

Optimized Pathways for Regional H₂ Infrastructure Transitions: A Case Study for Southern California

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Abstract

Southern California has been proposed as a likely site for developing a hydrogen refueling infrastructure. In this paper, we apply dynamic programming to identify optimized strategies for supplying hydrogen over time in Southern California. GIS-based traffic data are used to model the location and magnitude of hydrogen demand over time. Refueling stations are sited based on the location of demand and the trade-off between convenience and costs. We use engineering/economic models to describe a variety of possible hydrogen supply options. Both onsite and central production technologies including biomass gasification, coal gasification, natural gas reforming, and water electrolysis are investigated. For central production routes, several delivery modes are analyzed including liquid and compressed gas trucks, and gas pipelines. These technologies compete with each other to meet an exogenously estimated hydrogen demand over time at lowest cost. At each time step over a specified transition period, the model uses a dynamic programming algorithm to select the best strategy for building up the infrastructure. We find that 1) hydrogen could be cost competitive based on region-specific spatial optimization; 2) the best buildup strategy for Southern California could be industry hydrogen in early stage, bridged by onsite natural SMR and followed by biomass central gasification and then coal gasification with carbon capture and sequestration; 3) the feasibility of CCS is critical in CO₂ emissions mitigation.

Keywords: Hydrogen, Cost Estimate, Transition, Carbon Dioxide, Modeling.

Acronyms/abbreviations

BDT = Dry Bone Ton

CCS = carbon dioxide capture and storage

CO₂ = carbon dioxide

C-COALCCS = central production of H₂ via coal gasification with CCS

C-SMR, C-ELE, C-BIO = central production of H₂ via SMR, electrolysis and biomass gasification, respectively

C-SMRCCS, C-BIOCCS = C-SMR and C-BIO with CCS, respectively

DOE = the U.S. Department of Energy

D-SMR, D-ELE = distributed production of H₂ via SMR and electrolysis, respectively

EIA = Energy Information Administration

FCV = Fuel Cell Vehicle

HIT = H₂ Infrastructure Transition

H₂ = H₂

H₂I = H₂ Infrastructure

H₂IC = H₂I Configuration

MtCO₂ = million tons of CO₂

MtC = million tons of carbon

NPV = Net Present Value

O&M = Operating and Maintenance

SMR = Steam Methane Reforming

tonC = one ton of carbon

U.S. = United States

VMT = Vehicle Miles Traveled

NAE = National Academy of Engineering

1. Introduction

H2 as transportation fuel provides the promise of reducing air pollution, green house gas emissions, and oil dependence as related to transportation [1][2][3][4]. Although a H2I does not exist, the cost of H2 can be estimated via engineering-economic models [2]-[10].

The current knowledge of H2 cost is mostly derived from models that are based on nation-wide average parameters, regional idealized layout, pathway portion, pathway exclusion, static snapshot, non-optimization or, more commonly, a combination of the above. In light of the current methodological limitations, this paper incorporates existing static studies [2][6][7] and uses a dynamic programming approach to identify the optimal pathway strategy of supply H2 to Southern California. A H2 demand curve is estimated for 2010-2060 by assuming the DOE “Scenario 3” [18] and a 100% of new vehicle sale by fuel cell vehicles (FCV) in 2060. To minimize delivered H2 cost, the dynamic programming HIT model is developed to find where, when, by what technologies and at what sizes to build up a regional H2I.

2. Method and Data

The flowchart (Figure 1) illustrates the method in this paper is to find the least-cost H2 for Southern California. The PLANNER module compares all possible sequences of H2IC and selects the best one, while the ACCOUNTANT module provides cost data for the PLANNER module to evaluate and compare the costs of possible sequences.

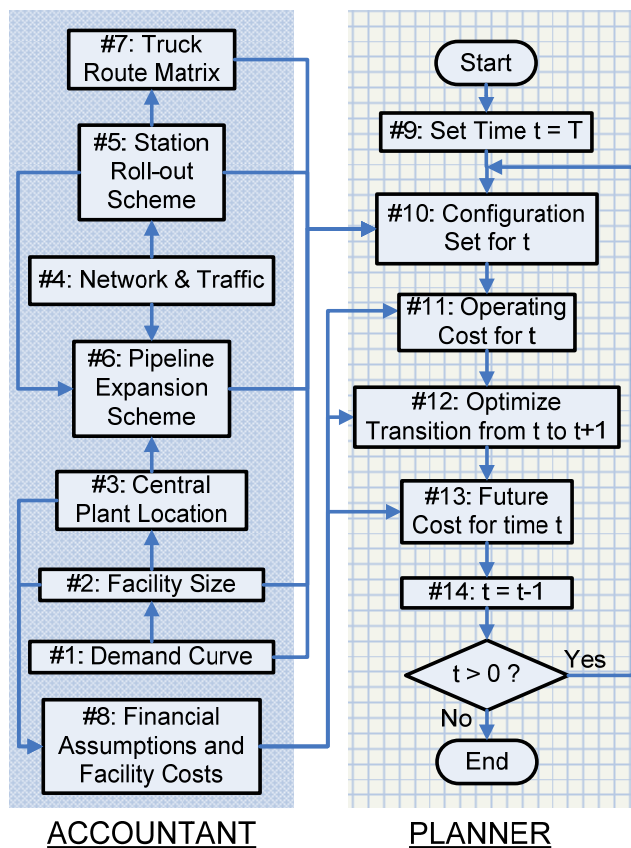


Figure 1: Flowchart of the HIT model

2.1 Study Scope

The study region includes five counties: Los Angeles, Orange, San Bernardino, Riverside and Ventura with the regional attributes in Table 1. We assume a time scope of 2010-2060 with 5 years per time step. We consider two onsite productions: D-SMR and D-ELE; six central productions: C-ELE, C-SMR, C-BIO, C-SMRCCS, C-BIOCCS and C-COALCCS; and chemical industry H2. We consider two H2 delivery modes: gaseous H2 via pipeline and liquid H2 via tanker truck.

Table 1: Southern California Overview (2005)

Population	17.6 million
Area	33,953 sq. mi.
Density	517/sq. mi.
Transport demand	154 billion VMT
Fuel Consumption	8.47 billion gallon
Vehicle Stock	11.4 million

2.2 Demand Scenario

VMT is projected by extrapolating an existing 2030 projection [19] and used to derive annual total new vehicle sale by considering annual per-vehicle VMT and fleet share by vehicle age [20]. Annual FCV sale and H2 demand (Figure 2) is estimated by assuming the DOE Scenario 3 [18] and a 100% FCV sale in 2060 (Step #1).

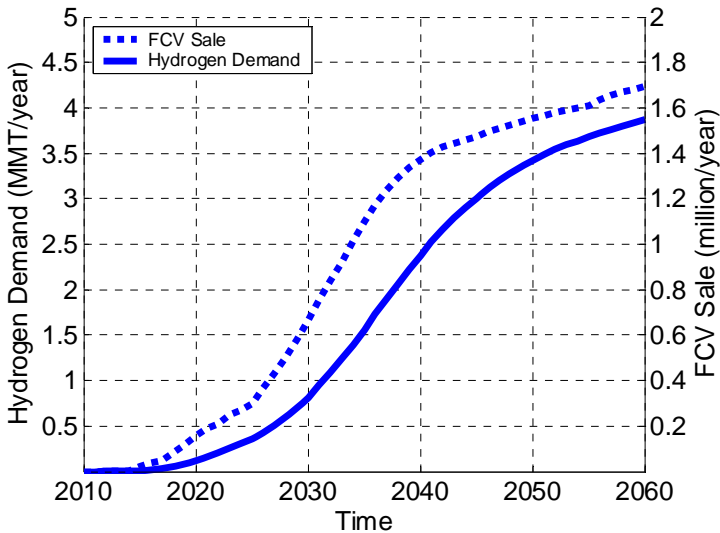


Figure 2: FCV Sale and H2 Demand

2.3 Technology

Technologies are represented by size, activity, life cycle costs (capital, fixed O&M and variable), efficiency and carbon emission. Technology improvement is described by decrease of costs and emission factors and increase of efficiency over time.

A uniform plant size of 1,400 ton/day is assumed for central production. A stackable module size of 500 kg/day and a size upper limit of 5,000 kg/day are assumed for refueling, D-SMR, and D-ELE stations.

Capital and fixed O&M costs, efficiency, and carbon emission factor for year 2010 are borrowed or derived from the DOE/H2A model [7], except that the CO₂ emission factor, 0.275 kg CO₂/kWh, for California grid electricity comes from EIA [21]. Because the DOE/H2A model does not provide future technology assessment, technology data for year 2060 are derived by using the ratios of “future optimism” and “current” assessments reported by NAE [2]. Data between 2010 and 2060 are derived via quadratic interpolation.

In calculating variable costs, we use the following feedstock prices (Table 2), which are assumed to be constant over time. For biomass, we estimate 7.94 million BDT/year of biomass available in the study region [22]. Currently there is no representation of biomass supply curve in the model.

An industry H₂ supply below 42,000 kg/day is available at a delivered cost of 2.80 \$/kg but not including station costs. The marginal cost of more industry H₂ is assumed to increase linearly to 10 \$/kg at 84,000 kg/day.

Table 2: Feedstock Prices

Feedstock	Price	Source
com. electricity	11.92 ¢/kWh	EIA [24], 2005, California
ind. electricity	9.55 ¢/kWh	ditto
com. natural gas	10.69 \$/kcf	ditto
ind. natural gas	9.84 \$/kcf	ditto
coal	23.30 \$/s.t.	EIA [24], 2005, Mountain
biomass	46 \$/bd	H2A [7]

For H₂ pipeline, a pipeline expansion scheme (Step #6) is generated to estimate the actual length, flow rate and diameter of each pipeline segment. Then rural pipeline costs are estimated from the formula found by Parker [12] (also adopted by the DOE/H2A model [7]). Tanker truck is represented as a rental service at a rate of 1.80 \$ per kg per 210 kilometres [2]. This rate includes the cost but not the carbon tax (calculated separately) of liquefaction electricity.

Costs of CO₂ pipeline are estimated with the same approach to H₂ pipeline costs. Because the carbon capture rate varies by technology¹, CO₂ pipeline diameter and costs are a function of length and plant technology.

We estimate an installed cost of 1.39 million dollars for an injection plant with injection capacity of 1,500 tons CO₂ per day and injection depth of 1,500 meters [23]. The number of injection plants is determined by the actual amount of CO₂ captured.

Some other financial assumptions include a 10% annual discount rate for private costs, a 40-year life for central plants, pipelines and sequestration plants, and 20-year life for refueling and onsite stations.

2.4 External Costs

The model considers refueling travel time cost and carbon tax as external costs. Travel time is assessed based on optimal station locations (explained next). A time value of 0.33 \$/min, equivalent to 50% of 40 \$/hour wage rate [25], is assumed to convert travel time into dollars. The optimal number of stations is a trade-off between time cost and station costs. A carbon tax of 20 \$/tonC in 2010, aggressively increased by 20 \$/tonC per time step, is assumed to represent the disbenefits of carbon emissions. The discount rate for external costs is also 10% annually.

¹ 2.34, 4.41, and 7.04 kg C/kg H₂ for SMR, coal gasification and biomass gasification, respectively [2]

2.5 Facility Location

Network and traffic data [26]-[28] are used to optimize station locations and derive the average refueling travel time as a function of station number (Step #5).

One estimate of the carbon storage capacity (saline formation) of the Basin & Range province is 889,055 MtCO₂ [29]. The overlay of the province on the study region (Figure 3) is assumed to be the carbon storage location.

A total of nine central plants are needed to meet the 2060 demand. The potential locations for central plants (Step #3) are selected by considering proximity to population, railroad, industry zones, and carbon storage area (Figure 3). With plant and station locations, pipeline segments, if selected into the decision sequence, are connected according to a pipeline expansion scheme (Step #6) that aims at minimizing the total pipeline length. A truck route matrix (Step #7) is also generated for assessing trucking cost if there are H₂ delivered by truck.

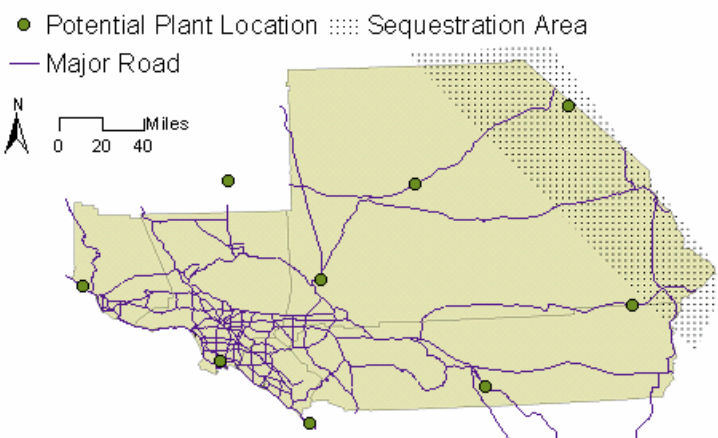


Figure 3: Network and Plant Location

2.6 Optimization

In principle, one can enumerate and evaluate the NPV of all possible sequences of H₂IC with the help of the ACCOUNTANT module (Figure 1) and select the one with the lowest NPV. However, this is practically impossible due to long computation time, so a dynamic programming framework [30] is implemented in the PLANNER module.

3. Results and Discussion

As shown in Figure 4, during 2010-2014, all H₂ supply comes from the chemical industry at 1,364.6 kg/day delivered via tanker truck to 4 refueling stations. For 2015-2019, a supply of 44,795 kg/day industry H₂ are delivered by tanker truck to 36 refueling stations, while 50 D-SMR stations are also built to meet the remaining demand of 62,215 kg/day. From 2020, central production begins to dominate, although industry H₂ and D-SMR also co-exist for some years to avoid low utilization of central production.

Although C-COALCCS dominates during most of the study period, the first central plant is by C-BIO, which is upgraded with CCS after 5 years to cut costs on carbon tax. Available biomass only allows for one C-BIO or C-BIOCCS plant. Other technologies, D-ELE, C-ELE, C-SMR, C-SMRCCS, do not enter the optimal decisions.

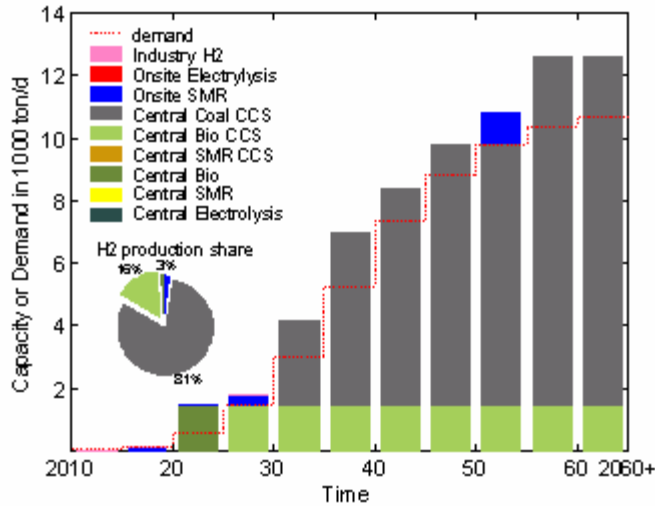


Figure 4: Capacity by Technology

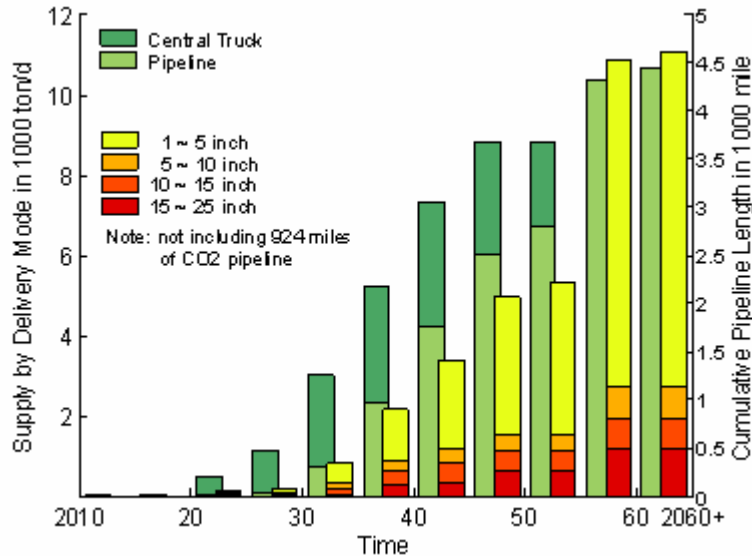


Figure 5: Delivery Mode

Regarding delivery mode (Figure 5), trucking gradually loses share to pipeline over time. H2 from a same central plant could be transported by pipeline to some high-demand areas while by truck to some low-demand areas. When the demand in areas previously served by truck increases to some level, economies of scale make pipeline more competitive and tanker truck loses the route businesses to pipeline, such as in 2055-2059.

The total pipeline length serving 2376 refueling stations in 2060 is 4,611 miles (1.94 mile pipeline per station), 76% of which are small pipelines with diameter below 5 inches. The total length is based on real distance and optimization and demonstrates a significant reduction from other estimates based on idealized layout. For example, the DOE/H2A model estimates a total pipeline length of 18,998 miles serving 4313 stations (4.40 mile pipeline per station) for a 100% penetration (current demand level) in the Los Angeles--Long Beach--Santa Ana region.

Station location optimization enables a small refueling network to provide a desired level of fuel accessibility. The tradeoff between travel time and station costs causes the refueling network to expand from 4 stations of an average size of 500 kg/day during 2010-2014 to 2376 stations of 5000 kg/day during 2055-2059. The average refueling travel time with 2376 stations is less than 50 seconds, which is already

an improvement from the 1 minute 50 seconds enabled by the existing 3850 gasoline stations in the study region². The approximate locations of H2 stations are shown for two time steps in Figure 6.

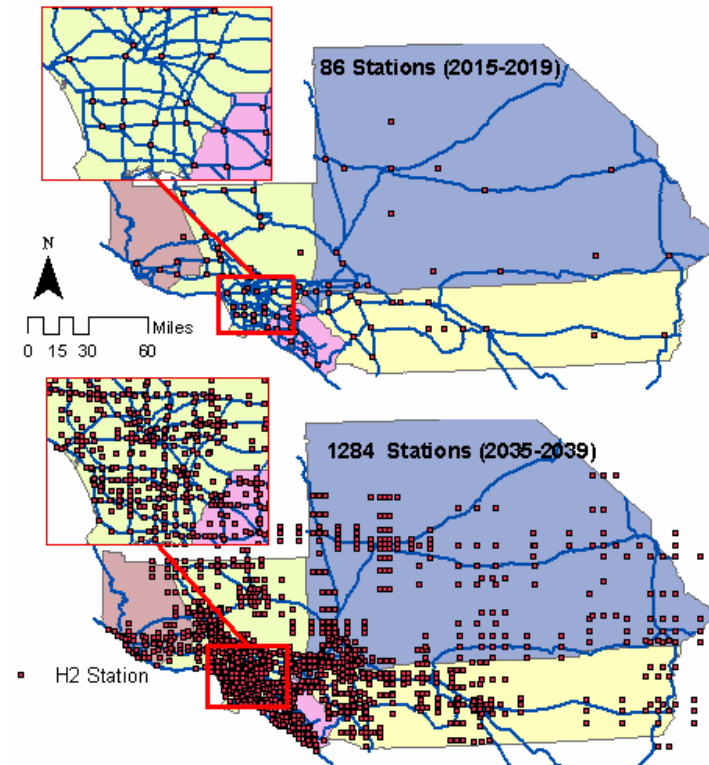


Figure 6: Station Location

The levelized hydrogen cost is 1.77 \$/kg. That is, if hydrogen is charged at 1.77 \$/kg, the revenues and the costs over time are translated into a zero NPV at 2010 based on 10% discount rate. It should be careful if one compares this estimate with other studies, because most of the other studies estimate hydrogen cost for individual hydrogen pathway.

The estimate suggests hydrogen supply for transportation in Southern California could be economically very attractive, if FCVs could compete with gasoline vehicles.

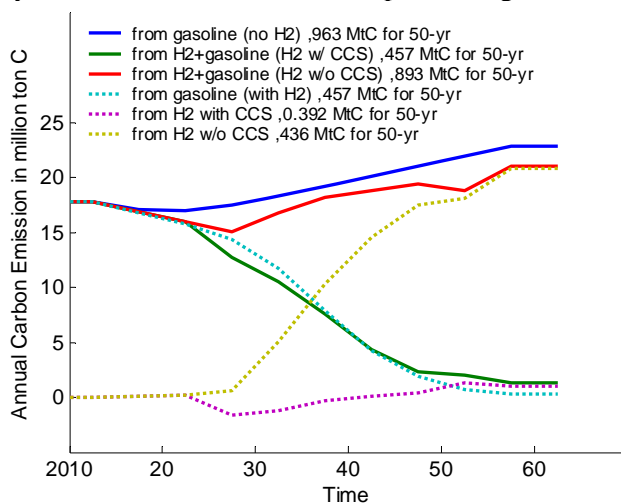


Figure 7: Annual Carbon Emission

² Nicholas [11] reports 1 minute 50 seconds for Sacramento. We assume this is also applicable to the study region

The total 50-year carbon emissions from conventional gasoline vehicles are about 963 MtC. The H₂ demand curve coupled with the optimal sequence of H₂IC could potentially reduce CO₂ emissions by about 50%. Sequestering CO₂ from biomass gasification results in negative contribution and offsets the CO₂ emissions from other technologies. The outcome is only 0.302 MtC during the 50 years attributed to H₂ supply. If CCS is not adopted, the transition sequence, dominated by coal gasification, provides positive but little CO₂ mitigation potential.

4. Conclusions

The HIT model based on dynamic programming is applied to discover “the regional least-cost H₂” in Southern California via optimization in terms of when, where, at what sizes and by what technologies to supply hydrogen for a 2010-2060 scope. The model considers pathway competition, pathway mix, technology improvement, carbon tax, refueling travel time and regional attributes including spatial distribution of demand, resource availability, and road network. Based on the base scenario data and assumptions, the model found an optimal sequence of H₂IC starting from chemical industry H₂, quickly followed with onsite SMR and later evolving into central production. The central production phase starts with biomass gasification but is later dominated by coal gasification. CCS is later adopted due to increasing carbon tax. Pipeline network gradually expands and eventually takes over all hydrogen delivery from trucking.

Optimization could significantly reduce estimate of hydrogen cost. H₂ from the chemical industry is competitive in early stages. If CCS is feasible, coal gasification with CCS is competitive. Biomass could be more competitive than coal, but is constrained by resource availability. With demand increasing, trucking gradually loses market share to pipeline.

The overall levelized cost is about 1.77 \$/kg, which indicate the affordability and economic attraction of building up a hydrogen infrastructure in Southern California, but without consideration of barriers on the vehicle side.

The optimal buildup decisions lead to 50% of CO₂ emissions mitigation. However, if CCS proves to be infeasible, hydrogen from coal gasification could achieve little CO₂ emissions mitigation.

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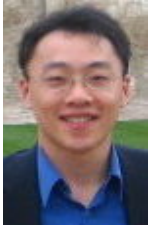
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