Supply Chain Network for Hydrogen Transportation in Spain

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Abstract

Hydrogen fuel is considered one of the major emerging renewable substitutes for fossil fuel. A crucial factor as to whether hydrogen will be successful depends on its cost as a substitute. Recently, there has been a growing interest in investigating the feasibility from a supply chain point of view.

This thesis intends to provide a comprehensive study of the feasibility of hydrogen as a transportation fuel from a supply chain point of view. The aim is to discover the most efficient, sustainable, and ultimately most cost-effective strategy to meet future transportation demand scenarios. This includes optimizing costs over production, compression, storage, distribution, and dispensation. Moreover, through the decision support model developed in this thesis, insightsregarding strategic approaches for hydrogen supply chain infrastructure developmentare developed, such as the tradeoff between centralized and distributed production.

A case study in Spain is presented to illustrate the supply chain. Different models are proposed to estimate electricity generation capacity, hydrogen production scheme, transportation topology, distribution methods and future demands. Six different scenarios, based on different production scheme, future demand level, are tested. Results from the case study indicate that it is more cost effective to transmit electricity from wind farms to locations close to demand sites to do contralized production. In terms of transportation, liquid gas truck is the preferred mode of transportationfrom production sites to local demand regions. The model can adapt be extended and adapted to consider other configurations of the supply chain network.

Thesis Supervisor : Dr. Jarrod Goentzel
Title: Executive of MLOG Program, Research Scientist

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1 Introduction and Motivation

Hydrogen is becoming more and more favorable as the energy carrier than petroleum. It is an environmentally cleaner source of energy to end-users, particularly in transportation applications. Significant reductions in carbon dioxide emissions would be possible if the current petroleum driven vechicles could be replaced by hyrdrogen driven vechiles immediately. With more environmental concern, hydrogen industry is growing at a enormous speed. Globally, some 50 million metric tons of hydrogen, equal to about 170 million tons of oil equivalent, were produced in 2004. The growth rate is around 10% per year. Within the United States, 2004 production was about 11 million metric tons (MMT), an average power flow of 48 gigawatts. As of 2005, the economic value of all hydrogen produced worldwide is about $135 billion per year[17]. It remains a non-trivial task to design a hydrogen infrastructure to support such a large scale hydrogen economy.

One of the major concern is hydrogen production, which could be centralized, distributed or mixture of both. Centralized production could give advantage in production efficiency and cost but also disvantage in high volumn storage and long range transportation. In particular, long range hydrogen transportation may be very expensive due to factors like compression technique and hydrogen diffusion through solid materials. These disvantages may lead to distributed or on-site production an attractive option which may make use of the electric grid to transmit the energy. However, problems such as energy loss during electricity transmission make the choice of production scheme a dilemma.

Aside from hydrogen production, transportation plays an important role in the hydrogen infrastructure. The transportation methods mainly consists of industrial hydrogen pipeline and hydrogen equipped filling station, compressed hydrogen tube trailers, liquid hydrogen trailers, liquid hydrogen tank trucks or dedicated onsite production as we mentioned earlier. Each of them has its own cost benefits and disvantages in certain area.

Because of the natrual gas pipes' success, pipeline seems one favorable option. The existing topology or even the pipes can be reusable for the hydrogen economy. However, due to the actively reactive nature of hydrogen, it is not feasible to transport hydrogen using the existing natural gas pipes. Building new pipes is expensive while we can enjoy the cost benefits of transporting hydrogen from two fixed points. But local dispensation is still required and possibly for the pipeline case. On the other hand, hydrogen piping can be avoided in distributed systems of hydrogen production, where hydrogen is routinely made on site using medium or small-sized generators which would produce enough hydrogen for personal use or perhaps a neighborhood. Distributed electrolysis would bypass the problems of distributing hydrogen by distributing electricity instead. It would use existing electrical networks to transport electricity to small, onsite electrolysers located at filling stations. A study conducted by the Pacific Northwest National Laboratory for the US Department of Energy in December 2006 found that the idle off-peak grid capacity in the US would be sufficient to power 84% of all vehicles in the US if they all were immediately replaced with electric vehicles.. In the end, a combination of options for hydrogen gas distribution may succeed [18].

One of the major purposes of the model in this thesiss is to address the proper balance between hydrogen distribution and long-distance electrical distribution is one of the primary questions that arises in the hydrogen economy. We develop a decision support model that optimizes the configuration of the hydrogen supply chain, from production to consumption, for various scenarios. The objective of the core model is to determine where to produce hydrogen, how much to produce at each location, and how to distribute the hydrogen to meet projected consumer demand in such a way as to minimize fixed capital costs plus variable operating costs subject to the technological and business logic constraints of the system. Two key features of our work are (1) the focus on renewable energy sources – wind-generated electricity to produce hydrogen via the electrolysis of water – and (2) the option of transporting electricity through the grid to facilitate distributed production of hydrogen.

2 Literature Review

2.1 Demand Estimation

Melaina's study (2003) [5] provided estimations of how many hydrogen fuel stations are required for the US with the same convenience level we can access gasoline stations today. Three approaches were proposed. The percentage of existing stations gave a reasonable estimation based on the empirical data of the gasoline stations. However, it remains unknown whether this approach can address the difference between high volume stations and low volumn stations. The second approach gives an estimation based on the demand of the metropolitan area. It is more accurate when it estimates a local area or a metropolitan area with high density. But high volume demand on the highway cannot be addressed, especically for big countries, e.g US. The third approach gives a complementary estimation to the second approach that is based on principal arterial roads. It covers the blind spot of the second approach. This study gives some great insights to estimate the lowest level distributions station in our model. A hybrid model of the three approaches is used in the thesis to estimate the hydrogen demand in Spain.

In Brey et al. (2007)'s study [16], they study the feasibility of satisfying 15% of Spain's energy demand for transport by 2010 through renewable sources, which includes production of hydrogen through photovoltaics, wind power, mini-hydraulic, high-temperature thermal solar, and biomass technologies. Notably, they mentioned in the study that 15% of energies comes from domestic, renewable sources. Only several regions will require inputs from their neighboring regions, such as Madrid, Balearic Islands, Canary Islands, and the Community of Valencia. In our estimation, we estimate the local demand categorized by local regions. Furthermore, one of our demand phases is based on the assumption of 15% of the domestic transportation demand. This information is also an interesting benchmark to our results in terms of where production should be located.

2.2 Distribution Methodology

Hugo et al. (2005) [2] presented a general framework of a hydrogen supply chain network using multi-objective optimization, which optimized over energy efficiency, environmental effect , production cost and distribution cost. Compared to our model, we mainly differ in several details which they referred to as criteria. First, we allow more flexible production scheme. In our model, hydrogen could be produced at any substation facilities connected to electric grid, where they specifies the topology of centralized production or distributed production. Moreover, our production model considers a variety of production modes to specify the electrolysis capacity and efficiency. Secondly, in their model, it seems to be focus more on natural gas technology as the basis point. This maybe a subconscious result as the project is in collaboration between BP Gas, Power & Renewables. Some of the other technologies may be undermined. Other notable difference is that we also did an estimation for the local demand in the future which could capture supply chain envolvement in the near futre. Even though our model mainly uses electricity from wind farms, it is easy to extend our electricity supply to other energy sources.

Almansoori and Shah (2006) [1] proposed a hydrogen supply chain model based on their case study of the United Kingdom. In their study, they discussed advantanges and tradeoffs under different scenario/configurations. The study first presented a complete mathematical model to address the importance of decision making in hydrogen supply chain network. This paper shares a similar motivation with our study based on U.K.'s case. Interestingly, they also concluded that hydrogen supply chain would prefer centralized production verus distributed production, liquid truck as transportation over compressed gas and railway and centralized storage or distributed storage. This result is consistent with the result presents in the study. However, it does not include many practical details in the decision model. Our model introduces more feasible options into the decision model. In production, we specifically consider the production mode of the electrolyzer as well as its economies of scale. This could explain where the model tends to prefer centralized production. In transportation, we introduce pipeline as the third transportation option. Considering hydrogen as a long term economic choice, pipeline is more viable than railway. Further detail would be given in the following sections. But this study gives a very good insight of future hydrogen supply chain network.

Yang and Ogden (2007) [9] focus on the distribution portion of the hydrogen supply chain and compared three dfferent transportation modes for hydrogen, liquid gas truck, compressed gas truck and compressed gas pipeline, with respect to cost, emissions and energy use. Their analysis is based on city characteristics and specific flow rate and distribution distance. Under their model, large demands that occur at high density are the most economical, which implies central production is more preferred than distributed production. Liquid truck may be the most cost-effective way to distribute hydrogen for low to moderate density cities. Both the thesis and their work is based on the United States Department of Energy's H2A study as a principal base of background information. However, their model does not include production. In the thesis, we present a complete optimization framework that includes all the scenarios in the supply chain network.

Floch et al. (2007) [15], investigate the viability of hydrogen production through alkaline electrolysis. This production scheme is not only closely related to renewable source, e.g. wind energy or solar energy, but also facilitate the cost effectiveness, namely the electricity cost variance between on and off peak prices. According to their analysis across different spot markets, they found that it is more cost effective where the cost of electricity is low. At the same time, they also pointed out that producing during off-peak hours could also effectively reduce the congestion in the electricity network during peak hours. With highly fluctuating electricity spot markets, it is also convenient to set up the production facility. The research provides an interesting approach to connect hydrogen production and electricity with electricity grid. This, indeed, is one effective way and an important part of the the hydrogen supply chain network. However, the authors only studied the price of electricity from a separate point of view. They did not take the hydrogen production into consideration, such as capacity. In this study, we investigate hydrogen production in detail, especially the electrolyzer. A variety of production schemes is examined in the analysis section, which address the gradual development of the hydrogen market. This approach provides a better insight of what role technology would play in the hydrogen economy. Indeed, it justifies investment in electrolysis technology where it might not seem evident from a macro-economic stance.

In Haeseldonckx and D'haeseleer's study (2007) [13], they investigate the feasibility of distributing hydrogen through existing natural gas infrastructure. Using natural gas pipeline is strongly motivated with respect to economic reasons which cannot only save huge amount of setup cost, but also make sure the mature natural gas pipeline topology. It would be really inspiring if the idea is feasible. From the study, hydrogen could be mixed into the pipeline with no more than 17% of the mixed gas. The major concern is due to hydrogen's highly reactive nature. The pipeline could be damaged by the reaction especially under such a highly pressured environment. Moreover, due to the variety of the pipeline history, it is risky to use the natural gas pipeline to distribute hydrogen. On the other hand, using the natural gas pipeline topology would still be a good idea. First of all, it is proved to survive and easy to build. Secondly, hydrogen economy could benefit more by distributing to lower demand spot, i.e. household. In this thesis, we use the natural gas pipeline topology in Spain as our basis point for our hydrogen pipeline. With our decision model, we would choose the corresponding pipeline as the distribution channel if it is the most cost-effective.

3 Technical Assumptions and Cost Parameters

The 2004 report "Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs" [6] by the National Academy of Engineering and the National Research Council in the US provides an extensive review of the literature to date and offers key recommendations for further research. One of the research areas identified was systems modeling and analysis for hydrogen delivery. Using the decision support model developed in this project, we can analyze alternatives for storage and distribution systems that connect supply and demand and address some of the issues raised in the 2004 report.

Key inputs to our decision support model are the technical assumptions and financial parameters regarding the production, storage, and distribution of hydrogen. The data for this project will come from the latest research reports and public data repositories. Two main sources for data are the US Department of Energy's Hydrogen Analysis (H2A) [6, 10, 11] Project and the HyWays Project report on Spain.

The H2A Project was formed in 2003 "to better leverage the combined talents and capabilities of analysts working on hydrogen systems, and to establish a consistent set of financial parameters and methodology for analyses. The foundation of H2A is to improve the transparency and consistency of the approach to analysis, to improve the understanding of the differences among analyses, and to seek better validation of analysis studies by industry." Publicly available from the H2A website are spreadsheet models that include standardized methodologies and parameter assumptions for estimating the costs of hydrogen production and delivery technologies.

HyWays was a project co-funded by research institutes, industry, and the European Commission with the objective of developing a roadmap for the large-scale introduction of hydrogen in the EU. One of the deliverables, the "HyWays Report on Spain", documents data on the energy requirements and cost components of different pathways to hydrogen energy.

One problem with the comparison of assumptions between HyWays and H2A is that they have different approaches to calculating costs. For example, different assumptions about plant sizes made it at times impossible to compare amounts of initial investment. In addition, HyWays classified costs as overhead costs and maintenance costs while H2A divided costs into fixed operating costs, variable operating and maintenance costs, and certain other costs. It was not clear where these overlapped, so these numbers could often not be compared.

Another problem was the difference between information offered by HyWays and H2A. The assumptions made by the H2A model are much easier to find. The spreadsheets they provide state clearly their many different assumptions about calculating costs, plant size, efficiency, and processes. HyWays, on the other had, only provides a short table summarizing the main assumptions for each method of production. Their calculations and descriptions were much less obvious to the reader. For example, the tables describing the costs of a hydrogen compressor and those for a compressed hydrogen truck include values for the "process scale" although this term is never explained.

In general, the H2A tool shows a more detailed analysis leading to each calculation. The one exception I would make is in the case of lifetime years. Although H2A assumed a standard lifetime of 40 years for each central plant and 20 years for each distribution component, the HyWays analysis has significantly more variety among lifetimes, presumably an indicator of closer analysis of this value.

The different units used by HyWays and H2A each have their benefits. HyWays' use of kWh/kWh makes it easy to see the energy tradeoffs required for the production of hydrogen. However, H2A's use of kg is more practical for other considerations, such as shipping and handling and for calculating vehicle consumption. Considering the fact that a supply chain model will be mostly preoccupied with the transportation and storage of hydrogen, it makes more sense to follow the H2A approach, even though it obscures the energy tradeoff.

One difference in their calculations brought up a decision with regard to

	H2A	HyWays
Natural Gas without carbon sequestration		
Production of Hyrdrogen (kWh)	1.424.	1.441
Electricity used in Production (kWh)	0.018	0.016
Lifetime of Plant (years)	40	15
Natural Gas with carbon sequestration		
Production of Hyrdrogen (kWh)	1.42	1.365
Electricity used in Production (kWh)	0.051	0.05
Lifetime of Plant (years)	40	25
Biomass		
Production of Hyrdrogen (kWh)	3.31	1.462
Electricity used in Production (kWh)	0.047	0.082
Lifetime of Plant (years)	40	25
Wind Power		
Production Power	$1,538	€1,200
Lifetime of Plant (years)	40	25
Forecourt Station		
Production of Hyrdrogen (kWh)	0.065	0.06
Lifetime of Plant (years)	20	20

Table 1: Parameter Comparison between H2A and HyWays

our own analysis. While both HyWays and H2A include hydrogen production, transportation, and distribution in their pathways, HyWays includes the addition step of transportation of feedstock. This highlights the necessity of clearly defining pathways and deciding how far back to extend the cost analysis.

After searching through and converting the values presented by the two projects, the following comparisons can be made between their key assumptions.

For natural gas, H2A assumes 4.501 Nm3 (without carbon sequestration) or 4.489 Nm3 (with carbon sequestration) yield 1 kg of hydrogen. A table of physical properties provided by H2A and definitions of units give the following equations:

$$1 \text{ Nm3 of natural gas} = 38{,}553 \text{ kJ}$$

$$0.0886 \text{ kg hydrogen} = 10.8 \text{ MJ}$$

$$1 \text{ Joule} = 2.77 * 10\hat{}{-7} \text{ kWh}$$

$$1 \text{ kg hydrogen} = 33.86 \text{ kWh}$$

$$1 \text{ Nm3 natural gas} = 10.71 \text{ kWh}$$

Using these equations, H2A assumes costs of 1.424 kWh/kWh (without carbon sequestration) and 1.420 kWh/kWh (with carbon sequestration). The analogous numbers for HyWays are 1.441 kWh/kWh (Haldor Topsoe process), 1.417 kWh/kWh (Linde process) and 1.365 kWh/kWh (Foster Wheeler process).

There is an additional measure of kWh/kWh of electricity used to produce the hydrogen. H2A uses .6 kWh (without carbon sequestration) and 1.73 (with carbon sequestration) of electricity to produce 1 kg of hydrogen from natural gas. This is equivalent to 0.018 kWh/kWh and 0.051 kWh/kWh, respectively. The values that HyWays uses are a 0.016 cost for Haldor Topsoe and a 0.05 gain for Linde. It is never explained why there is a gain here instead of a cost, so the H2A model would be a better guide in this instance.

When the feedstock is biomass, H2A equates 13.6 kg of biomass to 1 kg of hydrogen. Use previous equations from the physical properties table and

$$1 \text{ kg of dry poplar} = 19.6 \text{ MJ}$$

We can convert this to the assumption that biomass provides 2.19 kWh/kWh.

However, a comment in the spreadsheet indicates that the proportion of hydrogen to biomass in the base case is 45.2%, which would yield 2.21 kWh/kWh of biomass to hydrogen. The value used by HyWays is 1.4624 kWh/kWh. One reason for the discrepancy might be that there might be differences among the types of biomass used. Common sources are poplar and switchgrass. Another factor is the amount of moisture the biomass is assumed to contain.

When biomass is used to produce hydrogen, H2A cites 1.6 kWh of electricity for each kg of hydrogen produced. This is equivalent to 0.047 kWh/kWh, relatively close to the 0.082 kWh/kWh used by HyWays.

In the case of hydrogen production from wind power, a kWh/kWh measurement would not make sense. The key assumption here, in terms of cost calculation, was the investment required per kW produced. The assumption used by HyWays was 1200 Euros/kW. The total cost assumption used by H2A was determined by summing the costs of \$873/kW in capital costs and \$665/kW for electrolyzer requirements. This yields a total cots of \$1538/kW. Taking into account the exchange rate between dollars and Euros, this is not far off from 1200 Euros.

In the case of forecourt stations, H2A assumes 55.0 kWh of electricity per kg of hydrogen produced, and 2.2 kWh of electricity for compression, storage and dispensing per kg of hydrogen produced. This is 1.62 kWh/kWh overall and 0.065 kWh/kWh for compression, storage, and dispensing. The values used by HyWays are 0.07 kWh/kWh and 0.0647 kWh/kWh, depending on suction pressure. It is unclear which measure of electricity is used here, so once again it would be best to go with the H2A analysis.

4 Demand Model

In this study, the demand scenarios represent projections of consumer demand for hydrogen for fuel cell vehicles, considering the adoption of fuel cell vehicles in the consumer market at two different stages. Stage one focuses on "early adopters", primarily in metropolitan areas, while stage two assumes a higher adoption rate and expands geographically beyond metropolitan areas. Future scenarios will include demand projections for locations along major highways to create a "sustainable" network of hydrogen supply. Outside the scope of this project are demand projections for fleets, full adoption of fuel cell vehicles, and stationary demand.

In section 4.1, we describe the stations approach, a first version of the demand model in which the projections of consumer demand are made in terms of the number of filling stations within each municipality for each stage of market penetration. In section 4.2, we describe the consumption approach, a second version of the demand model in which projections of consumer demand are made at an aggregate level in terms of the required dispensing capacity (kg per day) per municipality for each stage of market penetration.

4.1 Consumer Demand at the Filling Station Level

The first version of the demand model, developed by Liskovich and Goentzel (2007) [4], makes projections of consumer demand in terms of the number of hydrogen filling stations within each municipality for each stage of market penetration. The availability of filling stations is linked to the growth in demand since without an appropriate network, people will not be willing to buy hydrogen fuel cell vehicles and the market will not be able to develop.

In developing their stations approach for modeling consumer demand, Liskovich and Goentzel build on the work of Melaina (2003). Melaina (2003) uses three different approaches to estimate the number of hydrogen stations that will be needed to meet expected demand in the US under two technology adoption stages. The first approach estimates the number of stations as a fraction of the current number of gas stations. The main difficulty with this approach is that simply taking a percentage may translate into too few filling stations located too far apart. The second approach considers metropolitan land areas, defined as areas of population greater than 95,000, and places one station per 129.5 km2 (46.6 km2) in the first stage (second stage). The main advantage of this approach is that it ensures that stations are not too far apart. The main difficulty is that it does not take into account the population density and hence station capacity. The third approach places stations along the principal roads with the highest traffic volumes, varying the distance between stations according to adoption stage and area (rural or urban).

To overcome some of the limitations of the fraction approach and the metropolitan land area approach, Liskovich and Goentzel develop the stations approach, which is a modified land area approach in that it adjusts the results of the land area approach using the population data. There are three key parameters required as input to this analysis: (i) minimum population density for each stage of market penetration, (ii) land area that one hydrogen filling station can serve, and (iii) maximum population that one hydrogen filling station can serve.

First, the approach considers only municipalities on the Spanish mainland that exceed a minimum population density to ensure that there will be enough demand for hydrogen fuel cell vehicles. Assuming that the same fraction of the population across all of the municipalities switches to a fuel cell vehicle, the more densely populated municipalities will have more demand and thus it should be more cost effective to supply these municipalities. Determining the proper values for the minimum population density is a subjective process, so the stations approach requires an appropriate value as input.

Second, as in the metropolitan land area approach of Melaina, the stations approach requires a value for the area that one hydrogen filling station can serve. The original estimates of 129.5 km2 in the first stage and 46.6 km2 in the second stage are based on the assumption that a person will travel at an average rate of 40 km/hr for 12 minutes and 7 minutes to get to the station. Again, since these values are subjective, the stations approach requires values for these parameters as inputs.

Third, in adjusting the results of the land area approach, Liskovich and Goentzel consider the maximum population that one hydrogen station can serve. To calculate this number, they use data from the H2A analysis. In H2A, a hydrogen filling station is assumed to have the potential to dispense a maximum of 1000 kg of hydrogen every day. Based on current predictions on the distance driven per year and the fuel economy of hydrogen, a hydrogen fuel cell vehicle is assumed to have a demand of 0.55 kg of hydrogen per day. Therefore, one hydrogen filling station can serve $1000/0.55 = 1818$ vehicles. To convert this number to the maximum population, consider further that the number of passenger vehicles per person in Spain is 0.4547 (in 2003); then, 1818 vehicles corresponds to 3998 people. Dividing this number by the appropriate market penetration percentage yields the maximum population that one hydrogen station can serve. For example, throughout this report, the market penetration values are 5% (20%) for stage one (two), yielding 79,965 (19,991) people per station.

Given values for all of the required inputs, the stations approach analysis proceeds as follows. For each municipality:

1. Calculate the population density by dividing the population of the municipality by the land area. If the population density is at least the minimum population density, go to 2.

2. Divide the land area of the municipality by the area that one station can serve to obtain a first estimate on the number of filling stations.

3. Calculate the adjustment factor:

   (a) Divide the land area of the municipality by the maximum population per station.

   (b) Divide the population density calculated in 1. by the density value calculated in a. and round up to the nearest integer. This integer value is the adjustment factor.

4. Calculate the number of stations for the municipality by multiplying the estimated number of stations (calculated in 2.) by the adjustment factor (calculated in 3b.).

What this stations approach achieves is to logically combine the population and land area data for each municipality. Stations are placed at regular intervals within the municipality in order to provide enough filling stations to make owning a hydrogen fuel cell vehicle feasible. Then, the number is adjusted to accommodate greater population density.

For demonstration purposes, suppose that the market penetration percentages are 5% in stage one and 20% in stage two and the minimum population density values are set to 1000 per km2 in stage one and 500 per km2 in stage two. Then, the results of the stations approach can be presented graphically. In Figure 1 and Figure 2, the number of filling stations per municipality is coded by size and color.

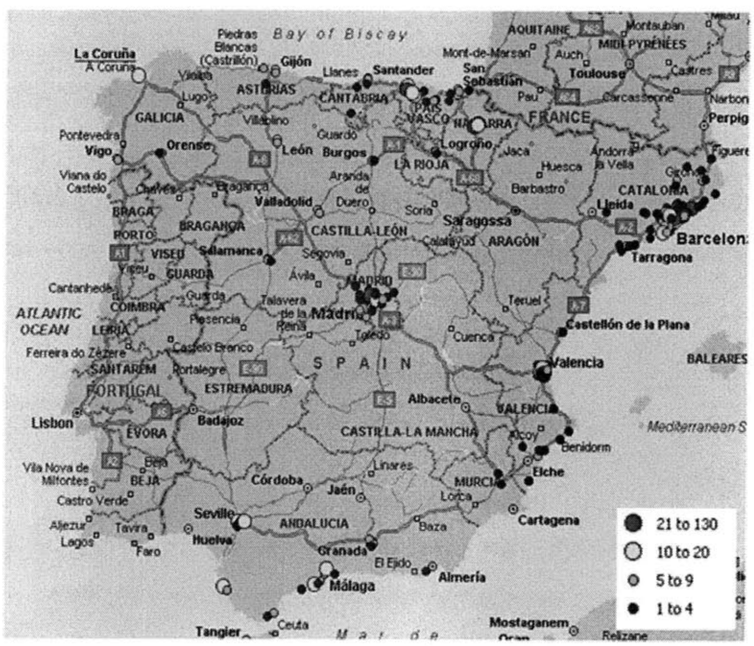

Figure 1: In stage 1, 1387 filling stations are located in 178 municipalities, resulting in stations being available to 41.6% of the population, covering 1.2% of the land area.

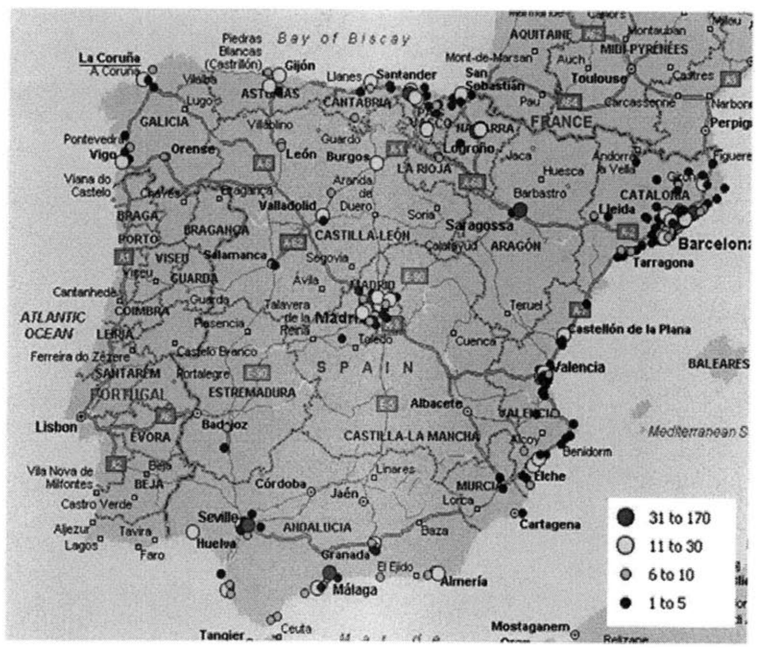

Figure 2: In stage 2, 2545 filling stations are located in 249 municipalities, resulting in stations being available to 49.6% of the population, covering 2.3% of the land area.

4.2 Consumer Demand at the Municipality Level

The stations approach of Liskovich and Goentzel uses both land area and population data to estimate consumer demand for hydrogen, expressed in terms of the number of stations to locate within a municipality. One issue with the approach is the variability in the sizes of the municipalities as the approach relies heavily on the population density value in determining the number of stations. In addition, by computing the number of stations, the approach is implicitly considering multiple demand locations within a municipality. Due to its strategic planning nature, however, the decision support model represents demand at one point for each municipality; therefore, we consider a consumption approach that estimates demand for a municipality at an aggregate level. The consumption approach uses only population data to estimate the demand for hydrogen, expressed in terms of the required dispensing capacity (kg per day) per municipality. Next, we briefly describe the method of calculation.

The consumption approach is similar to the stations approach in that we first calculate the population density of each municipality and include only those municipalities exceeding the minimum population density value. The minimum population density is a parameter, the value of which can be specified for each stage of market penetration. (For the baseline demand scenarios in this study, we specified minimum population density values of 1500 people per square kilometer for stage 1 and 500 people per square kilometer for stage 2.) The analysis considers municipalities on the Spanish mainland only.

For each included municipality and for each stage of market penetration, we estimate the average daily requirement of dispensed hydrogen (in units of kg) based on :

- the population of the municipality
- the market penetration percentage for the stage (expressed as a decimal) o 5% in stage 1, 20% in stage 2
- the average number of vehicles per person o 0.472 in 2006

	Stage 1	Stage 2
Number of municipalities supplied	139	249
Total daily consumption (kg)	210,712	1,110,224

Table 2: Summary of Consumption Approach

- the average daily hydrogen demand of a fuel cell vehicle o 0.55 kg

In particular, we compute the product of the four values to obtain the average daily requirement. In other words, we are transforming the population of a municipality into the number of potential fuel cell vehicle owners (by multiplying by the market penetration), then into the number of potential vehicles (by multiplying by the average number of vehicles per person), and finally into the average daily fuel required for those vehicles (by multiplying by the average daily fuel requirement per vehicle).

A key assumption of the baseline scenario is that the hydrogen delivery system will be designed to supply 100% of the demand. Other demand scenarios may consider percentages of demand less than 100%, reflected in the calculations by multiplying the baseline scenario demand value by the corresponding fraction of demand to be supplied.

In this study, we use the same population data and land area data for the consumption approach as Liskovich and Goentzel. In particular, the population data is 2006 census data from the Instituto Nacional de Estadística (INE), and the land area data is from the 2005 report Áreas Urbanas de España. The report provides a listing of all the municipalities that contain one or more urban nuclei; a population nucleus identified by the Nomenclátor Oficial de España is one that either has at least 10,000 inhabitants or has at least 5,000 inhabitants and is located in a municipality with at least 20,000 inhabitants. Excluding the municipalities not on the mainland, the data set contains 504 municipalities. Table 1 summarizes the results of the consumption approach for the dataset.

For demonstration purposes, suppose that the market penetration percentages are 5% in stage one and 20% in stage two and the minimum population density values are set to 1500 per km2 in stage one and 500 per km2 in stage two.

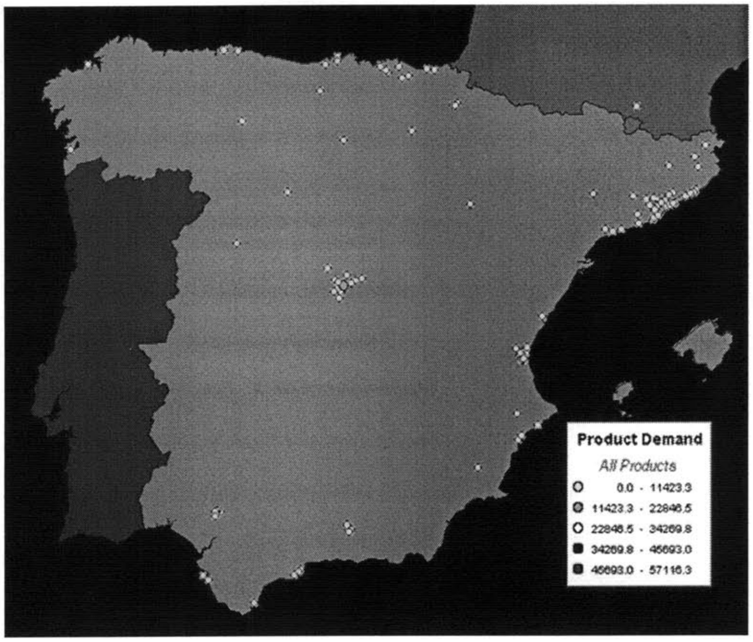

Figure 3: Results of the Consumption Approach for Phase 1. Annual consumption values (in 1000 kg) for 139 municipalities are coded by color.

Then, the results of the consumption approach can be presented graphically. In Figure 3 and Figure 4, the annual consumption (in 1000 kg) per municipality is coded by color.

The stations approach and the consumption approach are fundamentally different in that they produce demand projections in different units – number of stations per municipality versus kilograms of consumption per municipality. However, since both approaches limit the municipalities served based on the same minimum population density criterion, the results from the two approaches are consistent in terms of which municipalities are served. Therefore, performing the calculations of the consumption approach for each municipality supplied in the stations approach yields the same results as the consumption approach does.

The consumption approach projects the aggregate demand of a municipality, that is, the total kilograms of hydrogen required by all consumers within a municipality. Mapping the aggregate demand to individual filling station

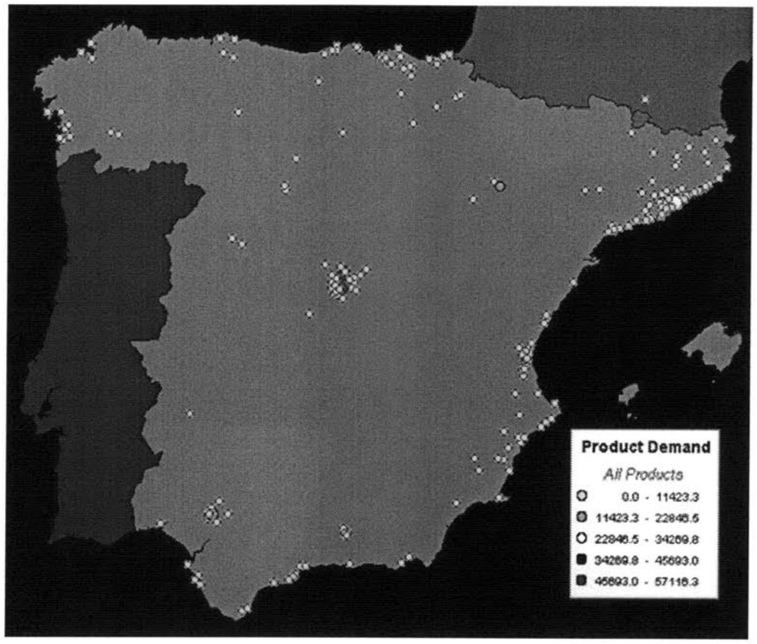

Figure 4: Results of the Consumption Approach for Phase 2. Annual consumption values (in 1000 kg) for 249 municipalities are coded by color

demand requires a separate approach that takes into account geographic and market characteristics of the municipality. Given filling station-level demands and policy guidelines for locating and equipping filling stations, a separate decision support model could determine the best configuration for the distribution network within a municipality.

Because the focus of the current study is strategic planning, detailed designs for the local distribution network are not necessary. However, a ballpark estimate on the number of stations within each municipality validates that the demand projections are the right order of magnitude. If we consider the range of practical filling station sizes to be 500 kg per day to 3000 kg per day (Yang and Ogden, 2007), then we can compute for each municipality the corresponding range of number of filling stations. To do so, we divide the daily consumption value of each municipality by 3000 kg (500 kg) and round up the value to the nearest integer to get a lower bound (upper bound).

	Stage 1	Stage 2
Total lower bound (3000 kg/day max)	172	511
Total upper bound (500 kg/day max)	495	2353
Total number of stations (stations approach)	1326	2615

Table 3: Estimating the Number of Filling Stations

Table 3 summarizes the results. The Total lower bound number is calculated as the sum of all of the lower bound values. Correspondingly, the Total upper bound number is calculated as the sum of all of the upper bound values. Note that these results assume that any municipality that meets the minimum population density will be supplied regardless of the daily consumption value; in other words, even municipalities with very low daily consumption values (e.g., 100 kg) will be served if the population density criterion is met. (The calculation can be modified easily to include a minimum consumption value criterion in addition to the minimum population density criterion.) As a point of reference, we include the Total number of stations as calculated in the stations approach.

As is evident in Table 3, the ballpark estimates based only on filling station size project fewer stations than the stations approach because factors such as land area and acceptable travel time are not considered. These results support the previous assertion that mapping aggregate demand to filling station-level demand requires a separate approach that takes into account geographic and market characteristics of the municipality.

5 Supply Model

Today, most hydrogen is produced from natural gas close to industrial demand locations. To realize the vision of the hydrogen economy, there is a need to be able to produce large quantities of hydrogen at competitive cost with minimal carbon emissions. Producing hydrogen via the electrolysis of water is attractive in that the byproducts are hydrogen and oxygen; however, the process is electricity-intensive. Electricity can be taken from the electric grid or generated by wind turbines. Electrolysis powered by wind generated electricity represents a possible path to hydrogen production with little to no emissions; the challenge is that wind is intermittent – it is not always blowing and it is variable when it does. While there are a number of hurdles to overcome, the potential of hydrogen production via electrolysis is high and warrants analysis. In particular, the supply model in this study considers producing hydrogen via electrolysis of water with two potential sources of electricity, wind generation and the electricity grid.

5.1 Electrolyzer Production Model

Electrolysis is the process of using electricity to split water molecules into hydrogen and oxygen. The reaction happens in a device called an electrolyzer, which consists of an anode and a cathode separated by an electrolyte. (An electrolyte is a chemical compound that is ionized.) When power is applied to an electrolyzer, the electrodes transmit the charge through the electrolyte, weakening the bound between the hydrogen and oxygen molecules and thus releasing oxygen and hydrogen gas. Electrolyzers function differently depending on the type of electrolyte used. There are two main commercialized electrolyzers. Alkaline electrolyzers, a more established technology, use an electrolyte solution of sodium or potassium hydroxide. Polymer electrolyte membrane (PEM) electrolyzers, a newer technology, use an electrolyte that is a solid specialty plastic material.

As input to the decision support model, we need information on electrolyzer capacity and electrolyzer costs.

5.1.1 Electrolyzer Capacity

An electrolyzer has a theoretical production capacity that quantifies the maximum number of kilograms of hydrogen that can be produced if the electrolyzer runs 24 hours a day. In an actual production setting, however, the electrolyzer will not be fully utilized and the extent to which it is utilized depends on the electricity supply. Multiple electrolyzers can be installed at one production site.

	Green	Gray
H2A	366.2	994.1
Future	440.8	1196.5

Table 4: Daily hydrogen production capacity (kg) for the supply scenarios

For the theoretical production capacity, we consider two technology scenarios. First, we consider the H2A technology scenario in which we use the parameters from the H2A analysis. The H2A analysis considers a Hydro bipolar alkaline electrolyzer system (Atmospheric Type No.5040 - 5150 Amp DC) that operates at 2330 kW. To determine the maximum production capacity, we need a value for the number of kWh required to produce 1 kilogram of hydrogen. The H2A analysis assumes that the electrolyzer requires 53.44 kWh per kg with current technology. Therefore, the theoretical production capacity is $2330/53.44 = 43.6$ kg per hour. Technology improvements over time should lead to a reduction in the number of kWh required to produce 1 kg of hydrogen. Therefore, we consider a Future technology scenario in which the electrolyzer requires 44.4 kWh to produce 1 kg of hydrogen. In this case, with the same 2330 kW, the theoretical production capacity is $2330/44.4 = 52.5$ kg per hour.

To calculate the actual production capacity, we need to consider the utilization of the electrolyzer, which depends in part on the electricity supply. In this study, we consider two levels of utilization, which relate to the source of the electricity supply. As we will describe in the next section, we consider two scenarios. In the Green scenario, we assume that electrolyzers only use wind-generated electricity, and we assume that the electrolyzer operates only 35% of the time. Thus, the actual production capacity of the electrolyzer is 35% of its theoretical maximum. In the Gray scenario, we assume that electrolyzers can use grid electricity, and we assume that the electrolyzer operates 95% of the time, reserving 5% for maintenance downtime. Thus, the actual production capacity of the electrolyzer is 95% of its theoretical maximum. Combining the two technology scenarios and the two utilization scenarios, we obtain the following production capacities (kg/day) for one electrolyzer unit:

2330 kW Electrolyzer @ 485 Nm3/hr Hydrogen	
1 Electrolyzer Unit	\$503280
1 Transformer/Rectifier Unit	\$94365
2 Compressor Units to 30 bar (435 psig)	\$456098
1 Gas Holder	\$235913
Other equipments	\$283095
Total:	**\$1572750**

Table 5: Electrolyzer Capital Costs

5.1.2 Electrolyzer Capital Costs

The capital cost includes all of the components necessary for an electrolyzer to produce hydrogen. The equipment components include 1 electrolyzer unit, 1 transformer/rectifier unit, 2 compressor units, and 1 gas container. Other pieces of equipment, such as water purifiers, may be required, however, we do not consider their costs. We assume that the capital costs are fixed, one-time costs and that there is no salvage value for any of the components. There is also an installation cost for each electrolyzer, which includes technical support and labor cost. The detail breakdown is shown in the following table.

For the equipment, there is an installation cost, which is assumed to be 20% of the capital cost and is a one-time sunk cost. Thus, the total capital cost of a single electrolyzer is

$$\$1{,}572{,}750 * 1.2 = \$1{,}887{,}300$$

5.1.3 Electrolyzer Fixed Operating Costs

The operating cost of an electrolyzer includes both operation and maintenance (O&M) costs and raw material costs. Again using the H2A parameters, we estimate the O&M cost as a cost per electrolyzer.

5.1.4 Electrolyzer Variable Costs

The variable cost for hydrogen production is composed of two parts: electricity cost and water cost, both of which are material costs. The electricity cost depends both on the electricity source (wind farm or grid) and the production

Fixed Operating Costs	
Labor cost, \$/year	\$312000
G&A (\$/year)	\$62400
Property taxes and insurance (\$/year)	\$2208641
Material costs for maintenance and repairs (\$/year)	\$2830950
Total Fixed Operating Costs:	**\$5413991**

Table 6: Electrolyzer Fixed Operating Costs

scenario (kWh to produce 1 kg). Details of the electricity costs will be provided later. Water costs are not explicitly considered in this study, mainly because the electricity cost dominates the variable cost but also because we assume that the cost is included in other components such as the water purifier.

5.2 Electricity Supply

Wind Generation

Wind turbines are used to generate electricity from the kinetic energy of wind. A wind farm is comprised of multiple wind turbines located together in a geographic area. The amount of energy generated by a wind turbine depends on the turbine's size and the wind speed through the rotors. Generally speaking, wind generation is practical only if the wind speed is 10 mph or greater. An important factor in wind energy production is the generator's efficiency. As a general rule, the harder the wind blows, the more efficient the generator is.

Each generator has a maximum capacity that it can reach, referred to as nameplate capacity. Nameplate capacity is the power that would be produced if the turbine operated at maximum output 100% of the time. At a wind farm, however, the wind blows steadily at times and not at all at other times. Even when the wind is blowing, the turbine may be operating at less than full capacity. Therefore, it is common to consider the capacity factor of a wind turbine. The capacity factor compares the actual amount of power produced during a time period to the maximum possible power that could have been produced at 100% efficiency during the time period. In this study, we use a capacity factor of 35% for all of the wind farms, which is a commonly assumed capacity factor in the literature.

To illustrate the impact of the capacity factor on electricity production for the wind farm, we consider the example of a wind farm with a power capacity of 10-MW. Given our assumption of 35% capacity factor, the wind farm is only producing energy 3066 hours out of the year (0.35 * 8760 hrs/year). Hence, the energy output per year is 30,660 MWh.

For this study, Acciona provided the coordinates for their wind farm locations along with the annual electrical power output capacity of each wind farm. The remaining wind farm locations and power capacities were obtained from the website of Asociación Empresarial Eólica (Spanish Wind Energy Association).

Electricity generated at a wind farm is transmitted to a substation of the electricity grid where it can be used to power an electrolyzer installed at the substation or it can be added to the grid. In the first case, the production of hydrogen is "green", resulting in minimal carbon emissions. The cost of the electricity generated is charged at a flat rate per kWh, and the cost is the same across all of the wind farms. In the second case, the electricity transmitted from the wind farm becomes part of the electricity grid mix, which includes both renewable and non-renewable energy sources. The grid is discussed in the next section.

Grid Toll

The electric grid connects sources of power to substations and substations to distribution stations. At substations, electrolyzers can be installed to produce hydrogen. The electricity supply for the installed electrolyzers may be wind-generated in the case of substations directly connected to wind farms; or the electricity supply may be from the grid; or both. Allowing electrolyzers to buy electricity from the grid facilitates distributed hydrogen production. By distributed production, we mean that electrolyzers can be installed at substations throughout the grid, not only at substations directly connected to wind farms. As mentioned above, electricity generated by a wind farm (that is not used to produce hydrogen) can be transmitted through the grid from one substation to another as part of the electricity grid mix. At a substation where an electrolyzer is installed, electricity purchased from the grid is charged at a flat cost per kWh, and the cost depends on the particular grid mix.

Electricity power transmission introduces energy loss and transmission congestion, so there should be a cost associated with transmitting electricity from one substation to another through the grid. In some grid systems (e.g. ISO-NE and PJM in the US), the electricity cost is determined at a particular node or a collection of nodes (zone), which reflects the supply and congestion conditions. Spain does not operate with nodal or zonal pricing. Hence, the cost of grid energy will not reflect the spatial supply/demand conditions.

This study aims to develop the infrastructure to enable renewable (wind-generated) sources of hydrogen, so we want to consider how wind energy would be distributed by the grid to facilitate distributed electrolysis. Using the grid to move wind energy is an alternative to transporting energy in the form of hydrogen generated at the wind farm.

To account for the cost of using the grid, we develop a toll cost that is proportional to distance (i.e., a cost per km) so that we can interpret the spatial aspects of solution output effectively. We introduce a toll in the form of a cost per kilometer (km) per kilowatt-hour (kWh) for transmitting electricity through the grid. There is no distance based toll used by the system operator, so we need to develop an approximation. To do so, we consider that the average electricity transmission distance in Spain is roughly 1000 km.

According to Paris et al (1984), long-distance transmission of electricity (thousands of kilometers) is cheap and efficient, with costs of US \$0.005 to \$0.02 per kWh. In comparison, the annual averaged large producer costs are US \$0.01 to US \$0.025 per kWh, retail rates are upwards of US \$0.10 per kWh, and multiples of retail rates are charged for instantaneous suppliers at unpredicted highest demand moments.

Given a corresponding transmission cost of \$0.01 for 1 kWh over 1000 km,

Scenario	toll ($/kg/km)
H2A	$0.0005344
Future	$0.000444

Table 7: Grid Toll Charge

we can compute a cost per km per kWh of $0.00001. Next, to better incorporate the toll within the model, we want to convert the cost from dollars per kWh per km to dollars per kg of hydrogen per km. In order to do the conversion, we need a value for the number of kWh required to produce 1 kilogram of hydrogen, a value which corresponds to the production scenarios. The table below shows the tolls corresponding to the two production scenarios, the H2A scenario and the future scenario.

5.3 Electricity Cost

Electricity cost is an important component of the electrolyzer cost, dominating the variable cost component. The electricity cost depends both on the electricity source (wind farm or grid) and the production scenario (kWh to produce 1 kg). In this study, we have two electricity sources and two production scenarios, so we have four electricity cost scenarios.

Green Scenarios

In the green scenarios, we allow electricity for the electrolyzers to come only from wind-generated electricity. Production happens only at substations connected directly to wind farms. As a result, the electrolyzers are operating only when there is enough wind. Hence, the utilization of the electrolyzer is the same as the assumption of the wind capacity factor, which is given as 35%. We consider these scenarios as a means of evaluating the feasibility and cost-effectiveness of a renewable energy-based hydrogen pathway.

We assume a standard cost for electricity supplied from a wind farm is $0.038 per kWh. For modeling purposes, we convert the cost per kWh to a cost per kg of hydrogen based on the value for the appropriate production scenario. Table 8

Production Scenario	H2A	Future
Green	\$2.03	\$1.69
Gray	\$2.67	\$2.22

Table 8: Electricity Costs for Electrolysis Production

summarizes the costs for the Green-H2A scenario and the Future-H2A scenario.

Gray Scenarios

In the gray scenarios, we allow electricity for the electrolyzers to be purchased from the grid to maximize utilization. Part of the electricity is obtained from the wind farms; the rest is purchased from the grid. From the study by Saur (2008), we assume that electricity from the grid costs \$0.05 per kWh.

As in the green scenarios, we convert the cost per kWh to a cost per kg based on the value for the appropriate production scenario. Table 8 summarizes the costs for the Gray-H2A scenario and the Gray-Future scenario.

6 Distribution Model

In the current study, we consider three modes of distributing hydrogen: liquid hydrogen via truck, compressed hydrogen gas at 2700 psi via truck, and compressed hydrogen gas at 1000 psi via pipeline.

6.1 Truck Distribution: Site Costs

For the two modes of truck distribution, we have developed cost models based on the data and methodologies of the H2A Hydrogen Delivery Scenario Analysis Model. Each cost model includes the site costs involved in transforming (liquefying or compressing), storing, and loading the hydrogen onto the truck and the transportation costs involved in transporting the hydrogen from a substation to a municipality. In the current study, we do not include detailed filling station costs but rather assume that the hydrogen would be delivered to one or more bulk storage locations outside each municipality. A separate decision support model is needed to determine the best configuration for the "last mile" (local) distribution network. Such a model requires mapping the aggregate municipality demand to individual filling station demand and characterizing the configuration of a hydrogen filling station.

Liquid Hydrogen Site Costs

The site costs for liquid hydrogen include capital costs and operation and maintenance (O&M) costs for the liquefier, liquid storage, and truck loading pump.

Liquefier

The capacity of the liquefier is sized to the daily plant capacity, that is, the amount of hydrogen produced by the electrolyzers. The maximum unit capacity of a liquefier is 200,000 kg per day. To support larger capacity values, multiple units of equal size are installed.

Let L be the liquefier unit capacity (tonne/day). Then:

capital cost of liquefier =

The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 0.5% of the capital cost. Liquefiers require substantial amounts of electricity, so the cost of electricity is a significant variable cost. The electricity usage is assumed to be 11 kWh per kg.

Liquid Hydrogen Storage

Since electrolyzers produce hydrogen on a continuous basis and the distribution is done by discrete capacity vehicles, there is a need for storage at the production site. The required size of the storage tank depends on a number of factors including the production flow rate and the delivery frequency. The H2A guidelines size the storage tank as a percentage of the daily flow. Using that guideline, it could happen that a truck arrives to load at a small production site to find insufficient supply. In our study, we calculate the storage capacity to be the maximum of two truckloads of supply or 12 hours of supply

The storage tank is sized to the required capacity using an appropriate number of standard 3500 m3 tanks and a customized tank for the remainder. Let S be the tank capacity in m3. Then:

capital cost of storage tank = [($-0.167) S^2+($2064.4)S+$977,886]

The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 0.5% of the capital cost.

Truck Loading Pump

The required pump capacity per hour is calculated by dividing the daily production flow (kilograms of hydrogen per day) by the number of hours per day. Each pump has a maximum capacity of 250 kg per hour. To support higher rates, multiple units of equal capacity are installed.

Let P be the pump capacity in kg per hour. Then:

capital cost of pump = [($567.1)P+$11,565]

The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 0.5% of the capital cost.

Compressed Hydrogen Gas Site Costs The

site costs for compressed hydrogen gas include capital costs and operation and maintenance (O&M) costs for the storage compressor, compressed hydrogen gas storage, and truck loading compressor.

Storage Compressor

Following H2A, the cost of the storage compressor is a function of the power requirement. Let F be the daily flow rate to the compressor. Then the power requirement (kW) for the compressor, denoted R, is

$$R = (0.03616)F/0.88$$

where the coefficient in the numerator is a calculated value based on the storage design and the value of the denominator is the compressor efficiency. Then,

$$\text{capital cost of storage compressor}{=}19,207(R^{0.6089})$$

The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 4% of the capital cost.

Compressed Gas Storage

Following the H2A model, we assume that compressed gas is stored in cylinders, each with a storage capacity of 89 kg. As with the liquid hydrogen, we calculate the required storage capacity to be the maximum of two truckloads of supply or 12 hours of supply. Then, we can compute the number of storage cylinders required by dividing the amount of required storage capacity by the storage capacity of each cylinder.

Let C be the storage capacity of each cylinder. Then:

$$\text{capital cost per cylinder} = \$900\text{C}$$

The total capital cost is computed by multiplying the capital cost per cylinder by the number of storage cylinders required. The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 0.5% of the capital cost.

Truck Loading Compressor

Following the H2A design, there are two truck loading compressors in operation, each designed at 50% of the total terminal capacity. As with the storage compressor, the cost of the truck loading compressor is a function of the power requirement. Let F be the daily flow rate to the compressor. Then the power requirement (kW) for the compressor, denoted R, is

$$R = (0.0368)F/0.88$$

where the coefficient in the numerator is a calculated value and the value of the denominator is the compressor efficiency. Then,

$$\text{capital cost of storage compressor}{=}19,207(R^{0.6089})$$

The annualized cost is computed using a capital recovery factor of 0.150. The annual O&M is assumed to be 4% of the capital cost.

6.2 Truck Distribution: Transportation Costs

In the transportation cost model, our approach differs from H2A and previous research in that we seek to model the costs of a third-party carrier. Our assumption is that the company that produces the hydrogen will not also own and operate a fleet of vehicles to deliver the hydrogen. Instead, third-party carriers will be hired to deliver loads, and the price to deliver a load will include a cost per kg and/or a cost per kg per km.

The structure of the transportation cost model is general enough that it can be used with little modification for either liquid hydrogen distribution or compressed hydrogen gas distribution. In this section, we explain several input parameters of the model and describe the cost calculations in the context of liquid hydrogen delivery. In what follows, substituting compressed gas for liquid hydrogen in the appropriate places will provide the relevant cost per kg and cost per kg per km for compressed gas.

We assume that in each trip the truck visits a single demand location, where it empties its entire load. The tractor and the empty tank then travel to a different production site to load or return to the same production site to load. In deriving the transportation costs, we need to consider the various states in which the tractor, the trailer, and the driver can be – loading or unloading, traveling full to a demand location, traveling empty to a production location, and idle. The portion of time spent traveling empty is captured in the backhaul efficiency parameter; the parameter can be set to a value ranging from 0 (no deadhead travel) to 1 (deadhead back to production site). The tractor idle time parameter and the trailer idle time parameter capture the portion of time that the tractor and trailer are not in use for whatever reason, such as no available loads or a general inability to use the equipment 100 % each day. In our analysis, we covert the idle time into a fraction of the day and use that fraction as an overhead charge. One more issue to address is that of restrictions on how many hours a driver can legally work. In this study, we assume that trips of more than 750 kilometers would require team drivers. Because the decision support model is determining the flows between production and demand, it is not possible to know in advance whether a trip will require team drivers. Therefore, the fraction of team driver trips parameter is used to roughly approximate the added cost for trips involving team drivers.

In the following text, we describe the calculations associated with determining a cost per kg and a cost per km per kg for delivery.

1. We compute a capital cost per hour for the tractor and the tank trailer by multiplying the capital cost of the tractor (trailer) by the capital recovery factor and then dividing by the number of hours the tractor (trailer) is available during one year.

2. We compute a weighted driver cost per hour that takes into account the fraction of team driver trips. Let f be the fraction of trips with team drivers and let c be the driver cost per hour. Then the weighted driver cost per hour (denoted wc) is equal to $cf + c(1 - f)$.

3. We compute an overhead charge to account for the idle time of the tractor (trailer). We divide the number of hours of idle time by the number of hours in a day (24). Then we use the resulting fraction to as an overhead charge to account for the idle time of the equipment.

4. Travel time contributions

   (a) Capital Cost: Start with the capital cost per hour and multiply it by (2 – backhaul efficiency parameter value) to get the capital cost per hour with backhaul Next, multiply the cost by (1 + overhead fraction) to obtain the capital cost per hour with backhaul and overhead. To convert the cost per hour to a cost per kilometer, divide the cost per hour by the average speed (km per hour). Finally, to get a capital cost per kilometer per kilogram, divide by the delivered capacity (kg).

(b) Driver cost: Start with the weighted driver cost per hour and multiply it by (2 – backhaul efficiency parameter value). Next multiply the cost by (1 + overhead fraction) to obtain the driver cost per hour with backhaul and overhead. To convert to a driver cost per kilometer, divide by the average speed (km per hour). Finally, to get a driver cost per kilometer per kilogram, divide by the delivered capacity (kg).

(c) Fuel cost: To obtain a fuel cost per km, divide the fuel cost per gallon by the average kilometers per gallon. Then divide by the delivered capacity (kg) to obtain a fuel cost per kilometer per kilogram.

(d) Total non-fuel costs: H2A provides values of variable operating costs, such as insurance, license and permits, and O&M, in terms of cost per kilometer. To convert to cost per kilometer per kilogram, divide by the delivered capacity (kg).

(e) Total cost per km per kg: compute the sum of the cost per km per kg in a through d above. Then to determine the portion of a trip cost that can be attributed to travel time, we compute the product of the cost per km per kg, the length of the segment in km, and the quantity of hydrogen in kg to be delivered.

5. Stop time contributions

   (a) Capital cost: Compute the total number of hours associated with loading and connecting the trailer at the production facility and disconnecting and unloading at the demand site. Multiply the number of hours by the capital cost per hour. Then multiply by (1 + overhead fraction) to obtain the capital cost per stop with overhead. Then divide by the delivered capacity (kg) to obtain the capital cost per kg.

(b) Driver cost: Start with the total number of hours associated with a stop. Multiply by the weighted driver cost per hour. Then, multiply by (1 + overhead fraction) to obtain the driver cost per stop with overhead. Then divide by the delivered capacity (kg) to obtain the driver cost per kg.

(c) Total cost per kg: compute the sum of the cost per kg in a and b above. Then to determine the portion of a trip cost that can be attributed to stop time, we compute the product of the cost per kg and the quantity of hydrogen to be delivered.

Appendix A. Liquid Hydrogen Truck Transportation Cost Model
Compressed Hydrogen Gas Truck Transportation Cost Model

6.3 Pipeline Distribution

Given an existing pipeline network, we would expect pipeline distribution to be a cost-effective means of transporting large quantities of compressed hydrogen from a centralized production location either to municipalities with large demand or to large bulk storage locations for transfer to compressed gas or liquid trucks. The main challenge associated with modeling pipeline distribution is that there is no available infrastructure that can be used. New infrastructure would be needed, requiring enormous capital investments and long lead times. The design of the network is critical since, once deployed, the pipeline topology is fixed; links cannot be added in the short-term to match variability in demand. And the infrastructure is likely to have a lifetime of 50 to 100 years! Therefore, the design and sizing of the pipeline are strategic decisions that should be made outside the context of this decision support model. Developing a model to determine an optimal configuration of a hydrogen pipeline network is outside the

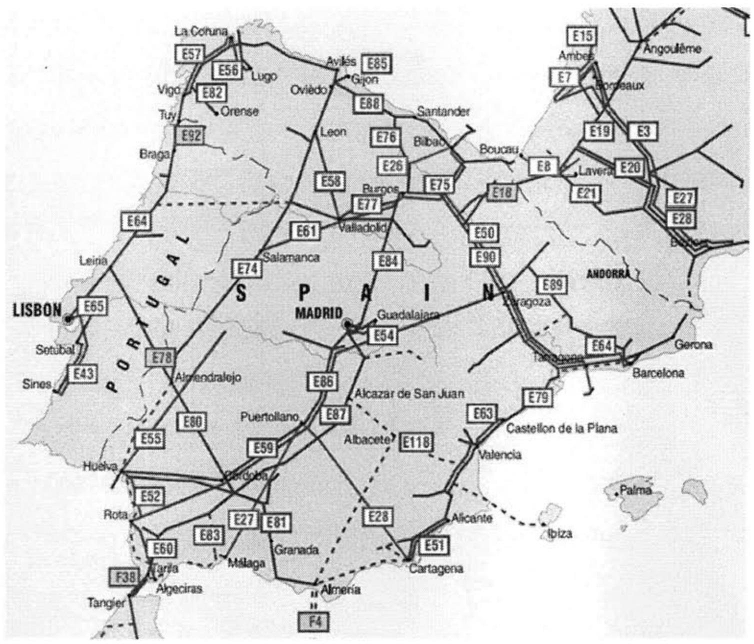

Figure 5: Existing pipeline infrastructure for Spain and Portugal

scope of this study.

Two objectives of this study are to gain insight into the conditions under which the different modes of transportation are cost-effective and to better understand the trade-offs between the different modes of transportation. Including the option of pipeline distribution in the model is important in this regard, however, working with a reasonable pipeline network configuration is sufficient.

6.3.1 Pipeline Topology

As a starting point for a pipeline network, we considered the existing pipelines in Spain for natural gas (red lines), oil (green lines), and other products (blue lines), as shown in Figure 6.1. In developing a baseline topology, we assume that the right-of-way costs associated with new infrastructure would be smaller along corridors with existing pipelines.

Next, we sorted the municipalities in our study in descending order of demand and overlaid the top 24 municipalities (each has a population exceeding

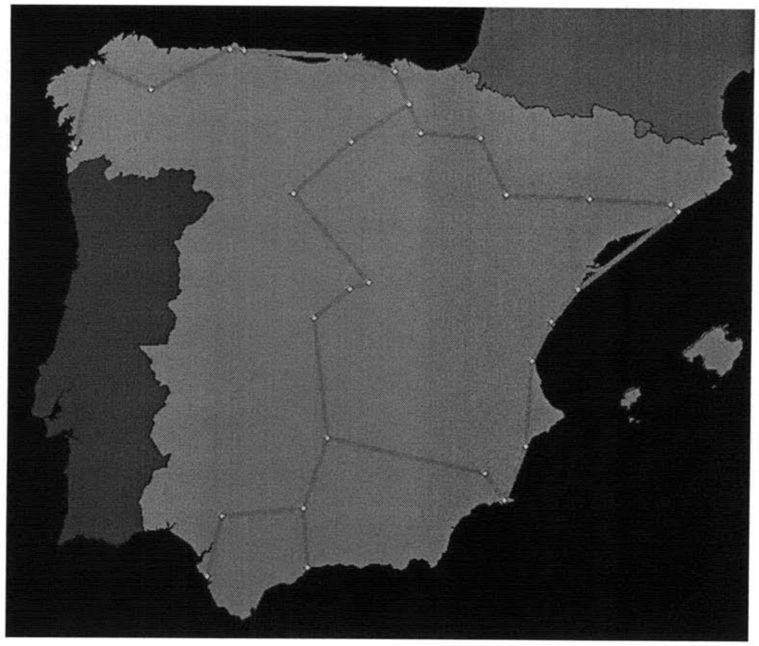

Figure 6: Baseline pipeline topology in the decision support model

200,000) on the pipeline map. Then, taking into consideration the locations of the wind farms, we heuristically selected a set of pipeline links. The baseline topology as included in the INFOR system is shown below. Comparing the two maps, the close correspondence between the red lines on the existing pipeline map and the proposed pipeline links is evident. Table 9 lists the pipeline links in the baseline topology.

6.3.2 Pipeline Cost Model

For pipeline distribution, we have developed a cost model based on the data and methodologies of the H2A Hydrogen Delivery Scenario Analysis Model. The pipeline cost model includes the production site costs involved in compressing the gas for the pipeline, the transmission costs associated with building and maintaining the pipeline, and the distribution site costs associated with transforming (liquefying or compressing), storing, and loading the hydrogen onto a truck for final delivery to a municipality. Analogous to the truck modes, we do

Origin	Destination	Origin	Destination
Vigo	Coruna (A)	Valladolid	Alcala De Henares
Coruna (A)	Lugo	Alcala De Henares	Madrid
Lugo	Aviles	Madrid	Torrijos
Aviles	Gijon	Torrijos	Puertollano
Gijon	Santander	Puertollano	Alcantarilla
Santander	Bilbao	Alcantarilla	Union
Bilbao	Vitoria-Gasteiz	Puertollano	Cordoba
Vitoria-Gasteiz	Logrono	Cordoba	Malaga
Logrono	Tudela	Cordoba	Sevilla
Tudela	Zaragoza	Sevilla	Puerto De Santa Maria
Zaragoza	Lerida	Barcelona	Benicarlo
Lerida	Sabadell	Benicarlo	Castellon De La Plana
Sabadell	Barcelona	Castellon De La Plana	Valencia
Vitoria-Gasteiz	Burgos	Valencia	Alicante/Alacant
Burgos	Valladolid	Alicante/Alacant	Union

Table 9: List of pipeline segments in baseline topology

not include detailed filling station costs but rather assume that the hydrogen would be delivered to one or more bulk storage locations outside each municipality. A separate decision support model is needed to determine the best configuration for the "last mile" (local) distribution network. Such a model requires mapping the aggregate municipality demand to individual filling station demand and characterizing the configuration of a hydrogen filling station.

Production Site Costs

At production sites, the hydrogen must be compressed for transmission through the pipeline. Following the H2A analysis, we assume a two-stage compressor with 2 compressors in operation at any one time and 1 backup compressor. The cost of the compressor is a function of the motor rating, which is a function of the design flow rate (kg/day) and a number of system design parameters. Let F be the design flow rate to each compressor. Using standard design parameters, the equation for calculating the motor rating (MR) per unit in kW simplifies to the following:

$$MR = (1.158)(2744.70)(F/(24 \times 60 \times 60 \times 2.0158))/0.88$$

Then, the cost per compressor is a function of the motor rating MR:

$$\text{compressor capital cost=\$19207}(MR^{0.6089})$$

The installation cost factor is 2.0, and the annualized cost is computed using a real fixed charge rate of 0.150. The annual O&M is assumed to be 4% of the capital cost.

Transmission Line Costs

Following the H2A analysis, there are three components for the initial capital investment costs for pipeline transmission lines: pipeline material costs, labor costs, and miscellaneous costs (surveys, engineering, supervision, interest, administration and overhead, and contingencies). Land capital costs, including right-of-way costs, are excluded from our analysis for now. Each cost component is a (nonlinear) function of the diameter of the pipe, and the diameter of the pipe depends on the desired flow through the system.

The flow through the system is a decision variable in our model and the equation to calculate the diameter is nonlinear, so we need to estimate an appropriate diameter in advance. To determine a starting point for the diameter, we analyzed several flow scenarios and computed the required diameter using the Panhandle B Equation. Based on this analysis, we chose a 4 inch diameter pipe to balance capacity against cost. Depending on the results of the scenario analysis, we can always increase or decrease the pipe diameter.

Pipeline Material Costs

Let D be the diameter in inches and let L be the length of the pipe segment in miles. Then, the pipeline material cost (PMC) is

$$PMC = (330.5D^2 + 687D + 26960)L + 35000$$

Labor Cost

Let D be the diameter in inches and let L be the length of the pipe segment in miles. Then, the labor cost (LC) is

$$LC = (343D^2 + 2074D + 170013)L + 185000$$

Miscellaneous Cost

Let D be the diameter in inches and let L be the length of the pipe segment in miles. Then, the miscellaneous cost (MC) is

$$MC = (8417D + 7324)L + 95000$$

Initial Capital Investment

The initial capital investment is the sum of the pipeline material costs, the labor costs, and the miscellaneous costs across all of the segments of the pipeline network. The installation cost factor of 1.1 is applied to the total, and the annualized cost is computed using a real fixed charge rate of 0.117.

Distribution Site Costs

The distribution site costs model the costs at a node in the pipeline network where hydrogen is removed from the pipeline to be delivered via liquid truck or compressed gas truck. The site costs vary depending on the mode of delivery. For liquid hydrogen, the site costs include capital costs and operation and maintenance (O&M) costs for the liquefier, liquid storage, and truck loading pump. For compressed hydrogen gas, the site costs include capital costs and operation and maintenance (O&M) costs for the storage compressor, compressed hydrogen gas storage, and truck loading compressor. The functional forms of these costs are identical to the liquid hydrogen site costs and the compressed gas site costs described in sections 6.1.1 and 6.1.2, respectively. The only difference is that the equipment is sized according to the flow rate from the pipeline, not from production.

7 Integrated Model

Given the operating parameters and the cost models for supply and distribution, the decision support model seeks to optimize the configuration of the hydrogen supply chain, from production to consumption, at a strategic planning level. The objective of the core model is to determine where to produce hydrogen, how much to produce at each location, how to supply the electricity for production, and how to distribute the hydrogen to meet projected consumer demand in such a way as to minimize fixed capital costs plus variable operating costs subject to satisfying technological and business logic constraints of the system. Given the scope and complexity of the decisions to be made, sophisticated mathematical optimization methods are required to determine the appropriate network structure for each scenario; neither a rule-based heuristic nor a spreadsheet-based model would be able to consider all of the interdependencies of the decisions. The INFOR Supply Chain Management (SCM) software that integrates data, modeling, solving, reports, and graphics is used to optimize the hydrogen supply chain.

In this section, we first present a schematic view of the network structure of the hydrogen supply chain and describe the nodes and the links that make up the network. Then, we provide some details of the implementation of the network structure in the INFOR software.

7.1 Hydrogen Supply Chain Network Structure

To illustrate the structure of the hydrogen supply chain model, consider the following schematic view.

Each wind farm location is represented by a yellow triangle. Since hydrogen production is not allowed on site at a wind farm, the electricity must be transmitted to a substation of the electric grid. A link between each wind farm and the three closest substations is created in the model. We assume that there is at least one existing connection, so there is no cost associated with transmitting

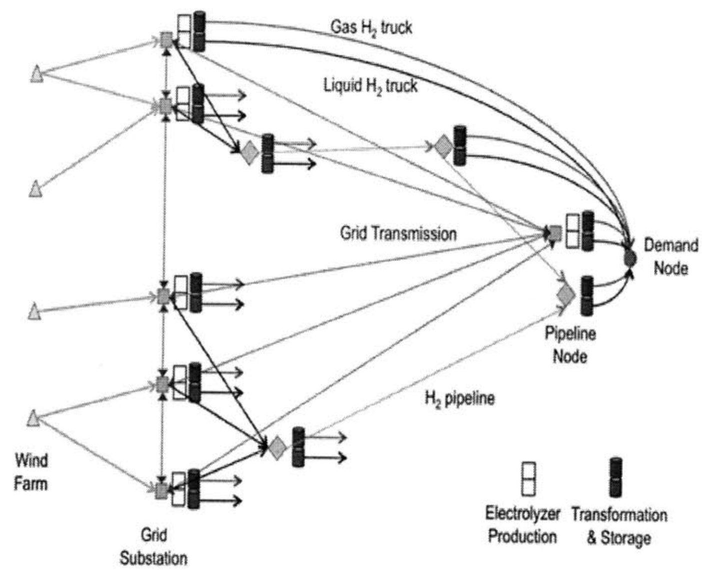

Figure 7: Schematic view of the network model

the electricity to the substation.

Each green rectangle represents a substation of the electric grid. Modeling all of the nodes and links of the electric grid is not practical due to the scope and complexity of the real grid. In particular, there are many intermediate nodes in a connection between two substations. We approximate the structure of the electric grid by aggregating nodes, bypassing intermediate nodes, and limiting the number of connections between nodes. Here, we connect each substation to every other substation within a 100 km radius. The resulting grid structure, depicted by the red links, is connected and loosely resembles the structure of the original grid.

Each blue diamond represents a node in the pipeline network. We constructed a pipeline topology based on the existing pipeline pathways. We allow each substation to connect to the nearest pipeline node; the cost of the connection depends on the pipe diameter and the distance. Here, we assume that the feeder pipes are 4 inches in diameter.

Each purple circle represents a demand, that is, the aggregated demand of a municipality. The links inbound to a demand node originate either from a substation or from a pipeline node and represent liquid or compressed gas truck distribution. Links are generated from every substation to every demand and from every pipeline node to every demand so as not to preclude cost-effective solutions.

Notice that there is a set of three nodes adjacent to some of the substation nodes. These nodes represent the installation of electrolyzers (the letter E within the node) and production of hydrogen at the substation, followed by distribution. Within our modeling framework, we have created duplicate nodes, one for each mode of distribution, in order to be able to accurately represent the costs of transformation, storage, and distribution for each mode.

Notice that there is a set of two nodes adjacent to some of the pipeline nodes. These nodes represent the distribution mode options available. Within our modeling framework, we have created duplicate nodes, one for each mode of truck distribution, in order to be able to accurately represent the costs of transformation, storage, and distribution for liquid gas and compressed gas trucks.

7.2 Implementation in INFOR SCM

In this section, we briefly discuss some aspects of implementing the hydrogen supply chain model in the INFOR SCM system.

7.2.1 Site Coordinates

One of the most important factors affecting the quality of the solution is the quality of the geographical information. The solutions typically are sensitive to the locations of the sites and their corresponding lanes. Here we provide some details of the geographical information for our study.

Acciona provided the coordinates and the generation capacity of the wind farms. The coordinates were calibrated based on the World Geodetic System 1984 and are imported into the INFOR software under the spheroidal coordinate system.

A third-party provided the coordinates of the electric grid substations. There are 251 substations at 220 kV and 150 substations at 400 kV. The original coordinates were originally calibrated under a different coordinate system, so they should be recalibrated.

7.2.2 Cost Implementation

Previously, we presented the cost functions for the production and distribution. As mentioned, some site costs are nonlinear, such as the liquefier cost. Introducing nonlinear cost functions into the system makes it difficult to solve. Instead, we use a step-based cost function. That is, we pre-calculate the cost based on the nonlinear function ahead of time by incrementing the appropriate parameter (such as number of liquefiers). Then, we map the pre-calculated value as a step cost function based on the parameter. For example, if the system chooses to use 5 electrolyzers at certain site, there would be a cost mapping to 5 electrolyzers under this scenario.

By introducing the step-based cost function, we have created a set of binary variables, which increases the effort required to solve the model. If we split the cost components of the system, we would amplify the number of binary variables very quickly. The second implementation we have in the system is to combine the fixed cost as a bundle cost. A number of the cost components in the model share the same set of parameters in their cost function. By combining the components together, we can reduce the number of binary variables with little effect on the solution of the model.

8 Mathematical Formulation

8.1 Notation

8.1.1 Sets

In this section, we define sets which represent different nodes and lanes we model in the formulation.

W = Set of windfarm locations

G = Set of substation (production site) locations

D = Set of local municipality (demand sites) locations

P = Pipeline node set

T = Mode of transportation set (it includes compressed gas truck; liquid gas truck; pipeline)

Tt = A subset of T where only compressed gas truck and liquid gas truck is included

E = Set of available electrolyzer production modules

V = Set of available pipeline conversion modules

WG = Set of available lanes connects windfarm and substations

EG = Set of electric grid lanes between substations

PIPE = Set of major pipeline lanes

GP = Set of feeder pipelines between substations and pipeline nodes

GD = Set of available transportation routes between substations and local municipalities

PD = Set of available transportation routes between pipeline nodes and local municipalities

8.1.2 Constants

$CAPW_w$ Denotes the wind farm capacity in units of kg per year. Outflow from wind farm w cannot exceed this number, for all w in W

$DEMAND_d$ Denotes the hydrgon demand at the local municipalities in units of kg per year. Each of the demand should be satified, for all d in D.

$TOLL$ Denotes the unit distance cost to transmit electricity through the electric grid in units of $\$/kg/km$.

EC Denotes the unit electricity cost $\$/kg$.

$PPC_{p_1p_2}$ Denotes the unit cost to transmit hydrogen from pipeline node p_1 to pipeline node p_2 in units of $\$/kg/km$ for all p_1p_2 in $PIPE$.

$LiqV$ Denotes the unit electricity cost for liquefaction$\$/kg$.

$TruckLoad_t$ Denotes the truckload capacity for one truck using transportation mode t in units of kg for all t in T.

$TruckFix_t$ Denotes the fixed cost for one truck using transportation mode t in units of dollars for all t in T.

$TruckVar_t$ Denotes the variable cost for one truck to deliver one kilogram hydrogen for one kilometer using transportation mode t in units of $\$/kg/km$ for all t in T.

$Distance_{g,d}$ Denotes the distance in kilometers between substation g and local municipality d in units of km.

$Distance_{p,d}$ Denotes the distance in kilometers between pipeline node p and local municipality d in units of km.

$PC_{e,g,t}$ denotes the capacity associated with production module e at substation g using transportation mode t in units of kg, for all e in E, g in G, t in T.

$PSC_{e,g,t}$ denotes the fixed cost associated with production module e at substation g using transportation mode t in units of km, for all e in E, g in G, t in T.

$CC_{v,p,t}$ denotes the capacity associated with conversion module v at substation p using transportation mode t in units of kg, for all v in V, p in P, t in Tt.

$CSC_{v,p,t}$ denotes the fixed cost associated with conversion module v at substation p using transportation mode t in units of km, for all v in V, p in P, t in Tt.

8.1.3 Decision Variables

Hydrogen Flows:

fwg_{wg} denotes flow from wind farm w to substation g, for all w in W, g in G, wg in WG.

fg_{g_1,g_2} denotes flow in the electric grid from substation g_1 to substation g_2, for all g_1 in G, g_2 in G, g_1g_2 in EG.

$fp_{p_1p_2}$ denotes flow in the pipeline from one pipeline node to pipeline node, for p_1 in P, p_2 in P, all p_1p_2 in $PIPE$.

fgp_{gp} denotes flow from the substation g to pipeline node p through the pipeline feeder, for all g in G, p in P, gp in GP.

$fgdt_{gd,t}$ denotes flow from substation g to local municipality d through transportation mode t. However, pipeline is not available to transmit to the local municipality, for all g in G, d in D, gd in GD,t in Tt.

$fpdt_{pd,t}$ denotes flow from pipeline p to local municipality d through transportation mode t, for all p in P, d in D, pd in PD, t in Tt.

All flows defined in the model are in untis of kg.

8.1.4 Binary Variables

$Yedt_{e,g,t}$ controls if module e is installed at substation g for transportation mode t, and 0 otherwise, for all e in E, g in G, t in T.

$Yvdt_{v,p,t}$ controls if module v is installed at pipeline node p for transportation mode t, and 0 otherwise, for all v in V, p in P, t in Tt.

8.1.5 Integer Variables

$Igdt_{gd,t}$ denotes the number of trucks from substation g to local municipality d using transportation mode t, for all g in G, d in D, gd in GD,t in Tt.

$Ipdt_{pd,t}$ denotes the number of trucks from pipeline node p to local municipality d using transportation mode t, for all p in P, d in D, pd in PD, t in Tt.

8.2 Constraints

8.2.1 Flow/site control from wind farm to substation

Wind farms are the basic supply nodes in our model. There is a capacity assigned to each of the wind farm so that no wind farm can provide more electricity than its cap

$$\sum_{g \in G} fwg_{w,g} \quad \leq \quad CAPW_w \qquad \forall w$$

8.2.2 Satisfy the Demand

The demand constraints are described as follows:

$$\sum_{g \in G} \sum_{t \in Tt} fgdt_{g,d,t} \quad + \sum_{p \in P} \sum_{t \in Tt} fpdt_{p,d,t} = \quad DEMAND_d \qquad \forall d$$

8.2.3 Flow balance at substation without electric grid

In the model, the production cannot store any hydrogen. Every inflow must goes to the local municipality

$$\begin{aligned}
\sum_{w\in W} fwg_{w,g} &= \sum_{d\in D}\sum_{t\in Tt} fgdt_{g,d,t} + \sum_{p\in P} fgp_{g,p} \qquad \forall g \\
fg_{eg} &= 0 \qquad\qquad\qquad\qquad \forall eg \in EG
\end{aligned}$$

8.2.4 Flow balance at substation with electric grid

When we allow other source of electricity to be the supply for the production in order to improve the electrolyzer's efficiency. In this case, we assume that there is no capacity on the electric grid. Instead, there is a toll cost to use the grid so that congestion on the electric grid could be properly avoided. In this constraint, we require that all the inflow should be equal all the outflow.

$$\begin{aligned}
&\sum_{w\in W} fwg_{w,g} \qquad\qquad + \sum_{g_1\in G, g_1 g\in EG} fg_{g_1,g} \\
&\sum_{d\in D}\sum_{t\in Tt} fgdt_{g,d,t} \quad + \sum_{p\in P, gp\in GP} fgp_{g,p} + \sum_{g_2\in G, gg_2\in EG} fg_{g,g_2} \quad \forall g \in G
\end{aligned}$$

8.2.5 Flow balance at pipeline node

At each pipeline node, there is no production facility. So the hydrogen inflow must equal to the hydrogen outflow. That is:

$$\sum_{g\in G} fgp_{g,p} + \sum_{p_1\in P, p_1 p\in PIPE} fp_{p_1,p} = \sum_{d\in D}\sum_{t\in Tt} fpdt_{p,d,t} + \sum_{p_2\in P, pp_2\in PIPE} fp_{p,p_2} \qquad \forall p$$

8.2.6 Production Fixed Cost

As we mentioned before, the fixed cost at the production site is the installation cost of discrete production units. Because of the economies of scale, the fixed cost does not increase in proportion to the number of discrete production units. In order to model the discrete units, we use binary control variables to represent whether or not we install production capacity of a particular size. Then corresponding to that production capacity is a single bundle cost that includes electrolyzer capital costs, liquefaction/compression costs, storage costs, pump costs and O&M costs. We need constraints to ensure that enough production capacity is installed for the corresponding flow by each transportation mode:

$$\begin{aligned}\sum_{d\in D} fgdt_{g,d,t} &\leq PC_{e,g,t} * Yegt_{e,g,t} \qquad \forall g, \forall t \in Tt \\ \sum_{p\in P} fgp_{g,p} &\leq PC_{e,g,t} * Yegt_{e,g,t} \qquad \forall g, \forall t \in Tt\end{aligned}$$

8.2.7 Pipeline conversion Fixed Cost

When we transmit hydrogen from pipeline to local municipalities, we need to compress the hydrogen either into liquid tank or compressed gas tank. This process would engage a fixed cost of the installed compressor/liquefier. Similar to the electrolyzer, the cost depends on the number of discrete units we need at the convention site. Here we use the step function to address the fixed cost:

$$\sum_{p\in P} fpdt_{p,d,t} \leq CC_{v,p,t} * Yvpt_{v,p,t} \qquad \forall p, t = pipeline$$

8.2.8 Truck Load cost function

In order to figure the transportation cost, we introduce integer variables to count the number of trucks used. Mathematically,

$$\begin{aligned}fgdt_{g,d,t} &\leq Igdt_{g,d,t} * TruckLoad_t \\ fpdt_{p,d,t} &\leq Ipdt_{p,d,t} * TruckLoad_t\end{aligned}$$

8.2.9 Non-negativity of the flows and truckloads

$$fwg_{w,g} \geq 0 \ , \ fp_{p_1,p_2} \geq 0, \ fg_{g_1,g_2} \geq 0,$$

$$fg_{g,p} \geq 0, fgdt_{g,d,t} \geq 0, fpdt_{p,d,t} \geq 0,$$

$$Igdt_{g,d,t} \geq 0, \ Ipdt_{p,d,t} \geq 0,$$

8.3 Objective Function

We want to minimize the total cost that the whole scenario engages which has the following component

Total Cost = Production Fixed Cost + Production Variable Cost + Transportation Cost + Pipeline conversion Cost + Pipeline Liquefaction Cost + Toll Cost + Pipeline Feeder Cost

Production Fixed Cost is:

$$PFC_{Total} = \sum_{g \in G} SiteCost_g = \sum_{g \in G} \sum_{e \in E} \sum_{t \in T} PSC_{e,g,i} * Yegt_{e,g,t}$$

Production Variable Cost is:

$$PVC_{Total} = \sum_{g \in G} PVC_g = (\sum_{gd \in GD} \sum_{t \in Tt} fgdt_{g,d,t} + \sum_{gp \in GP} fgp_{g,p}) * EC$$

Pipeline Conversion Fixed Cost is:

$$PPCC_{Total} = \sum_{p \in P} ConvFCost_p = \sum_{p \in P} \sum_{v \in V} \sum_{t \in Tt} CSC_{v,p,t} * Yvpt_{v,p,t}$$

Pipeline Liquefaction Variable Cost

$$PPVC_{Total} = \sum_{p \in P} \sum_{d \in D} \sum_{t = liquid} fpdt_{p,d,t} * LiqV$$

Pipeline Cost is:

$$PPC_{Total} = \sum_{p_1 p_2 \in PIPE} fp_{p_1,p_2} * PPC_{p_1,p_2}$$

Pipeline Feeder Cost is:

$$PPFC_{Total} = \sum_{gp \in GP} fgp_{g,p} * PPC_{g,p}$$

Transportation Cost:

$$\begin{aligned} TRANS_{Total} &= \sum_{gd \in GD} \sum_{t \in T} Igdt_{g,d,t} * (TruckFix_t + TruckVar_t * Distance_{g,d}) \\ &+ \sum_{pd \in PD} \sum_{t \in T} Ipdt_{p,d,t} * (TruckFix_t + TruckVar_t * Distance_{p,d}) \end{aligned}$$

Toll Cost is:

$$TOLL_{Total} = \sum_{g_1 g_2 \in EG} fg_{g_1,g_2} * TOLL$$

Objective Function is:

$$\begin{aligned} \min \quad TotalCost = PFC_{Total} + PVC_{Total} + TOLL_{Total} \\ +TRANS_{Total} + PPC_{Total} + PPFC_{Total} \\ PPCC_{Total} + PPVC_{Total} \end{aligned}$$

9 Scenario Analysis

In this section, we present results of the preliminary scenario analysis and discuss some insights from the results. To create the scenarios for analysis, we consider the two production scenarios (H2A, Future), the two electricity supply scenarios (Green, Gray), and the two stages of demand (Phase 1, Phase 2). With these three parameters, the complete set of scenarios includes eight combinations, however, we exclude two from consideration, the two corresponding to future production scenarios with phase 1 demand. These two combinations are incompatible in that phase 1 demand represents near-term early adopters while future production represents longer-term technology improvements.

For reference, we recap the definitions of the scenarios.

In the **H2A** scenarios, we assume the same production efficiency as modeled in the H2A analysis. In particular, we assume that the number of kWh required to produce 1 kg of hydrogen is 53.44. This value is intended to represent current

	Phase 1		Phase 2			
	H2A		H2A		Future	
	#	$/kg	#	$/kg	#	$/kg
Green	585	5.749	3060	5.6691	2510	4.8062
Gray	210	4.599	1110	4.4489	925	3.7949

Table 10: Summary of results for the major scenarios: number of electrolyzers and landed cost per kg

production efficiency conditions.

In the **Future** scenarios, we assume that technology improvements in the future will improve the production efficiency, requiring lower amounts of electricity. In particular, we assume that the number of kWh required to produce 1 kg of hydrogen is 44.4 in the Future scenario.

In the **Green** scenarios, we do not allow electrolyzers to use electricity from the grid, only from wind farms. The capacity factor is assumed to be 35%, meaning that the electrolyzers can run only 35% of the time. Moreover, since we do not allow electricity to be purchased from the grid, production can only be done at the substation located closest to the wind farm. Any hydrogen produced at the substation must be transported to the demand site via pipeline or truck.

In the **Gray** scenarios, we allow the electrolyzers to use electricity purchased from the grid. By purchasing from the grid, either at a station where there is no wind supply or at a station to supplement supply from the wind farm, the electrolyzer's utilization is higher. In these gray scenarios, we assume that electrolyzers will operate 95% of the time with the remaining 5% for maintenance.

In **Phase 1** demand, we assume a market penetration of 5% and set the minimum population density value to 1500 people per square kilometer.

In **Phase 2** demand, we assume a market penetration of 20% and set the minimum population density value to 500 people per square kilometer.

The following table summarizes the results of the scenario analysis in terms of the number of electrolyzers required in each scenario and the corresponding cost per kilogram of hydrogen.

9.1 Green-H2A-Phase 1

This section describes the solution for the H2A production scenario with the Green electricity supply under Phase 1 demand. There are two sites that are used to produce hydrogen: Madrid and Elian. The number of electrolyzers used in each site is 500 and 85 respectively. For this scenario, the model prefers centralized production, however, there is a limit of 500 electrolyzers per site. Therefore, once the production limit is reached at Madrid, a second production site is required. Note that the limit of 500 is a parameter setting, not a constraint on the system. For this scenario analysis, we choose the value of 500 because of the economies of scale of the fixed cost of the liquefier. Also, we need to consider whether 500 is a reasonable number of electrolyzers to manage at one site. The solution for this scenario suggests that doing sensitivity analysis on the total production capacity available at one site would be useful. In terms of transportation, liquid truck mode dominates the other transportation mode in this scenario. Neither compressed gas truck nor pipeline is used in this scenario. The cost breakdown is shown below along with the solution cost of $5.7490 per kilogram of hydrogen.

9.2 Gray-H2A-Phase 1

This section describes the solution for the H2A production scenario with the Gray electricity supply under Phase 1 demand.

Electrolyzers in the gray scenarios have higher utilization, working 95% of the time, thus, they can be viewed as more efficient than those in the green scenarios. As a result, given the same demand, fewer electrolyzers are required to satisfy demand as compared to the green scenarios. This is evident in Figure 9, as we can observe that there are only two sites that produce hydrogen, Madrid and Barcelona, using 120 and 90 electrolyzers respectively. Again, as in the green scenario, the model tends towards centralized production close to large demand sites. Interestingly, even though it is allowed, there is no electricity transmission

Mode	Green H2A Phase 1	
Total Flow	76,698.18 (,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$8,961.20	$0.12
Total Electricity Cost	$155,697.30	$2.03
Total Fixed Cost	$276,283.00	$3.60
Total Cost	$440,941.50	$5.75
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$8,961.20	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$155,697.30	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$276,283.00	
Pipeline Production	$0.00	

Table 11: Cost Details of the Solution for Green-H2A-Phase 1

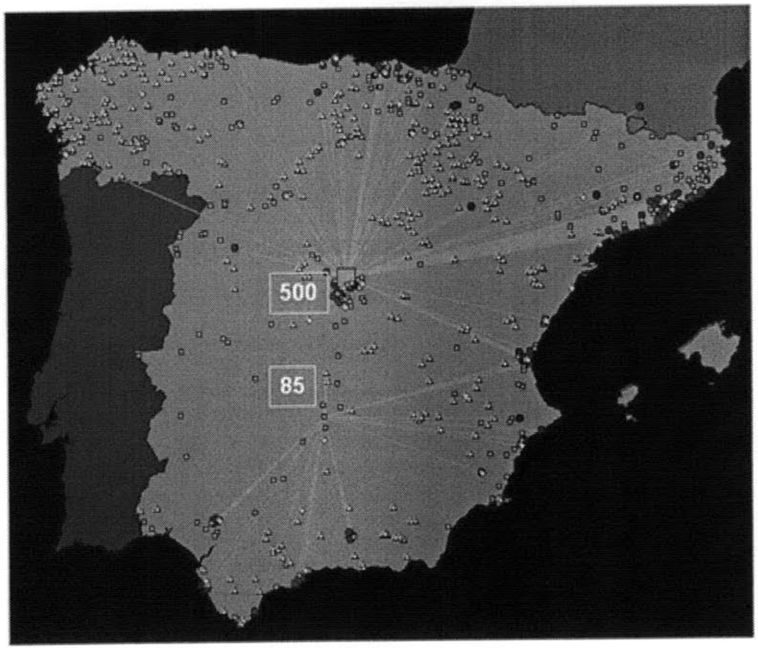

Figure 8: Solution for Green-H2A-Phase 1

through the grid; it is not required since the supply near the production site is large enough to satisfy demand.

On the transportation side, liquid truck dominates the other transportation modes again in the gray scenario. There are two explanations for this phenomenon. First, the tradeoff between choosing compressors are much more expensive than the tradeoff between choosing transportation method. Due tot the economic of scales of the liquefier, the system tends to choose centralized production. As a result, the production site cannot be very close to the demand sites compared to decentralized model. The distance between production site and demand site gives the incentive to use liquid truck as the transportation method because it demonstrates a cheaper way to transport in large volume and long distance. The cost breakdown is shown in Table 12 along with the solution cost of \$4.5990 per kilogram of hydrogen.

Mode	Gray H2A Phase 1	
Total Flow	76,698.18 (,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$7,793.89	$0.10
Total Electricity Cost	$206,329.00	$2.69
Total Fixed Cost	$138,615.00	$1.81
Total Cost	$352,737.89	$4.60
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$7,793.89	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$206,318.11	
Toll Cost	$10.89	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$138,615.00	
Pipeline Production	$0.00	

Table 12: Cost Details of the Solution for Gray-H2A-Phase 1

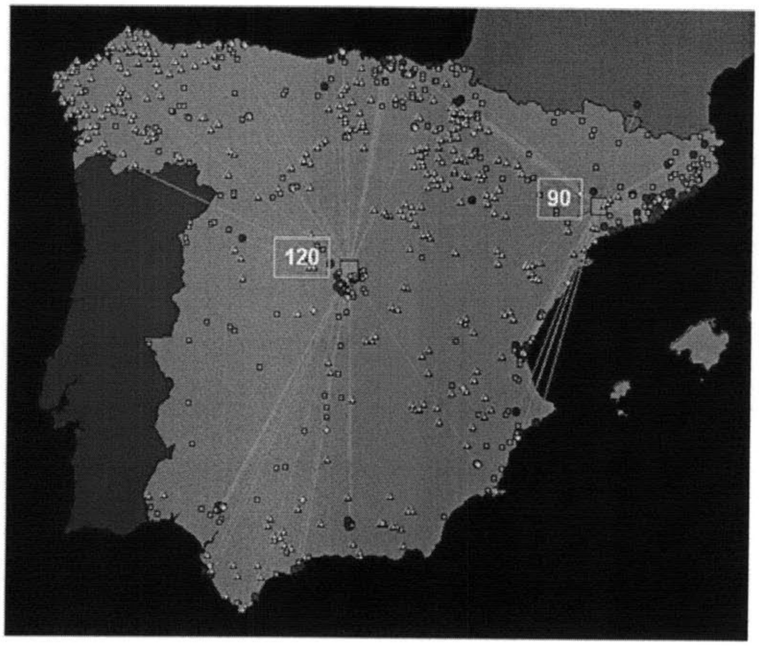

Figure 9: Solution for Gray-H2A-Phase 1

9.3 Green-H2A-Phase 2

This section describes the solution for the H2A production scenario with the Green electricity supply under Phase 2 demand.

The solution for the phase 2 demand is similar to the solution for the phase 1 demand, in that the solution tends towards large production at a small number of sites, which are close to large demands. Because the demand in phase 2 is significantly larger, there are now 7 production sites, 4 of them with the maximum 500 electrolyzers. Notice that there are 2 production sites in the area of Madrid, both with 500 electrolyzers. A large number of electrolyzers are required to satisfy the demand around Madrid, but the production capacity needs to be located at two substations due to the limit on the number of electrolyzers. The remaining production sites (Barcelona, Valencia, Pamplona and Malaga) are located around Spain, most close to large areas of demand, balancing the economies of scale in production and the transportation cost.

In terms of transportation, liquid truck dominates other the other trans-

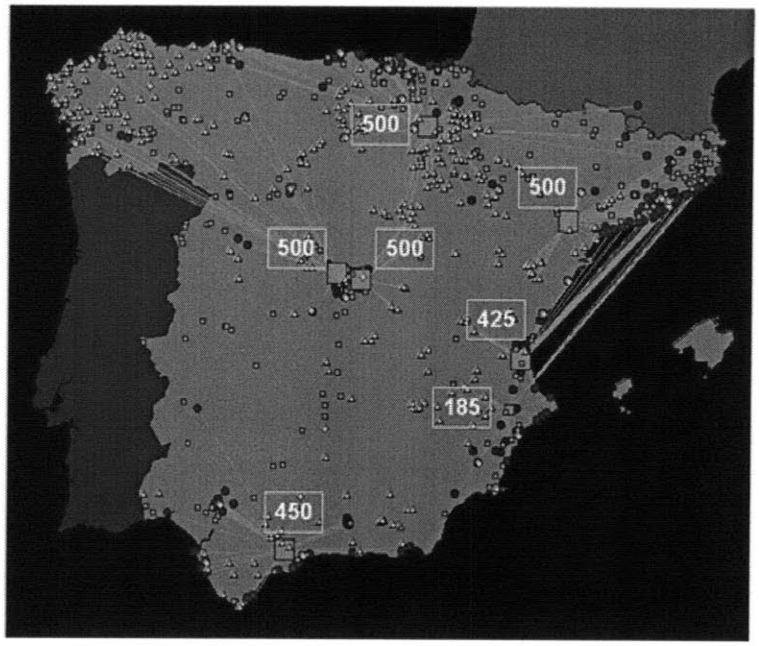

Figure 10: Solution for Green-H2A-Phase 2

portation modes as we have seen with the other scenarios. (Neither compressed gas truck nor pipeline is used in this scenario.) In Figure 10, the map of the solution displays the transportation links as straight line connections, some crossing the ocean. The current version of the decision support system approximates the true distance between two points using the straight-line distance, since the INFOR software does not include a comprehensive map of the roads in Spain. The error in this approximation is small enough since the purpose of the model is strategic planning. A refined set of routes would be provided in an implementation plan. The cost breakdown is shown in Table 13 along with the solution cost of \$5.6691 per kilogram of hydrogen. The cost per kilogram of hydrogen for phase 2 is lower than for phase 1 because the larger demand allows the system to exploit the economies of scale in the liquefier cost.

Mode	Green H2A Phase 2	
Total Flow	403,593.66(,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$38,108.11	$0.10
Total Electricity Cost	$819,295.06	$2.69
Total Fixed Cost	$1,430,595.00	$1.81
Total Cost	$2,287,998.17	$4.60
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$38,108.11	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$819,295.06	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$1,430,595.00	
Pipeline Production	$0.00	

Table 13: Cost Details of the Solution for Green-H2A-Phase 2

9.4 Green-Future-Phase 2

This section describes the solution for the Future production scenario with the Green electricity supply under Phase 2 demand.

In this scenario, the electricity supply is still restricted to the wind farms but now we assume that the production process is more efficient, due to technology improvements to be made in the future. As expected, we observe that the number of electrolyzers required to satisfy demand is fewer than in the Green-H2A-Phase 2 scenario. As we have seen with the other scenarios, the solution tends towards centralized production.

In this solution, there are 6 production sites: Madrid, Barcelona, Valencia, Pamplona, Malaga and Santiago de Compostela. Compared to the H2A scenario, the total number of electrolyzers has decreased, due to the increase in efficiency. Notice that in this scenario, the maximum number of electrolyzers at any one site is 450, even though the maximum allowable is still 500. The explanation is that because the cost function of the liquefier is nonlinear, the growth rate of the cost decreases as the number of electrolyzers increases. The more hydrogen liquefied, the cheaper it is to liquefy. However, there is a cost jump at 450 electrolyzers due to the capacity limitation of the liquefier. Installing a second liquefier increases the cost significantly and is not cost effective.

Compared to previous scenario, the total number of production sites has decreased but there is a new area, Santiago de Compostela, producing hydrogen. It supplies some demand around Madrid and Pamplona since it has surplus. The model prefers to fully utilize a single production site because of the economies of scales. Thus the surplus at Santiago de Compostela is used to satisfy the demand at Madrid, where in the previous scenario, there is no surplus at Santiago de Compostela because of lower efficiency. The model prefers to produce at Madrid.

In terms of transportation, liquid truck continues to dominate the other transportation modes. Neither compressed gas truck nor pipeline is used in this scenario. Also, some of the transportation routes cross the ocean since straight-line distances are modeled currently in the system. The cost breakdown is shown

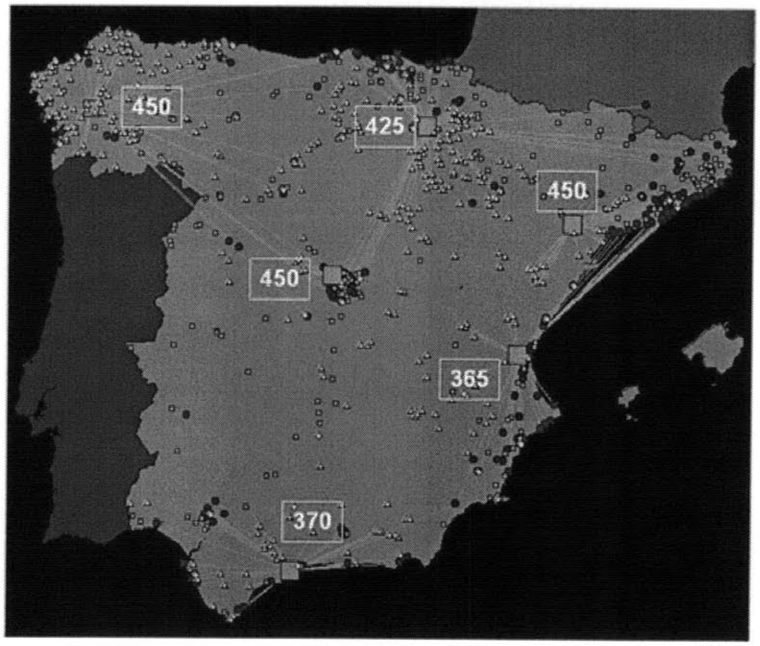

Figure 11: Solution for Green-FUT-Phase 2

in Table 14 along with the solution cost of \$4.8062 per kilogram of hydrogen, which is less than the cost in the Green-H2A-Phase 2 solution.

9.5 Gray-H2A-Phase 2

This section describes the solution for the H2A production scenario with the Gray electricity supply under Phase 2 demand.

On the production side, we observe that there are four sites that produce hydrogen: Madrid, Pamplona, Barcelona and Malaga. The number of electrolyzers installed at Madrid is 395 and at Pamplona is375. Both of these sites exceed the capacity of one liquefier and are required to install two. While this might appear to contradict our previous assertion that the model tends to produce at the maximum threshold, it does not. Upon closer examination, we can see that 395 electrolyzers is the capacity limit for 2 liquefiers under this gray-H2A scenario. Here, the model chooses to add a second liquefier rather than split production as it is more cost effective in this scenario. As in the other scenarios,

Mode	Green FUT Phase 2	
Total Flow	403,593.66(,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$38,335.65	$0.10
Total Electricity Cost	$682,073.25	$2.69
Total Fixed Cost	$1,219,344.00	$1.81
Total Cost	$1,939,752.90	$4.60
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$38,335.65	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$682,073.25	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$1,219,344.00	
Pipeline Production	$0.00	

Table 14: Cost Details of the Solution for Green-FUT-Phase 2

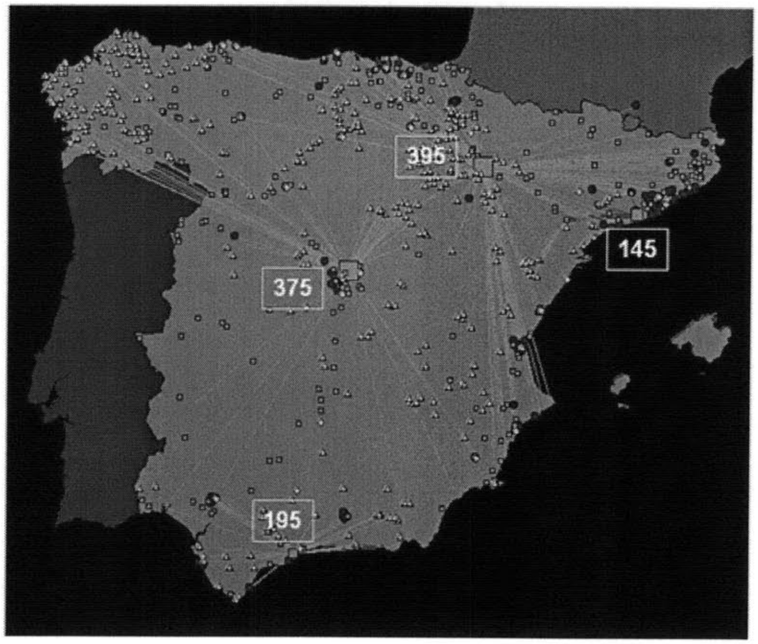

Figure 12: Solution for Gray-H2A-Phase 2

the model tends towards centralized production, siting production close to large demand areas.

On the transportation side, liquid truck continues to dominate the other transportation methods. Neither compressed gas truck nor pipeline is used in this scenario. Again, some of the transportation routes are shown crossing the ocean due to the straight-line connections. The cost breakdown is shown in Table 8.5 along with the solution cost of \$4.4489 per kilogram of hydrogen.

9.6 Gray-Future-Phase 2

This section describes the solution for the Future production scenario with the Gray electricity supply under Phase 2 demand.

On the production side, the solution is very similar to the solution of the Green-Future-Phase 2 scenario. There are 6 production sites that produce hydrogen. In this scenario, the capacity threshold due to liquefier economies of scale is 165 electrolyzers. We can see that there are two major production

Mode	Gray H2A Phase 2	
Total Flow	403,593.66(,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$39,806.36	$0.10
Total Electricity Cost	$1,087,560.96	$2.69
Total Fixed Cost	$668,197.00	$1.81
Total Cost	$1,795,564.32	$4.60
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$39,806.36	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$1,085,666.91	
Toll Cost	$1,894.05	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$668,197.00	
Pipeline Production	$0.00	

Table 15: Cost Details of the Solution for Gray-H2A-Phase 2

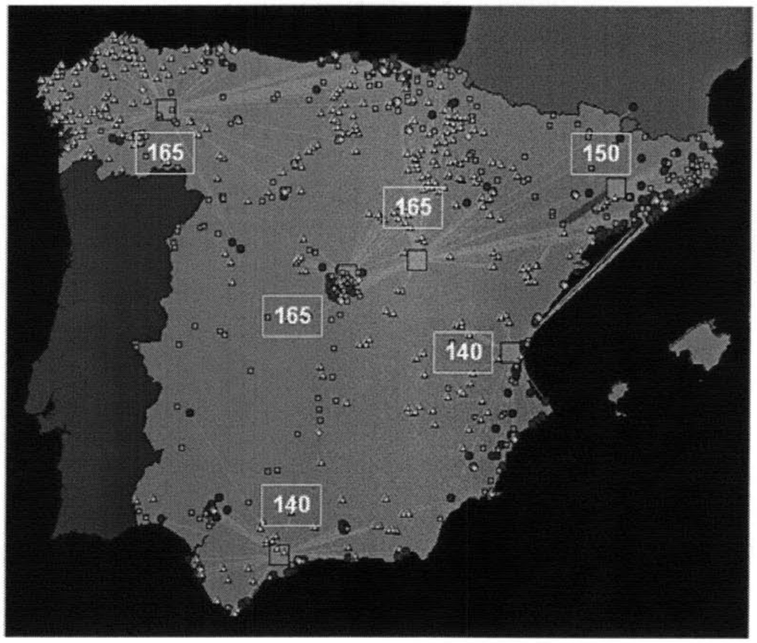

Figure 13: Solution for Gray-FUT-Phase 2

sites at Madrid and Santiago de Compostela. There is another production site between Madrid and Pamplona, which shares its supply with the remaining demand at Madrid and Pamplona. The other three production sites are located at Barcelona, Valencia and Malaga, each of which serves the local demand. The electricity grid is used in this scenario to transmit electricity from the wind farm to one substation near Barcelona since the Barcelona-area supply is not enough.

On the transportation side, liquid truck again dominates the other transportation modes. Neither compressed gas truck nor pipeline is used in this scenario. Some of the transportation routes cross the ocean due to the straight line connections. The cost breakdown is shown in Table 8.6 along with the solution cost of $3.7949 per kilogram of hydrogen.

Mode	Gray FUT Phase 2	
Total Flow	403,593.66(,000 kg)	Unit Cost
	(,000 $)	$ / per kg
Total Transportation	$38,076.35	$0.10
Total Electricity Cost	$897,182.81	$2.69
Total Fixed Cost	$596,355.00	$1.81
Total Cost	$1,531,614.16	$4.60
Detail Transportation Cost		
Compressed Gas by pipeline	$0.00	
Compressed Gas by substation	$0.00	
Liquid Gas by pipeline	$0.00	
Liquid Gas by substation	$38,076.35	
Pipeline Feeder	$0.00	
Main Pipeline	$0.00	
Detail Electricity Cost		
Electricity Cost	$895,977.89	
Toll Cost	$1,204.92	
Detail Fixed Cost		
Pipeline to Compressed Gas	$0.00	
Bundle Cost for Compressed Gas	$0.00	
Pipeline to Liquid Gas Station	$0.00	
Bundle Cost for Liquid Gas	$596,355.00	
Pipeline Production	$0.00	

Table 16: Cost Details of the Solution for Gray-FUT-Phase 2

10 Conclusion

In this thesis, I proposed a decision support model for the hydrogen supply chain network. The model provide a general framework with respect to supply chain network to investigate the feasibility of using hydrogen as fossil fuel substitue. With different configuration of parameters, it could be generalized to model other scenarios of the hydrogen economy. It is unique in the sense that it combines all the scenarios in a practical measure. It provides people a global view of the tradeoff between different components of the supply chain network, i.e. centralized production versus distributed production. Especially, it gives some useful insight to assist decision making when there is a large investment with capacity.

A case study based on Spain is given based on the model. Combinations of different production schemes and demand estimation are tested. In the solutions of six scenarios, we have observed the model tends towards centralized production close to the larger demand sites. This is mainly due to the economies of scales in the cost of the liquefiers. However, the capacity limitations of the liquefier constrain the extent of the centralization in that there is a large cost increase associated with adding another liquefier. In five of the six scenarios, only one liquefier is installed at each production site; in the sixth scenario (Gray-H2A-Phase2), two liquefiers are installed at two of the production sites and are used to maximum capacity. In the Gray-H2A-Phase 2 scenario, it is less expensive to install the second liquefier than to add a production site at another location. In terms of the locations of the production sites, there are common production sites across all six scenarios: Madrid, Barcelona, Valencia, Pamplona, Malaga and Santiago de Compostela. These locations correspond to areas with high demand.

In terms of transportation, liquid truck dominates all other transportation modes in all of the scenarios. Compared to compressed gas truck, liquid truck is more economical for transporting large volumes and long distance. Since the model prefers centralized production, the distance between production sites and demand sites can be relatively long. In theory, pipeline should be an attractive option for large volume and long distance transportation. However, as modeled, it appears that the initial capital investment to build the pipeline is too expensive relative to the other transportation options for the demand levels.

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