

MODELING INFRASTRUCTURE FOR A FOSSIL HYDROGEN ENERGY SYSTEM WITH CO₂ SEQUESTRATION

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ABSTRACT

Production of hydrogen (H₂) from fossil fuels with capture and sequestration of CO₂ 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 pipeline infrastructures: one for distributing H₂ to end-users and one for transmitting CO₂ to disposal sites and securely sequestering it. In this paper we develop a simple technical/economic model of a single fossil energy complex linked by pipelines to a geological CO₂ sequestration site and a H₂ demand center. The goals of the study are to better understand design issues and costs for the total system and to identify the most important factors influencing the sequestration cost of CO₂ and the delivered cost of H₂. For our base case (large flows of H₂ and CO₂; nearby CO₂ storage reservoirs with good characteristics), the most important factors contributing to the delivered cost of H₂ transportation fuel are H₂ production, pipeline distribution and refueling stations. The costs of CO₂ capture and compression at the H₂ plant are significant, but the costs of CO₂ pipeline transmission and storage are relatively small.

INTRODUCTION

Production of H₂ from fossil fuels with capture and sequestration of CO₂ would enable continued widespread use of fossil-derived fuels for applications such as transportation, with near-zero full fuel cycle emissions of both air pollutants and greenhouse gases [1]. A large-scale fossil H₂ system with CO₂ sequestration consists of one or more fossil energy complexes plus two pipeline networks—one for distributing H₂ to end-users (e.g. H₂ vehicles) and one for transmitting CO₂ to storage sites and securely sequestering it.

The performance and economics of the system depend on:

- the design of the central fossil energy conversion plant [scale, feedstock (e.g., coal vs. natural gas), process design, electricity co-production, separation technology, pressures and purity of H₂ and CO₂ products, sulfur removal options including co-sequestration of sulfur compounds and CO₂, location (distance from demand centers and sequestration sites)];
- the requirements of H₂ end-users (scale, geographic density of H₂ demand, H₂ purity, H₂ pressure);
- the characteristics of the CO₂ sequestration site (storage capacity, permeability, reservoir thickness, location);
- pipeline constraints (e.g., for CO₂ pipelines; moisture content must be low; for H₂ pipelines, materials must be selected to resist embrittlement; for both, availability of rights of way).

Several detailed technical and economic studies have been carried out for various parts of the system, including CO₂ capture from electric power plants [2-4], or H₂ plants [5-8], CO₂ transmission [9] and storage [10], and H₂

infrastructure [11, 12]. However, relatively little work has been done assessing the entire system in an integrated way. This study seeks to understand better the total system design and economics, for the special case of a single large fossil energy complex connected to a geological CO₂ sequestration site and a H₂ demand center (such as a city with a large concentration of H₂ vehicles) [13]. We estimate the delivered cost of H₂ with CO₂ sequestration as a function of fossil energy complex design, pipeline parameters, distance to sequestration site, and CO₂ injection site reservoir parameters. The model developed here can be extended to fossil H₂ energy systems that include multiple fossil energy complexes, H₂ demand centers and CO₂ sequestration sites.

MODEL OF A FOSSIL HYDROGEN ENERGY SYSTEM WITH CO₂ SEQUESTRATION

Overview of the System We consider energy systems producing H₂ and electricity from fossil feedstocks (natural gas or coal), with capture of CO₂, compression to 15 MPa for pipeline transmission as a supercritical fluid, and injection into an underground reservoir. H₂ is compressed to 6.8 MPa (1000 psi) for on-site storage, pipeline transmission and local distribution to H₂ vehicles. We consider H₂ plants with an output capacity of 1000 MW of H₂, higher heating value basis (25.4 tonnes H₂/hr). At an assumed 80% capacity factor, annual H₂ production is 25.2 million GJ (178,000 tonnes)—enough to fuel 1.4 million H₂ fuel cell cars having a fuel economy of 2.9 liters gasoline per 100 km (82 miles per gallon) and driven 17,700 km (11,000 miles) per year (the US average). To find levelized costs, we assume a 15% annual capital charge rate and an annual non-fuel O&M charge of 4% of the installed capital cost. Feedstock costs are USDOE projections for 2020 costs to electric utilities: \$3.75/GJ for natural gas and \$0.95/GJ for coal [14]. Costs are in constant 2001 US dollars.

Fossil Energy Complexes Producing Hydrogen and Electricity The assumed performance and cost characteristics of 1000 MW H₂ plants are summarized in Table 1. The coal-based and natural-gas-based energy complexes are taken from the “Conventional Technology” case in [8] and from [5] respectively. H₂ compression to 6.0 MPa and CO₂ compression to 15 MPa are included in all H₂ plant designs. From Table 1, we see that coal to H₂ plants have larger capital costs but lower feedstock costs, so that the levelized H₂ production cost is somewhat lower than for natural gas. The coal to H₂ plant produces about twice as much CO₂ as the natural gas to H₂ plant.

TABLE 1. 1000 MW FOSSIL H₂ PRODUCTION PLANTS W/CO₂ CAPTURE AND COMPRESSION

	H ₂ from Natural Gas [4]	H ₂ from Coal [8]
Electricity net production Mwe	0	31
First law efficiency, HHV = (H ₂ + elec _{out})/Feedstock _{in}	78%	68.7%
CO ₂ emitted (tonne/h) at full capacity	36	34
CO ₂ captured (tonne/h) at full capacity	204	406
Installed Capital Cost of H₂ Plant (million \$)	429	731
Levelized Cost of H₂ Production (\$/GJ HHV)		
Plant capital (=15% of capital cost)	2.56	4.35
Non-fuel O&M	0.39	1.00
Byproduct electricity credit	--	-0.26
Feedstock	4.71	1.41
Total	7.66	6.50

These results can be extended to smaller complexes, using appropriate scaling factors [13]. At 250 MW the H₂ production cost is about \$2/GJ higher than at 1000 MW [13].

Hydrogen Pipeline Distribution Costs for H₂ distribution and refueling systems are shown in Table 2. We assume that coal-derived H₂ is transmitted 100 km to the “city gate”, where it is recompressed and enters a local network bringing H₂ to refueling stations. Natural gas-derived H₂ is produced at the city gate. Based on the flow equations in [15,16], the optimal 100 km H₂ transmission pipeline diameter is 0.29 m, and the associated cost is \$0.35/GJ, for a 1000 MW plant and pipeline inlet and outlet pressures of 6.8 MPa and 1.4 MPa, respectively.

(For long distance pipelines, capital costs are taken from [15] and recent industry estimates [17].) For an alternative H₂ energy flow rate Q and pipeline length L, the cost can be estimated as (\$0.35/GJ) x (Q/1000 MW)^{-0.5} x (L/100 km)^{1.25}.

For local H₂ distribution within a city via small (0.1-0.2 m diameter) high pressure pipelines, we assume the installed cost of the H₂ pipelines is \$622/m (\$1,000,000 per mile), independent of pipeline diameter [11]. We assume that H₂ is distributed radially outward from a central hub through “spokes,” along which the pressure drops from 6.8 MPa to no less than 1.4 MPa at the outermost refueling stations. For our base case, each of 10 spokes has 25 refueling stations, each dispensing 2.4 tonnes (1 million standard cubic feet) of H₂ per day. Assuming an 80% capacity factor, this is matched to 5600 cars per station. For a geographically dense demand of 750 H₂ cars/km² (about half the average density of cars in the Los Angeles area), each “spoke” is 28 km long. The levelized cost for pipeline capital for this local H₂ distribution system is \$1.29/GJ.

An important component of the distribution system is above-ground H₂ storage at the central H₂ plant, with capacity equivalent to one half day’s production. This storage is needed to assure supply in case of outages and to account for time variations in H₂ demand. We assume a capital cost of \$5000 per GJ of H₂ storage capacity for storage cylinders, or \$216 million, based on current industrial bulk compressed H₂ gas container technology. The levelized cost contribution of central H₂ storage is significant, \$1.63/GJ(H₂). Lower cost bulk storage is clearly desirable, where possible; underground storage in aquifers or salt caverns is likely to be less costly [11]. (For comparison, at high levels of mass production (300,000/y) the capital cost of onboard high pressure H₂ cylinders for cars is projected to be about \$1500 per GJ of storage capacity [12].)

At lower H₂ demand density, the cost contribution of local pipeline distribution increases as (1/vehicle density)^{0.5}, while the central storage cost is insensitive to scale. Below a certain demand density, non-pipeline H₂ distribution or onsite H₂ production will provide a lower delivered cost.

TABLE 2. H₂ DELIVERY SYSTEM FOR 1000 MW H₂ PLANT SERVING 1.4 MILLION H₂ CARS

	H ₂ from natural gas	H ₂ from coal
H₂ Distribution and Refueling System Capital Cost (million \$)		
Central H ₂ Plant Buffer Storage(1/2 day’s output of H ₂ Plant)	216	216
H ₂ Pipeline from H ₂ Plant to City Gate 100 km(coal only)		47
Citygate H ₂ Booster compressor (24 MWe)		18
H ₂ Local Distribution Pipelines (750 cars/km ²)	171	171
<i>Sub-total H₂ Distribution (excluding refueling stations)</i>	387	452
H ₂ Refueling Stations (252 stations)	375	375
<i>Total</i>	762	827
Levelized Cost of H₂ Distribution and Refueling (\$/GJ H₂)		
Central H ₂ Plant Buffer Storage	1.63	1.63
H ₂ Pipeline from H ₂ Plant to City Gate 100 km (coal only)		0.35
Citygate H ₂ Booster compressor (coal only)		0.55
H ₂ Local Distribution Pipelines	1.29	1.29
<i>Sub-total H₂ Distribution (excuding.refueling station).</i>	2.92	3.27
H ₂ Refueling Station	6.06	6.06
<i>Total</i>	8.98	9.88

Hydrogen Refueling Stations H₂ is dispensed to vehicles at refueling stations as a high-pressure gas (at 34 MPa) for storage in onboard cylinders. It is estimated that a refueling station dispensing 2.4 tonnes (1 million standard cubic feet) of H₂ per day costs \$1.5 million, adding \$6.1/GJ to the delivered cost of H₂ (see Table 2) [11] About 80% of the capital cost and 50% of the levelized cost is due to H₂ compression at the station and storage cylinders. The remainder is due to capital for dispensers and controls, and labor costs. The cost of on-

board H₂ storage is not included. Development of a new H₂ storage technology that requires less capital and energy input than compressed gas could reduce refueling station costs.

CO₂ Pipeline To model supercritical CO₂ pipelines, we use pipeline flow equations developed in [16] and [18]. Published estimates of capital costs for CO₂ pipelines vary over more than a factor of two above and below the midrange value used here [6, 9, 10, 13, 20]. Local terrain, construction costs and rights of way are all 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 [13]:

$$\text{Cost (Q,L)} = \$700/\text{m} \times (Q/Q_0)^{0.48} \times (L/L_0)^{0.24} \quad [1]$$

Here Q₀ = 16,000 tonnes/day and L₀ = 100 km.

The levelized cost of CO₂ pipeline transmission is \$3.45/t CO₂ for the coal H₂ plant and \$5.26/tCO₂ for the natural gas H₂ plant. It is assumed that booster compressors are not needed for this 100 km pipeline. For transmission of more than 100 km, boosters might be needed.

CO₂ Sequestration The injection rate of CO₂ 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 CO₂ 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 [2]. Using a standard equation for flow into an injection well [2], 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 1000 MW natural gas (coal) to H₂ plant, producing about 5,000 (10,000) tonnes CO₂ per day, 2 (4) wells are needed. The installed capital cost of each well is [2]:

$$\text{Capital (\$/well)} = \$1.56 \text{ million} \times \text{well depth (km)} + \$1.25 \text{ million.}$$

We assume a well depth of 2 km. CO₂ is distributed by surface piping at the injection site from well to well. We require each reservoir to store 20 years of CO₂ production from the H₂ 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 H₂ plant. This implies a cost of \$3.2 (9.2) million, based on a piping cost from Equation

TABLE 3. CO₂ PIPELINE TRANSMISSION AND STORAGE SYSTEM

	H ₂ from natural gas	H ₂ from coal
CO₂ Disposal System (100 km pipeline, 2 km well depth, injection rate = 2500 t CO₂/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
<i>Total CO₂ Pipeline Transmission and Storage System</i>	52.5	82.4
Levelized Cost of CO₂ Disposal (\$/tCO₂)		
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
<i>Total CO₂ Pipeline Transmission and Storage System</i>	6.87	5.23
Total CO₂ Pipeline Transmission and Storage System (\$/GJ H₂)	0.39	0.59

[1], but assuming that the minimum cost is \$155,000/km (\$250,000/mile) [11]. As long as the aquifer characteristics allow such a relatively high injection rate, the cost of injection wells and associated piping is less than \$2/tonne CO₂ [\$0.10(0.26)/GJ(H₂) for H₂ from natural gas(coal).]

The total levelized cost of CO₂ pipeline transmission and storage is shown in Table 3. Per tonne of CO₂, the cost of CO₂ disposal is higher for natural gas, but because the coal plant produces about twice as much CO₂ as the natural gas H₂ plant, the contribution to the levelized cost of H₂ (\$/GJ) is higher for coal. However, the sum of the costs for CO₂ capture (\$1.33/GJ H₂ for natural gas [19] and \$0.95/GJ H₂ for coal [8]) and disposal (\$0.39/GJ H₂ for natural gas and \$0.59/GJ H₂ for coal) is about same for natural gas and coal.

SUMMARY OF RESULTS FOR SYSTEM CAPITAL COST AND DELIVERED HYDROGEN COST

In Figure 1, we summarize our results for 1000 MW H₂ plants based on natural gas and coal, with CO₂ capture.

System Capital Cost For the “fully developed” H₂ economy described here, serving a geographically concentrated market of 1.4 million H₂ cars, the total system capital cost varies from about \$1200-1600 million or \$900-1200/car. H₂ pipeline distribution systems and refueling stations, together, contribute about 1/2 to 2/3 of the total capital cost. These costs are dominated by H₂ compression and storage cylinders. This highlights the importance of developing better H₂ storage methods that require lower energy inputs and costs than high pressure compressed gas. H₂ production systems are also major contributors to the system capital cost, with coal plants about 1.7 times as capital intensive as natural gas plants. For our assumptions (100 km pipeline, and desirable reservoir characteristics), CO₂ pipelines and wells contribute only about 5% to the system capital cost. The incremental total system capital cost of sequestration for the 1 GW H₂ system considered here, relative to the same system without sequestration, is about 20% (3%) for natural gas (coal) H₂ energy systems [5, 8, 13].

Delivered Cost of Hydrogen For our base case, the delivered cost of H₂ is about \$17.0 (16.9)/GJ for H₂ from natural gas (coal) (Figure 1). H₂ production, distribution and refueling contribute 45% (38%), 17% (22)% and 35% (36)%, respectively. CO₂ capture compression, pipeline transmission and storage add about \$1.7 (1.5)/GJ (~10%) to the delivered cost of H₂ transportation fuel compared to cases where CO₂ is vented. Of this, only about \$0.39(0.59)/GJ or 2% (3%) is due to the CO₂ pipeline and storage. Delivered H₂ costs are sensitive to scale economies in both H₂ production and pipeline transmission. Geographic density of demand is key to the economic viability of widespread gaseous H₂ distribution. In the early stages, when demand is relatively low and geographically diffuse, trucked-in H₂ or distributed H₂ production (e.g., via small scale natural gas reforming at refueling sites) would be preferred from a cost perspective [11].

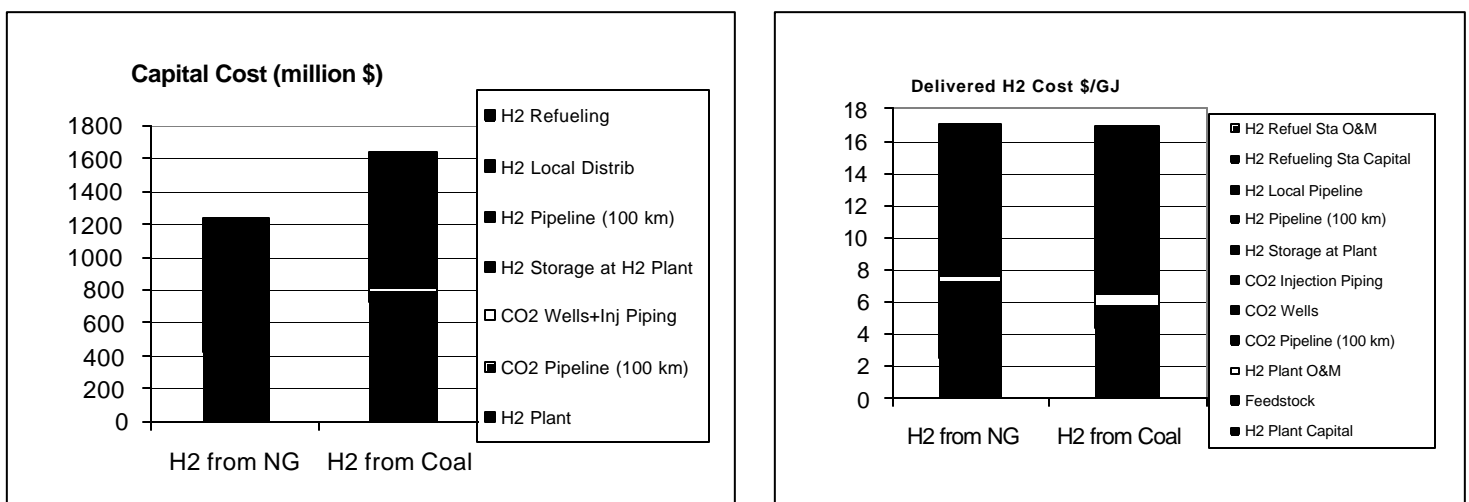


Figure 1. The system capital cost and the delivered cost of H₂ are shown for H₂ produced from natural gas and coal with CO₂ capture, transmission and storage, and H₂ pipeline distribution and refueling. The H₂ plant capacity is 1000 MW, which is large enough to support 1.4 million H₂ fuel cell cars.

CONCLUSIONS

Using a technical/economic model of large-scale fossil H₂ energy systems with CO₂ sequestration, we have identified the major factors contributing to the delivered cost of H₂, and their most important sensitivities. For our base case assumptions (large CO₂ and H₂ flows; a relatively nearby reservoir for CO₂ sequestration with good injection characteristics; a large, geographically dense H₂ demand), H₂ production, distribution and refueling were found to be the major costs contributing to the delivered H₂ cost. CO₂ capture and sequestration added only ~10%. Better methods of H₂ storage would reduce both refueling station and distribution system costs, as well as costs on-board vehicles. The models developed here will be used in a future regionally specific case study of H₂ infrastructure development with CO₂ sequestration, involving multiple sources and sinks for CO₂ and multiple H₂ demand sites.

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