefaction and Liquid Hydrogen Storage

Alternatively, hydrogen can be liquefied (at 20 K), stored in a dewar and delivered to refueling stations via cryogenic tank trucks. Liquefaction is more energy intensive than compression: electricity needed for liquefaction is about 33-40% of the energy content of the hydrogen (on a higher heat value basis). Liquefiers have strong scale economies, making them most suitable for use with large central plants. Liquid hydrogen distribution is preferred when small quantities of hydrogen are shipped long distances.

Hydrogen Transmission Pipelines

The cost of a hydrogen pipeline depends on the pipeline diameter and length. If the flow rate, pipeline length and inlet and outlet pressures, temperatures and gas properties are known, we can use steady-state fluid flow equations to estimate the pipeline diameter and the cost. In some cases, it may be desirable to add “booster” compressors along the pipeline to recompress the gas.

In Appendix E, we develop equations for hydrogen pipeline transmission costs as a function of pipeline flow rate and length. The levelized cost of the hydrogen pipeline (not including compression or storage) is given approximately by:

$$C_{pipe}[\$/GJ] = 0.15\left(\frac{Q[MW]}{1000MW}\right)^{-0.5}\left(\frac{L[km]}{100km}\right)^{1.25}$$

Pipeline capital costs scale inversely with hydrogen flow rate and almost linearly with distance.

Levelized costs are shown for hydrogen pipeline transmission including compression, storage at the central plant, and the pipeline are shown Figure 2.1.10, as a function of pipeline length and flow rate. We see that long distance transmission can add up to a few dollars per GJ to the cost of hydrogen. Hydrogen pipelines are well-suited for delivery of large quantities of energy.

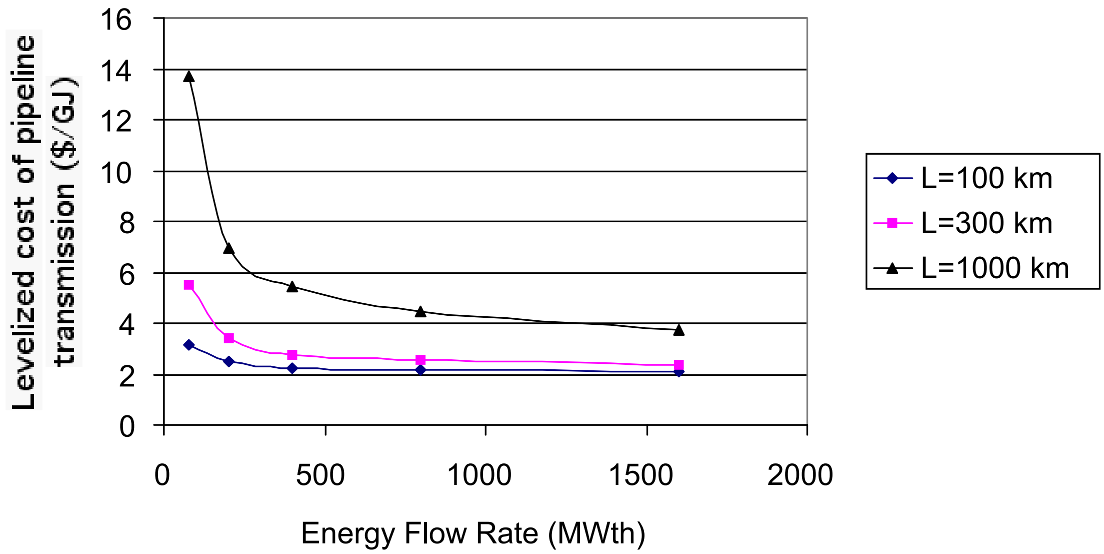


Figure 2.1.10. Levelized Cost of Hydrogen Pipeline Transmission (including compression, storage, and pipeline) vs. Pipeline Length and Energy Flow Rate (MWth)

Hydrogen Truck Delivery

Hydrogen can be delivered by truck as well as by pipeline. For truck delivery, hydrogen is compressed to high pressure and carried in a tube trailer or liquefied and carried in a cryogenic tank truck.

Recent studies by NREL (Amos 1998) and SFA Pacific (Simbeck and Chang 2002) have given estimates for the cost and performance of tube trailers and LH2 trucks. The precise cost of truck delivery depends on the delivery route and the amount of hydrogen delivered.

2.1.5.2. A Comparison "Point-to-Point" Hydrogen Delivery Costs

The detailed cost models described above are used to determine the cost of "point-to-point" hydrogen delivery for different transport modes as a function of hydrogen flow rate and transportation distance.[8] Figure 2.1.11 and Figure 2.1.12 show the least cost

[8] Hydrogen delivery includes compression or liquefaction and hydrogen storage at the central plant, and hydrogen transport via pipeline or truck. By "point to point", we mean delivery from the central H2 production plant to the edge of the city. Transport within the city via a local pipeline network is NOT included. Local distribution costs are estimated in the next section.

mode for any given flow and distance for point-to-point hydrogen transport. We see that at large flow rates, pipeline transport is the lowest cost option. For small quantities of hydrogen, compressed gas trucks are best at short distance and liquid hydrogen trucks at longer distance. The overall cost of point-to-point transmission ranges from several $/kg to less than $0.5/kg (for pipelines with large flow rates). Figure 2.1.11

Flowrate	Transport Distance [km]																		
kg H_2/day]	25	50	75	100	125	150	175	200	225	250	275	300	325	350	375	400	425	450	475
2000	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	L	L	L	L
4000	G	G	G	G	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L
6000	G	G	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L
8000	P	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L
10000	P	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L
14000	P	P	P	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L	L
18000	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L	L
22000	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L
24000	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L
28000	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L
32000	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L
36000	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L
40000	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L
44000	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L
48000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L
52000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L
56000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L
60000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L
64000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L
68000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
72000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
76000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
80000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
84000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
88000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
92000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
96000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
100000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P

Figure 2.1.11. Minimum cost delivery mode for a range of operating conditions (P – pipeline, G – compressed gas trucks, L – liquid trucks).

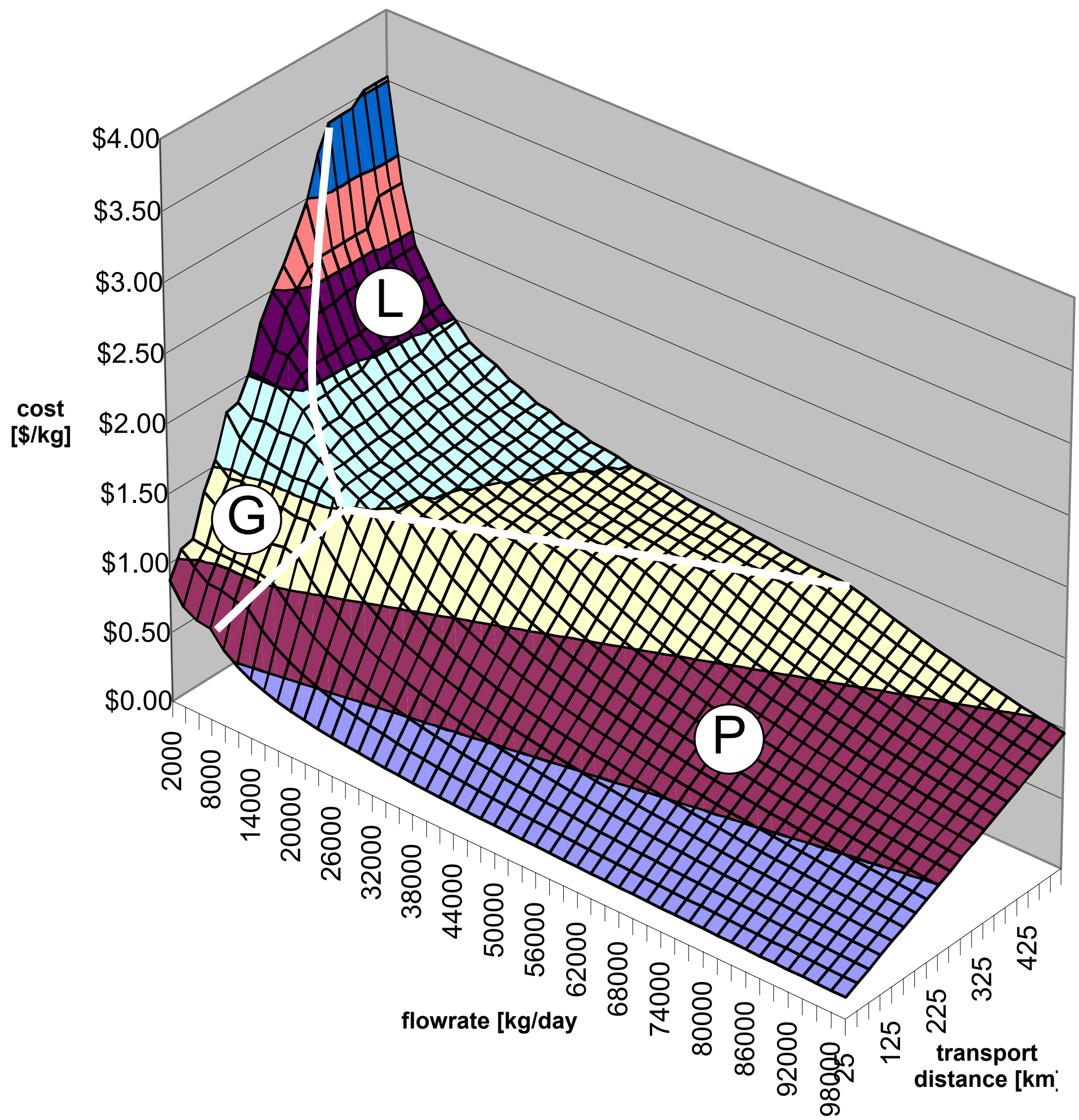


Figure 2.1.12. Graph of minimum cost for the three modes of hydrogen delivery as a function of flowrate and transport distance.

2.1.5.3. Designing a Local hydrogen distribution network

Idealized City Model

Once hydrogen from a central production plant is delivered to the city gate, it must be distributed to refueling stations located throughout the city. (These stations are sited for adequate customer convenience.) Distribution could be accomplished via trucks traveling to stations or a network of small-scale pipelines.

To estimate the cost of local distribution, it is important to know the location and size of refueling stations. Several researchers have looked at possible configurations for a network of refueling stations (Ogden 1999, Mintz 2002, Nicholas 2003). We have modeled the distribution network serving hydrogen stations using an "idealized city model".[9] We develop general expressions for a "generic" city in terms of its size, hydrogen demand and the resulting hydrogen infrastructure required to support this demand. This design is used to determine costs for hydrogen distribution. Using generalized, idealized city models speeds up the analysis and provides information about these distribution system characteristics for a wide range of cities.[10]

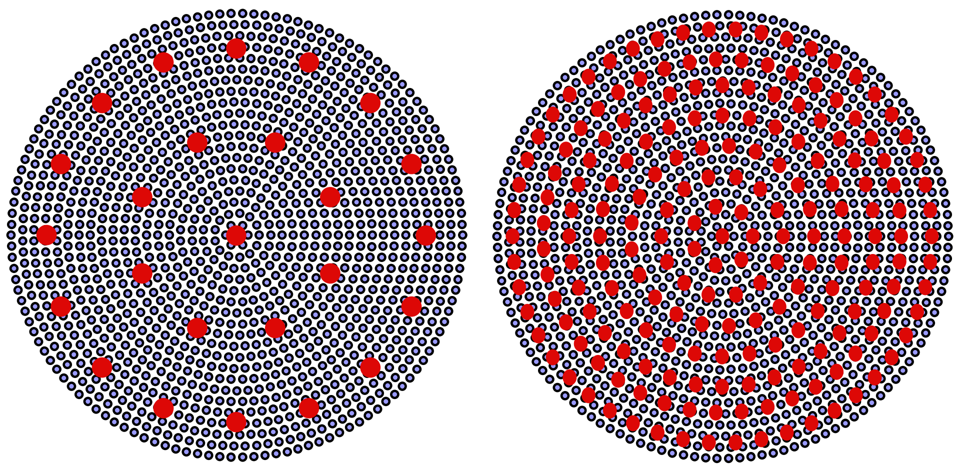


Figure 2.1.13. Idealized city model with 25 and 125 hydrogen stations distributed in rings throughout the city.

As shown in Figure 2.1.13 we assume the city is circular, with a radially distributed population. The city size is not specified as a fixed number of kilometers, but rather distribution system lengths are characterized as a function of the city radius. Distances are calculated in this city by following a grid (i.e. rectilinear) road network. The refueling stations are configured into rings that are concentric around the city center. Each city configuration consists of one or more rings of stations with varying numbers of stations in each ring. For a given station configuration, the radii of the rings of stations were varied in order to minimize the overall weighted average distance traveled

[9] Each demand area is treated as an ideal circular city. The layout of the distribution network (including the number of refueling stations and the length or distance of distributing hydrogen to those stations) is estimated as a function of the city's physical size (area) and hydrogen demand within the demand region.

[10] Where data is available, more detailed models can be used to determine station numbers, locations, convenience and distribution system layout using a detailed geographic study of the distribution system of a specific city/region using GIS tools (such as in Nicholas 2003).

for users. This analysis does not find an optimal configuration of stations, because the average distance between users and stations is only one criteria among many that will be used to optimally site refueling stations. Reducing the length and cost of the pipeline network to supply these stations is another important criteria. As a result, a comparison is made as to how convenience trades off against the distribution network length (i.e. the length of pipe required to connect each of the stations together and to the edge of the city (city gate)). In Figure 2.1.14, we show the total distribution length (in city radii) and the average distance between stations for cases with 5 to 75 refueling stations. [11]

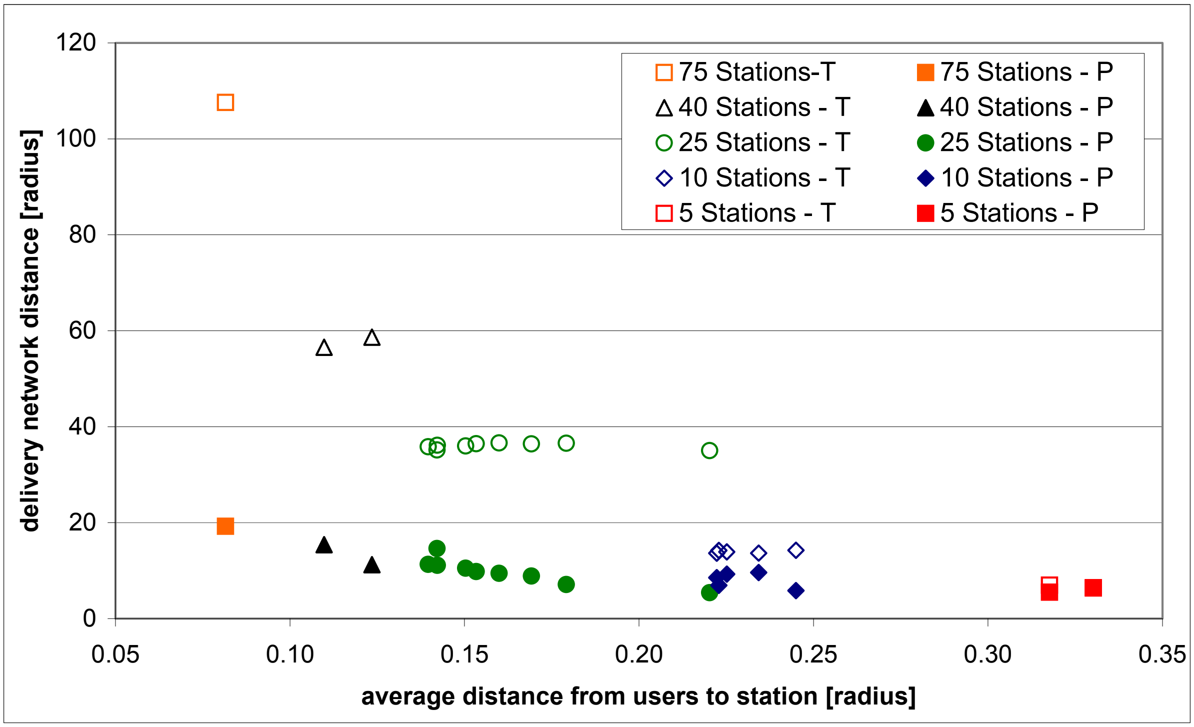


Figure 2.1.14. Tradeoff between convenience and delivery network distance for pipelines and trucks for different numbers and configurations of stations. (“P” denotes pipeline distribution, “T” truck distribution.)

In Figure 2.1.15, the pipeline length ($L_{pipeline}$) is shown to be a power law function of the number of stations, while the truck route distance scales linearly with the number of stations. Thus as the number of stations grows, the pipeline distribution modes become more efficient than trucks. The model results are plotted to compare length of the pipeline network or truck driving distance as a function of the number of stations. The

[11] Other studies (Nicholas 2003) have indicated that if 10-25% of current gasoline stations offered hydrogen, this might be sufficient for customer convenience. In a typical US city (where there are about 3000-4000 people per gasoline station), 10% coverage corresponds to 1 hydrogen station for every 30,000-40,000 people. (For cities ranging from 100,000-3,000,000 people, the number of hydrogen stations needed varies from about 3-100 stations)

data for pipeline length vs station number is fitted to a power function and for the homogeneous population density, the equation that describes this relationship is:

$$L_{pipeline} = \beta \cdot N_{stations}^{\ \gamma}$$

where $L_{pipeline}$ is the length of the pipeline (as a multiple of the city radius), $N_{stations}$ is the number of stations, β is 3.524 and γ is 0.4115.

For the truck delivery scenario, it is assumed that trucks do not travel to multiple stations on a given trip so that a linear equation describes this distance:

$$D_{truck} = 1.44 \cdot N_{stations}$$

As demand increases along the demand profile, additional stations are added to the network of stations. Although this model is not designed to calculate the marginal increase in pipeline length resulting from adding new refueling stations, the curve fit can be used to estimate, on average, the length of pipeline needed to supply additional refueling stations.

Given the hydrogen demand in a city of a certain physical size, an estimate can be made of the required number of refueling stations and using the equations above, the total length of pipeline or truck travel distance required to supply the network of refueling stations. The cost for the network can be calculated using cost models for truck or pipeline hydrogen delivery.

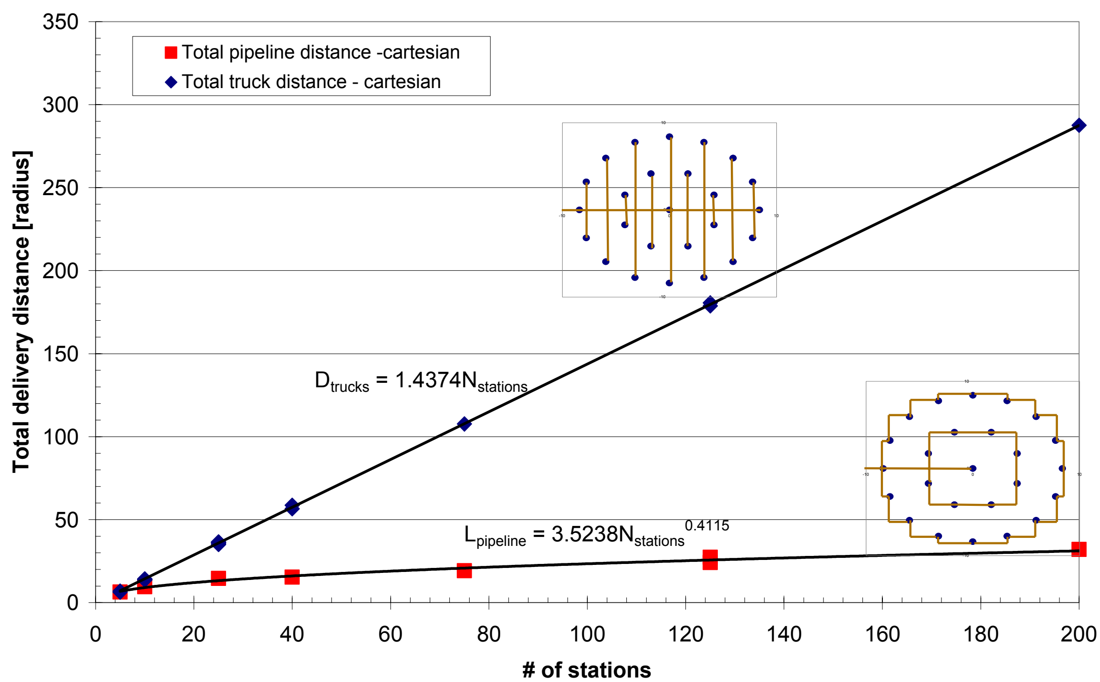


Figure 2.1.15. The relationship between the number of stations within the city and the total delivery distance for pipelines and trucks.

2.1.5.4. *Hydrogen Refueling Stations*

Costs for hydrogen refueling stations have been discussed by a number of authors (DTI et a. 1997, Ogden et al. 1998, Thomas et al 2000, Simbeck and Chang 2002, TIAX 2003, DTI 2003). [12]

In Table 2.1.5, we list the capital and operating costs for four types of refueling stations, including pipeline-delivered hydrogen, LH2 truck-delivered hydrogen, onsite steam methane reformers and onsite electrolyzers. A range of sizes is shown for stations dispensing 100,000 to 2 million scf H2 per day (240 – 4800 kg H2/day). H_2 is dispensed to vehicles at refueling stations as a high-pressure gas for storage in onboard cylinders (at 34 MPa). Each station could serve a fleet of several hundred to several thousand cars. There is a wide range of estimates. The cost of hydrogen refueling stations scales approximately linearly with size. This suggests that the capital cost for refueling station equipment would be about the same for a few large stations or many small ones. Of course, other costs such as land or permitting, that don't scale with size, might be higher if many small stations were built.

[12] Currently, the H2A group is analyzing the costs of refueling station designs. We will update these estimates as newer data become available. Analysis is also ongoing at UC Davis on today's hydrogen refueling station costs (Weinert 2004) and on hydrogen energy stations that reform natural gas to produce power and heat for a nearby building as well as hydrogen (Lipman 2004).

Table 2.1.5. Characteristics Of Hydrogen Refueling Stations

Type	Reference Size (kg/d)	Capital Cost as a function of size	Conversion Efficiency Feedstock -> H2	Electricity Use (kWhe/kgH2)	Total O&M cost $/y	Assumptions
ONSITE SMR						
Princeton – 100 units	240-4800	$951.07 x (kg/d) + 300,352	NG->H2 η =0.707 HHV	2.26 kWhe/kg H2	425.96 x kg/d + 53747	NG = $3/MBTU, Elec = $0.072/kWh
DTI – first unit	37-7500	$1155.6 x (kg/d) + 199,770	NG -> H2			
DTI – 100 units	37-7500	$435.11 x (kg/d) + 54266				
DTI – 1000 units	37-7500	$273.04 x (kg/d) + 34,054				
Simbeck 2002	470	1,480,000	η =70% LHV $119,000 NG $5.5/MBTU	2 kWhe/kg H2 $19,000/yr @ 7 cent/kwh	$235,000	NG=$5.5/MBTU; elec= $0.07/kWh
TIAX mature tech. 2003	690	1,175,000				
PIPELINE DELIVERED H2						
Princeton	240-4800	$602.64 x kg H2/d + 34667		2.48 kWhe/kg H2	$195.92 x (kg H2/d) + 43100	Elec = $0.072/kWh
Simbeck	470	520,000				elec= $0.07/kWh
TIAX	690	352,500				
LH2 TRUCK DELIVERED H2						
Princeton	240-4800	$225.51 x kg H2/d + 94664		0.27 kWhe/kg H2	$93.334 x kg H2/d + 45082	Elec = $0.072/kWh
Simbeck	470	680,000				Elec =$0.07/kWh
TIAX	690	423,000				
ONSITE ELECTROLYSIS						
Princeton	240-4800	$2528.7 x kg H2/d + 20433	Electricity η =80% HHV	49 kWhe/kg electrolysis + 4.16 kWhe/kg H2 compression	$736.63 x (kg H2/d) + 45990	Off-pk power Elec = 3 cent/kWh
DTI – first 1000 stations	37-75	$2258.9 x kg H2/d + 69760	Electricity η =80%			
Simbeck	470	4,150,000 $2157/kW	Electricity η =63.5% LHV	55 kWhe/kg H2 Electrolysis + 2.3 kWh/kg H2 Compression	700,000	elec= $0.07/kWh
TIAX	690	1,128,000				

2.1.5.5. *Summary of Component Costs and Performance for Fossil Hydrogen Energy System with CO2 Sequestration*

In Table 2.1.6 and Table 2.1.7, we summarize the costs and performance for various components of a hydrogen energy system. These simplified formulas allow us to estimate component capital and O&M costs as a function of size, feedstock, and electricity costs.

Table 2.1.6. Summary Economic Data for Large Central H2 Production Systems as a Function of Scale

	So = Reference H2 plant size	Cost(So) = Capital Investment for Ref. H2 Plant (million $)	α= Plant capital Scale factor (scale range)	η = Feedstock Conv. Eff to H2 on HHV basis	Co-products	Source
SMR, CO_2 vented	613 tonne H2 /d	262	0.7 (153-613 t/d)	0.81		Foster Wheeler (1996, 1998)
SMR, CO_2 captured	613 tonne H2 /d (5000 tCO2/d)	384 for plant + 45 (CO_2 compressor) =429 total	0.7 (153-613 t/d) 0.7 (CO_2 comp)	0.78		Foster Wheeler (1996, 1998)
Coal Gasifier, CO_2 vented	613 tonne H2 /d	659	0.828 (153-613 t/d)	0.736	Electricity (2.04 kWh/kg H2)	Kreutz 2002
Coal Gasifier, CO_2 captured	613 tonne H2 /d (10,000 tCO2/d)	613 for plant + 50 (CO_2 compressor) =663 total	0.828 (153-613 t/d) 0.7 (CO_2 comp)	0.705	Electricity (1.21 kWh/kg H2)	Kreutz 2002
CO_2 Sequestration (CO_2 compressor is included in fossil H2 plant cost estimates above)	16000 tonne CO_2 /d 100 km pipeline 2500 tonne CO_2 /d/well	\$70 million x $(Q/16000)^{0.48}$ x $(L/100)^{1.24}$ + Q/2500 x \$4.4 million/well + (Q/2500-1) x \$3.2 million	Pipeline + injection well + injection site piping			Ogden (2002)
Biomass Gasifier, CO_2 vented	165 tonne/d	172	0.7 (150-750 t/d)	0.636		Larson 1993; Simbeck and Chang 2002
Electrolysis	150 tonne/d 250 MW H2	\$75-150 million (\$300-600/kW)	0.9 (20-613 t/d)	0.8	Oxygen (8 kg/kg H2)	Ogden (1998)

CRF = 15%; non-fuel O&M = 4% of capital investment/y

Capital Cost at plant size S (\$) = Cost (S) = Cost (So) x $(S/So)^{\alpha}$

S = H2 plant capacity (tonne/d)

O&M Cost at plant size S (\$/y) = O&M(S) = 4% x Cost (So) x $(S/So)^{\alpha}$

Feedstock Cost (S) (\$/y)
= S x 365 d/y x capacity factor x HHV H2 (GJ/kg)/η x feedstock Cost (\$/GJ)

Byproduct credit (S) (\$/y)
= S x 365 d/y x capacity factor x Byprod (unit/kg H2) x Byprod price (\$/unit)

Levelized cost of H2(S) \$/kg
= [CRF x Cost(S) + O&M(S) + Feedstck Cost(S) + Byproduct credit(S)]/(capacity factor x S x 365 d/y)

Table 2.1.7. Economic Data for Gaseous Hydrogen Pipeline Transmission Systems as a Function of Scale (including hydrogen compression, large scale gaseous storage and transmission pipeline)

	Reference equipment size	**Capital Investment ($/kWe)**	**Equations with scaling factors**
H2 compressor *(note: in some studies H2 compression is included as part of the central H2 plant cost)*	20 MWe	$1600/kWe (multi stage) $900/kWe (single stage)	Scale factor of 0.9 for large H2 compressors (Simbeck and Chang 2002). Costs match well with Kreutz et al. 2002) H2 compressor electricity input = 2-10% of higher heating value of hydrogen compressed depending on compressor inlet and outlet pressures (see Appendix E). Assuming inlet pressure of 1.4 MPa, and outlet pressure of 6.8 MPa, and compressor efficiency of 70%, the electricity use is about 2% of the H2 energy. Compressor power (MWe) = [S (tonne/d) x (1000 MWH2/613 tonne/d) x (2-10% MWe/MWH2)] Capital cost of H2 compressor($) = (Compressor Power/20 MWe)$^{0.9}$ x $1600/kWe x 20 MWe S= H2 plant size (tonne H2/d)
H2 Storage	High pressure cylinders Bulk aboveground compressed gas storage Advanced automotive pressure cylinders Underground storage	$700/kg (kg of H2 storage capacity) " $200-250/kg $280-420/kg	Compressed gas storage is modular with little scale economy. For a H2 central plant, we assume storage equivalent to 1/2 day's production is needed. If S = plant output in tonne H2/d, Cost = $700,000 x 0.5 x S, for aboveground gas storage Cost = $280,000-420,000 x 0.5 x S, for underground storage
H2 Pipeline H2 Flow Length	100 km length; (Pin=6.8 MPa Pout=1.4 MPa) H2 Flow= 60 t/d 150 t/d 300 t/d 600 t/d	Pipe Diam. Cost (inch) (million$) D=4.8";$16-62 D=6.7",$16-62 D=8.7"$16-62 D=11.4"$17-62	Pipeline capital cost ($/m) $= \max \begin{cases} 0.3354 \times D^2 + 11.25 \times D + 2.31; \\ 155\text{-}620 \text{ (for rural-urban sites)} \end{cases}$ D = pipeline diameter in inches (D is found from hydrogen flow rate, pipeline inlet and outlet pressures, pipeline length, and flow regime (see Appendix E)

2.2. Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Options

In Task 2, we combine our "component" models of hydrogen production, CO_2 capture, transmission and sequestration, hydrogen compression, storage, distribution and refueling to describe an integrated fossil hydrogen system with CO_2 capture and sequestration.

2.2.1. Task 2.1. Develop Simple Model for Entire System and Perform Sensitivity Studies

In Task 2.1, we studied total system design and economics, for the special case of a single large fossil energy complex connected to a single geological CO_2 sequestration site and a single H_2 demand center (such as a city with a large concentration of H_2 vehicles). Results for this task were described in the first progress report for this contract. The system is shown in Figure 1.1.1. Using the component models from Task 1, we developed a simple analytical model linking the components into a total system. We then estimated the total delivered cost of H_2 with CO_2 sequestration for hydrogen produced from coal and natural gas (Figure 2.1.3). We conducted sensitivity studies to examine which parameters are most important in determining delivered hydrogen costs. For our base case assumptions (large CO_2 and H_2 flows; a relatively nearby reservoir for CO_2 sequestration with good injection characteristics; a large, geographically dense H_2 demand), H_2 production, distribution and refueling were found to be the major costs contributing to the delivered H_2 cost. CO_2 capture and sequestration added only ~10%. Better methods of H_2 storage would reduce both refueling station and distribution system costs, as well as costs on-board vehicles.

As a second step, we expanded this simple model to include better models of hydrogen demand and hydrogen distribution systems. Further, this improved model provides a potential interface with GIS database being developed in Task 3, allowing hydrogen system design and cost calculations based on quantities easily derived from GIS maps (see Figure F.1). In the next sections we present results for the cost of fossil hydrogen production with CO_2 sequestration including distribution of hydrogen to vehicles, as a function of geographic factors (size of demand, geographic density of demand, location of fossil energy complexes and sequestration sites), level of hydrogen use (e.g. market penetration of hydrogen vehicles), and technology.

2.2.1.1. An Integrated Hydrogen System Model

We consider a variety of possible hydrogen supply and delivery options, which are likely to be important in future hydrogen energy systems:

Centralized, large-scale production of hydrogen from:
- Steam reforming of natural gas with and without CO_2 sequestration
- Coal gasification with and without CO_2 sequestration
- Large scale electrolysis

Distributed production of hydrogen at refueling sites from:

- Natural gas reforming
- Electrolysis using off-peak power

For centralized production, we consider hydrogen delivery via truck (compressed gas or liquid), or via gas pipeline. For fossil hydrogen with CO_2 sequestration, we consider a disposal system for CO_2.

For each supply pathway, we estimate infrastructure costs as a function of a relatively small number of input variables embodying averaged and/or simplified information about geography, markets and technology.

INPUT variables:

Geographic factors:
Total number of vehicles in a region
Region size (km^2)

Market Factors:
fraction of hydrogen vehicles in fleet
refueling station coverage factor (fraction of all refueling stations that must offer H2 to assure adequate customer convenience)
Number of vehicles per gasoline refueling station today
Vehicle use miles/year

Technical Factors:
Vehicle Fuel Economy
Cost and performance of infrastructure components
Layout of distribution system (from idealized city model in Task 1.5)

From these inputs. we estimate for different production and delivery pathways:

OUTPUT OF MODEL:

H2 production capacity needed
Number of H2 refueling stations
H2 dispensed per station
Layout of hydrogen stations
Delivery system layout (pipeline length; truck route length)
Cost of entire system from production through delivery for different production and delivery options
Levelized cost of hydrogen

Details of this model are given in Appendix F.

2.2.1.2. Preliminary Results

We have just begun to work with this model to estimate the lowest cost alternatives as a function of market and geographic factors. As an example, we consider a city of 1 million people, where 10% of vehicles run on hydrogen (see Table 2.2.1 and Table 2.2.2).

Table 2.2.1. Characteristics of City and Calculated Infrastructure

Geographic Factors	
People	1 million people
Light Duty Vehicles (LDVs)	750,000 LDVs
LDVs/km2	1500
Area of city	500 km2
City radius (for circular city) km	12.6 km
Market factors	
Fraction H2 vehicles = fH2	10%
Gasoline Vehicles/gasoline station	3000
Coverage factor	20%
Vehicle performance	
H2 Vehicle Fuel Economy = 2.8 x Today's Gasoline LDV	57 mpgge
Miles travelled/y	15,000
H2 energy use/LDV/d	0.7 kg H2/d/LDV
H2 Vehicles and Refueling Stations	
# H2 vehicles in city	75,000
Total H2 production required kg/d	52.5 tonne H2/d
# H2 refueling stations	50
H2 refueling station size	1050 kg/d/sta
H2 cars/H2 sta	1500
Central Production Model	
Central production capacity tonne H2/d	65.6 tonne/d
Central plant storage capacity tonnes	26.25 compressed gas 52.5 Liquid H2
Pipeline Distribution Model	
Local distrib. pipeline length/city radius (Figure 2.1.15)	20
Local distrib pipeline length	252 km
Truck Distribution Model (assumes each truck makes 2 deliveries per day)	
Compressed Gas Trucks required	55
LH2 Trucks Required	7

Table 2.2.2. Capital Costs for Hydrogen Infrastructure Options (million $)

	Central production SMR + pipeline delivery, CO_2 vented	Central production SMR + LH2 truck delivery, CO_2 vented	Central production SMR + comp gas truck delivery, CO_2 vented	Onsite SMR	Onsite Electrolyzer
Capital costs Million $					
Central SMR	55	50.5	55		
Liquefier	-	54	-		
Comp Gas storage	18.3 1/2 day	2.54 1/2 day	18.3 1/ day		
Local Pipeline ($155-620/m)	38-150	-	-		
Trucks	-	4.4	29.5		
Refueling stations	33.3	16.6	33.3	64.9	122
TOTAL Capital cost ($million)	145-257	127	136	65	122
TOTAL Capital cost $/LDV	1933-3427	1699	1814	866	1628
Operating Costs (million $/yr)					
Natural Gas	12.60	12.60	12.60	20.06	
Electricity	2.85	8.91	2.85	2.60	30.56
Other O&M	6.23	5.75	10.58	2.60	4.88
Total O&M	21.67	27.26	26.03	25.26	35.44
LEVELIZED COST OF H2 $/kg					
Capital	1.42-2.51	1.25	1.33	0.64	1.19
NG	0.82	0.82	0.82	1.31	0.00
Electricity	0.19	0.58	0.19	0.17	1.99
Other O&M	0.41	0.38	0.69	0.17	0.32
Total	2.84-3.93	3.03	3.03	2.28	3.51

For this level of hydrogen vehicle use, in this size city, onsite SMR gives the lowest capital costs and delivered hydrogen costs. In Figure 2.2.1, we plot the capital cost of H_2 infrastructure per car as a function of hydrogen market penetration rate. For this set of assumptions, onsite SMRs are the lowest capital cost option for all values of $fH_2 > 1\%$ of the fleet (at these very low H_2 penetration rates, electrolyzers are less costly).

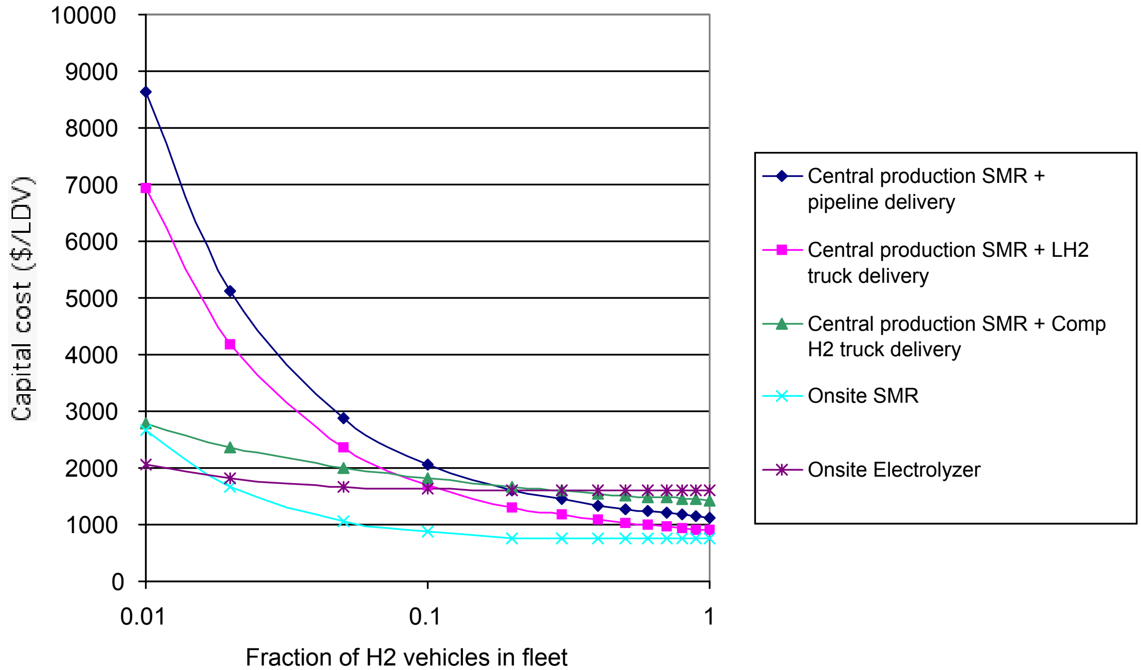


Figure 2.2.1. Capital Cost $/LDV for H_2 Infrastructure vs. Fraction of H_2 Vehicles

The delivered hydrogen cost ($/kg) is plotted versus fH2 in Figure 2.2.2. At very low hydrogen use, compressed gas trucks or electrolyzers give the lowest delivered costs. At very large fractions of H2 use, pipeline hydrogen gives the lowest delivered cost. This result is consistent with Figure 2.1.11.

2.2.2. Task 2.2 Explore Use of Mathematical Programming Techniques to Study More Complex Systems.

Although studies of the simple system in Task 2.1 are useful, a mature fossil hydrogen system would potentially involve a number of hydrogen production sites, hydrogen demand centers, and CO_2 sequestration sites. To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring use of mathematical programming methods to find the lowest cost system design. Thus far, we examined the suitability of several mathematical programming methods that could be used to optimize the design of a hydrogen energy system with CO_2 sequestration.

The basic design problem is shown in Figure 1.1.2. We have several hydrogen demand centers (shown in yellow) and primary resources. The question is how to connect these using the lowest cost system (including hydrogen production plants, hydrogen distribution and for fossil hydrogen options, a CO_2 disposal system.) The longer-term goal is to compare various possible transition pathways to find the lowest overall cost.

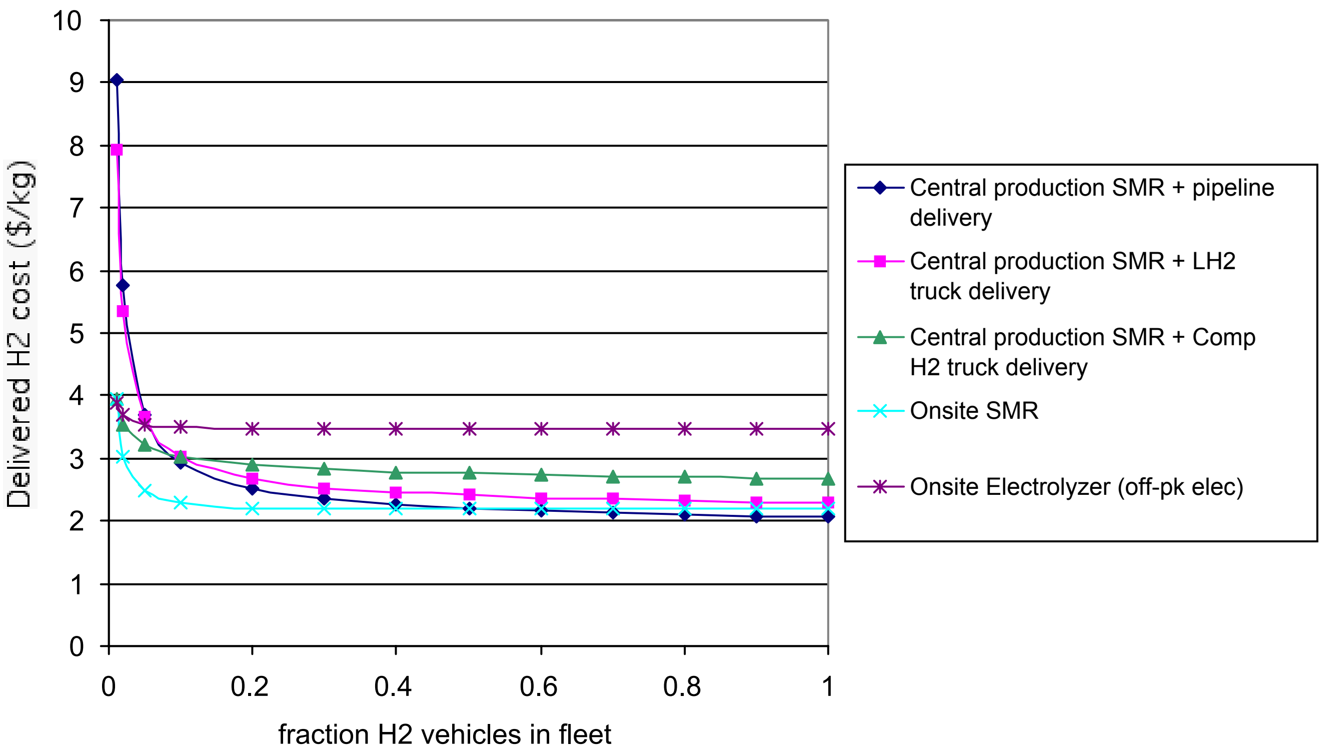


Figure 2.2.2. Delivered Cost of H_2 ($/kg) vs. Fraction of H_2 vehicles in Fleet for City of One Million People

This is a complex nonlinear optimization problem. As a first step, we reviewed the literature to understand how mathematical programming techniques had been applied to modeling pipeline systems (see Appendix H). (This is a subset of the overall design problem, as hydrogen production systems are not specifically included in this analysis.)

Several general classes of problems have been studied, relating to optimizing pipeline systems.

Design Optimization: In this category, we consider the design of a new pipeline network. Since the network doesn't exist yet, we must decide how many compressor stations (if any) are needed, where they should be located, where the interconnection of two (or more) pipes should happen, and what size (diameter and length) each pipe segment should be. Constraints may include mass balance at each node, gas flow equation in every pipe segment, the work equation of compressors and limits on the pressure or flow rate. Infinitely many designs can meet the constraints. The design and building cost is used as the objective function to select one design out of the design space.

Steady-State Operation Optimization: In this case, the network already exists, so pipe size, number and location of compressor stations are already known. The objective is to minimize the fuel consumption by compressors, which is determined by the suction and discharge pressure at each compressor station and the flow-rate of gas going through these compressors.

Table 2.2.3 summarizes the objective function (e.g. the cost function to be minimized), the constraints, and the optimization variables. Table 2.2.4 shows some of the approaches that have been applied to these two classes of pipeline design problems. Dynamic operation has also been treated, but we do not consider this here, because of its complexity.

Table 2.2.3. Objective Function Used in Various Pipeline Studies

	Design Optimization	Steady-state Operation optimization
Objective function	$building\ \cos t = f(pipe\ diameter, pipe\ length, \#\ of\ compressor, terrain, \ldots)$	$operation\ \cos t\ (fuel\ comsumed) = f(pressure, flowrate, \ldots)$
Constraints	1. mass flow balance equation at each node 2. gas flow equation at each pipe segment, i.e. pressure drop equation 3. working equation of each compressor 4. limits imposed on pressure or flow-rate	Same as the left
Optimization variables	pipe diameter and length, location of compressor stations and other interconnection points, etc.	flow-rate, suction and discharge pressure at each compressor station, etc.

In our studies so far we have concentrated on minimizing pipeline distances as a surrogate for minimizing costs. As described below (Task 3) this was accomplished by finding the minimum spanning tree connecting hydrogen supply (a central hydrogen plant) with demand centers (cities).

Table 2.2.4. Mathematical Programming Methods Used in Various Studies to Model Pipelines

Traditional optimization techniques	Pure linear programming
	Nonlinear programming
	    Sequential linear programming (SLP)
	    General reduced gradient method (GRG)
	    Inter-point method
	    Newton-Raphson method
	    Sequential unconstrained minimization technique (SUMT)
	Dynamic programming

Nontraditional optimization techniques	Genetic algorithms Simulated annealing Neural network Artificial ants

2.3. Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

2.3.1. Task Overview

In this task, we explore how H_2 and CO_2 infrastructures might develop in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

In this task, the goal is to derive insights about.

- Time constants and costs. How fast can we implement hydrogen fuel infrastructure? How much will it cost? What are the best strategies? What level of demand is needed for widespread implementation of H_2 energy system?

- Sensitivities to: technology performance and costs, size and density of demand, local availability of primary sources, characteristics of CO_2 sequestration sites, market growth, policies.

- Rules for thumb for optimizing H_2 and CO_2 infrastructure development.

To better visualize our results, we use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks.

We developed a GIS database for the state of Ohio, an area where coal-fired power plants are widely used. A survey of relevant GIS data sets was conducted (see Appendix I), and a database was built, including:

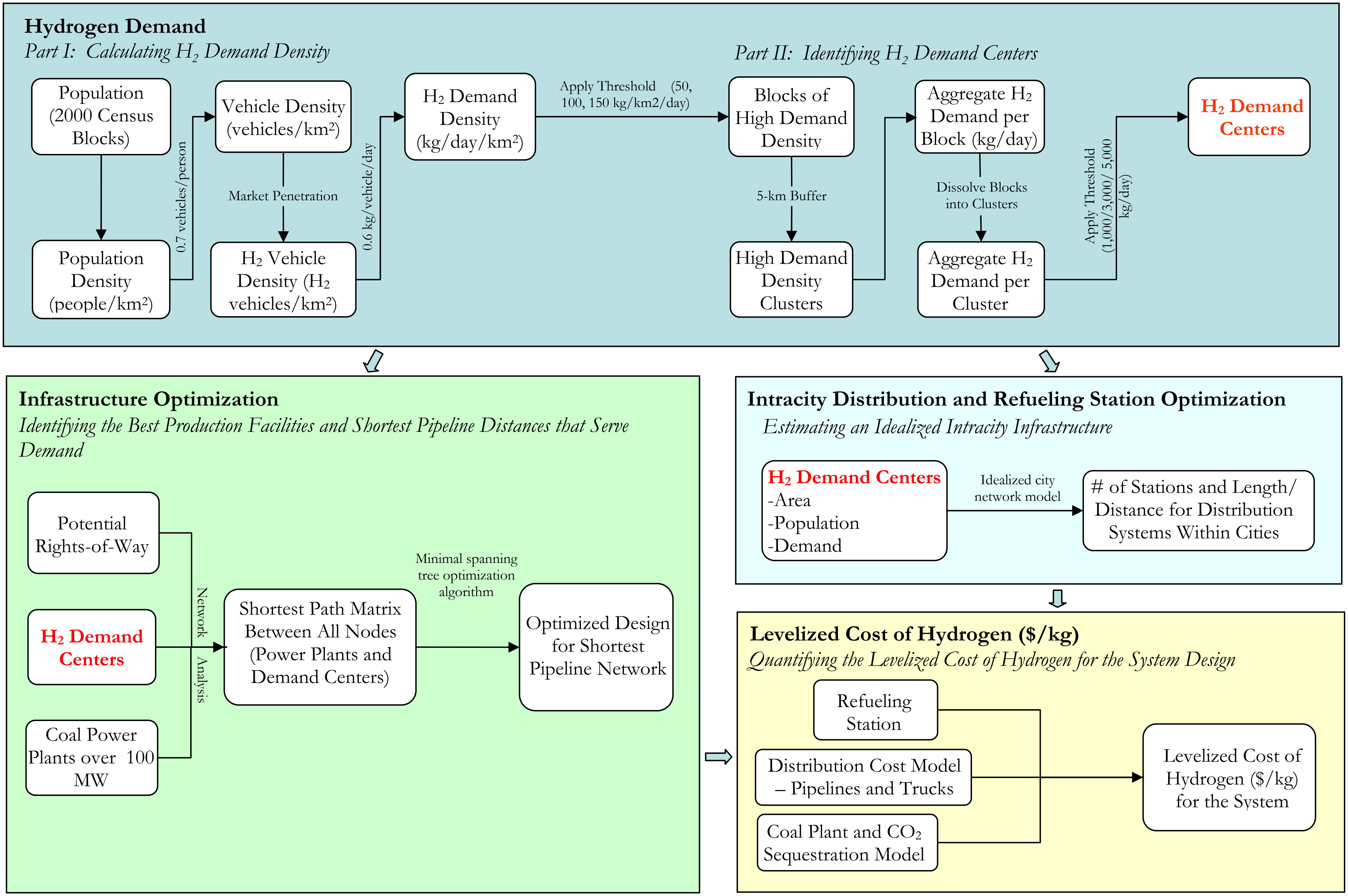
- Population density data, which is used to estimate hydrogen demands
- Data on the existing natural gas system
- Information on the electricity system and power plants
- Information on roads, railroads
- Data on the existing gasoline refueling infrastructure
- Information on sites for CO_2 sequestration

We combined this data into a single data base showing features such as hydrogen demand density, location of power plants, etc.[13] This is used a basis for analyzing alternative configurations for hydrogen supply and CO_2 disposal.

The overall flowchart for the GIS-based modeling is shown in Figure 2.3.1.

[13] Data sources used in building this database are given in Appendix H.

Figure 2.3.1. GIS modeling flowchart



2.3.2. *Estimating Hydrogen demand*

2.3.2.1. *Methodology*

In developing an optimized hydrogen infrastructure for the state of Ohio, it is first necessary to identify the quantity and location of hydrogen demand under different market penetration scenarios. In this study, hydrogen demand was calculated for two hypothetical steady-state scenarios in which: 1) hydrogen fuel cell vehicles (FCV's) make up 10% of the light duty vehicle (LDV) fleet and 2) FCV's make up 50% of the LDV fleet. The objective is to identify "demand centers" in which there is sufficient hydrogen demand to warrant investment in infrastructure.

To complete this analysis, a Geographic Information System (GIS) was used to derive hydrogen demand from block-level Census 2000 population data (US Census Bureau, 2000). The following steps were followed to identify hydrogen demand density in Ohio under the two FCV market penetration scenarios.

1. As FCV demand will occur in the future, a base year of 2030 was used for the analysis. Projected population change statistics (%) from 2000-2030 by county (Ohio Department of Development, 2004) were used to calculate population in the year 2030.
2. Population density was calculated by dividing the population of each census block by its area (km^2) to arrive at persons/km^2.
3. An estimate of total LDV's per km^2 was calculated by multiplying the population density by an estimate of auto ownership per person. A factor of 0.7 vehicles/person was derived from Ohio Department of Public Safety data, which indicates that 8.3 million vehicles are registered among approximately 11,353,140 people.
4. Hydrogen vehicle density (H_2 vehicles/km^2) was calculated for the two market penetration scenarios by multiplying the total LDV's per km^2 by 10% and 50%.
5. Hydrogen demand density (kg H_2/day/km^2) was derived by multiplying the number of H_2 vehicles with an estimate of average vehicle fuel use (0.6 kg H_2/day/vehicle). This estimate is based on the assumption that the average vehicle travels 15,000 miles/year and has a fuel economy of 65 miles/kg.

In summary,

$$\frac{kgH_2/day}{km^2} = \left(\frac{persons}{km^2}\right)\underbrace{\left(\frac{total\ vehicles}{person}\right)}_{(0.7)}\underbrace{\left(\frac{H_2 vehicles}{total\ vehicles}\right)}_{(10\%\ \text{and}\ 50\%)}\underbrace{\left(\frac{kgH_2/day}{vehicle}\right)}_{0.6}$$

Given hydrogen demand density throughout the state, the next step was to identify census blocks with sufficient demand to warrant consideration for infrastructure. Three density thresholds (50, 100, and 150 kg/day/km$^{2)}$ were analyzed to examine their ability to capture hydrogen demand. The results of this sensitivity analysis will be presented in the next section. A GIS was used to select census blocks that met each threshold. Upon examining the results, it was apparent that the selections did not result in uniform areas of high density, but rather concentrations of high density census blocks with holes caused by low density blocks. Figure 2.3.2 illustrates this phenomenon within the city of Columbus for the three thresholds.

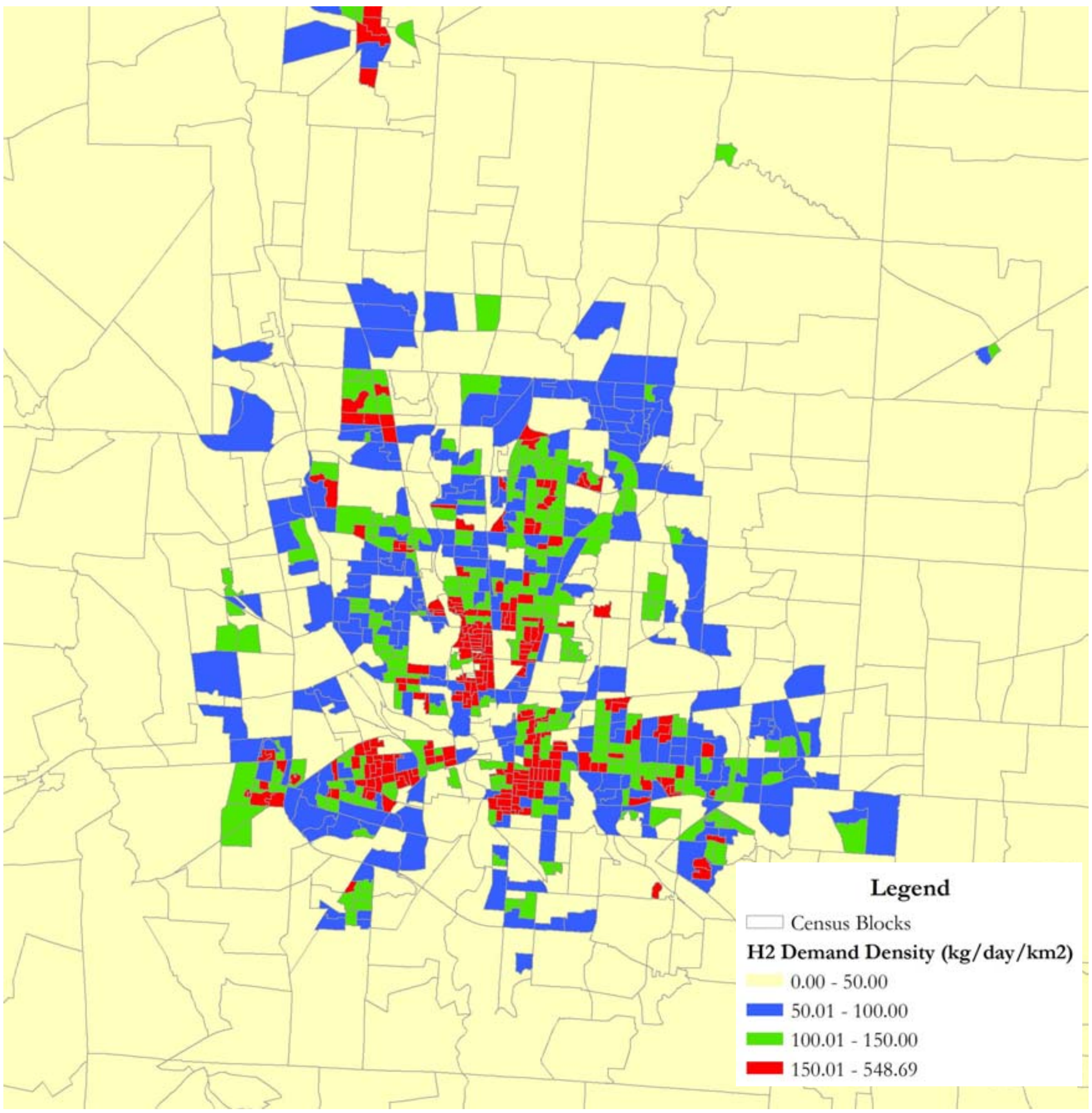


Figure 2.3.2. Hydrogen demand density given different density thresholds in Columbus, Ohio

In designing an optimized infrastructure, it was decided to identify uniform demand centers rather than islands of small disjointed clusters. Consequently, a 5-kilometer buffer was used to aggregate these clusters into uniform, consolidated shapes. The buffer was generated from the high demand density blocks and then all census blocks that were completely contained within the buffer were aggregated to form the demand clusters. Figure 2.3.3 illustrates the results from this analysis for the city of Columbus. Using the 100 kg/day/km^2 threshold, a total of 67 and 98 demand clusters were identified statewide for the 10% and 50% scenarios, respectively.

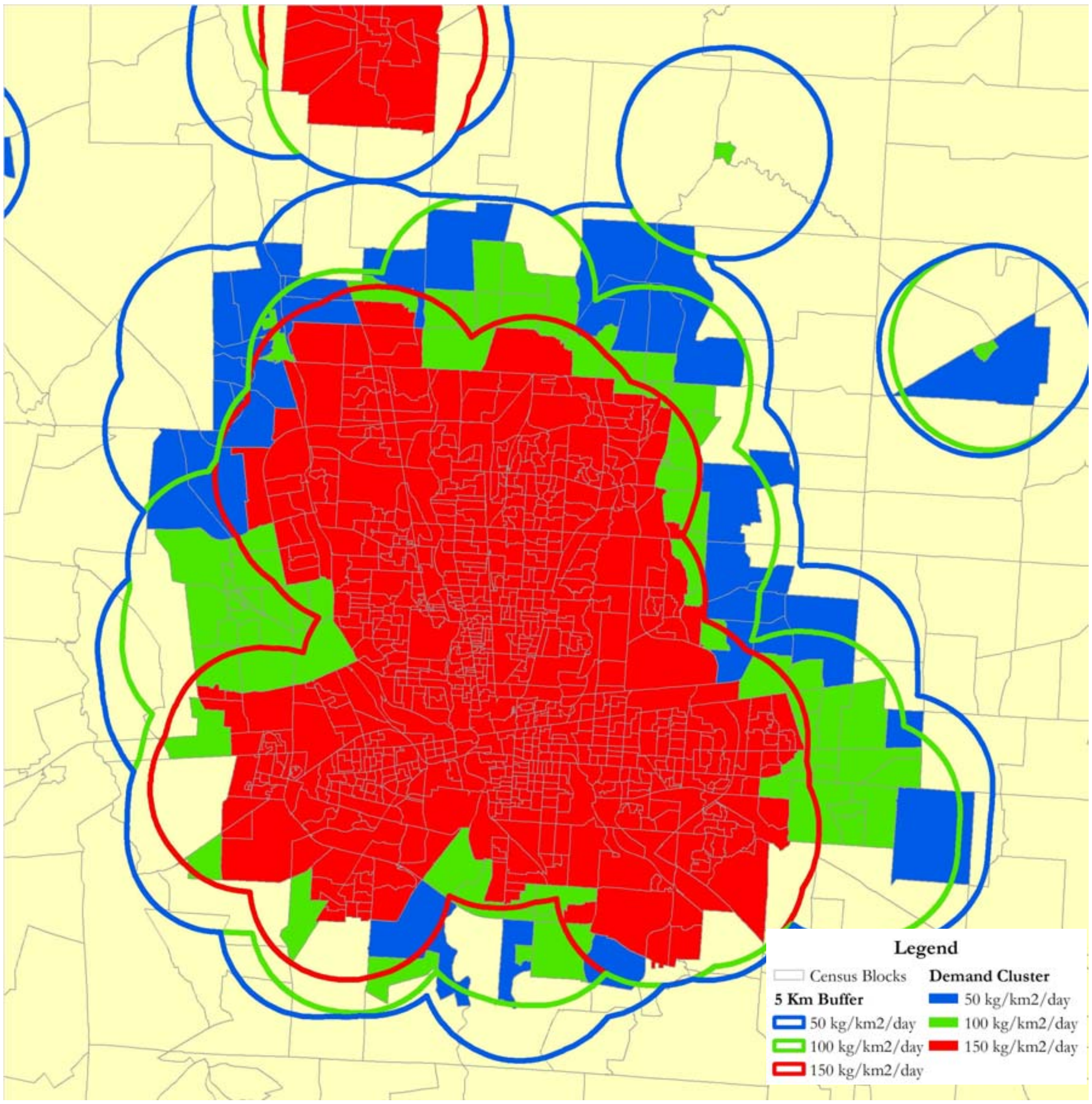


Figure 2.3.3. Demand clusters under different density thresholds in Columbus, Ohio

Given these demand clusters, the next step was to identify a subset consisting of clusters that have sufficient aggregate demand to support a single fueling station. To calculate aggregate demand, total hydrogen demand was identified for each census block by multiplying the demand per km^2 with the area (km^2) of each block. Aggregate demand for each demand cluster was then calculated by summing the demand for all component blocks. A threshold was then used to eliminate clusters that do not have sufficient demand to support a fueling station. Three thresholds were tested, including 1,000, 3,000, and 5,000 kg/day. The results of the sensitivity analyses are discussed in the next section. For the "base" case that used a density threshold of 100 kg/day/ km^2, it was discovered that the hydrogen demand varied from 85 to 63,235 kg/day under the 10% scenario and from 115 to 754,836 kg/day under the 50% scenario. Figure 2.3.4 shows the results for the 10% scenario.

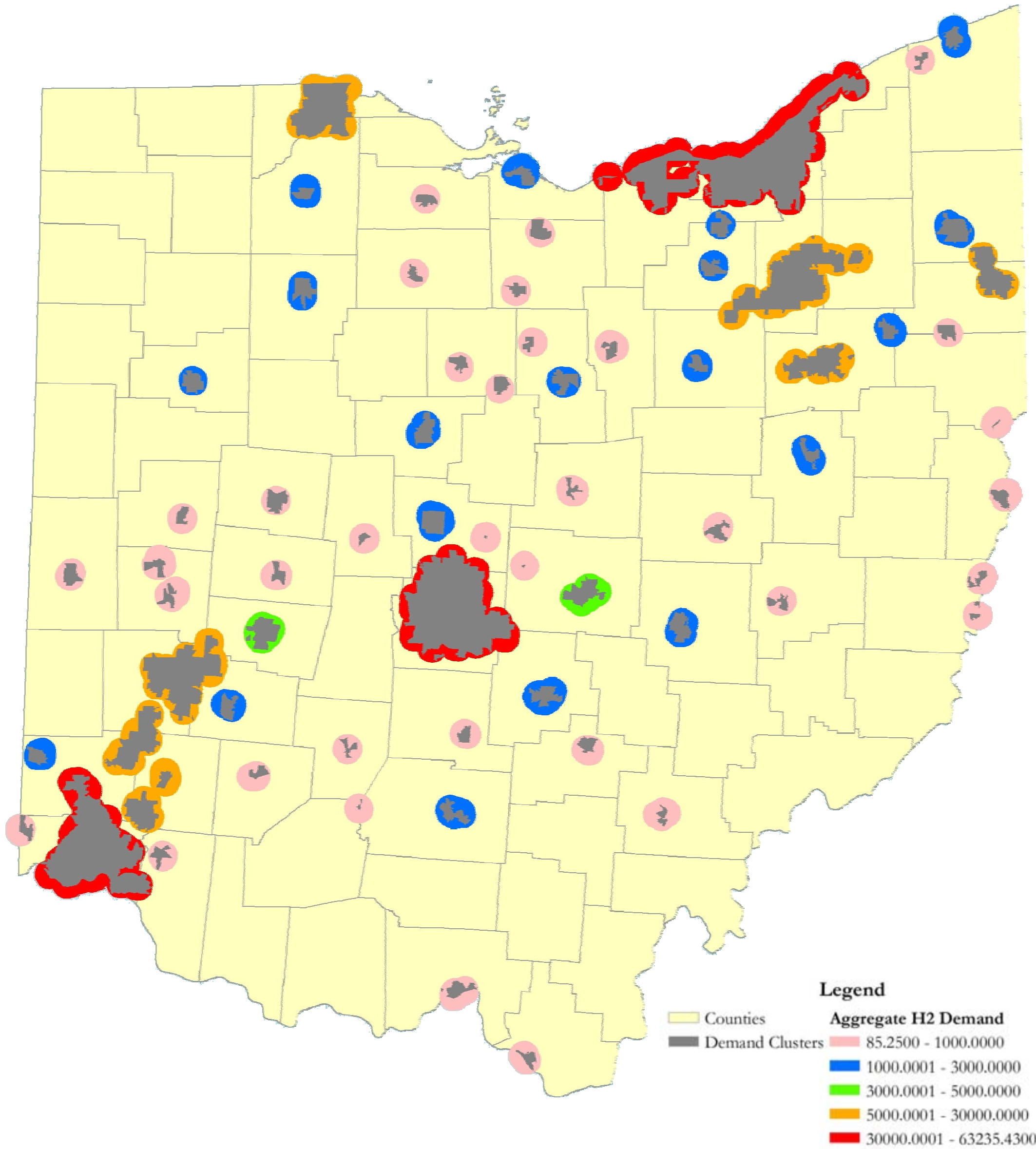


Figure 2.3.4. Demand clusters and associated aggregate hydrogen demand

Using the "base" case aggregate threshold of 3,000 kg/day, all demand clusters with a demand below this threshold were erased, leaving twelve demand centers under the 10% scenario and thirty-nine under the 50% scenario. The final demand centers using the "base" thresholds are illustrated for the 10% and 50% scenarios in Figure 2.3.5 and Figure 2.3.6, respectively.

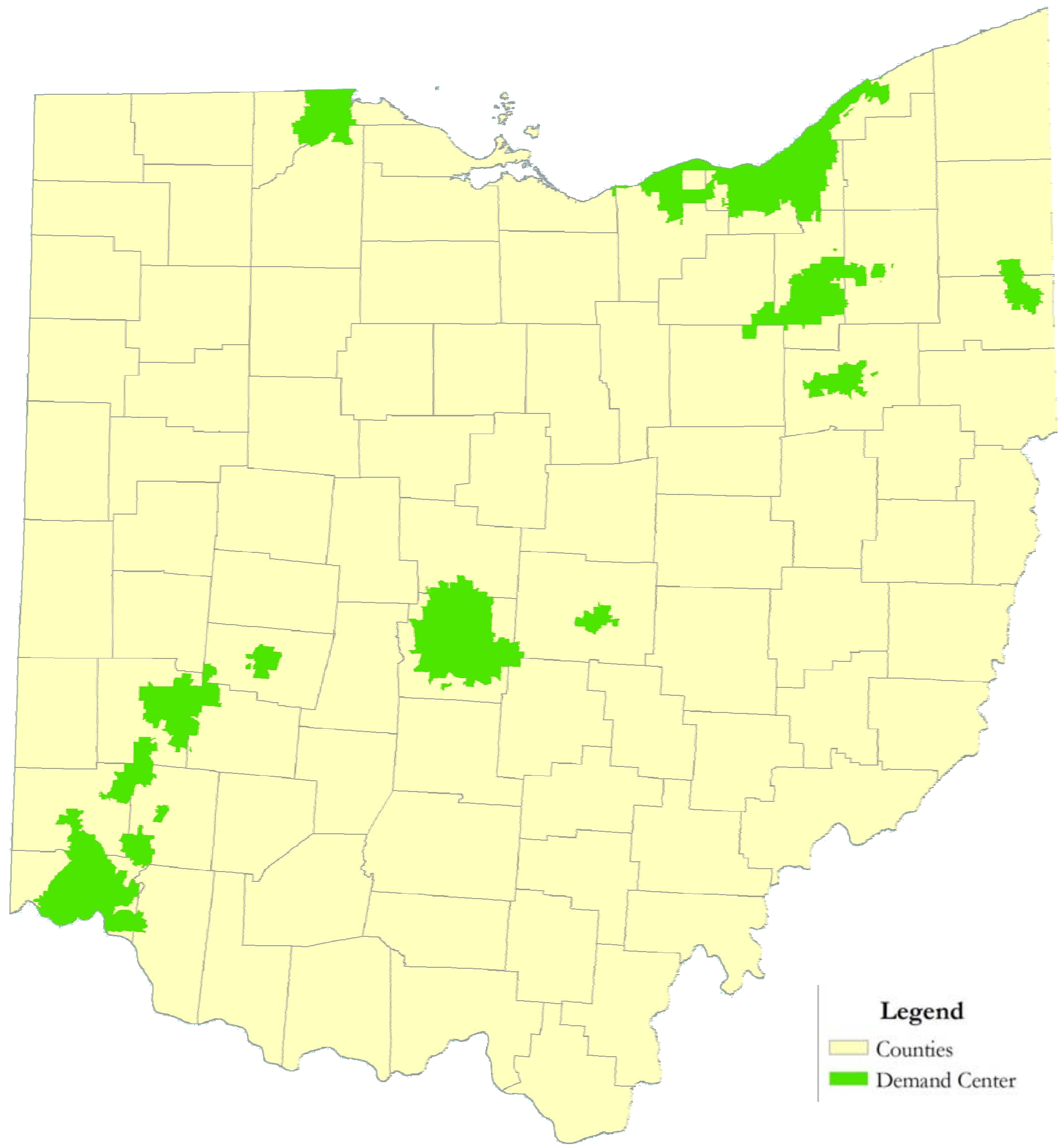


Figure 2.3.5. Demand centers with 10% market penetration

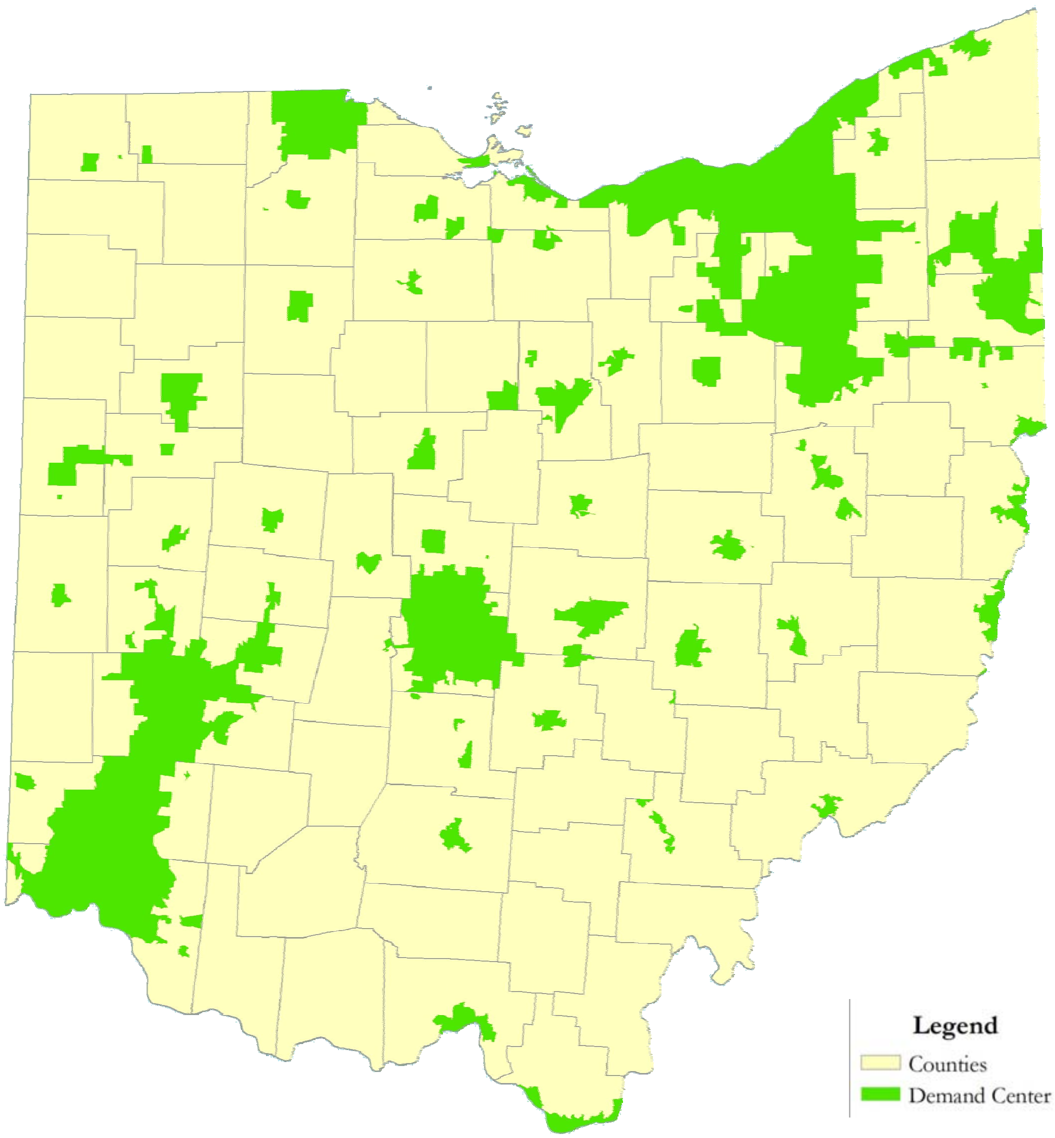


Figure 2.3.6. Demand centers with 50% market penetration

2.3.2.2. Sensitivity Analysis

In order to understand the spatial distribution and quantity of hydrogen demand under the 10% and 50% market penetration scenarios, we used two thresholds to identify areas of high demand. The first threshold (density threshold) was used to identify high demand density and develop demand clusters. The second threshold (aggregate threshold) was used to highlight areas with sufficient aggregate demand to warrant investment in infrastructure. As a result, it served to identify the optimized demand centers as a subset of the initial demand clusters. In order to determine appropriate thresholds, we conducted a sensitivity analysis using three threshold scenarios to analyze their impact on the extent and quantity of hydrogen demand. The three scenarios considered are shown in Table 2.3.1.

Table 2.3.1. Threshold values for each scenario

	Scenario 1 [low threshold]	**Scenario 2 [base]**	**Scenario 3 [high threshold]**
Density Threshold	50 (kg H_2/day/km^2)	100 (kg H_2/day/km^2)	150 (kg H_2/day/km^2)
Aggregate Threshold	1000 (kg H_2/day)	3000 (kg H_2/day)	5000 (kg H_2/day)

To compare these scenarios, we calculated the percent of statewide hydrogen demand captured within the demand centers (kg H_2/day), the percent of statewide land area captured (km^2), and the number of demand centers. Table 2.3.2 summarizes the results.

Table 2.3.2. Results for each threshold scenario

	Scenario 1 [low threshold]	**Scenario 2 [base]**	**Scenario 3 [high threshold]**
H_2 Demand (% of Ohio total)	63.65%	47.21%	32.32%
Area (% of Ohio total)	8.83%	4.84%	2.59%
Number of Demand Centers	25	12	8

As expected, a greater percentage of hydrogen demand is captured over a larger land area and in more demand centers as the threshold is lowered. The following figures illustrate the results for demand centers with varying levels of hydrogen demand. We categorized the demand centers into five groups based on the quantity of aggregate hydrogen demand: 0 - 5,000 kg/day, 5,000 – 10,000 kg/day, 10,000 – 20,000 kg/day, 20,000 – 40,000 kg/day, and greater than 40,000 kg/day. Figure 2.3.7 identifies the number of demand centers in each group.

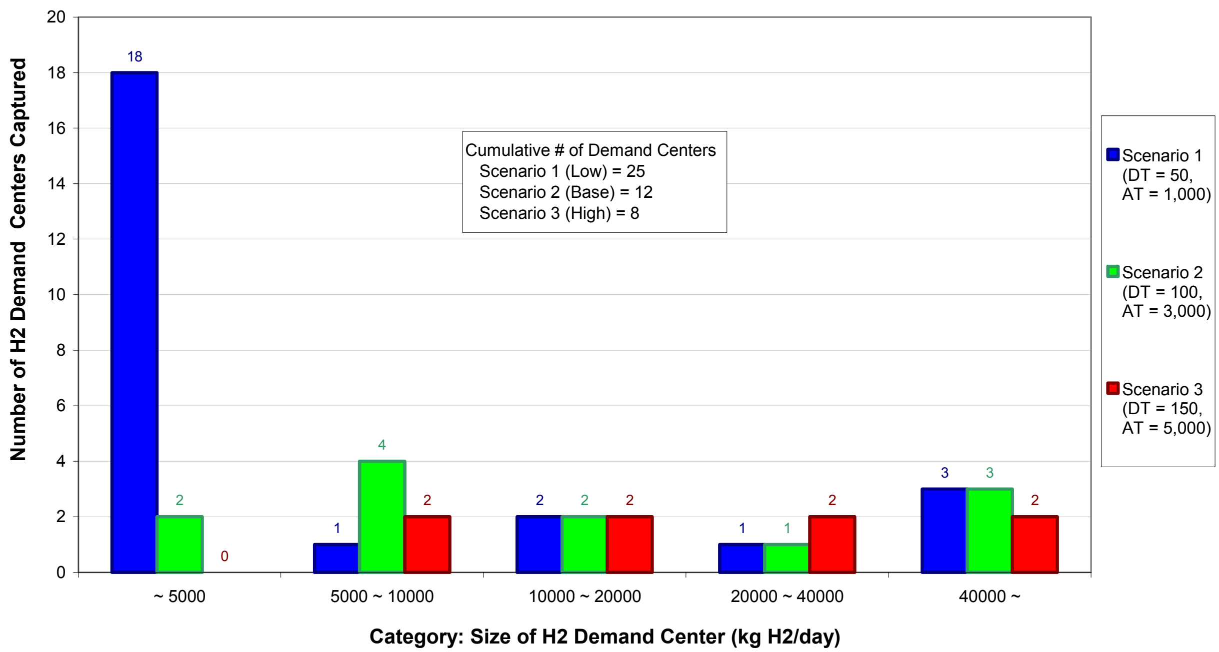


Figure 2.3.7. Number of hydrogen demand centers

This figure indicates that the "low" threshold results in a large number of centers with low hydrogen demand (1,000 to 5,000 kg/day). Depending on the location of these small centers, it may be cost prohibitive to supply them with hydrogen given their low demand. Consequently, it may be preferable to use a higher threshold to eliminate some of these smaller demand centers. The "low" threshold scenario not only results in more demand centers, but also cause demand centers to increase in size, resulting in more large demand centers (> 40,000 kg/day). Figure 2.3.8 illustrates the percent of total hydrogen demand for each group.

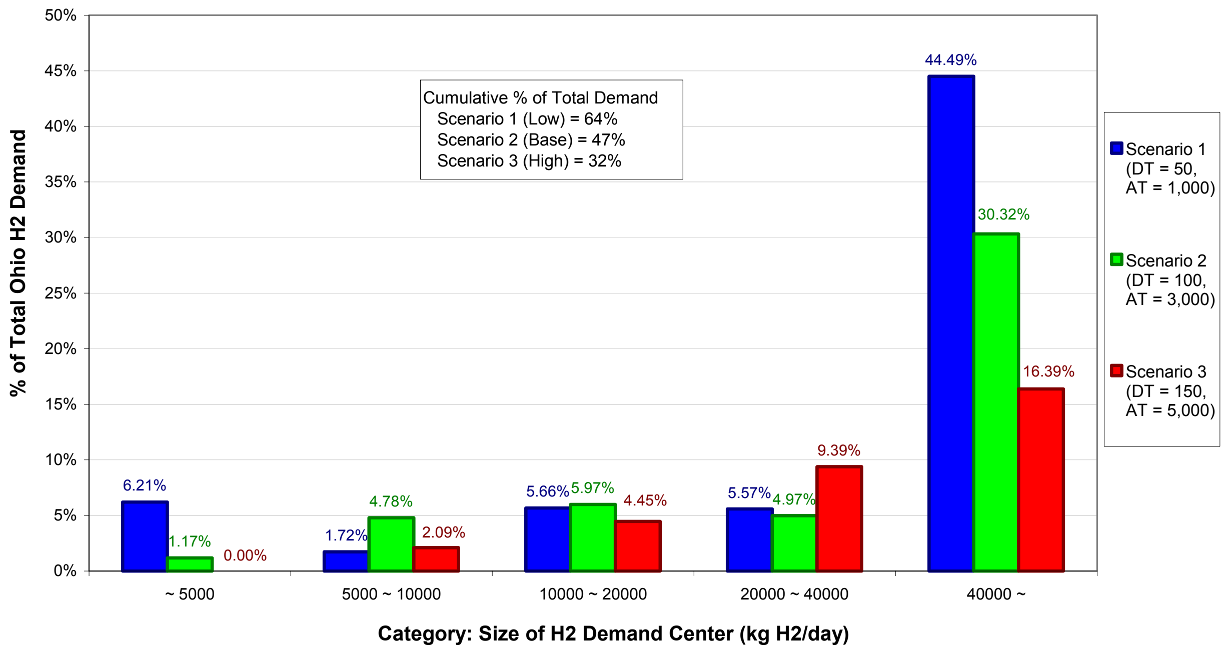


Figure 2.3.8. Percent of statewide hydrogen demand captured

This figure indicates that the "low" threshold captures more of the hydrogen demand within Ohio. In particular, it captures more demand in small and large demand centers because less small demand centers are eliminated and larger centers expand in size. Although this scenario does result in a 36% increase in the capture of demand over the "base" scenario, it requires infrastructure to be installed to over twice as many demand centers. The "high" scenario captures only 50% of the demand met by the "low" threshold. Figure 2.3.9 indicates the percent of total Ohio land area captured within each group.

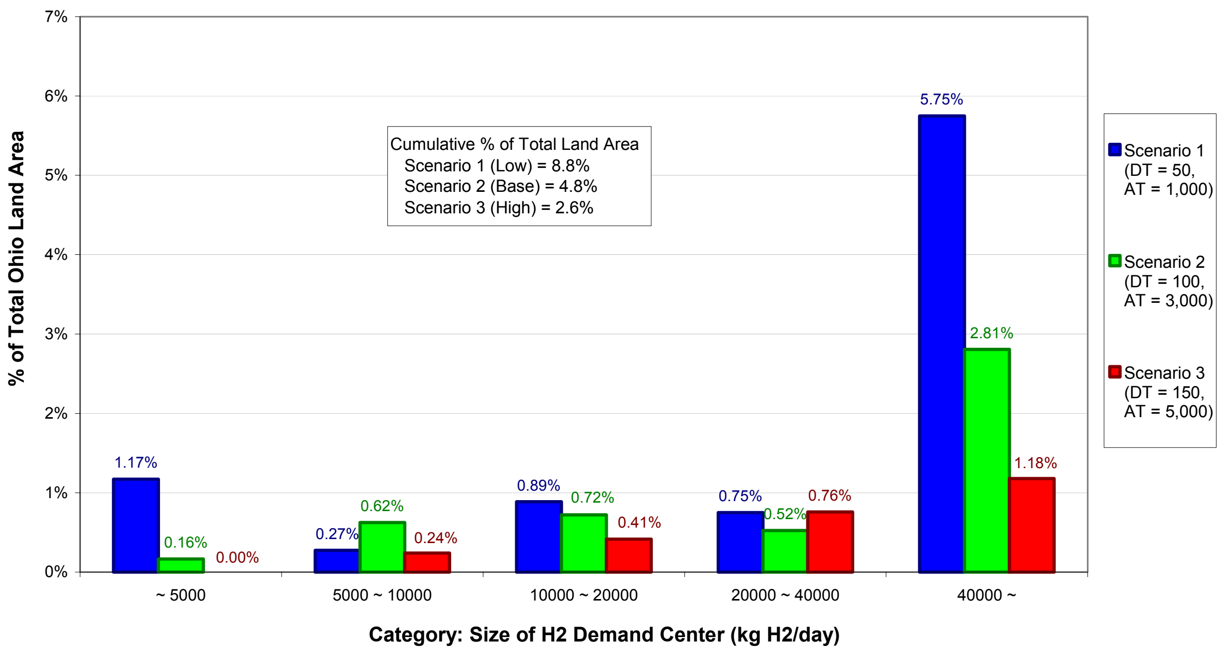


Figure 2.3.9. Percent of statewide land area captured

The "low" threshold scenario captures significantly more land area, especially in small and large demand centers. This result suggests that the "low" threshold would require more extensive intracity infrastructures, resulting in higher costs. The "low" scenario occupies 83% more land than the "base" scenario and 238% more land than the "high" threshold. Figure 2.3.10 illustrates the spatial distribution of the three scenarios given 10% market penetration.

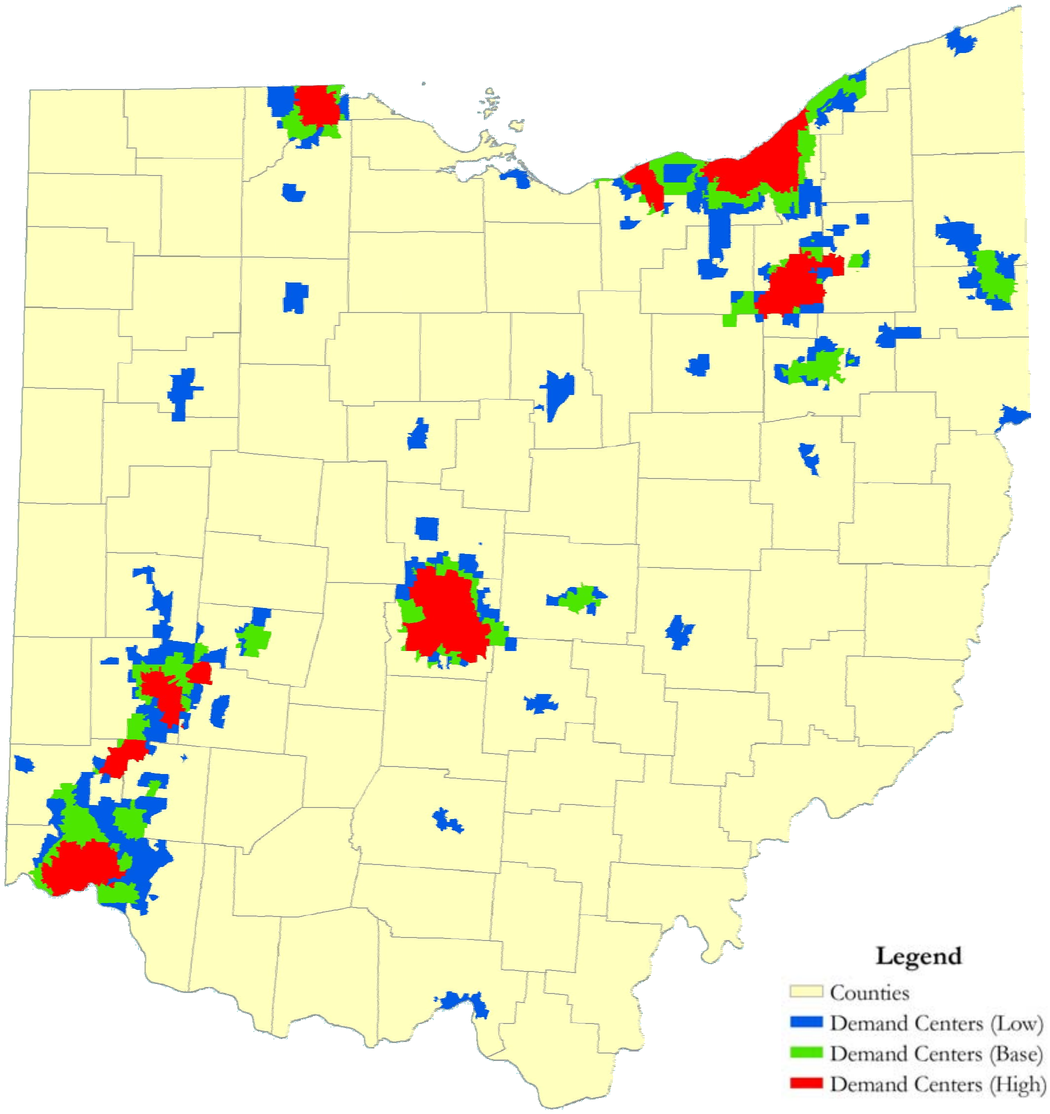


Figure 2.3.10. Spatial distribution of demand centers given the three threshold scenarios

This figure illustrates how the demand centers expand in size and number as the thresholds are lowered. In comparison with the "base" scenario, the "low" scenario captures 36% more of the state hydrogen demand, but requires service to twice as many demand centers and 83% more land area. However, it does capture 64% of hydrogen demand in less than 10% of the land area. In contrast, the "high" scenario captures 32% less hydrogen demand than the "base" and addresses 46% less land area and 33% fewer demand centers. It captures 32% of the hydrogen demand in 2.6% of the land area. The "base" scenario captures 47% of hydrogen demand in less than 5% of the land area. In the future, it will be interesting to calculate the levelized cost of hydrogen under each scenario in order to determine which thresholds are the most cost-effective. For example, although the "low" threshold scenario requires extensive expansion of infrastructure for a relatively small gain in the capture of hydrogen demand, it may allow for the capture of economies of scale, resulting in favorable economics. An analysis of cost will be conducted in the near future.

2.3.3. Infrastructure Components

Determination of Hydrogen production capacity - Central plant

Information about coal electricity plants in Ohio is obtained from the EPA's eGrid database, including plant data such as electricity output, coal input, CO_2 emissions, and plant efficiency. This information is used to predict the hydrogen production capacity for each of these locations (see Table 2.3.3). This H_2 capacity can be calculated a number of different ways. One key assumption is that each coal plant site is currently limited with respect to its coal supply and handling capacity. This assumption will limit the ability of these coal plants to increase their coal inputs significantly. The first is to constrain only the existing coal input and re-direct that feedstock from electricity production to hydrogen production. Given a 65% conversion coal-to-H_2 efficiency, the hydrogen production capacity can be easily calculated.

A second strategy is to maintain both the coal input and electricity output, while co-producing hydrogen. Advanced integrated coal gasifier combined cycle (IGCC) technology can dramatically increase coal-to-electricity efficiency, requiring less coal input for the same electricity output. This allows the excess coal input to be converted to hydrogen by oversizing the gasifier and diverting a stream of hydrogen to be utilized as a transportation fuel. This can significantly reduce the capital costs associated with hydrogen production as compared to a standalone plant of the same H_2 capacity.

Other strategies can be used to determine the potential hydrogen capacity of existing coal plant sites as well as other non-existing sites. For the initial analysis, the potential production plant locations was limited to existing utility coal plants over 100 MW electricity output and conversion to a dedicated H_2 production facility was considered.

In this analysis, coal plants producing mostly hydrogen with some co-production of electricity were considered with associated capture and compression of CO_2 for sequestration based upon Kreutz et al 2002. The majority of the energy output is in the form of hydrogen (~97%) with the remaining energy output as electricity (~3%). The gross electricity production is about 14% of the total output, but electricity demands within the plant for compression lead to lower net electricity output. The plant has a coal input to H_2 output efficiency of 66% and an overall net efficiency of 69% (coal to H_2 + electricity). Hydrogen is compressed to approximately 1000 psi for transport.

Table 2.3.3. Data for utility coal plants over 100MW electricity output and estimates for H_2 capacity given complete coal conversion and efficiency improvements.

ID	Plant Name	H2 Capacity - Full Conversion (kg/day)	Plant Efficiency	H2Capacity - IGCC Conversion (42%) (kg/day)	CO_2 emissions (kg/kWh)
1	ASHTABULA	138,530	40.14%	2,578	0.87
2	AVON LAKE	429,126	34.81%	30,840	1.01
3	BAY SHORE	445,308	32.33%	43,042	1.08
4	CARDINAL	1,449,802	36.62%	77,933	0.96
5	CONESVILLE	1,556,646	33.82%	127,330	1.04
6	EASTLAKE	791,977	32.27%	77,023	1.08
7	GEN J M GAVIN	2,505,969	32.11%	247,850	1.09
8	HAMILTON	51,944	23.22%	9,756	1.46
9	KAMMER	568,833	36.75%	29,841	0.95
10	KYGER CREEK	1,088,682	35.74%	68,132	0.98
11	LAKE SHORE	70,761	23.73%	12,928	1.47
12	MIAMI FORT	1,294,250	31.38%	137,507	1.12
13	MITCHELL	1,213,062	35.39%	80,196	0.99
14	MOUNTAINEER (1301)	1,004,843	35.53%	65,047	0.99
15	MUSKINGUM RIVER	1,147,087	35.62%	73,158	0.98
16	NILES	188,992	30.64%	21,474	1.14
17	O H HUTCHINGS	150,727	28.51%	20,334	1.21
18	PHIL SPORN	909,740	36.42%	50,726	0.96
19	PICWAY	67,121	30.36%	7,814	1.15
20	PLEASANTS	1,053,605	34.50%	79,068	1.01
21	R E BURGER	292,972	32.31%	28,389	1.08
22	RICHARD GORSUCH	247,459	26.98%	37,164	1.30
23	W H SAMMIS	1,861,267	33.06%	166,415	1.06
24	WILLOW ISLAND	249,229	28.98%	32,457	1.18
	TOTAL	**18,777,930**	**33.87%**	**1,527,001**	**1.04**

Carbon capture

In the plant configuration chosen, 92% of the CO_2 is captured and sequestered while approximately 8% is emitted to the atmosphere. This system uses "conventional" technologies for gas separation: glycol absorption for CO_2 capture and pressure swing adsorption for hydrogen purification. Kreutz et al. also describe advanced technologies for separations including an inorganic membrane for coupled separation and water gas shift reaction. CO_2 is separated from the syngas stream after the WGS reactors using an absorption tower with (Selexol). The CO_2 stream is dehydrated and compressed to 2200 psi creating a supercritical stream for transport.

On-site production

Natural gas steam methane reformers (NG-SMRs) are used for producing hydrogen at the refueling station. Small natural gas steam reformers are curently being developed by a number of companies including H2Gen, Plug Power, Air Products, and Ztek for stationary and transportation fuel cell applications. These small reformers, which are combined with compressors, hydrogen storage tanks and hydrogen fuel dispensers form the basis of a stand-alone hydrogen vehicle refueling station.

2.3.4. Infrastructure Optimization

Network Analysis

One of the main components of this analysis is the determination of the lowest cost network for supplying hydrogen to the demand clusters from a hydrogen production plant that is located at one of the existing coal plant sites. The network components, as described in Tasks 1.4 and 1.5, include the identified demand clusters, existing energy rights-of-way (i.e. natural gas pipelines), coal plants, and CO_2 sequestration sites (some of which are shown on Figure 2.3.12). The optimization of this network in order to minimize the cost of hydrogen production, distribution and refueling is a critical component of this model.

Optimization modeling

The spatial design of the infrastructure, i.e. the location(s) of hydrogen production plant locations, sequestration sites and the network (pipelines) for hydrogen distribution to the demand clusters is carried out by a network optimization algorithm. This optimization routine minimizes the total pipeline length to connect all demand clusters to one or more H_2 production plants. It is based upon the minimal spanning tree algorithm, which minimizes pipeline length from a number of potential hydrogen production plant locations (sources) to a series of demand clusters (sinks). The main constraint is that each of the sinks must be connect to a source, either directly or through another sink. The input of this optimization routine is a matrix that specifies the shortest network length for every given pair of nodes (i.e. sources or sinks). To generate this matrix (shown in Table 2.3.4), an algorithm was developed using the GIS network analyst.

Network methods used in this study

A network is an interconnected or interrelated chain, group, or system. It can be represented conceptually and digitally by nodes and links (Figure 2.3.11). Nodes represent intersections, interchanges, or confluence points on the network, and links represent transportation or transmission paths between nodes. Types of nodes can be: stops, which are locations visited along a path, or; centers, which are locations where there is a supply or attraction.

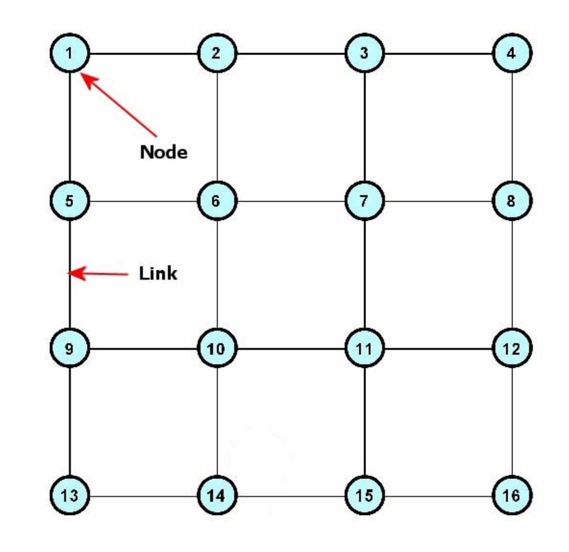


Figure 2.3.11. Conceptual Network Structure

ArcView 3.2 Desktop GIS was selected for the GIS-based network analysis. This software package was chosen for being readily available, customizable, expandable, and familiar to GIS users in the research group. ArcView, with the Network Analyst extension, allows the user to solve many network-based problems, such as: finding the most efficient travel route from one location to the next; generating travel directions; finding the closest service facility to a market; defining service areas based on travel time; finding the best location for a service center; and determining the number of trips that will be generated from one location to another.

This project used Network Analyst to find the shortest route between two locations along the network. In this case, we calculated the shortest routes between all of the coal power plants over 100MW capacity (sources) and the centers of the demand clusters (sinks) along the natural gas pipeline right-of-way (network). The output is a table of the shortest distances between all sources and sinks. Given more time, the GIS software could be re-programmed to optimize routes and locations for a more seamless modeling effort. However, pre-existing optimization routines were used for calculating the best routes between locations and minimizing network costs.

Table 2.3.4. Distance matrix for network optimization indicating distance between demand clusters to other demand clusters and coal plants

		Demand Clusters											
		3	**7**	**13**	**16**	**23**	**43**	**48**	**49**	**52**	**57**	**62**	**65**
	101	283	72.18	171.2	139.9	163.8	288	406.4	308	428	446.7	458.8	481
	102	158.2	104.9	152	81.06	106.8	181.3	299.7	201.3	321.3	340	352.1	374.3
	103	21.36	209.9	257	186	211.8	226.5	344.9	246.6	366.5	385.2	397.3	419.5
	104	363.3	242.3	186.5	181.2	150.1	218.2	311.9	237	333.5	337.4	349.4	371.6
	105	266.2	195.8	161.8	131.4	101	69.58	205.3	107	227	245.7	257.8	280
	106	229.5	17.19	128.6	90.43	114.3	234.4	352.8	254.5	374.4	393.1	405.2	427.4
	107	406.5	338.8	304.2	273.8	243.3	194.2	258.2	189.3	279.8	283.7	295.7	317.9
	108	405.2	393.6	411.9	350	337.3	204.4	89.04	156.3	53.8	25.39	40.27	21.93
	109	338	218.9	163	156	124.8	192.9	279.6	204.7	301.2	305.1	317.2	339.4
Coal	**110**	408.7	341.1	306.5	276.1	245.6	196.5	260.5	191.5	282.1	285.9	298	320.2
Plants	**111**	191.6	67.37	117	57.83	83.61	198.1	316.5	218.2	338.1	356.8	368.9	391.1
	112	445.1	433.4	451.8	389.9	377.1	244.2	134	196.2	98.72	70.52	73.13	54.79
	113	336.7	217.5	161.7	154.6	123.5	191.6	278.3	203.4	299.9	303.7	315.8	338
	114	396.9	329.3	294.7	264.3	233.8	184.7	248.7	179.7	270.3	274.1	286.2	308.4
	115	358.3	250.9	216.3	185.9	155.4	146	210	141	231.6	235.4	247.5	269.7
	116	262.3	114.3	49.47	81.53	83.2	229.3	357.2	258.8	378.8	397.5	409.6	431.8
	117	385	373.4	391.7	329.8	317.1	184.2	57.48	136.1	22.23	6.17	31.08	53.28
	118	396.9	329.3	294.7	264.3	233.8	184.7	248.7	179.7	270.3	274.1	286.2	308.4
	119	285.2	273.6	291.9	230	217.2	72.96	98.97	51.77	120.6	125.8	137.9	160.1
	120	390	291	242.1	226	195.5	177.8	241.7	172.8	263.4	267.2	279.3	301.5
	121	336.1	215.2	159.3	154.1	122.9	191	284.7	209.9	306.4	310.2	322.3	344.5
	122	366.2	272	235.3	206.9	176.5	154	218	149	239.6	243.4	255.5	277.7
	123	309.8	161.8	97.94	126.1	122.1	207.3	343	244.7	364.6	379.5	391.6	413.8
	124	389.6	290.6	241.7	225.6	195.1	177.4	241.3	172.4	263	266.8	278.9	301.1
	3	0	212.3	259.3	188.4	214.2	228.9	347.3	248.9	368.9	387.6	399.7	421.9
	7	212.3	0	111.4	73.24	97.15	217.2	335.6	237.3	357.2	375.9	388	410.2
	13	259.3	111.4	0	78.56	80.23	226.1	354	255.6	375.6	394.3	406.4	428.6
	16	188.4	73.24	78.56	0	32.13	173.6	292.1	193.7	313.7	332.4	344.5	366.7
	23	214.2	97.15	80.23	32.13	0	160.9	279.3	181	300.9	319.6	331.7	353.9
Demand	**43**	228.9	217.2	226.1	173.6	160.9	0	159.9	69.65	181.5	186.7	198.8	221
Clusters	**48**	347.3	335.6	354	292.1	279.3	159.9	0	98.34	35.25	63.66	88.56	110.8
	49	248.9	237.3	255.6	193.7	181	69.65	98.34	0	120	138.7	150.7	172.9
	52	368.9	357.2	375.6	313.7	300.9	181.5	35.25	120	0	28.41	53.31	75.51
	57	387.6	375.9	394.3	332.4	319.6	186.7	63.66	138.7	28.41	0	33.64	47.31
	62	399.7	388	406.4	344.5	331.7	198.8	88.56	150.7	53.31	33.64	0	49.93
	65	421.9	410.2	428.6	366.7	353.9	221	110.8	172.9	75.51	47.31	49.93	0

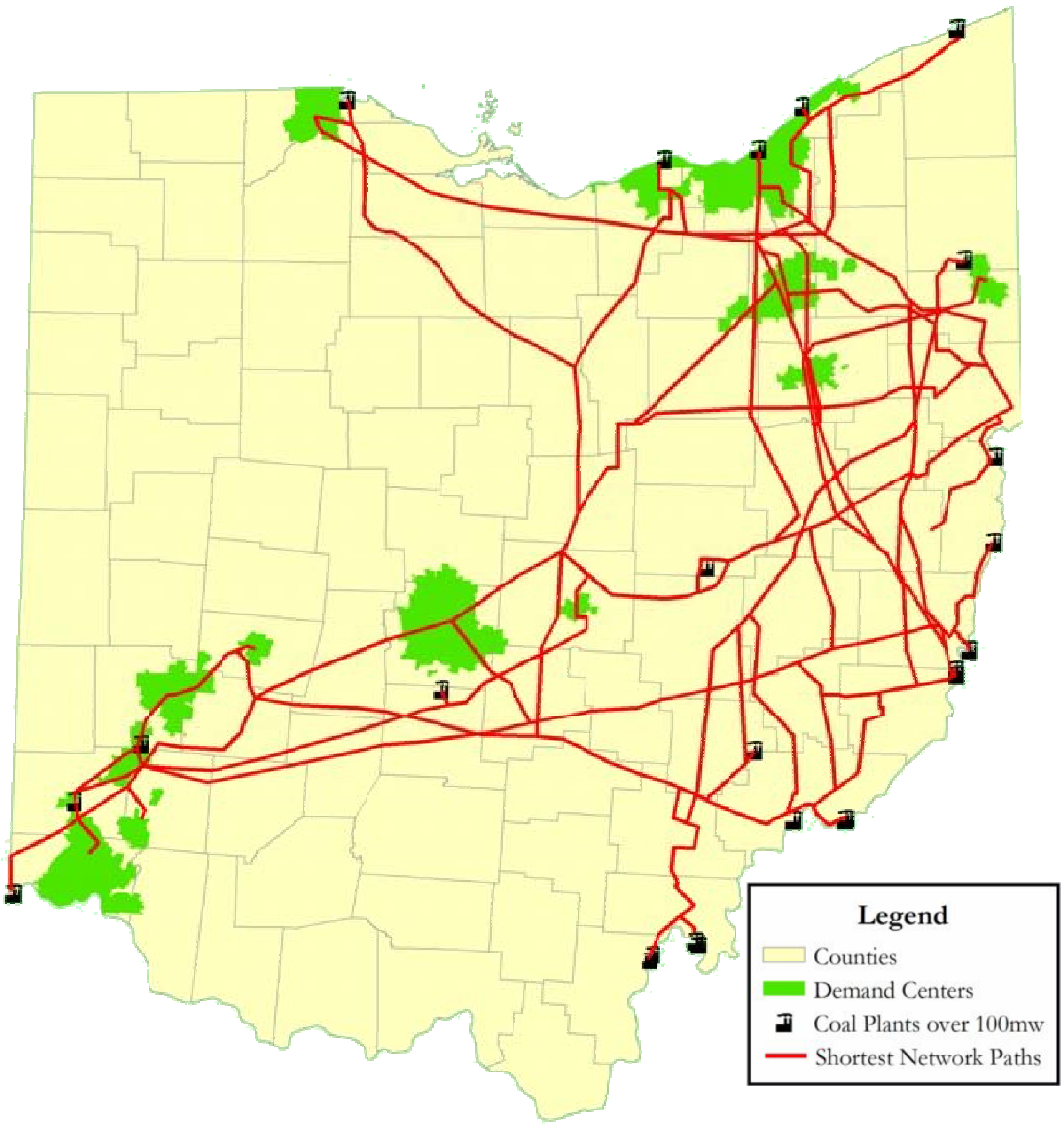


Figure 2.3.12. Nodes and paths for the hydrogen distribution infrastructure network including demand clusters, coal plants and potential hydrogen pipeline locations

Network Cost Minimization

The goal of minimizing network costs is approximated by minimizing the total length of pipeline passing through a specified number of sources and connecting all the sinks. The minimal spanning tree is by definition the shortest connection path to meet the specified criteria and by definition reaches links all of the specified nodes without any loops (or duplicative pipelines).

The optimization routine chooses the shortest path from the sources to all sinks. The sink that is chosen in this shortest path now becomes a "source" and again the shortest path between the new set of sources and remaining sinks is chosen. This process is repeated until all sinks are connected together via pipeline to other sources or sinks. Once the locations of the hydrogen production plants and pipelines are determined (shown in Figure 2.3.13 and Table 2.3.5), the capacity of the hydrogen production plant and flow through the pipelines is determined and costs can be calculated.

Table 2.3.5. Decision table indication which pipelines are built for the minimal spanning pipeline network for one coal plant source.

		Demand Clusters											
		3	**7**	**13**	**16**	**23**	**43**	**48**	**49**	**52**	**57**	**62**	**65**
Coal Plant	**105**	0	0	0	0	**1**	**1**	0	0	0	0	0	0
Demand Clusters	**3**	0	0	0	0	0	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0
	16	**1**	**1**	**1**	0	0	0	0	0	0	0	0	0
	23	0	0	0	**1**	0	0	0	0	0	0	0	0
	43	0	0	0	0	0	0	0	**1**	0	0	0	0
	48	0	0	0	0	0	0	0	0	**1**	0	0	0
	49	0	0	0	0	0	0	**1**	0	0	0	0	0
	52	0	0	0	0	0	0	0	0	0	**1**	0	0
	57	0	0	0	0	0	0	0	0	0	0	**1**	**1**
	62	0	0	0	0	0	0	0	0	0	0	0	0
	65	0	0	0	0	0	0	0	0	0	0	0	0

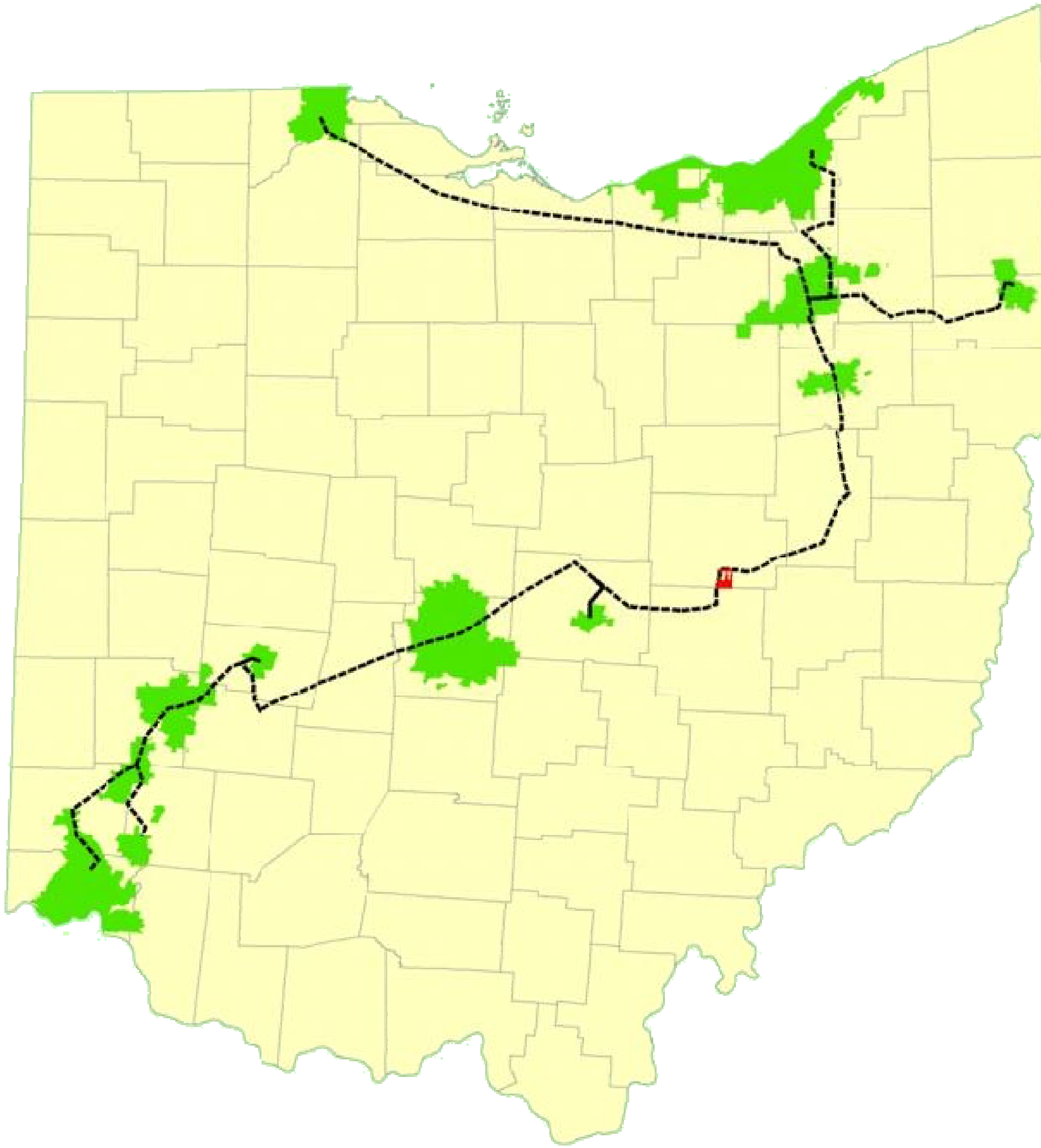


Figure 2.3.13. Layout of the minimum network length for one hydrogen production plant at the 10% hydrogen vehicle market penetration level

Idealized city models

In addition to the central hydrogen production facility and the intercity pipelines, additional infrastructure is required. This includes refueling stations as well as the hydrogen distribution systems within the city gate to supply refueling stations. The number of refueling stations in each demand cluster is calculated from an average sized refueling station and then the idealized city model, described earlier under Task 1.5, is applied to each of the demand clusters to determine intracity distribution network length. From the total hydrogen demand, an estimate is made for the required number of refueling stations within each cluster. The number of stations is related functionally to the length of the hydrogen distribution length and multiplied by the radius of the demand cluster. The equivalent radius is used, which is determined from the calculated area of each demand cluster as identified from GIS. The data for the 10% demand case is shown in Table 2.3.6.

Table 2.3.6. 10% Demand cluster information including intracity distribution pipeline network length

Cluster name	Population	10% H_2 demand (kg/day)	Estimated refueling stations	10% of stations	Cluster Area (km^2)	Equiv City R (km)	Pipe Length (km)
Toledo	374,722	14,740	125	13	329.3	10.2	93
Greater Cleveland Metro Area	1,589,673	63,235	530	53	1242.7	19.9	339
Youngstown	147,732	5,535	50	5	159.8	7.1	42
Cuyahoga Falls	470,162	26,454	157	16	558.4	13.3	134
Canton	168,996	6,853	57	6	170.3	7.4	47
Newark	54,111	3,105	19	2	83.0	5.1	19
Springfield	74,291	3,105	25	3	93.2	5.4	25
Greater Columbus Metro Area	1,043,387	56,281	348	35	958.3	17.5	248
Dayton	425,515	17,145	142	15	440.7	11.8	115
Carlisle	109,448	6,585	37	4	205.0	8.1	42
Mason	81,984	6,380	28	3	130.5	6.4	29
Greater Cincinnati Metro Area	880,316	43,300	294	30	798.2	15.9	212
TOTAL	**5,420,337**	**252,718**	**1,812**	**185**			**1,345**

2.3.5. Early Results for Infrastructure Design and Delivered Cost

The following figure shows the hydrogen cost comparison for on-site and centralized production of hydrogen. The total delivered hydrogen cost ($/kg) in the centralized case is broken down into several categories including the costs associated with the central coal gasification plant, the H_2 transmission pipelines and compressors, the pipeline distribution network within the demand clusters, the refueling stations, and CO_2 pipelines and injection wells. The total delivered costs for the onsite production are not further separated because all of the costs are associated with the refueling station.

Figure 2.3.14 and Table 2.3.7 show that at the 10% level, onsite production is cheaper than centralized production with distribution, whereas at the 50% level, central production is less expensive. The costs are influenced strongly by the extent of the intercity and intracity pipeline distribution lengths and thus are very region specific. In areas with higher hydrogen demand density, the transportation costs will be reduced, while lower demand density will lead to higher transportation costs.

The feedstock costs are significant because of the differences in price for natural gas (assumed to be \$6/MMBTU at the refueling station) and coal prices (approximately \$1.36/MMBTU).

Table 2.3.7. Details of final hydrogen infrastructure for 10% and 50% market penetration levels.

Final Network Details		
Demand Level	10%	50%
Coal Plant	Conesville	Conesville
Coal plant capacity (H_2 flow)	252,718 kg/day	1,975,074 kg/day
Number of clusters	12	39
Length of intercity pipeline	936 km	2656 km
Length of intracity pipeline	1082 km	4452 km
CO_2 sequestration flowrate	4,196 tonnes/day	32,444 tonnes/day
CO_2 emissions	4.4 kg CO_2/kg H_2	4.3 kg CO_2/kg H_2
Total capital cost	\$1.3 billion	\$5.5 billion
H_2 price	\$3.65/kg	\$2.60/kg

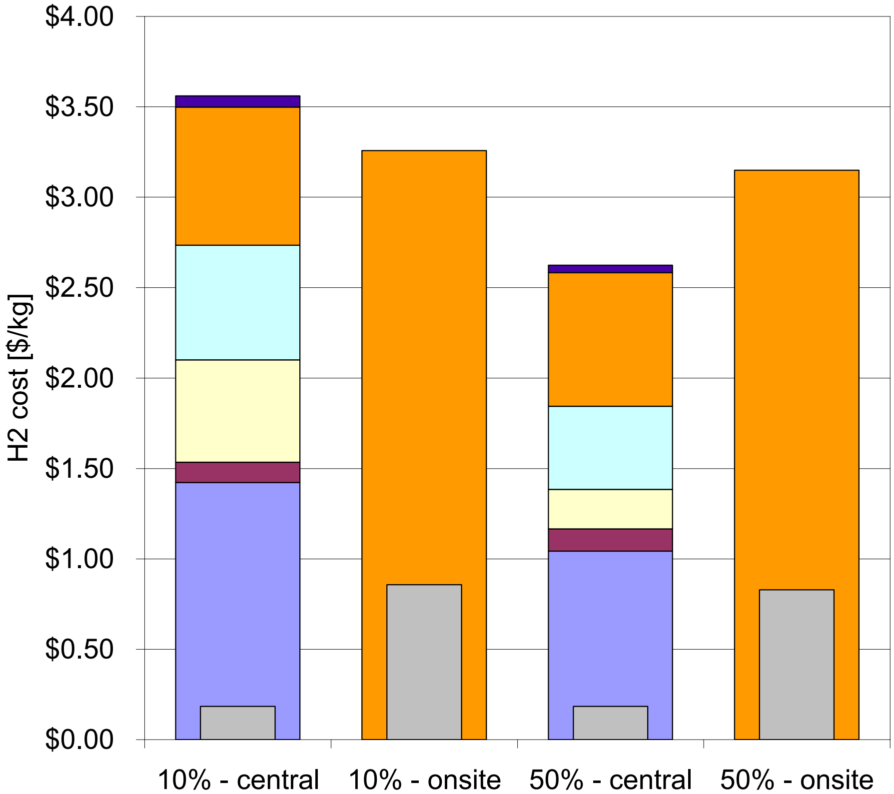


Figure 2.3.14. Costs comparision for central and distributed hydrogen production for the 10% and 50% market penetration levels.

3.0 CONCLUSION

In our research under this contract, we have made significant progress toward understanding the systems aspects of fossil hydrogen systems with CO_2 sequestration, and meeting our objectives for the overall project. Below, we summarize by Task the current status of the project and plans for future work.

3.1. Task 1.0 Implement Technical and Economic Models of the System Components

We have synthesized cost and performance estimates for hydrogen production systems with CO_2 capture, hydrogen pipelines, hydrogen refueling stations, CO_2 pipelines, and CO_2 injection sites. As new results become available we plan to improve these cost and performance estimates.

3.2. Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Network

Studies with a simple analytic model linking one hydrogen production center, one hydrogen demand center and one sequestration site were completed, and papers were presented at conferences. Further, we have extended this model to allow us to calculate the system design and cost as a function of relatively few, easily defined parameters. Inputs to the model include: Geographic factors (Total number of light duty vehicles (LDV) per square kilometer, City size); Market Factors (fraction H2 vehicles in fleet; fraction of all stations serving H2 for customer convenience; LDVs/station; Vehicle use miles/year); Technical Factors (Vehicle Fuel Economy, Cost and performance of infrastructure components, Layout of distribution system). We can estimate for different production and delivery pathways: H2 production capacity needed , number of H2 refueling stations , H2 dispensed per station, geographic density of H2 stations, cost of entire system from production through delivery for different production and delivery options, levelized delivered cost of hydrogen.

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we explored use mathematical programming methods to find the lowest cost system design. We have looked at several nonlinear programming approaches to modeling CO_2 pipeline disposal systems, and used a minimum spanning tree approach to model hydrogen pipelines.

3.3. Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

In this task, we studied how H_2 and CO_2 infrastructures might develop, in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. To better visualize our results, we use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks.

We have developed a GIS data base showing potential demand for hydrogen, location of existing infrastructure, including current coal-fired power plants and major road and railroads (which are potential rights of way for hydrogen or CO_2 pipelines) and possible sites for CO_2 sequestration. We used this database to estimate costs for a coal based hydrogen infrastructure, corresponding to different levels of hydrogen use in Ohio.

4.0 FUTURE WORK

As an extension of this work, we are proposing a three-year research program to assess possible transition strategies from today's energy system toward one based on large-scale fossil energy systems co-producing hydrogen, electricity, and possibly other fuels, coupled with capture and sequestration of CO_2. This will be accomplished by using a variety of analytic and simulation methods for studying the entire system in an integrated way. The project will make use of geographic information system (GIS) data to develop geographic-specific case studies for various regions of the United States. The proposed regional modeling studies will interface closely with the USDOE's Carbon Sequestration Regional Partnership program.

Key Questions

- What are the technical, geographic, and market conditions that must be met for fossil-derived hydrogen with carbon capture and storage to compete in future energy markets. What are the most important technical goals that must be met for the components and for the entire system?

- What is the impact of regional specific/geographic issues. Which areas of the US are likely to become adopters of fossil hydrogen energy with CO2 sequestration. What is the effect of existing infrastructure on the design of a future fossil energy system?

- How do multi-product strategies impact the economics and transition strategies?

- What is the potential impact of policy (for example, how would a carbon tax or other polices impact economics?)

- What are a range of plausible scenarios for future development of fossil hydrogen systems with CO_2 capture and sequestration?

Specific future tasks are described below.

4.1. Task 1. Improve and Extend Models of Fossil Hydrogen Energy Systems with Carbon Capture and Sequestration

Task 1.1. Incorporate new information that is now becoming available, and will be developed over the next few years, as input to our models.
Task 1.2. Extend the techniques we have developed to model regional energy system transitions.

4.2. Task 2. Understand The Implications Of New Carbon Capture And Sequestration Technologies For Widespread Use Of Fossil Hydrogen As An Energy Carrier

Task 2.1. Understand implications of alternative CCS technologies for fossil hydrogen energy, considering natural gas and coal-based hydrogen plants. (NETL is sponsoring technical/economic studies providing up-to-date information on current and future technologies for CCS for various applications. These studies will form the basis for the analysis, which will be carried out in collaboration with Princeton researchers.)

Task 2.2. Study how current fossil energy plants might evolve over time to reduce carbon emissions. Consider conversion of current coal-fired power plants to coal gasification-based energy complexes, producing both electricity and hydrogen, with CO_2 capture and sequestration.

4.3. Task 3. Carry out a series of regional case studies of a transition to fossil hydrogen energy systems with CO2 capture and sequestration.

Assess possible transition paths from the present "fleet" of fossil energy plants toward widespread use of fossil-derived energy carriers (hydrogen and electricity) with CO_2 capture and sequestration. Through GIS-based case studies, we will seek to understand how a transition might occur in different regions. The underlying question is "What are the necessary conditions for successful transition to a fossil hydrogen economy?"

Task 3.1. Understand the current "fleet" of fossil power plants and other energy production facilities (refineries) that might become part of a future low carbon emitting energy system. In collaboration with NETL, implement GIS data with this information.

Task 3.2. Understand the potential for regional CO_2 sequestration, using data being developed by NETL under the Carbon Sequestration Regional Partnership Program. Use regional GIS databases on characteristics of potential CO_2 sequestration sites, including depleted oil and gas fields, deep saline aquifers and coal beds. Incorporate GIS layers for regional CO_2 sequestration sites into our models.

Task 3.3. Develop a series of integrated GIS databases for various regions within the US, including estimates of energy demands, location and characteristics of existing fossil energy plants and other infrastructure (such as rights of way, gasoline refueling sites and roads), information on possible future supplies, location and characteristics of CO_2 sequestration sites.

Task 3.4. Use the models and techniques developed in Phase I and Task 1 to analyze the economics of fossil hydrogen systems in various regions in the US.

Task 3.5. Develop a national assessment of the long term potential for fossil hydrogen with CO_2 sequestration for the United States. Starting from today's fossil energy system, assess transition paths.

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LIST OF ACRONYMS AND ABBREVIATIONS

CMI	Carbon Mitigation Initiative. Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor Company to find solutions to global warming and climate change.
FCV	fuel cell vehicle
GIS	geographic information system
GJ	gigajoule (= 10^9 Joules)
LDV	light duty vehicle
SMR	steam methane reforming.
USDOE	United States Department of Energy

APPENDICES

APPENDIX 0. CONVERSION FACTORS AND ECONOMIC ASSUMPTIONS

1 GJ (Gigajoule) = 10^9 Joules = 0.95 Million BTU
1 EJ (Exajoule) = 10^{18} Joules = 0.95 Quadrillion (10^{15}) BTUs

1 million standard cubic feet (scf)
= 26,850 Normal cubic meters (m_N^3)
= 343 GJ (HHV)

1 million scf/day = 2.66 tons/day
= 3.97 MW H_2 (based on the HHV of hydrogen)

1 scf H_2 = 343 kJ (HHV) = 325 BTU (HHV); 1 lb H_2 = 64.4 MJ (HHV) = 61.4 kBTU (HHV) = 187.8 scf
1 m_N^3 = 12.8 MJ (HHV); 1 kg H_2 =141.9 MJ (HHV) = 414 scf

1 gallon gasoline = 130.8 MJ (HHV) ; 115,400 BTU/gallon (LHV)
Gasoline Heating value = 45.9 MJ/kg (HHV) ; 43.0 MJ/kg (LHV)
$1/gallon gasoline = $7.67/GJ (HHV)

BASE CASE ECONOMIC ASSUMPTIONS

In estimating levelized costs of hydrogen and CO_2, we use the “base case” economic assumptions in Table 1.

Table 1. Economic assumptions

CRF = annual capital charge rate	0.15
Annual non-fuel O&M as a fraction of installed capital cost	0.04
Capacity factor	80%
Natural Gas Price ($/GJ) HHV	3.75
Coal Price ($/GJ) HHV	0.95
Electricity Price ($/kWhe)	0.036
Off-peak Electricity ($/kWhe)	0.03
Biomass ($/GJ)	2.0

Feedstock costs are USDOE projections for 2020 costs to electric utilities: $3.75/GJ for natural gas and $0.95/GJ for coal (US DOE EIA 2002). The electricity price of $0.036/kWh is based on electricity produced in a natural gas turbine combined cycle, assuming a natural gas price of $3.75/GJ (Williams 2002.) Costs are in constant 2001 US dollars.

In Table 2, we summarize the assumptions and range of parameters considered for fossil hydrogen systems with CO_2 sequestration. We consider energy systems producing H_2 and electricity from fossil feedstocks (natural gas or coal), with capture of CO_2, compression to 15 MPa for pipeline transmission as a supercritical fluid, and injection into an underground reservoir. H_2 is compressed to 6.8 MPa (1000 psi) for on-site storage, pipeline transmission and local distribution to H_2 vehicles. We consider H_2 plants with an output capacity of 250-1000 MW of H_2, higher heating value basis (150-600 tonnes H_2/day). At an assumed 80% capacity factor, annual H_2 production is 6.3-25.2 million GJ (45,000-178,000 tonnes)—enough to fuel 0.25-1 million H_2 fuel cell cars having a fuel economy of 4 liters gasoline per 100 km (60 miles per gallon) and driven 25,000 km (15,000 miles) per year (the US average). Hydrogen refueling stations are assumed to dispense 2500 kg of hydrogen per day or about 1 million standard cubic feet per day. This would be enough to support a fleet of about 4000 cars.

In Table 3, we compare hydrogen demands with hydrogen supply options. (Large demands and large supplies are shown in boldface type. For large fossil supplies, we indicate the amount of CO2 that could be captured during hydrogen production.) Large

Table 2. Parameter Ranges Considered in this Study for Fossil Hydrogen Systems with CO2 Sequestration

Hydrogen Production Capacity Range at Fossil Energy Complex	250 – 1000 MW H_2 (HHV) (150-600 tonnes H_2/day) (62-252 million scf H_2/d)
Associated CO_2 production Range	
Natural gas -> H2 Plant, 85% of CO_2 captured	51-204 tonne CO_2/h
Coal -> H2 Plant, 90% of CO_2 captured	101-406 tonne CO_2/h
H_2 Plant Capacity Factor	80%
H_2 Buffer Storage Capacity at Production Site	1/2 day's production
H_2 Local Distribution Pipeline	
H_2 Inlet Pressure	6.8 MPa (1000 psi)
H_2 Outlet Pressure (at refueling station)	>1.4 MPa (200 psi)
Pipeline capital cost ($/m)	$155-622/m ($0.25-1 million/mile)
Hydrogen Demand	
1 H2 Fuel Cell Car (60 mpgge, 15,000 mi/y)	0.6 kg/day
1 H2 Bus (7 mpgge, 50,000 mi/yr)	20 kg/day
H_2 Refueling Stations	
Hydrogen dispensed per day	2.4 tonne/day (1 million scf/d)
Dispensing Pressure to Vehicle	6000 psia
Onboard H_2 Storage Pressure	34.5 MPa (5000 psia)
CO_2 Pipeline	
CO_2 Pipeline flow rate (range)	1,000-10,000 tonnes/day
Inlet Pressure (at H_2 Plant)	15 MPa
Outlet Pressure (at Sequestration Site)	10 MPa
Pipeline Length (range)	10-1000 km
CO_2 Sequestration Site	
Well depth	2 km
Permeability (milliDarcy)	> 50 milliDarcy
Reservoir Layer Thickness	50 m
Maximum flow rate per well	2500 tonnes/day/well

Table 3. Hydrogen Supply and Demand

H_2 Demands	***kg H_2/day***			
1 H_2 FC car (60 mpg, 15,000 mi/y)	0.6			
1 H_2 FC Bus (7 mpge, 50,000 mi/y)	20			
100-1000 H_2 FC car fleet cars (60 mpg, 20,000 mi/y)	80-800			
100 –1000 FC Buses	2000-20,000			
100,000 cars (~1% of cars in LA)	**60,000**			
1 million cars (~10% of cars in LA)	**600,000**			
10 million cars (~100% cars in LA)	**6,000,000**			
H_2 Supplies	***kg H_2/day***	***Size of H_2 FC car fleet supported***	***Size of H_2 FC Bus fleet***	***CO2 Captured from Large Fossil H2 Plants (tonne/d)***
6.0 Compressed H_2 gas truck (1/day)	420	700	21	n.a
7.0 Liquid H2 truck (1/day)	3600	6000	180	n.a
8.0 Onsite electrolyzer	2.4-2400	4-4000	0.12-120	n.a.
9.0 Onsite steam methane reformer (SMR)	240-4800	400-8000	12-240	n.a
Industrial scale steam methane reformer	**48,000-480,000**	**80,000-800,000**	**2400-24,000**	**400-4000**
Coal gasifier H_2 plant w/CO_2 seq.	**150,000-600,000**	**250,000-1,000,000**	**7500-30,000**	**2500-10,000**
H_2 from 10% of NG Flow into LA	**1,700,000**	**3 million**	**85,000**	**15,000**
H_2 from 1000 MW off-peak power	**240,000**	**400,000**	**12,000**	**n.a**

APPENDIX A. MODELING THE FOSSIL ENERGY COMPLEX

In this section, we describe simplified models of fossil hydrogen production plants with CO2 capture. We consider hydrogen production from natural gas and from coal.

In the fossil energy complex, a synthetic gas (or syngas) is produced via gasification of coal or steam reforming of methane. The syngas undergoes a water gas shift reaction to increase the hydrogen content. CO_2 is removed from the syngas using a separation system (such as an amine scrubber, a physical adsorption system like Selexol or a pressure swing adsorption system or PSA) and is available at near atmospheric pressure. CO_2 is then compressed from capture pressure to a supercritical state and pumped to pipeline transmission pressures of 15-20 MPa (150-200 bar). In some cases, electricity is co-produced with hydrogen. Simplified diagrams of the process from producing hydrogen from natural gas and coal shown in Figures 3 and 4.

The term "CO_2 capture" generally refers to CO_2 separation and compression prior to pipeline transport to a sequestration site. In this report, we disaggregated the costs of CO_2 separation as distinct from those of CO_2 compression. This allows us to vary the parameters controlling compression costs (such as CO_2 outlet pressure and electricity cost) separately from the plant design, to examine the impact of CO_2 outlet pressure on cost.

As a basis for modeling natural gas-based hydrogen plants, we use a recent study by Foster Wheeler (1996) and data from Air Products and Chemicals (Ogden 1999). As part of the CMI, researchers at Princeton have developed ASPEN-plus process and cost models for a variety of coal-based systems co-producing H_2 and electricity with CO_2 capture (Kreutz, Williams, Socolow and Chiesa 2002), that include alternative options for sulfur removal and disposal. We use the results of these detailed process design studies to produce a simplified model for the cost and performance of fossil H_2 plants as a function of scale, feedstock and process design.

Hydrogen Production from Natural Gas

For natural gas steam methane reforming plants, we use cost and performance estimates from a recent study by Foster Wheeler (Foster Wheeler 1996). Hydrogen is produced at 60 bar output pressure, at the rate of 1000 MWth on a higher heating value basis (this is equivalent to 600 tonnes H2 per day or 252 million standard cubic feet per day). Two cases are shown: one with CO_2 vented and one with capture of 85% of the CO_2. The CO_2 is compressed to 112 bar. Capital costs for these plants are given in Table 4.

From the capital costs in Table 4, the levelized cost for hydrogen production with and without CO_2 separation can be estimated, given the natural gas price, other operation and maintenance costs, the capacity factor and the capital recovery factor (CRF) (see Table 1). The levelized cost of hydrogen production from natural gas with and without CO_2 sequestration is shown in Table 5. CO2 sequestration adds about 25% to the hydrogen production cost.

Another estimate of the cost of CO_2 separation during hydrogen production is based on data from engineers at Air Products and Chemicals (Ogden 1999) for a vacuum swing adsorption (VSA) CO_2 capture system (see Table 6). This type of system could be added as a retrofit to capture CO_2 at an existing steam methane reformer plant. The cost of CO_2 separation (not including compression) is estimated to be about \$0.36-0.38/GJ H_2 on a HHV basis, or about \$13.0-13.7/tonne CO_2. (This is based on capture of about
The total capital cost was obtained by multiplying the equipment cost by 1.40 to account for taxes, freight, installation, owner's costs and engineering.
The levelized cost is found assuming a capital recovery factor of 15%, annual non-fuel O&M costs of 4%, and an 80% capacity factor.

56% of the carbon input in the natural gas feedstock or 28 kg CO_2 captured/GJ H_2 HHV. Electricity for the vacuum swing adsorption system accounts for about 45% of the cost and capital and non-electricity O&M about 55%). CO_2 is available at 0.1 MPa, and ambient temperature. The cost of CO_2 separation is less than that with the Foster-Wheeler system, but a substantially lower fraction of the carbon is captured (56% versus 85%).

Hydrogen and Electricity from Coal Gasification

Kreutz, Chiesa and Williams (2002) have modeled the performance and economics of systems for co-producing hydrogen and electricity from gasified coal, with separation and capture of 85% of the CO_2 emissions. (A simplified process flow diagram for the system is shown in Figure 4.) A variety of cases were considered with and without CO_2 capture, varying the gasifier pressure and the treatment of sulfur (see Table 7).

Table 4. Cost and Performance of Natural Gas Based Hydrogen Production Plants w/ and w/o CO_2 Capture (Foster Wheeler 1996)

	CO_2 vented	**CO_2 captured**
Hydrogen Production MWth (at 60 bar output pressure)	1000	1000
First law efficiency HHV basis	81%	78%
CO_2 emission rate (kgC/GJ H_2)	17.56	2.74
CO_2 Sequestration Rate (tonne/h)	0	204
Capital Investment (million $)		
Reformer	48.65	67.90
Purification	23.65	58.08
CO_2 Compression	0	35.67 (for an estimated CO_2 compressor power of 18.6 MWe)
Other	123.95	174.67
Subtotal	**196.25**	**336.32**
Subtotal (excluding CO_2 compressor)	196.25	300.65
Added costs		
Engineering, construction management, commissioning, training	9.13	16.94
Catalysts and chemical	8.75	9.00
Clients costs	24.00	28.00
Contingency	23.81	39.03
TOTAL INSTALLED CAPITAL COST (million $)	**261.94**	**429.3**
TOTAL INSTALLED CAPITAL COST (excluding CO_2 compressor)	261.94	384.0 (to get the installed capital cost the subtotal without the CO2 compressor has been scaled using the same ratio as subtotal for the total plant)
Incremental Installed Capital Cost for CO_2 Capture (million $)		167.36
Incremental Installed Capital Cost for CO_2 Capture excluding CO_2 compression (million $)		122.06

Table 5. Levelized cost of hydrogen production from natural gas with and without CO_2 separation and compression

Levelized Cost of H_2 Production with CO_2 separation, excluding CO_2 compression ($/GJ H_2) HHV	**CO_2 vented**	**CO_2 captured**
Capital (excluding CO_2 compression)	1.56	2.28
Natural Gas Feedstock	4.20	4.36
Non-fuel O&M	0.42	0.61
CO2 Compressor Capital and O&M	n.a.	0.34
CO2 Compressor Electricity	n.a	0.27
Total (including CO2 compression)	n.a.	7.86
Total (excluding CO_2 compression)	6.17	7.25
Incremental cost of CO_2 separation and compression	**n.a.**	
$/GJ H2 HHV		1.69
$/tonne CO_2		29.8
Incremental cost of CO_2 separation only (excluding CO2 compression)	**n.a.**	
$/GJ H2 HHV		1.08
$/tonne CO_2		19.0

Table 6. Cost of CO_2 Separation During Hydrogen Production Via Large Scale Retrofit to Steam Methane Reforming Plant

Hydrogen Production	80 million scf/day 193 tonnes/day 27,440 GJ/day HHV
CO_2 Production	850 ton/day (771 tonnes/day) 0.18 scf CO2/scf H2 3.99 kg CO2/kg H2
CO_2 Purity	95%
CO_2 pressure	1 atm
Power required for VSA Compressor	3400 kW
Equipment Cost of PSA only	$4-4.5 million
Equipment Cost of VSA only, including compressor	$6-6.6 million
Added factor for freight, taxes, installation	15%
Owner's costs and engineering	25%
Total installed capital cost for PSA only (no CO_2 recovery)[a]	$5.6-6.3 million
Total installed capital cost for PSA + VSA (CO_2 recovery)	$14-15.5 million
Incremental installed capital cost for CO_2 recovery	$8.4-9.2 million
Incremental Levelized Hydrogen Production Cost for CO_2 Separation[b]	
Incremental Capital Cost for VSA	$0.16-0.17/GJ HHV H2
Incremental Non-fuel O&M for VSA	$0.04-0.05/GJ HHV H2
Cost for VSA Compressor Power @ 5.6 cents/kWh	$0.17/GJ HHV
Total Incremental Cost for CO_2 Separation in VSA	$0.37-0.38/GJ HHV $13.0-13.7/tonne CO2

Source: Bob Moore, Air Products and Chemicals. Inc., private communications, May 1997.

Table 7. Cases Considered for Hydrogen and Electricity Production from Coal

CASE	Gasifier Pressure	Sulfur removal	Sequestration
Hi P, No CO_2 Seq	120 bar	Yes	No
Hi P, CO_2 Seq	120 bar	Yes	CO_2 only
Hi P, CO_2 + H_2S Co-Seq	120 bar	No	CO_2 + H_2S
Lo P, No CO_2 Seq	70 bar	Yes	No
Lo P, CO_2 Seq	70 bar	Yes	CO_2 only
Lo P, CO_2 + H_2S Co-Seq	70 bar	No	CO_2 + H_2S

For each case in Table 7, the sizes, capital costs and O&M costs of the various fossil energy plant components were estimated, along with the energy consumption, hydrogen and electricity production, and carbon emissions (Kreutz 2002). From these studies, we can examine the impact of plant design on the economics of H_2 production and CO_2 capture (Table 8). This is complicated, because the plant design changes in several ways, depending on whether CO_2 is captured, and whether sulfur compounds are separated.

With CO_2 capture (versus CO_2 venting), additional electricity can be co-produced at the plant, for a given hydrogen output. Although some of this electricity is used in the plant for CO2 compression, there is still excess electricity produced, above the plant demands. A credit is claimed for by-product electricity.

When co-sequestration of H_2S and CO_2 is done, sulfur removal equipment is not needed, so there are savings on capital costs, compared to a case with sulfur removal and CO_2 separation. As compared to the case where CO_2 is vented, the capital cost of the fossil energy complex is almost unchanged when H_2S is co-sequestered with CO_2, when CO_2 compressor costs are included. The savings on sulfur removal equipment approximately balance the extra costs for separating and compressing CO_2.

For a case with sulfur removal and CO_2 capture, the plant capital costs and levelized cost of hydrogen are higher than the case where CO_2 is vented.

Figure 5 shows the levelized cost of hydrogen production (in $/GJ) from natural gas and coal with and without CO_2 capture. We assume that each plant has a hydrogen output of 1000 MWth. Each component contributing to the cost is shown (e.g. capital costs, feedstock costs, O&M and by-product credits). For coal plants, by-product electricity is a factor in determining the hydrogen cost. (We show a by-product credit for the total amount of electricity produced. In cases with CO_2 compression, some of this credit is applied to the cost of compressor power, so the net power exported is the by-product electricity minus the compressor electricity.) The cost of hydrogen from natural gas is increased by about 25% with CO_2 capture. The cost of hydrogen from coal is about the same with co-sequestration of CO_2 and H_2S.

For our assumptions, the cost of hydrogen production from coal is slightly less than for hydrogen from natural gas, with or without CO_2 sequestration.

Sensitivity to the Electricity Cost

The cost of hydrogen from coal is sensitive to the assumed cost of electricity. For the cases shown in Figure 5, electricity is valued at 3.6 cents/kWh. If electricity is worth more than this, the by-product credit is increased, and the cost of hydrogen from coal is reduced by about \$0.2/GJ for each added cent per kWh of electricity cost.

Effects of Scale on the Cost of H2 Production and CO2 Separation in Fossil Energy Complexes

The cost of hydrogen production and CO_2 separation depend on the plant size. We assume that process equipment capital costs depend on size according to a power law,

$$\text{Cost}(C) = \text{Cost}(C_o) \times (C/C_o)^{\alpha}$$

where Co is a reference capacity, Cost(Co) is the cost at capacity Co, C is the actual capacity, and the power α is typically in the range 0.3-1, depending on the technology.

For hydrogen from coal, Kreutz (2002) estimated that the capital cost of the plant scales approximately as $\alpha = 0.828$, where Co = 863 MWth H_2 output. For hydrogen from natural gas, we assume that for capital equipment $\alpha = 0.7$, except for CO_2 compressors, which are assumed to scale as $\alpha = 0.3$ (see section on CO_2 compressors below and in Appendix C).

The cost contribution of capital to the levelized hydrogen scales as

$$PH_2(C) = PH_2(C_o) \times (C/C_o)^{\alpha-1}$$

In Table 9, the cost contributions of capital and non-fuel O&M to the levelized hydrogen cost scale as the 1-α power, while the other contributions (for compressor power, coal feedstock) are unchanged with scale. The levelized cost of hydrogen can be calculated as a function of plant size for coal-based and natural gas based hydrogen plants (see Tables 9 and 10). The cost of hydrogen increases at smaller plant sizes. For example, for a natural gas based hydrogen plant with CO_2 capture, the cost of hydrogen increases from \$7.86/GJ to \$9.91/GJ, about 27%, as the plant size decreases from 1000 to 250 MWth hydrogen output.

In Figure 6, we plot the levelized cost of hydrogen production from natural gas and coal as a function of plant size, assuming the CO2 is vented. In Figure 6, we show how the cost of H_2 production with CO_2 separation varies with plant size for natural gas based and coal based hydrogen plants. CO_2 capture is costlier in the natural gas based hydrogen plant than in the coal plant. This is true even though more carbon must be processed in the coal plant, because of the electricity byproduct credit for electricity produced at the coal plant.

Because coal plants are more capital intensive than natural gas plants, the hydrogen cost is slightly more sensitive to scale for coal.

Table 8. Cost and Performance for Hydrogen and Electricity Production from Coal (70 bar gasifier) (Kreutz 2002)

	CO_2 Vented, sulfur removal	CO_2 Capture, sulfur removal	CO_2 capture, co-sequestration of CO_2 and H_2S
H2 Production MWth	1000	1000	1000
Electricity production (net power out) MWe	52.2	30.9	30.9
First law efficiency HHV	0.736	0.705	0.705
CO2 emission rate (kgC/GJ H2 HHV)	35.6	2.61	2.61
CO2 captured (tonne/h)	0	437.4	437.4
Installed Capital Cost of Fossil Energy Complex (million $) = 1.16 x Bare Capital Equipment Cost			
H2 Plant excluding CO_2 compressor	658.6	707.2	612.6
CO2 Compressor	0	51.7 (36.6 MWe)	51.7 (36.6 MWe)
H2 Plant including CO2 Compressor	658.6	758.9	663.4
Incremental plant cost for CO2 capture including CO2 compression	0	100.3	4.8
Incremental plant cost for CO2 separation excluding CO2 compression	0	48.7	-46.0
Levelized Cost of H2 Production ($/GJ HHV)			
Plant capital except CO2 Compressor	3.92	4.20	3.64
Non-fuel O&M	1.04	1.12	0.97
Feedstock cost	1.26	1.32	1.32
CO2 compression capital + O&M		0.39	0.39
CO2 compressor power		0.37	0.37
Electricity credit incl comp pwr	-0.52	-0.675	-0.675
Total without CO2 compression	5.70	5.97	5.23
Total with CO2 compression		6.73	6.01
Incremental Cost of CO2 Capture, excluding CO2 compression			
$/GJ H2 (HHV)		0.27	-0.44
$/tonne CO2		2.22	-3.56
Incremental Cost of CO2 Capture, including CO2 compression			
$/GJ H2 (HHV)		1.02	0.31
$/tonne CO2		8.43	2.56

Table 9. Cost of Hydrogen Production from Coal as a Function of Plant Size

	CO_2 Vented, sulfur removal			CO_2 Capture, sulfur removal			CO_2 capture, co-sequestration of CO_2 and H_2S		
H2 Production MWth	1000	500	250	1000	500	250	1000	500	250
CO2 captured (tonne/h)				437.4	218.7	109.4	437.4	218.7	109.4
Levelized Cost of H2 Production ($/GJ HHV)									
Plant capital except CO2 Compressor	3.92	4.41	4.97	4.20	4.74	5.34	3.64	4.10	4.62
Non-fuel O&M	1.04	1.18	1.33	1.12	1.26	1.42	0.97	1.09	1.23
Feedstock cost	1.26	1.26	1.26	1.32	1.32	1.32	1.32	1.32	1.32
CO2 compression capital + O&M				0.39	0.63	1.03	0.39	0.63	1.03
CO2 compressor power				0.37	0.37	0.37	0.37	0.37	0.37
Electricity credit incl comp pwr	-0.52	-0.52	-0.52	-0.68	-0.68	-0.68	-0.68	-0.68	-0.68
Total without CO2 compression	**5.70**	**6.33**	**7.03**	5.97	6.65	7.41	5.26	5.84	6.50
Total with CO2 compression				**6.73**	**7.64**	**8.80**	**6.01**	**6.84**	**7.89**
Incremental Cost of CO2 Capture, excluding CO2 compression									
$/GJ H2 (HHV)				0.27	0.32	0.37	-0.44	-0.48	-0.53
$/tonne CO2				2.22	2.64	3.07	-3.65	-3.98	-4.38
Incremental Cost of CO2 Capture, including CO2 compression									
$/GJ H2 (HHV)				1.02	1.32	1.77	0.31	0.51	0.86
$/tonne CO2				8.43	10.9	14.5	2.56	4.24	7.08

Table 10. Cost of Hydrogen Production from Natural Gas as a Function of Plant Size

	CO_2 Vented			CO_2 Captured		
H2 Production MWth	1000	500	250	1000	500	250
CO2 captured (tonne/h)	0	0	0	204	102	51
Levelized Cost of H2 Production ($/GJ HHV)						
Plant capital except CO2 Compressor	1.56	1.92	2.36	2.28	2.81	3.46
Non-fuel O&M	0.41	0.50	0.62	0.61	0.75	0.92
Feedstock cost	4.20	4.20	4.20	4.36	4.36	4.36
CO2 compressor capital + non-electric O&M				0.34	0.55	0.90
CO2 compressor power				0.27	0.27	0.27
Total without CO2 compression	6.17	6.63	7.19	7.25	7.92	8.74
Total with CO2 compression				7.86	8.74	9.91
Incremental Cost of CO2 Separation only, excluding CO2 compression						
$/GJ H2 (HHV)				1.08	1.29	1.55
$/tonne CO2				19.06	22.81	27.43
Incremental Cost of CO2 Capture, including CO2 separation and compression						
$/GJ H2 (HHV)				1.69	2.11	2.72
$/tonne CO2				29.82	37.32	48.03

APPENDIX B. CO_2 COMPRESSION AT THE FOSSIL ENERGY COMPLEX

The power required for CO_2 compression can be approximated by the formula for isentropic compression of a gas in a multi-stage compressor (Christodoulou 1984):

P_{cm}=

$$Q \times (P_b/T_b) \times (T_1/n_c) \times Z_{ave} \times [N\gamma/(\gamma-1)] \times [(P_{cout}/P_{cin})^{[(\gamma-1)/N\gamma]} - 1]/1000 \qquad [B.1]$$

where:

P_{cm} = compressor power requirement (kW)
Q = gas flow rate in Nm^3/s
P_b = reference pressure = 101,300 Newtons/m^2 (atmospheric pressure)
T_b = reference temperature = 298^oK
T_1 = average gas temperature = 313^oK (40 C)
P_{cin}=inlet pressure to compressor = 0.1 MPa = $P_{plantout}$
P_{cout}=outlet pressure from compressor = 15.0 MPa
N = number of compressor stages = 5
n_c = compressor efficiency = 70% for large (pipeline scale) CO_2
Z_{ave}= average compressibility = [Z(Pin) + Z(Pout)] /2 = 0.625 for CO_2
γ = ratio of specific heats
(for hydrogen = 1.41, for methane = 1.30, for CO_2 = 1.289)

This formula gives results that closely match those from more detailed calculations by Chiesa and Kreutz at Princeton University. The power for compression is about 6% of the electrical output of a coal fired power plant with pre-combustion CO_2 capture (Kreutz 2001).

Capital Cost of CO_2 Compressors

A wide range of capital costs for CO_2 compressors have been reported in the literature.

Hendriks estimated the cost of a 500 tonne/h CO_2 compressor to be $730/kWe (Hendriks 1994).

Researchers at Argonne National Laboratory (in R. Doctor, et al. “Hydrogen Production and CO_2 Recovery, Transport and Use from a KRW Oxygen Blown Gasification Combined Cycle System,” ANL , May 1999, Table 7.3) estimated the installed costs for 3-stage CO_2 compressors operating from 50 to 2100 psia, for several CO_2 flow rates. In one case, each stage was estimated to require a power of 4276 hp = 3.19 MWe and the total installed cost for each stage is $2.734 million. The total power required is 9.57

MWe and the total cost is $8.2 million. This gives a capital cost of $857/kWe. Capital costs were also given for a smaller capacity compressor (6.52 MWe), costing $1048/kWe.

Power requirement kWe	$	$/kWe
9570	8.20 million	857
6521	6.84 million	1048

In an earlier report Doctor 1994 gives a lower capital cost estimate for compressors.

CO2 Flow rate (million scf/d)	Capital Cost for Compressor and Drying $/kW	Power Req. (MWe)
13354	392	82
2671	457	16
1335	548	8.2

Foster Wheeler (1996) estimated considerably higher capital costs for CO_2 compressors. For a CO_2 compressor from 1 to 110 barg, F-W estimated installed equipment costs at two flow rates. I estimated the power requirements for CO_2 compression at these pressures and flow rates using the equations in the previous section (power requirements were not explicitly given in F-W study). The specific costs ($/kW) are in the range $1900-2500/kW , more than twice Doctor's estimate.

CO_2 Flow rate (tonne/d)	Power Requirement (MWe) (calculated using equations in previous section)	Capital Cost (million $)= bare equip. cost x 1.3 for engineering, contingency, etc.	$/kWe
4903	18.6	35.7 x 1.3	2493
15,658	59.6	88.2 x 1.3	1923

In a recent study by the Carbon Capture Project (CCP 2000), the capital cost of CO_2 compressors for compression from 1 to 80 bar was estimated at several flow rates

CO2 Flow rate	Power	Capital Cost	$/kWe

(tonne/d)	Requirement (MWe) (calculated using equations in previous section)	installed (million $) (includes factor of 1.848 for engineering, contingencies, etc.	
2599	9.1	13.9	1518
5471	19.2	17.0	902
10,192	35.8	20.7	583

Figure B.1 shows the various estimates for compressor installed capital cost ($/kWe) plotted versus CO_2 flow rate. There is a wide range of costs, which highlights the need to get better cost estimates. We are in the process of obtaining these from various sources.

In the calculations that follow, we use the CCP CO_2 compressor capital cost estimates. The capital costs fit reasonably well to the following expressions:

CO_2 Compressor capital cost = \$13.86 x 10^6 x (flow rate in tonnes CO_2/d/ 2599)$^{0.3}$

or (using power requirements calculated using the equations in the previous section)

CO_2 Compressor capital cost ($/kWe)
= \$1518/kW x [9130/compressor power(kWe)]$^{0.7}$

The compressor lifetime is taken to be 20 years. The capacity factor of the system is taken to be 80%. The levelized cost of CO_2 compression is then

Levelized Cost of Compression ($/tonne CO_2) =
(CRF + O&M) x
Pcm(kW) x \$1518/kW x [9130/Pcm(kWe)]$^{0.7}$/(8760 x 0.8 x tonnes CO_2/year)
\+ Pelec ($/kWh) x Pcm(kW)/ (tonnes CO_2/h) [B.2]

Where:

tonnes CO_2/year =
Q (Nm^3/s) x 3.17 x 10^7 sec/year x 1.965 kg CO_2/Nm^3/(1000 kg/tonne)

And the values for CRF, O&M and Pelec are given in Table 1 of the main text.

The levelized cost of compression is plotted in Figures B.2 and B.3 for various compressor sizes and pressure differences, for CO_2 flows from a 1000 MW H2 plant producing 437 tonnes CO_2/h (H_2 from coal) and 204 tonnes CO_2/h (H_2 from natural gas). The levelized cost of compression is found to be about $4-6/tonne CO_2, for compressor electricity costing 3.6 cents/kwh. About $3/tonne CO_2 is due to power costs, the remainder to capital costs.

Compressor capital costs are sensitive to scale, although power costs per GJ of hydrogen or tonne of CO_2 are independent of the compressor power. The power cost of compression per GJ of H_2 is sensitive to the electricity cost.

Compression costs are somewhat sensitive to the compressor outlet pressure. This pressure is typically at least 15 MPa, to assure that the CO_2 stays above the critical pressure throughout the pipeline. Figures B.2 and B.3 show the dependence of the levelized cost of compression on the compressor outlet pressure, assuming at inlet pressure of 0.1 MPa. There is a modest incremental cost of about $1/tonne CO_2 to increase the outlet pressure from 80 to 150 bar for pipeline transmission.

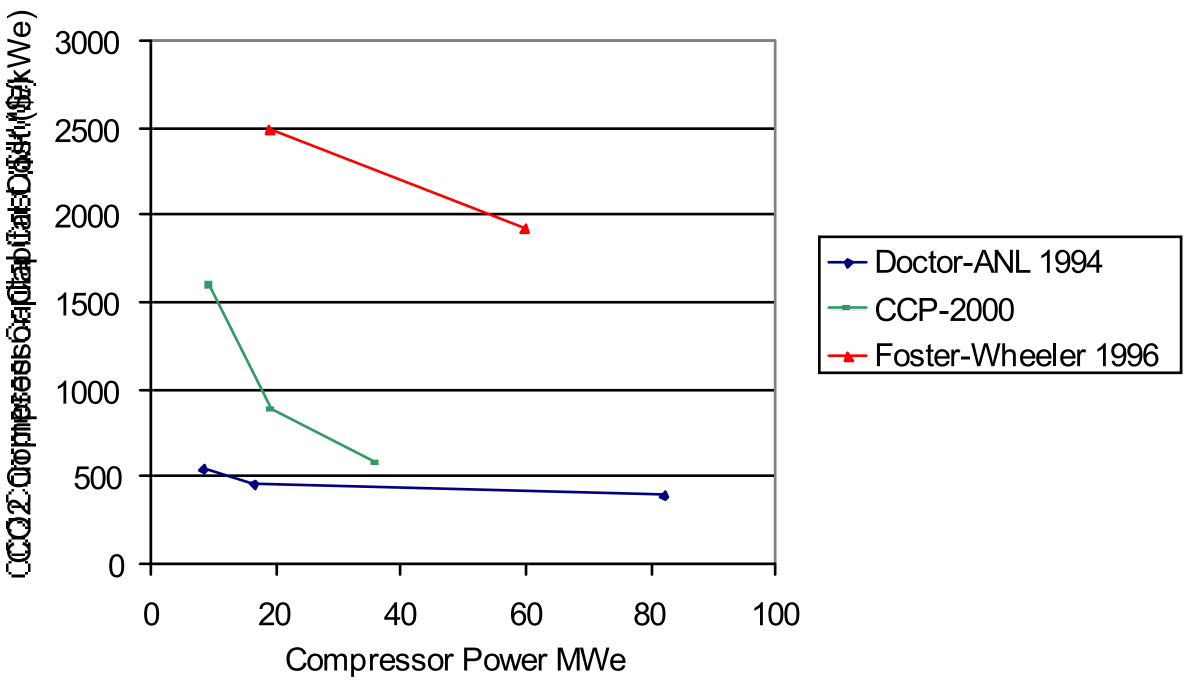


Figure B.1 Capital Cost of CO2 Compressors versus power according to several studies.

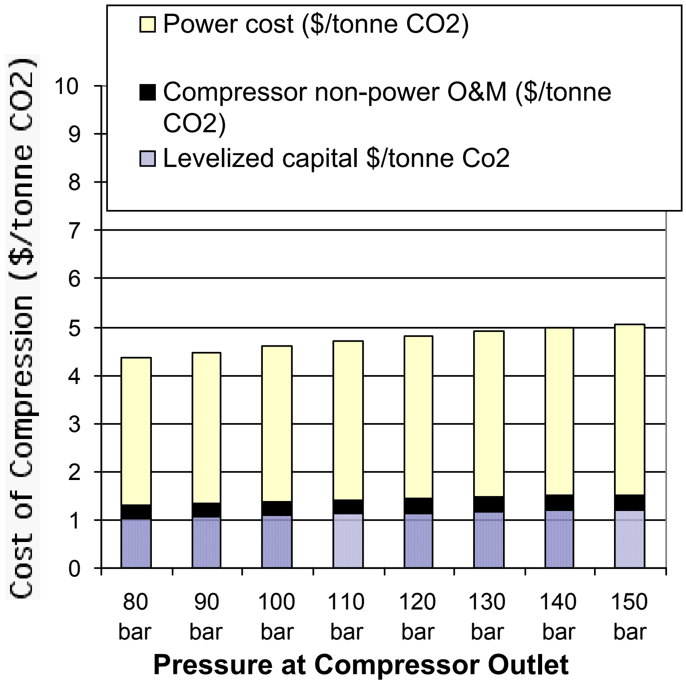
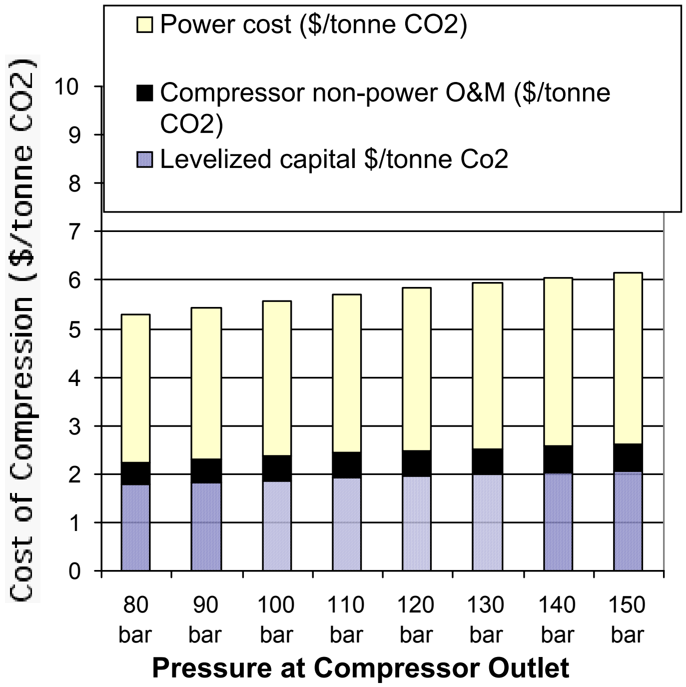


Figure B.2. Levelized Cost of CO_2 Compression for a 1000 MWth Coal Based Hydrogen Plant Capturing 437 tonne CO_2/h

Figure B.3. Levelized Cost of CO2 Compression for a 1000 MWth Natural Gas-Based Hydrogen Plant Capturing 204 tonne CO2/h



APPENDIX C. CO_2 PIPELINE CALCULATIONS

Flow rate of supercritical CO_2 as function of pipeline parameters

The equations determining the steady state flow rate of supercritical CO_2 as a function of pipeline diameter, inlet and outlet pressure, operating temperature pipeline length and gas composition have been adapted from (Farris 1983). For a pipeline of length L, the upstream and downstream pressures P_{inpipe} and $P_{outpipe}$, the volumetric flow rate Q, and the pipeline diameter D are related as follows (Farris 1983, p.150):

$$Q = C_1 \sqrt{(1/f)}\, [(P_{inpipe}{}^2 - P_{outpipe}{}^2 - C_2\{G \Delta h P^2_{avg} / Z_{avg}\, T_{avg}\}) / (G\, T_{avg}\, Z_{avg}\, L)]^{0.5}\, D^{2.5}\, E \quad [C.1]$$

where:

Q = gas flow rate, Nm^3/s (MSCF/D 1000 standard cubic feet per day)

P_{inpipe} = pipeline inlet pressure, kPa (psia) = Pcout

$P_{outpipe}$ = pipeline outlet pressure, kPa (psia)

G = specific gravity compared to air

with pure CO_2, the specific gravity G = 44.011/28.97 = 1.519

T_{avg} = average temperature, °K (°R)

In our calculations, average temperatures will range from 40-100°F

(499.67-559.67°R), or 4.44-37.78°C

Z_{avg} = fluid compressibility at average pipeline pressure, P_{avg}

For typical parameters this is about 0.17-0.30 (see Tables 1 and 2 below) for

pure CO_2 and 2-5% slightly higher if 1.5% SO_2 impurity is present

f = friction factor (see Eq. 2 below)

L = length of pipeline, km (mi)

D = internal pipeline diameter, m (in)

Δh = change in elevation downstream minus upstream, m (ft)

E = pipeline efficiency, fraction

C_1 = constant, 18.921 (1.3688)

C_2 = constant, 0.06836 (0.03750)

The friction factor f depends on the flow regime (laminar, partially turbulent, or fully turbulent). The flow regime can be determined from Reynolds number. For CO_2 pipelines with flow rates appropriate to capture from large fossil energy complexes, we find that the Reynolds number is very large, and the flow can be assumed to be fully turbulent.

We use the Nikuradse equation for fully turbulent flow to find f (Mohitpour et al. 2000, p.76):

$$\sqrt{(1/f)} = 4 \log_{10} \left[3.7 \, (D/K_e)\right] \qquad [C.2]$$

This equation only depends on the inner diameter D of the pipeline and the effective roughness of the pipe, K_e. A coated pipe is assumed, with K_e value of approximately 250×10^{-6} in. (Mohitpour et al. 2000, p.76). This gives f = 0.002268 for a 12 in. pipe and f = 0.002088 for a 20 in. pipe. (Note that the friction factor f is defined differently in many fluid dynamics textbooks, to be a value f'= 4 x f.)

Graphs for the density of CO_2 and compressibility Z_{avg} as a function of pressure and temperature (Farris) have been used to estimate Z_{avg}.

The compressibility factor for pure CO_2 near the critical point is shown in Table C.1. At pressures near atmospheric, the compressibility is near 1.

Table C.1: Compressibility Factors of Pure CO_2

	Temperature	
Pressure (psia)	<20 C	40 C
1281	0.175	0.325
1428	0.195	0.305
1581	0.21	0.295
1745	0.235	0.300

The compressibility factor changes with the addition of impurities. With 1.5% SO_2 added, the compressibility changes by 2-5% (see Table C.2).

Table C.2: Compressibility Factors of CO_2 with 1.5% wt. SO_2

	Temperature	
Pressure (psia)	<20 C	40 C
1281	0.183	0.332
1428	0.203	0.312
1581	0.218	0.302
1745	0.243	0.307

According to Farris, velocities of 2-4 m/s give the best economics. The pressure drop per length used in Farris's base case is 19.3 psi/mile (or 82.7 Pa/m).

The flow rates we calculate from these equations match well with those given in various references on CO_2 pipeline transmission (Farris 1983, Mohitpour 2000).

We have not considered booster compressor stations in this analysis, although this will be included in later work.

Pipeline Capital Cost Equations

I have compared CO_2 pipeline capital costs cited in the literature for a range of pipeline diameters. These costs are summarized in Figure C.1. All costs are expressed in 2001 US$. The conversion rate of $1.25 per ECU is used.

Estimates given by Joule II (Holloway 1996), IEA and Argonne National Laboratory (Doctor et al. 1999) included only pipeline capital. Skovholt's (1993) costs included the cost of CO_2 compressors (for initial compression from atmospheric to 110 bar) as well as pipeline costs.

Cost estimates differ widely among the studies. This is probably due to of differing assumptions about the terrain, and labor costs. The slope of the lines are similar, even though the values vary considerably with the study. This might reflect the fact that the total installed pipeline capital cost is the sum of the cost for the pipe itself plus pipelaying and other installation costs that could vary greatly with terrain. An average of IEA and Joule II gives about the same as Skovholt's middle range cost (even though Skovholt included compressors in his capital cost estimate.) Christodoulou's costs are much lower than the others. I would be skeptical of any cost less than about $155/m (or $250,000/mile which everyone I've talked to in the pipeline world quotes as a minimum cost even for small diameter high pressure gas pipelines under ideal conditions: level ground, no road crossings.)

To estimate the pipeline capital costs we use capital costs from Skovholt 1993, as representing an average of the data. From Figure 3 of Skovholt, we find the following costs

Table C.3

Pipeline diameter (inches)	Base Case Cost ($/m)	High Cost Case ($/m)	Low Cost Case ($/m)
16	700	900	450
30	1300	1800	800
40	1800	2500	1000
64	3500	2100	4700

The capital cost per unit length can be written approximately as a function of D

$$Cost\ (D) = Cost\ (Do) \times (D/Do)^{1.2} \qquad [C.3]$$

Where:
D = pipeline diameter
Cost (D) is the capital cost of the pipeline per unit length $/m
Do = reference diameter = 16 inches
Cost (Do) = cost/m at reference diameter of 16 inches = $700/m (from Table C.3 above)

The total capital cost of the pipeline ($) is

$Capital_{pipeline}$ = Cost(D) ($/m) x L (m)

Sensitivity of the Pipeline Cost to Flow Rate Q and Length L

We would like to rewrite the cost equation (C.3) as a function of CO2 flow rate Q and length L, rather than D. This will allow us to look at the sensitivity of the pipeline cost as a function of Q and L without explicitly solving for the pipeline diameter.

The diameter D can be related to the flow rate Q and pipeline length L via Equation (C.1).
To simplify the cost equations, we assume that all the parameters are the same for each arc in the pipeline network, except for the length L, diameter D and flow rate Q. Also, we assume that there is no elevation change in the pipeline, $\Delta h=0$.

Consider a pipeline segment (or arc) with flow rate Q, diameter D and length L , we find

$$Q = Const \times D^{2.5} / L^{0.5}$$

Where

$\text{Const} = C_1 \sqrt{(1/f)} \, [(P_u^2 - P_d^2) / (G \, T_{avg} \, Z_{avg})]^{0.5} \, E$

Actually, "Const" is not quite a constant, since $\sqrt{(1/f)}$ depends weakly on the diameter D through the Nikuradse Eqn.

$\sqrt{(1/f)} = 4 \log_{10} [3.7 (D/K_e)]$

where $K_e = 250 \times 10^{-6}$ in

However, $\sqrt{(1/f)}$ varies by only about 10% over the range of interest D =16 to 64 inches, so we approximate it as a constant.

Then:

$D = [Q \times L^{0.5} / \text{Const}]^{0.4}$ (C.4)

We can use this equation to derive an estimate of pipeline cost per unit length as a function of flow rate and pipeline length. From Eq. C.3

$\text{Cost}(D) = \text{Cost}(Do) \times (D/Do)^{1.2}$

Cost(D) can be rewritten as :

Cost (D) = Cost (Q,L),

where Q is the flow rate at diameter D and length L,

$\text{Cost}(Q, L) = \text{Cost}(Qo, Lo) \times (Q/Qo)^{0.48} \times (L/Lo)^{0.24}$

For a given flow rate, the capital cost per unit length goes up as the 0.48 power of (Q/Qo) times the 0.24 power of (L/Lo). The higher the flow rate, the higher the cost per unit length, but the cost increases more slowly than linearly. The longer the pipeline compared to the reference length, the higher the cost per unit meter, but this increases quite slowly.

For Qo = 16,000 tonnes/day and Lo=100 km, Do=16 inches, and

Cost (Qo, Lo) = $700/m

Then scaling

Cost (Q,L) = \$700/m x $(Q/Qo)^{0.48}$ x $(L/Lo)^{0.24}$ [C.5]

For Q= 11,000 tonne/day, L=100 km

Cost (Q,L) = \$700 x $(11000/16000)^{0.48}$ x $(100/100)^{0.24}$= \$585/m

For Q = 11,000 tonne/day, L=200 km

Cost (Q,L) = \$700 x $(11000/16000)^{0.48}$ x $(200/100)^{0.24}$= \$691/m

$Capital_{pipeline}$ = Cost(D) (\$/m) x L (m)

The capital cost $Capital_{pipeline}$ is approximately proportional to $Q^{0.48}$, $L^{1.24}$

The levelized cost of CO2 disposal is given by

Cpipeline (\$/tonne CO2) = (CRF + O&M) x $Capital_{pipeline}$/tonnes CO2 per year
= (CRF + O&M) x $Capital_{pipeline}$/[Q (Nm^3/s) x 3.17 x 10^7 sec/year x 1.965 kg CO_2/Nm^3/(1000 kg/tonne)]

The levelized cost is proportional to $Q^{-0.52}$, $L^{1.24}$. As the flow rate increases, the cost goes down as approximately the $Q^{-0.52}$ power. As length increases the levelized cost increases slightly faster than linearly, as $L^{1.24}$

In Figures C.2 and C.3, we show the cost of pipeline transmission as a function of flow rates (from 1000 to 10,000 tonnes CO2/day) and pipeline length (from 50 to 1000 km). For reference, a 1000 MWth (250 million scf/day) H2 plant using steam methane reforming would produce about 4800 tonnes CO2/day. A 1000 MWth hydrogen plant based on coal gasification would produce about 11,000 tonnes CO2/day. We assume that the inlet pressure is 15 MPa, and the outlet pressure is 10 MPa. The cost of pipeline transmission varies from less than \$10 per tonne CO2 (for 50 km pipelines) to almost \$100/tonne CO2 for a 1000 km pipeline with a CO2 flow rate corresponding to 200 MWth H2 production per day (enough to fuel a fleet of several hundred thousand hydrogen fuel cell cars).

The contribution of CO2 pipeline capital to the hydrogen cost from coal and natural gas hydrogen plants are shown in Figures C.4 and C.5. The CO2 pipeline cost per GJ of hydrogen is generally much less than the production cost of hydrogen (\$6-7/GJ) except for long distances and small flow rates. Costs per GJ of H2 are higher for coal plants than for natural gas, because more CO2 is produced per GJ of hydrogen.

Comparing the costs estimated from this formula, we find values that are quite similar (Figure C.6). The Joule II formula for the capital cost per meter shows no dependence on L, while the cost function derived here has a dependence on L that is slightly greater than linear.

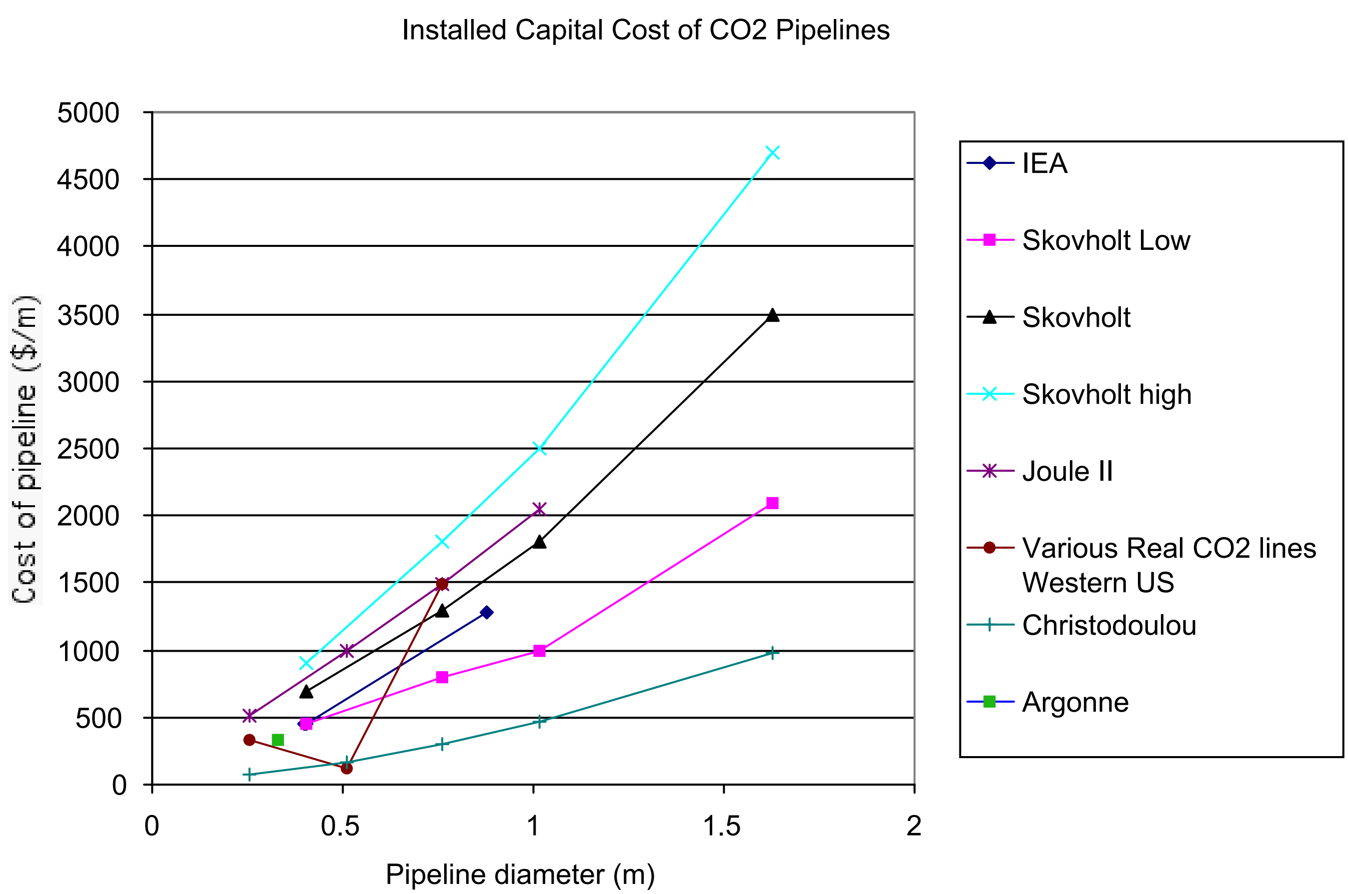


Figure C.1. Installed Capital Cost of CO2 Pipelines in $/m

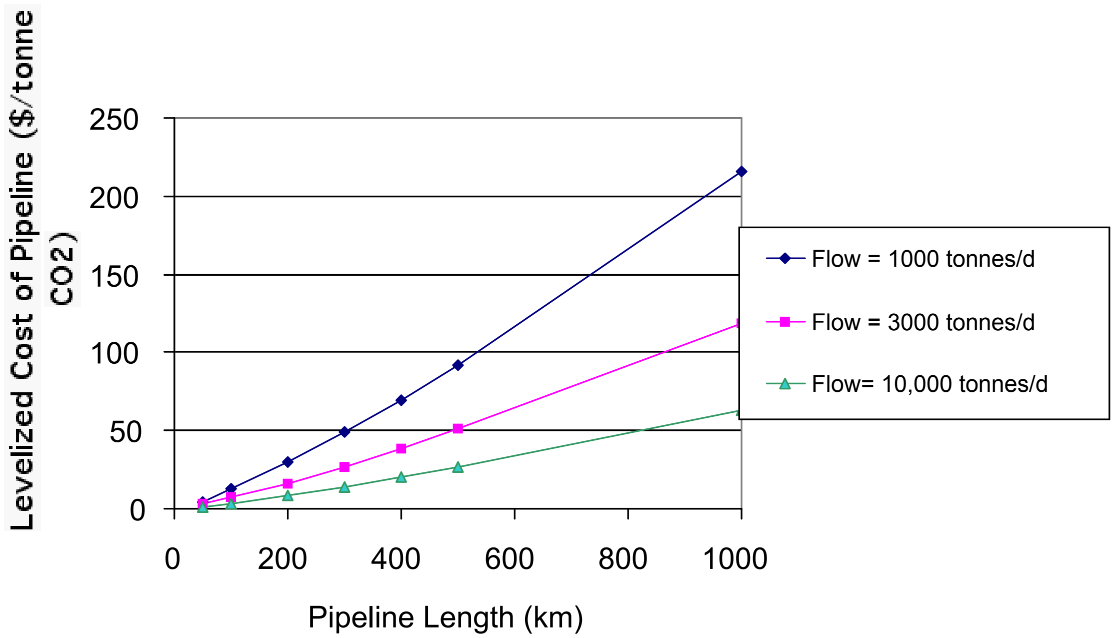
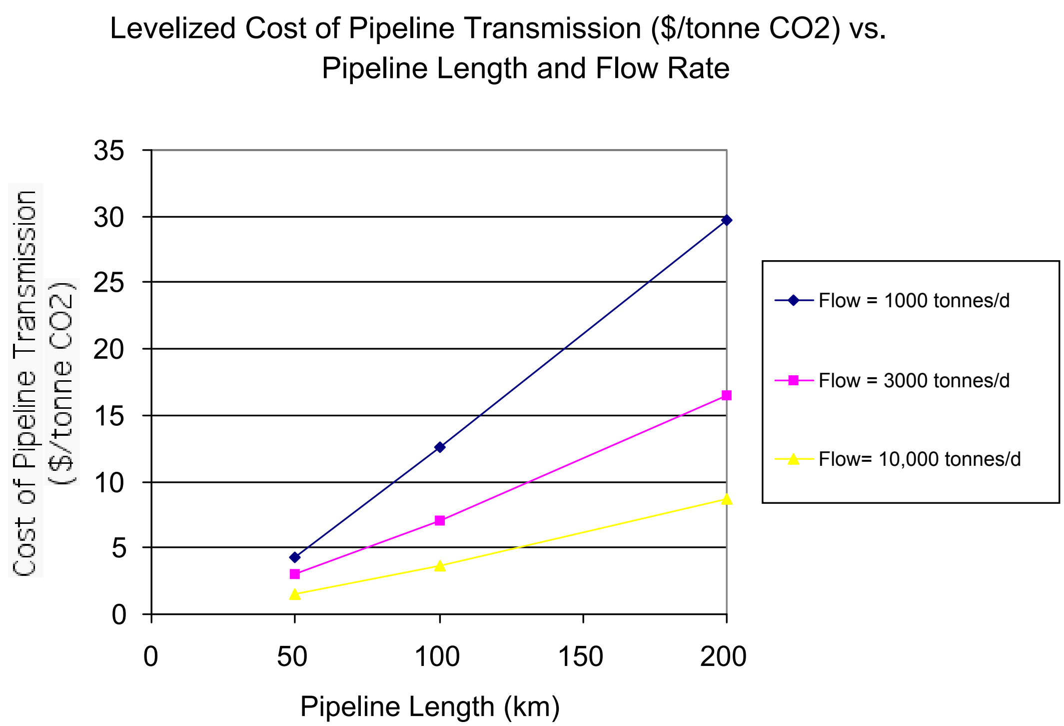


Figure C.2. Levelized cost of Pipeline Transmission vs. pipeline length and flow rate

Figure C.3



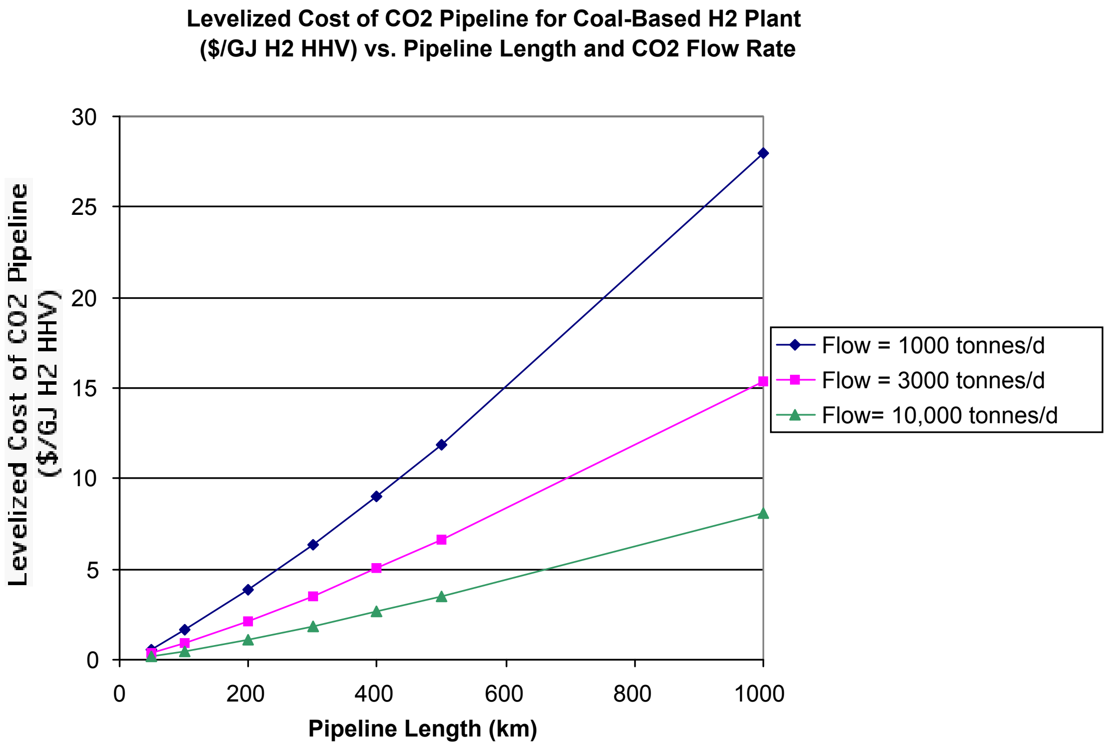


Figure C.4

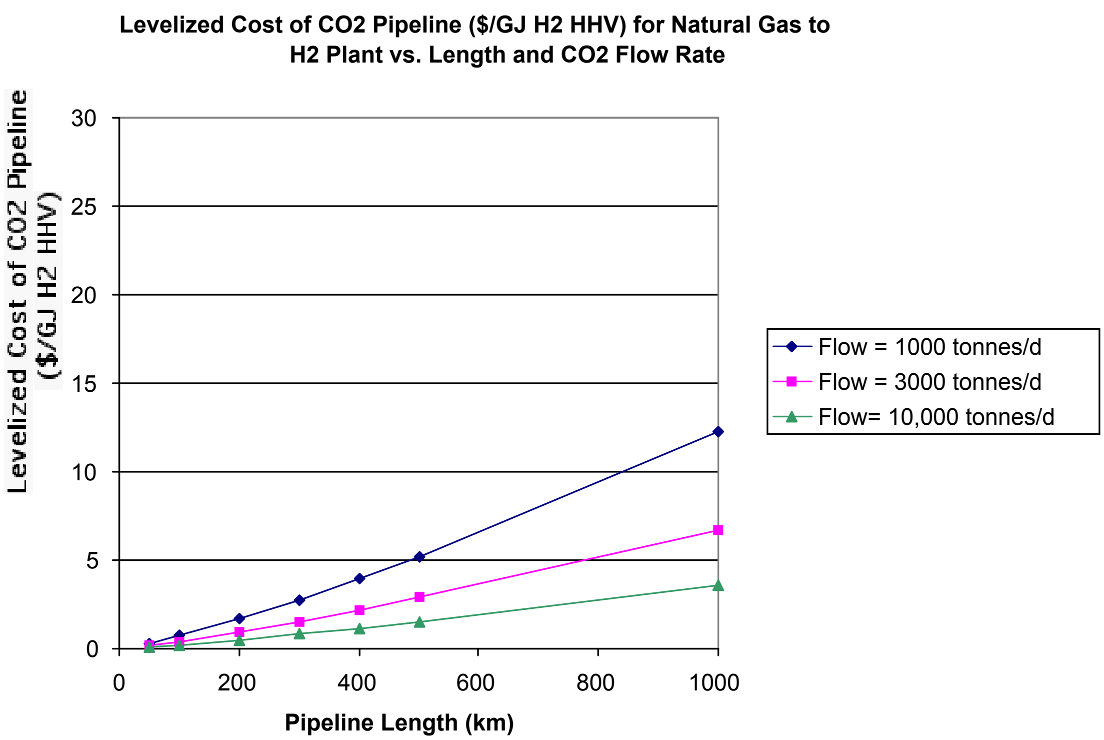


Figure C5

APPENDIX D. INJECTION RATE INTO UNDERGROUND RESERVOIRS, CALCULATIONS FOR INJECTION SITE COSTS

CO_2 is injected into an underground reservoir, such as an aquifer or depleted gas or oil reservoir. The injection rate into the well is given by (Hendrik 1994)

$$q_s = \rho_r/\rho_s \times 2\pi\, k\, h\, \Delta P/[\ln(r_e/r_w) \times \mu] \qquad [D.1]$$

where:

q_s = flow rate of CO_2 into injection well (Nm^3/s)
ρ_s = density of gas under standard conditions (kg/m^3) = 1.964 kg/m^3 for CO_2
ρ_r = density of gas at reservoir pressure (kg/m3) = 750 kg/m^3 for CO2
k = permeability of reservoir (m^2) , range = 0.6 – 60 x 10-14
h = thickness of reservoir = 10-200 meters
ΔP = pressure difference between pressure of CO2 at the bottom of the well, and the pressure of the aquifer at a point far from the well = Pinjout – Paquifer.
For flow, $\Delta P > 0$. To avoid problems $\Delta P <$ 0.09-0.18 x Paquifer
re = radius of influence of injected CO2 in the aquifer
rw = radius of the well
ln(re/rw) = 7.5 (Hendrik 1994 gives a range of 7-8 for this parameter)
μ = viscosity = 6 x 10-5 Pa.s (at injection pressure of 8000 kPa) to 9 x 10-5 Pa.s (at injection pressure of 20,000 kPa)

Where:

Pinjout = pressure at the bottom of the well
Paquifer = pressure in the aquifer far from the well

The pressure in the aquifer is given by

Paquifer = dP/dz x depth [D.2]

Where :

dP/dz = 11.5 – 23.0 kPa/m (range from Hendrik, 1994).
depth = depth of well in meters

The pressure at the bottom of the well is given by the injection pressure plus the weight of the water column in the well . This can be approximated by:

Pinjout = + 10.5 kPa/m x depth (Hendrik, 1994) [D.3]

Where
P_{injin} = pressure at the top of the well.

If $P_{outpipe} > 10$ MPa, it should be possible to inject into an aquifer with a low pressure gradient, without any additional compression. In this case

$P_{injin} = P_{outpipe}$

For deep wells into aquifers with high pressure gradients, an additional compressor might be needed at the wellhead.

If compression is needed at the well, the compressor power can be estimated as in Eq. [B.1] above. The compression needs are quite low for injection site compression from 10 to 15 MPa, as compared to compression at the energy complex from 0.1 to 15 MPa.

The flow rate per well is given in Figure D.1 as a function of permeability and aquifer thickness for low and high pressure aquifers.

We limit the CO2 flow rate at any one well to 2500 tonne/day, as suggested in the Joule II report. (This limit occurs because of frictional losses at higher flow rates that lead to undesirable heating.)

Number of Wells

The number of wells needed is

$N_{well} = Q/ q_s$ [D.4]

The cost per well has been estimated by Hendrik as

$Cost_{well}$ (\$/well) = \$1.25 million/well/km x depth (km) + \$1.0 million [D.5]

The total capital cost for wells is

$Capital_{well}$ (\$) = $Cost_{well}$ (\$/well) x N_{well} [D.6]

The capital cost of wells varies as h^{-1}, k^{-1}, ΔP^{-1}, μ, ρ_r^{-1}

In Figure D.2, we show the number of wells needed to dispose of the CO2 output from 1000 MWth hydrogen plants based on natural gas and coal, as a function of permeability, for a reservoir thickness of 50 m. We see that at low permeability 12 wells will be needed to dispose of the CO2 from the coal plant. As permeability (or equivalently thickness) increases, the number of wells needed drops rapidly. For permeabilities above about 40 milliDarcy, at the limiting flow rate of 2500 tonne CO2/day, only 2 wells are needed to take up the CO2 output of a natural gas based H2 plant, and 5 wells are needed to take up the output of a coal to hydrogen plant.

Associated Piping at the Injection Site

The area needed for the injection field is given by

Area (m^2) = $Q_{tot}/(\phi_{eff} \times n_{se} \times \rho \times h)$ [D.7]

Where:
Q_{tot} = quantity of CO2 to be stored (kg)
= Q (Nm^3/s) x 1.964 kg/Nm^3 x 3.17 x 10^7 s/year x 20 years
= 20 years output from fossil energy complex plant.
ϕ_{eff} = effective porosity = 20% (Hendrik 1994)
n_{se} = sweep efficiency = 2% (aquifer); 90% (gas or oil well)
ρ = density of CO_2 at the bottom of the well = 750 kg/m^3
h = thickness of aquifer (m)

The area needed to dispose of 20 years' worth of CO2 from 1000 MWth natural gas to hydrogen and coal to hydrogen plants is shown in Figure D.3 as a function of aquifer thickness. An area of about 500 km^2 is needed to accept CO2 from a coal plant, if the layer thickness is 50 m. For a natural gas to hydrogen plant, the area is 235 km2.

The length of pipe at the field needed to connect the wells depends on the number of wells needed.

The layout of the injection piping will try to minimize costs. For the case of a 1000 MWth coal plant, and an injection site with good permeability, 5 wells will be needed.

Assuming that each well has a circle of influence of radius r_{well}, then the total area

Area = $N_{well} \times \pi\, r_{well}^2$ [D.8]

Assuming the flow is split into Nwell equal parts, each pipe going to a well has a diameter

= $D/(N_{well})^{0.5}$

The cost of field piping varies with diameter as in Eq, C.5.

The total length of associated piping = $(N_{well}-1) \times 2\, r_{well}$

The cost of piping varies as $n_{se}^{-1/2}$, $\phi_{eff}^{-1/2}$, $h^{-3/2}$, k^{-1}, ΔP^{-1}, μ, $\rho_r^{-3/2}$

Capital costs at the injection site depend on the permeability and the reservoir thickness. The viscosity increases with increased aquifer pressure, which reduces the flow into each well and increases the need for associated piping. In Figure D.5, we show the kilometers of field piping needed to dispose of 310 tonnes CO2/h, as a function of permeability and aquifer pressure. The length of injection field piping rises rapidly for low permeability.

Simplified expression for above ground piping costs.

Assume that the aquifer parameters are such that the CO2 flow rate into each well is 2500 tonne/day or 104 tonne/h CO2.

Then the number of wells is:

N_{well} = Q/ 2500 tonne/d, rounded up to the nearest integer

The length of associated pipeline at the site is

$(N_{well}-1) \times 2\ r_{well}$

where:

$r_{well} = (\text{Area}/\ \pi\ N_{well}\ )^{0.5}$

$r_{well} = [Q_{tot}/(\phi_{eff} \times n_{se} \times \rho \times h \times \pi\ N_{well}\ ]^{0.5}$

$r_{well} = \{\ Q\ (\text{tonne/d}) \times 365\ \text{d/y} \times 20\ \text{years}\ \ /[\phi_{eff} \times n_{se} \times \rho \times h \times \pi\ N_{well}]\ \}^{0.5}$

$r_{well} =$
$\{\ 2500\ \text{t/d} \times 365\ \text{d/y} \times 20\ \text{y}/[\phi_{eff} \times n_{se} \times \rho \times h\ \pi]\ \ Q\ (\text{tonne/d})/(\text{Nwell} \times 2500)\}^{0.5}$
For our base case values:

ϕ_{eff} = effective porosity = 20% (Hendrik 1994)
n_{se} = sweep efficiency = 2% (aquifer)
ρ = density of CO_2 at the bottom of the well = 750 kg/m^3
h=50 m

$r_{well} = 6223\ \text{m} \times [Q\ (\text{tonne/d})/(\text{Nwell} \times 2500)]^{0.5}$

The diameter of the injection field piping is given by:

$\text{Dwell} = D/(N_{well})^{0.5}$

Where D is the diameter of the main pipeline

$D = Do\ [(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}$

Q = flow rate in main pipeline (tonne/d)
L = length of main pipeline (km)
Do = 16 inches
Qo= 16,000 tonne/d
Lo=100 km

$Dwell = Do\ [(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}/(N_{well})^{0.5}$

And the capital cost of the associated piping ($/m) is given by

$Cost\ (Dwell) = Cost\ (Do) \times (Dwell/Do)^{1.2}$

$Cost\ (Dwell) = Cost\ (Do) \times \{[(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}/(N_{well})^{0.5}\}^{1.2}$

Where
Cost (Do) = $700/m
Do = 16 inches
Qo =16,000 tonne/d
Lo=100 km
Q = flow in main pipeline (tonne/d)
L = length of main pipeline (km)

The total capital cost of the associated piping is:

Cost of injection field piping ($)
$= \$700/m \times \{[(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}/(N_{well})^{0.5}\}^{1.2} \times (N_{well}-1) \times 2\ r_{well}$

Cost of injection field piping ($) =
$\$700/m \times \{[(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}/(N_{well})^{0.5}\}^{1.2} \times$
$(N_{well}-1) \times 2 \times 6223\ m \times [Q\ (tonne/d)/(Nwell \times 2500)]^{0.5}$

For flow rates in the 100 to 500 tonne per h range, for a 100 km pipeline

Hydrogen Plant CO2 output tonne/h	Capital Cost of Injection site piping (million $)	Levelized Cost of Injection ($/tonne CO2)

100	0 (because only 1 well is needed)	0
200	3.16 (2 wells)	0.43
300	6.02 (3 wells)	0.54
400	8.73 (4 wells)	0.59
500	11.32 (5 wells)	0.61

The contribution of the injection piping to the levelized cost of CO_2 disposal is given by:

Levelized cost (\$/tonne CO_2)
 = (CRF + O&M) x capital cost/(capacity factor x tonnes CO_2/h x 8760 h/y)
= $(0.15 + 0.04) \times \$700/\text{m} \times \{[(Q/Qo) \times (L/Lo)^{0.5}]^{0.4}/(N_{well})^{0.5}\}^{1.2} \times$
$(N_{well}-1) \times 2 \times 6223\ \text{m} \times [Q\ (\text{tonne/d})/(Nwell \times 2500)]^{0.5}/(\text{capacity factor} \times Q \times 8760$ h/y)

Figures D.4-6 summarize the cost of injection field piping. The "jumps" are due to the fact that the number of wells is an integer. Below flow rates of about 100 t CO_2/h, only one well is needed, so the field piping costs are zero. As the flow rate increases the piping length goes up. Cost is almost linear above flow rates of 100 t/h, and the levelized cost approaches \$0.62/tonne CO_2 in the limit of large flows. (Levelized costs are smaller at smaller flow rates because a shorter length of pipe is required per unit of CO_2 sequestered.) The capital cost for injection field piping is considerably less than for the main pipeline (assumed to be 100 km in length).

Figure D.1

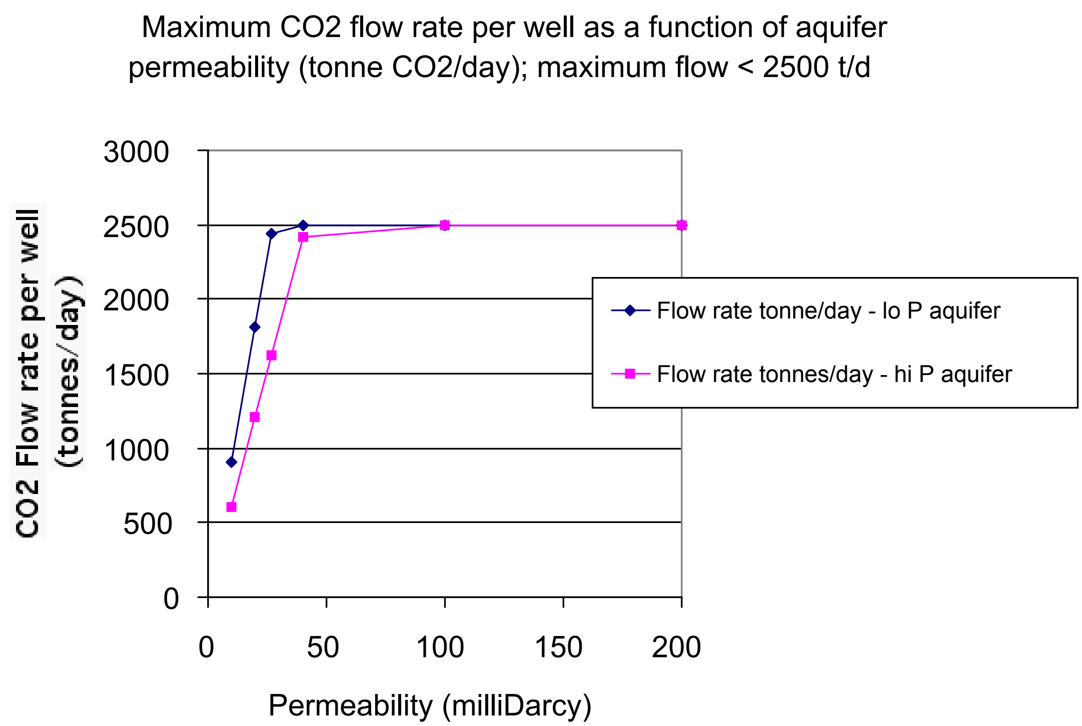


Figure D.2

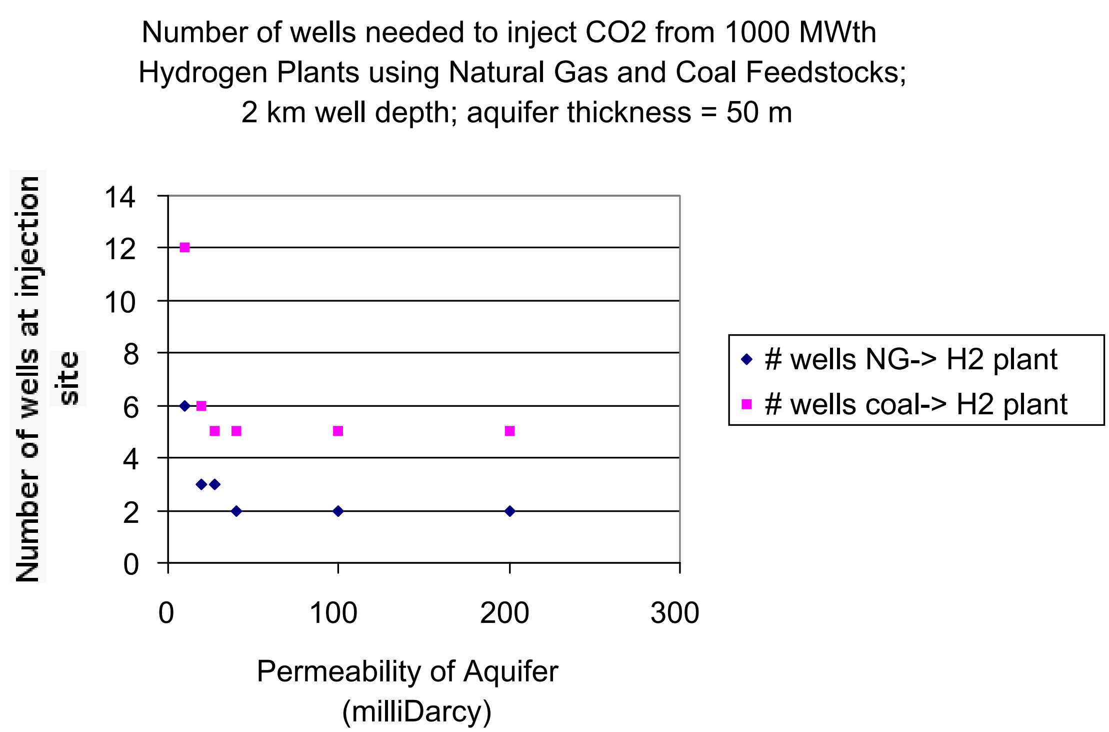


Figure D.3

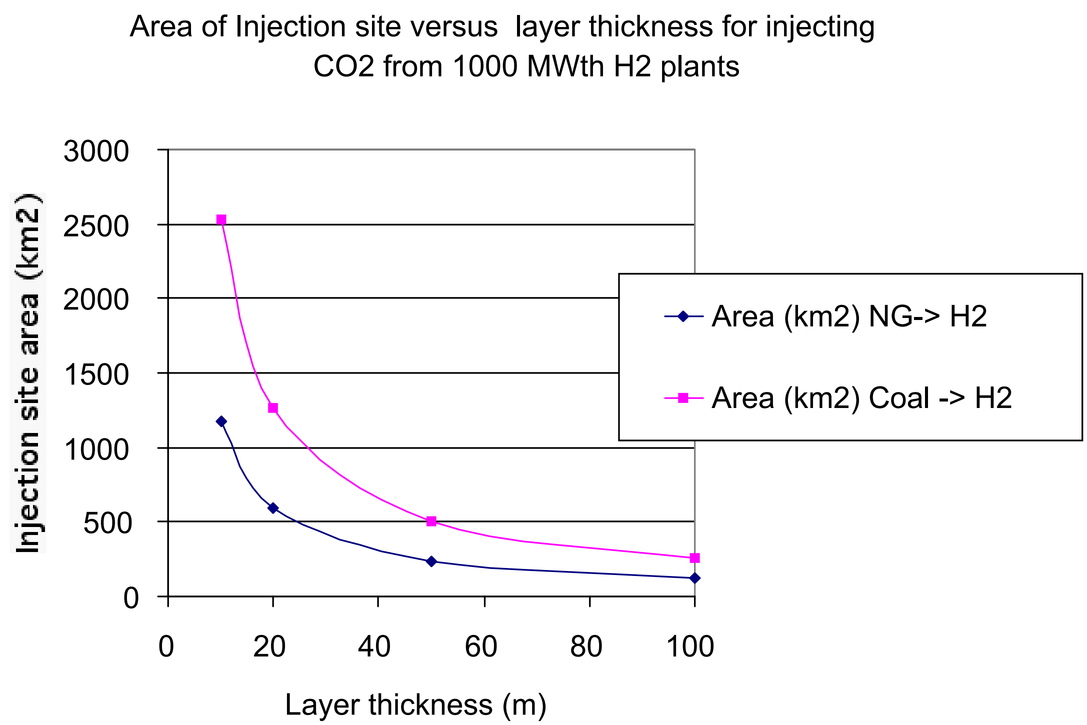
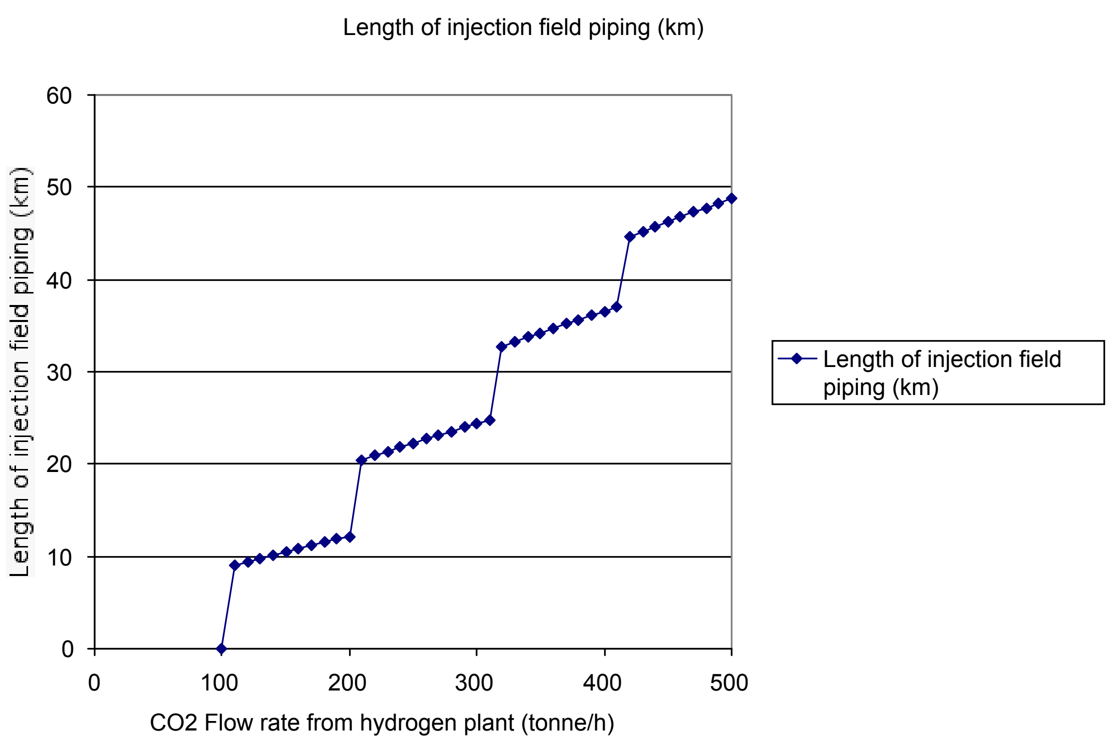


Figure D.4



APPENDIX E. HYDROGEN FUEL DELIVERY INFRASTRUCTURE: HYDROGEN COMPRESSION, STORAGE, PIPELINE TRANSMISSION, LOCAL PIPELINE DISTRIBUTION AND REFUELING STATIONS

In this Appendix, we estimate the costs of the hydrogen fuel delivery infrastructure required to bring hydrogen from the fossil energy complex to vehicles. There are many ways to store and distribute hydrogen. These include:

- storage as a compressed gas with delivery via compressed gas truck (tube trailer)
- storage as a compressed gas with delivery by pipeline
- storage as a cryogenic liquid with delivery by liquid hydrogen truck

Truck and pipeline delivery are used commercially today. Generally, truck delivery is preferred when small quantities of hydrogen must be delivered long distances. For large scale fossil hydrogen plants with CO2 sequestration, located near a city with a high geographic density of hydrogen demand, gaseous storage with delivery by gas pipeline is projected to give the lowest costs (Ogden 1999, Amos 1998). In this report, we focus on this alternative.

A sketch of the assumed hydrogen infrastructure is shown in Figure E.1
The hydrogen delivery system includes hydrogen compression and storage (at the H2 production plant site), pipeline transmission from the plant to the hydrogen demand (assuming that the hydrogen plant is located some distance from the city), recompression for local pipeline distribution (this might or might not be needed depending on the distance between the hydrogen plant and the demand), a local pipeline distribution network, and hydrogen refueling stations.

In the sections that follow, we develop equations for the costs of hydrogen compression, storage, pipeline delivery and refueling stations.

Hydrogen Compression

Compressor Power Requirements:

The compressor power is calculated via:

P_{cm}=

$$Q_h \text{ x } (P_b/T_b)\text{x}(T_1/n_c)\text{x } Z \text{ x } [N\gamma/(\gamma-1)] \text{ x } [(P_{out}/P_{in})^{[(\gamma-1)/N\gamma]} -1]/1000 \qquad [E.1]$$

where:

P_{cm} = compressor power requirement (kW)

Q_h = gas flow rate in Nm^3/s

P_b = reference pressure = 101,300 Newtons/m^2 (atmospheric pressure)

T_b = reference temperature = 298^{o}K

T_1 = initial gas temperature = 298^{o}K

P_{in}=inlet pressure to compressor

P_{out}=outlet pressure from compressor

N = number of compressor stages

n_c = compressor efficiency = 55% (from RIX) for small hydrogen compressors (100 kW - 1 MW) and 70% for large (pipeline scale) natural gas and hydrogen compressors.

Z = compressibility = 1

γ = ratio of specific heats
(for hydrogen = 1.41, for methane = 1.30)

For hydrogen the compressor power needed is given by:

$$P_{cm}H2= Q_{scfmH2} \times 0.164/n_c \times N \times [(P_{out}/P_{in})^{0.291/N} - 1] \quad [E.2]$$

where:

Q_{scfmH2} = hydrogen flow rate in scf/minute

For methane the compressor power needed is:

$$P_{cm}CH4= Q_{scfmCH4} \times 0.2068/n_c \times N \times [(P_{out}/P_{in})^{0.231/N} - 1] \quad [E.3]$$

where:

$Q_{scfmCH4}$ = methane flow rate in scf/minute

This power equation gives a good match to manufacturers' data for power requirements.

Solving Eq. E.2 and E.3 for the power requirements for hydrogen and methane compression, we see that for the same energy flow rate, the ratio of the hydrogen compressor power requirement to the methane compressor power requirement is:

$$PcmH2/PcmCH4 = (HHV\ CH4/HHV\ H2) \times (0.164/0.2068) \times [(P_{out}/P_{in})^{0.291/N} - 1]/[(P_{out}/P_{in})^{0.231/N} - 1]$$

$$= 2.366 \times [(P_{out}/P_{in})^{0.291/N} - 1]/[(P_{out}/P_{in})^{0.231/N} - 1]$$

For a variety of compressor inlet pressures, keeping the same energy flow rate of gas in the pipeline, the compressor power is about three times higher for hydrogen than for natural gas.

Table E.1. Ratio of Power Requirements for Compression of H2 and CH4

Pin (psia)	Pout (psia)	N = #compressor stages	PcmH2/ PcmCH4
14.7	1000	4	3.08
100	1000	2	3.09
200	1000	2	3.06
300	1000	1	3.10

Compressor Capital Costs

Based on data for a number of hydrogen compressors in the range 50-500 kW we find that the capital cost is about $2000/kW for multi-stage compressors, and about $700-1100/kW for single stage compressors with pressure ratios of 2.5-4.

It is also possible to estimate hydrogen compressor costs based on a formula given by (Darrow et. al 1977).

$C_c = 535 \times (1 - Q_h/2.832) + 268 + C_{drive}$

where

C_c = compressor capital cost ($/kW)

Q_h = hydrogen flow rate in Nm^3/s

C_{drive} = cost of motor drive ($/kW)

and

P_{cm} (kW)	C_{drive} ($/kW)
< 522	200
522-1679	160
1679-2611	80
2611-4103	65
> 4103	42

This formula appears to match the cost of single stage compressors fairly well, but underestimates the capital cost of multi-stage compressors as compared to manufacturers' data.

For pipeline applications, we find that compressor powers of 10's to 100's of MW are needed. The cost of hydrogen compressors in this size range is assumed to be $750/kW, with efficiency of 70% (Directed Technologies 1997)

Natural gas compressors in this size range are assumed to cost \$600/kW.

Comparing costs for natural gas and hydrogen compressors, we see that the power requirement is about 3 times larger for hydrogen than for methane, and the capital cost is about 4 times larger.

Hydrogen compression costs at the hydrogen plant.

The levelized cost contribution of hydrogen compression is:

P_C(\$/GJ) =
(CRF + OM) * (Ccm + Pcm*8760 h/y * Pelec) / Eflow(GJ/yr)   [E.4]

where
P_C = levelized cost of hydrogen compression in \$/GJ
CRF = capital recovery factor = 0.15 (See Table 1)
OM = O&M costs per year as a fraction of installed capital cost = 0.04 (See Table 1)
Ccm = installed capital cost of compressor (\$)
Pcm = compressor power (kW)
Pelec = electricity cost (\$/kwh) = 3.6 cents/kWh (Table 1)
Eflow = energy flow per year (GJ/year) = energy flow/day*365 d/y
=H2 plant capacity (GJ/d) x capacity factor x 365 d/y

From Table E.2, we find that the cost of large scale hydrogen compression at the central plant from hydrogen plant outlet pressure of 200 psia to pipeline pressure of 1000 psia is about \$0.5/GJ. About 70% of the levelized compression cost is associated with electricity costs (assuming that power costs 3.6 cents/kWh).

The energy requirement for hydrogen compression from 200 to 1000 psi is about 2% of the energy content of the hydrogen (on a higher heating value basis). In Figure E.2 we show the hydrogen compression energy requirement as a function of inlet and outlet pressures.
.

Table E.2 Cost of Compression for Hydrogen, assuming Pin=200 psia, Pout=1000 psia

Max Energy Flow in piepline (MWth H2)	QH2 (million scf/day)	Hydrogen flow (kg/d)	H2 Pipeline Compressor Power Required (MW)	H2 Compressor Cost (million $)	Power cost ($/GJ H2) for electricty @ 6 cents/kwh	Total Compressor Cost capital + O&M + Power ($/GJ)	Total Compression Cost ($/kg H2)
100	25	60	2.2	1.6	0.33	0.49	0.07
250	63	150	5.4	4.1	0.33	0.49	0.07
500	126	300	10.8	8.1	0.33	0.49	0.07
1000	252	600	21.6	16.2	0.33	0.49	0.07
2000	504	1200	43.2	32.4	0.33	0.49	0.07

Hydrogen storage at the production plant

In the case of large centralized fossil hydrogen production, it is desirable to run the hydrogen production plant continuously. However, the system-wide demand profile for transportation fuel will vary over the day, weekly and even seasonally, so that some storage capacity (about 12 to 24 hours of production) will be needed in the system. For a pipeline distribution system, several options are available.

1) *Hydrogen could be stored in the pipeline.* No extra capital costs would be incurred, although some extra compression might be required. The viability of this option depends on the pipeline length and operating pressures as well as the demand profile. For example, with inlet pressure of 500 psia and outlet pressure of 200 psia a pipeline 30 km in length, and 3 inches in diameter could be used to transmit 5 million scf/day. The total storage volume available would be about 19000 cubic feet. If the pipeline pressure were raised to 1000 psia, if would be possible to store about 1.3 million scf in the pipeline or about 6 hours production from a system producing 5 million scf/day. Depending on the demand profile, this might be sufficient.

2) *Hydrogen could be stored at the refueling station.* Storage cylinders would be available to accept the nighttime production of hydrogen, delivered by pipeline. Since some storage is already required at the station to meet demand peaks, this storage strategy would increase the filling station contribution to the delivered cost of hydrogen by only about $0.2-0.5/GJ. This is the option chosen in our designs, where we assume that 6 hours of storage is located at the station. This also covers pipeline outages.

3) *Hydrogen could be stored at the production site.* This would add costs for compression and storage of perhaps 2 dollars per GJ of hydrogen. This option is also used in our study, where is is assumed that 12 hours of bulk central storage is used.

Bulk gaseous storage at the central plant can be accomplished in several ways (Taylor et.al 1986). First hydrogen is compressed from production pressure (typically 200 psi for steam reforming or gasification systems) to storage pressure of perhaps 1000 psi (assuming that the pipeline will be fed from storage). For very large quantities (on the order of 100 million scf or more), underground gas storage might be used. Capital costs for underground storage are typically $2000-3000 per GJ of hydrogen storage capacity (Taylor et al. 1986)

Otherwise, above ground pressure vessels are favored. High pressure (1000-8000 psi) bulk hydrogen storage in standard aboveground pressure cylinders costs about $4000-5000/GJ of hydrogen stored. A 1997 study by Air Products and Chemicals gave costs for high pressure (5000 psia) gas storage of $11.7 million for a system storing 36,000 lb H2m and $117 million for a system storing 360,000 lb H2. There appears to be no economy of scale for storage in pressure cylinders. The capital cost is about $5000/GJ. (It is interesting to note that advanced composite high pressure cylinders for storing hydrogen on vehicles are projected to cost about $1500 per GJ of stored hydrogen capacity, at 5000 psia. So it is conceivable that future capital costs for storage might be reduced.)

Our base case hydrogen plant with an output of 1000 MW H2 produces 86,400 GJ/day. So 1/2 day's storage would be 43,200 GJ and would cost

$5000/GJ x 43200 GJ = $216 million

The levelized cost contribution of storage for this case would be:

P_{sto}($/GJ) = (CRF + OM) * Csto ($) / Eflow(GJ/yr) [E.5]

For our base case assumptions,

Psto ($/GJ) =$1.62/GJ

In this study, we have assumed that the demand is large and geographically concentrated, so that gaseous hydrogen distribution by pipeline gives the lowest costs. We have focussed on gaseous hydrogen storage, but it is also possible to liquefy hydrogen (at 20 K), store it in a cryogenic dewar and deliver it to refueling stations via cryogenic tank truck as a liquid. Liquid hydrogen delivery is more cost effective for small demands that are widely dispersed geographically.

Hydrogen pipeline costs

The costs of hydrogen transmission (from the central hydrogen plant to the citygate) and the cost of local hydrogen pipeline distribution are estimated below.

Equation for Gas Flow In A Pipeline

For a gas pipeline of length L, the inlet and outlet pressures P1 and P2, the volumetric flow rate Q, and the pipeline diameter D are related as follows (see Eq. A-13, p. 238, Christodoulou 1984):

$$Q = \frac{\pi}{8} \frac{T_b}{P_b} \left(\frac{1}{f}\right)^{0.5} \left(\frac{R}{W_a\, G\, T\, L\, Z}\right)^{0.5} \left(P_1^2 - P_2^2\right)^{0.5} D^{2.5} \qquad \text{[E.5]}$$

where:

Q = flow rate (m_N^3/s)

R = universal gas constant = 8314.34 J/(kg·mol·°K)
W_a = molecular weight of air = 28.97
G = dimensionless gas specific gravity
(= 0.0696 for H_2, 0.553 for CH_4 1.0 for air)
T_b = reference temperature = 298°K
Pb = reference pressure = 101325 N/m^2 (1 atm)
Z = compressibility = 1
L = length of pipeline (m)
P_1 = inlet pressure (N/m^2)
P_2 = outlet pressure (N/m^2)
T = gas temperature (°K)
D = pipe diameter (m)
f = dimensionless friction factor (depends on flow regime)

Evaluating the friction factor f

Evaluating the friction factor f depends on the pipe roughness and the velocity profile in the pipe. Various approximations were considered in (Christodoulou 1984, see summary in Table A.2, p. 245). The friction factor can be expressed as a function of the dimensionless Reynolds number, which is given by:

$Re = 0.011459\ (Q\ G\ P_b)/(\mu\ D\ Tb)$

where:

μ = dynamic viscosity in lb/(ft.sec)
G = gas specific gravity
Q = flow rate in standard cubic feet/hr
Pb = reference pressure (psia) = 14.7 psia
Tb = reference temperature (^oR) = 568^oR (= 298^oK)
D = pipeline diameter (inches)

Table E.3 Physical properties of Hydrogen and Methane

Property	H2	CH4
G = gas specific gravity	0.0696	0.553
μ = dynamic viscosity (from Handbook of Chemistry and Physics, p. F-59-60)	5.9 x 10-6 lb/(ft.sec)	7.30 x 10-6 lb/(ft.sec)
Higher Heating Value (kJ/scf)	343	1080

The values of G and μ are given in Table E.3 for hydrogen and methane. Substituting in the values for hydrogen gives

Re = 3.496 Q (scf/hr) / D (inches)
= 0.14567 x 106 Q (million scf/day)/D (inches) [E.6]

For methane, we find

Re = 22.466 Q (scf/hr) / D (inches)
= 0.93608 x 106 Q (million scf/day)/D (inches) [E.7]

Table E.4. Typical values of Reynolds numbers Re for long distance gas pipelines (if L=100 km, P1=1000 psia, P2=300 psia)

D (inches)	QH2 (million scf/day)	Re Hydrogen	QCH4 (million scf/day)	Re Methane
8	120	2.1 x 106	40	4.7 x 106
11	240	3.2 x 106	80	6.8 x 106
20	1200	8.7 x 106	400	19 x 106
40	5800	21 x 106	1900	44 x 106
48	12000	36 x 106	4000	78 x 106

Review of formulas for friction factor

Various approximations are used for (1/f)0.5 depending on the type of flow (turbulent, partially turbulent or laminar), the smoothness of the pipe and the Reynolds number. (These are summarized in Table A.2, p. 245 of Christodoulou 1984)

For fully turbulent flow, the "rough pipe" formula is used:

$(1/f)^{0.5} = 4 \log_{10}(3.7\ D/k) + 2.273$ [E.8]

where k = roughness factor = 0.0007 inches
D = pipeline diameter in inches,

According to Christodoulou, this formula gives good agreement over a range of natural gas pipeline operating conditions. Note that this formula is the same for natural gas and hydrogen and has no dependence on the Reynolds number.

For partially turbulent flow, and for Re in the range 5 to 20 x 10^6, Christodoulou suggests the **"Panhandle-A" Eqn.**

$(1/f)^{0.5} = 6.87 \times Re^{0.073}$ [E.9]

For hydrogen
$(1/f)^{0.5} = 6.87 \times [0.14567 \times 10^6\ Q\ \text{(million scf/day)}/D\ \text{(inches)}]^{0.073}$
$= 20.63 \times [Q\ \text{(million scf/h)}/D\ \text{(inches)}]^{0.073}$
$= 16.36 \times [Q\ \text{(million scf/day)}/D\ \text{(inches)}]^{0.073}$ [E.10]

For methane
$(1/f)^{0.5} = 6.87 \times [0.93608 \times 10^6\ Q\ \text{(million scf/day)}/D\ \text{(inches)}]^{0.073}$
$= 23.63 \times [Q\ \text{(million scf/h)}/D\ \text{(inches)}]^{0.073}$
$= 18.74 \times [Q\ \text{(million scf/day)}/D\ \text{(inches)}]^{0.073}$ [E.11]

Neither Eq. E.10 or E.11 may apply directly to small diameter hydrogen pipelines (less than 12"), where the Reynolds numbers may be lower than 5 x 10^6. In this case we may want to use the **"improved flow"** formula

$(1/f)^{0.5} = 5.18\ Re^{0.0909}$ [E.12],

which is an approximation valid for smooth pipes with Re in the range 6 x 10^4 to 7 x 10^6.

For hydrogen

$(1/f)^{0.5}$= 5.18 x [0.14567 x 10^6 Q(million scf/day)/D (inches)] $^{0.0909}$

= 20.37 x [Q (million scf/h)/D (inches)] $^{0.0909}$

= 15.26 x [Q (million scf/day)/D (inches)] $^{0.0909}$ [E.13]

For methane

$(1/f)^{0.5}$= 5.18 x [0.93608 x 10^6 Q(million scf/day)/D (inches)] $^{0.0909}$

= 24.13 x [Q (million h/day)/D (inches)] $^{0.0909}$

= 18.08 x [Q (million scf/day)/D (inches)] $^{0.0909}$ [E.14]

Choosing a formula for $(1/f)^{0.5}$

At small pipeline diameter and low flow rate, the Reynolds number Re will be low and the "improved flow" formula may hold. We can check to see where a transition from partially turblent to smooth pipe flow occurs by setting Eq. E.10 (E.11) and E.13 (E.14) equal.

$6.87 \times Recrit^{0.073} = 5.18\ Recrit^{0.0909}$

=> Recrit = 7 x 10^6

For Reynolds numbers larger than Recrit, we have partially turbulent flow and use the Panhandle-A Equation [Eq. E.9]. If Re<Recrit, we have smooth pipe flow and use the improved flow equation [Eq. E.12].

.

The transition from partially turbulent to turbulent flow can be found by setting Eq. E.9 equal to Eq. E.8 and finding the critical flow rate Qc where the two equations are equal. This gives

$4 \log_{10}(3.7\ D/k) + 2.273 = 6.87 \times Re^{0.073}$

=> $[4 \log_{10}(3.7\ D/k) + 2.273]^{1/.073} = 2.92 \times 10^{11} \times Re$

$$=> [4 \log_{10}(3.7\ D/k) + 2.273]^{13.699}$$
$$= 2.92 \times 10^{11} \times 0.011459\ (Q_c\ G\ P_b)/(\mu\ D\ T_b)$$

Solving for the flow rate Q_c in scf/hr

$$Q_c = 2.99 \times 10^{-10}\ (\mu\ D\ T_b)/(G\ P_b) \times [4 \log_{10}(3.7\ D/k) + 2.273]^{13.699} \qquad [E.15]$$

If Q> Qc, the flow is fully turbulent and the rough pipe approx. holds. If Q< Qc then the Panhandle-A eqn. holds. Note that for hydrogen vs. methane at a given pipe diameter, the critical flow rate Qc for transition from partially turbulent to turbulent flow is substantially higher for hydrogen by a factor of

$$(\mu H2/GH2)/(\mu CH4/GCH4) = (5.3/0.0696)/(7.3/.55) = 5.74$$

As a rule for selecting a formula for $(1/f)^{0.5}$,

If Re < 5 x 10^6, use Improved Flow Eq. [E.12]
If Re > 5 x 10^6, and Q<Qc, use Panhandle A Eq [E.9]
If Q>Qc, use Rough Pipe Eq. [E.8]

Eqn for flow rate Q as a function of pipeline diameter D

We can now substitute Eq. [E.8] , [E.9] or [E.12] for $(1/f)^{0.5}$ into Eq. [E.4], which gives us a relationship between the flow rate Q and the diameter D.

If the improved flow equation is used, we have:

$$Q = \frac{\pi\ T_b}{8\ P_b} \left(\frac{R}{W_a\ G\ T\ L\ Z}\right)^{0.5} (P_1^2 - P_2^2)^{0.5}\ D^{2.5} \quad x$$

$$3.781 \times [(Q\ G\ P_b)/(\mu\ D\ T_b)]^{0.0909} \qquad [E.16]$$

If the Pandhandle-A Eqn. is used, Eq. E.3 becomes:

$$Q = \frac{\pi\ T_b}{8\ P_b} \left(\frac{R}{W_a\ G\ T\ L\ Z}\right)^{0.5} (P_1^2 - P_2^2)^{0.5}\ D^{2.5} \quad x$$

$5.336 \times [(Q\ G\ P_b)/(\mu\ D\ T_b)]^{0.073}$ [E.17]

With the rough-pipe equation, we find

$$Q = \frac{\pi}{8}\frac{T_b}{P_b}\left(\frac{R}{W_a\ G\ T\ L\ Z}\right)^{0.5} (P_1^2 - P_2^2)^{0.5}\ D^{2.5} \times$$

$$[4 \log_{10}(3.7\ D/k) + 2.273] \qquad [E.18]$$

where the same units are used as in Eq. E.4.

If the desired gas flow rate Q is fixed, we can solve Eq. E.16, E.17, or E.18 for D. Before looking at some particular cases, we compare energy flow in hydrogen and methane pipelines.

General Relation for Energy Flow Rate in Hydrogen vs. Natural Gas Pipelines

Let's estimate how much energy can be transmitted as natural gas vs. hydrogen in an identical pipeline, with the same inlet and outlet pressures. From Eq. E.16, the ratio of volumetric flow rates is given by:

$$Q_{H2}/Q_{CH4} = [(G_{H2}/G_{CH4})^{-.4091} \times (\mu_{H2}/\mu_{CH4})^{-.0909}]^{1/0.9091}$$

$$=[(0.0696/.55)^{-.4091} \times (5.9/7.3)^{-.0909}]^{1/0.9091}$$
$$= 2.590$$

Then the energy flow rate of hydrogen compared to natural gas is given by

$$Q_{H2} \times 343 / (Q_{NG} \times 1080) = 2.590 \times 343/1080 = 0.82,$$

assuming the higher heating value of hydrogen is 343 GJ/scf, and the higher heating value of natural gas is 1080 GJ/scf.

For the same pipeline diameter and pressure conditions, the energy flow rate of hydrogen is about 82% that of natural gas.

This result is about the same if the Panhandle-A Eqn. is used instead, yielding an energy flow rate for hydrogen which is 88% that of methane.

General relation for Pipeline diameter required for a particular energy flow rate: H2 vs. CH4

If we want to deliver the same amount of energy via hydrogen and methane, how does the diameter of the pipe compare? Assume the inlet and outlet pressures, pipeline length and energy flow rate are the same. In Eq. E.19 only μ and G vary between hydrogen and methane.

H2 pipeline energy flow = NG pipeline energy flow
$Q_{H2} \times HHV_{H2} = Q_{NG} \times HHV_{NG}$
$Q_{H2} = 1080/343 \times Q_{NG}$ =>
$G_{H2}^{-.4091} \times \mu_{H2}^{-.0909} \times D_{H2}^{2.4091} =$
$1080/343 \times G_{NG}^{-.4091} \times \mu_{NG}^{-.0909} \times D_{NG}^{2.4091}$

=> $D_{H2}/D_{NG} = [1080/343 \times (G_{H2}/G_{CH4})^{.4091} \times (\mu_{H2}/\mu_{NG})^{.0909}]^{1/2.4091}$
$= [1080/343 \times (0.0696/.55)^{.4091} \times (5.9/7.3)^{.0909}]^{1/2.4091}$
$= (3.15 \times 0.4293 \times 0.981)^{.4151}$
$= 1.12$

This says the hydrogen pipeline diameter must be about 12% larger to ensure the same energy flow rate.

<u>Equation for pipeline diameter for hydrogen and natural gas pipelines, for a given flow rate.</u>

We can solve Eq.s E.16, E.17, and E.18 analytically for D, if Q, P1, P2, L, etc. are known.

We assume:

$T_b = T = 298^oK$,
$P_b = 101325\ N/m^2$ (=1 atm),
Z=1
$R=8314.34\ J/(kg.mol.^oK)$
Wa = 28.94

Converting to a new set of units:

For hydrogen Eq. [E.4] becomes:

$$Q = 0.0001799 \times (1/L)^{0.5} \times (1/f)^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b^2]^{0.5} \times D^{2.5} \quad [E.19]$$

where:

Q = flow rate (million scf/h)
L = length of pipeline (km)
P_1 = inlet pressure
P_2 = outlet pressure
Pb = reference pressure = (1 atm)
D = pipe diameter (inches)
f = dimensionless friction factor (depends on flow regime)

Substituting Eq. E.11, E.12 into Eq. E.19, we have for hydrogen

using the Panhandle-A equation,

$$Q = 0.0001799 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/Pb^2]^{0.5} \times D^{2.5} \times 20.63 \times [Q \text{ (million scf/h)}/D \text{ (inches)}]^{0.073}$$

=>

$$D = \{Q^{0.927} \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 269.44 \}^{0.412} \quad [15]$$

using the improved flow equation

$$Q = 0.0001799 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{0.5} \times D^{2.5} \times 20.37 \times [Q \text{ (million scf/h)}/D \text{ (inches)}]^{0.0909}$$

$$D = \{Q^{0.9091} \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 274.26 \}^{0.415} \quad [16]$$

With the rough pipe formula

$$Q = 0.0001799 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/Pb^2]^{0.5} \times D^{2.5} \times [4 \log_{10}(3.7 D/k) + 2.273]$$

$$D \times [4 \log_{10}(3.7 D/k) + 2.273]^{0.4} = \{Q \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 5558.6\}^{0.4}$$

Substituting Eq. 6b, 7b into Eq. 14, we have for methane

using the Panhandle-A equation,

$$Q = 0.00006386 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{0.5} \times D^{2.5} \times 23.63 \times [Q \text{ (million scf/h)}/D \text{ (inches)}]^{0.073}$$

=>

$$D = \{Q^{0.927} \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 662.68 \}^{0.412} \quad [17]$$

using the improved flow equation

$$Q = 0.00006386 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b^2]^{0.5} \times D^{2.5}$$
$$\times 24.13 \times [Q \text{ (million scf/h)}/D \text{ (inches)}]^{0.0909}$$

$$D = \{Q^{0.9091} \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 648.95\}^{0.415} \quad [18]$$

using the rough pipe formula

$$Q = 0.00006386 \times (1/L)^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b^2]^{0.5} \times D^{2.5}$$
$$\times [4 \log_{10}(3.7\, D/k) + 2.273]$$

$$D \times [4 \log_{10}(3.7\, D/k) + 2.273]^{0.4} =$$
$$\{Q \times L^{0.5} \times [(P_1/P_b)^2 - (P_2/P_b)^2]^{-0.5} \times 1565.9\}^{0.4}$$

We can now solve for the pipeline diameter, given the flow rate.

Choosing a flow rate

For hydrogen production from fossil fuels with sequestration of CO_2, we assume that 250-1000 MWth of H2 would be produced (equivalently the hydrogen output would be about 63-252 million scf/day), in order to take advantage of scale economies in hydrogen production.

For reference, to provide hydrogen to 1 million 80 mpg equivalent hydrogen fuel cell cars, each driven 11,000 miles per year (the US average annual mileage for passenger cars), a steam reformer with capacity of 144 million scf H2/day or 49,300 GJ/day or 570 MW would be needed.

If all the cars in Los Angeles (about 10 million vehicles) converted to hydrogen FCVs, this would require 10 times the flow rate of hydrogen or 1440 million scf/day or 493,000 GJ/day (5700 MW H2).

To match the energy flow rate in the current Southern California Gas Company distribution system (about 3 billion scf NG/day), almost 4,000,000 GJ/day would be needed. This is roughly eight times energy flow needed if hydrogen were to supply the total automotive fuel market.

Calculation of pipeline diameter D as a function of flow rate

Assume
P1 = 1000 psia (pipeline inlet pressure)
P2 = 200 psia (pipeline outlet pressure)

The pipeline diameter is plotted as a function of flow rate Q in Figure E.3 for hydrogen and natural gas, for several pipeline lengths. For example, for L = 100 km we have

Estimating the Installed Capital Cost of the Pipeline for Hydrogen

Once D is known, the cost of the pipeline (escalated from 1984 to 2000 $ costs for steel) can be estimated from Christodoulou (1984) via the equation (see Chistodoulou Eq. 2-3-4.b):

$$Pc = 0.2236 \times D^2 + 7.501 \times D + 1.54 \qquad [E.20]$$

where

Pc = the total installed capital cost in $/m of pipeline length
D = pipe diameter (inches)

This equation is based on data for natural gas pipelines, and includes the costs of the pipe (including shipping costs), plus installation, safety testing and coating.

Based on the literature for hydrogen pipelines, we assume that the installed pipeline costs are about 50% higher for hydrogen, so that

$$PcH2 = 0.3354 \times D^2 + 11.25 \times D + 2.31 \qquad [E.21]$$

It is worth noting that Christodoulou's formula probably underestimates the installed cost of smaller scale hydrogen pipelines. According to data from industrial gas suppliers, the installed cost of a 3" diameter hydrogen pipeline is about $250,000/mile ($155/m of pipeline length) under favorable conditions (no road crossings, level ground).

We assume that the minimum cost is $155-620/m for small diameter high pressure hydrogen pipelines installed in an urban area.

$$PcH2\ (\$/m) = \max \left[\begin{array}{l} 0.3354 \times D^2 + 11.25 \times D + 2.31 \\ 155\text{-}620 \text{ (for rural-urban sites)} \end{array} \right. \qquad [E22]$$

Recent data for oil and gas pipelines from the Oil and Gas Journal suggests that costs for pipelines longer than about 20 miles are in the range $20,000-30,000/in-diameter/mile. So a pipeline > 20 miles in length and, 10 inches in diameter would cost about $200,000-300,000/mile. This is roughly consistent with Christodoulou’s formula.

However, Oil and Gas Journal data for smaller diameter pipelines shows a large spread, and an increase in the cost per/in-diam/mile. For local H2 distribution in 3” diameter lines, we assume that the pipeline capital cost ($) is simply proportional to the length, and that the cost is $155-620/m, where the range reflects differences in terrain and degree of urbanization (need for road crossings, etc., in a city that would increase the installed pipeline cost). The assumed cost functions for hydrogen pipelines are plotted in Figure E,4.

The diameters and levelized costs for hydrogen pipelines only (not including compression or storage) are shown in table E.5 for a 100 km pipeline with inlet pressure of 1000 psia and outlet pressure of 200 psia.

Table E.5 Diameters and costs for hydrogen pipelines as a function of energy flow rate for a 100 km pipeline (does not include compression or storage costs), assuming an inlet pressure of 1000 psia and outlet pressure of 200 psia.

Max Energy Flow (MW)	QH2 (million scf/day)	Hydrogen flow (kg/d)	Pipeline Diameter (inches)	Pipeline cost ($/m)	Pipeline cost (million $)	Levelized Cost of Pipeline ($/GJ)
100	25	60	4.76	155	15.5	1.46
250	63	150	6.73	155	15.5	0.58
500	126	300	8.74	155	15.5	0.29
1000	252	600	11.35	173	17.3	0.16
2000	504	1200	14.75	242	24.2	0.11

For cases of interest, the pipeline itself adds less than $1/GJ to the levelized cost of hydrogen. For an alternative H_2 energy flow rate Q (in the range where Q> 500 MW) and pipeline length L, the levelized cost of a hydrogen pipeline can be approximated as ($0.13/GJ) x $(Q/1000\ MW)^{-0.5}$ x $(L/100\ km)^{1.25}$, assuming an inlet pressure of 1000 psi and an outlet pressure of 200 psia.

Estimate of the Levelized Cost of Transmission for Hydrogen

The levelized cost of gas transmission (including hydrogen compression and storage at the plant, and pipeline transmission to the citygate) can be estimated as follows:

$P_T(\$/GJ) =$
$[(CRF + OM) * (C_{pipe} + Ccm + Csto) + Pcm*8760\ h/y * Pelec] / Eflow(GJ/yr)$

where
P_T = levelized cost of pipeline transmission in $/GJ
CRF = capital recovery factor = 0.15
OM = O&M costs per year as a fraction of installed capital cost = 0.04
Cpipe = installed capital cost of pipeline ($)

Ccm = installed capital cost of compressor ($)
Csto = installed capital cost of storage ($)
= H2 plant capacity (GJ/d) x 1/2 day x storage cost ($/GJ)
Pcm = compressor power (kW)
Pelec = electricity cost ($/kwh)
Eflow = energy flow per year (GJ/year) = energy flow/day*365 d/y =
Capacity factor x H2 plant capacity (GJ/.d) x 365 d/y

The costs of hydrogen transmission is shown in Figure E.3 and Table E.5 for a variety of cases.

For all the 100 km and 300 km pipeline cases, the levelized cost of hydrogen transmission is less than $1/GJ. This is small compared to the cost of hydrogen production at large scale ($5-8/GJ, depending on the technology).

Local Pipeline Distribution Systems

Once hydrogen is delivered to the city gate, it must be distributed to refueling stations. This could be accomplished via truck or small scale pipelines. For a large, geographically dense demand, hydrogen pipeline distribution promises the lowest cost, so we focus on this alternative.

Hydrogen can be delivered from a central production point to refueling stations via small scale pipelines (Ogden et.al 1995, Ogden et.al. 1996). We assume that a 3" hydrogen pipeline capable of operation at up to 1000 psi costs $1 million per mile installed. The flow rate of hydrogen through the line can be estimated as shown in Figure E.4. The levelized cost of hydrogen pipeline delivery through a local pipeline is roughly

Cost of pipeline delivery ($/GJ) =

1.2 x (pipeline length in km) x (installed cost in million$/mile) /(hydrogen flow rate in million scf.day)

The extent of the pipeline system needed depends on the geographical density of the demand, and the required density of refueling stations.

For a pipeline distribution system with radial "spokes", sketched in Figure E.1, the delivery cost can be calculated as a function of numbers of cars per km2 (Figure E.5). We see that densities less than about 200 cars/km^2, the cost of pipeline distribution increases rapidly. For a low density of cars, other distribution modes such as liquid hydrogen trucks are less costly and would probably be preferred.

Hydrogen Refueling Stations

We consider refueling stations where hydrogen is delivered by pipeline at about 200 psia pressure.

Hydrogen Refueling Station Components

Here we describe equipment used in hydrogen refueling stations: hydrogen compressors, storage and dispensers.

Hydrogen Compressors

Hydrogen compressors must bring hydrogen to the high pressures required for storage on the vehicle. Assuming that hydrogen leaves the PSA unit at 200 psia, and that the vehicle storage pressure is in the range 3600-8000 psia, a multi-stage compressor will be needed. (As a rule of thumb, it is possible to increase the pressure by a factor of 4 for each compressor stage. Thus, to compress from 200 to 8000 psia requires 3 stages.) To achieve such high pressures, a positive displacement reciprocal pump will be needed. (Centrifugal compressors cannot achieve these high pressures because of leakage, and piston compressors have too high losses due to friction.)

For fuel cell quality hydrogen, contamination of hydrogen by oil from the compressor is a concern. Compressors are available with oil-free lubrication. Alternatively, oil might be filtered out after compression.

Costs and performance for hydrogen compressors were obtained from RIX Industries (Ogden 1998), a company which manufactures oil-free hydrogen compressors for a wide range of pressures and flow rates. Data were obtained for the specific flow rates and pressures found in our case studies (Table E.7).

In a few cases where specific data were not available, we estimated the compressor power requirement by Eq. [E.1]

The energy requirements for compression is shown in Figure E.2, for inlet pressures of 14.7 psia and 200 psia, and outlet pressures of 1000-8000 psia. The electrical energy requirement is typically 2-9% of the energy content of the hydrogen on a higher heating value basis.

Gaseous Hydrogen High Pressure Storage Cylinders

Hydrogen storage cylinders capable of handling high pressures will be required for gaseous hydrogen refueling stations. The amount of storage needed will depend on the station capacity and hourly demand profile. Depending on the refueling strategy, storage cylinders must operate at pressures of about 1000-8000 psia.

Data were obtained from Christy Park Industries for seamless steel pressure vessels designed for hydrogen storage. These are shown in Table E.8 for a range of design pressures. (The maximum operating pressure is 90% of the design pressure.) The installed cost per vessel is approximately independent of storage pressure, because the weight of steel used is about the same in each case, and the costs of manufacturing and installing the vessels is similar. An important difference is the water volume of each vessel, which decreases with pressure, as the wall thickness increases. Vessels can be manifolded in groups of 3 to 12 vessels. The lifetime of pressure vessels is at least 10 years. Typically, state regulations require reinspection every few years to ensure safety.

Hydrogen Dispensers

Compressed gas hydrogen dispensing systems for vehicles are not commercially available at present. However, the design of a hydrogen dispenser should be similar to that for vehicles using compressed natural gas.

The hydrogen dispenser must be able to withstand hydrogen embrittlement at the desired pressures, temperatures and flow rates. Several companies offer refueling dispensers for compressed natural gas vehicles. For example, DVCO offers CNG dispenser units with a working pressure of up to 5000 psig, and a dual hose system much like a conventional gasoline pump. For CNG vehicles, maximum flowrates of 400 scf/minute are typical, because the piping in CNG vehicles can handle this amount without creating backpressure to the pump. A dual hose CNG dispenser unit rated to deliver 400 scf/minute at 5000 psig to each vehicle would cost about $25,000 (Cranston 1993).

In order to adapt CNG dispensers to hydrogen service, a number of changes would be needed. Most components in CNG systems are rated only up to 5000 psi, while higher pressure systems may be needed with hydrogen. Materials used must be checked for compatibility with high pressure hydrogen.

As a very rough estimate we assume that hydrogen dispensers capable of delivering hydrogen at up to 5000 psia will cost twice as much as today's CNG dispensers. For a 2 hose unit capable of fueling two cars, each at a rate of 400 scf H_2/minute, the cost would be $50,000.

<u>**Refueling Station Designs for Gaseous Pipeline Delivery to Station**</u>

Our assumed design for refueling stations connected to a hydrogen local gas pipeline distribution system are shown in Tables E.9 and E.10 (Ogden 1998). A range of sizes is shown for stations dispensing 100,000 to 2 million scf H2 per day (240 – 4800 kg H2/day). Each station could serve a fleet of several hundred to several thousand cars (the average gasoline station today serves about 2000 cars total or about 300 cars per day). The cost of refueling stations is significant, adding about $6-9/GJ H2 to the delivered hydrogen cost, depending on the station size. Almost half of this cost is due to labor costs.

Total Cost for Hydrogen Delivery as a Function of Scale

In Table E.6, we summarize our results for a base case hydrogen distribution system connecting a central hydrogen plant with CO2 capture with city containing a significant number of hydrogen vehicles. The cost of delivery is generally greater than the cost of production, with roughly half of the delivery costs due to the refueling station. There are strong scale economies in pipeline transmission and distribution systems. At the low end of the size range considered (100 MW hydrogen plant), costs for hydrogen delivery are about twice those of production. In addition, refueling stations tend to be more costly at smaller sizes (for small hydrogen flows, we assume distribution to smaller refueling stations to allow customer convenience of having many stations). If a large hydrogen plant can be sited near a city, this removes the necessity for a hydrogen transmission pipeline and recompression at the city-gate, reducing delivery costs by about $2/GJ.

Table E.6 Overall Cost of Hydrogen Delivery from H2 plant to vehicle assuming the H2 plant is 100 km from the citygate

Max Energy Flow (MW)	Compression at H2 plant from 200 to 1000 psi	H2 storage =1/2 day's production ($/GJ)	H2 transmission pipeline from H2 plant to citygate 100 km ($/GJ)	Recompres from 200 to 1000 psi at citygate ($/GJ)	Local Distrib pipelines ($/GJ)	Refueling station size (million scf/d)	Refuelin g stations ($/GJ)	Total cost of H2 delivery ($/GJ)
100	0.49	1.62	1.46	0.49	8.36	0.2	7.3	19.72
250	0.49	1.62	0.58	0.49	3.34	0.5	6.2	12.72
500	0.49	1.62	0.29	0.49	1.67	1	6.0	10.56
1000	0.49	1.62	0.16	0.49	1.25	1	6.0	10.01
2000	0.49	1.62	0.11	0.49	1.25	1	6.0	9.96

Table E.7. Compressor Power Requirements And Costs As A Function Of Flow Rate And Pressure

Inlet Pressure (psig)	Outlet Pressure (psig)	Flow rate (scfm)	Power Required (kW)	Installed Capital Cost ($)	Capital Costs ($/kW)
		MULTI-STAGE COMPRESSORS			
200	2000	254	57	147,000	2580
200	3600	254	75	160,000	2133
200	5000	254	82	170,000	2073
200	5900	254	87	173,000	1989
200	8400	254	98	190,000	1939
		SINGLE STAGE COMPRESSORS			
750	3000	1600	266	180,000	677
1000	5000	1600	276	200,000	725
2000	3600	1600	87	115,000	1322
2000	5000	1600	141	160,000	1135
2000	8000	1600	229	200,000	873
3000	3600	1600	25	100,000	4000
3000	5000	1600	75	120,000	1600
3000	8000	1600	152	140,000	921

$/kW is independent of max. flow rate for the range 175-700 scf/m. Source: RIX Industries.

Table E.8. Data On Commercially Available Hydrogen Storage Vessels

Design Pressure (psig)	Maximum Operating Pressure (psig)	Water Volume (ft^3)	Capacity H_2 @ Max. Pressure (scf)	Installed Cost per Vessel ($)
2450	2200	62.9	8662	10,500
4000	3600	46.3	9837	10,500
5169	4650	24.6	6487	10,500
5471	4900	26.6	7317	10,500
5500	5000	34.2	9563	10,500
6343	5900	27.6	8775	10,500
9420	8400	14.5	6005	10,500

Source: R. Dowling, Christy Park Industries, 1994.

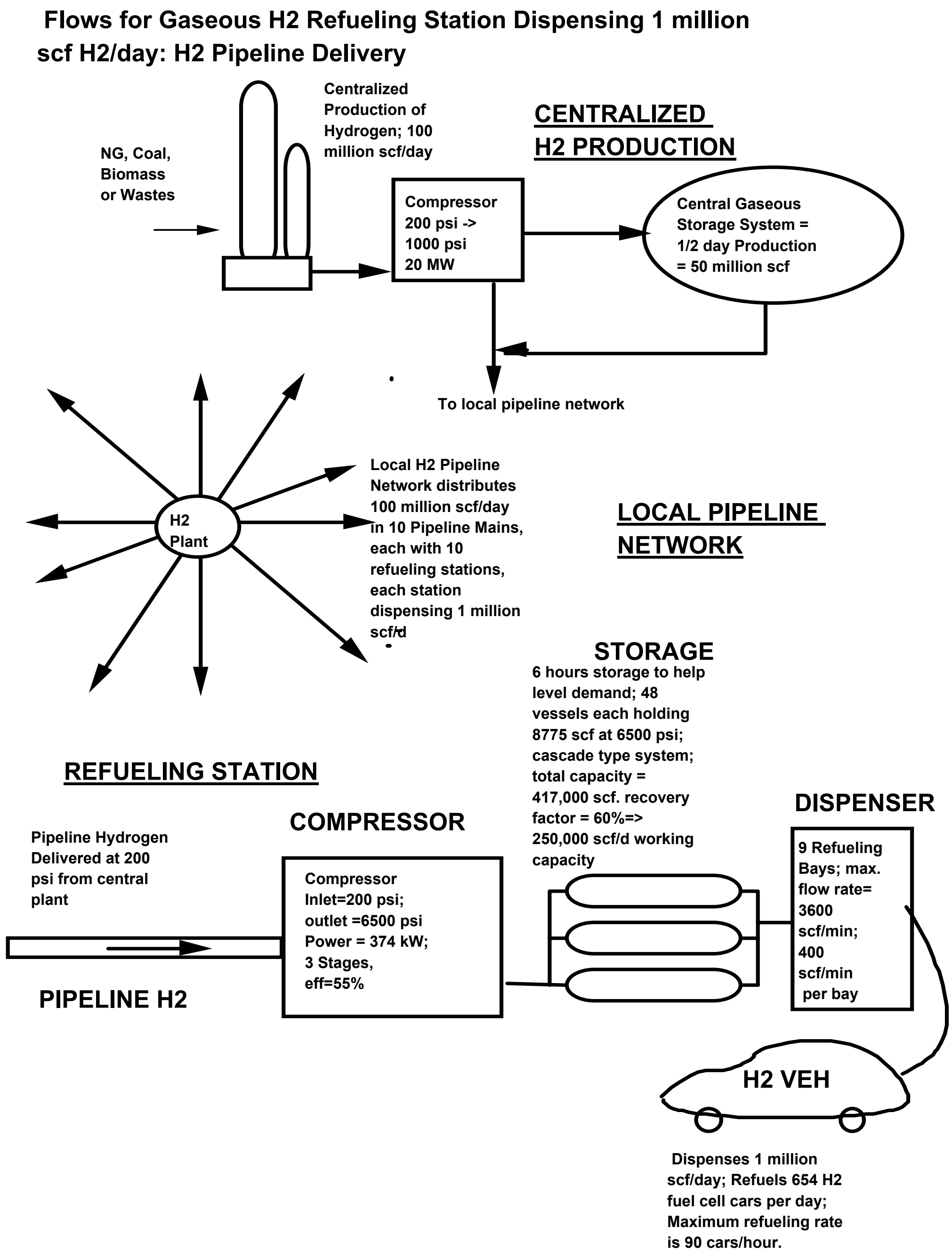
TABLE E.9. DESIGNS OF HYDROGEN REFUELING STATIONS VS. STATION SIZE : PIPELINE H2 DELIVERY

	STATION CAPACITY (SCF H2/DAY)			
	100,000	**366,000**	**1,000,000**	**2,000,000**
HYDROGEN STORAGE VESSELS				
Hydrogen Dispensed from Storage (scf/d)	25,000	91,500	250,000	500,000
Hydrogen Recovery from Storage	0.599	0.599	0.599	0.599
Hydrogen storage capacity needed (scf)	41,740	152,755	417,400	834,724
Storage pressure (psi)	5900	5900	5900	5900
Pressure Cylinder capacity/vessel (scf)	8775	8775	8775	8775
# Vessels	5	18	48	96
Capital Cost of vessels ($)	52500	189,000	504,000	1,008,000
O&M Cost for Vessels ($/yr)	500	1800	4800	9600
HYDROGEN COMPRESSOR				
Storage compressor flow rate (scf/min)	104.2	381.25	1041.7	2083.3
Compressor inlet pressure (psi)	200	200	200	200
Compressor outlet pressure (psi)	6500	6500	6500	6500
Compressor efficiency	0.55	0.55	0.55	0.55
Compressor power (kW)	37.4	137	374	749
# Compressor stages	3	3	3	3
Compressor capital cost ($)	74,861	273,990.	748,608.	1,497,216.
Compressor O&M ($/yr)	3000	3000	3000	3000
Compressor electricity use (kwh/yr)	218593.	800052.	2185936.	4371872.
Electricity rate ($/kWh)	0.072	0.072	0.072	0.072
Compressor electricity cost ($/yr)	15739	57604	157388	314775
Compressor electricity use (kwh./1000 scf)	5.99	5.99	5.99	5.99
HYDROGEN DISPENSER				
Peak hourly average H2 output rate (scf/min)	208.3	762.5	2083	4167
#cars served/day	65.4	239.364	654	1308
Peak hour cars served	8.2	30	82	164
Number of bays	1	3	9	17
Installed capital cost ($)	25,000	75,000	225,000	425,000
TOTAL CAPITAL COST ($)	194,361	548,491	1,488,081	2,940,717
LABOR COSTS ($/YR @ $15/HR)	65,700	131,400	328,500	591,300

TABLE E.10. SUMMARY OF CAPITAL COSTS, O&M COSTS AND DELIVERED HYDROGEN COSTS VS. STATION SIZE : PIPELINE HYDROGEN

	STATION CAPACITY (SCF/D)			
REFUELING STATION INSTALLED CAPITAL COST($)	**100,000**	**366,000**	**1,000,000**	**2,000,000**
H2 Storage Cylinders	84000	189000	504000	1008000
Hydrogen Storage Compressor	74861	273991	7486081	1497217
Hydrogen Dispenser	25000	75000	225000	425000
Controls	10500	10500	10500	10500
TOTAL($)	194,361	548,491	1,488,081	2,940,717
OPERATING COSTS ($/YR)				
Compressor electricity	15739	57604	157387	314,775
Compressor O&M	3000	3000	3000	3000
Cylinder O&M	500	1800	4800	9600
Labor	65700	131400	328500	591300
TOTAL ($/YR)	84939	193804	493687	918675
DELIVERED H2 COST ($/GJ)				
Storage Cylinder capital	0.789	0.48	0.47	0.47
Storage Cyliner O&M	0.064	0.039	0.038	0.038
Compressor Capital	0.973	0.973	0.973	0.973
Compressor O&M	0.240	0.065	0.024	0.012
Compressor Electricity	1.257	1.257	1.257	1.257
Dispenser + Controls Capital	0.333	0.219	0.221	0.204
Labor	5.248	2.868	2.624	2.362
SUBTOTAL: Cost of Refueling Station	8.90	5.91	5.61	5.32
Cost of Pipeline Hydrogen	12	12	12	12
TOTAL DELIVERED HYDROGEN COST ($/GJ)	20.9	17.9	17.6	17.3
VEHICLES FUELED/DAY				
H2 FCV automobiles	65	240	650	1300
H2 FCV buses	8	30	77	154

Figure E.1



Flows for Gaseous H2 Refueling Station Dispensing 1 million scf H2/day: H2 Pipeline Delivery
Centralized Production of Hydrogen; 100 million scf/day
CENTRALIZED H2 PRODUCTION
NG, Coal, Biomass or Wastes
Compressor 200 psi -> 1000 psi 20 MW
Central Gaseous Storage System = 1/2 day Production = 50 million scf
To local pipeline network
H2 Plant
Local H2 Pipeline Network distributes 100 million scf/day in 10 Pipeline Mains, each with 10 refueling stations, each station dispensing 1 million scf/d
LOCAL PIPELINE NETWORK
STORAGE
6 hours storage to help level demand; 48 vessels each holding 8775 scf at 6500 psi; cascade type system; total capacity = 417,000 scf. recovery factor = 60%=> 250,000 scf/d working capacity
REFUELING STATION
COMPRESSOR
DISPENSER
Pipeline Hydrogen Delivered at 200 psi from central plant
Compressor Inlet=200 psi; outlet =6500 psi Power = 374 kW; 3 Stages, eff=55%
9 Refueling Bays; max. flow rate= 3600 scf/min; 400 scf/min per bay
PIPELINE H2
H2 VEH
Dispenses 1 million scf/day; Refuels 654 H2 fuel cell cars per day; Maximum refueling rate is 90 cars/hour.

Figure E.2

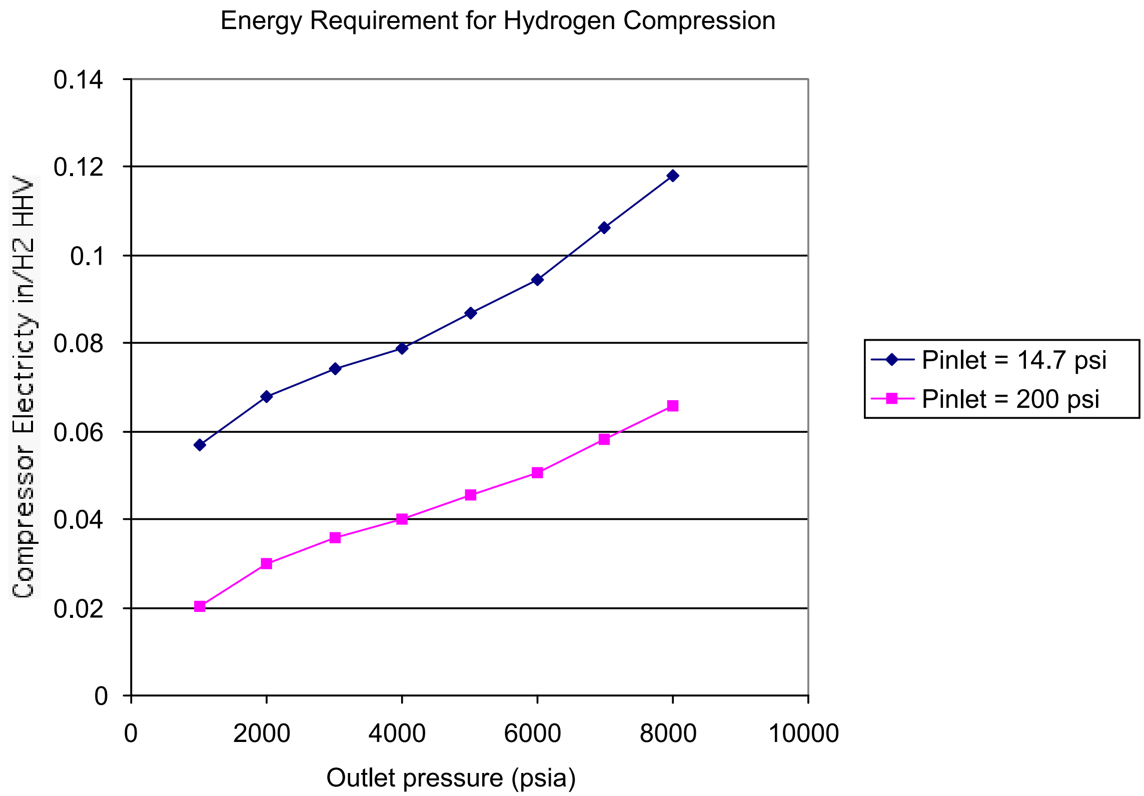


Figure E.3

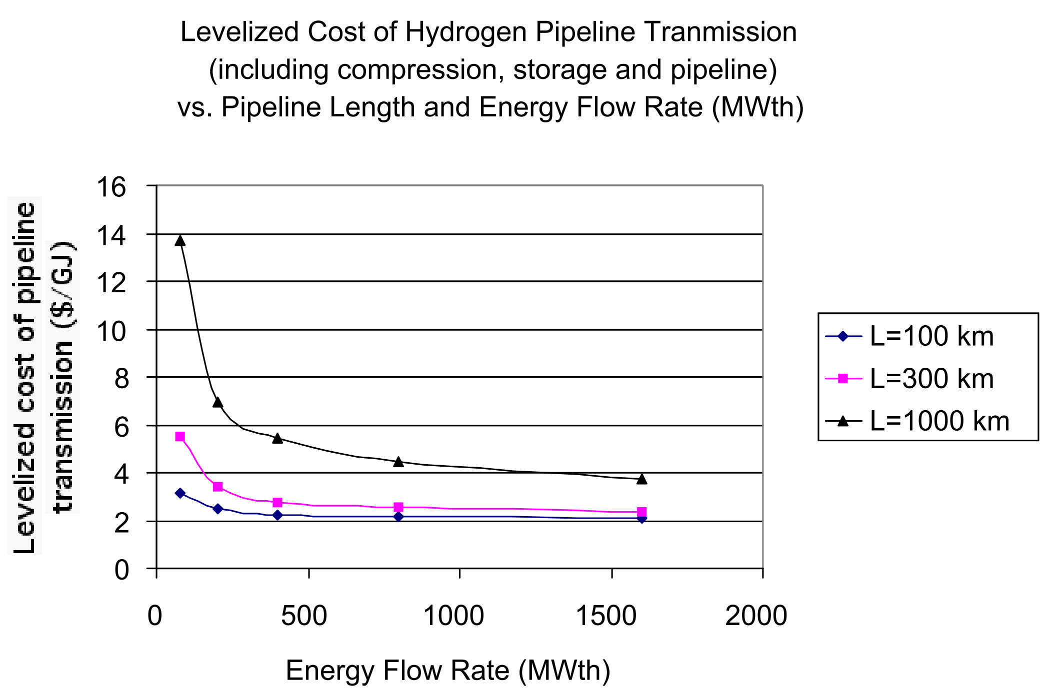
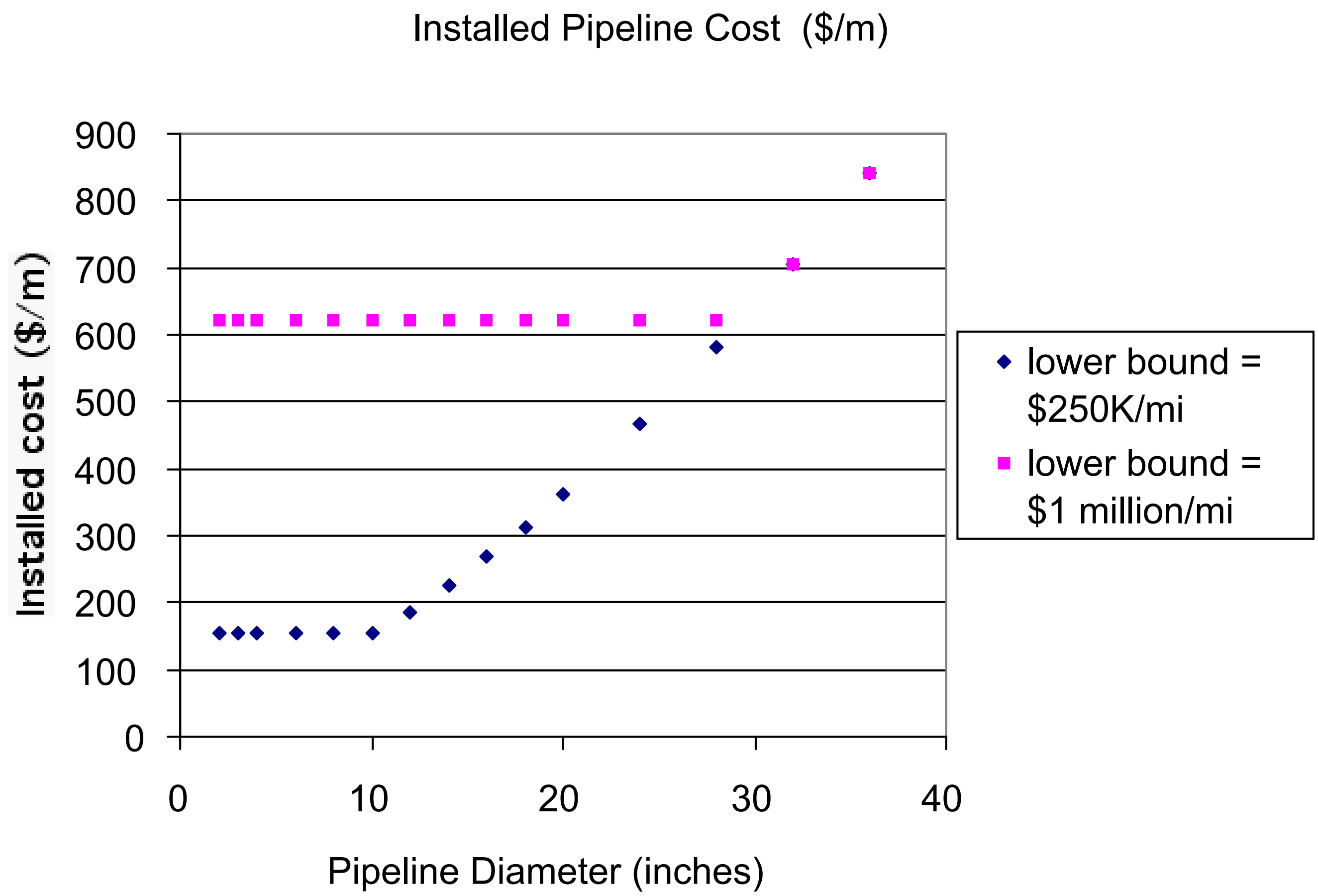


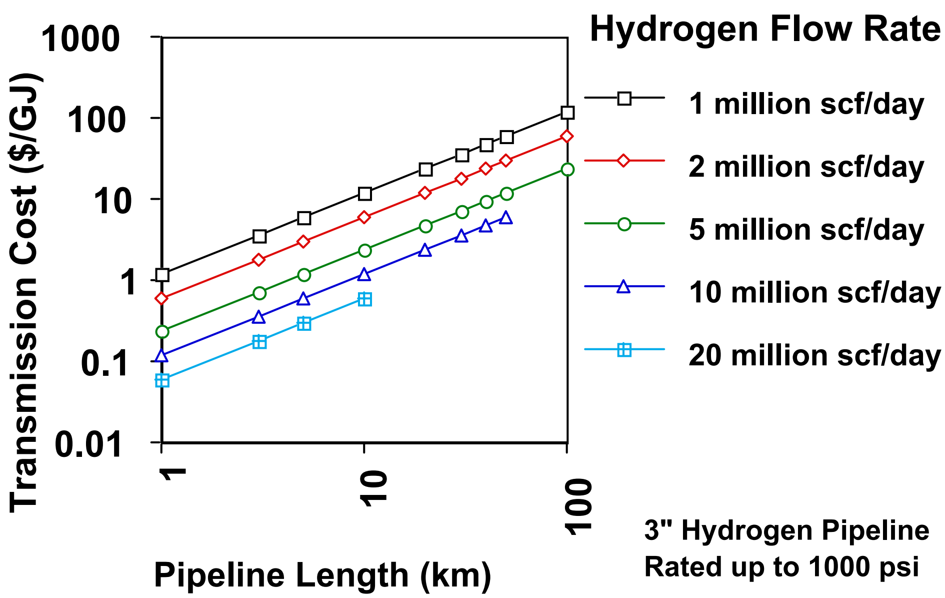
Figure E.4



Installed Pipeline Cost ($/m)
Installed cost ($/m)
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
Pipeline Diameter (inches)
lower bound = $250K/mi
lower bound = $1 million/mi

Figure E.5

Figure A.11. Cost of Hydrogen Pipeline Transmission vs. Pipeline Length and Flow Rate



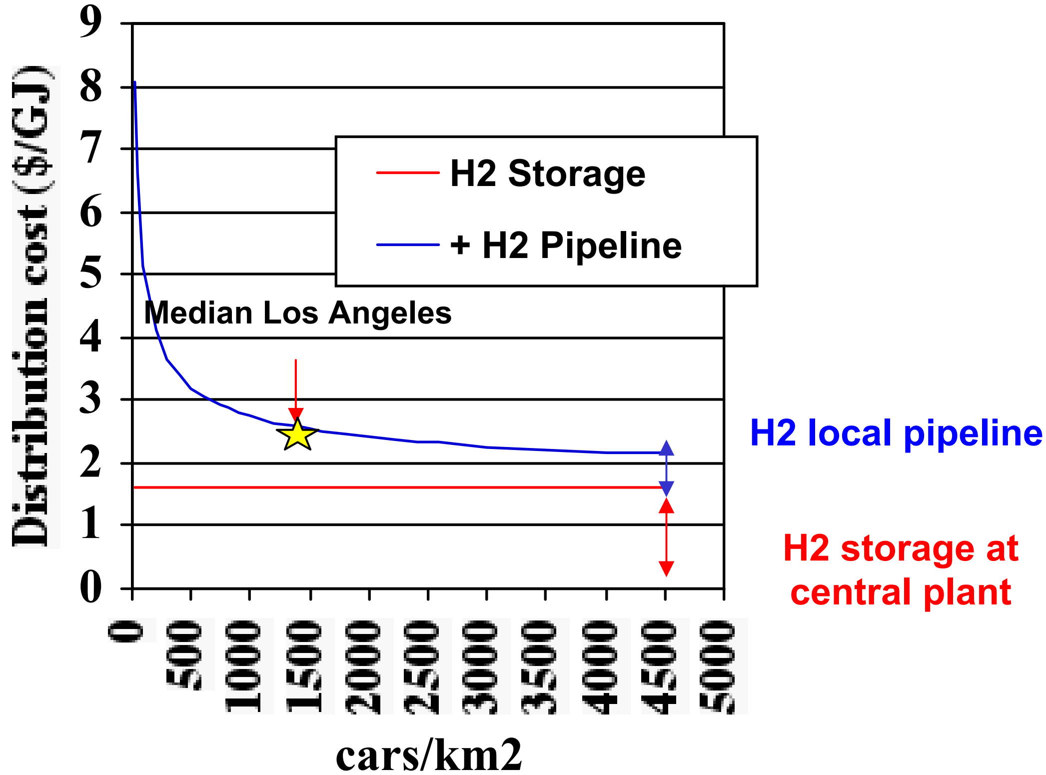
3" Hydrogen Pipeline
Rated up to 1000 psi

Pipeline cost =
$1 million/mile

Inlet Pressure = 1000 psia
Outlet Pressure > 200 psia

1 million scf/day serves a fleet of 9200 Fuel Cell Cars
or 140 Fuel Cell Buses

Figure E.6 Local H_2 Pipeline Distribution Cost vs. Geographic Density Of H_2 Cars



APPENDIX F. An Integrated Hydrogen System Model

As a first step toward modeling transitions, we developed a simple model to connect supply and demand. We estimate infrastructure costs as a function of a relatively small number of variables embodying averaged and/or simplified information about:

- H2 markets
- Geographic factors
- Cost and performance of H2 technologies (vehicles and infrastructure)

<u>Modeling Hydrogen Demand</u>

Understanding the evolution of a hydrogen fuel delivery infrastructure depends on the spatial and time characteristics of the hydrogen demand. We have developed a simple method to model the magnitude, spatial distribution, and time dependence of hydrogen demand, based on Geographic Information System (GIS) data on vehicle populations, and projections for energy use in hydrogen vehicles, and market penetration rates.

As outlined in Section 1.4, we estimate the total hydrogen demand in a city (or "demand cluster") based on:

The total population in the city (calculated from GIS map)
The number of vehicles per person
The market penetration of hydrogen vehicles (fraction of H2 vehicles in the total fleet).
The projected hydrogen use per vehicle (see Table F.1)

A map of hydrogen demand density versus location and time then can be calculated ($kg/d/km^2$). This is shown in Figure F.1, for the state of Ohio. The lighter colors indicate low demand density, the darker colors higher density. The cities of Cleveland, Columbus and Cincinnati are obvious areas of high demand. As time progresses, demand grows, as shown by darkening of the areas around the cities.

Table F.1. Assumed Characteristics Of Hydrogen Fueled Light Duty Vehicles

	H2 Light Duty Vehicle
Average Fuel economy	40-80 miles per gallon gasoline equivalent; or 2-4 X the fuel economy of today's light duty vehicles
Fuel Storage	H_2 gas @5000 psi
H_2 stored onboard scf (kg)	5 kg
Range (mi)	200-400
Miles/yr	15,000
Hydrogen use per LDV year (kg H2/yr)	187-375
Average H_2 use per LDV (kg H2/d)	0.5-1.0

Preliminary Method for Sizing and Siting Refueling Stations within a City

Once the hydrogen demand density is known, we need to decide how many refueling stations are required, how much hydrogen they dispense and where they should be sited. The number, location and size of refueling stations have a major effect of the design and cost of infrastructure.

In general, siting and sizing hydrogen refueling stations is a complex problem. To make this more tractable, we make several simplifying assumptions about hydrogen refueling stations:

- We consider general light duty vehicle markets rather than niches such as fleets.
- All hydrogen refueling stations are the same size.
- Stations are distributed in space according to an idealized model that can be easily related to geography of the region being studied.[14] An idealized version of the delivery system layout is specified. This is developed in Section 1.5 in an "idealized city" model.

[14] We use GIS data to help guide the process of siting and sizing refueling stations, assuming they might be similar to gasoline stations today – which may or may not turn out to be the case. GIS maps can be used to show where gasoline stations are located. For several cities we examined, stations tend to cluster along major roads in "spoke" or "ring" like patterns. Often, more than one station is found at major intersections or at freeway exits. This suggests that today's convenience level could be preserved, if some fraction of current gasoline stations offered hydrogen. Various studies have estimated the number of alternative fueled stations needed for customer convenience to be in the range of 10-25%. For typical US urban vehicle densities of 750-1500 LDV/km^2, there is one gasoline station per 1.3-4 km^2 (assuming each station serves 2000-3000 LDVs). If 25% coverage is needed, equal convenience might be found with one hydrogen station per 5-16 km^2.

Based on these assumptions, we have developed a preliminary method for sizing and siting refueling stations that takes into account geographic, market factors and vehicle fuel economy and annual mileage. Input variables are listed below.

Geographic factors:

LDV/km^2 = Number of gasoline LDVs per square kilometer
= 750-1500 LDVs/km^2 (this estimate is derived from GIS maps)

Area (km^2) = Area of region (city) considered (user input depending on region)
LDVs = Area x LDV/km^2

Market Factors:

GasoLDV/sta
= Number of gasoline light duty vehicles (LDVs) per gasoline refueling station
= 2000 – 3000 (derived from US average ~ 2000 LDVs/station, and from looking at GIS maps of refueling stations in several US cities ~ 3000 LDVs/station)

fH2 = Fraction of hydrogen vehicles in the total fleet. (This fraction is time dependent and varies with the market penetration model used.)

fcov = minimum fraction of existing gasoline stations that must offer H2 to maintain adequate customer convenience. Market studies suggest fcov = 10-25% (urban); 25-50% (rural).

Vehicle Technology:

H2 LDVEnergy
= Average H2 vehicle fuel energy use (kg H2/d/LDV) = 0.5-1.0 kg H2/d (vehicle simulation studies suggest future fuel economy for H2 vehicles could be 2-4 times that for current gasoline vehicles see Table 2; mileage per year is from EIA projections for future vehicle use).

Sizing and siting H2 stations

We now use these input variables to design and cost alternatives for hydrogen infrastructure. The density of gasoline refueling stations in the city is given by:

Gaso sta/km^2=LDV/km^2/GasoLDV/sta=(750-1500)/(2000-3000)
= 0.25-0.75 Gaso sta/km^2

For customer convenience, we assume that the density of H2 refueling stations must be at least fcov times the density of gasoline stations (market studies indicate fcov= 10-25%):

H2sta/km^2 > fcov x Gaso sta/km^2

The number of H2 vehicles per km^2 = fH2 x LDVs/km^2

The total number of H2 vehicles per station is

$$\text{H2 LDV/sta} = \text{fH2} \times (\text{gasoLDV/sta})/\text{fcov}$$

We might wish to limit the H2 station size so that the maximum number of H2 vehicles served is the same as for gasoline stations today. In this case:

$$\text{H2 LDV/sta} = \min \begin{cases} \text{fH2} \times (\text{gasoLDV/sta})/\text{fcov} \\ \text{GasoLDV/sta} \end{cases}$$

The H2 required per station (kg H2/d/sta) is then:

$$\text{H2 kg/d/sta} = \min \begin{cases} \text{fH2} \times (\text{gasoLDV/sta})/\text{fcov} \times \text{H2 LDVEnergy} \\ \text{GasoLDV/sta} \times \text{H2 LDVEnergy} \end{cases}$$

H2 stations = fH2 x #LDVs x H2 LDVEnergy (kgH2/d/LDV)/ (H2 kg/d/sta)

When the fraction of H2 vehicles in the fleet, fH2 > fcov, more hydrogen stations would be built rather than increasing the size of the existing H2 stations.

Even without having detailed knowledge of the exact locations of refueling sites, the simplified analysis above can give some idea of how a delivery system for hydrogen might be designed within a city, and how much it might cost.

This simple model is appealing, because it allows one to design (and cost) the infrastructure based on relatively few inputs related to the average characteristics of the geography of the region and the market. Obviously, this approach to siting and sizing stations has many limitations. For example, traffic flows and proximity to resources for hydrogen production have not been considered. (Today's gasoline stations are sited at busy intersections or interstate sites, where many customers have ready access.) These models for hydrogen demand and refueling station sizing will be improved in future work.

<u>Designing And Costing H2 Infrastructure Alternatives</u>

To provide hydrogen at refueling stations, we consider a variety of possible hydrogen supply and delivery options, which are likely to be important in future hydrogen energy systems:

Centralized, large-scale production of hydrogen from:

- Steam reforming of natural gas with and without CO_2 sequestration
- Coal gasification with and without CO_2 sequestration
- Biomass gasification
- Large scale electrolysis

Distributed production of hydrogen at refueling sites from:
- Natural gas reforming
- Electrolysis using off-peak power

For centralized production, we consider hydrogen delivery via truck (compressed gas or liquid), or via gas pipeline. For fossil hydrogen with CO_2 sequestration, we consider a disposal system for CO_2.

At refueling stations, we assume that hydrogen is dispensed to vehicles as a compressed gas for onboard storage at 5000 psi.

For central production, we assume that hydrogen storage is located at the central plant (as well as some storage at refueling stations). For onsite hydrogen production, no hydrogen distribution infrastructure is needed, although large levels of hydrogen production from natural gas or electricity might require increases in distribution capacity for these energy carriers.

Sizing the production system

The required hydrogen production capacity is found from the number of vehicles in the region of interest.

H2Production Capacity (kg H2/d):
    H2 LDVEnergy x fH2 x LDVs/km2 x Area (km2)

Where:
    H2 LDVEnergy
        = Average H2 vehicle fuel energy use (kg H2/d/LDV) = 0.5-1.0 kg H2/d
    Area (km^2) = Area of region (city) considered (user input depending on region)
    LDV/km^2 = total LDVs/km2
    fH2 = Fraction of hydrogen vehicles in the total fleet. (This fraction is time dependent and varies with the market penetration model used.)

For central production, production capacity could concentrated in one place. For onsite production at refueling stations, many small production systems are used.

Designing, sizing and costing the distribution system

We now specify the layout of the delivery system for various alternatives:

a. delivery by hydrogen gas pipeline,
b. compressed gas truck (tube trailer or mobile refueler)
c. liquid hydrogen truck

The idealized models for the spatial distribution of hydrogen stations, and delivery system layout in Section 1.5 allow us to estimate the length of a local pipeline distribution system needed to reach stations within a city, as a function of the "radius" of the city. Depending on the number of hydrogen stations, the required pipeline length for an ideal system is typically 4-7 times the city radius.

In future work, we will use GIS data to look at how much real cities depart from the ideal models.

Costing Infrastructure Alternatives

Having sized the production system, distribution system, and refueling stations, we now compare capital costs and levelized delivered costs of hydrogen ($/kg) for different hydrogen production and delivery options.

Costs and performance for hydrogen production systems, delivery systems and refueling stations are summarized in Tables F.2-F.8. Capital and operating costs are parameterized in terms of scale, energy costs, and for delivery options, distances. These cost models (developed by Ogden as part of work for the USDOE) are in good agreement with other studies of hydrogen infrastructure costs.

Table F.2. Parameter Ranges Considered in this Study for H2 Energy Systems with Central H2 Production and Local Distribution

Hydrogen Production Capacity Range	250 – 1000 MW H_2 (HHV) (153-613 tonnes H_2/day) (62-252 million scf H_2/d)
H_2 Plant Capacity Factor	80%
H_2 Buffer Storage Capacity at Production Site	1/2 day's production
H_2 Local Distribution Pipeline	
H_2 Inlet Pressure	6.8 MPa (1000 psi)
H_2 Outlet Pressure (at refueling station)	>1.4 MPa (200 psi)
Pipeline capital cost ($/m)	$155-622/m ($0.25-1 million/mile)
Hydrogen Demand	
Ave Light Duty H2 Vehicle (Fuel economy = 2-4 X today's gasoline LDVs = 40-80 mpgge; 15,000 mi/y)	0.5-1.0 kg/day
1 H2 Bus (7 mpgge, 50,000 mi/yr)	20 kg/day
Total LDVs served by plant	150,000-1.2 million vehicles
H_2 Refueling Stations	
Hydrogen dispensed per day per station (240-9600 cars served per station)	0.24-4.8 tonne/day (0.1 –2 million scf/d)
Number of H2 refueling stations required	60-250
Dispensing Pressure to Vehicle	6000 psia
Onboard H_2 Storage Pressure	34.5 MPa (5000 psia)
Associated CO_2 Production for Fossil H2 Plants	
Natural gas -> H2 Plant, 85% of CO_2 captured	51-204 tonne CO_2/h
Coal -> H2 Plant, 90% of CO_2 captured	101-406 tonne CO_2/h
CO_2 Pipeline for Fossil H2 Plants	
CO_2 Pipeline flow rate (range)	1,000-10,000 tonnes/day
Inlet Pressure (at H_2 Plant)	15 MPa
Outlet Pressure (at Sequestration Site)	10 MPa
Pipeline Length (range)	10-1000 km
CO_2 Sequestration Site	
Well depth	2 km
Permeability (milliDarcy)	> 50 milliDarcy
Reservoir Layer Thickness	50 m
Maximum flow rate per well	2500 tonnes/day/well

Table F.3. Summary Economic Data for Large Central H2 Production Systems as a Function of Scale

	So = Reference H2 plant size	Cost(So) = Capital Investment for Ref. H2 Plant (million $)	α= Plant capital Scale factor (scale range)	η = Feedstock Conv. Eff to H2 on HHV basis	Co-products	Source
SMR, CO2 vented	613 tonne H2 /d	262	0.7 (153-613 t/d)	0.81		Foster Wheeler (1996, 1998)
SMR, CO2 captured	613 tonne H2 /d (5000 tCO2/d)	384 for plant + 45 (CO2 compressor) =429 total	0.7 (153-613 t/d) 0.7 (CO2 comp)	0.78		Foster Wheeler (1996, 1998)
Coal Gasifier, CO2 vented	613 tonne H2 /d	659	0.828 (153-613 t/d)	0.736	Electricity (2.04 kWh/kg H2)	Kreutz 2002
Coal Gasifier, CO2 captured	613 tonne H2 /d (10,000 tCO2/d)	613 for plant + 50 (CO2 compressor) =663 total	0.828 (153-613 t/d) 0.7 (CO2 comp)	0.705	Electricity (1.21 kWh/kg H2)	Kreutz 2002
CO2 Sequestration (CO2 compressor is included in fossil H2 plant cost estimates above)	16000 tonne CO2/d 100 km pipeline 2500 tonne CO2/d/well	$70 million x $(Q/16000)^{0.48}$ x $(L/100)^{1.24}$ + Q/2500 x $4.4 million/well + (Q/2500-1) x $3.2 million	Pipeline + injection well + injection site piping			Ogden (2002)
Biomass Gasifier, CO2 vented	165 tonne/d	172	0.7 (150-750 t/d)	0.636		Larson 1993; Simbeck and Chang 2002
Electrolysis	150 tonne/d 250 MW H2	$75-150 million ($300-600/kW)	0.9 (20-613 t/d)	0.8	Oxygen (8 kg/kg H2)	Ogden (1998)

CRF = 15%; non-fuel O&M = 4% of capital investment/y

Capital Cost at plant size S ($) = Cost (S) = Cost (So) x $(S/So)^{\alpha}$

S = H2 plant capacity (tonne/d)

O&M Cost at plant size S ($/y) = O&M(S) = 4% x Cost (So) x $(S/So)^{\alpha}$

Feedstock Cost (S) ($/y)
= S x 365 d/y x capacity factor x HHV H2 (GJ/kg)/η x feedstock Cost ($/GJ)

Byproduct credit (S) ($/y)
= S x 365 d/y x capacity factor x Byprod (unit/kg H2) x Byprod price ($/unit)

Levelized cost of H2(S) $/kg
= [CRF x Cost(S) + O&M(S) + Feedstck Cost(S) + Byproduct credit(S)]/(capacity factor x S x 365 d/y)

Table F.4. Economic Data for Gaseous Hydrogen Pipeline Transmission Systems as a Function of Scale (including hydrogen compression, large scale gaseous storage and transmission pipeline)

	Reference equipment size	**Capital Investment ($/kWe)**	**Equations with scaling factors**
H2 compressor *(note: in some studies H2 compression is included as part of the central H2 plant cost)*	20 MWe	$1600/kWe (multi stage) $900/kWe (single stage)	Scale factor of 0.9 for large H2 compressors (Simbeck and Chang 2002). Costs match well with Kreutz et al. 2002) H2 compressor electricity input = 2-10% of higher heating value of hydrogen compressed depending on compressor inlet and outlet pressures (see Appendix E). Assuming inlet pressure of 1.4 MPa, and outlet pressure of 6.8 MPa, and compressor efficiency of 70%, the electricity use is about 2% of the H2 energy. Compressor power (MWe) = [S (tonne/d) x (1000 MWH2/613 tonne/d) x (2-10% MWe/MWH2)] Capital cost of H2 compressor($) = (Compressor Power/20 MWe)$^{0.9}$ x $1600/kWe x 20 MWe S= H2 plant size (tonne H2/d)
H2 Storage	High pressure cylinders Bulk aboveground compressed gas storage Advanced automotive pressure cylinders Underground storage	$700/kg (kg of H2 storage capacity) " $200-250/kg $280-420/kg	Compressed gas storage is modular with little scale economy. For a H2 central plant, we assume storage equivalent to 1/2 day's production is needed. If S = plant output in tonne H2/d, Cost = $700,000 x 0.5 x S, for aboveground gas storage Cost = $280,000-420,000 x 0.5 x S, for underground storage
H2 Pipeline H2 Flow Length	100 km length; (Pin=6.8 MPa Pout=1.4 MPa) H2 Flow= 60 t/d 150 t/d 300 t/d 600 t/d	Pipe Diam. Cost (inch) (million$) D=4.8";$16-62 D=6.7",$16-62 D=8.7"$16-62 D=11.4"$17-62	Pipeline capital cost ($/m) = max $\begin{cases} 0.3354 \times D^2 + 11.25 \times D + 2.31; \\ 155\text{-}620 \text{ (for rural-urban sites)} \end{cases}$ D = pipeline diameter in inches (D is found from hydrogen flow rate, pipeline inlet and outlet pressures, pipeline length, and flow regime (see Appendix E)

Table F.5. Capital Cost of Hydrogen Liquification and Liquid Hydrogen Storage

Hydrogen Production Plant Capacity (million scf H2/day)	Liquifier Size (tonnes LH2 out/day)	Liquifier Capital Cost (million $)	LH2 Storage Size (tonnes)	Storage Capital Cost (million $)	Total Capital Cost for Liquifier + LH2 Storage (million $)
10.6	30	40	30	2.6	43
35	100	70	100	4.4	74
106	300	126	300	7.9	134
160	450	190	450	12	202

Cost ($million) = 0.3441 t/d + 30.802   LH2 liquefier
Cost ($ million) = 0.0216 t/d + 1.9764   LH2 storage

Typically for liquifiers electrical energy input equal to about 33-40% of the higher heating value of H2 is needed.

Table F.6. Energy Delivered by Truck as Liquid Hydrogen and Compressed Hydrogen Gas

	Storage volume on truck (m^3)	Weight of stored hydrogen (kg)	Energy carried per truck (GJ)	Number of cars fueled per truckload	Truckloads per day to supply 650 cars/day (1 million scf/day)
Liquid Hydrogen (not including dewar)	60	3600 kg H2	510	1020	0.65
Compressed Hydrogen Gas at 2400 psi stored in 16 pressure cylinders (including pressure cylinders; filled cylinder = 0.96% H2 by weight, assumes that hydrogen fills up 85% of total system volume)[a]	28.5	42000 kg (includes both hydrogen and cylinders. Hydrogen wt. = 420 kg)	60	120	5.4

a. Each cylinder holds 10,334 scf of hydrogen at 2400 psig. The entire truck, which has 16 cylinders holds 176,000 scf. This is equivalent to 420 kg of hydrogen or 60 GJ per truck.

Table F.7. Costs for Truck Delivery of Hydrogen[a]

	Cost (1995$)
COMPRESSED GAS STORAGE	
Jumbo Tube Trailer 16 tubes, total hydrogen storage capacity of 4670 m^3 or 176,000 scf or 60 GJ	$406,000
Cab for trailer	$130,000
Maintenance on trailer, cab, fuel , taxes	$43,500/yr
Labor costs (1 person) incl. benefits	$50,000/yr
LIQUID HYDROGEN	
Trailer, capacity 16,000 gallons (60 m^3), holds 510 GJ or 3600 kg H2	$500,000[b]
Cab for trailer	$130,000
Maintenance on trailer, cab, fuel , taxes	$43,500/yr
Labor costs (1 person) incl. benefits	$50,000/yr
ALL TRUCKS	
Lifetime	14.6 yr[c]

a. Source is Taylor et.al. 1986, except as noted.

b. Rambach et. al 1996.

c. Davis, ORNL Transportation Data Book 1996.

Matt Ringer NREL says $100,000 for cab. Gasoline tanker with trailer is $60,000. Wade says compressed gas tube trailer cab is $90K, $60 K for undercarriage, $100 K for tanks. Steve Lasher says $220K for whole compressed gas tube trailer truck.

Hydrogen Refueling Stations

Costs for hydrogen refueling stations have been discussed by a number of authors (DTI et a. 1997, Ogden et al. 1998, Thomas et al 2000, TIAX 2003, DTI 2003). Currently, the H2A group is analyzing the costs of refueling station designs. We will update these estimates as newer data become available. This also ties in well with work being done by Jonathan Weinert on today's refueling station costs, and by Tim Lipman's work on H2E stations.

In Table F.8 we list the capital and operating costs for four types of refueling stations , including pipeline-delivered hydrogen, LH2 truck-delivered hydrogen, onsite steam methane reformers and onsite electrolyzers, according to several recent studies (Ogden 1998, DTI 1997, Simbeck and Chang 2002, and TIAX 2003). A range of sizes is shown for stations dispensing 100,000 to 2 million scf H2 per day (240 – 4800 kg H2/day). H_2 is dispensed to vehicles at refueling stations as a high-pressure gas for storage in onboard cylinders (at 34 MPa). Each station could serve a fleet of several hundred to several thousand cars. There is a wide range of estimates (see also Figure 9). The cost of hydrogen refueling stations scales approximately linear with size. This suggests that the capital cost for refueling station equipment would be about the same for a few large stations or many small ones. Of course, other costs such as land or permitting, that don't scale with size, might be higher if many small stations were built.

Table F.8. Characteristics Of Hydrogen Refueling Stations

Type	Reference Size (kg/d)	Capital Cost as a function of size	Conversion Efficiency Feedstock -> H2	Electricity Use (kWhe/kgH2)	Total O&M cost $/y	Assumptions
ONSITE SMR						
Princeton – 100 units	240-4800	$951.07 x (kg/d) + 300,352	NG->H2 η =0.707 HHV	2.26 kWhe/kg H2	425.96 x kg/d + 53747	NG = $3/MBTU, Elec = $0.072/kWh
DTI – first unit	37-7500	$1155.6 x (kg/d) + 199,770	NG -> H2			
DTI – 100 units	37-7500	$435.11 x (kg/d) + 54266				
DTI – 1000 units	37-7500	$273.04 x (kg/d) + 34,054				
Simbeck 2002	470	1,480,000	η =70% LHV $119,000 NG $5.5/MBTU	2 kWhe/kg H2 $19,000/yr @ 7 cent/kwh	$235,000	NG=$5.5/MBTU; elec= $0.07/kWh
TIAX mature tech. 2003	690	1,175,000				
PIPELINE DELIVERED H2						
Princeton	240-4800	$602.64 x kg H2/d + 34667		2.48 kWhe/kg H2	$195.92 x (kg H2/d) + 43100	Elec = $0.072/kWh
Simbeck	470	520,000				elec= $0.07/kWh
TIAX	690	352,500				
LH2 TRUCK DELIVERED H2						
Princeton	240-4800	$225.51 x kg H2/d + 94664		0.27 kWhe/kg H2	$93.334 x kg H2/d + 45082	Elec = $0.072/kWh
Simbeck	470	680,000				Elec =$0.07/kWh
TIAX	690	423,000				
ONSITE ELECTROLYSIS						
Princeton	240-4800	$2528.7 x kg H2/d + 20433	Electricity η =80% HHV	49 kWhe/kg electrolysis + 4.16 kWhe/kg H2 compression	$736.63 x (kg H2/d) + 45990	Off-pk power Elec = 3 cent/kWh
DTI – first 1000 stations	37-75	$2258.9 x kg H2/d + 69760	Electricity η =80%			
Simbeck	470	4,150,000 $2157/kW	Electricity η =63.5% LHV	55 kWhe/kg H2 Electrolysis + 2.3 kWh/kg H2 Compression	700,000	elec= $0.07/kWh
TIAX	690	1,128,000				

Summary of Component Cost and Performance Models

We have synthesized simplified cost estimates for the components of a hydrogen energy system as a function of scale, energy prices (for natural gas, coal, biomass and electricity), and spatial factors such as the geographic density of demand. These estimates will be refined as results from ongoing studies by the H2A and the NRC become available. In the interim, we will use these estimates as a basis for costing the different parts of a hydrogen energy system as a function of scale, allowing us to make comparisons among transition pathways.

Using the simple model for sizing and siting hydrogen refueling stations and distribution systems developed earlier (task 1a, we can estimate preliminary costs for different demand and delivery scenarios.

<u>INPUTS</u>

<u>Geographic factors:</u>
Total LDVs/km2
Region size

<u>Market Factors:</u>
fH2 = fraction H2 vehicles in fleet
fcov = coverage factor (fraction of all stations serving H2 for customer convenience)
LDVs/station
Vehicle use miles/year

<u>Technical Factors:</u>
Vehicle Fuel Economy
Cost and performance of infrastructure components
Layout of distribution system

<u>We can estimate for different production and delivery pathways:</u>
H2 production capacity needed
Number of H2 refueling stations
H2 dispensed per station
Density of H2 stations
Cost of entire system from production through delivery for different production and delivery options
Levelized cost of hydrogen

<u>Preliminary Results</u>

We have just begun to work with this model to estimate the lowest cost alternatives as a function of market and geographic factors. As an example, we consider a city of 1 million people, where 10% of vehicles run on H2 (see Tables F.9-F.10).

Table F.9. Characteristics of City and Calculated Infrastructure

Geographic Factors	
People	1 million people
Light Duty Vehicles	750,000 LDVs
LDVs/km2	1500
Area of city	500 km2
City radius (for circular city) km	12.6 km
Market factors	
Fraction H2 vehicles = fH2	10%
Gasoline Vehicles/gasoline station	3000
Coverage factor	20%
Vehicle performance	
H2 Vehicle Fuel Economy = 2.8 x Today's Gasoline LDV	57 mpgge
Miles travelled/y	15,000
H2 energy use/LDV/d	0.7 kg H2/d/LDV
H2 Vehicles and Refueling Stations	
# H2 vehicles in city	75,000
Total H2 production required kg/d	52.5 tonne H2/d
# H2 refueling stations	50
H2 refueling station size	1050 kg/d/sta
H2 cars/H2 sta	1500
Central Production Model	
Central production capacity tonne H2/d	65.6 tonne/d
Central plant storage capacity tonnes	26.26 compressed gas 52.5 Liquid H2
Pipeline Distribution Model	
Local distrib. pipeline length/city radius (from Chris Yang's models)	6 (range is from 4-7)
Local distrib pipeline length	75.7 km
Truck Distribution Model (assumes each truck makes 2 deliveries per day)	
Compressed Gas Trucks required	55
LH2 Trucks Required	7

Table F.10. Capital Costs for Hydrogen Infrastructure Options (million $)

	Central production	Central production	Central production	Onsite SMR	Onsite Electrolyzer

	SMR + pipeline delivery, CO2 vented	SMR + LH2 truck delivery, CO2 vented	SMR + comp gas truck delivery, CO2 vented		
Capital costs Million $					
Central SMR	55	50.5	55		
Liquefier	-	54	-		
Comp Gas storage	18.3 1/2 day	2.54 1/2 day	18.3 1/ day		
Local Pipeline ($620/m)	46.9	-	-		
Trucks	-	4.4	29.5		
Refueling stations	33.3	16.6	33.3	64.9	122
TOTAL Capital cost ($million)	156	127	136	65	122
TOTAL Capital cost $/LDV	2075	1699	1814	866	1628
Operating Costs (million $/yr)					
Natural Gas	12.60	12.60	12.60	20.06	
Electricity	2.85	8.91	2.85	2.60	30.56
Other O&M	6.23	5.75	10.58	2.60	4.88
Total O&M	21.67	27.26	26.03	25.26	35.44
LEVELIZED COST OF H2 $/kg					
Capital	1.52	1.25	1.33	0.64	1.19
NG	0.82	0.82	0.82	1.31	0.00
Electricity	0.19	0.58	0.19	0.17	1.99
Other O&M	0.41	0.38	0.69	0.17	0.32
Total	2.94	3.03	3.03	2.28	3.51

For this level of hydrogen vehicle use, in this size city, onsite SMR gives the lowest capital costs and delivered hydrogen costs. In Figure F.1, we plot the capital cost of H2 infrastructure per car as a function of hydrogen market penetration rate. For this set of assumptions, onsite SMRs are the lowest capital cost option for all values of fH2 > 1% of the fleet (at these very low H2 penetration rates, electrolyzers are less costly).

The delivered hydrogen cost ($/kg) is plotted versus fH2 in Figure F.2. At very low hydrogen use, compressed gas trucks or electrolyzers give the lowest delivered costs. At very large fractions of H2 use, pipeline hydrogen gives the lowest delivered cost.

Of course, this calculation does not take into account environmental benefits that might arise with central production of hydrogen and use of renewable resources or capture of CO2.

We have just begun to use this model to explore how the results depend on important parameters.

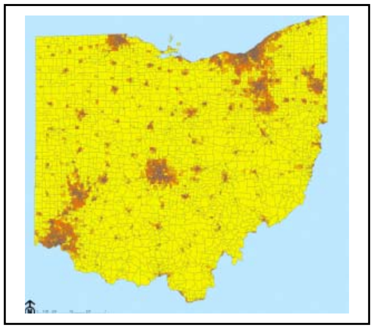
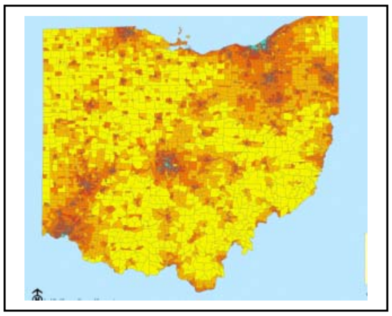
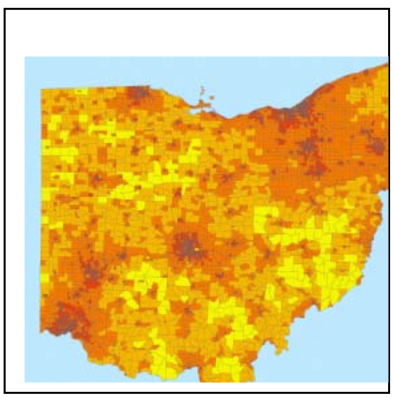


Figure F.1. Hydrogen demand density (kg H2/d/km2) over time at years 1, 5, 10 and 15, assuming that 25% of new light duty vehicles use hydrogen, starting in year 1.





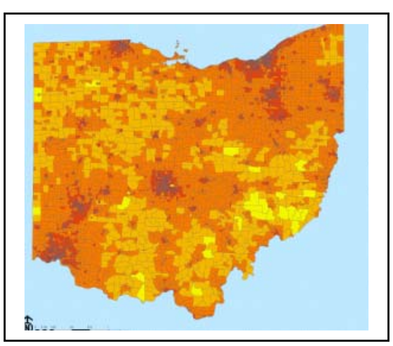
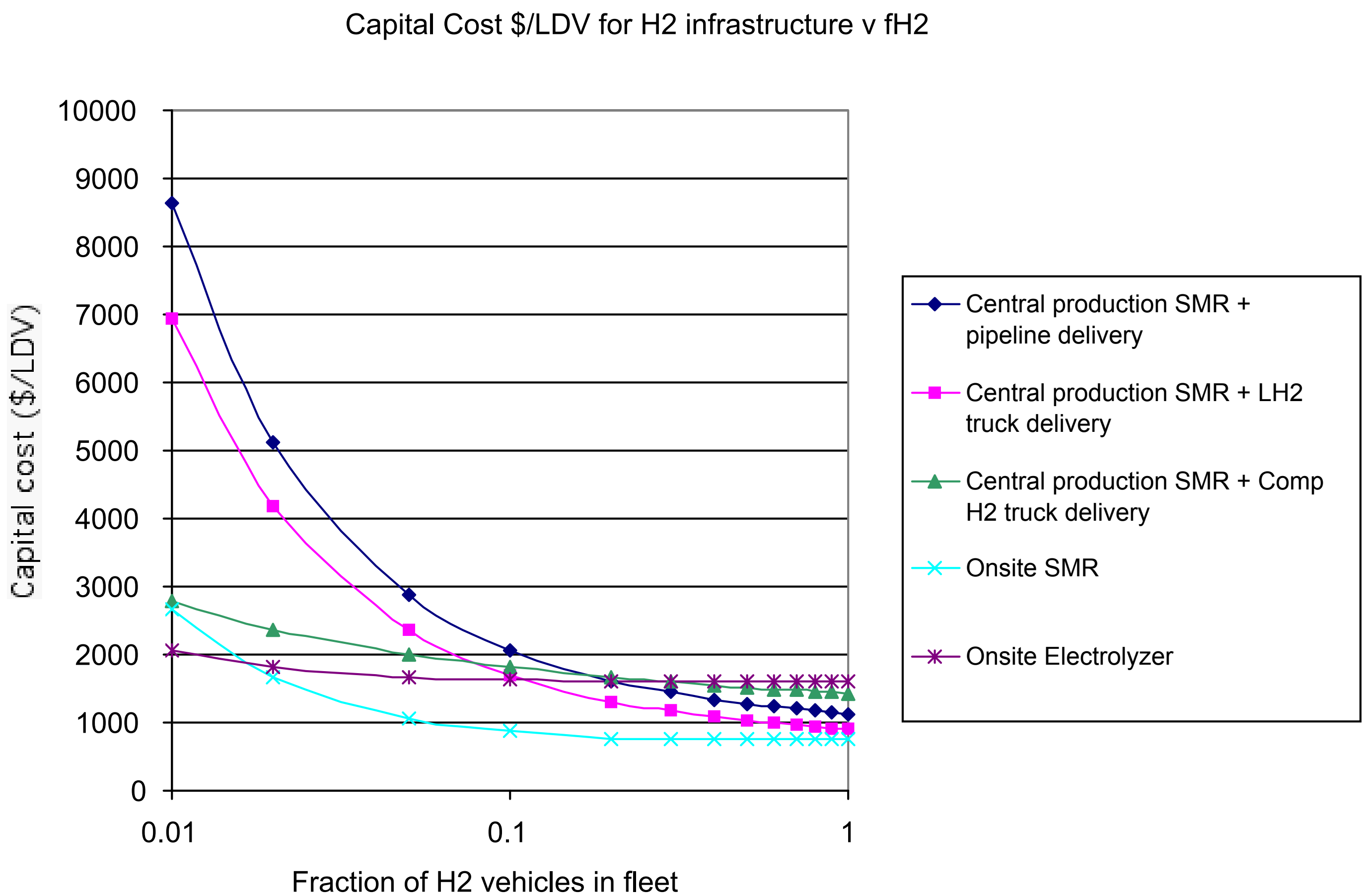


Figure F.2.



Capital Cost $/LDV for H2 infrastructure v fH2
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Capital cost ($/LDV)
0.01
0.1
1
Fraction of H2 vehicles in fleet
Central production SMR + pipeline delivery
Central production SMR + LH2 truck delivery
Central production SMR + Comp H2 truck delivery
Onsite SMR
Onsite Electrolyzer

Figure F.3

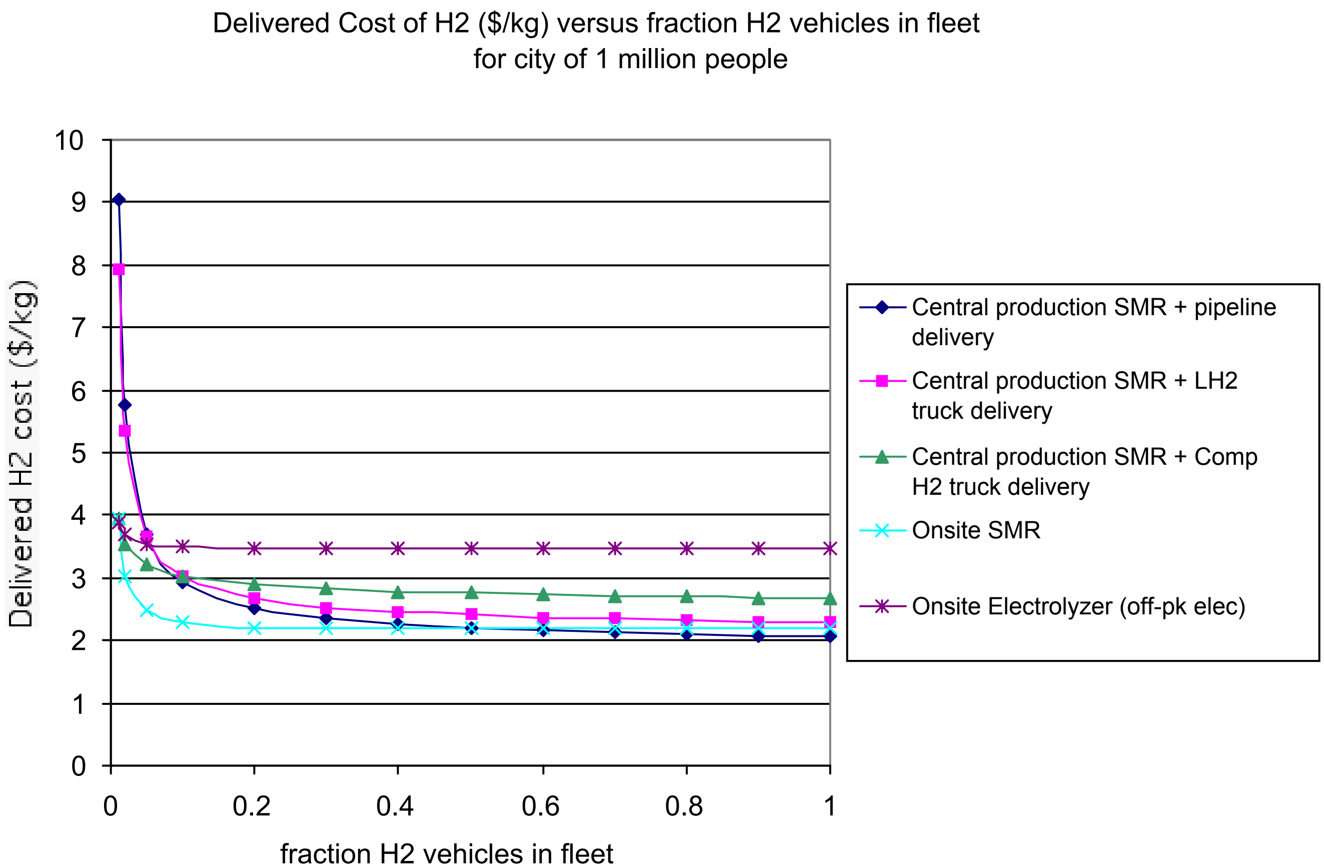
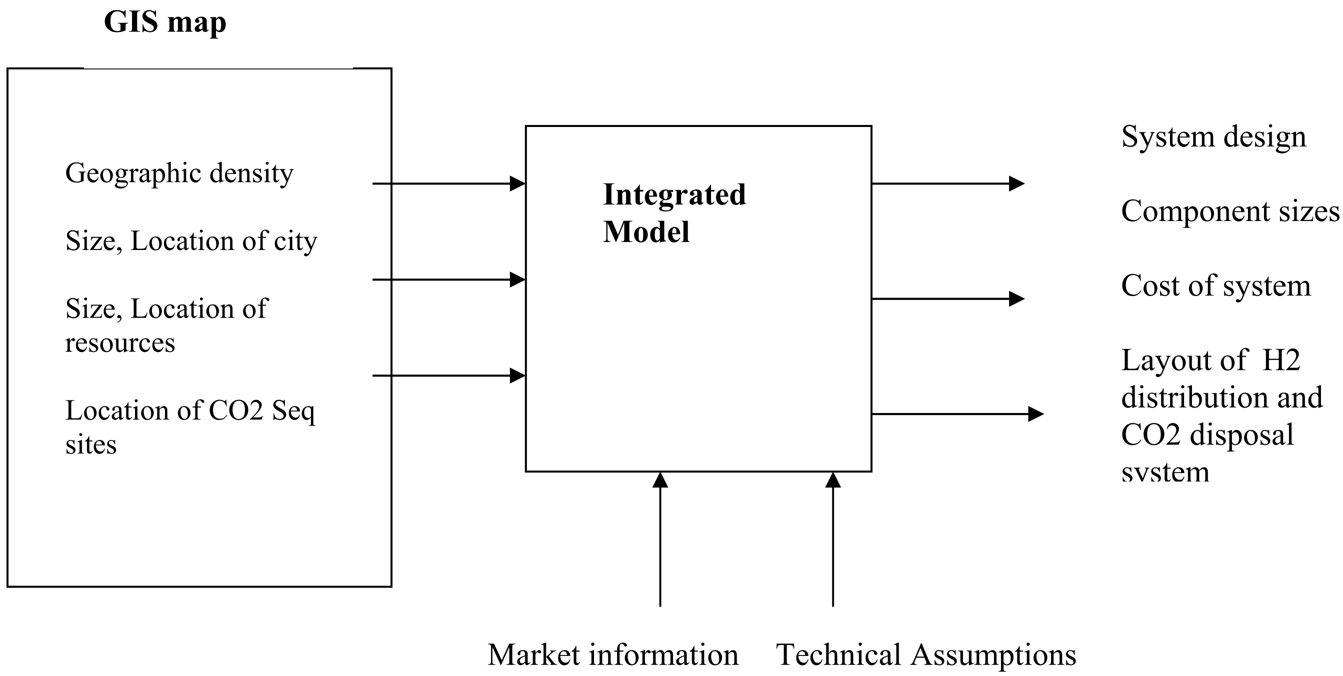

Delivered Cost of H2 ($/kg) versus fraction H2 vehicles in fleet
for city of 1 million people
Delivered H2 cost ($/kg)
10
9
8
7
6
5
4
3
2
1
0
0
0.2
0.4
0.6
0.8
1
fraction H2 vehicles in fleet
Central production SMR + pipeline delivery
Central production SMR + LH2 truck delivery
Central production SMR + Comp H2 truck delivery
Onsite SMR
Onsite Electrolyzer (off-pk elec)

Figure F.4. Interface of Simple Integrated Model with GIS Database



APPENDIX G. LITERATURE REVIEW OF MATHEMATICAL PROGRAMMING METHODS APPLIED TO PIPELINE SYSTEM DESIGN

Linear Programming

In the early years of gas pipeline study, the steady-state operation problem was considered by researchers (Sekirnjak, 1996). They dealt with a very simple network model, consisting of a few sources and sinks. To avoid the nonlinearity caused by the gas flow equation, the network was separated into high, medium and low pressure subsystems, connected by compressors. The pressure drop was neglected within each subsystem, and the only decision variables were the flow-rates through each segment. Thus the network was basically modeled by a set of flow balance equations. This was purely a linear model and then the model could be solved by linear programming techniques. This first optimization application was presented at 12th IGU World Gas Conference in Nice, 1973 (Larcher, et al).

	Design Optimization	Steady-state Operation optimization
Objective function	$building \cos t = f(pipe\ diameter,\ pipe\ length,\ \#\ of\ \ compressor,\ terrain, \ldots)$	$operation \cos t\ (fuel\ comsumed) = f(pressure,\ flowrate, \ldots)$
Constraints	1. mass flow balance equation at each node 2. gas flow equation at each pipe segment, i.e. pressure drop equation 3. working equation of each compressor 4. limits imposed on pressure or flow-rate	Same as the left
Optimization variables	pipe diameter and length, location of compressor stations and other interconnection points, etc.	flow-rate, suction and discharge pressure at each compressor station, etc.

Table G-1.

Traditional optimization techniques	Pure linear programming
	Nonlinear programming
	    Sequential linear programming (SLP)
	    General reduced gradient method (GRG)
	    Inter-point method
	    Newton-Raphson method
	    Sequential unconstrained minimization technique (SUMT)
	Dynamic programming

Nontraditional optimization techniques	Genetic algorithms Simulated annealing Neural network Artificial ants

Table G-2

The advantage of LP method is that it has unique optimum, which is the global optimum. The disadvantage is that it can only solve small size network roughly and the pressure difference between sources and sinks here must be relatively small so that three subsystems are enough to make the approximation of constant pressure within one subsystem. Otherwise, two possibilities may appear: one is that the computing error becomes too large to tolerate if keeping the same division of three subsystems and the other is to increase the number of subsystems that is essentially a method of linearizing the nonlinear model, so has its own problems of convergence and tolerance.

Non-Linear Programming

Pipeline system design is an inherently nonlinear problem, so nonlinear programming techniques is a natural tools. Sequential linear programming was used to optimize the steady-state operation of gas pipeline. Edgar (1978) presented a computer algorithm to optimize the design of a gas transmission network. Two solution techniques were used: one was the Generalized Reduced Gradient (GRG) method; the second method was to combine the branch-and-bound scheme with GRG. The techniques were applied to different type of cost functions respectively. Daniel de Wolf (1996) considered the optimal dimensioning of gas transmission network when the net work topology is known. His presented a way to compute the first order derivatives, and used the bundle method (Penalty parameter) for optimization. Siregar (2000) repeated Wolf's work. Djebedjian (2000) applied the sequential unconstrained minimization technique (SUMT) to the operation optimization of hydraulic pipeline system. Benson (2001) took the LOQO nonlinear solver which is based on inner-point method to solve the design problem of small-scale CO_2 pipeline network. Both the network topology and the dimension of pipes are unknown variables in her optimization model.

One prominent problem caused by the nonconvexity is how to judge whether the optimum you get is the global optimum. Since most nonlinear optimization techniques are based on iterative methods and the initial value may determines which optimum is found to some extent, changing the initial value may give another solution. Another approach is to find some upper bound for the objective function at pre-processing and use it as one criterion to discard some local optimums (Wu et al. 2000).

Dynamic Programming

DP has allowed optimization of pressures in steady-state gas pipeline simulations for the past thirty years. This approach allows full used of nonlinear hydraulic models and nonlinear and even discontinuous compressor station models. Any objective function can be used that is a simple sum of costs at each station as a function of flow and inlet/outlet pressures.

The first application on gas pipeline was by Larson and Wong (1968). They applied the method to fuel cost minimization in a single, straight line system and used a recursive formulation, finding the optimal suction and discharge pressures of a fixed number of compressor stations. The length and diameter of the pipeline segments were considered fixed because DP was unable to accommodate a large number of decision variables. The first attempt at optimizing a branching structure in the pipeline industry using DP was by Zimmer in 1975. Recent advances have generated a new DP technique, which is called non-sequential (Carter, 1998) or non-serial DP (Bertelè, 1972). Rather than attempting to formulate DP as a recursive algorithm, in this approach we simply look at a system, grab two or three connected compressor or regular elements, and replace them by a "virtual" composite element that behaves just like its components operating in an optimal manner. These elements can be selected from anywhere in the system, so the idea of "recursion" is really not a good description for this process. The process continues, reducing the number of elements in the problem by one each time, until the system can be reduced no further. Typically, that occurs when there is exactly one virtual element left, which completely characterizes the optimal behavior of the entire pipeline network. The best pipeline operation can then be found by just searching one simple table for the lowest occurring value. Using non-sequential dynamic programming allows one to rapidly and exactly solve these problems even with extensive transmission networks involving extensive branching and looping.

Nontraditional Algorithms

In recent years, a variety of "nontraditional" techniques have been publicized for optimization problems of this sort. Among these methods are Simulated Annealing, Neural Network, Genetic Algorithms and Artificial Ants. The hope is that these methods can give a "more global" optimum. We plan to explore these options further in later work.

APPENDIX H. GIS DATA SOURCES USED IN THIS STUDY

Layer	Source	Format
GENERAL INFORMATION		
Census Population: Population by block Population by block group Population by Tract Population by County Population by State	www.geographynetwork.com	Internet Server
Template Data USA: Cities Capital Cities US Boundaries Rivers State Boundaries Counties Lakes Neighboring Countries Major Roads: Interstate Highways Limited Access Highways Local roads Ramps	ArcGIS 8.1, ESRIDATA	Shapefile
EXISTING NATURAL GAS INFRASTRUCTURE		
CNG Fuel Stations Station Name Street Address & phone no.	Alternative Fuels Data Centre www.afdc.nrel.gov/refuelling	Geodatabase table
Natural gas transmission and distribution	GASTRANS (USDOE)	
ELECTRICITY SYSTEM		
Coal Plants: E-GRID Plant File	NETL, DOE	Geodatabase table
Coal Plants: Plant name Utility ID State Source Metric_Ton	BEG NETL, DOE	Shapefile

GASOLINE STATIONS	BusinessMAP Pro 2.0	
CO2 SEQUESTRATION SITES		
Brine Wells: State County Geobasin Wellname Upper depth Lower depth Methgrade PH Chemical composition Mass balance Source..etc..	NETL, DOE Bureau of Economic Geology (BEG), University of Texas	Geodatabase table
Formation Study Area: Clipping Basin Area Perimeter	BEG NETL, DOE	Shapefile
DATA FOR THE STATE OF OHIO		
Electric Transmission Lines: Length	PUCO	Shapefile
Electric Sub-Stations: Name	PUCO	Shapefile
Railroads: Length	PUCO	Shapefile

PUCO = Public Utilities Commission of Ohio

BEG = the Bureau of Economic Geology (BEG) at the University of Texas, Austin

The data matrix by the Bureau of Economic Geology (BEG) at the University of Texas, Austin provided databases. The data matrix gave extensive information about 16 parameters in 21 basins. These were illustrated as formation study areas on the map. The parameters for each basin were:

1. depth
2. permeability / hydraulic conductivity
3. formation thickness
4. net sand thickness
5. percent shale
6. continuity
7. top seal thickness
8. continuity top seal

9. hydrocarbon production
10. fluid residence time
11. flow direction
12. a)formation temperature; b)formation pressure; c)water salinity
13. rock / water reaction
14. porosity
15. water chemistry
16. rock mineralogy

<u>**Data List of Ohio Project**</u>

Task 3: Case study of Fossil Hydrogen Production in the Midwestern US
Development of GIS Database – creating the database for Ohio case study

As mentioned, the GIS is a tool for visualizing and managing geographical data, which means we used those data (i.e. the attribute table) to create maps. The following is a list of the data[15] used in the Ohio case study.

1. POWER PLANT OVER 100W

- Data Type: Shape file Feature Class
- Geometry Type: Point
- Attributes: power plant name; parent company information, capacity, etc.
- Source Detail: E-GRID2000 contains nonutility + utility-owned power plant data for years 96-98.

2. BRINE WELL

- Data Type: Shape file Feature Class
- Geometry Type: Point
- Attributes: geo-basin, well name, upper depth, lower depth, method, PH, calcium, chloride, magnesium, potassium, sodium, sulfate, source, etc.
- Source Detail: National Energy Technology Lab (NETL), including: [1] brine formation data, and [2] brine chemistry data.

3. ELECTRIC TRANSMISSION LINES

- Data Type: Shape file Feature Class
- Geometry Type: Line
- Attributes: Fnode, Tnode, length, Dbcode, etc.

4. RAILROADS

- Data Type: Shape file Feature Class
- Geometry Type: Line

[15] Some of the data may be used in our future analyses

- Attributes: Fnode, Tnode, length, Dbcode, etc.

5. MAJOR ROADS (i.e. HIGHWAYS, LOCAL ROADS, RAMPS)

- Data Type: Shape file Feature Class
- Geometry Type: Line
- Attributes: highway name, length, state FIP, alternative name, type of road, etc.
- Source Detail: ESRI Media Kit 2002 – East USA data.

6. CENSUS DATA (i.e. BLOCK GROUPS)

- Data Type: Shape file Feature Class
- Geometry Type: Polygon
- Attributes: population[16] (2000), population density, area, number of households, etc.
- Source Detail: ESRI Media Kit 2002 – East USA data.

7. NG PIPELINE RECEIPT POINT

- Data Type: XY Data Source
- Attributes: pipeline name, point name, purchaser, average flow, capacity, coincident, non-coincident, region, etc.

8. CNG STATIONS

- Data Type: Shape file Feature Class
- Geometry Type: Point
- Attributes: station name, phone number, address, etc.

9. NG PIPELINES (12 companies)

- Data Type: Shape file Feature Class
- Geometry Type: Line
- Attributes: length, PSIA, etc.

---

[16] There is population by race, gender, renter/owner, and age.

10. COUNTIES

- Data Type: Shape file Feature Class
- Geometry Type: Polygon
- Attributes: name, area, perimeter, etc.

11. CITIES

- Data Type: Shape file Feature Class
- Geometry Type: Polygon
- Attributes: name, area, perimeter, etc.

12. ELECTRIC SUB-STATIONS

- Data Type: Shape file Feature Class
- Geometry Type: Point
- Attributes: name

13. ELECTRIC AREA

- Data Type: Shape file Feature Class
- Geometry Type: Polygon
- Attributes: name, area, perimeter, etc.

APPENDIX I GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEFINITIONS

A Geographic Information System (GIS) is a collection of computer hardware and software and geographic data designed to capture, store, manipulate, analyze, and display spatial and non-spatial information (Huxold, 1991).

GIS incorporates the elements of computer cartography and relational databases into one system, fully integrating spatial and tabular data. The most important characteristic of GIS is that every mapped feature is linked to a record in a tabular database and may be related to records in other databases as well. This linkage between maps and tabular data makes the storage and analysis of complex geographic data possible.

The first major component of GIS is spatial data. There are two fundamental approaches to representing the spatial component in a GIS: the vector model and the raster model (Figure 1). In the vector model, features in the real world are represented by the points and lines that represent their locations and boundaries, as if they were to be drawn by hand. Points, lines, and polygons are used to represent irregularly distributed geographic features in the real world (Aronoff, 1993). A line may represent a road, stream, or pipeline network. A polygon may represent a stand of trees or a building footprint (demand cluster). Points may represent light poles, individual trees, or coal power plants.

In the raster model, called a GRID in ArcView and ARC/INFO, the space is regularly subdivided into discrete cells that are almost always square. The location of geographic features is defined by the row and column position of the cells they occupy. The area that each cell represents defines the spatial resolution of the GRID. The position of geographic objects is only recorded to the nearest cell (Aronoff, 1993).

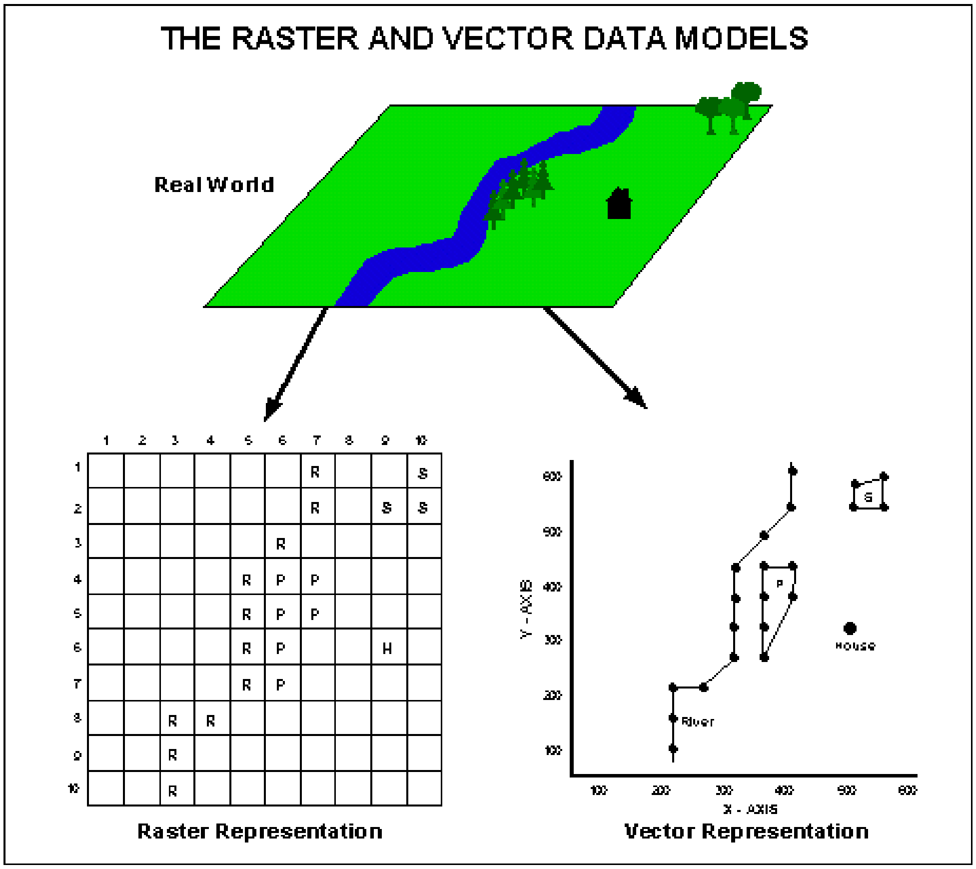


Figure 1 - Comparison of the Raster and Vector Spatial Data Models
(Adapted from Aronoff, 1993)

The other major component of a GIS is a Database Management System (DBMS). A DBMS is used to store, manipulate and retrieve data from a database. It does this by storing data such that interrelationships that exist between data sets can be exploited to easily retrieve and/or manipulate that data (Healey, 1991). It is this element that makes GIS a powerful analysis tool rather than just a cartographic tool.

The power of DBMS and the utility of spatial data models allow the GIS user to make complex spatial analyses: the heart of GIS. GIS can be used to query data, such as pointing at a feature and retrieving its name, or pointing to a feature and retrieving all the attribute information about features within a certain distance of a feature (Maguire and Dangermond, 1991). This can also be done with what is called map algebra, the process of comparing spatial features in two or more map layers.

An additional component of GIS is the presentation of results. Geographic data can be represented by maps, graphs, statistical summaries and reports, tables, and lists (Maguire and Dangermond, 1991). Multimedia reports, containing many of these items, can be generated within GIS. GIS are also capable of complex cartographic modeling.

ArcView GIS

ArcView was the GIS software chosen for the current study. ArcView is a desktop GIS available from Environmental Systems Research Institute (ESRI). ArcView can view, edit, and analyze ARC/INFO coverages as well as shapefiles, a data format created specifically for ArcView. ArcView can import, analyze and export large database files in various formats, such as INFO, dBase, and comma-delimited text. ArcView also has the tools to aid in the development of maps, charts, and complex multimedia presentations.

ArcView's standard toolbox can be expanded through the use of extensions that add functionality. For example, the Spatial Analyst Extension adds the capability to create, manipulate, and analyze raster (GRID) data. Network Analyst adds the ability to create, manipulate, and analyze network-based data. Custom ArcView functions and tools can also be developed using Avenue, ArcView's programming language.

Avenue Programming

Avenue is an object-oriented programming language that is part of ArcView. Avenue is fully integrated with ArcView and the custom scripts will run on any of the platforms for which ArcView is available. There are many uses for Avenue: customizing the way ArcView is used; performing certain repetitive or complex tasks; or developing a complete application that works within ArcView's graphical user interface.

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