Integration of flexible grid-based electrolysis hydrogen production for vehicles reduces costs and greenhouse gas emissions

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Highlights

- Hydrogen (H_2) demand from fuel cell vehicles is simulated in 2030 in the western US
- Electrolysis-based H_2 production is simulated using the PLEXOS electricity model
- Added capacity yields flexible H_2 generation, reducing costs and greenhouse gases

Keywords

hydrogen fuel cell vehicle; electricity sector; optimization; hydrogen electrolysis; transportation; greenhouse gas

Abstract

Hydrogen fuel cell electric vehicles (FCEVs) are proposed as an option for lowering greenhouse gas (GHG) emissions from the transportation sector, with the added advantages of high specific energy density and rapid refueling, two important challenges that battery electric vehicles have not yet fully overcome. As FCEV market share expands, potentially low-GHG hydrogen production methods such as water electrolysis will become more important, despite being currently more expensive than steam methane reforming. Moreover, oversizing electrolysis capacity could result in increased grid flexibility and lower generation costs. In this paper, we simulate temporal FCEV hydrogen refueling demand met by electrolysis for the U.S. Western Interconnect (WI) electricity grid by estimating time-resolved hydrogen consumption for light, medium- and heavy-duty vehicles. By varying the electrolyzer capacity factor to treat hydrogen production as a flexible load, the resulting time-varying hydrogen generation, average electricity cost, renewables curtailment and GHG emissions are compared. Our results indicate that increasing hydrogen production flexibility lowers generation cost and GHG emissions, but there is a tradeoff between lowering operational cost and increasing electrolyzer capital cost, yielding a minimum total system cost at 80% capacity factor when the future electrolyzer cost reaches $300/kW.

1. Introduction

Transportation is a major global consumer of energy (28%) and source of greenhouse gas (GHG) emissions (24%), growing to as much as 10.3 $GtCO_2$/yr. globally in 2040 assuming minimal shifting away from petroleum-based fuels [1]. There were approximately 1.2 billion vehicles on the world’s roads in 2014, with 95% of those being light-duty passenger vehicles; by 2035, this number may increase to 2 billion, and reach 2.5 billion by 2050 [2].

According to many, the transportation sector will be among the most difficult to decarbonize, due to a combination of urban infrastructure built around vehicle dependency, rapid adoption of vehicles in the developing world, mature and inexpensive combustion-based engine technologies, low fuel costs, and great reliance on petroleum-derived fuels for many non-highway modes like aviation and marine transport [3][4][5][6]. One way to decarbonize the sector is through electric vehicles (EVs), whose sales have grown rapidly since 2010, stimulated in part by falling battery costs and strong government policies in several countries. EVs recently surpassed 5 million cumulative sales at the end of 2018, up 62% from the previous year [7]. Most projections of future transportation vehicles assume accelerating growth of battery and plug-in hybrid EVs, with optimistic forecasts indicating >250 million EVs by 2030 and >550 million by 2040 [7][8].

However, hydrogen can also play an important role in our future transportation system [9][10] . Currently, three light-duty hydrogen fuel cell electric vehicles (FCEVs) are commercially available in some parts of the U.S. [11]: the Toyota Mirai [12], Hyundai Nexo [13] and Honda Clarity [14]. Outside the U.S., China is starting to embrace a hydrogen future, with a vision of 1 million FCEVs on the road by 2029 [15]. The country is home to many established companies as well as new startups pursuing hydrogen, and its government is investing tens of millions of U.S. dollars in R&D and purchase subsidies [16]. Smaller vehicles, such as motorcycles and scooters, are also being developed for global markets by companies such as Intelligent Energy [17], Suzuki [18][19], Honda in collaboration with Nissan and Toyota, as well as Volkswagen, Hyundai and General Motors [20].

Meanwhile, heavy-duty FCEVs are being developed around the world. FCEV buses are being evaluated in many locations in the U.S. [21]; the California Fuel Cell Partnership maintains a growing map of FCEV bus activities globally [22]. Hyundai, Kenworth, Nikola, Toyota, TransPower, UPS and US Hybrid are also developing FCEV trucks [23][24][25][26][27]. In 2017, China Railway Rolling Corporation Tangshan Co. began demonstrating the world's first FCEV tramcar in Tangshan, China; the company also plans to introduce the technology in Quanzhou, Taizhou and Tianjin, China, as well as Toronto [28]. In Germany, Alstom has introduced the Coradia iLint, a first-of-its-kind FCEV train that was placed into service in 2018 and has since expanded to six German states. Starting in 2021, the Landesnahverkehrsgesellschaft Niedersachsen (LNVG) will begin transporting regular passengers on 14 such trains in Saxony, Germany [29]. In the U.K., the HydroFLEX train began tests in June 2019 [30]. There is also interest in hydrogen-powered ships [31] and airplanes [32].

The production of hydrogen without substantial GHG emissions will be key to lowering emissions from the transportation sector. Pavlos and Andreas provide a comprehensive review of typical hydrogen production processes [33]. Hydrogen can be generated from many existing energy sources, but most hydrogen produced today is made from steam reforming of methane from natural gas, which is inexpensive and 85% efficient, but emits CO_2 (and can leak methane, a potent GHG). While some hydrogen could be made from biomass [34], fossil resources with CO_2 capture and sequestration [35], or even resources that remain in the ground along with produced CO_2 [36], water electrolysis using grid electricity with a high fraction of renewable sources is a scalable, flexible, and distributed approach with low GHG emissions.

About 4% of global hydrogen is produced by electrolysis today [37]. Previous literature has examined the cost of various electrolysis technologies, including proton exchange membrane, alkaline and solid oxide [38][39][40][41]. Ursua et al. projects that water electrolysis will be deployed in the future because both hydrogen and electricity can be produced flexibly and transported long distances [42]. Also, hydrogen production can be coordinated with the needs of the electricity grid. At high levels of renewable electricity, the GHG emissions associated with hydrogen production can become quite low. Moreover, the ability to generate hydrogen flexibly using water electrolysis can help maintain grid stability and reduce average operational costs. While dispensed hydrogen costs between $12 and $16 per kg today [43], many expect that hydrogen retail prices could drop significantly with greater station utilization [44][45][46]. In the current study, the average hydrogen production cost from electrolysis is assumed to be reduced to $2-4/kg, consistent with U.S. Department of Energy targets [45].

Renewable electricity capacity continues to increase rapidly in many parts of the world, with about 100 GW of solar PV, 50 GW of wind, and 30 GW of other renewable generation (excluding large hydropower) installed in 2018, bringing the total global renewable electricity capacity to 2,400 GW [47]. As renewables become a greater contributor to electricity grids they will create operational challenges, such as balancing instantaneous power demand with fluctuating and intermittent power output from an increasing share of generators [48]. While flexible grid resources that address these issues exist today, they are mostly fossil-based, such as ramping natural gas or coal plants [48]. To minimize electricity-sector GHG emissions, a combination of more widespread load flexibility, dedicated energy storage, and low-GHG generation technologies capable of output flexibility (including hydro, biomass, geothermal and concentrating solar power) must be developed. Grid-connected EVs have been identified as a growing flexible load resource that could play an increasingly important role in renewables integration [49], but hydrogen generation via electrolysis can also act as an energy storage buffer to help match electricity supply to demand [50].

In this study, we simulate hydrogen production via electrolysis in the western U.S. supporting 5.3 million FCEVs. These forecasts, while aggressive for 2030, are consistent with the industry's long-term forecasts of 20% FCEV penetrations for cars and trucks [51]. For example, the IEA has developed FCEV scenarios assuming 12-25% of passenger light duty vehicle stock and 5-10% of freight vehicle stock (light commercial, medium-duty and heavy-duty trucks) are hydrogen-powered by 2050 [52]. Our purpose is to investigate the time-dependent influence (and cost in particular) of hydrogen refueling on grid operations under different assumptions of electrolysis flexibility, using a large-scale power system model. This study, while limited to one specific year and region, can be readily generalized to other electric grids and FCEV penetration levels, providing potentially useful results applicable to many parts of the world.

2. Methodology

The model structure we employ can be divided into three components. The first component estimates time-resolved energy consumption of FCEVs by class (light-duty, medium-duty, etc.). Energy consumption is then converted to hydrogen dispensing profiles according to refueling behavior assumptions specific to each vehicle class. Next, hydrogen refueling demand is aggregated geographically, and optimal locations of hydrogen dispensing stations are determined. Finally, the electrolysis load for hydrogen production is added to overall electricity demand, and we simulate electricity grid output by generator (including renewables curtailment) to obtain electricity production operational costs. Finally, we include estimates of hydrogen electrolysis capital costs to arrive at an overall cost of producing hydrogen via grid electrolysis under various flexibility assumptions. This approach is presented graphically in Figure 1.

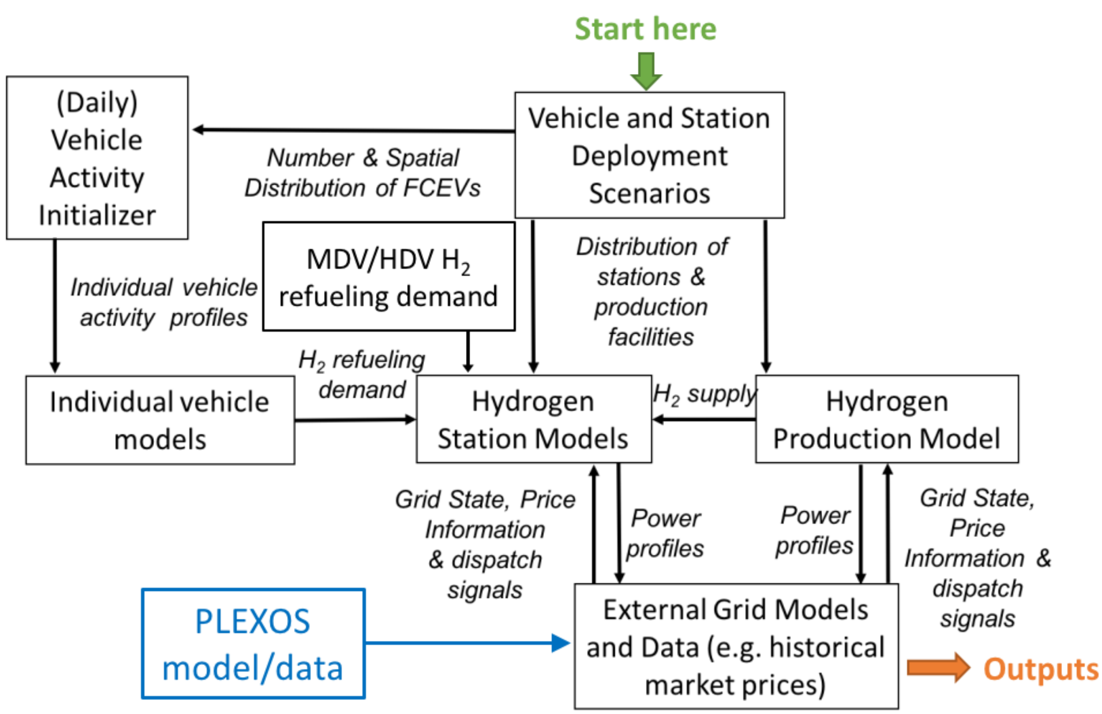

Figure 1. The overall methodology structure for this work

The hydrogen production model plays a central role in the analysis. The first step is to calculate the hydrogen refueling profiles for stations, which is calculated from vehicle number forecasts, geographical vehicle distributions, vehicle energy consumption, and hydrogen refueling estimates. After obtaining the hydrogen refueling demand time profile, the electricity load for hydrogen generation is added to the existing load on the electricity grid. We chose the PLEXOS production cost model to simulate electricity generation in 2030 to meet this total load. Based on the simulation results, the total generation cost and CO_2 emissions were calculated, which places the flexible hydrogen production process into an integrated power system context.

2.1 Modeled vehicles

The goal of this research is to investigate the influence of hydrogen production on the electricity grid with significant numbers (~millions) of FCEVs. As a reference scenario, the 2030 Low Carbon Grid Study (LCGS), which was developed by the National Renewable Energy Laboratory (NREL), is selected as a base case without FCEVs [53]. We then developed different vehicle and hydrogen generation scenarios when calculating the hydrogen consumption and production models. As shown in Table 1, the vehicle classes cover a large range of gross vehicle weights, ranging from light-duty vehicles (≤3,853 kg) to Class 8 heavy-duty trucks and buses (>11,786 kg).

Table 1. Vehicle class definitions and projected number of FCEVs in 2030 for California

Vehicle class	Abbre-viation	Definition	Gross vehicle weight (GVW)	Projected number of FCEVs
Light-duty vehicle	LDV	Passenger cars and light trucks (class 2a)	≤3,853 kg (≤ 8,500 lbs.)	5.0 million (18%)*
Medium-duty vehicles	MDV	All class 2b-6 vehicles	3,854-11,786 kg (8,501-26,000 lbs.)	274,000 (23%)*
Heavy-duty vehicles	HDV	All class 7 and 8 vehicles except buses	>11,786 kg (>26,000 lbs.)	33,500 (9%)*
Buses	BUS	Urban, school and other buses		19,400 (26%)*

* The fraction of vehicle stock in 2030 for California

We chose four vehicle types to represent the hydrogen demand of the 2030 transportation system in California: light-duty vehicles (LDVs), medium-duty vehicles (MDVs), heavy-duty vehicles (HDVs), and buses (BUS, which are separated from other HDVs as a standalone category). We defined each vehicle type using definitions provided by the U.S. Environmental Protection Agency [54]. The total number of FCEVs of each vehicle type is shown in the rightmost column of Table 1. Numbers are synthesized from a variety of 2030 projections that include both FCEVs and EVs (collectively, zero-emission vehicles or ZEVs) and are consistent with the industry's long-term forecasts of 20% hydrogen vehicle penetrations for cars and trucks [46][55]. Given the uncertainty in the future choice of low-GHG vehicle technologies, an assumption based on total ZEVs seemed appropriate when constructing an optimistic future scenario for FCEVs.

2.2 Estimating hydrogen refilling demand

2.2.1 Light-duty vehicles

For LDVs, we represent all vehicles with the Toyota Mirai, as it currently has the largest stock share of FCEVs in the world [56]. The Mirai, which has a 5-kg hydrogen tank, can drive 502 km on a full hydrogen tank [57]. We employ a detailed vehicle physics model called V2G-Sim to simulate the energy consumption of each vehicle [58], based on a set of empirical parameters calibrated specifically to the Mirai, along with instantaneous speed to estimate second-by-second energy consumption. Trip data are provided from the National Household Travel Survey (NHTS) for California. Based on the average speed of each trip (see Figure S1 in the Supplementary Materials), one of three reference driving cycles developed by the U.S. Environmental Protection Agency (UDDS, US06, HWFET) [59] is chosen to represent the selected trip, and this cycle is applied repeatedly as needed to generate a vehicle speed vs. time profile throughout each trip. As a result, a time-dependent hydrogen consumption array is estimated for each vehicle [58].

We use a probabilistic approach to determine when hydrogen refilling takes place. Based on real-world data of FCEV refilling behavior [60], a continuous refilling profile is calculated (see Figure S2 in the Supplementary Materials). There is a probability that refueling will occur when the tank level is lower than 100% and that probability grows as the hydrogen remaining in the tank (known as the state of energy or SOE) decreases. We assume that an FCEV is fully refueled when stopping at a hydrogen refueling station. The hydrogen refilling demand (shown in Figures S3 and S4 in the Supplementary Materials) is obtained by launching V2G-Sim and merging the refilling profiles generated through the above approach.

2.2.2 Medium- and heavy-duty vehicles

For other vehicle classes, we used data from the California EMissions FACtor (EMFAC) model to obtain gasoline or diesel energy consumption per hour for one representative subclass each of MDV, HDV and BUS [61]. We then applied a conversion factor based on the difference in efficiency between hydrogen fuel cells and diesel engines to estimate the expected energy consumption per kg of hydrogen [62][63]. The EMFAC tool can simulate the fuel consumption for all vehicle classes [64]. All medium- and heavy-duty vehicles shown in Table 1 are chosen to calculate the hourly fuel consumption rate across the entire state. The fuel consumption was converted to the equivalent hydrogen consumption using the energy content of each fuel and an efficiency ratio of ~1.5 between hydrogen fuel cells and diesel engines [65].

To generate fuel consumption temporal profiles of individual vehicles, we opted for a stochastic sampling of the hourly aggregate fuel consumption data provided by EMFAC, following a probability curve for refueling similar to that of LDVs (see Figure S5 in the Supplementary Materials).

2.3 Geographic distribution of vehicles and filling stations

The Scenario Evaluation and Regionalization Analysis (SERA) model [66][67]outputs the FCEV numbers and locations of hydrogen filling stations. Based on the EMFAC result, the actual hydrogen refuel profile for the California region is scaled accordingly, which forms the input into PLEXOS for the economic analysis [68]. Combining the hydrogen refueling profiles for each FCEV class, the aggregated hydrogen refuel profile is calculated.

2.4 Importing hydrogen refueling profiles into PLEXOS

In order to implement the hydrogen electrolyzer operation in PLEXOS, an object was chosen that satisfied two basic requirements: 1) It allowed for flexible production of hydrogen (as long as the station had enough hydrogen to supply FCEV demand, the electrolysis load could be shifted around), and 2) it was able to enforce a hydrogen storage limitation. We therefore chose the pumped-storage hydroelectric (PSH) power station object to model hydrogen production and storage devices, which satisfied these requirements (with stored “water” representing hydrogen). After adding hydrogen production and storage units using PSH objects in the LCGS PLEXOS model, the system can simulate and optimize when to produce hydrogen. The objective function is to minimize the total system cost to satisfy the electricity demand and other grid constraints for one year.

The following scenarios were defined in order to investigate the influence of the flexible load on the grid operations:

- Business-as-usual (BAU). A reference scenario representing the Western Interconnect (WI) area electricity grid without any FCEVs included.
- Inflexible scenario. This scenario represents the integrated grid after adding the FCEV load to the BAU scenario. In this scenario, the hydrogen generating rate is fixed, e.g., the capacity factor (CF) = 100%, and the electrolyzer is constantly operated at the maximum rated power to meet the FCEV hydrogen demand throughout the year. This is an idealized case, as it offers no flexibility in electrolyzer operation, and there is no extra capacity to generate more hydrogen if demand increases. While an unlimited amount of hydrogen storage is initially assumed in the model, this is subsequently reduced to the maximum level needed annually for cost estimation purposes (see section 3.3).
- Flexible scenarios. As in the Inflexible scenario, the Flexible scenarios represent an integrated grid after adding FCEV load to the BAU scenario, but the hydrogen generation rate is variable. In other words, the electrolyzer is oversized for the hydrogen demand, allowing for variable operation. Hence, the electrolyzer can work across a wider range of hydrogen generation output rates than in the Inflexible scenario. This is more realistic because the electrolyzer should be configured to have extra capacity to generate hydrogen at times when it is favorable for the system to produce more hydrogen, or to meet increases in future demand. We explore a range of flexible scenarios in 10% decrements from CF = 90% to 50%.

Based on estimates from the literature [69], 1 kg of hydrogen requires between 48 and 67.5 kWh of electricity to produce it via electrolysis. We assumed a value of 54.3 kWh/kg in our model. With an annual hydrogen demand of 981 million kg for all vehicles, the electricity demand to generate the hydrogen was 49.1 TWh, for an average power level of 5.6 GW, which represents the minimum power size of the electrolyzer (P_{min}).

P_{flex} represent the maximum power capacity of the electrolyzer. In the Inflexible scenario, CF = 100%, which means $P_{flex}$is equal to P_{min}. In the CF = 50% scenario, $P_{flex}$is twice as large as P_{min}; thus ${P_{flex}}_{50} = 11.2$ GW. The electrolyzer in this scenario has much more flexible capacity with which to generate the hydrogen. For example, the electrolyzer can generate more hydrogen when the overall electricity load or the average electricity cost per unit is low, and reduce its hydrogen output during high load or high price periods. In general, the larger the electrolyzer is sized, the more flexibility is enabled in hydrogen generation to reduce the system cost, but at a certain point, the cost savings is not enough to cover the cost of the larger electrolyzer. Thus, there is an optimum point of flexibility that minimizes total system cost. In the following section, the key output parameters will be shown to analyze the economic opportunities across different scenarios.

2.5 Electrolyzer and hydrogen storage cost estimation

The output of the PLEXOS simulations provides the operation cost of hydrogen production. However, to estimate the total system cost, the capital costs of electrolyzers and hydrogen storage tanks were included. According to [70], the capital cost of a tank is around \$26/kWh, and the 2020 target electrolyzer capital cost is around \$300/kW [45]. We assume the lifetime of these components are 20 years, and the yearly discount rate is 10%, in order to convert these capital costs into annualized costs.

3. Results

Figure 2 shows a one-week snapshot (January 8-14, 2030) of hourly hydrogen production for two electrolyzer capacities (CF = 50% and 100%), as well as the hydrogen consumption (withdrawal) rate, which is assumed to be the same for both cases, and the net storage levels, which are the accumulated differences between hydrogen production and withdrawal rates in each hour. All values are expressed in equivalent GW (production and consumption) or GWh (storage). We see in the CF = 100% case, hydrogen production is by necessity constant, whereas for the CF = 50% it is quite variable, often swinging between zero and maximum output multiple times per day. With hydrogen demand highest during daytime hours, and lowest at night, in both cases there is a depletion of hydrogen storage through the evening hours, reaching a minimum close to midnight. Hydrogen storage is then built up again in early morning hours. However, in the CF = 100% case, constant production leads to a single peak storage level each day (around 6 am), whereas in the CF = 50% case, variable production leads to two daily storage peaks (at around 5 am and 2 pm) and an overall larger daily range in storage level.

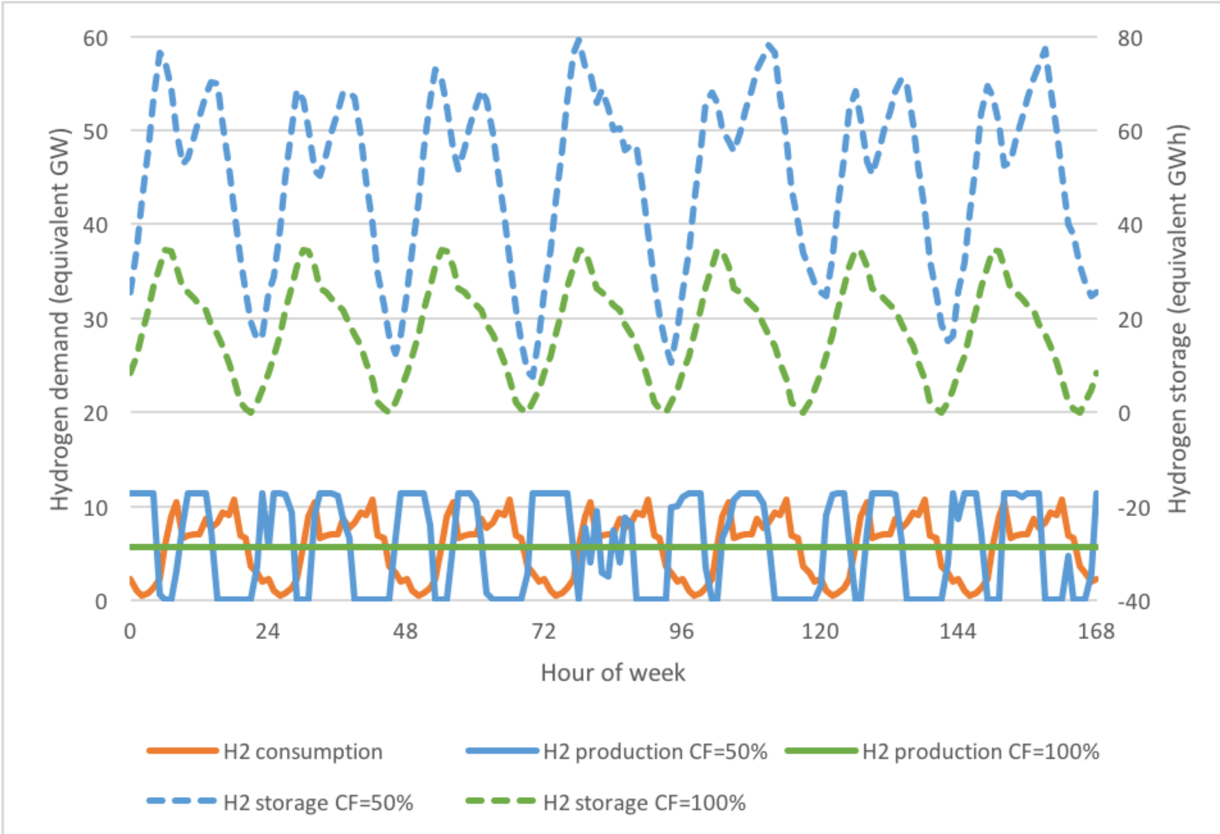

Figure 2. Hydrogen demand (production and consumption, left-hand axis) and hydrogen storage (right-hand axis) comparison for two scenarios: CF = 50% and CF = 100% (inflexible)

3.1 Average and marginal electricity unit costs

Figure 3, panel (a) shows the average cost per unit output ($/MWh) in all scenarios. The average electricity cost per unit output for the WI is defined as follows:

$$UC_{ave} = \frac{C_{all}}{L_{all}} \tag{1}$$

Here UC_{ave} is the average electricity unit cost ($/MWh); C_{all} is the total system cost ($) in a scenario that includes the cost of fuel, operations and maintenance, and generator startup and shutdown (see Figure S6 in Supplementary Materials); and L_{all} is the total system load (MWh) including hydrogen production, if applicable.

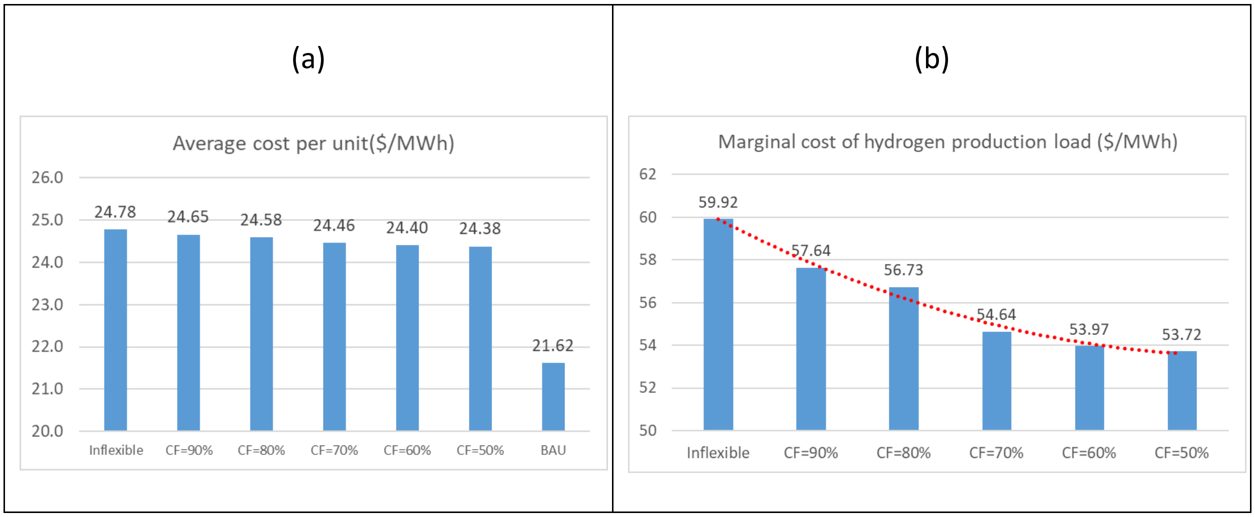

Figure 3. (a) Average electricity cost per unit output for BAU and various hydrogen scenarios across the WI. (b) Marginal electricity cost (defined in the text) per unit output for hydrogen scenarios.

The average costs in the hydrogen scenarios are all significantly higher than the BAU scenario, because the newly added hydrogen load must be supplied by more expensive generators, in contrast to the existing load that is by definition served using the lowest-cost generators.

The marginal cost per unit output measures the cost of the newly added load. We define marginal cost according to the following equation:

$$UC_{marg} = \frac{C_{all} - C_{BAU}}{L_{all} - L_{BAU}} \tag{2}$$

where UC_{marg} is the marginal electricity cost per unit output ($/MWh), C_{BAU} is the total system cost ($) in the BAU scenario, and L_{BAU} is the system load (MWh) without any hydrogen production.

Figure 3, panel (b) shows the marginal cost per unit output for the hydrogen cases, which highlights the increased cost: the marginal cost is more than twice as high as the average cost. The marginal cost also decreases with decreasing CF, implying that the value of flexible operation increases, decreasing operating costs. However, the red dotted line (quadratic best-fit curve) shows that as CF decreases, the electricity cost decreases more slowly, so the additional value of flexible operation diminishes.

3.2 Generation mixes of added load

The marginal operating cost for renewable energy generation is assumed to be zero in PLEXOS. In contrast, the traditional generators consume fossil fuels and have higher operational costs. For example, the average combined cycle natural gas generator cost is \$56.6/MWh. Thus, using the natural gas generator will lead to a higher system operating cost. As shown in Figure 4, panel (a), the blue bar is the generation output for each kind of the generator type in the BAU scenario, while the orange bar represents the CF = 50% scenario. The majority of these two datasets are overlapped.

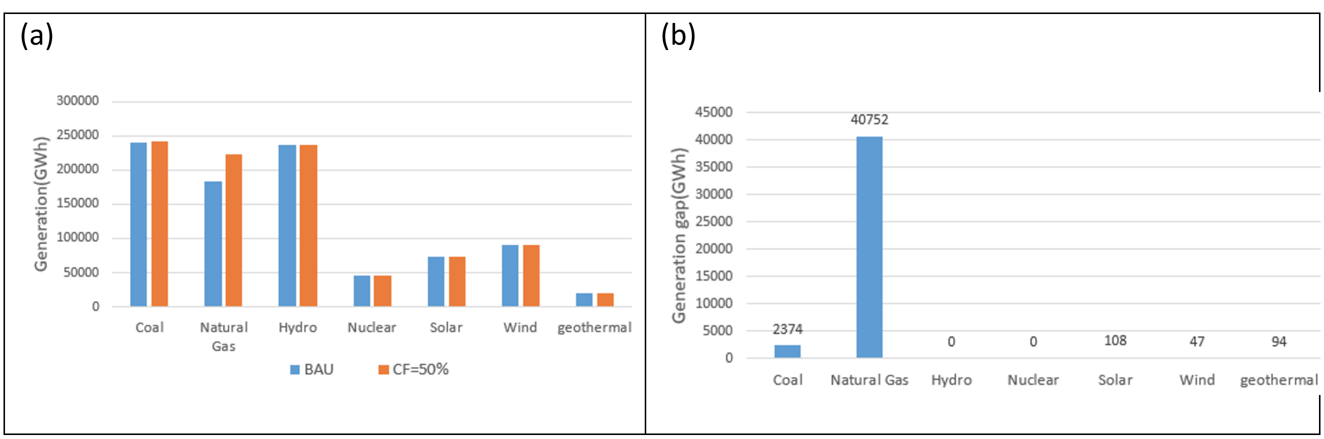

Figure 4. Generation output (in GWh) for each generator type: (a) Comparison of generation mix between BAU and CF=50% scenarios; (b) Net generation increase from flexible hydrogen load (difference between CF = 50% and BAU scenarios)

To make the comparison clear, the difference in generation between the two scenarios is shown in Figure 4, panel (b). Compared to the BAU scenario, the hydrogen demand requires 43.4 TWh/yr. of electricity in the CF = 50% scenario. About 94% (40.8 TWh/yr.) of that electricity is supplied by natural gas generators. If we consider the supply curve, it is reasonable that the newly added load leads to a higher average cost per unit for the electricity consumption, because PLEXOS does not build new generation capacity to respond to increases in demand. Also, PLEXOS has already optimized the BAU case to achieve the lowest operation cost, which means that any additional electricity consumption will use the next lowest cost generator, which always leads to higher average generation cost. Note, however, that a small amount of zero-cost renewable generation (solar, wind and geothermal) is also utilized, but these resources are quickly saturated.

3.3 Benefit versus cost comparison

To determine the optimal amount of electrolyzer flexibility, we have included estimates of the capital cost of electrolyzers and associated hydrogen storage infrastructure, and subtracted the BAU costs, to arrive at the total marginal cost to install and operate the electrolyzers for each scenario (Table 2 and Figure 5). We see that the total cost has a minimum point of \$3.55 billion/yr. at CF = 80%, indicating an intersection between decreasing operational costs and increasing capital costs. However, the results are sensitive to the equipment cost. While we assumed a target electrolyzer cost of \$300/kW, the current cost is much higher (>\$1,000/kW), which would result in the lowest-cost scenario being the inflexible case, with no advantage to oversizing.

Table 2. Storage size, electrolyzer size, and annualized capital and operations costs for hydrogen production.

Scenarios	Storage size (GWh)	Annualized storage cost ($B/yr)	Electrolyzer size (GW)	Annualized Electrolyzer cost ($B/yr)	Annual capital cost ($B/yr)	Annualized operation cost ($B/yr)	Total cost ($B/yr)	Nominal cost of H_2 ($/kg)
Inflexible	52	$0.21	5.6	$0.39	$0.60	$2.98	$3.59	$2.706
CF = 90%	62	$0.25	6.3	$0.43	$0.69	$2.87	$3.56	$2.684
CF = 80%	72	$0.30	7.1	$0.48	$0.78	$2.77	$3.55	$2.683
CF = 70%	82	$0.34	8.1	$0.55	$0.89	$2.72	$3.61	$2.725
CF = 60%	92	$0.38	9.5	$0.65	$1.02	$2.69	$3.71	$2.801
CF = 50%	100	$0.41	11.2	$0.77	$1.19	$2.67	$3.86	$2.913

(a)	(b)

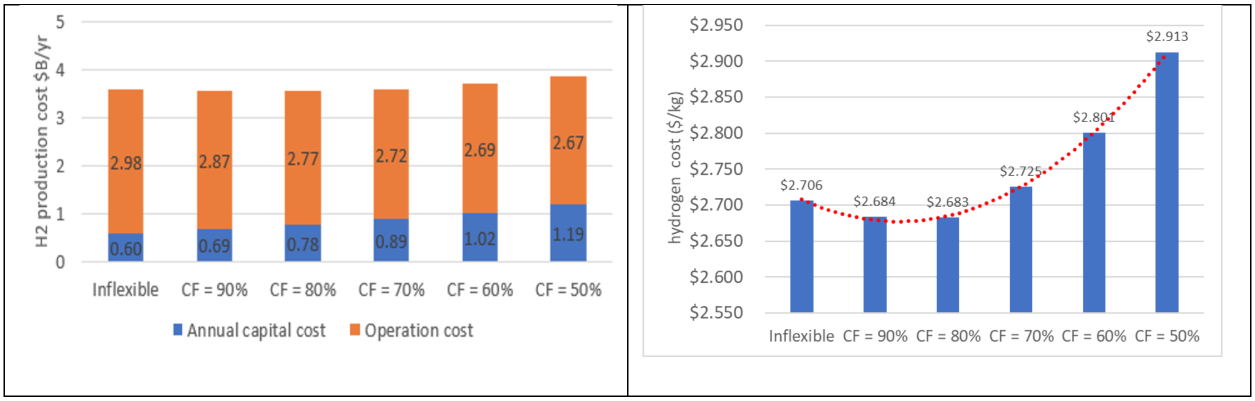

Figure 5. (a) Total system cost (including the capital cost and operating expenses); (b) Complete cost for hydrogen production ($/kg)

3.4 Renewables curtailment

A natural follow-on question to ask, after considering the marginal cost of generators in the presence of hydrogen electrolyzer loads, is how load flexibility affects renewables curtailment, or the amount of renewables generation (primarily from intermittent wind and solar PV generators) that is not utilized by the grid and thus "curtailed." While the total amount of renewables curtailment, shown in Table 3, is small compared with overall generation in all cases, it does change measurably, though there are no meaningful differences among hydrogen scenarios. For the entire WI, curtailment drops from 4.06% in the BAU case to 3.02% in the hydrogen case, whereas for California, curtailment drops from 4.88% in the BAU case to 3.01% in the hydrogen case—a nearly 50% reduction. The total renewable energy generation is the same in all cases (236.2 TWh in the WI and 122.9 TWh in California). The reduction in curtailment, 2.47 TWh/yr. across the WI, is a small fraction of total hydrogen electrolysis demand of 43 TWh/yr., but is worth $62 million/yr. at an average electricity price of $25/MWh. Therefore, while hydrogen production does decrease renewables curtailment, it is due primarily to additional load, and is not altered by increased load flexibility. By comparison, a study in the

E.U. indicated that flexibility measures could reduce curtailment on that grid of wind and solar PV from 7.0% to 1.6%, or 67 TWh/yr in 2040 [71].

Table 3. Renewables curtailment fraction (defined as 1 – ratio of renewable electricity used to renewable electricity generated)

Region	BAU	Hydrogen
Western Interconnect	4.06%	3.02%
California	4.88%	3.01%

3.5 Greenhouse gas emissions

Figure 6 presents total annual carbon dioxide (CO_2) emissions from the WI electricity grid in the FCEV cases, plus transportation-sector emissions from an identical number of conventional vehicles in the BAU case (see Table S1 in Supplementary Materials). For the same reason that we see higher average electricity costs when additional load is added to the system, the hydrogen scenarios where additional load is added increase emissions compared to BAU. This is because the additional generation to meet the new electricity load comes largely from natural gas generators, which results in higher overall GHG emissions. However, compared to the additional GHG emissions from conventional vehicles in the BAU scenario, this increase is only slightly higher: 3.2-3.8 million metric tons CO_2 ($MMtCO_2$)/yr. depending on the scenario, or ~1% of total emissions. Comparing only the hydrogen scenarios in panel (b), greater flexibility results in lower emissions by up to 0.6 $MMtCO_2$ /yr.—not enough to reduce the total below the BAU scenario, but an important reduction. Since GHG emissions were not the objective of the optimization, this result is not causal, but happens nonetheless due to reductions in natural gas generation with additional flexibility from the electrolyzers. If the grid's renewable generation fraction were higher, or dedicated renewable resources were built to provide electricity for hydrogen production, the resulting GHG emissions in the hydrogen scenarios would be significantly lower than in the BAU scenario.

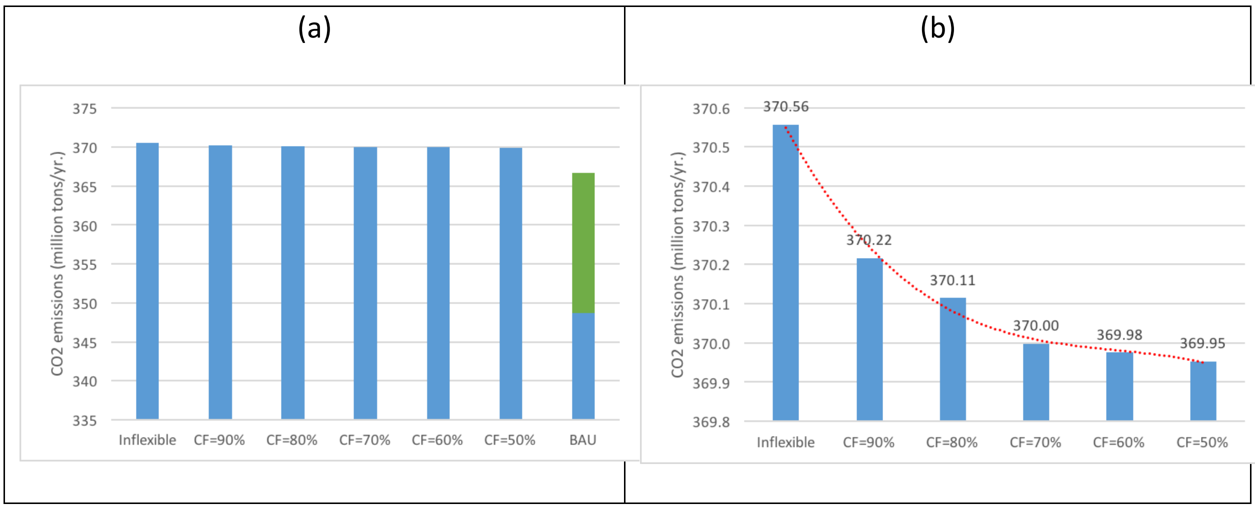

Figure 6. Annual greenhouse gas emissions (a) total for all scenarios and (b) total for hydrogen scenarios. Blue = electricity sector CO_2 emissions; green = vehicle sector marginal CO_2 emissions.

3.6 Study limitations

In our scenario, LDVs represent ~90% of the total hydrogen demand. Therefore, even though non-LDV hydrogen refueling demand has a somewhat different diurnal profile from LDVs, it has little influence on the overall demand and almost no impact on the results. While out of scope for this project, future work could explore scenarios with different compositions of LDV and non-LDV hydrogen vehicles, such as a case where there are many more non-LDVs than in our reference case, to identify the role that vehicle composition has on the results. To make this a meaningful comparison, however, better estimates of non-LDV hydrogen demand temporal profiles will be required.

Our simulations also did not take into account the possibility of EVs providing additional flexible loads to the grid along with hydrogen electrolysis. Future work could include realistic market shares of both FCEVs and EVs, and in particular explore whether the different temporal load shapes associated with these vehicle types could provide opportunities for synergistic load-shifting (via controlled charging of EVs, and spare hydrogen production capacity for FCEVs), further reducing grid costs.

The PLEXOS model employed in our study was not run in a capacity-expansion mode so the generation mix was fixed, and generators were selected only to minimize total cost of meeting load. As a result, dispatchable generators with significant marginal cost, such as natural gas, were overwhelmingly selected over renewable generators that had zero marginal cost, because the output of these latter generators could not be increased (however, curtailment was reduced slightly in the hydrogen scenarios relative to the BAU). As a result, GHG emissions associated with hydrogen generation were much higher than might be expected if that electricity was produced primarily from renewable sources; total GHG emissions were even slightly higher than the BAU scenario with conventional petroleum-based vehicles. However, in a future electricity grid built to maximize the use of renewable generation for new loads such as from hydrogen electrolysis, marginal GHG emissions are expected to be much lower, leading to significant reductions relative to the BAU scenario.

4. Conclusion

Hydrogen electrolysis can be regarded as a large, flexible load added to the electricity grid. This flexible load can provide support to the grid in a variety of ways including shifting load demand profiles and mitigating generator startups and shutdowns. In the scenarios explored in the paper, the hydrogen electrolysis load constituted ~3% of overall grid load, yet the average electricity cost increased between 12.8% (in the 50% CF scenario) and 14.6% (in the 100% CF scenario). While this cost increase is high, resulting in a marginal electricity cost that is more than twice the average electricity cost, greater flexibility can reduce these grid operational costs by more than $6/MWh, or nearly 30% of the average BAU cost. In addition to reducing generation costs, adding hydrogen production can also reduce renewables curtailment by almost 50%, and load flexibility can decrease GHG emissions by up to 0.6 $MMtCO_2$/yr. However, there is a balance point between cost savings from increased load flexibility and the additional capital costs associated with larger electrolyzer capacity that is underutilized. Combining the levelized cost calculation approach with an avoided cost for grid impacts, this analysis calculates the benefits and costs for flexible hydrogen production. Under future electrolyzer and storage cost assumptions, an optimal least-cost point occurs at a flexibility level of CF = 80%, corresponding to a 25% oversizing of hydrogen electrolysis capacity. However, while these results are sensitive to a number of assumptions including the power system that is modeled, hydrogen demand profiles, and future costs, the results are potentially applicable to many parts of the world with similar future grid configurations and FCEV penetration levels. Finally, while the method for calculating grid benefits using a production cost model is unique, it is also resource intensive, which limits the number of sensitivities that can be performed. Future work will build on these findings and explore a greater number of sensitive parameters to better characterize the role that flexible hydrogen generation can play in lowering the costs of hydrogen electrolysis and improvements of grid operations.

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