Optimal Design of a Fossil Fuel-Based Hydrogen Infrastructure with Carbon Capture and Sequestration: Case Study in Ohio

UCD-ITS-RP-05-07

Nils Johnson[1], Project Manager
Christopher Yang, Ph.D.[1], Research Engineer
Jason Ni[1], Graduate student
Joshua Johnson[2], GIS Specialist
Zhenhong Lin[1], Graduate student
Joan M. Ogden, Ph.D.[1], Associate Professor

[1]Institute of Transportation Studies
[2]Information Center for the Environment
University of California
Davis, CA 95616

Presented at the National Hydrogen Association (NHA) Annual Hydrogen Conference, entitled "Partnering for the Global Hydrogen Future"
Washington, DC

March 29 – April 1, 2005

OPTIMAL DESIGN OF A FOSSIL FUEL-BASED HYDROGEN INFRASTRUCTURE WITH CARBON CAPTURE AND SEQUESTRATION: CASE STUDY IN OHIO

N. Johnson[1], C. Yang[1], J. Ni[1], J. Johnson[2], Z. Lin[1], and J. Ogden[1]

1. Introduction

The use of hydrogen as a light-duty transportation fuel requires the development of a widespread regional hydrogen infrastructure, including production facilities, a distribution network, and refueling stations. In the case of fossil-based hydrogen production with carbon capture and sequestration, additional infrastructure is needed for CO_2 disposal. If construction of this infrastructure is to proceed, it is necessary to identify strategies for minimizing the cost while maximizing the utility during the transition. We have developed an infrastructure model that identifies the major parameters that determine infrastructure cost and uses a geographic information system (GIS) to apply these parameters to optimize infrastructure design for a given region.

In this paper, the model is applied to a regional case study of a potential coal-based hydrogen economy in Ohio with CO_2 capture and sequestration. The objective is to model the optimal hydrogen infrastructure design for the entire state under different market penetration scenarios. GIS facilitates this analysis by allowing one to use existing spatially-referenced data, such as population distribution, coal resources, existing infrastructure, and CO_2 sequestration sites, to calculate the location and magnitude of hydrogen demand and optimize the placement of production facilities and pipeline networks for transporting hydrogen and carbon dioxide. Engineering/economic models that identify the costs and technical performance of infrastructure components allow for the calculation of the costs, energy usage and emissions of different hydrogen infrastructure options. Based on these parameters, it is possible to identify the lowest cost infrastructure design for supplying hydrogen to users under multiple scenarios. The goal of this research is to increase understanding of the economics and design issues related to hydrogen infrastructure development under real-world constraints.

2. Scenarios Considered

In this study, two hydrogen production technologies and two market penetration levels are considered, resulting in a total of four infrastructure scenarios (Table 1). The two production technologies are centralized production of hydrogen using coal gasification and distributed hydrogen production using steam methane

[1] Institute of Transportation Studies, University of California, Davis
[2] Information Center for the Environment, University of California, Davis

reformers at refueling stations. For each of these production cases, infrastructure is designed and evaluated at two market penetration levels of hydrogen vehicles, 10% and 50%, in order to examine how the results might differ for early and more mature hydrogen markets. For the centralized coal production scenarios, it is assumed that the hydrogen will be distributed via pipeline and the CO_2 will be captured and sequestered. In the distributed production scenarios, it is not economically viable to capture and sequester CO_2. The costs, emissions, and overall energy efficiency of these four scenarios will be calculated and compared in order to identify the optimal infrastructure design at each market penetration level.

	Feedstock	Market Penetration	Distribution	CO_2 Sequestration
Centralized	Coal	10%	Pipeline	Yes
	Coal	50%	Pipeline	Yes
Onsite	Natural Gas	10%	N/A	No
	Natural Gas	50%	N/A	No

Table 1: Infrastructure scenarios considered in this study

3. The Modeling Process

In modeling a transition to a hydrogen-based transportation system, the Transitional Hydrogen Infrastructure Modeling (THIM) project at ITS-Davis[3] has made significant progress in compiling existing data and developing methodologies and tools for designing and costing the variety of potential pathways to a hydrogen future. This paper focuses on the GIS-based modeling tools that have been developed for optimizing hydrogen infrastructure for a given region and steady-state demand level. In this section, detailed explanations of the methodologies for modeling hydrogen demand and the optimal infrastructure for supplying this demand are provided.

In performing the GIS analysis, several existing spatial datasets were used, including census block population [1], existing coal power plants[2], existing pipeline rights-of-way [3], brine well locations[4], and interstate highways [5]. These datasets are illustrated in Figure 1. The US Census data is used to identify hydrogen demand density based on population density. The existing coal power plants and pipeline rights-of-way are used to constrain the hydrogen infrastructure analysis by assuming that coal-to-hydrogen facilities will be sited in the same locations as existing coal plants and hydrogen pipelines will follow existing rights-of-way. Brine wells access deep saline aquifers, which are potential reservoirs for CO_2 sequestration. Consequently, these wells act as proxies for CO_2 sequestration sites.

---

[3] Institute of Transportation Studies at the University of California, Davis

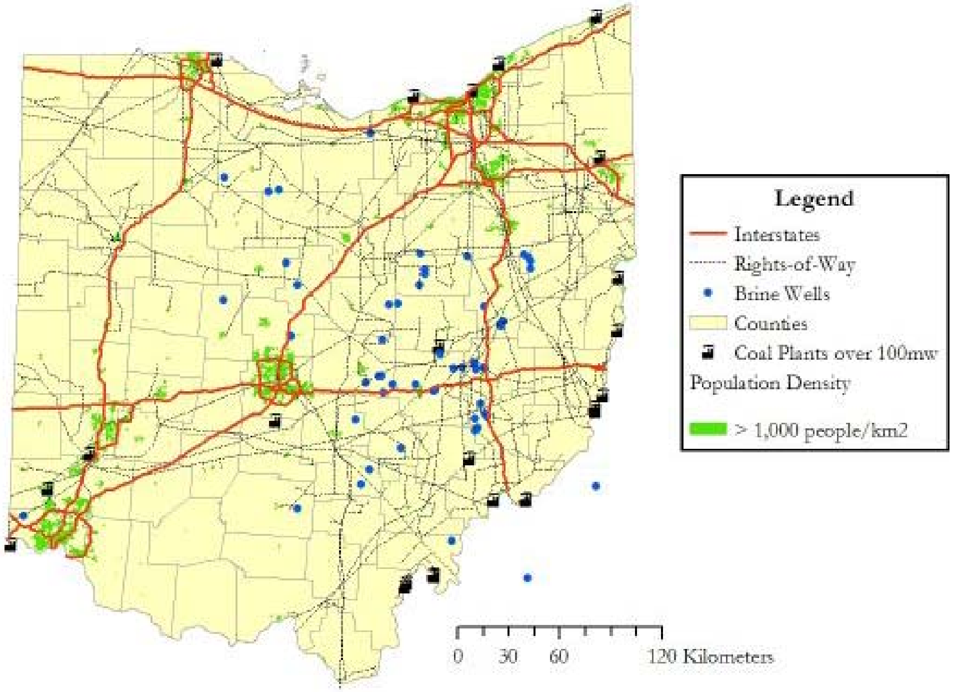


Figure 1: Ohio GIS datasets

3.1 Modeling Hydrogen Demand

Understanding the evolution of a hydrogen fuel delivery infrastructure depends on the spatial characteristics of the hydrogen demand. A preliminary method has been developed to model the magnitude and spatial distribution of hydrogen demand based on exogenously-derived market penetration levels and GIS data [6]. Currently, this model is used to examine steady-state (i.e., non-transition) market penetration scenarios in which demand is derived based on fixed percentages of hydrogen fuel cell vehicle (HFCV) penetration (e.g., 10%).

The current methodology employs census-derived population density, which is mapped at the census-block level, to calculate hydrogen demand density based on per-capita vehicle ownership, projections for daily hydrogen use per vehicle, and market penetration levels. Depending on the analysis year, current or projected population density can be used. Buffers are then applied to areas of high demand density to aggregate neighboring census blocks into demand clusters. The aggregate hydrogen demand within each cluster is then calculated and a threshold is applied to retain only the clusters with sufficient hydrogen demand to warrant investment in infrastructure (> 3,000 kg H_2/day). These remaining clusters are considered the viable hydrogen "demand centers" to which hydrogen should be supplied at a given HFCV penetration. Although this method contains many simplifying assumptions, it provides a means for identifying potentially viable locations for hydrogen infrastructure investment at various static market penetration levels.

In order to automate the modeling process, a custom user interface was developed in ESRI ArcGIS™ software that allows users to specify their own information regarding inputs such as per-capita vehicle ownership and hydrogen vehicle market penetration (Figure 2). Through this interface, the model can be applied to any region with U.S. Census data.

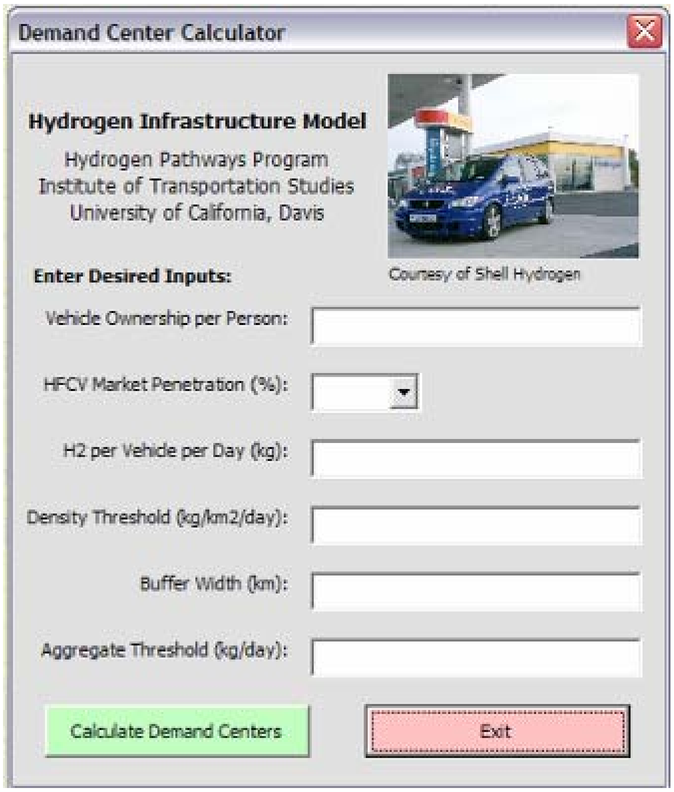
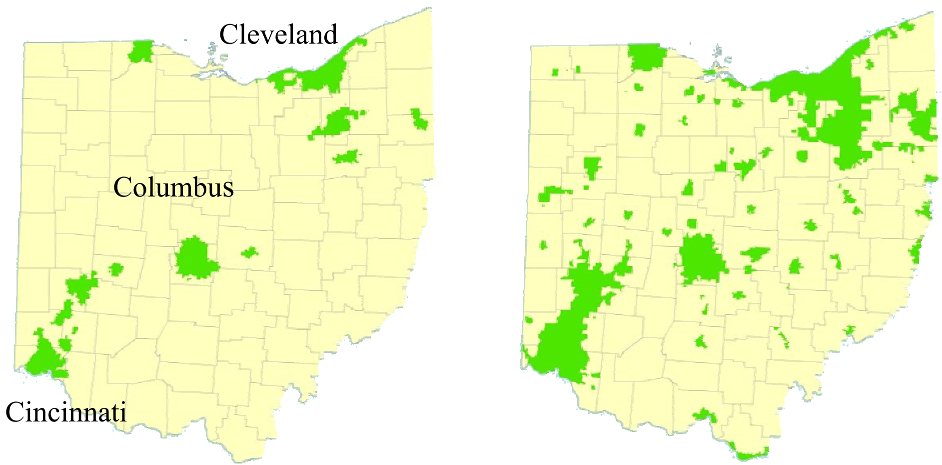


Figure 2: Custom user interface

In this case study, the statewide hydrogen demand throughout Ohio is modeled, assuming that per-capita vehicle ownership is 0.7 and daily hydrogen use per vehicle is 0.6 kg [6]. At 10% market penetration, the twelve resulting demand centers are indicated in Figure 3a. These demand centers occupy less than 5% of the statewide land area, but capture about 48% of the statewide hydrogen demand, which amounts to 253 tonnes H_2 per day. Twenty-three percent of the statewide demand is captured in the three largest cities of Columbus, Cincinnati, and Cleveland. At 50% market penetration, the demand centers increase in size and quantity (Figure 3b). There are 39 demand centers that capture 74% of the statewide hydrogen demand, or approximately 2,000 tonnes of H_2 per day. This is equivalent to about 2,750 MW_t of hydrogen. Since coal can produce hydrogen more efficiently than electricity[4], a coal facility that could produce 2,000 tonnes of hydrogen per day would need the same coal input as a 1,600 MW_e coal-fired

[4]The average coal-fired steam plant produces electricity at about 35% efficiency [2], while a more modern integrated gasification combined cycle (IGCC) plant could produce hydrogen at ~65% efficiency [7,10].

steam plant that produces electricity. As 1,600 MW_e is within the size range of existing coal to electricity facilities in Ohio, it is possible that a single coal facility could meet the statewide hydrogen demand at 50% market penetration.



a) 10% market penetration b) 50% market penetration

Figure 3: Demand centers at 10% and 50% market penetration

3.2 Optimizing Supply: Production and Transmission

Given the location and quantity of hydrogen demand, the next step is to optimize the siting of production facilities and distribution networks for delivering hydrogen to the demand centers. In evaluating the location of coal-to-hydrogen facilities, it is assumed that these plants will be sited in the same locations as existing coal plants and will have access to the same amount of coal input. Data regarding Ohio coal plants is available from the EPA's eGrid power plant database, which provides information such as electricity output, coal input, CO_2 and other important emissions, and plant efficiency[2].

Given the coal available at each existing plant, the potential hydrogen production of the facilities greater than 100MW_e is calculated for two conversion scenarios (Table 2). In both scenarios, it is assumed that the existing coal-fired steam plants are converted to more modern and efficient integrated gasification combined cycle (IGCC) plants and the coal input to the plant is maintained. The first scenario assumes that the existing plant is converted to produce only hydrogen at an efficiency of 65% [7]. In this case, the largest coal facility could produce greater than 2,500 tonnes of H_2 per day. If all of the coal facilities statewide were converted to produce only hydrogen, they could produce enough hydrogen to supply approximately 31 million hydrogen vehicles (~18,800 tonnes per day), which is 3.5 times the number of gasoline vehicles currently in Ohio.

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

Table 2: H_2 Production Potential of Existing Coal Facilities for Two Conversion Scenarios

The fourth column in Table 2 indicates the efficiencies for producing electricity from coal in each of the existing coal facilities[2]. These values range from 23% to 40%. Assuming that these facilities are converted to IGCC plants, the coal-to-electricity conversion efficiency would increase to about 42%. Consequently, in the second conversion scenario, it is assumed that the plants will continue to produce the same amount of electricity, but the gains in efficiency will result in excess energy, which can then be used to produce hydrogen. If all of the coal facilities were converted in this manner, they could produce about 1,500 tonnes of H_2 per day, or enough to supply about 30% of the vehicles in the state. This quantity is about six times the hydrogen required at 10% market penetration, but would not be sufficient to meet demand at 50% market penetration. The estimation of hydrogen production potential indicates that a *single* coal-to-hydrogen plant could meet statewide demand at both 10% and 50% market penetration if the plant is converted to produce hydrogen exclusively. With this knowledge, the next step is to identify the coal facility or facilities that minimize the distance of the pipeline network, which connects the coal facilities to the demand centers. The potential production and transmission infrastructure, including all rights-of-way and coal facilities, is illustrated in Figure 4.

In order to assess the optimal pipeline network, GIS was used to identify the shortest distance pathways between all the coal facilities and demand centers as well as between the demand centers themselves. Figure 5 shows the results of this analysis at 10% market penetration, where the red lines indicate the shortest distance pathways. This network represents the portfolio of possible pipeline segments that connect coal facilities and demand centers. For each segment, the distance is calculated and then imported into a matrix in an Excel spreadsheet (Figure 6).

In the top portion of the table are the distances between each coal facility and demand center and the bottom portion includes the distances between the demand centers themselves. A minimal spanning tree optimization algorithm was then applied to identify the optimal pipeline network and production facility for delivering hydrogen to the demand centers. At 10% market penetration, it is assumed that a single coal plant will supply the entire state since the demand is very low (~250 tonnes per day). Consequently, the optimization algorithm was run for several iterations, involving a single coal facility and all the demand centers. In each iteration, the demand centers and coal facility are equivalent to nodes, which the optimization algorithm connects by identifying the pipeline network with the minimum length.

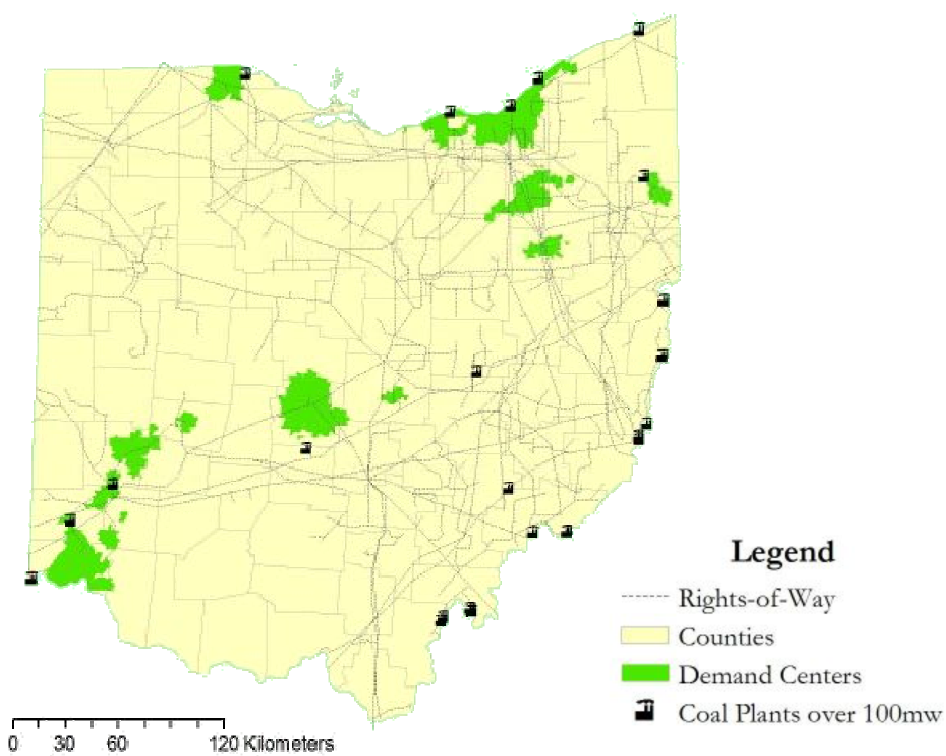


Figure 4: Potential production and transmission infrastructure

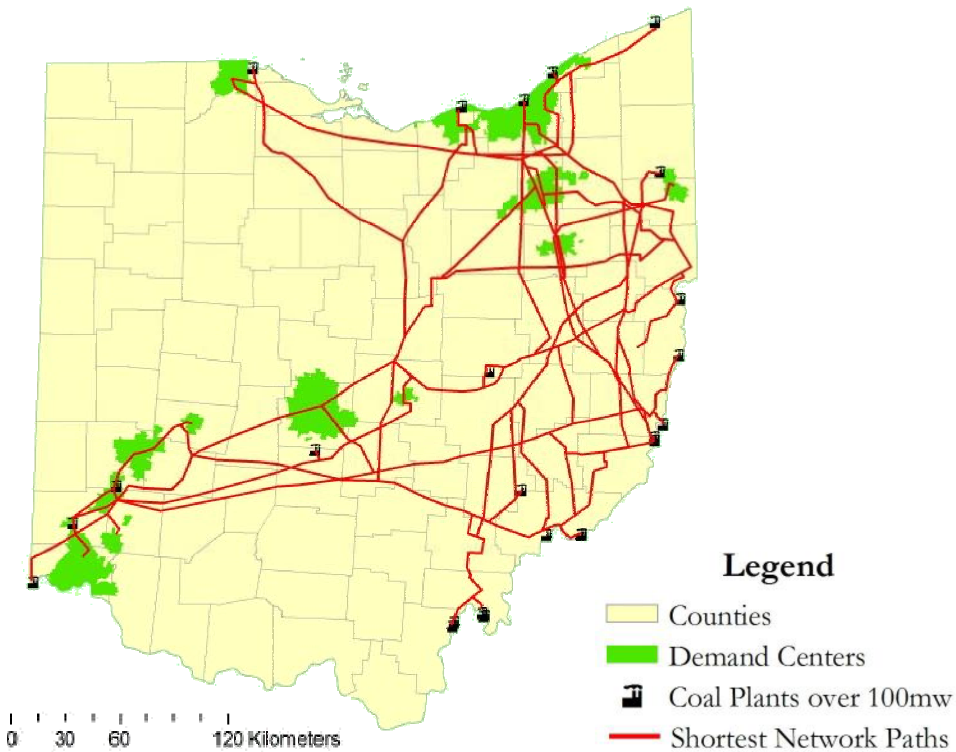


Figure 5: Shortest distance pathways between coal facilities and demand centers (10% market penetration)

Distance matrix for all nodes

		Demand Clusters											
		3	7	13	16	23	43	48	49	52	57	62	65
Coal Plants	101	283	72	171	140	164	288	406	308	428	447	459	481
	102	158	105	152	81	107	181	300	201	321	340	352	374
	103	21	210	257	186	212	226	345	247	367	385	397	420
	104	363	242	186	181	150	218	312	237	334	337	349	372
	105	266	196	162	131	101	70	205	107	227	246	258	280
	106	229	17	129	90	114	234	353	254	374	393	405	427
	107	406	339	304	274	243	194	258	189	280	284	296	318
	108	405	394	412	350	337	204	89	156	54	25	40	22
	109	338	219	163	156	125	193	280	205	301	305	317	339
	110	409	341	306	276	246	196	260	192	282	286	298	320
	111	192	67	117	58	84	198	317	218	338	357	369	391
	112	445	433	452	390	377	244	134	196	99	71	73	55
	113	337	218	162	155	123	192	278	203	300	304	316	338
	114	397	329	295	264	234	185	249	180	270	274	286	308
	115	358	251	216	186	155	146	210	141	232	235	248	270
	116	262	114	49	82	83	229	357	259	379	397	410	432
	117	385	373	392	330	317	184	57	136	22	6.2	31	53
	118	397	329	295	264	234	185	249	180	270	274	286	308
	119	285	274	292	230	217	73	99	52	121	126	138	160
	120	390	291	242	226	196	178	242	173	263	267	279	302
	121	336	215	159	154	123	191	285	210	306	310	322	344
	122	366	272	235	207	176	154	218	149	240	243	256	278
	123	310	162	98	126	122	207	343	245	365	380	392	414
	124	390	291	242	226	195	177	241	172	263	267	279	301
Demand Clusters	3	0	212	259	188	214	229	347	249	369	388	400	422
	7	212	0	111	73	97	217	336	237	357	376	388	410
	13	259	111	0	79	80	226	354	256	376	394	406	429
	16	188	73	79	0	32	174	292	194	314	332	344	367
	23	214	97	80	32	0	161	279	181	301	320	332	354
	43	229	217	226	174	161	0	160	70	182	187	199	221
	48	347	336	354	292	279	160	0	98	35	64	89	111
	49	249	237	256	194	181	70	98	0	120	139	151	173
	52	369	357	376	314	301	182	35	120	0	28	53	76
	57	388	376	394	332	320	187	64	139	28	0	34	47
	62	400	388	406	344	332	199	89	151	53	34	0	50
	65	422	410	429	367	354	221	111	173	76	47	50	0

Decision table

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

Figure 6: Optimization matrix and decision table (10% market penetration)

In optimizing the pipeline network, the algorithm first selects the two nodes that are connected by the shortest segment of pipeline. It then identifies the next nearest node (via pipeline) and continues until all the demand centers and the coal facility are connected. The iterations that were run for each coal facility are then compared and the production and transmission design that results in the minimum pipeline distance is selected as the optimal infrastructure at a given market penetration level. The optimized design is then imported back into GIS for visualization.

At 10% market penetration (Figure 7), the optimal infrastructure design includes a single coal facility, producing about 250 tonnes of H_2 per day, and twelve demand centers connected by 936 km of transmission pipeline. In addition, there is a CO_2 sequestration system that must be able to handle about 4,500 tonnes of CO_2 per day. A brine well is located immediately adjacent to the optimal production facility so a separate optimization for the CO_2 infrastructure was not necessary.

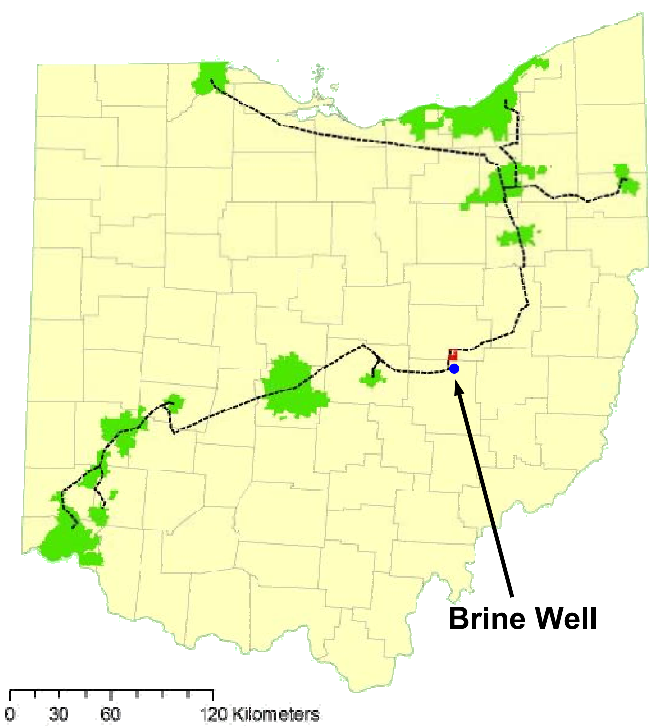


Figure 7: Optimal infrastructure design at 10% market penetration

At 50% market penetration, the optimal infrastructure design (Figure 8) includes a single coal facility, producing about 2,000 tonnes of H_2 per day, and thirty-nine demand centers connected by ~ 2,300 km of transmission pipeline. The CO_2 sequestration site is again located adjacent to the production facility and must handle about 34,000 tonnes of CO_2 per day. A scenario in which two production facilities would supply the statewide hydrogen demand was also considered, but it was discovered that this scenario only decreases the pipeline distance by about 100 km while incurring the cost of an additional coal facility. As a result, it is less expensive to produce the hydrogen at a single facility.

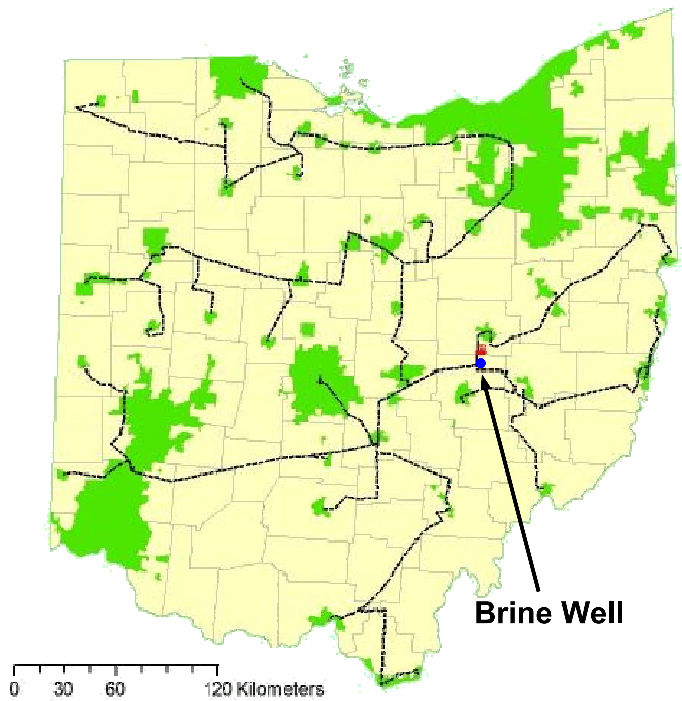


Figure 8: Optimal infrastructure design at 50% market penetration

3.3 Intracity Distribution and Station Siting

Given the location and quantity of demand, the location and production capacity of the coal facility, and the location of the hydrogen pipelines, the next step is to identify the infrastructure required for delivering hydrogen to consumers within the demand center boundaries. A GIS-based methodology has not been developed for optimizing intracity hydrogen distribution and refueling station siting. Instead, an idealized city model was used to simplify the estimation of the distribution pipeline length and number of refueling stations [8]. This model assumes that each demand center is represented by a circle of equivalent area (Figure 9a). Within this circle, the refueling stations are arranged along concentric rings and connected by pipelines (Figure 9b). As a result of this simplification, the distribution pipeline length can be estimated by the demand center area and the number of refueling stations.

The number of hydrogen refueling stations within each demand center is estimated based on population. Assuming that existing gasoline stations serve approximately 3,000 vehicles [9], the number of gasoline stations is estimated by multiplying the population by the vehicle ownership rate (0.7) and then dividing this number by 3,000. It is then assumed that the number of hydrogen refueling stations as a percentage of the gasoline stations is equivalent to the market penetration level. Consequently, at 10% market penetration, it is estimated that the number of hydrogen stations will be 10% of gasoline stations. At 10% market penetration, 147 hydrogen refueling stations are required within the statewide demand centers. At 50% market penetration, 1,117 hydrogen stations are required. These stations deliver an average of 1,800 kg H_2 per day. In the onsite production scenario, the same number and size of stations is used for each market penetration level.

Given the number of stations and area associated with each demand center, the intracity pipeline distance is estimated. At 10% market penetration, approximately 1,300 km of intracity pipeline is required statewide and the 50% market penetration scenario requires about 5,300 km.

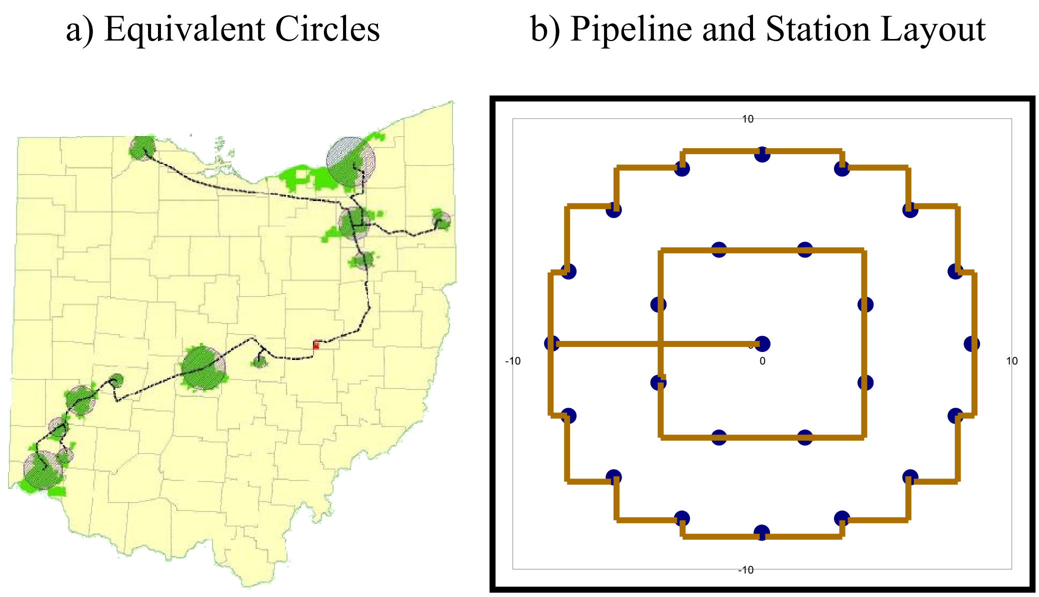


Figure 9: Idealized city model

3.4 Intercity Station Siting

The final component of regional infrastructure design is the siting of intercity stations. These stations are intended to provide connectivity between demand centers so that hydrogen vehicle owners can travel reliably along interstate highways. In order to optimize intercity station siting, the first step is to identify *potential* station sites. These sites are identified by selecting all major intersections[5] that involve interstate highways and are within five kilometers of an intercity demand cluster (Figure 10). The intercity demand clusters are the demand clusters that were identified in the demand analysis, but did not have sufficient hydrogen demand to qualify as a demand center (blue and pink clusters in Figure 10).

For each of the potential station sites, the following information is calculated. First, the average daily traffic (ADT) flow is estimated based on Ohio DOT data

[5] Major intersections are defined as those involving interstate, US, and State highways as defined by the Ohio Department of Transportation.

for the highway segments involved in each intersection (i.e., station site). Next, the distance from the site to the nearest demand cluster is calculated and the associated hydrogen demand of this cluster is assigned to the site. Finally, the distance from each site to the corridor endpoints is calculated. Given this information, the optimal intercity station sites are identified by selecting potential sites that are close to large demand clusters, have significant average daily traffic flow, and are located greater than 30 kilometers from the corridor endpoints, or demand centers. These criteria ensure that the optimized stations will be located at sites with ample vehicle traffic, near cities with some potential local hydrogen demand, and distant from demand centers where there are sufficient refueling stations.

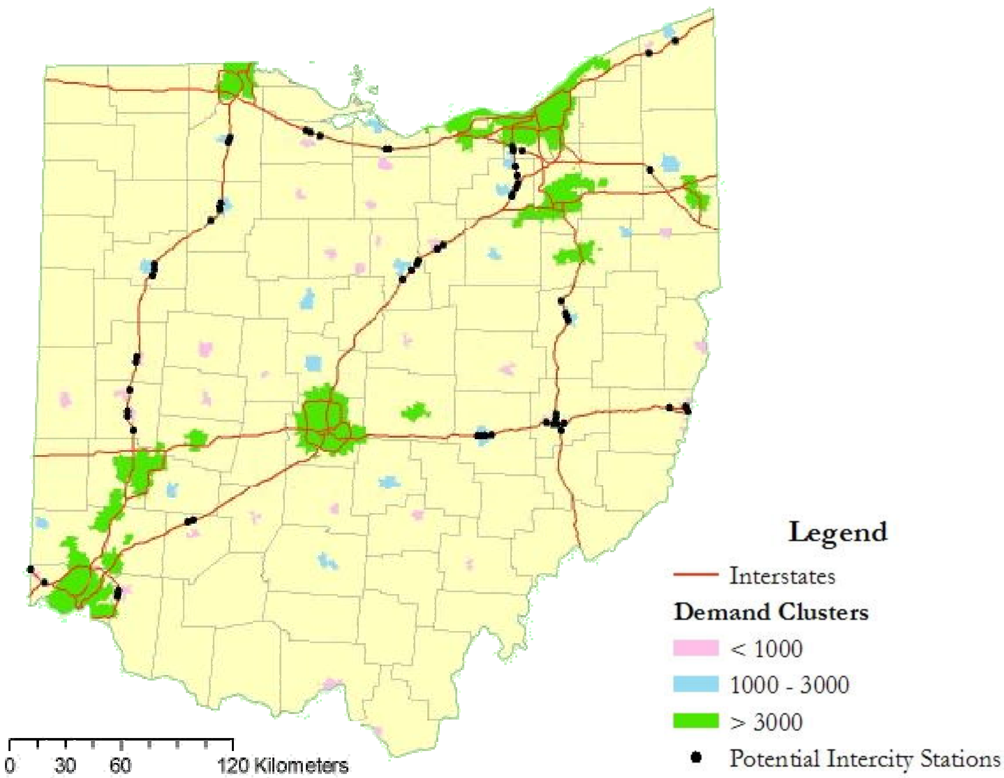


Figure 10: Potential intercity station sites

As a result, ten optimal intercity stations are identified in which it is assumed that the hydrogen will be produced onsite using natural gas reformation (Figure 11). The daily hydrogen demand at these sites is estimated by combining the local and intercity traveler demands. The local demand is defined as the demand associated with the nearest demand cluster, whereas the intercity traveler demand is estimated based on the minimum ADT along the associated interstate corridor. Assuming that 80% of the minimum ADT are intercity travelers, 10% of these vehicles operate on hydrogen, and 25% of these vehicles stop to refuel between demand centers, the number of hydrogen vehicles stopping at each intercity station is identified. Given the number of vehicles and assuming that the average fill is three kilograms, the intercity traveler hydrogen demand is estimated. These assumptions are preliminary and will be refined based on a literature review. Based on this analysis, all of the intercity stations create an additional hydrogen demand of approximately twenty tonnes per day and the average station demand is about 2,000 kilograms per day. Given these stations, hydrogen vehicle drivers will not have to travel more than 60 miles between hydrogen stations along the interstate highways.

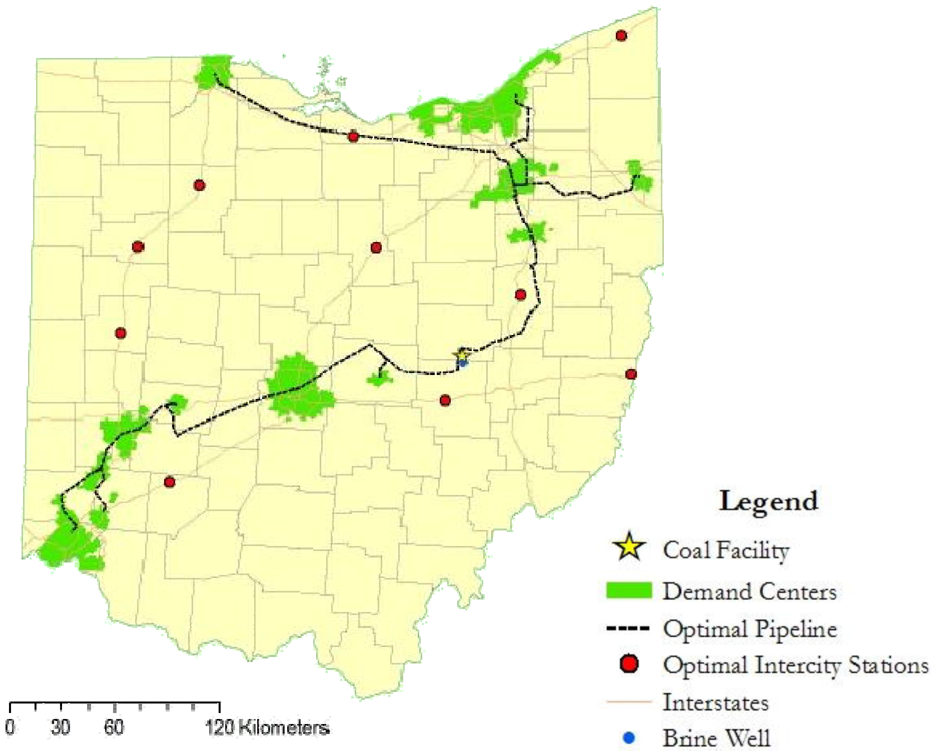


Figure 11: Optimal intercity stations and infrastructure design at 10% market penetration

3.5 Engineering and Economic Models

Once the optimal infrastructure design has been determined, engineering and economic models for each of the infrastructure components are used to determine the cost and technical performance of the system. The models encompass the range of processes and equipment necessary for hydrogen production, transport and distribution, and dispensing as well as sequestration of carbon dioxide.

Central Plant Hydrogen Production
Hydrogen production is modeled for a large coal gasification plant with electricity co-production and carbon capture based upon designs and modeling from Kreutz et al [7, 10]. The capacity of each plant is constrained by the location and coal input of the existing coal steam power plant as detailed in the EPA eGrid database[2]. The production plants are designed to maximize the hydrogen output (~97% of energy output) with minor electricity co-production (~3%) to provide for electrical requirements (such as compression) and enhance overall plant

efficiency. The results of these detailed process design studies are used to produce a simplified model for the cost and performance of fossil H_2 plants as a function of scale, feedstock and process design. From these studies, the coal-to-hydrogen efficiencies are assumed to be 65%. Based upon the demand, we calculated the size of the gasification plant to meet this demand and the capital and O&M costs were estimated from these studies based upon scaling factors for process equipment. The central plant cost includes the cost of capturing carbon dioxide for sequestration via "conventional" technologies (glycol absorption for CO_2 capture).

CO_2 Sequestration
In the plant design chosen, 92% of the CO_2 is captured and sequestered while 8% is emitted to the atmosphere [7, 10-12]. Once CO_2 has been captured at the central hydrogen plant, it must be dehydrated and compressed to a supercritical state and transported via pipeline to the underground sequestration site. Supercritical pressure for CO_2 is 15 Mpa, which permits efficient pipeline transmission of CO_2. CO_2 pipeline costs and technical performance are estimated based upon system designs studied at the Princeton University CMI[6] program [13]. Pipeline costs are based upon a power law function for flowrate and length[14]. Finally, the CO_2 must be injected into an underground geological formation such as a deep saline aquifer. Since we do not currently have accurate data to characterize the injection sites (capacity, depth, permeability, and pressures), we assumed injection costs based upon some generic values associated with large reservoirs [13]. Each well is assumed to be capable of handling up to 2,500 tonnes of CO_2 per day.

Transmission and Distribution Pipelines
Pipelines are used for the transmission of hydrogen from the central hydrogen production plant to each of the demand clusters as well as distribution within each of the demand clusters to the network of refueling stations located within those clusters. Detailed steady-state pipe flow equations are used to model the pressure drop and diameter tradeoffs for hydrogen as well as determining material requirements and overall pipeline costs [13, 15]. Costs are related to a number of factors including pipeline flowrate, required outlet pressure, and length. For simplicity, the steady state performance of the ringed network of pipelines within the demand clusters is not explicitly modeled. The estimates used for the small pipelines for hydrogen distribution within the city appear to be acceptable because the costs associated with the pipeline are mainly due to installation and right-of-way as opposed to the diameter and material cost of the pipeline itself.

Refueling Stations
For the scenarios involving onsite hydrogen production from natural gas, the refueling station will include all of the equipment and costs associated with hydrogen production via SMR, compression, storage and dispensing. A refueling station cost model is used to estimate the costs of stations for both on-site production and delivered hydrogen [16]. The stations are assumed to have a

[6] Carbon Mitigation Initiative

maximum size of 1,800 kg/day and small modular reformers can be added in 600 kg/day increments. These SMR units are assumed to be fairly low cost ($400,000 for a 600 kg/day capacity).

For centrally produced hydrogen from coal that is distributed via pipeline, the stations do not include hydrogen production, but do include compressors, hydrogen storage and dispensing. High-pressure gaseous storage costs are assumed to be $400/kg (H2A forecourt costs [17]). Storage requirements for these station types will differ because of the difference between the maximum throughput of pipelines versus an onsite SMR. It is assumed that a station with an onsite SMR would require approximately 75% of a day's production in the form of storage, while stations with pipeline delivery can reduce the storage requirement to 25%.

4. Scenario Evaluation

Given the optimized infrastructure design for each scenario, the cost, overall energy efficiency, and CO_2 emissions are evaluated and compared. At 10% market penetration, the optimal infrastructure design for the centralized coal-to-hydrogen scenario is illustrated in Figure 11. This design serves approximately 420,000 hydrogen vehicles and includes one coal-to-hydrogen plant that produces 253 tonnes H_2 per day and 936 kilometers of intercity transmission pipeline that connect the coal facility to the twelve demand centers. Within the demand centers, there are 1,344 kilometers of intracity distribution pipeline and 147 intracity refueling stations that deliver hydrogen to consumers. In addition, ten intercity refueling stations provide connectivity between demand centers and one CO_2 sequestration site handles the approximately 4,500 tonnes CO_2 that is generated from the coal facility daily.

At 50% market penetration, the optimal infrastructure design serves about 3.3 million hydrogen vehicles and includes one coal-to-hydrogen plant that produces 1,975 tonnes H_2 per day (see Figure 8). This facility is linked to the 39 demand centers by 2,286 kilometers of intercity pipeline while 5,260 kilometers of intracity pipeline and 1,117 refueling stations deliver hydrogen to consumers within the demand centers. Finally, there is a single CO_2 sequestration site that handles about 35,000 tonnes CO_2 per day. Intercity stations are not necessary at 50% market penetration since demand centers occur along the interstates.

Table 3 lists the capital and installation costs associated with each of the infrastructure components for the four design scenarios. In addition, Figure 12 compares the four options based on the levelized cost of hydrogen (delivered), which includes O&M and feedstock costs. Based on these graphs, it is apparent that the onsite scenario ($2.47/kg) results in a significantly lower levelized cost of hydrogen than the centralized scenario ($3.54/kg) at 10% market penetration. When market penetration is increased to 50%, the production and distribution costs associated with centralized production benefit greatly from economies of scale and result in a significant decrease in the levelized cost to $2.57/kg. However, onsite production still remains slightly cheaper at $2.47/kg.

	Coal – 10% Market Penetration	Coal – 50% Market Penetration	Onsite – 10% Market Penetration	Onsite – 50% Market Penetration
H_2 Production	$351	$1,926	-	-
H_2 Compressors	$30	$192	-	-
Transmission Pipelines	$358	$1,068	-	-
Distribution (Intracity) Pipelines	$439	$2,493	-	-
Refueling Stations	$164	$1,246	$499	$4,100
CO_2 Sequestration	$55	$268	-	-
Intercity Stations	$37	-	$37	-
TOTAL	**$1,434**	**$7,192**	**$536**	**$4,100**
Number of Vehicles	421,197	3,291,791	421,197	3,291,791
Infrastructure Cost per Vehicle	$3,404	$2,185	$1,273	$1,245

Table 3: Capital and Installation Costs ($ Millions)

If policymakers were to institute a $50 per tonne carbon tax, the levelized cost associated with onsite production would increase by about $0.17 to $2.64 per kg, since sequestration of CO_2 is not performed in this scenario, while the centralized coal scenario with sequestration would only increase by $0.06 to about $2.63 per kg. As a result, at 50% market penetration, the centralized coal scenario becomes economically favorable. Furthermore, assuming a natural gas cost of $7/mmbtu, the feedstock cost associated with onsite natural gas reformation constitutes a major portion of the hydrogen cost. As a result, if the natural gas feedstock cost were to increase by as little as 10%, the coal scenario would become favorable. As the price of coal feedstock is unlikely to change significantly in the near future, the coal scenario is less sensitive than the onsite (natural gas) scenario to fluctuations in feedstock price.

CO_2 emissions are evaluated for several well-to-wheels scenarios, including coal-based hydrogen with and without sequestration, onsite production of hydrogen using natural gas reformation, and the existing gasoline-based transportation system. For the hydrogen-based scenarios, it is assumed that fuel cell vehicles (with fuel economy equivalent to ~ 60 mpg gasoline) will dominate the market, whereas the gasoline-based scenario assumes advanced internal combustion engine (ICE) vehicles (with fuel economy equivalent to ~ 40 mpg gasoline). For the coal with sequestration scenario, it is assumed that 92% of the CO_2 is captured at the plant and the electricity used in the scenario is not decarbonized, but has emissions consistent with the standard Ohio grid mix.

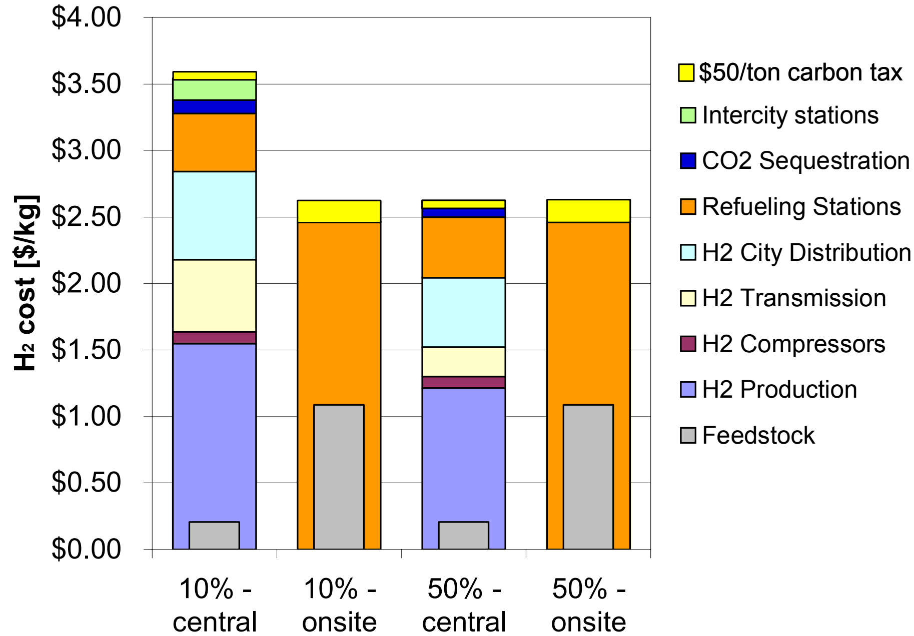


Figure 12: Comparison of levelized H_2 cost for the four scenarios

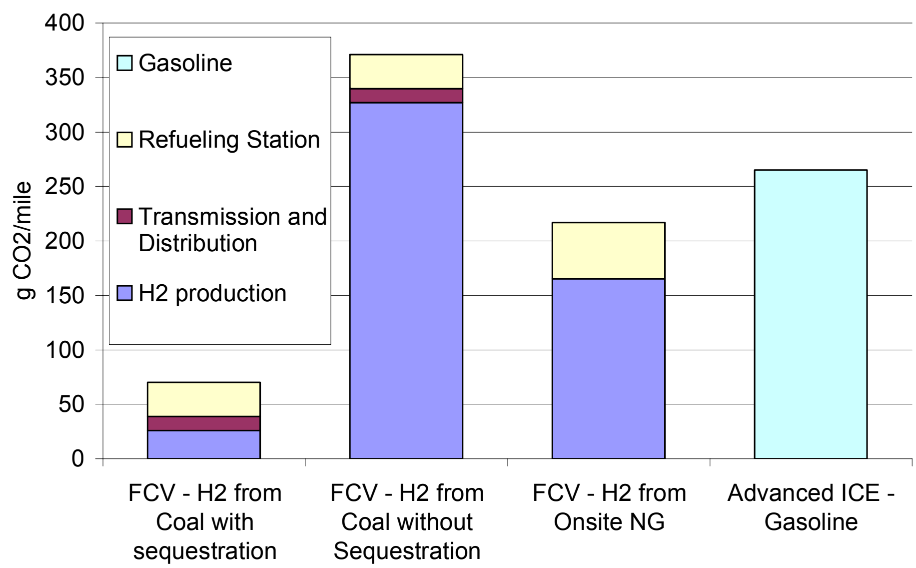


Figure 13: Comparison of well-to-wheels CO_2 emissions

The well-to-wheels CO_2 emissions associated with each scenario are illustrated in Figure 13. This figure indicates that the coal with sequestration scenario is preferable on a CO_2 emissions basis with about a third of the emissions as the onsite production scenario. Both of the hydrogen scenarios considered in this study are preferable to a gasoline-based infrastructure using advanced ICE's, but the scenario in which hydrogen is produced from coal without sequestration is the worst option.

The overall well-to-tank energy efficiency of the two production/distribution pathways is also evaluated. The centralized coal with sequestration scenario has an efficiency of 56% while the onsite production scenario results in 63% efficiency. Consequently, on an efficiency basis, the onsite scenario is favorable.

5. Future Plans

Although this effort represents a significant step forward in modeling hydrogen infrastructure for a specific geographic region, the project is in its infancy. In the future, researchers plan to improve and extend the model in order to capture the inherent complexities associated with energy systems. For example, alternative scenarios will be evaluated, including applying the model to other regions, examining scenarios in which a mix of feedstocks and multiple production facility types are used to produce hydrogen, and evaluating mixed mode scenarios in which centralized and distributed production occur concurrently within a region. In addition, efforts will be made to improve distribution models by refining pipeline costs based on other geographic characteristics besides distance, such as terrain and land use, comparing pipeline and truck distribution, and developing GIS-based models for intracity distribution and refueling station siting. Researchers will continue to develop computer-based tools, including refining the demand modeling tool to consider other demographic factors besides population, developing more sophisticated and integrated optimization tools for analyzing complex scenarios, and developing a flexible computer user interface that will allow users to run the integrated model in other regions. Finally, methods will be explored for adding time dependence to the model, allowing simulation of alternative transition strategies.

6. Conclusion

During this project, GIS-based tools were successfully developed for optimizing hydrogen infrastructure and demand for two relatively simple production and distribution pathways and two market penetration scenarios. Furthermore, these tools were combined with engineering and economic models and idealized city models to design and evaluate infrastructure alternatives based on cost, CO_2 emissions, and overall energy efficiency. These tools and methods can also be easily applied to other regions within the United States. Despite achieving these early goals, the model will be further refined and enhanced in order to capture the complexities associated with designing and implementing a hydrogen-based transportation system. This research is supported by the sponsors of the Hydrogen Pathways Program at ITS-Davis and the National Energy Technology Laboratory.

References

1. *US Census Data*. 2000, US Census Bureau.
2. EPA, *eGrid Database*. 2004, Environmental Protection Agency: Washington DC. p. Powerplant data.
3. *GasTrans*, US Department of Energy: Washington DC.
4. NETL, *Brine Well Locations*. 2003, National Energy Technology Laboratory.
5. *Interstate Highway Data*. 2004, Ohio Deptment of Transportation.
6. Ni, J., et al. *Estimating Hydrogen Demand Distribution Using Geographic Information Systems (GIS)*. in *National Hydrogen Association*. 2005. Washington DC.
7. Chiesa, P., et al., *Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology.Part A: Performance and emissions.* International Journal of Hydrogen Energy, 2005. **30**: p. 747-767.
8. Yang, C. and J.M. Ogden. *A Simplified Integrated Model for Studying Transitions To A Hydrogen Economy*. in *NHA Hydrogen Conference and Expo*. 2004. Los Angeles, CA.
9. Melaina, M.W., *Initiating hydrogen infrastructures: preliminary analysis of a sufficient number of initial hydroen stations in the US.* International Journal of Hydrogen Energy, 2003. **28**: p. 742-755.
10. Kreutz, T.G., et al., *Co-production of hydrogen, electricity andCO2 from coal with commercially ready technology. Part B: Economic analysis.* International Journal of Hydrogen Energy, 2005. **30**: p. 769-784.
11. Chiesa, P., et al. *Co-production of Hydrogen, Electricity and CO2 from Coal using Commercially-Ready Technology*. in *Second Annual Conference on Carbon Sequestration*. 2003. Washington DC.
12. Kreutz, T.G., et al. *Production of Hydrogen and Electricity from Coal with CO2 Capture*. in *6th International Conference on Greenhouse Gas Control Technologies*. 2002. Kyoto, Japan.
13. Ogden, J.M. *Modeling Infrastructure for a Fossil Hydrogen Energy System with CO2 Sequestration*. in *GHGT-6 Conference*. 2002. Japan.
14. Wang, W., *CO2 Pipeline Network Optimization*, in *Mechanical and Aerospace Engineering*. 2003, Princeton University: Princeton, NJ. p. 80.
15. Mohitpour, M., H. Golshan, and A. Murray, *Pipeline Design & Construction: A Practical Approach*. 2000, New York: ASME Press. 654.
16. Yang, C. and J.M. Ogden. *Analyzing Natural Gas Based Hydrogen Infrastructure – Optimizing Transitions From Distributed To Centralized H2 Production*. in *National Hydrogen Association*. 2005. Washington DC.
17. Lasher, S., B.D. James, and M. Ringer. *H2A Forecourt Team Overview*. in *National Hydrogen Association*. 2004.

Author Biographies

Nils Johnson is a project manager within the Hydrogen Pathways Program at the Institute of Transportation Studies at the University of California, Davis. He manages the Transitional Hydrogen Infrastructure Modeling (THIM) project, which is an ongoing effort to evaluate how a hydrogen infrastructure might develop through time. Mr. Johnson has a BA in political science from Haverford College and a Master of Forestry and Master of Environmental Management from the Nicholas School of the Environment at Duke University.

Dr. Christopher Yang is a Research Engineer at the Institute of Transportation Studies at the University of California, Davis. His primary research focus is on modeling of hydrogen production and distribution infrastructure and understanding how a hydrogen economy might evolve over time. Other research topics include a study on the interactions between fuel and electricity production in a hydrogen economy. He recently completed his PhD from Princeton University in the Mechanical and Aerospace Engineering Department where he collaborated with faculty in a multidisciplinary lab focused on fuel cell membrane research.

Jason Ni received his BS degree from the department of Civil Engineering at National Taiwan University, and a Master of Transportation Engineering and Master of City Planning from UC Berkeley. Jason joined UC Davis in Fall of 2003 as a Ph.D. student in the Transportation Technology and Policy program. He has been working with Professor Joan Ogden on modeling hydrogen demand using GIS.

Joshua Johnson is a GIS Research Analyst at the Information Center for the Environment at the University of California, Davis. He specializes in the application of GIS to the study of environmental issues.

Zhenhong Lin is currently a PhD candidate in Transportation Technology and Policy at the University of California, Davis. He focuses on modeling hydrogen infrastructure using mathematical programming and has research experience in fuel cell vehicles and the Chinese automotive industry.

Dr. Joan Ogden is Associate Professor of Environmental Science and Policy at the University of California, Davis and Co-Director of the Hydrogen Pathways Program at the campus's Institute of Transportation Studies. Her recent work centers on the use of hydrogen as an energy carrier, hydrogen infrastructure strategies, and applications of fuel cell technology in transportation and stationary power production. She participated in the U.S. DOE Hydrogen Vision process in 2001, and headed the systems integration team for the National Hydrogen Roadmap in 2002. She is active in the H2A, a group of hydrogen analysts convened by the Department of Energy to develop a consistent framework for analyzing hydrogen systems, and serves on the Blueprint Plan advisory panel for the California Hydrogen Highway Network.