

ASSESSING STRATEGIES FOR FUEL AND ELECTRICITY PRODUCTION IN A CALIFORNIA HYDROGEN ECONOMY

R.W. McCarthy¹, C. Yang¹, J.M. Ogden¹

1. Introduction

Hydrogen and electricity are both high-quality energy carriers that can be made from diverse primary energy resources and can be inter-converted using electrolyzers and fuel cells. Unlike today's energy system, where electricity and transportation fuels have very different supply chains, these characteristics suggest that supply pathways for electricity and transportation fuels might "converge" in a future hydrogen economy. If both sectors come to rely on the same primary energy sources, the implications could be significant, and might lead to profound changes in the way energy is supplied. While a switch from gasoline to hydrogen might lead to higher demand for primary energy resources (such as biomass, natural gas, or coal), it would also offer opportunities to improve the efficiency and reliability of energy supply by integrating the electricity and transportation fuel systems. For example, efficiency gains and cost reductions might be realized by co-producing hydrogen and electricity at the same facility. Interactions between electricity and hydrogen could be crucial issues for the future of a hydrogen economy, but have not been studied extensively. Further analysis is needed to understand the impact of this convergence in terms of emissions, prices, reliability, and resource availability on a regional basis.

In this paper, we describe preliminary results from an ongoing assessment of the interactions between hydrogen and electricity. As a first step, we have used the Long-range Energy Alternative Planning system (LEAP), developed by the Stockholm Environment Institute (SEI), to evaluate different scenarios for hydrogen and electricity demand and supply in California in terms of primary energy use and greenhouse gas emissions.

2. Background and motivation

Researchers at UC Davis are studying the economic, energy, environmental, and resource impacts associated with large-scale use and production of hydrogen in California. Recently, we have begun to analyze the interaction between hydrogen and electricity supply systems, and how the development of one sector might affect the other.

Before delving into the details of how hydrogen and electricity interact on an hourly basis, we addressed the following higher level questions about California's energy use, considering both electricity and fuels. The timeframe of the analysis is the next 25 years (2005-2030):

¹ Institute of Transportation Studies, University of California, Davis, One Shields Avenue, Davis, CA 95616-8762, USA

- 1) What are projected demands for electricity and transportation fuels in California?
- 2) What are possible scenarios for hydrogen demand in this timeframe?
- 3) What are possible scenarios for supplying electricity and fuels through conversion of fossil, renewable and nuclear primary sources?
- 4) What are demands for primary energy for different scenarios?
- 5) How do greenhouse gas emissions vary for different scenarios?

3. LEAP model of hydrogen and electricity supply and demand

To better understand the system-wide impacts associated with different scenarios for hydrogen and electricity supply, we developed a simplified model of the energy system in California using LEAP. LEAP is a scenario-based accounting tool that facilitates energy supply and demand calculations and the assessment of technology and policy alternatives. Figure 1 outlines the general framework of the model. The user defines key variables (such as vehicle miles traveled and fuel economy) from which LEAP constructs demand scenarios. A set of “transformations” characterize energy conversion processes and are matched with demand to provide final outputs in terms of emissions and resource consumption. Technology and policy alternatives may be investigated as they influence key variables, demand scenarios, or transformations.

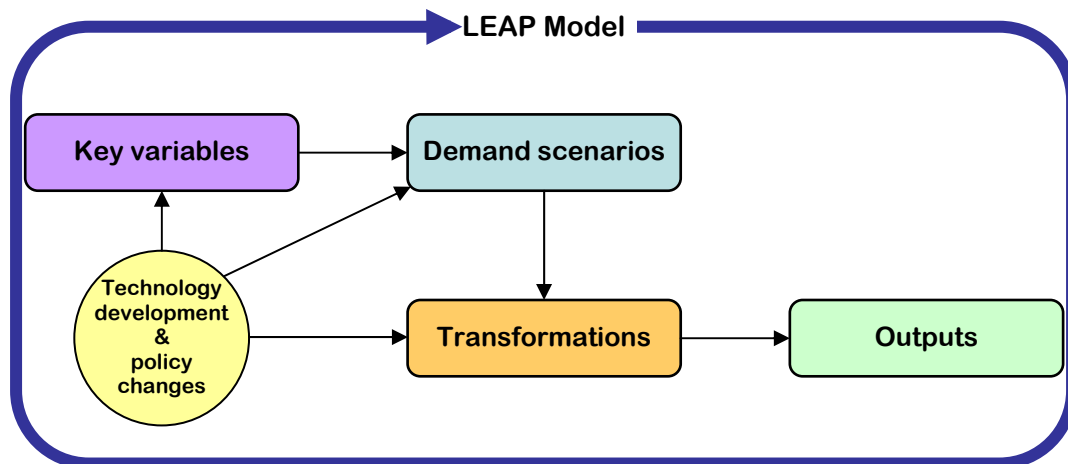
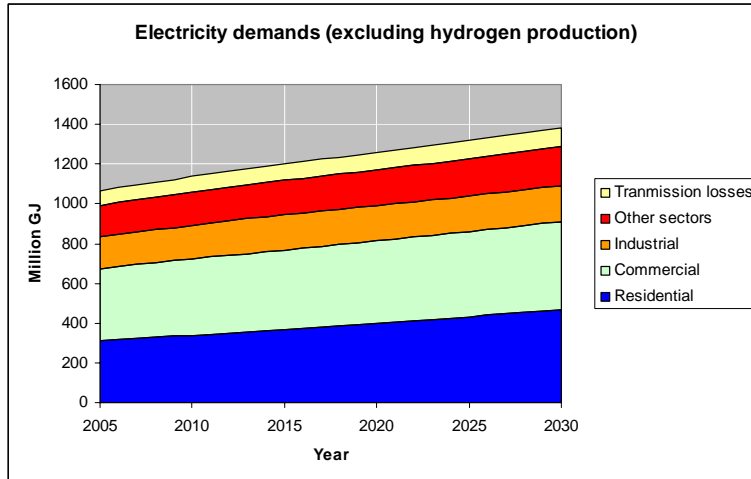


Figure 1. LEAP model framework. LEAP develops demand scenarios based on key variables input by the user, which are matched with supply (“transformations”) to develop outputs in terms of emissions or resource consumption. Effects of technology development or policy changes can be assessed at any stage of the model.

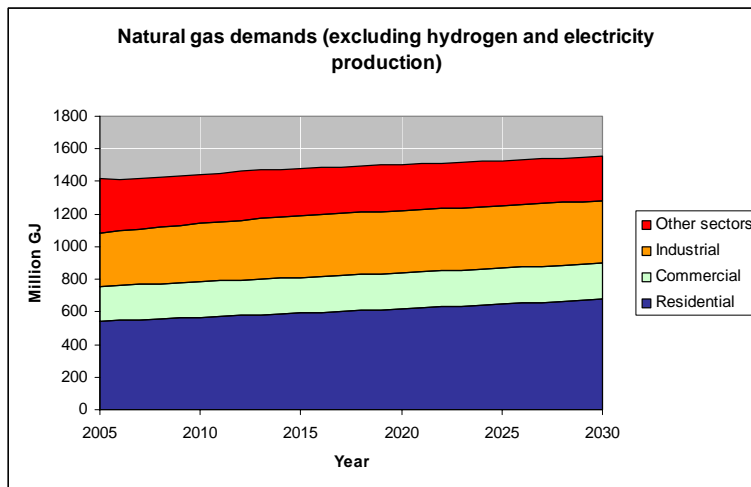
3.1. Energy demand assumptions

Electricity and natural gas

Our preliminary model relies on electricity and natural gas demand projections from the California Energy Commission (CEC) [1], which we extrapolated through 2030 (Figure 2). Assuming no additional demands from hydrogen, electricity demand is projected to increase at an average rate of about 0.9% per year, and natural gas demand is projected to increase an about 0.2% annually.



(a)



(b)

Figure 2. Projected energy demands by sector in California through 2030. (a) Projected electricity demands, and (b) projected natural gas demands.

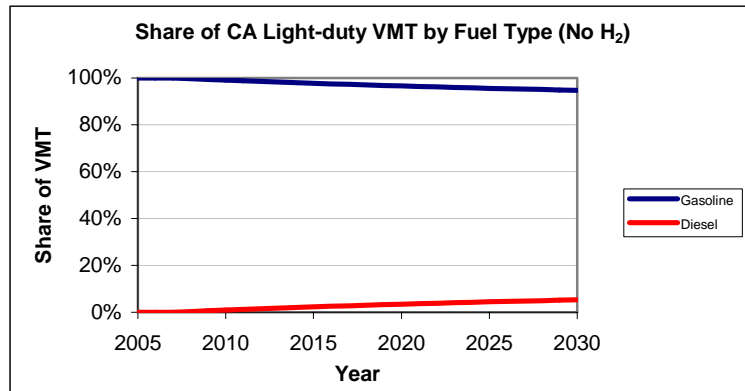
We also input load shapes for electricity and natural gas demands over time. Electricity demand profiles were based on season and time of day, according to the National Energy Modeling System (NEMS) methodology used by the EIA [2]. Natural gas demand was based on seasonal variations only, constructed from historical data for from the EIA. Based on these load shapes, LEAP derived annual load duration curves. This allowed us to allocate electricity generation among different types of power plants (see discussion on our electricity dispatch model, below).

Transportation fuels

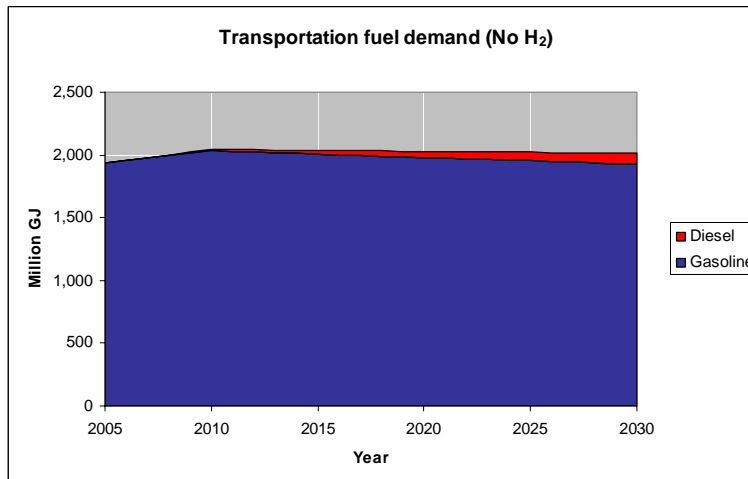
We base our transportation fuel scenarios on extrapolated demand projections for light duty vehicles from the CEC [3], which considers six scenarios based on three gasoline price cases, and including or excluding the greenhouse gas

emission limit now under consideration in California (the “Pavley Law,” AB1493). We adapt the “high” gasoline price case (their middle case), which assumes that gasoline costs \$2.25/gal (in 2005\$) in 2025, with the greenhouse gas emission limit.

Our resulting reference case (assuming no hydrogen penetration), is illustrated in Figure 3. We assume there is no demand for diesel fuel for light duty vehicles until 2008, after which demand increases as it supplies an increasing share of vehicle miles traveled (VMT). Fuel economy in the light duty vehicle fleet is presumed to increase from 20.5 mpg in 2005 to about 29 mpg in 2030 as a result of high gasoline prices and the greenhouse gas emissions limit. Consequently, gasoline demand declines from a peak of 2,030 GJ in 2010 (16.2 billion gallons) to 1,925 GJ by 2030 (15.4 billion gallons). Total light duty vehicle fuel demand is slightly less in 2030 than at its peak in 2010, at about 2,014 GJ (16.0 billion gallons), compared with 2,044 GJ at its peak (16.3 billion gallons).



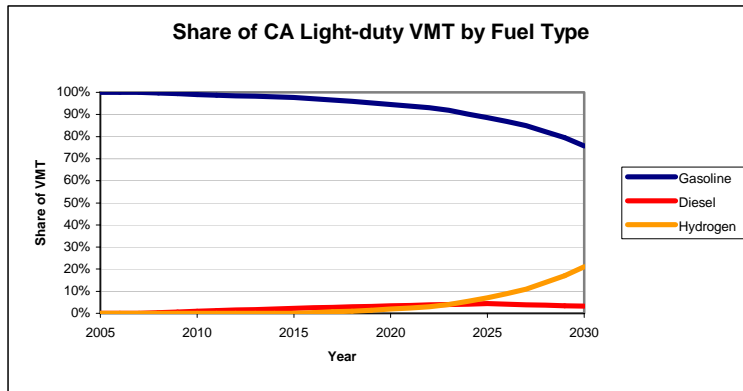
(a)



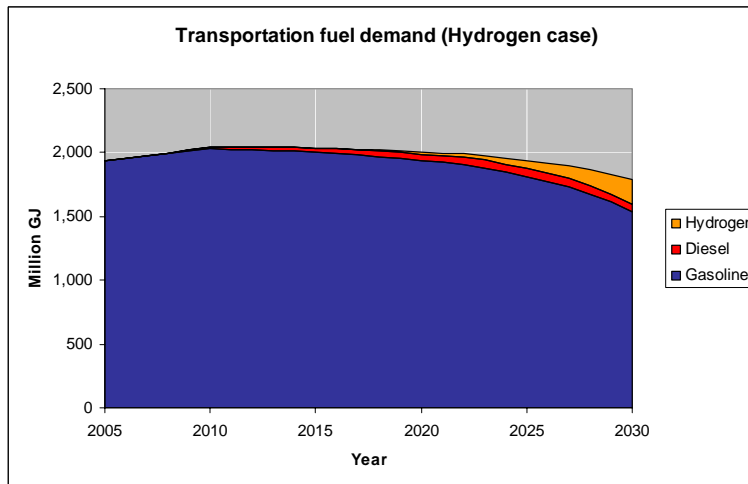
(b)

Figure 3. Projected transportation fuel demands in California through 2030 assuming no hydrogen penetration. (a) Vehicle miles traveled by fuel, and (b) annual fuel demands.

For scenarios including hydrogen penetration, we adapted the demands depicted in Figure 3 according to the hydrogen penetration scenario from the National Academies' *Hydrogen Economy* study [4]. Transportation fuel demands, including hydrogen, are illustrated in Figure 4. Based on the share of VMT met by hydrogen vehicles, we adjusted gasoline and diesel fuel demands from Figure 3 accordingly, and calculated hydrogen demand assuming a hydrogen vehicle fuel economy of 60 mpgge (miles per gallon gasoline equivalent). Comparing Figures 3b and 4b, we see that the penetration of efficient hydrogen vehicles reduces overall transportation fuel demand by 223 GJ by 2030, and reduces combined gasoline and diesel demands by 420 GJ.



(a)



(b)

Figure 4. Adapted transportation fuel demands in California through 2030 assuming hydrogen penetration according to the National Academies' hydrogen penetration scenario from *The Hydrogen Economy*. (a) Vehicle miles traveled by fuel type, and (b) annual fuel demands.

3.2. Energy supply scenarios

We consider a total of 10 supply scenarios (two electricity supply scenarios and five hydrogen supply scenarios) to compare the impacts of various hydrogen and

electricity production options on a statewide level. We describe these here, and delineate them with an abbreviation that is referenced in the preliminary results, below.

Electricity supply

- *Reference case (Ref)*. California's renewable portfolio standard (RPS) of 20% is met by 2017, and renewables maintain a 20% share of the growing electricity generation mix for the remainder of the study. Imports are fixed at 2000 levels, and all other capacity additions come from new natural gas combined-cycle plants.
- *High RPS (RPS)*. California's accelerated RPS targets are adopted, with 20% of generation coming from renewable sources by 2010 and 33% from renewables by 2020 and through the remainder of the study. Imports are fixed at 2000 levels, and all other capacity additions come from new natural gas combined-cycle plants.

Hydrogen supply

- *Reference case (no hydrogen by 2030)*. Hydrogen does not penetrate the market as a light duty vehicle fuel. There is no hydrogen demand over the duration of the study.
- *NAS Hydrogen Demand (21% of VMT supplied by hydrogen fuel cell vehicles by 2030)*. We assume that hydrogen penetrates the market at the rate shown in Figure 4. Four options for hydrogen supply are modeled:
 - *Steam methane reformation (SMR)*. All hydrogen is produced from natural gas, via steam methane reformation.
 - *Renewable electrolysis (Ren)*. All hydrogen is produced via electrolysis using electricity generated from renewable resources.
 - *Grid electrolysis (Grid)*. All hydrogen is produced via electrolysis using electricity generated in proportion to the grid mix.
 - *Coal co-production (Co)*. All hydrogen is produced at large, centralized coal-gasification hydrogen and electricity co-production plants. The assumed plant is based on a typical plant from [5,6], and converts 57.5% of the input coal energy to hydrogen and 4.2% to electricity, based on lower heating values. The plants do not sequester CO₂.

3.3. *Electricity generation modeling*

We integrated performance parameters associated with typical electricity generation technologies with the scenario assumptions to characterize possible future compositions of the electricity sector in California.

Existing electricity system

We modeled electricity generation in California (including imports to the state) based on the existing system. The future electricity system was modeled by adding capacity and dispatching generation according to our electricity supply scenarios. The existing system was modeled using data from the Environmental

Protection Agency’s (EPA) eGRID2002 database [7], which classifies power plants by capacity, electricity production, and plant type in each of the states in the year 2000. We categorized plants according to fuel and technology, and calculated aggregate capacity and generation as well as average efficiency and CO₂ emissions from the data for each category. For out-of-state generation, we assumed imports comprised 20% of California’s electricity supply in 2000 – consisting of 50% coal, 30% hydro, 10% natural gas, and 10% wind – and attributed average emission factors embedded in LEAP to each technology.

Table 1 lists the plant types included in our analysis, their total capacity and generation in 2000, and average efficiency and CO₂ emissions. Efficiencies were included, which allowed us to calculate fuel costs that were used in modeling dispatch (described below).

Table 1. Composition of the electricity grid in California in 2000, based on electricity generation plant type classifications included in the model.

Plant type	Capacity		Generation		Efficiency (%)	CO ₂ emissions (kg/MWh)
	(MW)	Share (%)	(GWh)	Share (%)		
NG CC	12,682	21.3	44,766	17.2	35.7	545
NG GT	5,240	8.8	26,671	10.2	36.8	523
NG ST	11,022	18.5	33,519	12.9	30.2	598
Nuclear	4,555	7.7	35,176	13.5	N/A	0
Hydro	9,381	15.8	36,971	14.2	N/A	0
Pumped hydro	3,792	6.4	2,190	0.8	N/A	0
Coal	398	0.7	2,862	1.1	34.5	833
Oil	526	0.9	1,839	0.7	26.5	3,909
Renewables	5,915	10.0	24,218	9.3	N/A	16
Solar	414	0.7	873	0.3		0
Wind	1,531	2.6	3,518	1.3		0
Geo.	2,492	4.2	12,308	4.7		0
Biomass	1,478	2.5	7,518	2.9		51
Imports	N/A	N/A	52,000	20.1	N/A	608
Coal			26,000	10.1		950
Hydro			15,600	6.0		0
NG			5,200	2.0		533
Wind			5,200	2.0		0

Capacity additions

We characterized the variable O&M cost of each plant type based on inputs used in the EIA’s 2005 Annual Energy Outlook [8]. We did not include future cost reductions based on learning, but those will be added to subsequent versions of our model. Fuel costs were determined by multiplying the average heat rate (fuel input per kilowatt-hour of electricity produced) for each plant type by the projected cost of the primary feedstock. The feedstock costs were an input to the model, based on EIA projections from the 2006 Annual Energy Outlook [9].

We modeled capacity additions by stipulating the addition size and build order for selected plant types. Based on these parameters, LEAP adds capacity when needed in order to maintain an adequate reserve margin (fixed at 15%). Since our

two electricity scenarios call solely for renewables and natural gas combined cycle capacity additions, we constrained the LEAP model to add only those plants, in increments of 400 MW and 500 MW, respectively. That is, when capacity fell below the level needed to maintain reserve margins, LEAP would add 400 MW of average renewable plants or 500 MW of average natural gas combined cycle plants, and repeat as necessary. Improving this portion of the model is a primary focus of future development. Ultimately, we will have the model select new plants based on levelized production costs or some other parameter of interest.

Electricity dispatch model

Given a set of plant type capacities in a particular year, we model dispatch to determine their actual generation (i.e., GWh produced). Table 2 describes the parameters we used in modeling dispatch for each of the plants.

LEAP calculates an electricity demand profile according to input peak demands and load profiles. It then allocates distribution according to a set of user-defined dispatch rules and plant availability. We dispatched generation as follows:

- Coal, hydro, and nuclear plants are assumed to be base-loaded and operate to full available capacity.
- Renewables are required to fill the RPS requirements for both scenarios, and pumped hydro plants are set to operate at their year 2000 share.
- Other fossil-based plants are dispatched in ascending order of running cost, defined as the sum of variable O&M costs and fuel costs.

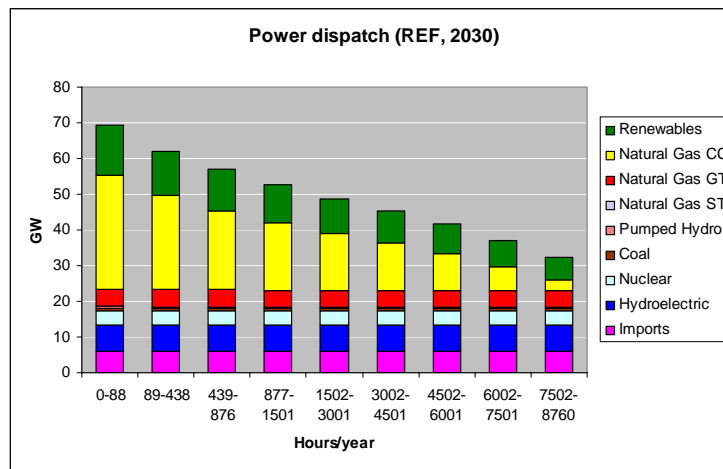
We note that operating costs are not relevant for plants that do not dispatch according to running cost (i.e. baseload plants, renewables and pumped hydro), and are not included in the table.

Table 2. Parameters used to model electricity plant dispatch.

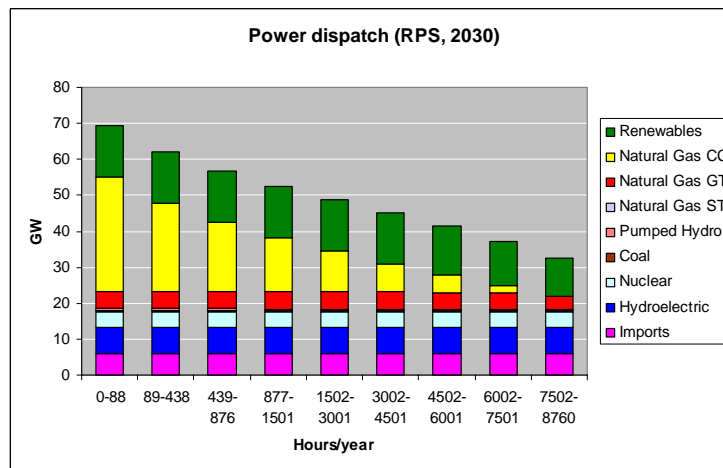
Plant type	Dispatch rule	Availability (%)	Variable cost (\$/MWh)	2030 fuel cost (\$/kWh)
NG CC	Running cost	90	0.26	0.055
NG GT	Running cost	90	0.45	0.053
NG ST	Running cost	90	0.45	0.065
Oil ICE	Running cost	90	0.45	0.123
Coal ST	Full capacity	90	N/A	N/A
Hydroelectric	Full capacity	80	N/A	N/A
Nuclear	Full capacity	90	N/A	N/A
Imports	Full capacity	100	N/A	N/A
Renewables	Process share	60	N/A	N/A
Pumped hydro	Process share	90	N/A	N/A

Based on the parameters described in Table 2, LEAP allocates shares of generation to each plant type over an average load curve derived from the input demand profiles. This is illustrated in Figure 5, which shows dispatch for the two

electricity supply scenarios in the year 2030. LEAP divides the load curve into nine segments depicting the number of hours per year that demand is at some average fraction of the peak. We see that the peak electricity demand in 2030 (assuming no electricity is required for fuels production) is about 70 GW, which represents the average of peak demands for the 88 hours of the year with the highest hourly demand. Also, it is apparent that natural gas combined cycle plants serve as the primary load following generation. This is a result of the added combined cycle capacity stipulated by the scenarios, as well as our dispatch rules. In addition to the base-loaded plants, natural gas-based gas turbine plants operate at essentially full capacity in each of the scenarios, with a few exceptions. Natural-gas based steam plants are essentially unutilized by 2030 due to the higher operating cost imposed by their lower efficiencies, and only provide a small fraction of generation during the peak hours for a few scenarios. Oil-fired turbines are the most expensive plants to run, and do not provide generation in any of the scenarios.



(a)

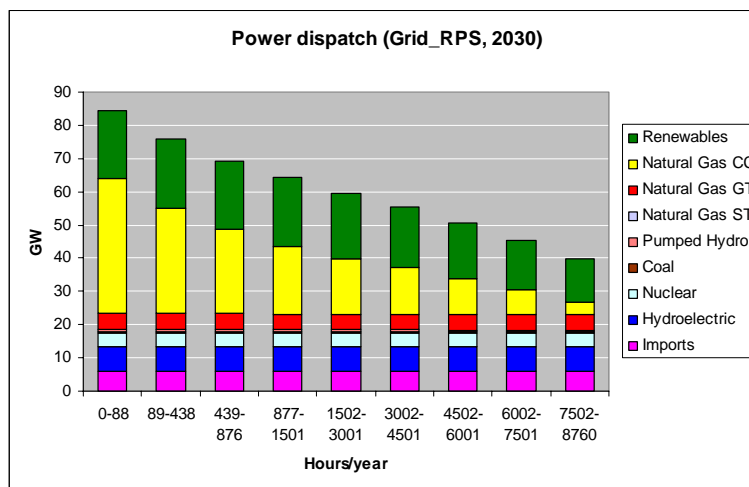


(b)

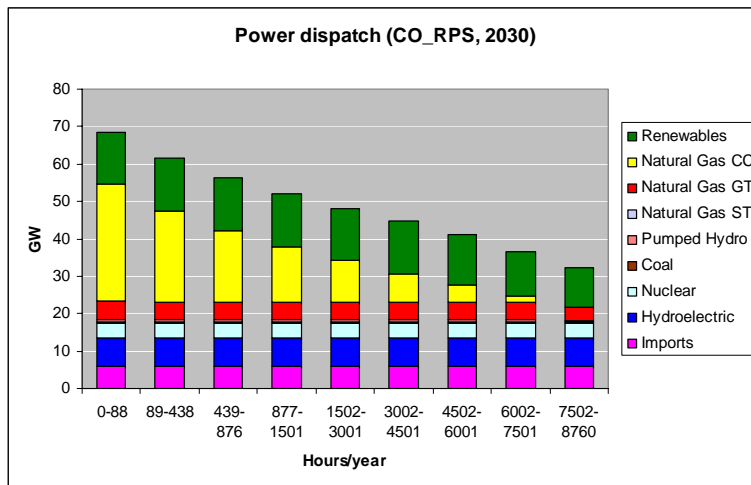
Figure 5. Electricity dispatch in 2030 for (a) reference electricity scenario (REF), and (b) high RPS electricity scenario (RPS).

Comparing the two figures, we notice the effects of the increased RPS standard. Figure 5b, which relates to the *Hi RPS* electricity scenario, has a higher share of generation supplied by renewables than the reference scenario depicted in Figure 5a, and consequently has a smaller share met by natural gas combined cycle plants. This is to be expected and is in line with our scenario descriptions, but the dispatch curves show that for about 15% of the year (hours 7502-8760) no natural gas combined cycle plants are operating at all in the *Hi RPS* electricity scenario (note that natural gas-based gas turbine plants are still operating, however).

If hydrogen production via grid electrolysis or co-production is included, the dispatch models change somewhat. Figure 6 shows dispatch for *Hi RPS* for the two fuel production scenarios in 2030 (note that in the renewable electrolysis cases – where renewable electricity generation for hydrogen production is assumed to be independent of the electricity grid – and the SMR cases, dispatch will be the same as for the reference electricity scenarios). In both cases, hydrogen production is assumed to be distributed evenly throughout the day, so the average demands are increased or decreased by the same proportion for each of the hourly segments. In the grid electrolysis case (Figure 6a), electricity demand increases by about 22% in each of the time segments, resulting in increased average demands of 15.1 GW during the peak period (0-88 hours) and 7.1 GW during the minimum demand period (7502-8760 hours). Including hydrogen production from co-production (Figure 6b) reduces average electricity demands by 1%, or by about 800 MW during peak demand periods and by about 300 MW during minimum demand periods. The increased generation in the grid electrolysis case results in more renewables and natural gas combined cycle capacity, and a greater share of generation from natural gas combined cycles (since generation from the base-loaded plants and the share from renewables are fixed). In the case of co-production, the reduced demand results in a small reduction (not visible on the graph) in the share of generation from natural gas combined cycles, and a slight increase in generation from natural gas-based gas turbines, compared to the *High RPS* reference electricity scenario.



(a)



(b)

Figure 6. Electricity dispatch in 2030 for (a) grid electrolysis based on the high RPS electricity scenario (*Grid_RPS*), and (b) co-production based on the high RPS electricity scenario (*Co_RPS*).

3.4. Transportation fuels supply modeling

Similar to the electricity sector, we integrate performance parameters associated with typical transportation fuels production technologies with the scenario assumptions to characterize fuels production in California. For gasoline and diesel production – which we do not focus on in this study – we only specified production efficiencies and greenhouse gas emissions. Hydrogen production was modeled in greater detail, described below.

An important note, and a limitation of this analysis, is that we do not include transport in the fuels supply pathways of this analysis. The “first-step” modeling we present here only considers hydrogen and electricity production. Future versions of the model will include the costs, emissions, and energy use associated with transporting fuels. For hydrogen transport, we will model compressed gas trucks, liquid trucks, and pipelines.

Hydrogen production modeling

We modeled hydrogen supply beginning with zero demand and meeting future demands with a single production technology as specified by the supply scenarios. Future versions of the model will allow several production technologies to supply hydrogen demands. Such scenarios will be modeled in a similar manner as the electricity system, including endogenous capacity additions according to levelized cost and potentially, hydrogen dispatch according to feedstock fuel and technology type. These elements are only included in a very limited capacity in this version of the model.

Similar to our modeling of the electricity sector, we defined typical plants for each of the hydrogen production scenarios. The co-production plant was modeled

based on [5,6], and parameters for the other plants came from the National Academies' *Hydrogen Economy* study [4].

The parameters characterizing the hydrogen production plants are summarized in Table 3. We classified one typical plant for each of the supply scenarios. SMR and grid electrolysis were based on midsized plants, and renewable electrolysis and co-production were based on distributed and centralized plants, respectively. It might be somewhat misleading to compare a system based on centralized production to one based on distributed production, but we felt that the sizes here were the most likely to exist for the technologies over the time frame of the study.

Table 3. Hydrogen production plant performance parameters.

Plant type	Efficiency (%)	Availability (%)	CO ₂ emissions (kg/kg H ₂)
SMR (midsized)	69	80	9.83
Grid electrolysis (midsized)	63.5	80	0
Renewable electrolysis (midsized)	63.5	80	0
Co-production (centralized)	57.5 (H ₂) 4.2 (e ⁻)	80	18.74

Capacity was added incrementally to meet annual demand increases, based on these typical plants.

4. Preliminary results

We present results obtained from our input assumptions for the 10 hydrogen and electricity supply scenarios described above. These results are preliminary, but also indicative of the type of results we will obtain through future, more detailed modeling.

4.1. Resource requirements

Natural gas and renewables requirements necessary to meet electricity, natural gas, and transportation fuels demands are depicted in Figures 7 and 8, respectively, for each scenario. Solid lines correspond to the *Reference* electricity scenario and dashed lines represent the *Hi RPS* electricity scenario. The colors correspond to the transportation pathways (the reference electricity cases, in orange, represent the non-hydrogen transportation fuel cases). We note that these scenarios were run without placing constraints on supplies of the feedstocks. Scenarios requiring dramatic increases in consumption of a particular feedstock might not be feasible, but the results bound a set of possible outcomes.

We see that the scenarios based on the *Reference* electricity case result in higher natural gas consumption, as combined cycle natural gas plants comprise a greater portion of generation. Hydrogen production via grid electrolysis or SMR both increase natural gas requirements compared to the base case. Grid electrolysis for the *Reference* electricity case (*Grid_Ref*) results in the highest natural gas requirement – even higher than hydrogen production from SMR – due to the high

fraction of electricity generation met by natural gas plants and the assumed efficiencies of the production technologies. The discrepancy between the two hydrogen supply scenarios is smaller for the *Hi RPS* electricity cases, where natural gas-fired generation constitutes a smaller portion of electricity generation. The effects of hydrogen and electricity co-production become barely noticeable by 2030, as hydrogen begins to penetrate the market at rates sufficient to see electricity generation from coal-based co-production facilities begin to offset some electricity generation from natural gas. Finally, renewable electrolysis results in no extra natural gas demand as compared to the reference scenarios.

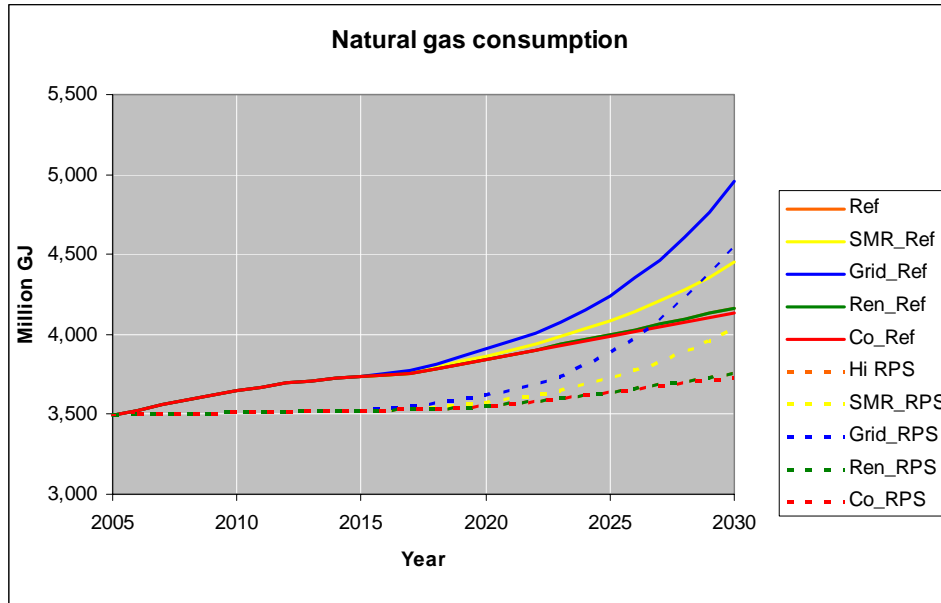


Figure 7. Preliminary modeling results: Natural gas requirements for each scenario.

Renewables consumption is illustrated in Figure 8. Except for *Ren_RPS*, scenarios based on *Hi RPS* electricity see about a one-third increase in renewables consumption by 2030 as compared to the *Reference* electricity case. Hydrogen production from renewable electrolysis doubles renewables consumption by 2030 in the *Reference* electricity case, and increases renewables requirements by about 75% in the *Hi RPS* case. Grid electrolysis also increases renewables consumption, as the increased electricity demand requires more electricity generation from renewables to maintain the RPS share. SMR has a negligible effect on renewables consumption, and co-production decreases renewables consumption slightly by 2030, as co-product electricity displaces some generation from the grid.

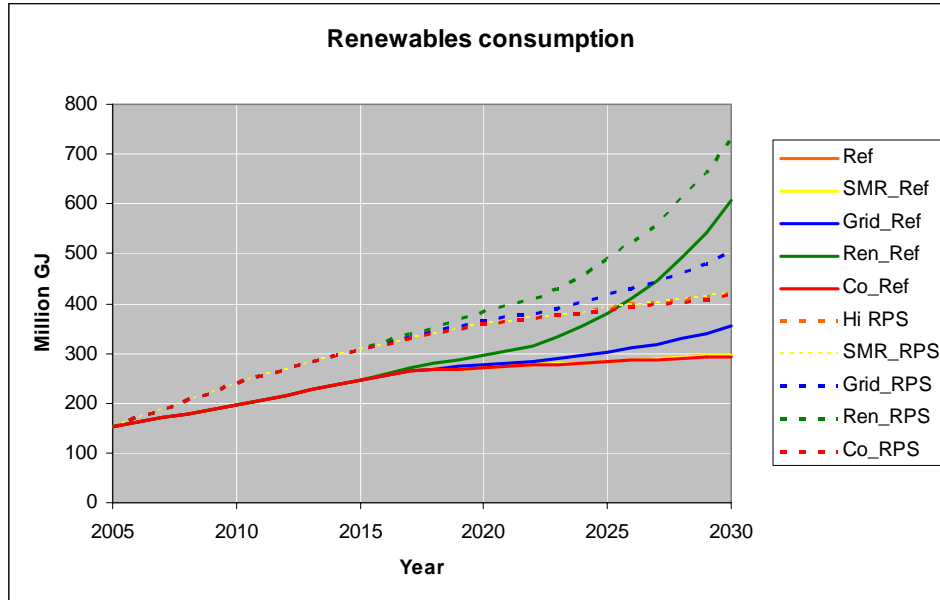


Figure 8. Preliminary modeling results: Renewables requirements for each scenario.

4.2. Greenhouse gas emissions

Greenhouse gas emissions are depicted for each scenario in Figure 9. We see that hydrogen production relying on grid electricity might actually increase emissions compared to the reference cases (i.e., no hydrogen penetration). Hydrogen production from renewables leads to the lowest emissions, but they remain above current levels throughout the duration of the study. Emissions begin to decline in 2027 in the *Ren_RPS* case, and in 2028 in the *Ren_Ref* case.

Production of hydrogen from fossil fuels leads to a decrease in emissions in each case. Emissions reductions from the *SMR* cases are noticeable, and emissions actually begin to decline in 2030. Interestingly, we also notice that co-production of hydrogen and electricity from coal results in slight emissions reductions compared with the reference cases. In future versions of the model we will include carbon sequestration, which would reduce emissions from coal- and natural gas-based plants even further.

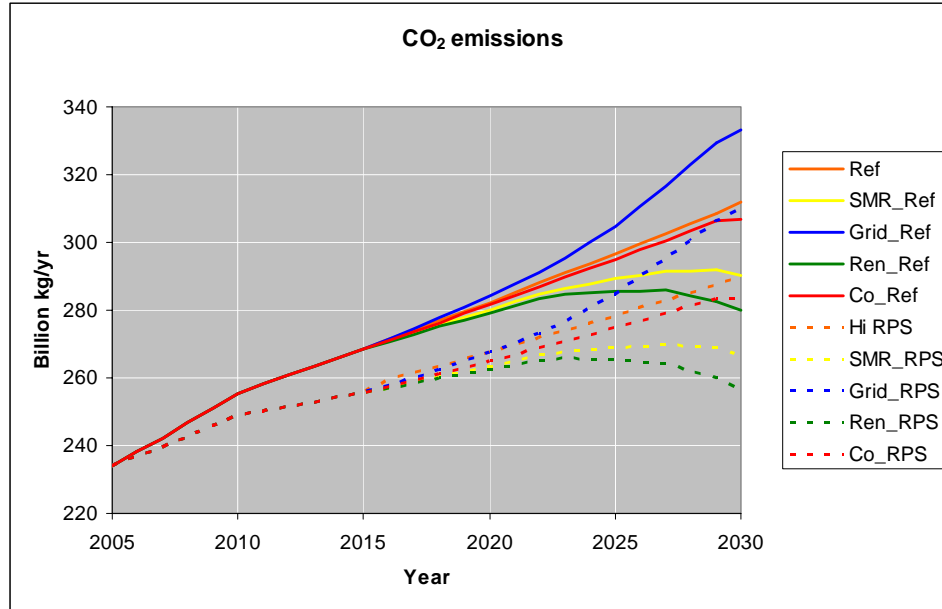


Figure 9. Preliminary modeling results: Carbon dioxide emissions for each scenario.

5. Future directions

The preliminary results we presented are only indicative of our intended findings after conducting more rigorous analyses. Here we describe expected improvements to future versions of the model.

- Improve modeling of fuels transport. Include costs and emissions of diesel, gasoline, and hydrogen transmission and distribution. We will include gas trucks, liquid trucks, and pipelines for hydrogen transport.
- The model currently relies on demand projections from the CEC, EIA, and National Academies [1,3,9,10], and hydrogen and electricity production technology costs and performance parameters from various sources in the literature [8,11]. As the project progresses, we will incorporate more consistent data founded on geographic- and time-dependent parameters, including:
 - Regional feedstock availability, demand profiles, and electricity grid mixes
 - California-specific fuel costs, and price elasticities
 - Performance and cost parameters regarding hydrogen supply pathways will come from a set of engineering economic models developed by H2A and at UC Davis [12-15].
 - We will model co-production plants to develop performance and cost parameters for optimal systems based on plant size, H₂/electricity ratio, conversion efficiency, and other relevant parameters.
- Consider additional supply scenarios that include all production technologies and consider supply profiles for hydrogen (e.g., off peak

production of hydrogen via electrolysis), carbon sequestration, and interaction between electricity and hydrogen supply

- Model the availability, composition, and evolution of imported and renewable electricity supplies in greater detail
- Improve the modeling of capacity additions and dispatch for both hydrogen production and electricity generation to include economics (e.g., projected leveled production costs, learning, payback periods), greenhouse gas emissions limits, and plant retirement
- Include economics as an output, specifically leveled hydrogen production and electricity generation costs
- Include a constraint on resources and allocate feedstocks and technologies according to integrated hydrogen and electricity supply scenarios based on costs and emissions
- Extend the time frame of the model to 2050

6. Acknowledgements

We would like to thank the California Energy Commission and the Hydrogen Pathways Program at UC Davis and its sponsors for financial support.

7. References

1. CEC (2005) California energy demand 2006-2016: Staff energy demand forecast (revised September 2005). California Energy Commission, CEC-400-2005-034-SF-ED2, September. <http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF>
2. EIA (2004) The Electricity Market Module of the National Energy Modeling System - Model Documentation Report. Washington, DC, Energy Information Administration.
3. CEC (2005) Forecasts of California transportation energy demand 2005-2025. California Energy Commission, CEC-600-2005-008, April. <http://www.energy.ca.gov/2005publications/CEC-600-2005-008/CEC-600-2005-008.PDF>
4. National Research Council (2004) The hydrogen economy: Opportunities, costs, barriers, and R&D needs. The National Academies Press, Washington, DC. www.nap.edu
5. Chiesa, P., Consonni, S., Kreutz, T., and R. Williams (2005) Co-production of hydrogen, electricity and CO₂ from coal with commercially ready technology. Part A: Performance and emissions. *International Journal of Hydrogen Energy*, **30**(7): 747-767.
6. Kreutz, T., Williams, R., Consonni, S., and P. Chiesa (2005) Co-production of hydrogen, electricity, and CO₂ from coal with commercially ready technology. Part B: Economic analysis. *International Journal of Hydrogen Energy*, **30**(7): 747-767.
7. EPA (2003) Emissions and generation resource integrated database (eGRID2002). U.S. Environmental Protection Agency. <http://www.epa.gov/cleanenergy/egrid/index.htm>
8. EIA (2005) Assumptions to the annual energy outlook 2005. Energy Information Administration, Washington, DC.
9. EIA (2006) Annual energy outlook 2006 with projections to 2030. Energy Information Administration, DOE/EIA-0383(2006), Washington, DC, February.
10. CEC (2005) 2005 Integrated energy policy report. California Energy Commission, CEC-100-2005-007-CMF, November. <http://www.eia.doe.gov/oiaf/aeo/index.html>
11. Consonni, S., and F. Vigano (2005) Decarbonized hydrogen and electricity from natural gas. *International Journal of Hydrogen Energy*, **30**(7): 701-718.
12. Johnson, N., Yang, C., Ni, J., Johnston, J., Lin, Z., and J. Ogden (2005) Optimal design of a fossil fuel-based hydrogen infrastructure with carbon capture and sequestration: Case study in Ohio. *Partnering for the Global Hydrogen Future, NHA Conference*, Washington, DC,

- April. Publication No. UCD-ITS-RP-05-07.
<http://hydrogen.its.ucdavis.edu/workshops/nha2005/nha2005papers/johnsonnha>
13. Ni, J., Johnson, N., Ogden, J., Yang, C., and J. Johnston (2005) Estimating hydrogen demand distribution using geographic information systems (GIS). *Partnering for the Global Hydrogen Future, NHA Conference*, Washington, DC, April. Publication No. UCD-ITS-RP-05-10. <http://hydrogen.its.ucdavis.edu/workshops/nha2005/nha2005papers/Ninha>
 14. Yang, C. and J. Ogden (2005) Analyzing natural gas based hydrogen infrastructure – optimizing transitions from distributed to centralized H₂ production. *Partnering for the Global Hydrogen Future, NHA Conference*, Washington, DC, April.
<http://hydrogen.its.ucdavis.edu/workshops/nha2005/nha2005papers/Yangnha>
 15. Ogden, J., Yang, C., Johnson, N., Ni, J., and Z. Lin (2005) Technical and economic assessment of transition strategies toward widespread use of hydrogen as an energy carrier. *Hydrogen Pathways Report to the United States Department of Energy*, UCD-ITS-RR-05-06, January. <http://its.ucdavis.edu/publications/2005/UCD-ITS-RR-05-06.pdf>

8. Author Biographies

Ryan W. McCarthy

Ryan is a PhD student in Civil and Environmental Engineering at the University of California, Davis. His research interests revolve around the integration of hydrogen supply systems with other energy sectors, and the associated impacts on economics, the environment, reliability, and resource use. His current work focuses on co-production of hydrogen and electricity, and interactions between the hydrogen, natural gas, and electricity sectors in California. Ryan served as technical lead for UC Davis' Team Eno in NHA's 2004 Hydrogen Student Design Competition, and participated on the Societal Benefits topic team for the California Hydrogen Highway Network. He received a Master's degree in Civil Engineering at UC Davis, and holds a B.S. in Structural Engineering from the University of California, San Diego.

Dr. Christopher Yang

Christopher Yang is a Research Engineer at the Institute of Transportation Studies at the University of California, Davis and co-director for the "Infrastructure Modeling" Track within the Hydrogen Pathways program. His primary research focus is on modeling of hydrogen production and distribution infrastructure in order to understand how a hydrogen economy might evolve over time. Other research interests include interactions between fuel and electricity production in a hydrogen economy.

Dr. Joan M. Ogden

Dr. Joan Ogden is Associate Professor of Environmental Science and Policy at the University of California, Davis and Co-Director of the Hydrogen Pathway Program at the campus's Institute of Transportation Studies. Her primary research interest is technical and economic assessment of new energy technologies, especially in the areas of alternative fuels, fuel cells, renewable energy and energy conservation. Her recent work centers on the use of hydrogen as an energy carrier, hydrogen infrastructure strategies, and applications of fuel cell technology in transportation and stationary power production. She participated in the U.S. DOE Hydrogen Vision process in 2001, and headed the

systems integration team for the National Hydrogen Roadmap in 2002. She is active in the H2A, a group of hydrogen analysts convened by the Department of Energy to develop a consistent framework for analyzing hydrogen systems, and serves on the Blueprint Plan advisory panel for the California Hydrogen Highway Network.