41623R03

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

Semi-Annual Technical Progress Report No. 3

Reporting Start Date: September 23, 2003
Reporting End Date: March 22, 2004

Principal Author:
Dr. Joan M. Ogden
jmogden@ucdavis.edu

Date Report Issued: May 2004

DOE Award Number: DE-FC26-02NT41623

Address of Submitting Organization:
Princeton Environmental Institute
27 Guyot Hall
Princeton University
Princeton, NJ 08544

DISCLAIMER

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

Dr. Joan M. Ogden
Jason Ni
Institute of Transportation Studies
University of California
Davis, CA 95616

Elizabeth Kaijuka
Princeton Environmental Institute
Princeton University
Princeton, NJ 08544

ABSTRACT

In this third semi-annual progress report, we describe research results from an ongoing study of fossil hydrogen energy systems with CO_2 sequestration. This work was performed under NETL Award No. DE-FC26-02NT41623, during the six-month period September 2003 through March 2004.

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 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.

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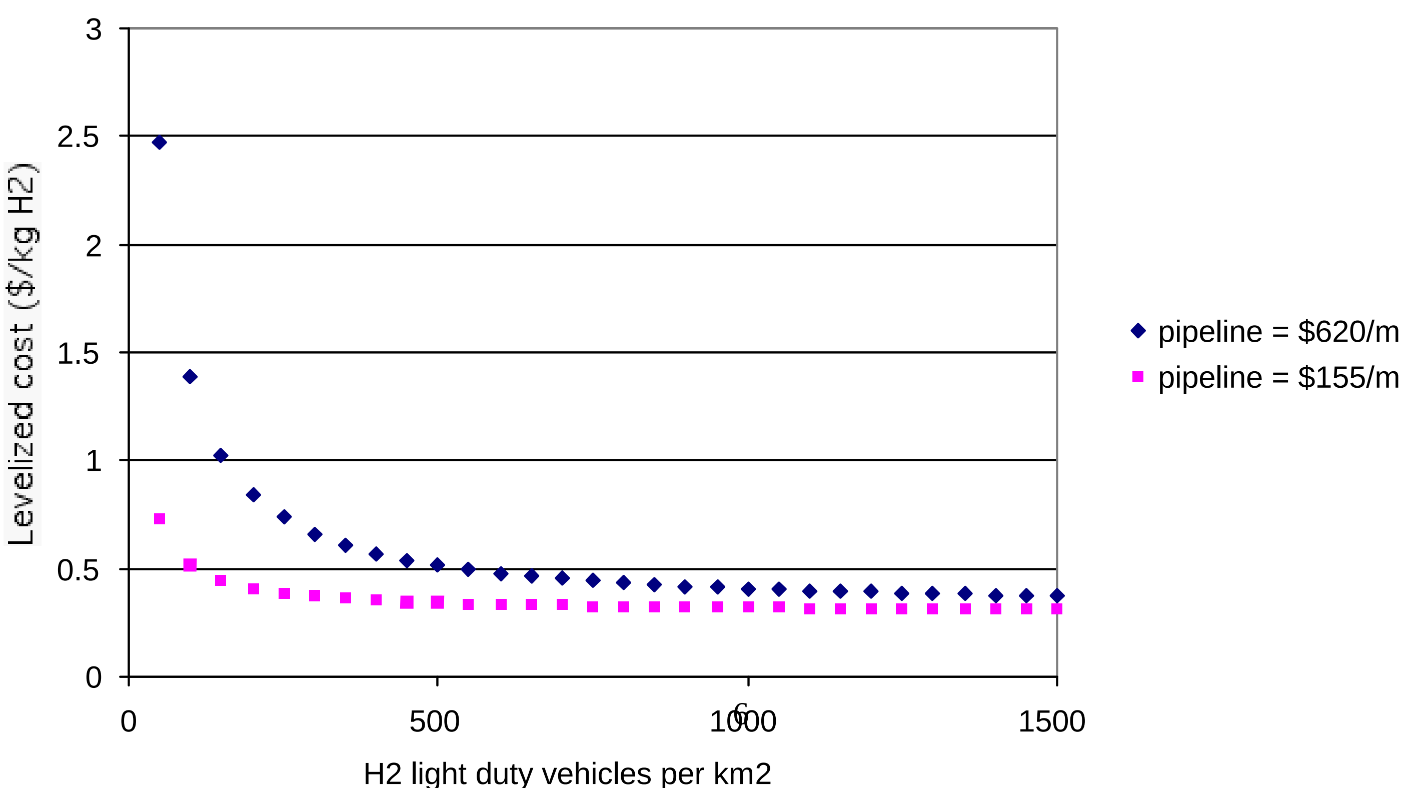

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EXECUTIVE SUMMARY

In this third semi-annual progress report, we describe research results from an ongoing study of fossil hydrogen energy systems with CO_2 sequestration. This work was performed during the second six months (September 2003-March 2004) of the project 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 location, size, 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.

Three tasks are ongoing.

Task 1.0 Implement Technical and Economic Models of the System Components

Here we utilize data and component models of fossil energy complexes with H_2 production, and CO_2 sequestration already developed or undergoing development as part of the ongoing Carbon Mitigation Initiative (CMI). (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.) Additional models for H_2 distribution systems and refueling stations are being 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), and those of other researchers (Mintz et al. 2003, Amos 1998, Thomas et al. 1998). In addition, 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. During the period September 2003-March 2004, the principal investigator took part in developing this database, and led the team looking at hydrogen delivery systems. The H2A spreadsheets should become available in the summer of 2004. In addition the National Academy of Engineering recently released an assessment of the Hydrogen Economy. It is expected that data on hydrogen technologies will be released as part of this study as well. We will be updating 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 the many input parameters described above (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.

During the period September 2003-March 2004, we extended this simple model, by indexing it to a specified level of demand. Results were derived for the cost of fossil hydrogen production with CO2 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. market penetration of hydrogen vehicles), and technology.

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring 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

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 CO2 sequestration potential such as the MIDCARB project. Input from these projects will be used to estimate the best options for sequestration.

INTRODUCTION

In this progress report, we present results from an ongoing assessment of fossil H_2 energy systems with CO_2 sequestration. This research was performed under a no-cost extension of NETL Award No. DE-FC26-02NT41623, during the time period from September 2003 to March 2004.

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, 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 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, we have shown a single fossil energy complex, serving a single demand, and one CO2 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 2).

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 CO2 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.

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 over time 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 are carrying 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 are ongoing. [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).]

Task 1.0 Implement Technical and Economic Models of the System Components

Before developing a total system model, we develop technical/economic models for the various parts (or components) of the system. Here performance and cost of each "component" of the system is characterized as a function of scale and other relevant parameters. In this Task, we utilize data and models of fossil energy complexes with H_2 production, and CO_2 sequestration developed as part of the ongoing Carbon Mitigation Initiative (CMI). (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.) Additional models for H_2 distribution systems and refueling stations are being 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), and those of other researchers (Mintz et al. 2003, Amos 1999, Thomas et al. 1998). 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 the summer of 2004. In addition the National Academy of Engineering recently released an assessment of the Hydrogen Economy. We will be updating 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 a single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center (see Figure 1). For specificity, we chose a base case hydrogen plant size of 1000 MWth hydrogen output (equivalent to about 600 tonnes H2 per day or 252 million standard cubic feet – see Appendix A for conversion factors). 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.). Analytic sensitivity studies of this "simple system" are used to provide us with insights on which parameters are most important in determining costs.

Recently, we have expanded this simple model to include better models of hydrogen demand and hydrogen distribution systems including multiple sources and demand centers. Further, the improved model provides an interface with the GIS database developed in Task 3, allowing us to make hydrogen system design and cost calculations based on quantities easily derived from GIS maps. Results from this improved model are given in this report.

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring use mathematical programming methods to find the lowest cost system design. This work is described under Task 2 below. 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

In this task, we 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. 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 work was begun on building a database. We used this database to answer simple questions about fossil energy systems with CO2 sequestration. Results are given below.

RESULTS AND DISCUSSION

Task 1.0 Implement Technical And Economic Models Of The System Components

In the first progress report for this contract, we described technical/economic models of various parts of a fossil hydrogen system with CO_2 sequestration. These include:

- The fossil energy complex for producing hydrogen and electricity from natural gas or coal
- CO_2 compression and pipeline transport
- CO_2 injection into underground geological formations
- Hydrogen demand for vehicles
- Hydrogen fuel delivery infrastructure (including hydrogen compression, storage, pipeline transmission and refueling stations)

We surveyed estimates for system component costs and performance that are available in public domain literature, and from ongoing work at Princeton University. We 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. In particular, we utilized data and component models of fossil energy complexes with H_2 production, and CO_2 sequestration already developed or undergoing development as part of the ongoing Carbon Mitigation Initiative (CMI) project at Princeton University. Additional 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), and those of other researchers (Mintz et al. 2003, Amos 1999, Thomas et al. 1998). Details on the models for various parts of the system are given in the first progress report for this contract (Ogden 2003).

During the past year the principal investigator worked closely with other members of the H2A group, a group of analysts convened by the USDOE to study hydrogen systems. One goal of the H2A group to is develop a set of EXCEL spreadsheets summarizing the best current estimates for performance and cost of hydrogen production technologies, including fossil energy plants with CO2 capture, and hydrogen delivery and refueling systems. During the period September 2003-March 2004, the principal investigator took part in developing this database, and led the team looking at hydrogen delivery systems. As part of this work, the P.I. took part in a working meeting of the H2A group at NREL (Feb 3-4, 2004). The purpose was to develop models of hydrogen systems for review by industrial collaborators from energy, automotive and chemical companies. The review took place in Washington, DC on February 23-25. After this meeting the PI did extensive follow-up with industrial reviewers to incorporate their suggestions into the H2A models. The H2A's work will be presented at the National Hydrogen Association Meeting in April 2004.The H2A spreadsheets should become available in the summer of 2004. The PI will update her models to reflect these results.

The P.I. visited Princeton University in November 2003 to attend the 3rd Annual meeting of the Carbon Mitigation Initiative, and received an update on activities there.

The National Academy of Engineering recently released an assessment of the Hydrogen Economy. It is expected that data on hydrogen technologies will be released as part of this study as well. We will be updating our models to include the new information contained in these studies.

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 system.

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. 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 a number of cases of interest. 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.

During the period September 2003-March 2004, 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. In the next sections we present results for the cost of fossil hydrogen production with CO2 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.

First Step: A Simple 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)

Modeling Hydrogen Demand

Using GIS Data to Model Hydrogen Demand Spatially and Over Time

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. This method for calculating a hydrogen demand map is described below (see Figure 3 for a sketch of the overall process).

- 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 (we calculate the fraction of new vehicles using hydrogen each year). This could be done in various ways. One could devise criteria for estimating how many new hydrogen vehicles are sold each year, based on projections of when they become competitive with other advanced, low polluting technologies like gasoline internal combustion engine technologies. Perhaps the simplest possible model is to assume that a “zero emission vehicle mandate” is put in place, so that a fixed fraction of new vehicles sold must use hydrogen, starting at some point in time. 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). Table 1 illustrates how the cumulative fraction of hydrogen vehicles in the light duty fleets grows over time, for a very simple model of market penetration. In this simple “ZEV mandate” model, we assume that a constant fraction of all new cars are hydrogen cars (the ZEV mandate level ranges from 10%,

25%, 50%, and 100%). We also assume that new cars sales are 7% of the total fleet each year, and that vehicles are replaced after 14 years. We see that the number of hydrogen vehicles grows linearly in time, reaching saturation at about 14 years. Other, more realistic market penetration scenarios will be examined in future work. It is more likely that hydrogen use would grow first in urban areas, so that demand might not grow uniformly across the entire state.

- The hydrogen use per vehicle (kg H_2/d/vehicle) is estimated from assumptions about hydrogen vehicle fuel economy and miles traveled. Our assumptions about future hydrogen vehicle fuel economy and use are shown in Table 2.
- A map of hydrogen demand density versus location and time then can be calculated (kg/d/km^2). This is shown in Figure 4, 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 1. Fraction of hydrogen vehicles in the light duty fleet as a function of market penetration rate and year, for a simple market penetration model where a constant fraction of new vehicles each year are hydrogen-fueled.

H2 Light Du Vehicles (fractic of new LDVs)	Year 1	Year 5	Year 10	Year 15
10%	0.7%	3.5%	7%	10%
25%	1.8%	9%	18%	25%
50%	3.5%	18%	35%	50%
100%	7%	35%	70%	100%

Table 2. 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. This tells us where the hydrogen must be delivered and how much is required.

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.[1]
- An idealized version of the delivery system layout is specified. For pipelines, this could be a "ring" structure or radial "spokes". For truck delivery, a delivery schedule could be postulated. (In general, the layout of the delivery system is also a complex problem that will be addressed future work through GIS-based studies. For example, the location of rights of way or low cost resources for H2 production might have a large effect on layout.)

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:

[1] 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. This is shown in Figure 4 for the Columbus, Ohio area. 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.

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.

From a small number of simple inputs characterizing the geography, market penetration rate, and vehicle characteristics, we estimated the number of H2 stations, the amount of hydrogen dispensed at each station, and the geographic density of H2 stations. This is used to size the hydrogen production and delivery system needed. 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 gasoline 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:

- delivery by hydrogen gas pipeline,
- compressed gas truck (tube trailer or mobile refueler)
- liquid hydrogen truck

We have developed idealized models for the spatial distribution of hydrogen stations, and delivery system layout, that 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 stations per km2, the required pipeline length for an ideal system is typically 4-7 times the city radius. This is shown in Figure 5, based on studies by Christopher Yang at UC Davis (Yang and Ogden 2004).

(These distances might be larger for real cities, as pipelines might have to be sited on existing rights of way, and hydrogen delivery trucks would have to use major roads. However, even without having detailed knowledge of the exact locations of refueling sites, this kind of transparent simplified analysis can give some idea of how a delivery system for hydrogen might be designed within a city, and how much it might cost. 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 4-10 (Ogden 2004). 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.

Infrastructure Cost Model Assumptions

Economic Assumptions

The "base case" economic assumptions in Table 3 are used in our analysis to estimate levelized costs of hydrogen.

Table 3. 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.

System Parameter Assumptions

In Table 4, we summarize assumptions about the size range for central production plants, the hydrogen demand, and hydrogen refueling stations. For large scale, centralized hydrogen production plants, we assume that 150-600 tonnes per day of hydrogen (or 60-250 million scf H2/day or 250-1000 MW of H2 on a higher heating value basis) are produced. We assume that hydrogen equal to 1/2 day's production is stored at the central plant. For pipeline distribution options, hydrogen is compressed to 1000 psi (6.8 MPa) and delivered to refueling stations at 200 psi (1.4 MPa). Refueling stations dispense 240-4800 kg H2/d at 6000 psi for onboard storage at 5000 psi. For fossil hydrogen plants with CO2 capture, the characteristics of the CO2 sequestration site are described.

Centralized Production of Hydrogen

In Table 5, we show capital and operating costs for central hydrogen production options as a function of scale and energy prices.

Long Distance Hydrogen Pipeline Transmission

The costs of a hydrogen gas pipeline long distance transmission system are summarized in Table 6, as a function of plant size, pipeline flow rate and pipeline length.

As part of the transmission system, we assume that hydrogen is compressed from production system pressure (typically 200 psi (1.4 MPa)) to pipeline pressure (1000 psi (6.8 MPa)). The cost of hydrogen compression to 1000 psi is included in our cost estimates for central hydrogen plants. (In this table, we have calculated it separately to look at scale dependence.)

Further we assume that hydrogen storage equal to 1/2 day's production from the central plant is needed. Costs for storage are shown as a function of size and technology.

Local pipeline distribution

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 ($622/km) installed. The flow rate of hydrogen through the line can be estimated from pipeline flow equations as shown in Figure 6 for a 3” diameter pipeline. (The right hand end-point of each line represents the distance where the pressure has dropped to 200 psia. This is as far as the hydrogen will travel at this flow rate and pipeline size without recompression.)

Table 4. 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 5. 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 6. 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**
H_2 compressor *(note: in some studies H_2 compression is included as part of the central H_2 plant cost)*	20 MWe	$1600/kWe (multi stage) $900/kWe (single stage)	Scale factor of 0.9 for large H_2 compressors (Simbeck and Chang 2002). Costs match well with Kreutz et al. 2002) H_2 compressor electricity input = 2-10% of higher heating value of hydrogen compressed depending on compressor inlet and outlet pressures (see Appendix E). Assuming inlet pressure of 1.4 MPa, and outlet pressure of 6.8 MPa, and compressor efficiency of 70%, the electricity use is about 2% of the H_2 energy. Compressor power (MWe) = [S (tonne/d) x (1000 MWH2/613 tonne/d) x (2-10% MWe/MWH2)] Capital cost of H_2 compressor($) = (Compressor Power/20 MWe)$^{0.9}$ x $1600/kWe x 20 MWe S= H_2 plant size (tonne H_2/d)
H_2 Storage	High pressure cylinders Bulk aboveground compressed gas storage Advanced automotive pressure cylinders Underground storage	$700/kg (kg of H_2 storage capacity) " $200-250/kg $280-420/kg	Compressed gas storage is modular with little scale economy. For a H_2 central plant, we assume storage equivalent to 1/2 day's production is needed. If S = plant output in tonne H_2/d, Cost = $700,000 x 0.5 x S, for aboveground gas storage Cost = $280,000-420,000 x 0.5 x S, for underground storage
H_2 Pipeline H_2 Flow Length	100 km length; (Pin=6.8 MPa Pout=1.4 MPa) H_2 Flow= 60 t/d 150 t/d 300 t/d 600 t/d	Pipe Diam. Cost (inch) (million$) 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)

At larger pipeline diameter, this distance increases.) The levelized cost of hydrogen pipeline delivery through a local pipeline is roughly

Cost of pipeline delivery (\$/kg) =
0.652 x (pipeline length in km)
x (installed cost in million \$/km) /(pipeline hydrogen flow rate in tonne/day)

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

Various layouts for pipeline networks could be used. For a pipeline distribution system with radial "spokes," sketched in Figure 7, the delivery cost can be calculated as a function of numbers of cars per km^2 (Figure 8). We include costs for the pipeline plus H2 compression (costing about \$0.07/kg) and 1/2 day's storage (about \$0.23/kg) at the central hydrogen production plant. (At high vehicle densities, the pipeline itself is a minor contributor to the total.) We see that densities less than about 200 cars/km^2, the cost of local pipeline distribution increases rapidly. For a low density of cars, other distribution modes such as liquid hydrogen trucks or onsite production are less costly and would probably be preferred. Other delivery system designs are being researched by Chris Yang.

Hydrogen distribution by truck

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. In future work with the H2A group, we will develop cost estimates for delivery as a function of demand characteristics. In Tables 7-9 below, we show assumed costs for liquefaction and liquid hydrogen storage systems, and for liquid hydrogen and compressed gas trucks (Ogden 1998).

Table 7. 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 8. 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 9. 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 10, 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 10. 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

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 H2 (see Tables 11, 12).

Table 11. 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	26.25 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 12. Capital Costs for Hydrogen Infrastructure Options (million $)

	Central production SMR + pipeline delivery, CO2 vented	Central production SMR + LH2 truck delivery, CO2 vented	Central production SMR + comp gas truck delivery, CO2 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 ($620/m)	46.9	-	-		
Trucks	-	4.4	29.5		
Refueling stations	33.3	16.6	33.3	64.9	122
TOTAL Capital cost ($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 10, 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 11. 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 CO_2.

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

<u>Using this Simple Model with Input from GIS Data Base</u>

The simplified model described here could be readily used with input from a GIS data base. Hydrogen demand in a city can be estimated, along with distances between fossil energy complexes (e.g. at existing coal-fired power plants) and cities, and distances between fossil hydrogen plants and CO_2 sequestration sites. In Figure 12, we illustrate how the interface might be done to give approximate cost estimates for infrastructure.

<u>Future Work: Adding Time Dependence</u>

Time dependence could be introduced into this simple model, by making fH2 a function of time. For example, we can use a "logistics" curve to model market penetration rates. Other market penetration models could be devised based on market competitiveness and/or policy. (In addition, energy prices, vehicle populations, technological cost and performance could be made dynamic. This would allow us to look at the potential impact on infrastructure of a technical breakthrough in, for example, hydrogen storage or small scale hydrogen production.)

If we know fH2 as a function of time, we can then estimate the cost at each year of various infrastructure configurations. The equations in Tables 5-10 give us an objective function for infrastructure cost as a function of scale, energy prices, market penetration rate and geography. We will explore with colleagues at UC Davis, the possibilities for using mathematical programming methods to optimize the time-integrated cost of hydrogen infrastructure development. One interesting question is when (or even whether) long term costs will be lowered by switching from distributed to centralized production, and what role policy instruments such as carbon taxes might play in encouraging such a change. A related question is the cost of “stranded assets”, if a switch is made to centralized production (salvage values for equipment will be included in the calculation).

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 CO2 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.

Thusfar, we examined the suitability of several mathematical programming methods that could be used to optimize the design of a hydrogen energy system with CO2 sequestration More work on Task 2 remains to be done to understand the best tools for carrying out an optimization of the system.

The basic design problem is shown in Figure 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 CO2 disposal system.) The longer-term goal is to compare various possible transition pathways to find the lowest overall cost. In earlier progress reports we discussed various methods that might be used to solve this complex non-linear optimization problem (Ogden 2003b).

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

In this task, we 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.

In this task, we hope 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.

In previous reports, we described the initial development of a GIS database for the state of Ohio, an area where coal-fired power plants are widely used. As a first step, a survey of relevant GIS data sets was conducted, and initial work was begun on building a database. The preliminary database includes:

- 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. This is shown in Figure 13. We use this geographic data as a basis for analyzing alternative configurations for hydrogen supply and CO_2 disposal. Data sources used in building this database are given in Appendix B.

We have begun to add costs to the GIS data base for hydrogen plants of different sizes. The first plan is to the use the simplified integrated model described in this report as a basis for estimating infrastructure costs. Part of the effort the past months involved transferring GIS programs from Princeton to UC Davis. To facilitate database development a collaboration was begun with GIS programming experts at UC Davis's Information Center for the Environment (ICE).

Task 3: Future work

The next step in modeling are including data on CO2 sequestration sites. There are several ongoing projects to model the location, characteristics and capacity of CO2 sequestration sites in the US. The MIDCARB project (MIDCARB project**,** http://www.midcarb.org) is particularly relevant to our proposed study of fossil hydrogen infrastructure in the Midwestern US.

We have been in communication with researchers at the MIDCARB project. They expressed interest with collaborating with us on providing GIS data on potential CO2 sequestration site capacities and injectivities. This information is still undergoing development. Once these GIS data layers become available for the Midwest, they have agreed to share the information and we will add this to our database. In addition,we hope to interact with the NETCARB projects now getting underway.

We will add costs to the GIS model, allowing us to estimate costs for alternative pathways for supplying fossil hydrogen to meet a specified demand. We will use techniques developed in Task 2 to find the lowest cost system designs.

CONCLUSION

During the third six months of research under this contract, we have made significant progress toward understanding the systems aspects of fossil hydrogen systems with CO2 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.

Task 1.0 Implement Technical and Economic Models of the System Components

Description: Here we utilize data and component models of fossil energy complexes with H_2 production, H_2 distribution systems and refueling stations and CO_2 sequestration being developed as part of earlier work at Princeton and other efforts.

Status: We have surveyed estimates for system component costs and performance that are available in public domain literature, and from ongoing work at Princeton. We have synthesized cost and performance estimates for hydrogen production systems with CO2 capture, hydrogen pipelines, hydrogen refueling stations, CO2 pipelines, and CO2 injection sites. This work was described in earlier progress reports.

Future Work: As new results become available we plan to improve these cost and performance estimates. In particular, the principal investigator Joan Ogden has been involved with the H2A group, an ongoing effort at the USDOE, which brings together analysts (funded under various DOE programs) who study hydrogen systems. This group has been reviewing the costs and performance of hydrogen production, delivery and refueling systems. Access to these data will give improved estimates of components costs and performance under Task 1. The National Research Council is producing a report on hydrogen that will include models of hydrogen components. The results of these efforts have recently become available. In addition, the PI will check with the latest results from modeling efforts under the CMI project at Princeton. Our work will be updated to reflect the new information contained in these studies.

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

Description: As a first step, we developed a simple analytical model linking the components of the system. We considered single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center. To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring use mathematical programming methods to find the lowest cost system design.

Status: 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. We have looked at several nonlinear programming approaches to modeling CO_2 pipeline disposal systems.

Future Work: More work on Task 2 remains to be done to understand the best tools for carrying out an optimization of the system.

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

Description: In this task, we 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. 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.

Status: 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. Preliminary results have been presented at two conferences in 2003. We have not yet estimated costs for alternative pathways for developing fossil hydrogen as an energy carrier. We have begun dialog to coordinate with other ongoing GIS based studies of CO_2 sequestration potential such as the MIDCARB project.

Schedule for Completing the Work and Deliverables

Over the year (until August 2004), we plan to complete the three tasks set forth in the original statement of work. In addition, we will use improved understanding from ongoing studies (for example those by the H2A group and the MIDCARB project), to improve our results, especially for Tasks 1 and 3.

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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)
SMR	steam methane reforming.
USDOE	United States Department of Energy Research

APPENDIX A. CONVERSION FACTORS

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)

APPENDIX B . 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

FIGURES

Figure 1.

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

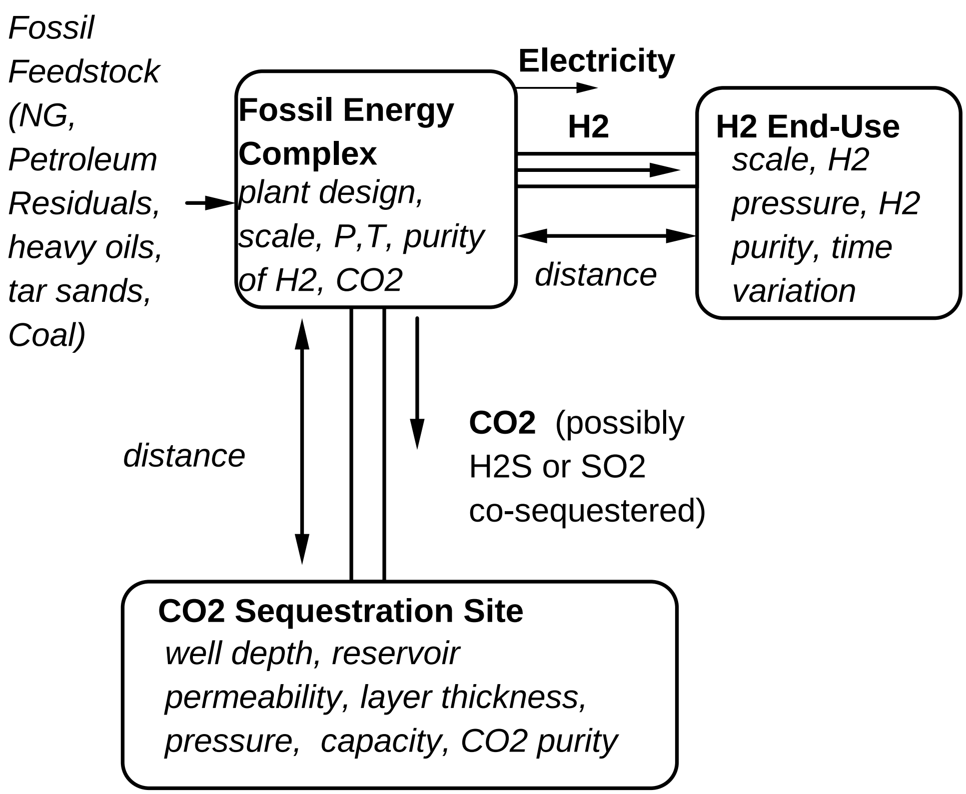


Figure 2. Modeling hydrogen infrastructure development. Top: Energy system with growing hydrogen demand. Bottom: A possible infrastructure configuration to serve this demand. The goal is to find the lowest cost design.

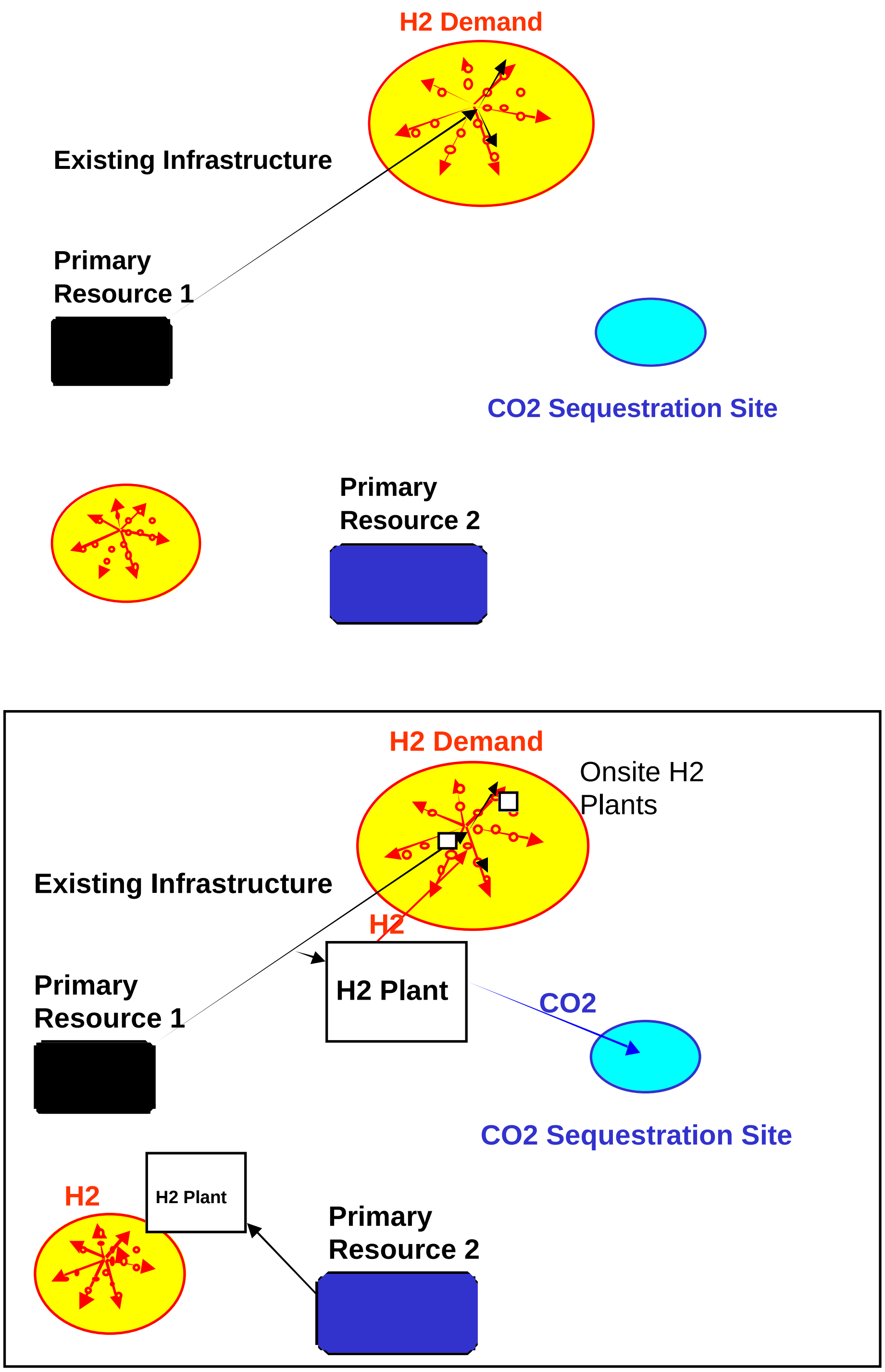
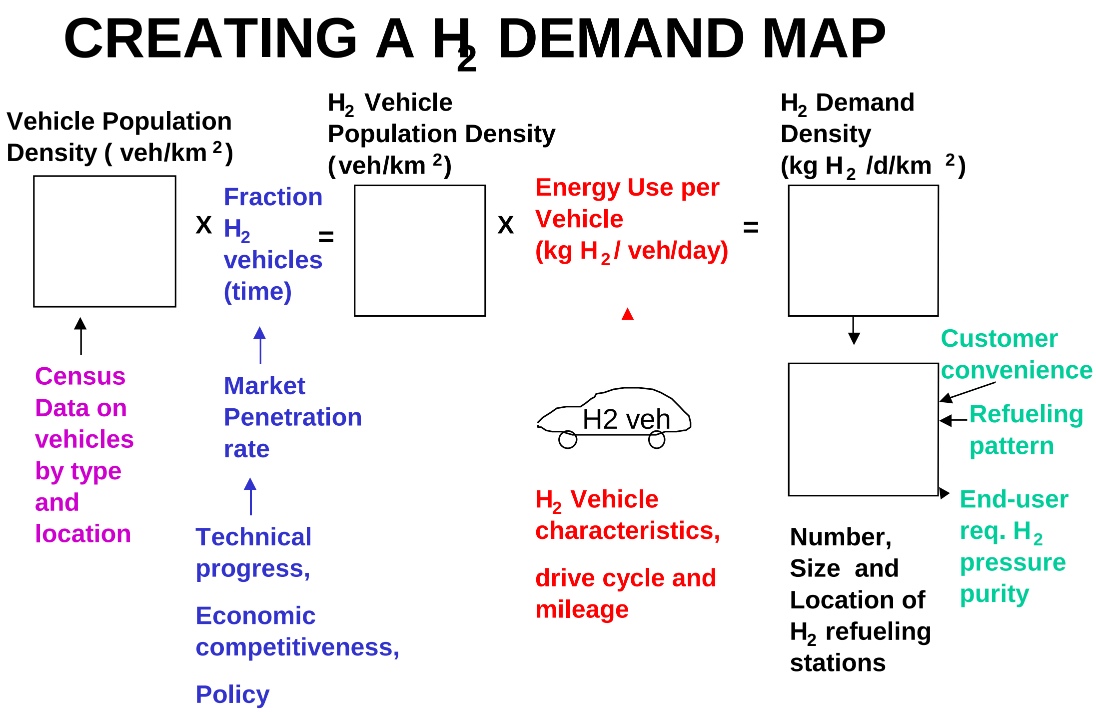


Figure 3. Possible method for creating a hydrogen demand map



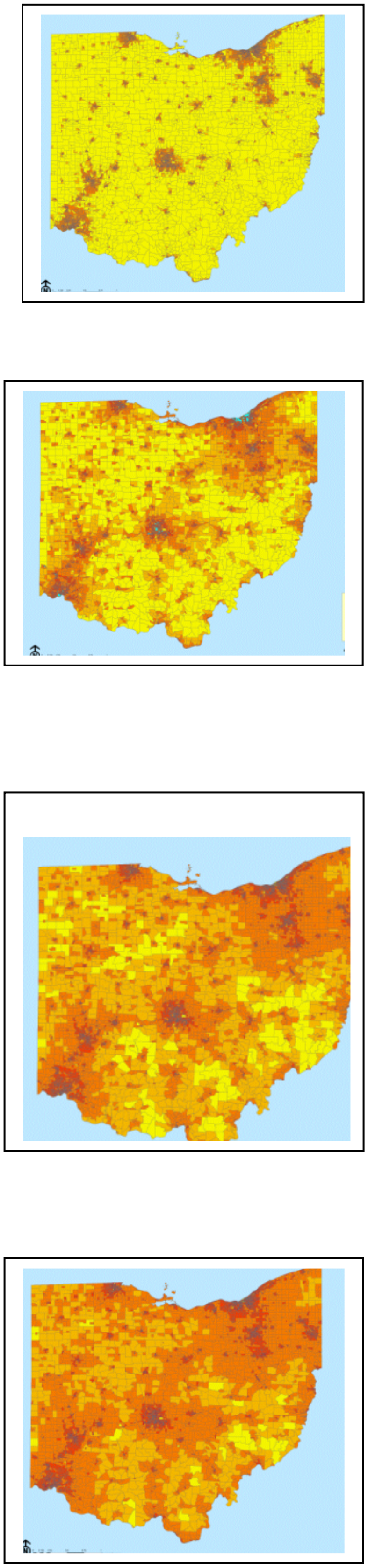


Figure 4. Hydrogen demand density (kg H2/d/km2) over time at years 1, 5, 10 and 15, assuming that 25% of new light duty vehicles use hydrogen, starting in year 1.

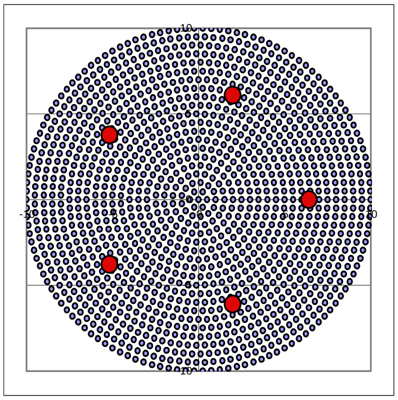


Figure 5a Sample station configurations (red) for model city with 1322 homogeneously distributed population centers (blue) and 5 and 25 stations respectively.

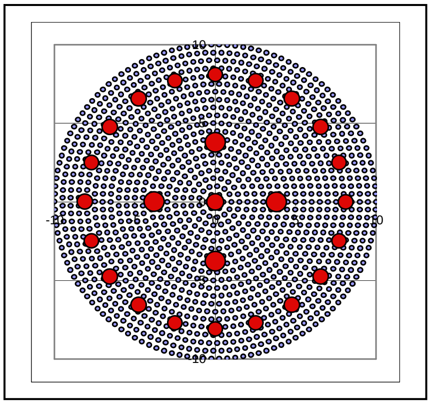


Figure 5b. Length of pipeline distribution system versus city radius for various station configurations (e.g.10A-10E are five variants on placing 10 stations within a city)

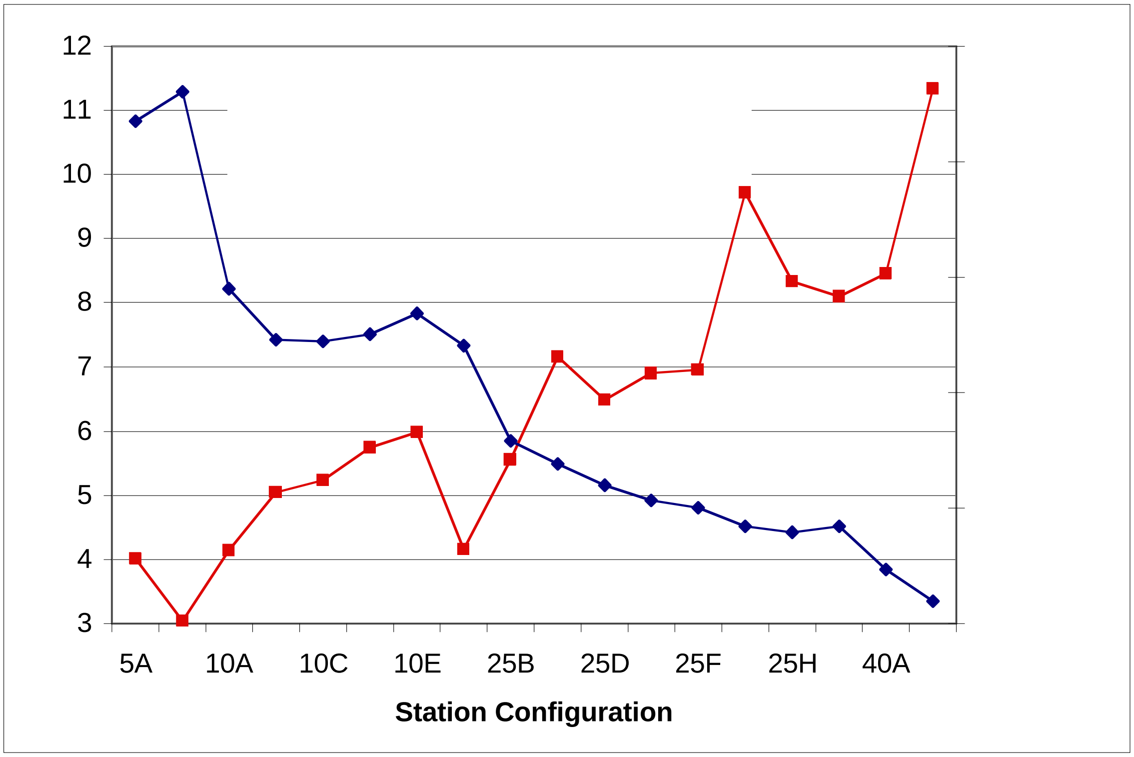


Figure 6.

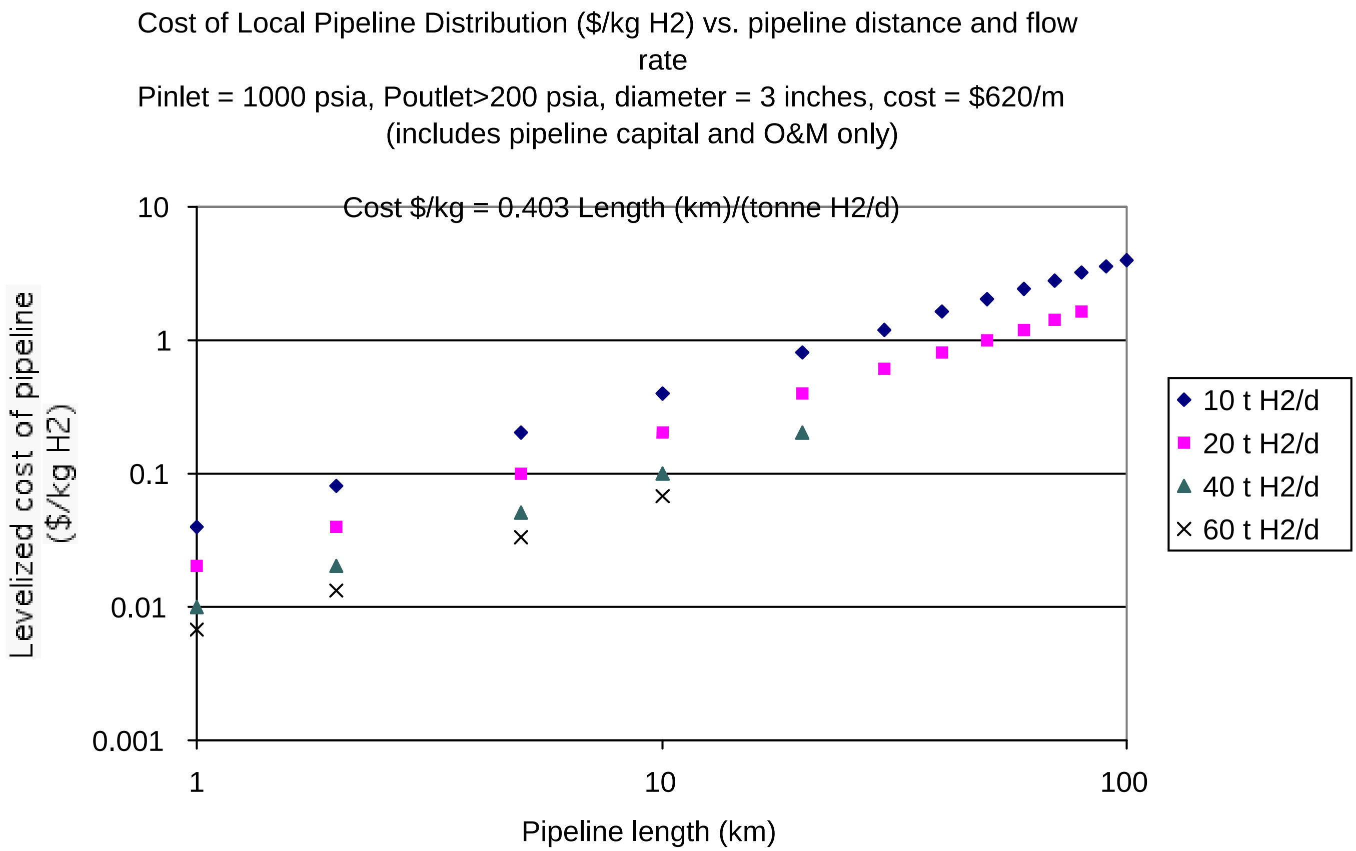
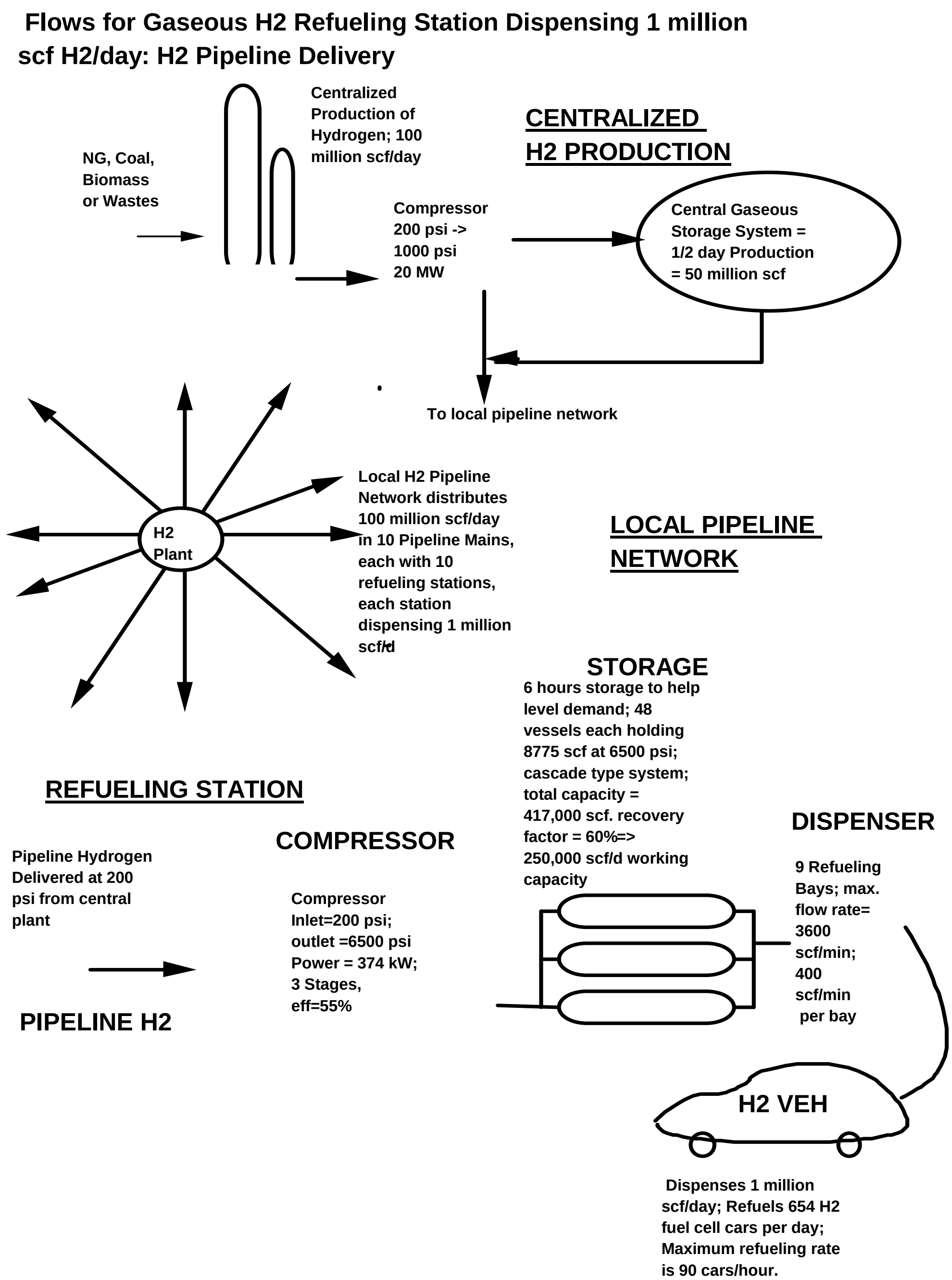

Cost of Local Pipeline Distribution ($/kg H2) vs. pipeline distance and flow rate
Pinlet = 1000 psia, Poutlet>200 psia, diameter = 3 inches, cost = $620/m
(includes pipeline capital and O&M only)
Cost $/kg = 0.403 Length (km)/(tonne H2/d)
Levelized cost of pipeline ($/kg H2)
10
1
0.1
0.01
0.001
1
10
100
Pipeline length (km)
10 t H2/d
20 t H2/d
40 t H2/d
60 t H2/d

Figure 7.



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 8. Cost of local hydrogen pipeline distribution (including 1/2 day storage), as a function of geographic density of hydrogen vehicles.

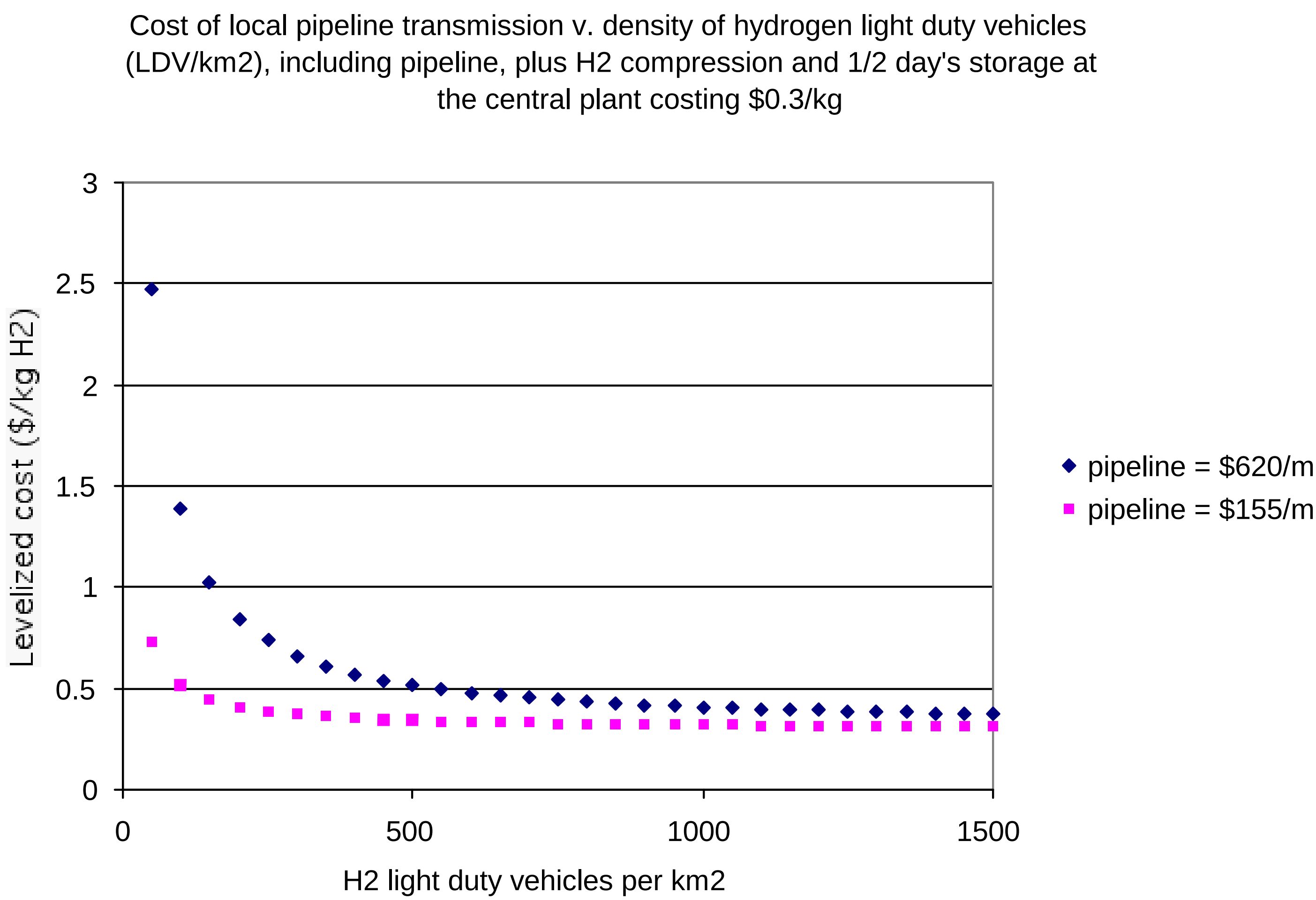


Figure 9. Estimates of the capital costs of hydrogen refueling stations according to various studies

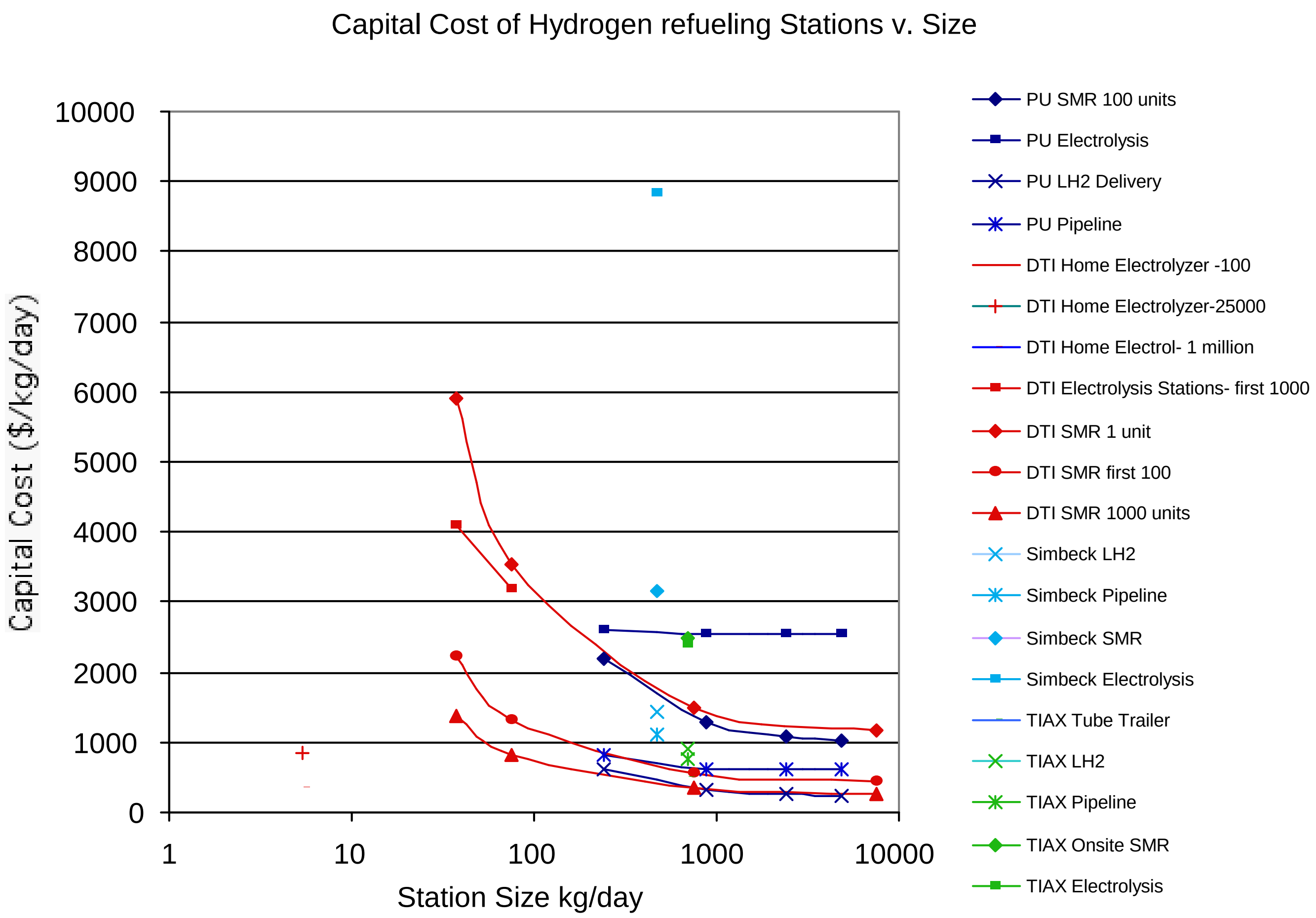


Figure 10.

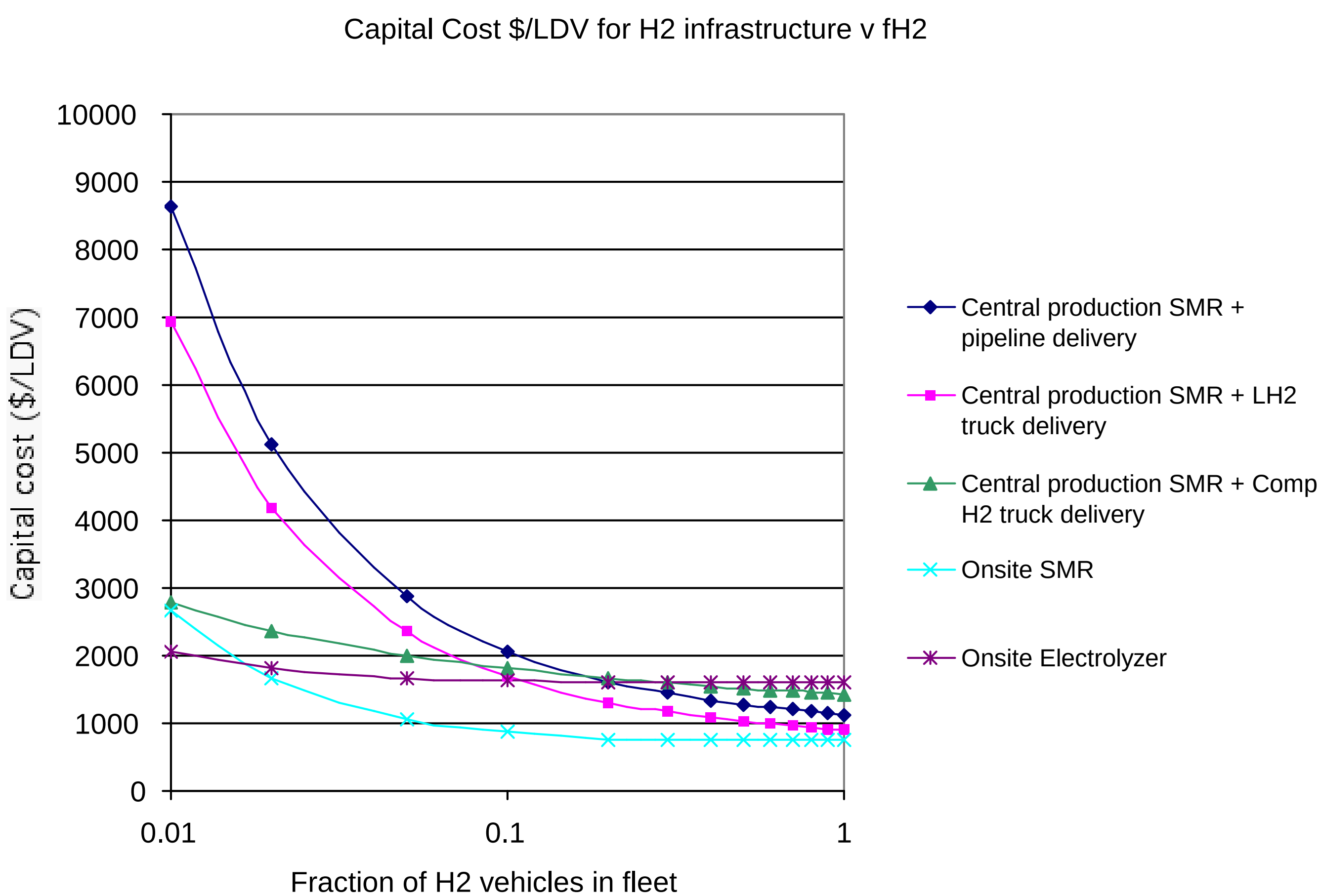

Capital Cost $/LDV for H2 infrastructure v fH2
Capital cost ($/LDV)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0.01
0.1
1
Fraction of H2 vehicles in fleet
Central production SMR + pipeline delivery
Central production SMR + LH2 truck delivery
Central production SMR + Comp H2 truck delivery
Onsite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

Figure 11.

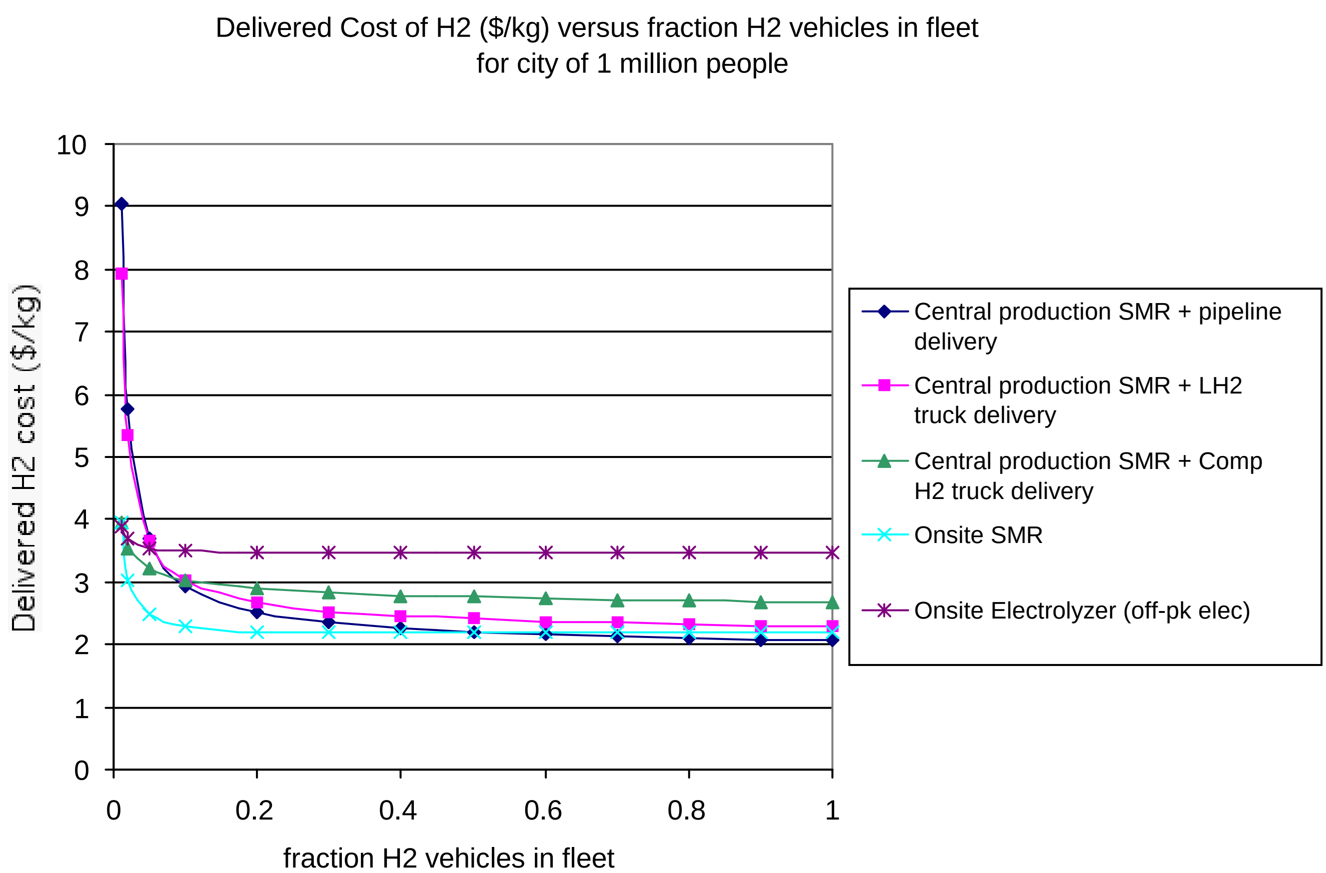

Delivered Cost of H2 ($/kg) versus fraction H2 vehicles in fleet
for city of 1 million people
10
9
8
7
6
5
4
3
2
1
0
Delivered H2 cost ($/kg)
0
0.2
0.4
0.6
0.8
1
fraction H2 vehicles in fleet
Central production SMR + pipeline delivery
Central production SMR + LH2 truck delivery
Central production SMR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

Figure 12. Interface of Simple Integrated Model with GIS Database

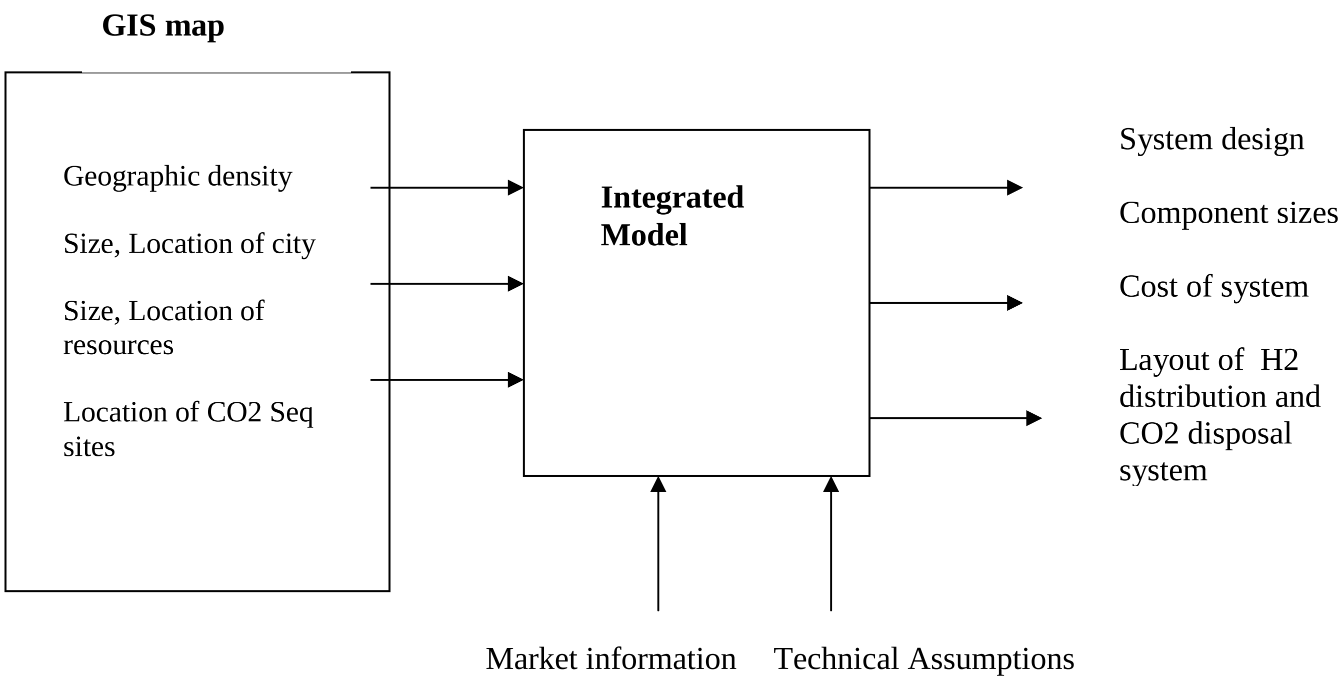


Figure 13. Hydrogen demand density, plus existing infrastructure