Community Energy: Analysis of Hydrogen Distributed Energy Systems with Photovoltaics for Load Leveling and Vehicle Refueling

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Acronyms

DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Energy
EV	electric vehicle
FCEV	fuel cell electric vehicle
H_2	hydrogen
LCOE	levelized cost of energy (hydrogen or electricity)
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PV	photovoltaic

Executive Summary

The combination of high levels of distributed (rooftop) photovoltaics (PV) and high electric vehicle (EV) penetration presents unique challenges and opportunities for distribution grid integration. The impacts of home vehicle charging on electricity distribution infrastructure have been studied by various utilities as part of EV readiness planning (see studies referenced in Metropolitan Energy Center et al. 2012). They find that residential feeders were most susceptible to reliability impacts, experiencing distribution transformer overloads and thermal overloads starting at EV penetration levels of 20%. Small-scale distributed renewable generation, such as rooftop PV, also involves unique flexibility challenges associated with its location at the low-capacity terminus of the electricity distribution system. These small-scale systems can reach very high local penetration levels in neighborhoods, and the introduction of home vehicle charging presents both an added challenge and opportunity that might be addressed by small-scale energy storage systems.

Energy storage could complement PV electricity generation at the community level. Because PV generation is intermittent, strategies must be implemented to integrate it into the electricity system. Hydrogen and fuel cell technologies offer possible PV integration strategies, including the community-level approaches analyzed in this report: (1) using hydrogen production, storage, and reconversion to electricity to level PV generation and grid loads (reconversion scenario); (2) using hydrogen production and storage to capture peak PV generation and refuel hydrogen fuel cell electric vehicles (FCEVs) (hydrogen fueling scenario); and (3) a comparison scenario using a battery system to store electricity for EV nighttime charging (electric charging scenario).

These approaches are applied to a community of 100 residences, approximated by the electricity demand of a small hotel in Boulder, Colorado. To assess the impact of increasing PV market penetration, three levels of PV power generation spanning a broad range in comparison to the community's electricity demand were studied. The simulated community is served by a PV system sized at 1,200 m^2 (~185 kW, producing electricity equivalent to 50% of annual building electricity load), 4,000 m^2 (~610 kW, producing 170% of the annual building load), or 7,000 m^2 (~1,070 kW, producing 290% of the annual building load). The three energy storage scenarios and building and PV system sizes are summarized in Table ES-1.

Table ES-1. Energy Storage Scenarios

Scenarios			**Common to All Scenarios**	
	Storage System	**Storage System Output & Recipient**	**Building Load Characteristics**	**PV System (kW/% of yearly building load)**
1. Reconversion	Hydrogen	Electricity to Homes	Maximum 125.3 kW Minimum 28.4 kW Average 65.4 kW Total 572,518 kWh	185/50 610/170 1,070/290
2. Hydrogen Fueling	Hydrogen	Hydrogen to FCEVs		
3. Electric Charging	Battery	Electricity to EVs		

In the reconversion scenario, electricity from the PV panels satisfies building demand directly, and excess PV electricity produces hydrogen via an electrolyzer. A fuel cell converts the hydrogen back into electricity to serve the building demand when PV output is inadequate, and grid electricity satisfies any demand that cannot be met directly by the PV system or stored hydrogen.

The results of the analysis show a relatively complex relationship between PV system size and the economics of power generation from each system as illustrated in Table ES-2. Costs tend to increase as the difference between the PV system output and the building load increases because more electricity is routed through the storage system, which must be larger. In addition to the increased costs for the larger system, routing electricity through the storage system results in losses due to the inefficiency of the conversion technologies. For our analysis, the equipment efficiencies for the electrolyzer and fuel cell result in a round-trip efficiency of 34%–41%, incurring a large cost penalty. However, this upward trend in cost is balanced by better utilization of the storage equipment (electrolyzer, hydrogen tanks, and fuel cell) for the larger systems. Thus, when considering the entire system delivering electricity to the building, the lowest cost is for the smallest storage system, which incurs the lowest cost for equipment and the lowest penalty for losses. When considering the cost of only stored electricity, the largest system is the least expensive because better equipment utilization improves the economics per kWh of stored energy.

Table ES-2. Levelized Cost of Electricity for the Reconversion Scenarios

Scenario	Total Direct Capital Cost Including PV System ($K)	Levelized Cost of All Electricity (Direct Supply to Building + Stored Electricity) (¢/kWh)[b]	Total Direct Capital Cost without PV System ($K)	Levelized Cost of Stored Electricity (¢/kWh)[b]
185 kW PV/storage system	$727	33	$271	109
610 kW PV/storage system	$2,958	57	$1,438	62
1,070 kW PV/storage system[a]	$3,393	45	$733	36

[a] The 1,070 kW PV system produces close to 3 times the building load. Therefore, nearly the entire building load can be supplied with the PV system direct output plus stored electricity. After supplying the building load, a large fraction of the PV system output (44%) is sold to the grid at the cost of producing it.
[b] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system.

The vehicle-refueling scenarios are similar to the reconversion scenario, except that vehicles use the excess energy instead of buildings, and no electricity is sold back to the grid. The amount of electricity produced in excess of the building load determines the number of vehicles—either hydrogen fuel cell vehicles or plug-in electric vehicles—that could be fueled in each case. The vehicle-refueling methods include electrolytic hydrogen production for hydrogen-powered vehicles and battery storage for plug-in electric vehicles.

The vehicle-refueling cost analysis is performed for two cases: Case 1, in which all PV electricity output in excess of the building load is used for vehicle refueling, and Case 2, in which all PV electricity output before noon is used for vehicle refueling in addition to all PV output in excess of the building load.

The vehicle-refueling analysis shows the potential for community-level hydrogen refueling using only renewably generated electricity (Table ES-3). With the 610 kW PV system, the number of fuel cell vehicles served (70–80) roughly matches the modeled community size (100 households). The levelized hydrogen cost ranges from $34/kg ($1.01/kWh) to $11/kg ($0.34/kWh). The cost of battery storage of electricity for electric vehicles ranges from $0.57/kWh–$0.39/kWh, also decreasing with increasing system size. The levelized cost of hydrogen is high for even the most favorable case in comparison to expected early commercial station hydrogen costs. However, the system produces 100% renewable hydrogen and provides potentially valuable load leveling of distributed PV output, allowing for grid integration of much larger PV systems. The hydrogen system cost reduction for the larger systems, as for the load-leveling system, is due to better utilization of the equipment. The hydrogen system configuration is also more flexible than the battery system because there are more independent pieces of equipment. For small systems, this is a disadvantage, but for larger systems the increased flexibility reduces costs because an incremental increase in hydrogen storage capacity per kWh (hydrogen tank) is less expensive than an incremental (per kWh) increase in electrochemical storage. Even though the hydrogen system is lower cost than the battery system for the largest storage case, the electric vehicle is less expensive on a fuel ¢/mile basis because of its higher efficiency in comparison to the fuel cell vehicle.

Table ES-3. Summary of Vehicle-Refueling Cost Results

Hydrogen for Fuel Cell Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (kW)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)/ ($/kWh)	H_2 Cost (¢/mi)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)/ ($/kWh)	H_2 Cost (¢/mi)
185	1,804	9	34/1.01	56	3,541	17	22/0.66	38
610	14,564	72	13/0.39	22	16,985	84	12/0.37	21
1,070	29,274	146	12/0.35	20	31,898	159	11/0.34	19
Electricity for Battery-Electric Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (kW)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)
185	61,726	17	0.57	17	121,936	35	0.45	13
610	500,755	143	0.41	12	585,475	168	0.40	12
1,070	1,008,212	289	0.39	11	1,100,877	316	0.39	11

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system. For the 610 and 1,070 kW PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles versus 55.6 kWh/100 miles for fuel cell electric vehicles [DOE, 2013. Fuel Economy.gov: Accessed June 20, 2013.]) still results in a lower per-mile cost for the battery-electric vehicle system.

For both the reconversion and vehicle fueling scenarios, the system cost is highly dependent on component costs and system configuration. In all scenarios, the reconversion or refueling system reduces peaks and valleys in grid demand and energy fed onto the grid. Figure ES-1 illustrates the potential benefit of diverting excess PV electricity to a storage system. In the absence of a storage system (either hydrogen or battery), the maximum power routed to the grid for the mid-range PV system is four times the maximum building load (kW). Both the reconversion and vehicle fueling scenarios reduce or completely eliminate reverse power flows onto the grid. Storage and/or diversion of excess electricity from distributed generation systems that can smooth seasonal and daily variations in PV system output may be advantageous for very high levels of PV penetration.

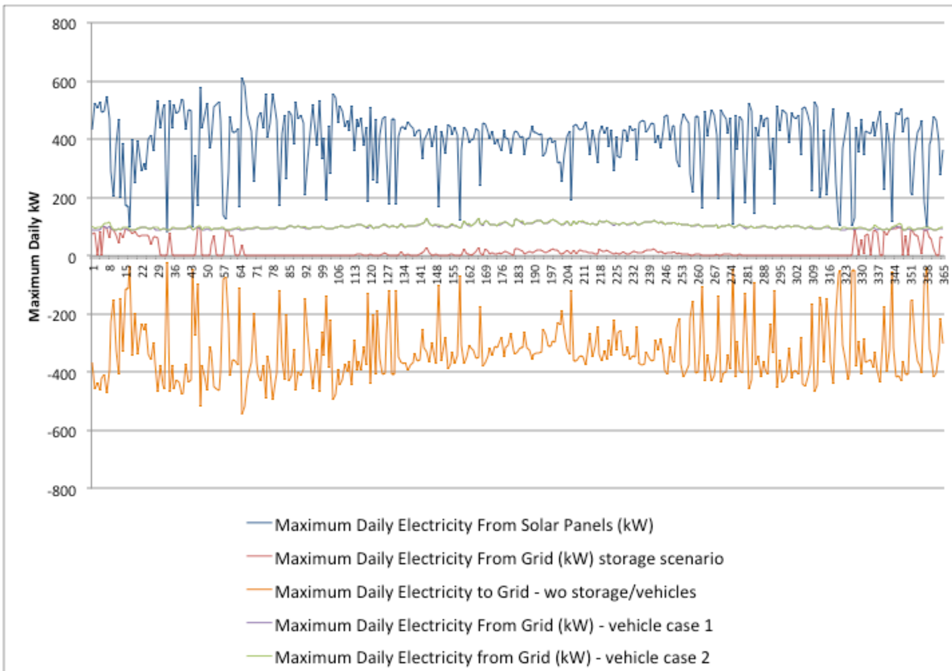

Figure ES-1. Maximum daily fluctuations in PV system output and grid interactions (610 kW PV system)

In summary, the three primary findings of the study are:

- Both the reconversion and vehicle fueling scenarios provided smoothing of electricity flows to and from the grid. This leveling function is especially important for integration of distributed PV and electric vehicle fueling, either plug-in electric vehicles or FCEVs, at the low-capacity terminus of the electric grid. Although none of the scenarios resulted in a levelized cost of energy (LCOE) of stored electricity that is competitive with grid electricity, smoothing of power flows may be critical for integration of distributed generation and fueling technologies.
- The vehicle fueling scenarios are more cost effective than the reconversion scenarios because stored energy (electricity or hydrogen) is not reconverted to electricity in the fueling scenarios and therefore does not incur a penalty for large efficiency losses. The best case levelized cost of stored electricity for the reconversion scenarios was

$0.36/kWh for the largest PV system. The least cost for the vehicle fueling scenarios was the hydrogen fueling for Case 2 for the largest PV system, which resulted in a levelized cost of $0.34/kWh.

- For the smallest PV system, battery storage for EVs was lower cost than the electrolyzer and hydrogen storage system for FCEVs; $0.45/kWh for Case 2 for the battery system and $0.66/kWh ($22/kg) for the Case 2 hydrogen system. The hydrogen system for FCEVs is lower cost for larger PV systems, with a best case LCOE of $0.34/kWh for Case 2 for the largest system compared to $0.39/kWh for the largest Case 2 battery system. Overall, of the systems studied, the best case scenario was for hydrogen vehicle fueling for the largest PV system where morning output and all electricity in excess of the building load was diverted to the hydrogen storage system (Case 2).

Future work will focus on development of methods for optimizing the equipment and distributed generation systems for the most economical operation. Optimization of system sizes and configuration would allow cost targets to be developed for each of the various components.

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1 Introduction

Higher penetrations of distributed renewable energy systems, specifically residential rooftop photovoltaic (PV) systems, could affect loading and capacity margins for community-level electricity distribution systems. PV output typically peaks slightly before the highest daily electricity demand. This offset could cause overloading of local distribution equipment at high PV penetration levels. The addition of plug-in electric vehicles, which would primarily be charged at residences, might also affect loading of distribution systems. Several researchers have analyzed the effect of electric and plug-in hybrid electric vehicles on the grid (Denholm et al. 2013; Srivastava et al. 2010). Denholm et al. analyzed options for integrating PV and electric vehicle charging, finding benefits of mid-day vehicle charging for reduction of petroleum use and potentially enabling smaller vehicle batteries. While the analysis by Denholm et al. focused on mid-day charging at commercial places of business, this analysis addresses the unique challenges of integrating large penetrations of PV at the residential level where grid capacity constraints may be most acute.

Hydrogen (H_2) energy storage could complement PV electricity generation at the community level. Because PV generation is intermittent, strategies must be implemented to integrate it into the electricity system. Hydrogen and fuel cell technologies offer possible PV integration strategies, including three community-level approaches discussed in this paper: (1) using hydrogen production, storage, and reconversion to electricity to level PV generation and grid loads, (2) using hydrogen production and storage to capture peak PV generation and fuel hydrogen-powered vehicles, and (3) using batteries to capture peak PV generation and fuel plug-in electric vehicles.

Energy storage is one potential strategy for addressing load variations due to high residential PV penetration. This brief study analyzes the costs and benefits of installing hydrogen-based energy storage for community-level PV system load leveling. It examines the effects of increasing PV penetration in residential neighborhoods on the use of grid electricity and the opportunity for hydrogen energy storage.

Peak PV output could also be diverted for use directly in electric vehicles or, after conversion to hydrogen, in hydrogen-powered fuel cell vehicles. In this analysis, the electricity or hydrogen is temporarily stored in batteries or hydrogen tanks so that vehicles can be refueled when the residents return home in the evening.

The target scenario for the study is approximately 100 single-family, detached houses served by a single pad-mounted transformer at the end of a grid distribution line. As PV penetration increases for these houses, what are the opportunities and economics for energy storage using hydrogen? How does that compare to diverting the excess electricity to fueling of vehicles? A modified version of the U.S. Department of Energy's (DOE) Fuel Cell Power Model (FCPower 2012) was used to perform this analysis.

The next section describes the building profile and PV systems followed by the reconversion and vehicle-refueling systems. Section 3 shows cost analysis results for the reconversion and vehicle-refueling systems, Section 4 offers conclusions, and Section 5 includes suggestions for future work.

2 System Descriptions and Energy Flows

The following subsections detail the characteristics of the building profile used in both the reconversion and vehicle-refueling scenarios; the electrolyzer, fuel cell, and PV systems used in the scenarios; and the reconversion and vehicle-refueling systems themselves.

2.1 Building Profile and PV Systems

The same building profile was used for the reconversion and vehicle-refueling scenarios. The hourly load profile for a small hotel in Boulder, Colorado, was used as a surrogate for a community of 100 residences (Field et al. 2010; NREL 2009). The hotel load profile is expected to be similar to the load profile for a residence because of similar use patterns; most people get up and ready for work in the morning and then return later in the afternoon. This use pattern results in a peak in electricity demand between 6:00 a.m. and 10:00 a.m. and another between 5:00 p.m. and 10:00 p.m. Because the hotel load, with an average demand of about 65 kW, is larger than would be expected for 10–15 single family residences (with an average demand of 1–2 kW per household), the analysis was scaled up in size. However, the PV system costs are scaled linearly, and the energy flow relationships are the same as for a smaller system. Some characteristics of the hotel building load profile are listed in Table 1. Figure 1 plots the electricity demand for the hotel during a typical day in July.

Table 1. Key Characteristics of the Boulder Hotel Building Load Profile

Building Load Statistics	
Demand maximum (kW)	125.3
Demand minimum (kW)	28.4
Demand average (kW)	65.4
Demand std dev (kW)	22.8
Demand total (kWh/year)	572,518

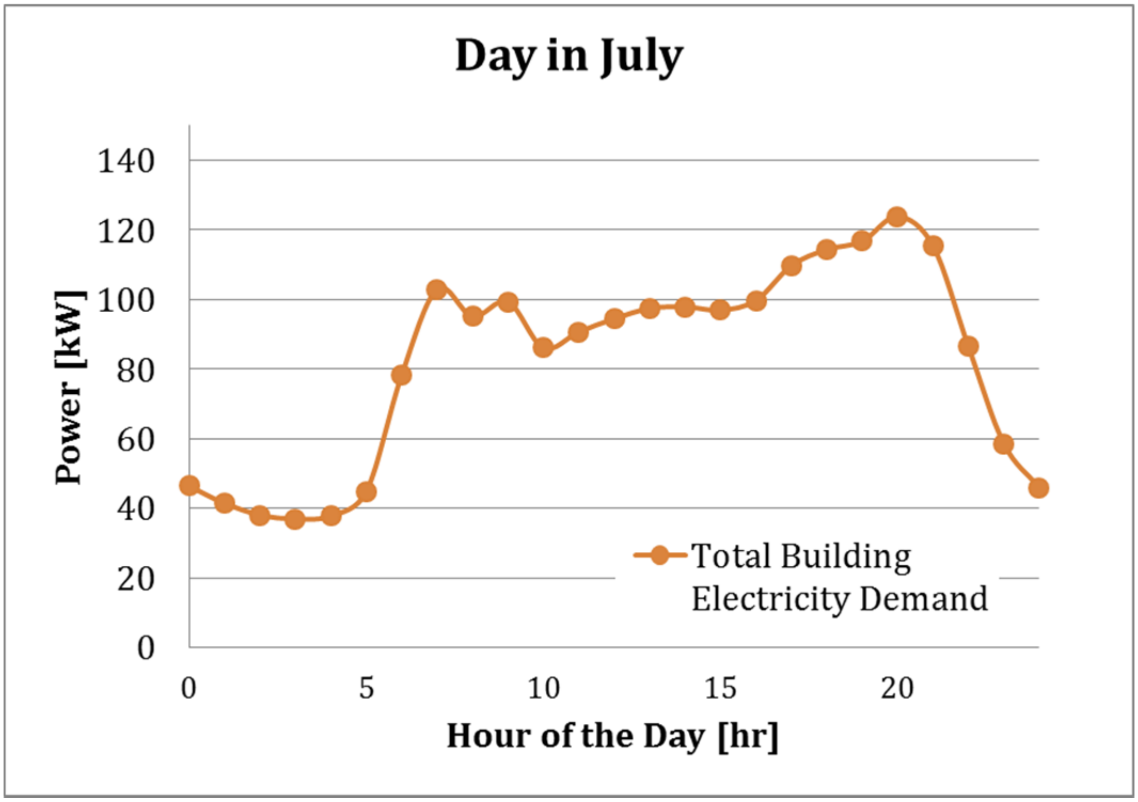

Figure 1. Building electricity demand profile, selected day in July

The same PV systems were used for the reconversion and vehicle-refueling scenarios (Table 2). The three PV systems range in size from about half the yearly building load to almost three times the building load. The capacity factor for the PV systems is 18%.[1] NREL's hourly solar resource data for Boulder, Colorado (NREL 2009), was imported into the FCPower model for use in the simulations.

Table 2. Key PV System Performance Parameters

PV System Size (m^2)	Peak Rated Output (kW)	Yearly Output (kWh)	Approximate Percent of Building Load
1,200	185	286,704	50%
4,000	610	955,681	170%
7,000	1,070	1,672,442	290%

2.2 Reconversion System

Figure 2 shows a schematic representation of the equipment and building layout for the reconversion system. Electricity from the PV panels is first used to satisfy the building demand directly (100 houses approximated by the hotel profile as described previously). If the output

[1] The capacity factor is calculated as the actual PV output (kWh) divided by the potential output if the PV panels were producing at their maximum power for 24 hours a day.

from the PV system is higher than the building demand at that time, the electricity is routed to the electrolyzer where it is used to produce hydrogen for storage. During periods when the demand is high but PV output is low, for example in the evening, the stored hydrogen is used in the fuel cell to produce electricity for the building demand. Any additional building demand is met using electricity from the grid. On rare occasions, the storage system may be full, and excess electricity from the PV system is routed to the transformer and fed onto the grid. In this scenario, the fuel cell output is only used to satisfy the building demand and is never routed to the grid.

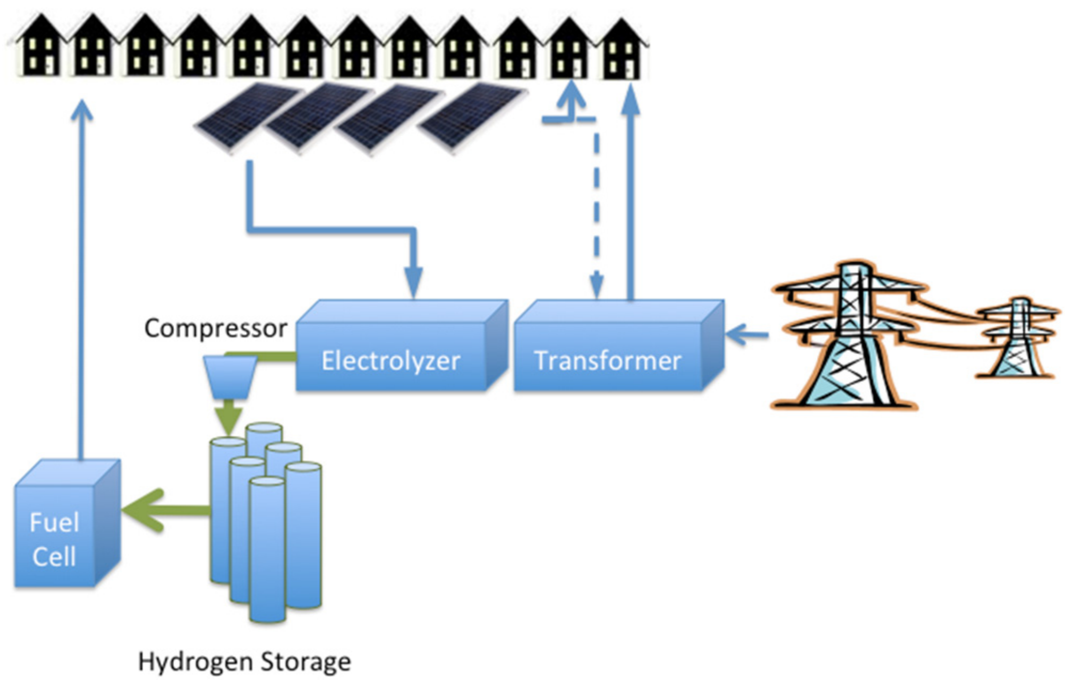

Figure 2. Schematic diagram of equipment and energy flows for the reconversion system

Seasonal variation in the PV system output has a marked effect on the sizing of the storage systems for the three PV system sizes. Seasonal fluctuations in PV output/H_2 produced by the electrolysis system can be accommodated for the 185 and 610 kW systems. However, sizing the hydrogen production and storage system to accommodate seasonal variations in hydrogen production for the 1,070 kW PV system is not practical. Therefore, for the 1,070 kW system, both the electrolyzer and hydrogen storage system are scaled down, and more electricity is routed to the grid.

For the 185 kW PV system, the PV electrical output exceeds the building load during certain times of the day, but the total daily output never exceeds the total daily load. Therefore, for the 185 kW system, the storage system cycles daily, and electricity is never sold back to the grid. In contrast, for the 610 and 1,070 kW systems, the daily PV output often exceeds the daily load, so multi-day storage is needed. For the 610 kW system, 780 kg (~14,600 kWh), which is equivalent to approximately 9 days of storage, accommodates the seasonal variation in PV output, and no electricity is sold back to the grid. For the 1,070 kW system, it is not feasible to fully account for seasonal variation in PV output with storage. Therefore, the storage system for the 1,070 kW system was sized to approximately 4 days of storage, and a considerable amount of electricity is sold to the grid during periods when the storage system is full.

Table 3 shows the efficiencies of the electrolyzer, fuel cell, and compressor modeled in the system. Efficiency curves are taken from the Fuel Cell Power Model (NREL 2009).

Table 3. Efficiencies of the Reconversion System's Electrolyzer, Fuel Cell, and Compressor

Model Parameter	Units	Value
Electrolyzer efficiency	%LHV	66%–74%[a]
Fuel cell efficiency	%LHV	53%–58%
Compressor system efficiency		95%–97%
Total round-trip efficiency		34%–41%

[a] 78%–87% higher heating value (HHV).

Figure 3 shows the energy flows for this system (with 185 kW of PV) during a day in October. On this day, there is sufficient PV generation to carry the load without using the grid and produce hydrogen for storage (purple "Xs" in Figure 3) from about 10:00 a.m. to 5:00 p.m. Sufficient hydrogen is stored during the day to carry part of the load in the evening; however, no hydrogen remains to produce electricity during the early morning hours. As Figure 4 shows, for the scenario with 185 kW of PV, there is a wide variation in the amount of hydrogen produced during various times of the year. During periods of high demand (e.g., the day in July) or low solar output (e.g., the day in January), very little hydrogen is produced.

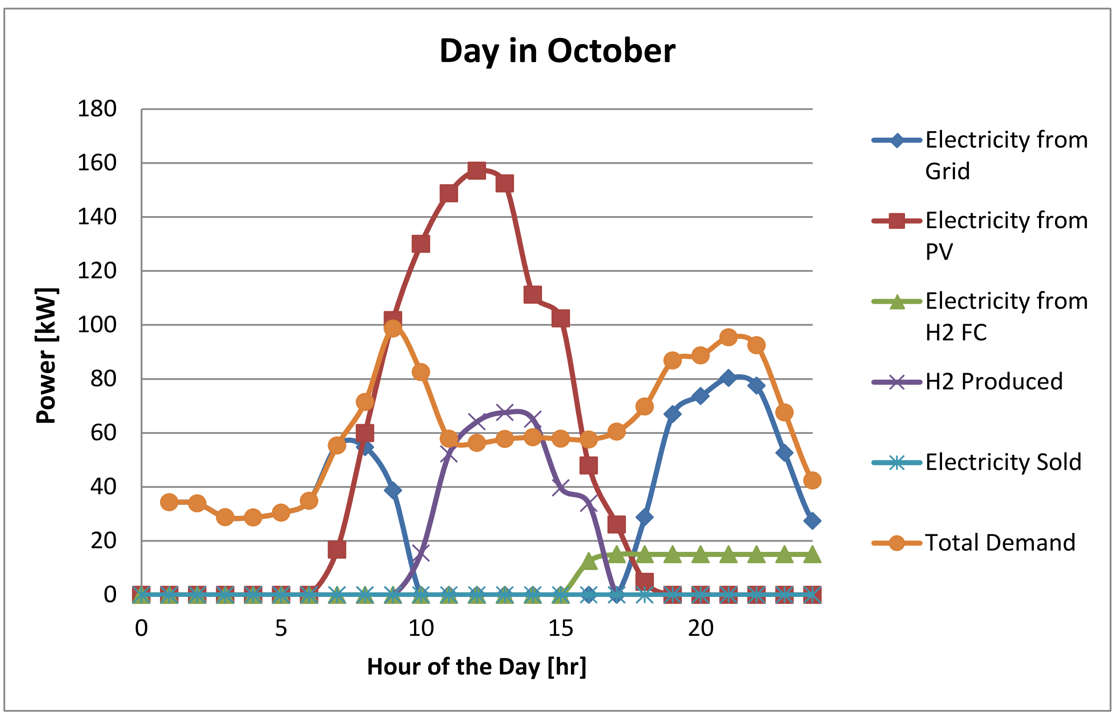

Figure 3. Boulder hotel electricity demand, PV generation, and storage system energy flows for a typical day in October (185 kW PV)

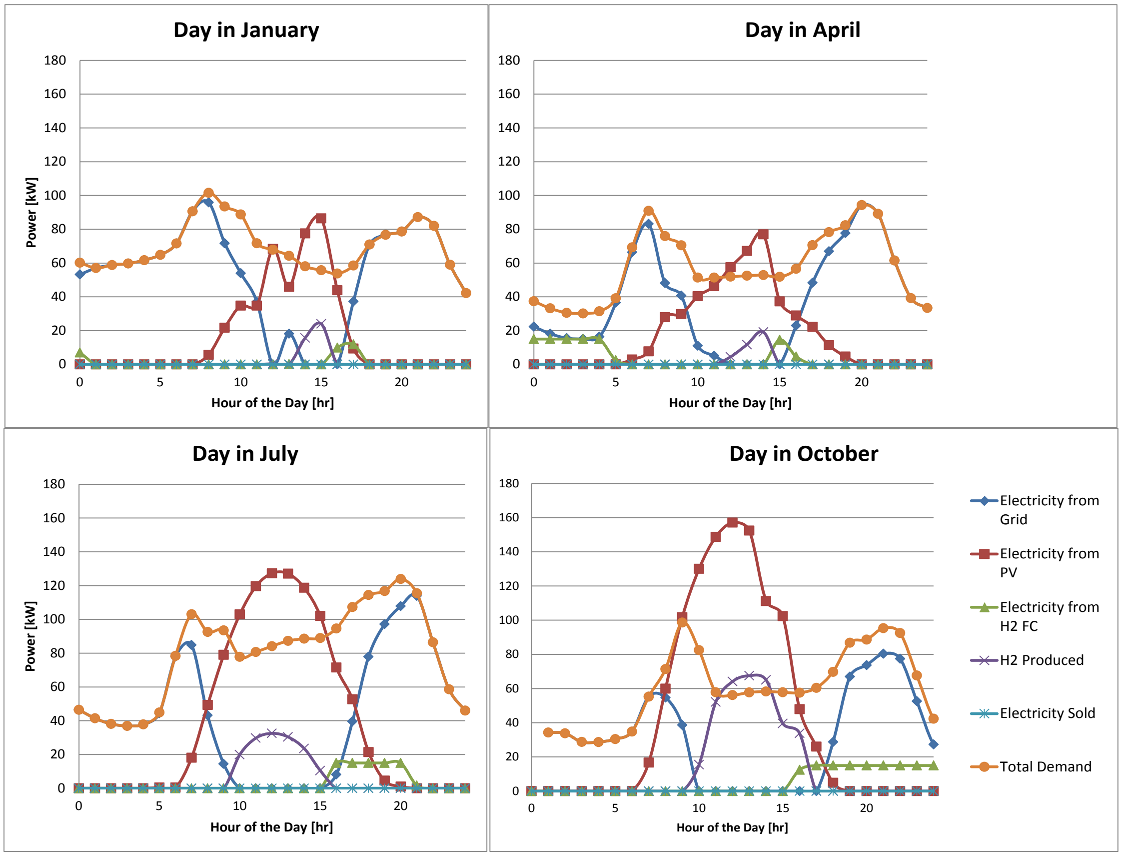

Figure 4. Seasonal variation with 185 kW of PV, four selected days

With 185 kW of PV installed, there is insufficient hydrogen production/storage to completely offset morning and evening peak power draws from the grid, especially during the summer when demand is higher. However, peak draws from the grid are reduced 10%–15% in the afternoon and evening peak period for part of the year. The peak output from the PV system is usually between 120 and 160 kW, which typically occurs when the building load is around the average of 65 kW. Without the storage system, the transformer occasionally would need to accommodate the difference in output of up to 100 kW of electricity being fed onto the grid. The storage system completely eliminates this energy flow. Table 4 summarizes the energy flows for the 185 kW PV/energy storage system. Figure 5 and Figure 6 show energy flows on various days for the 610 and 1,070 kW PV systems.

Table 4. Summary of Energy Flows for 185 kW PV/Energy Storage System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output During Operation [h/yr])	Percent of Building Load (Building + Compressor)
PV system	183 kW (peak rated output)	286,704 kWh	18	50 (total) 34 (direct supply)
Electrolyzer	127 kW input	1,833 kg	38 [1,904]	—
Hydrogen storage	16 kg	~ 1 cycle per day	—	—
Hydrogen fuel cell	15 kW output	32,094 kWh	89 [2,402]	6
Grid	—	348,771 kWh	—	61
Electricity sold	—	0 kWh	—	—

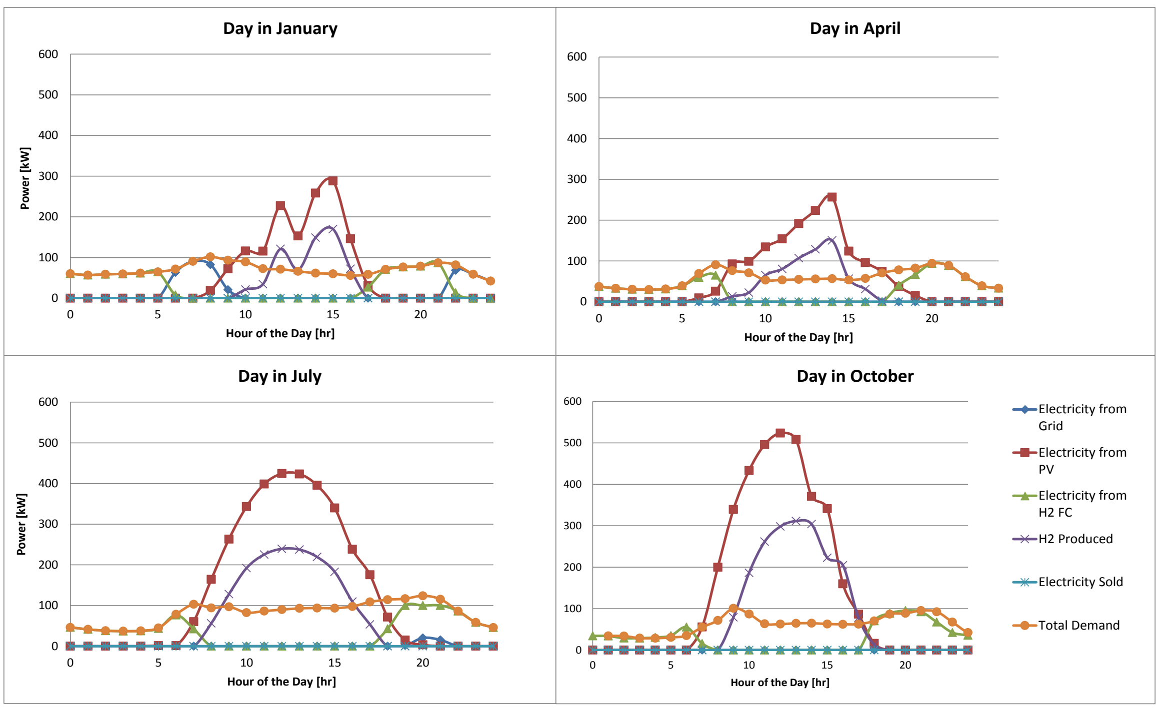

Figure 5. Seasonal variation with 610 kW of PV

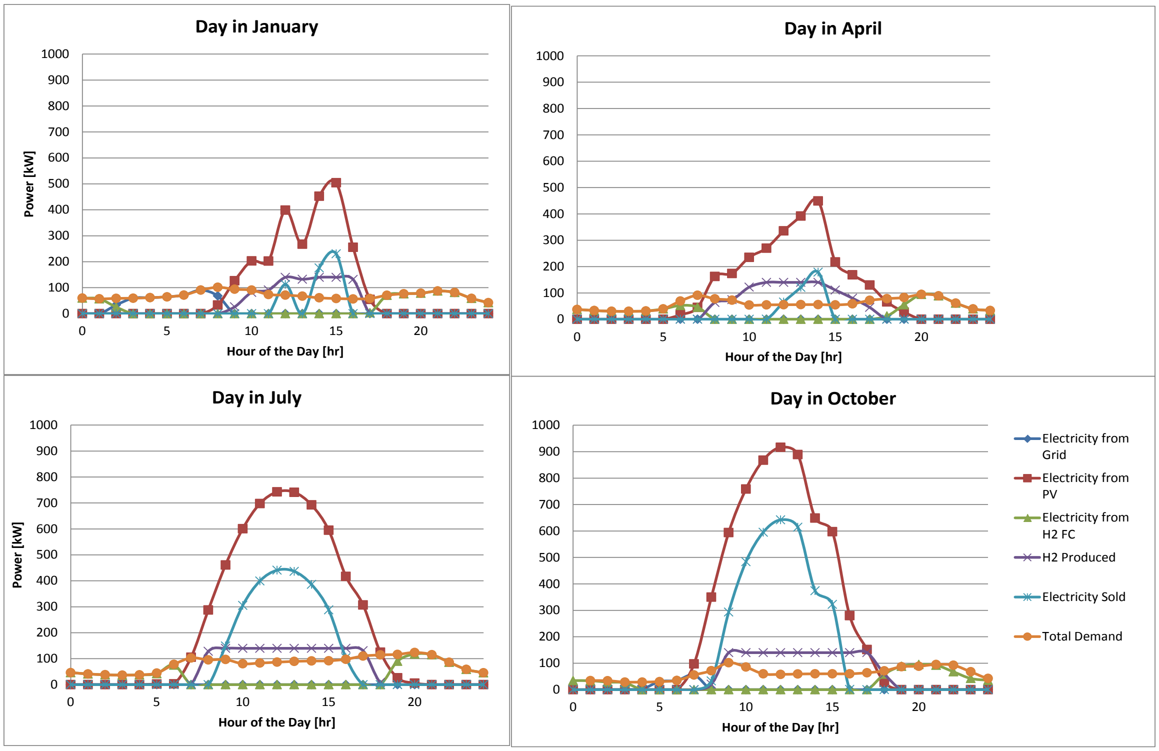

Figure 6. Seasonal variation with 1,070 kW of PV

Table 5 summarizes the energy flows for the 610 kW system. The total yearly PV output is 167% of the building yearly load. However, only about 48% of the PV output occurs at times when it can directly supply the building load. For this configuration, there is insufficient hydrogen production/storage to offset morning and evening peak power draws from the grid completely, especially during the summer when demand is higher. However, peak draws from the grid are reduced 50%–75% in the afternoon and evening peak period for most of the year.

Table 5. Summary of Energy Flows for 610 kW PV System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output During Operation [h/yr])	Percent of Building Load (Building + Compressor)
PV system	611 kW (peak rated output)	955,681 kWh	18	167 (total) 48 (direct supply)
Electrolyzer	578 kW input	14,797 kg	39 [3,265]	—
Hydrogen storage	780 kg	Variable days of storage depending on the season	—	—
Hydrogen fuel cell	100 kW output	277,770 kWh	55 [5,065]	47
Grid	—	25,995 kWh	—	4
Electricity sold	—	0 kWh	—	—

Table 6 summarizes the energy flows for the 1,070 kW system. The total yearly PV output is 292% of the building yearly load. However, only about 51% of the building load can be supplied by the PV system directly. In this scenario, there is sufficient hydrogen production and storage capacity to supply 42% of the building load using the hydrogen fuel cell. The hydrogen fuel cell for the 1,070 kW system supplies less of the building load than the fuel cell for the 610 kW system because storage for the 1,070 kW system is smaller than for the 610 kW system and thus provides less seasonal storage than for the 610 kW system. The peak output from the PV system is about 1,070 kW, which typically occurs when the building load is 60–100 kW. Without the storage system, the transformer would need to accommodate the difference in output of close to 1,000 kW of electricity being fed onto the grid. The storage system reduces this energy flow by diverting some of the excess electricity to the electrolyzer. In the configuration analyzed, the electrolyzer reduces peak electricity flow to the grid by 220 kW, the input electricity capacity of the electrolyzer. For the 1,070 kW PV system scenario, not all peaks in energy flow to the grid are eliminated. In this scenario, there are several occasions when the energy flow to the grid exceeds 700 kW.

Table 6. Summary of Energy Flows for 1,070 kW PV System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output During Operation [h/yr])	Percent of Building Load (Building + Compressor)
PV system	1,069 kW (peak rated output)	1,672,442 kWh	18	292 (total) 51 (direct supply)
Electrolyzer	221 kW input	12,757 kg	84 [3,619]	—
Hydrogen storage	325 kg	Variable days of storage depending on the season	—	—
Hydrogen fuel cell	125 kW output	246,321 kWh	45 [4,388]	42
Grid	—	38,405 kWh	—	7
Electricity sold	—	729,410 kWh	—	44% of PV output

2.3 Vehicle-Refueling Scenarios

The vehicle-refueling system is similar to the reconversion system, except that vehicles absorb the excess energy instead of buildings, and no electricity is sold back to the grid. The vehicle refueling serves the purpose of load leveling, eliminating large electricity fluctuations and reverse power flow from the PV system through the transformer. The modeled community consists of about 100 houses (approximated with the hotel profile described previously) with corresponding vehicle-refueling demand. Electricity from the PV system supplies the building load; when PV output is less than the building load, the grid supplies the difference. The transformer and distribution lines have enough capacity to supply the peak building load. Figure 7 shows a schematic of the system.

The PV system also produces all fuel for the vehicles (i.e., the grid does not supply electricity for vehicle fuel). Two types of vehicle-refueling systems are compared in this analysis. One uses electrolytic hydrogen production for hydrogen-powered vehicles (Figure 8), and the other uses battery storage for charging plug-in electric vehicles (Figure 9).

The vehicle-refueling cost analysis was performed for two cases:

- Case 1—All PV electricity output in excess of the building load is used for vehicle refueling.
- Case 2—All PV electricity output before noon is used for vehicle refueling in addition to all PV output in excess of the building load.

Figure 10 shows schematics of the PV electricity output used for vehicle refueling in Case 1 and Case 2.

In the hydrogen vehicle-refueling analysis, an electrolyzer is sized to accommodate the maximum electricity production used to generate hydrogen.[2] The compressor is sized to the peak hourly hydrogen flow rate. The storage system is assumed to cycle fully each day (i.e., there is no multi-day storage). The amount of hydrogen storage needed was calculated by running the model with very large daily hydrogen demand to ensure that the analysis simulates daily cycling of the storage system. The storage volume needed was then set at the maximum amount of hydrogen in storage at any time during the year (for the very high demand case) plus 50% or a minimum value for a full tank refueling based on the assumed cascade system volume of 65 kg. This results in about 75 kg of storage for the smallest system (185 kW PV Case 1), which produces only an average of approximately 5 kg/day. A relatively large excess storage was assumed for the larger systems to account for the large daily fluctuations in PV output and the fact that actual hydrogen refueling is likely to be less uniform than modeled. The analysis does not assume that the additional storage accounts for seasonal variations in hydrogen/electricity demand or production. Month-to-month variations in production are not large; the average monthly hydrogen production for the 610 kW system is ~1,200 kg/month with a standard deviation of ~140 kg/month. However, the high and low production months (March and December, respectively) only roughly correspond to expected high and low demand months (June–August and November–January, respectively); so in reality, it might be necessary to refuel vehicles off site occasionally during part of the summer. There is also a predictable dip in PV output during the hottest part of the summer, when fuel demand is expected to peak. Although the analysis did not explicitly address seasonal variations in production or demand, it is likely that the additional storage modeled would be sufficient to accommodate them.

One 350-bar hydrogen dispenser with two hoses is used for daily hydrogen production ranging from only about 5 kg/day for the 185 kW Case 1 system to about 90 kg/day for the 1,070 kW Case 2 system. It is expected that hydrogen fuel cell vehicles used primarily for commuting would be refueled about once per week. Although most vehicle manufacturers are planning for 700-bar refueling, 350-bar dispensing is assumed for this analysis. Vehicles designed for the higher pressure are capable of being refueled at lower pressure (although the tank cannot be completely filled), and 700-bar dispensers are considerably more complex and expensive than

[2] In this analysis, the maximum electricity production used to generate hydrogen is calculated for two cases: In Case 1, it is the difference between the PV output and the building load, and in Case 2 it is the amount in Case 1 plus all PV electricity generated before noon.

350-bar dispensers. The additional expense was not felt to be justified for the low throughput of hydrogen and community-based refueling envisioned in this study.

The alternative vehicle-refueling system uses electricity to charge a zinc-air storage battery system consisting of one or more batteries that may be located together or distributed through the community. The batteries are used to store energy for a brief period (less than 1 day) so that battery-electric vehicles can be charged in the evening and overnight. The battery system is sized to accommodate the maximum difference between the PV daily output (kWh) and the building load plus 50% in order to have enough capacity to charge several vehicles (for the smaller system cases) and to more closely match the hydrogen systems. The battery system is assumed to discharge fully each day (i.e., there is no multi-day storage), and each vehicle is refueled with a home-based Level 1 (120V) charging unit (comparable to a 350-bar hydrogen system). The zinc-air battery/vehicle charging system is assumed to have an overall electrical efficiency of 73%.[3] The purpose of modeling this battery-electric system is to provide a reasonable contrast with the hydrogen fuel cell system rather than to model a real-world battery-electric system in detail.

The hydrogen and electric vehicles are assumed to have identical charging profiles every day of the year, and all vehicles are refueled between 4:00 p.m. and 9:00 p.m. Although this is a more realistic profile for hydrogen refueling than for electric vehicle nighttime charging, the differences in profiles do not affect the analysis because neither type of vehicle would be refueled at a time when a significant amount of PV electricity could be used directly for vehicle fueling. In all cases, the amount of fuel produced is determined by how much of the PV output can be directed to the battery or electrolyzer. Therefore, the same amount of electricity is used for vehicle refueling whether the vehicles are powered by hydrogen or electricity; the battery-electric system simply powers more vehicles because of its higher efficiency.[4] Figure 11 shows the vehicular hydrogen/electricity demand profile along with the building electricity demand profile. Figure 12 shows all the system energy flows. Table 7 and Table 8 show the energy flows for Cases 1 and 2.

[3] Zinc-air battery round-trip efficiency was assumed to be slightly less than the value reported by Rastler (2010) to account for losses in home charging of vehicles.
[4] The all-electric vehicles are based on a Nissan Leaf with a 100-mile all-electric range that is driven 12,000 miles per year.

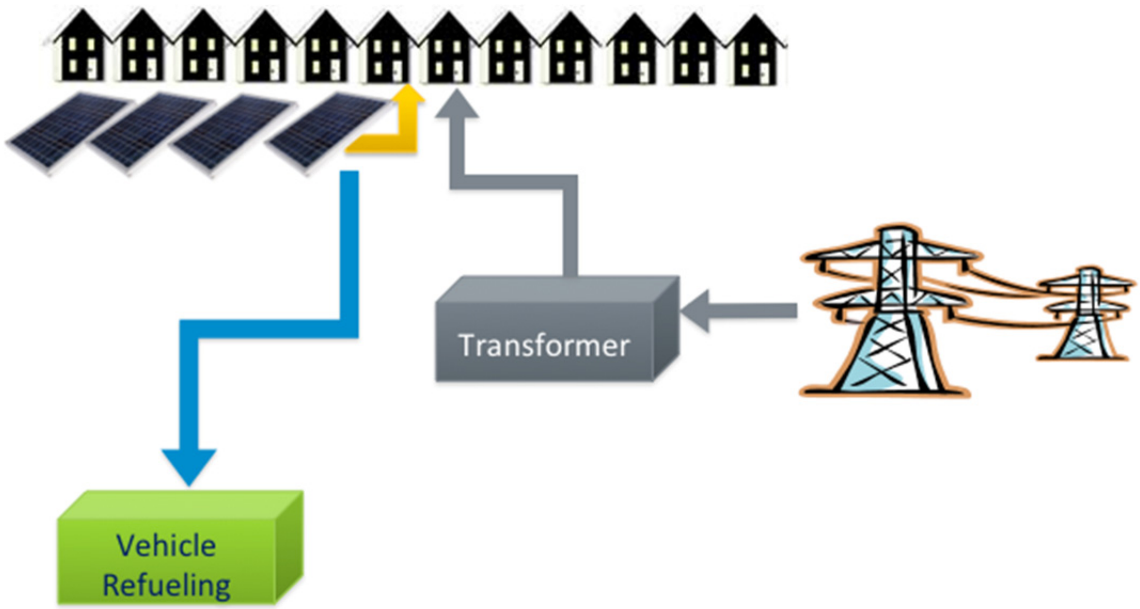

Figure 7. Schematic diagram of equipment and energy flows for the vehicle-refueling system. (There is no energy flow from the vehicle-refueling system to the building.)

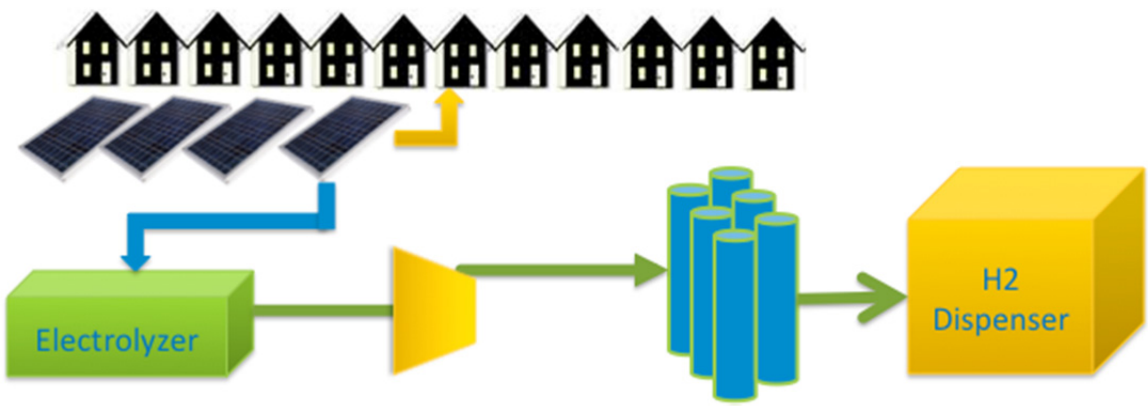

Figure 8. Detail of hydrogen vehicle-refueling configuration. (There is no energy flow from the vehicle-refueling system to the building.)

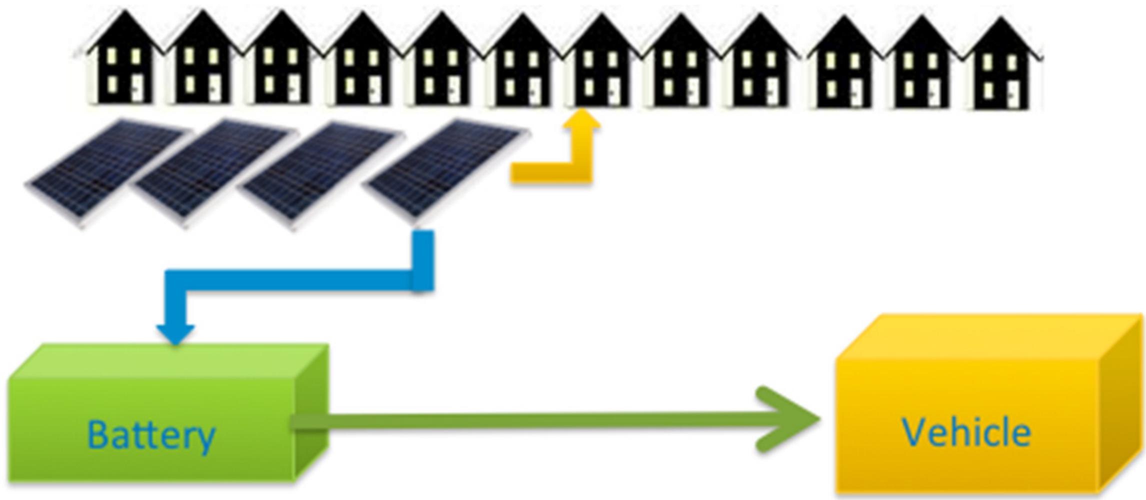

Figure 9. Detail of alternative (battery) vehicle-refueling configuration. (There is no energy flow from the vehicle-refueling system to the building.)

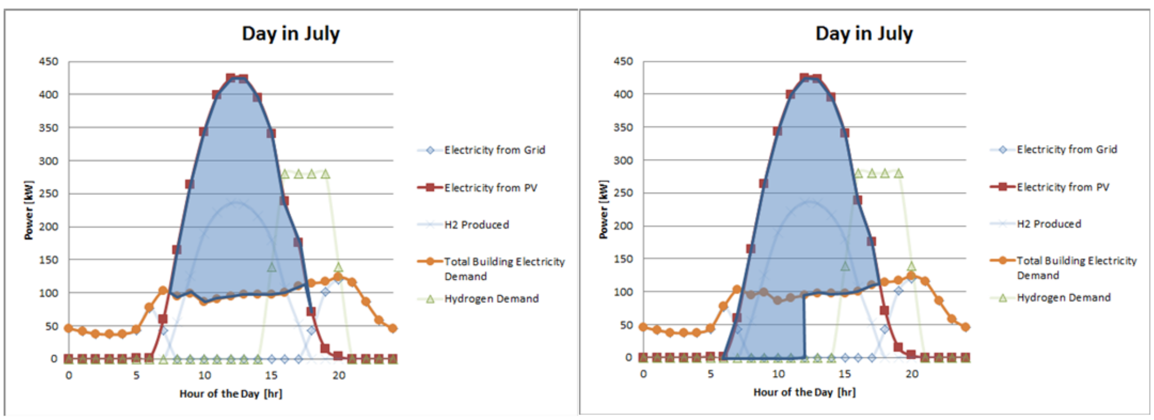

Figure 10. PV electricity output used for vehicle refueling in Case 1 (left) and Case 2 (right)

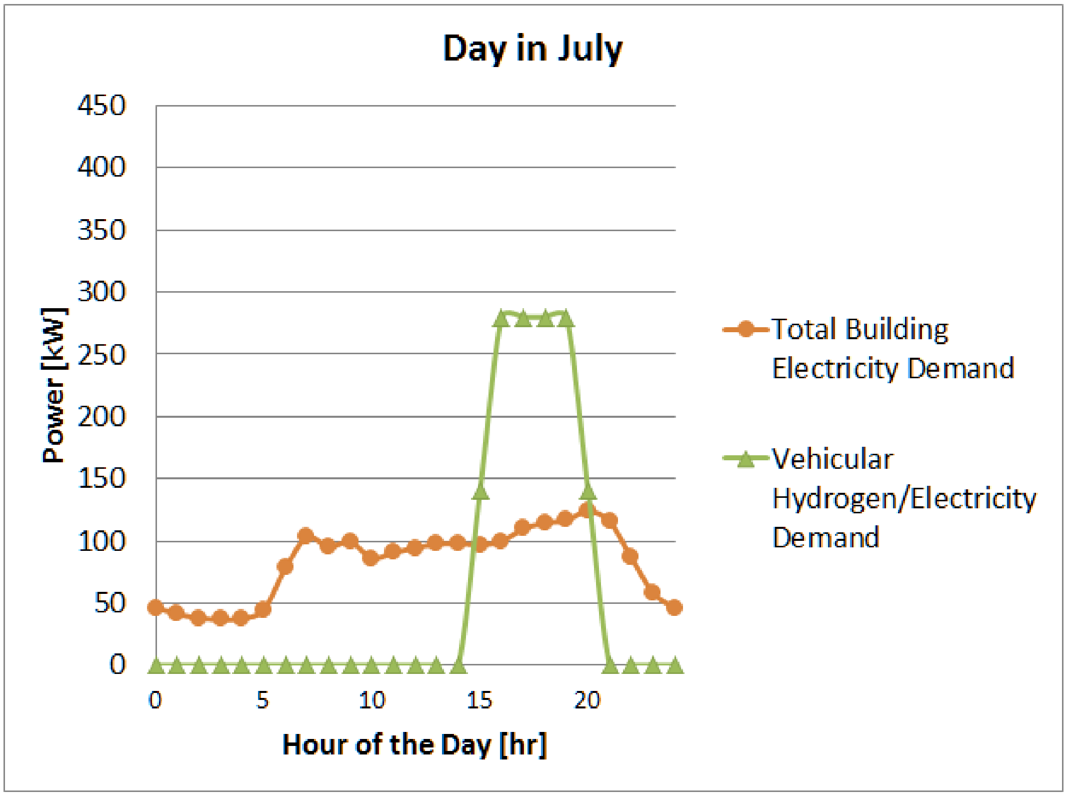

Figure 11. Example vehicular hydrogen/electricity demand profile (610 kW PV system)

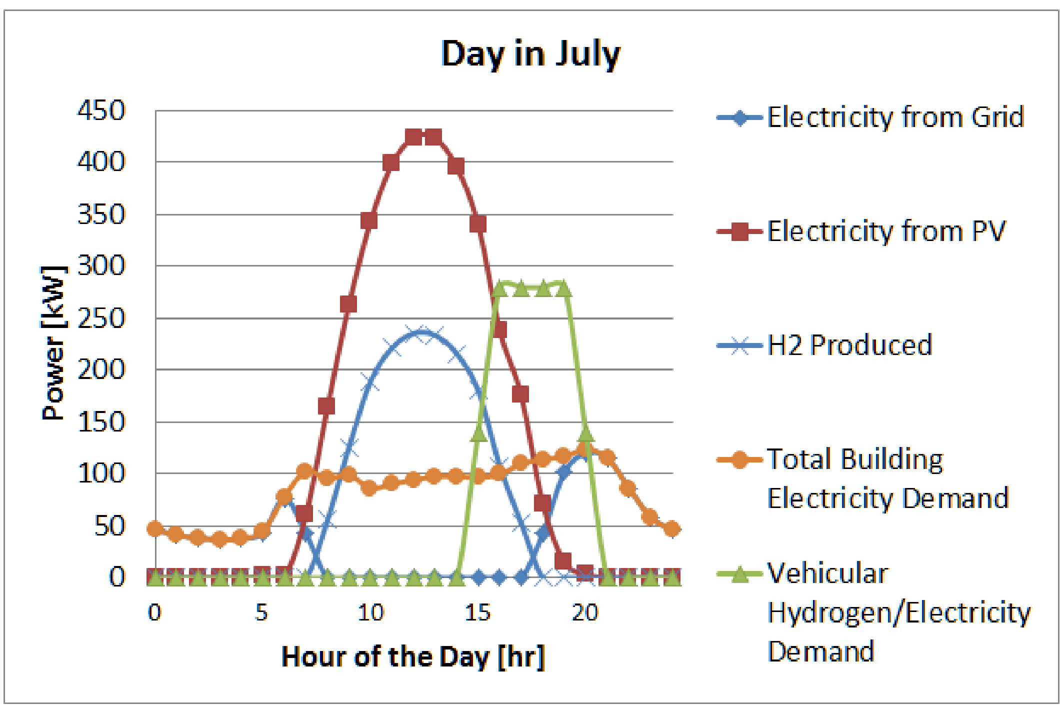

Figure 12. Building electricity demand, vehicular hydrogen/electricity demand, PV and grid electricity supply, and hydrogen produced (or electricity to storage) during a typical day in July (610 kW PV system)—Hydrogen Case 1

Table 7. Summary of Energy Flows for Vehicle-Refueling System (Hydrogen and Battery/Electric Systems)—Case 1

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output During Operation [h/yr])	Percent of Building Load
185 kW PV System				
PV system	183 kW	286,704 kWh	18	50 (total) 35 (direct supply)
Electrolyzer (H_2 system)	127 kW input	1,804 kg	36 [1,904]	—
Hydrogen storage (H_2 system)	75 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	61,726 kWh	—	—
Battery storage (battery system)	589 kWh	~ 1 cycle per day	—	—
Grid	—	370,486 kWh	—	65
610 kW PV System				
PV system	611 kW	955,681 kWh	18	167 (total) 47 (direct supply)
Electrolyzer (H_2 system)	560 kW input	14,564 kg	40 [3,265]	—
Hydrogen storage (H_2 system)	85 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	500,755 kWh	—	—
Battery storage (battery system)	2,954 kWh	~ 1 cycle per day	—	—
Grid	—	303,744 kWh	—	53
1,070 kW PV System				
PV system	1,069 kW	1,672,442 kWh	18	292 (total) 51 (direct supply)
Electrolyzer (H_2 system)	1,013 kW input	29,274 kg	39 [3,669]	—
Hydrogen storage (H_2 system)	165 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	1,008,212 kWh	—	—
Battery storage (battery system)	5,530 kWh	~ 1 cycle per day	—	—
Grid	—	283,082 kWh	—	49

Table 8. Summary of Energy Flows for Vehicle-Refueling System (Hydrogen and Battery/Electric Systems)—Case 2

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output During Operation [h/yr])	Percent of Building Load
185 kW PV System				
PV system	183 kW	286,704 kWh	18	50 (total) 21 (direct supply)
Electrolyzer (H_2 system)	105 kW input	3,541 kg	36 [3,137]	—
Hydrogen storage (H_2 system)	90 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	121,936 kWh	—	—
Battery storage (battery system)	2,493 kWh	~ 1 cycle per day	—	—
Grid	—	453,078 kWh	—	79
610 kW PV System				
PV system	611 kW	955,681 kWh	18	167 (total) 27 (direct supply)
Electrolyzer (H_2 system)	554 kW input	16,985 kg	38 [3,907]	—
Hydrogen storage (H_2 system)	95 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	585,475 kWh	—	—
Battery storage (battery system)	3,305 kWh	~ 1 cycle per day	—	—
Grid	—	419,957 kWh	—	73
1,070 kW PV System				
PV system	1,069 kW	1,672,442 kWh	18	292 (total) 28 (direct supply)
Electrolyzer (H_2 system)	1,013 kW input	31,898 kg	38 [4,110]	—
Hydrogen storage (H_2 system)	165 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	1,095,214 kWh	—	—
Battery storage (battery system)	5,914 kWh	~ 1 cycle per day	—	—
Grid	—	410,195 kWh	—	72

2.4 Comparison of Reconversion and Vehicle-Refueling Systems

The general strategy employed for the reconversion cases was to minimize and smooth the electricity demand that must be met by the grid. In the vehicle-refueling cases, the strategy focused on producing vehicle fuel (either hydrogen or electricity) exclusively from the renewable resource in the most cost-effective manner. Figure 13 illustrates the effect of each strategy on the amount of grid electricity purchased monthly for the 610 kW case. Note that some grid electricity is purchased almost every month for the storage scenario case, especially during the winter, even though the solar panels produce almost double the building load overall and produce nearly 50% more electricity than the building load during the winter. This occurs because the storage system, which is large enough to accommodate seasonal variations in PV system output (see Figure 14) for the energy storage scenario, gradually empties in the fall as PV daily electricity production decreases. During the winter, only electricity produced that day is available for electricity generation from the hydrogen fuel cell in the evening and overnight. On a cloudy day when little electricity is generated by the PV panels, there is no “cushion” of hydrogen in storage, and electricity must be purchased. For the two hydrogen vehicle cases, the electricity used to generate hydrogen is permanently removed from the electrical system for the building and grid. There is no electricity generation from the storage system. The grid electricity needed to satisfy the building load is reduced because some electricity from the PV system can be directly routed to the building. Less grid electricity is required for hydrogen vehicle Case 1 (purple line in Figure 13) than for hydrogen vehicle Case 2 (green line in Figure 13) because the electricity from the solar panels is routed to the building for a longer period each day in Case 1. In all cases, the grid demand is reduced and smoothed as compared to the building demand alone.

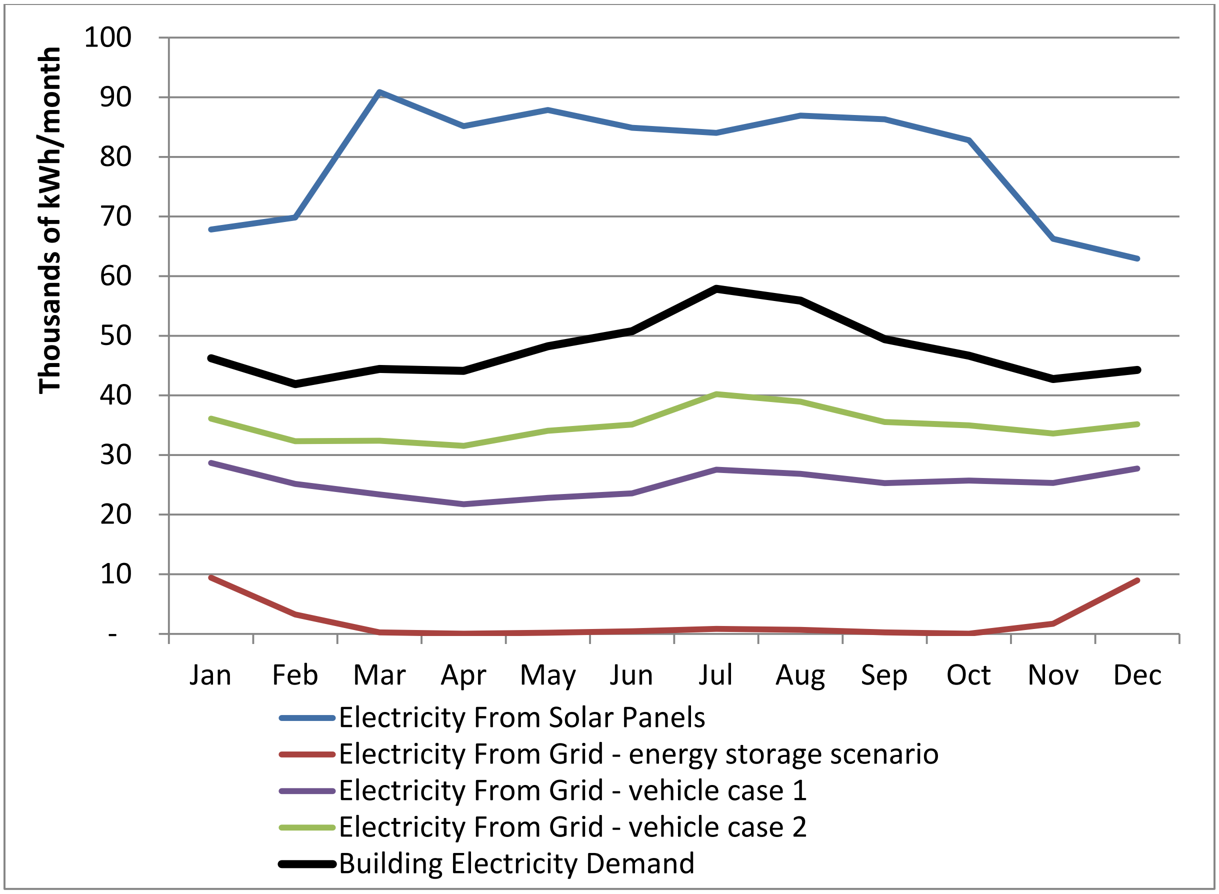

Figure 13. Monthly PV system output and electricity from the grid (610 kW PV system)

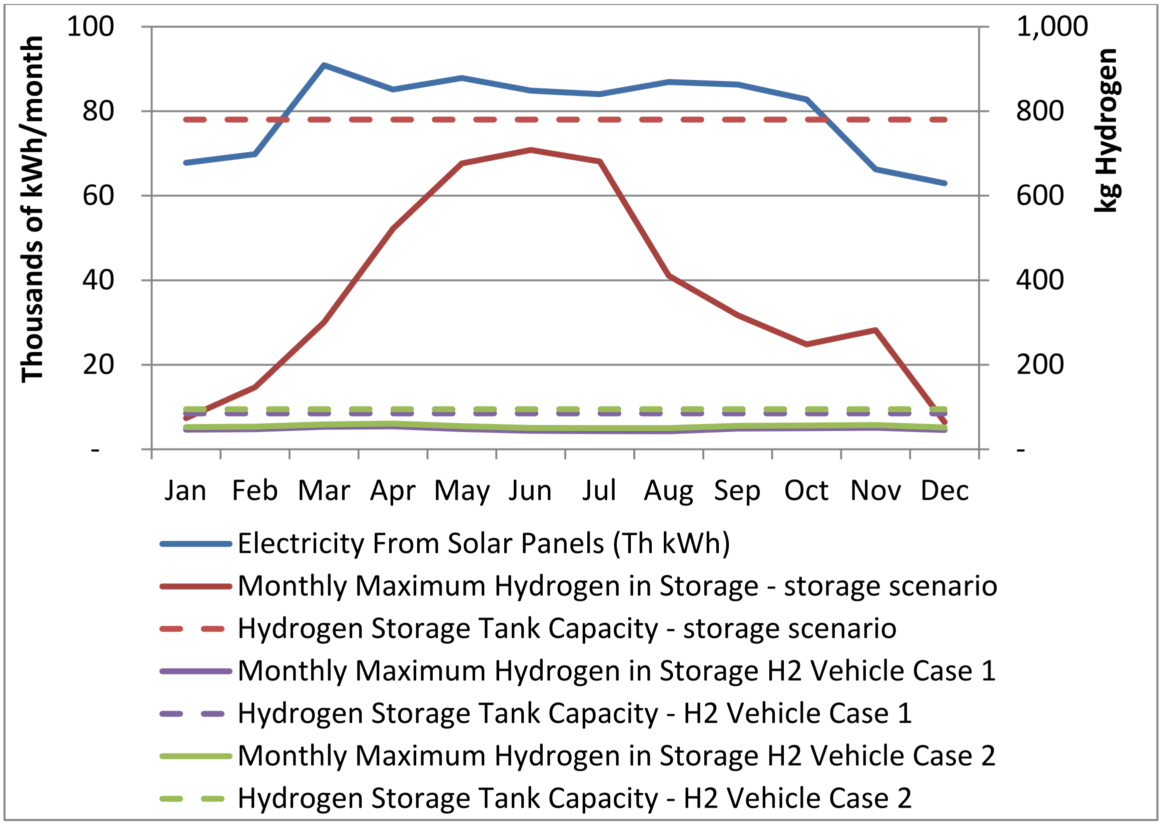

Figure 14. Monthly maximum hydrogen in storage for various scenarios (610 kW PV system)

The smoothing effect of energy storage and diversion of excess PV production to vehicles is illustrated in Figure 15, which plots the maximum daily fluctuations in PV output and grid interactions for the 610 kW PV system case. Electricity that would have been routed to the grid in the absence of a storage or vehicle-refueling system is shown in orange. With no storage or vehicle-refueling system, the maximum difference within a single day between drawing electricity from the grid and routing electricity to the grid is 633 kW. With storage, the maximum is 103 kW, and with either of the hydrogen vehicle-refueling systems, the maximum is 131 kW.

Monthly PV output and electricity from the grid for the 1,070 kW case is shown in Figure 16. Monthly maximum hydrogen in storage is shown in Figure 17.

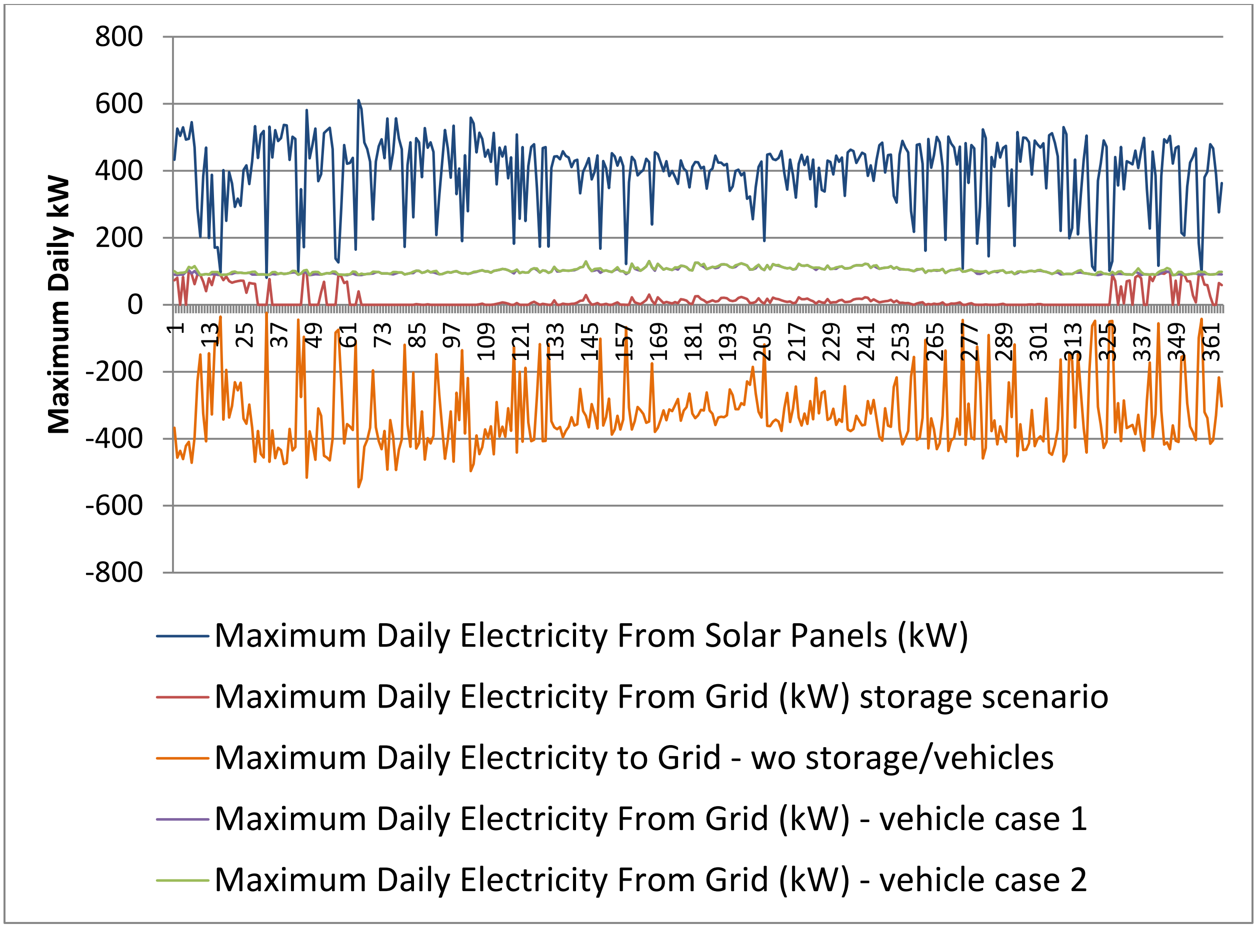

Figure 15. Maximum daily fluctuations in PV system output and grid interactions (610 kW PV system)

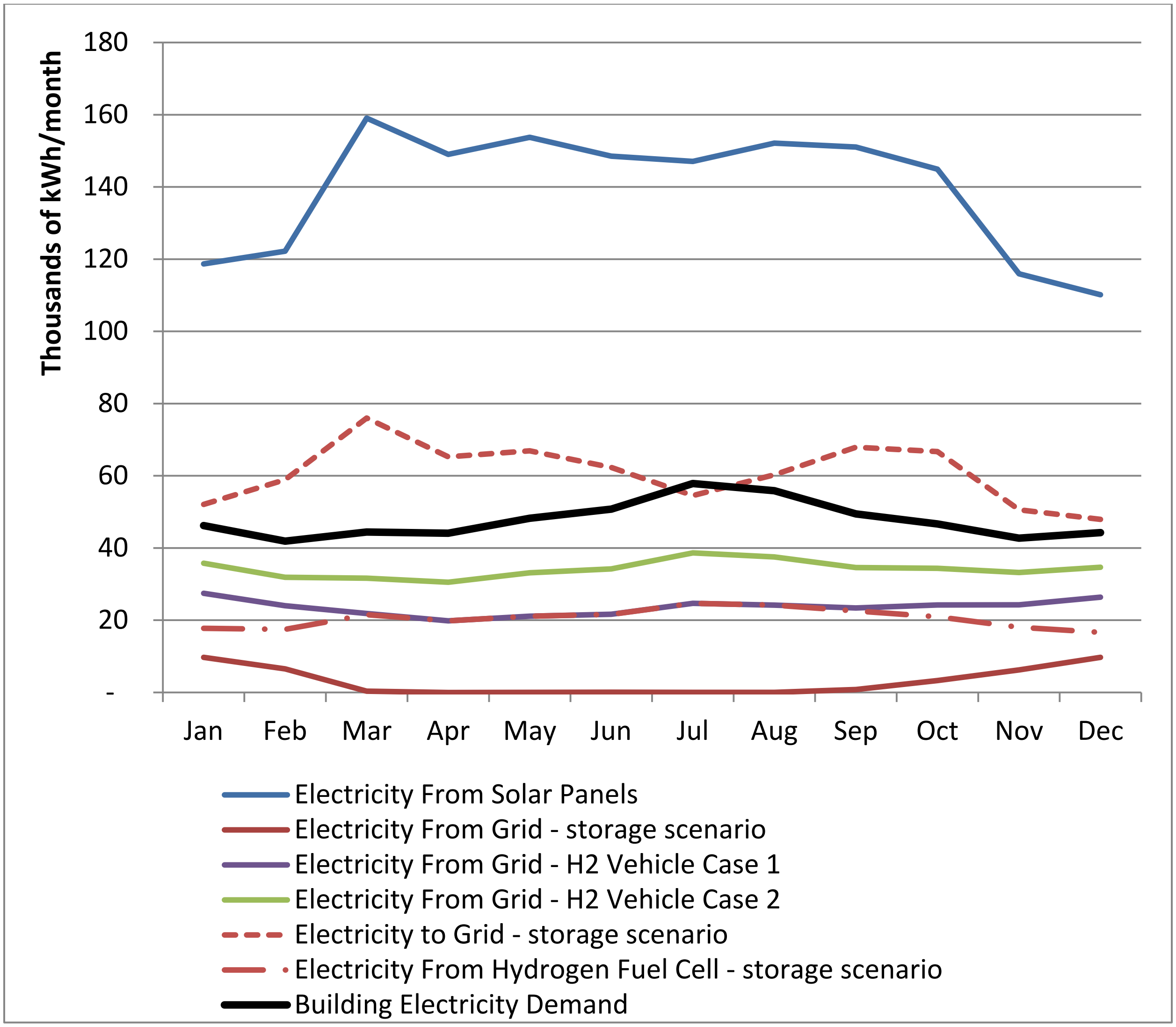

Figure 16. Monthly PV system output and electricity from the grid (1,070 kW PV system)

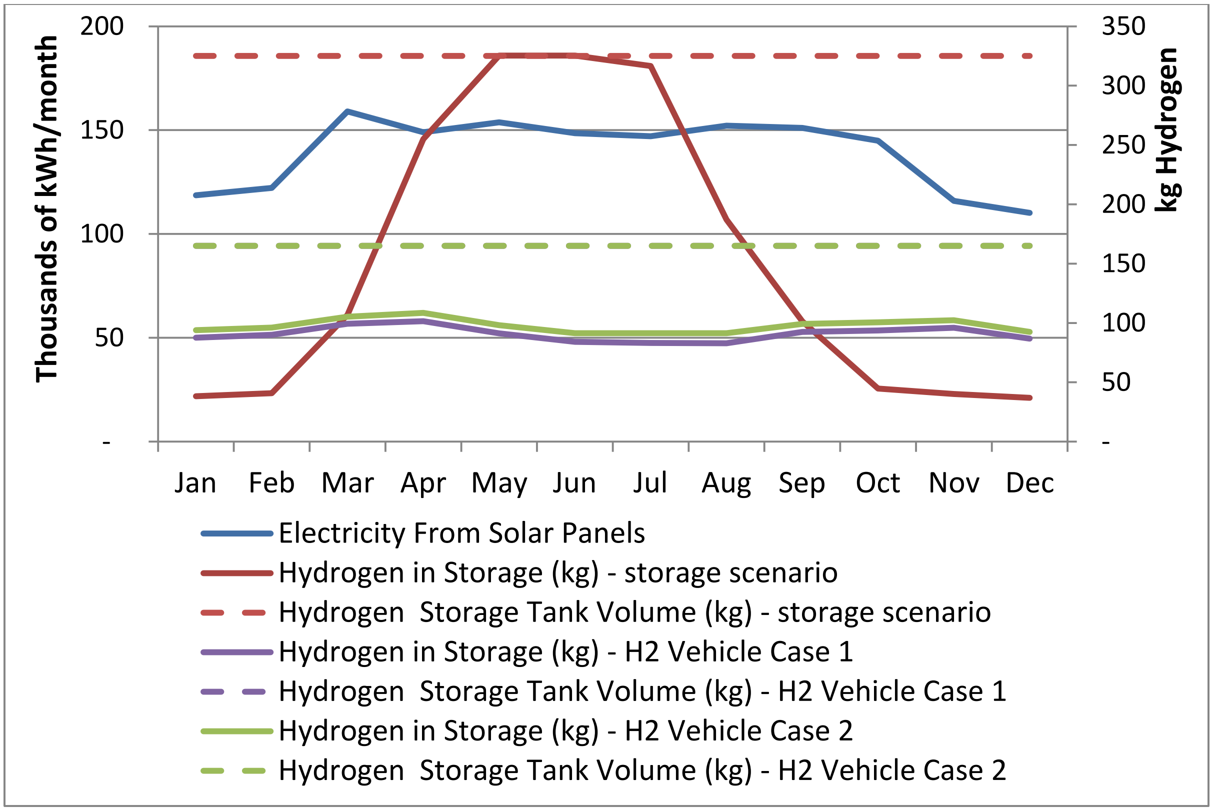

Figure 17. Monthly PV system output and electricity from the grid (1,070 kW PV system)

3 Cost Analysis Results

A modified version of the NREL Fuel Cell Power (FCPower 2012) spreadsheet model was used as the basis for the economic analyses for the community energy storage scenarios. The FCPower model incorporates the lifecycle discounted cash flow methodology developed for the H2A hydrogen production model (DOE H2A Production Analysis 2012). A detailed explanation of the economic methodology is provided in an NREL technical manual for the economic evaluation of energy efficiency and renewable energy projects (Short et al. 1995). Cash flows, including revenues, variable and fixed operating expenses (such as fuel, labor, interest on debt, and taxes), capital expenditures, and repayment of principal, are aggregated yearly over the lifetime of the project. This methodology captures the time dependence of costs and revenues over the life of the project. For example, the methodology accurately captures costs associated with replacement of equipment components at specific times in the future. All per kWh or per kg costs presented are levelized costs, including all direct and indirect costs and operating expenses over the life of the system.

An initial analysis of the PV system alone (without a storage system) was performed to establish a baseline cost for the PV-generated electricity. Because the PV system capital costs are assumed to be the same on a $/watt basis for all three system sizes, the levelized cost of energy (LCOE) of electricity generated over the 30-year assumed life of the system is the same: 15¢/kWh for all of the systems. This value was used as the "selling price" for electricity routed directly to the building. In this way, the cost of the solar system was apportioned between the building and the storage/vehicle fuel production system. The apportioned cost of the solar system is included in the LCOE results of the storage or fuel production cases unless specifically stated otherwise.

Table 9 lists the equipment and associated costs for the community energy storage scenarios. All equipment costs are assumed to scale linearly within the size ranges of the analysis except compressor costs, which scale with kW power rating, and control and safety equipment and electrical upgrades for the hydrogen systems, which are assumed to be fixed costs. Table 10 lists the financial parameters used in the analysis.

Table 9. Equipment Costs for Reconversion and Vehicle-Refueling Scenarios

Equipment Costs 2010$					
	Unit	**Equipment Size Range**	**Cost Unit**	**Cost (Installed) [replacement/ refurbishment % of installed cost/interval]**	**Installed Cost Reference**
Electrolyzer	kW	105–1,013	$/kW input	~$600 [25%/10 years]	HTAC (2011). ($750 including all balance-of-plant and indirect costs. DOE Independent Review [2009] installed cost ~$540/kW [2010])
Hydrogen storage tanks (load leveling)	kg	16–780	$/kg H_2	~$1,350	H2A (2012). Installed cost for low-pressure storage
Hydrogen storage tanks (vehicle refueling)	kg	75–165	$/kg H_2	~$1,350–$1,400	H2A (2012). Installed cost for low-pressure and cascade storage
Hydrogen storage compressor + balance-of-plant, installed (load leveling)	kW	4–20	$/kW	$11,000–$7,200 [100%/10 years]	H2A (2012)
Hydrogen storage compressor (vehicle refueling)	kW	5–44	$/kW	$10,400–$2,600	H2A (2012)
Hydrogen fuel cell	kW	15–125	$/kW	~$950 [30%/15 years]	HTAC (2011)
Hydrogen dispenser	—	1	$/unit	~$64,000	H2A (2012)
Zinc-air battery	kWh	600–6,000	$kWh	$315	Rastler (2010). Based on max kWh in “storage” at any time
Electrical upgrades and charging stations	—	—	$	5% of installed battery cost	HTAC (2011)

Equipment Costs 2010$					
	Unit	**Equipment Size Range**	**Cost Unit**	**Cost (Installed) [replacement/ refurbishment % of installed cost/interval]**	**Installed Cost Reference**
PV system	kW	180–1,070	$/kW installed	~$2,500	HTAC (2011) (Barbose et al. [2012] installed cost for >100kW residential or commercial systems ~$4.75/W 2011$)
Indirect costs (site preparation, engineering, contingency, permitting)			28% of installed equipment cost		H2A (2012)
Energy Cost					
Levelized cost of grid electricity for building supply without a PV/storage system	$0.12	$/kWh			
Revenue for electricity sold	$0.12	$/kWh			

Notes and assumptions:

1. Vehicle-refueling storage systems include low-pressure tanks (~$1,000/kg) and one cascade storage system (~$1,700/kg, 65 kg H_2 in a three-tank system).
2. For the vehicle-refueling systems, one primary compressor is assumed for both low-pressure and cascade storage: ~2.4 kW compressor power/(kg/h) H_2 flow rate.
3. The compressor system assumes a 200 psi input pressure and a 3,600 psi output pressure.
4. Model parameters are based on a 2020 planning timeframe.
5. Model parameters assume a manufacturing scale of 1,000 systems per year.

Table 10. Financial Analysis Parameters

Model Parameter	Units	Value
Insurance	% of initial direct capital	2%
Annual O&M rate	% of initial direct capital	2%
Inflation rate		2%
Total tax rate		0%
Reference dollar year for costs		2010
Financing	Debt financing, 15 years	100%
Interest rate on debt		8%
Real, after-tax rate of return required		0%
System life	years	30

Notes and assumptions:

1. Annual O&M costs are calculated as a percent of initial capital and include the periodic replacement of components. Compressor system electricity use is scaled based on the hydrogen flow rate, and is added to the building load (i.e., there is not a separate O&M cost associated with the electrical use for the compressors).

3.1 Reconversion

The LCOE from the storage system for each of the scenarios is listed in Table 11. The total direct capital cost and LCOE for the system, including the PV system cost, are calculations of the total cost of energy supplied by the combination of the PV system directly supplying electricity to the building plus the cost of routing some of the electricity through the storage system. Credit is taken for any electricity that is sold back to the grid. Electricity sold back to the grid is assumed to be sold at 12¢/kWh, which is the same price as supplementary electricity purchased from the grid. For the total direct capital cost and LCOE without the PV system costs, the costs presented are for the storage system only, and the LCOE applies only to the electricity output from the storage system. In this case, electricity from the PV system to the electrolyzer is assumed to be "free," and the costs presented represent only the cost of purchasing the equipment and non-energy operating costs for the storage system. If the electricity that is routed to the storage system could be sold for 6¢/kWh instead, the cost of electricity to the electrolyzer could be assumed to be worth 6¢/kWh. Recalculating the costs assuming that electricity routed to the electrolyzer costs 6¢/kWh, and using the 185 kW PV system case as an example, illustrates the effect of the additional cost. For the 185 kW PV case, about 32,000 kWh of electricity are produced from the storage system. At zero cost for the electricity supply to the electrolyzer, the cost of output electricity is about $1.09 per kWh. This cost increases to $1.26/kWh if the input electricity is 6¢/kWh. The output electricity cost is highly sensitive to the cost of input electricity because of the inefficiency of the electrolyzer/storage/hydrogen fuel cell system. In this case, the round-trip efficiency of the storage system is between 35% and 40%, resulting in about 2.5 kWh electricity used for every kWh of electricity produced from the fuel cell.

The LCOE for the full systems increases for the larger systems because of the high PV system costs, but variations in equipment utilization make the 1,070 kW system overall slightly lower cost than the 610 kW system. The 1,070 kW system has better utilization of the electrolyzer than the 610 kW system: 3,619 hours/year operating at an average of 84% of peak output for the 1,070 kW system, and 3,265 hours/year operating at an average of 39% of peak output for the 610 kW system. However, the fuel cell utilization is better for the 610 kW system than for the 1,070 kW system: 5,065 hours/year at 55% of peak for the 610 kW system versus 4,388 hours/year at 45% of peak for the 1,070 kW system. In the case of the 1,070 kW system, electricity produced by the PV system must be sold to the grid at a lower cost than the cost of generating it (12¢/kWh versus 15¢/kWh, respectively).

In contrast, focusing only on the cost of storing electricity shows the opposite trend. The storage system is used much more effectively for higher penetrations of PV so the costs of stored electricity decrease. Careful attention must be paid to matching the storage system to the particular application. There are many variables including the electrolyzer size, storage system size, and fuel cell size that must be considered together with the building load characteristics and PV system output to optimize the system to achieve the goals for the application.

Table 11. Reconversion System Costs with and without PV Costs Included

Scenario	Total Direct Capital Cost Including PV System ($K)	LCOE of Electricity (Direct Supply + Electricity from Storage) (¢/kWh)	Total Direct Capital Cost without PV System ($K)	LCOE of Stored Electricity (¢/kWh)[a]
185 kW PV/storage system	$727	33	$271	109
610 kW PV/storage system	$2,958	57	$1,438	62
1,070 kW PV/storage system	$3,393	45	$733	36

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system.

The equipment cost breakdown for scenarios analyzed is shown in Figure 18. The balance-of-plant components, including electrical upgrades and control and safety equipment, are included in the category labeled “Hydrogen Compressor.” In these scenarios, the hydrogen storage system (compressor and storage tanks) comprises more than 50% of the non-PV system costs. The electrolyzer cost is higher than the fuel cell cost in all cases even though the electrolyzer is lower cost than the hydrogen fuel cell on a per-kW basis. This occurs because the electrolyzer must be sized to capture electricity produced by the PV system during a relatively short period in the middle of the day when PV output peaks and demand is relatively low. In contrast, the hydrogen fuel cell can be sized to slowly feed electricity back to the building load during a relatively long period when demand is steady and there is no PV output. The results of an analysis of the sensitivity of the 610 kW PV system case output electricity cost to equipment cost are presented in Figure 19.

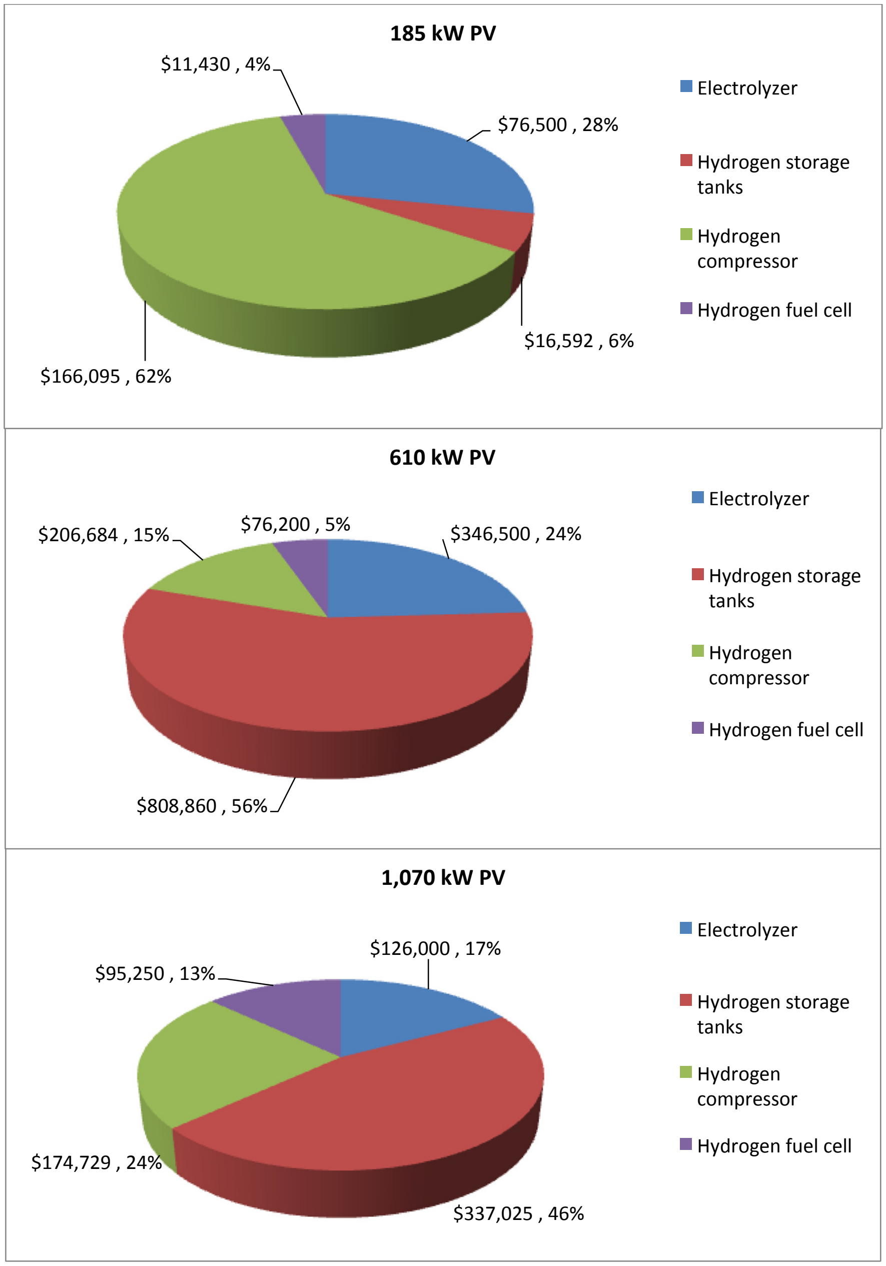

Figure 18. Capital cost breakdown for hydrogen storage systems for 185 kW PV system (top), 610 kW PV system (center), and 1,070 kW PV system (bottom)

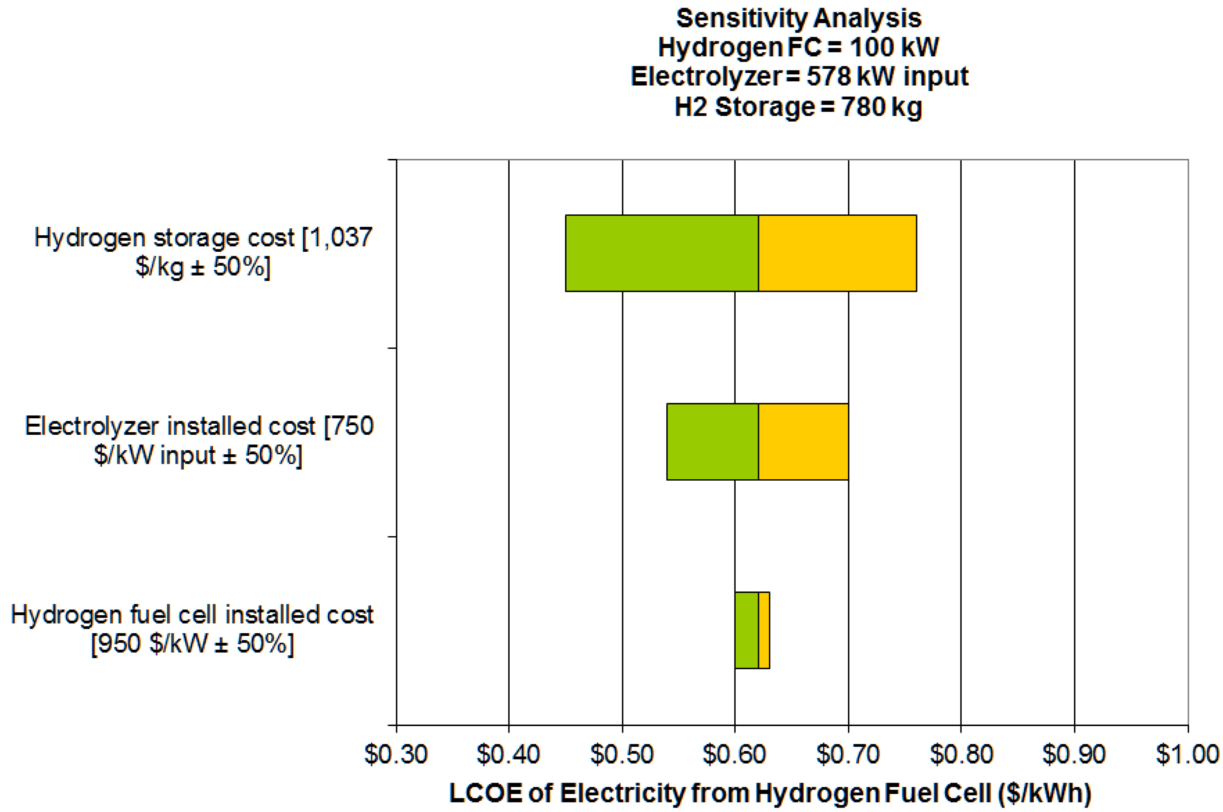

Figure 19. Sensitivity of output electricity LCOE to equipment cost for the 610 kW PV system case

3.2 Vehicle Refueling

Figure 20 shows the total system capital costs for Case 1. The PV system dominates the capital costs followed, for the larger systems, by the electrolyzer. Figure 21 shows the capital cost breakdown for the hydrogen system only. The electrolyzer accounts for 16% (185 kW PV system), 40% (610 kW system), and 45% (1,070 kW system) of the hydrogen system costs. For the smallest PV system, hydrogen storage accounts for the largest capital cost (22%).

Figure 22 compares the hydrogen system capital costs of Case 1 versus Case 2. For the smallest PV system, Case 2 capital costs are substantially higher, primarily owing to higher hydrogen storage and electrolysis costs. For this system, 96% more hydrogen is produced annually in Case 2 than in Case 1 because the extra PV output used to produce hydrogen before noon in Case 2 accounts for almost as much total hydrogen production as the PV output in excess of the building load. Thus, the electrolyzer and hydrogen storage must be substantially larger in Case 2 than in Case 1 to accommodate the higher hydrogen production rates and extra hydrogen storage. As the PV system size increases, the contribution of the extra morning hydrogen production becomes smaller. For the 610 kW system, Case 2 produces only 17% more hydrogen annually than Case 1, and Case 2 capital costs are only slightly higher. For the 1,070 kW system, Case 2 produces only 9% more than Case 1, and the capital costs are almost identical.

Table 12 summarizes the Case 1 and Case 2 cost results for both the hydrogen and battery-electric vehicle-refueling systems. On a per-mile basis, electric storage/refueling is 30% to 60% of the cost of hydrogen storage/refueling. The largest differential is for the 185 kW PV system, for which the hydrogen capital cost is about twice as high as the battery-electric capital cost (Figure 23). For the 610 kW and 1,070 kW PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles versus 55.6 kWh/100 miles for fuel cell electric vehicle [DOE 2013] still results in a lower per-mile cost for the battery-electric vehicle system.

In both cases, for the hydrogen and electric systems, diverting more electricity from the PV system for vehicle refueling improves the economics; this effect is more pronounced for the hydrogen system. The best hydrogen cost is from the Case 2 1,070 kW PV system. In this scenario, about 90% of the PV output goes to hydrogen production or battery storage, and the PV system supplies 28% of the building load. The hydrogen system produces about 32,000 kg of hydrogen per year (about 90 kg/day), enough to supply 159 vehicles, at a cost of $11/kg or 19 ¢/mile.

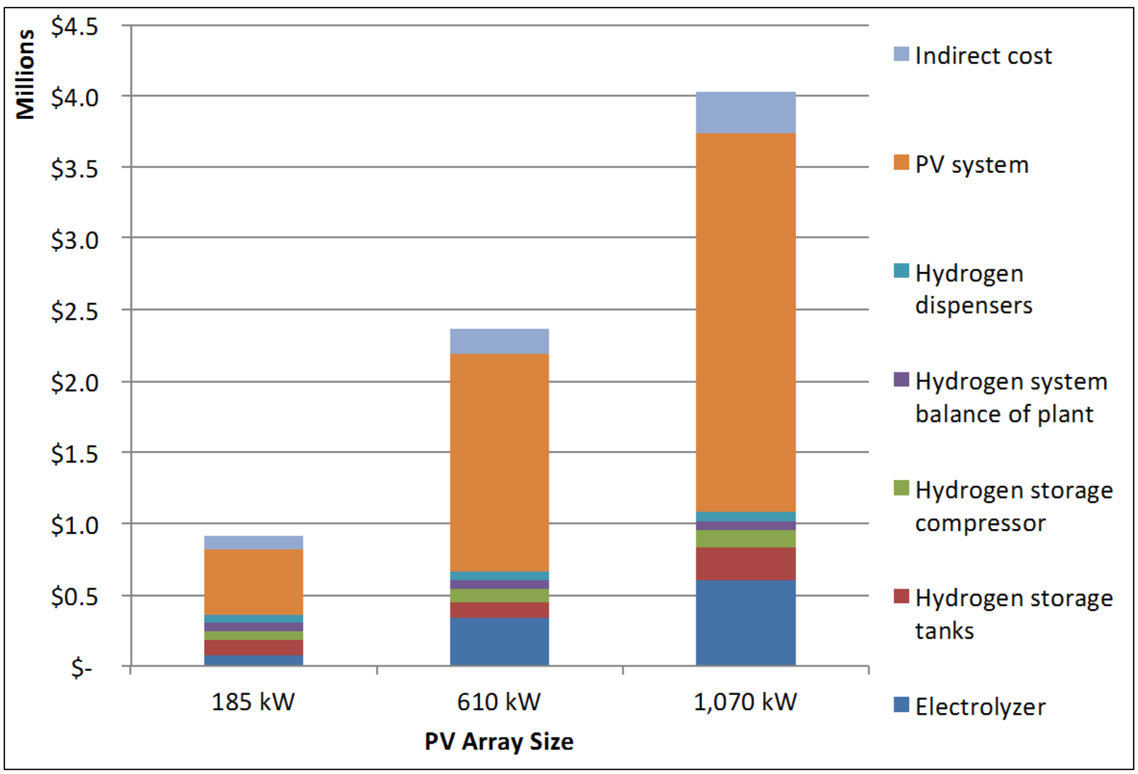

Figure 20. Total PV-hydrogen system capital costs—Case 1

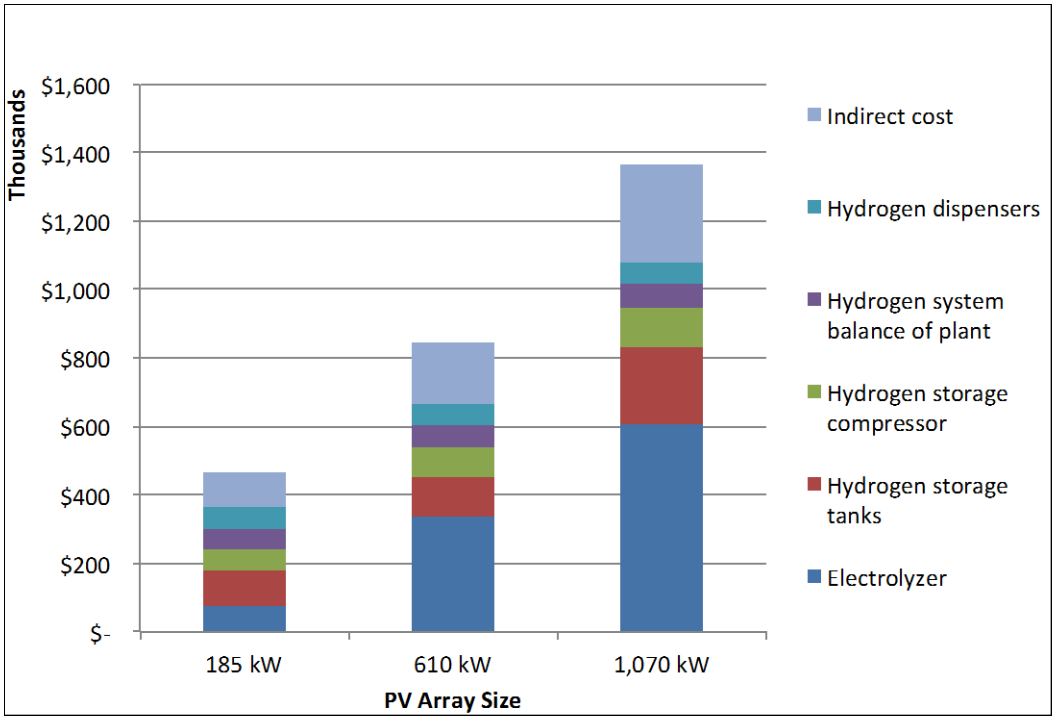

Figure 21. Hydrogen system capital costs—Case 1

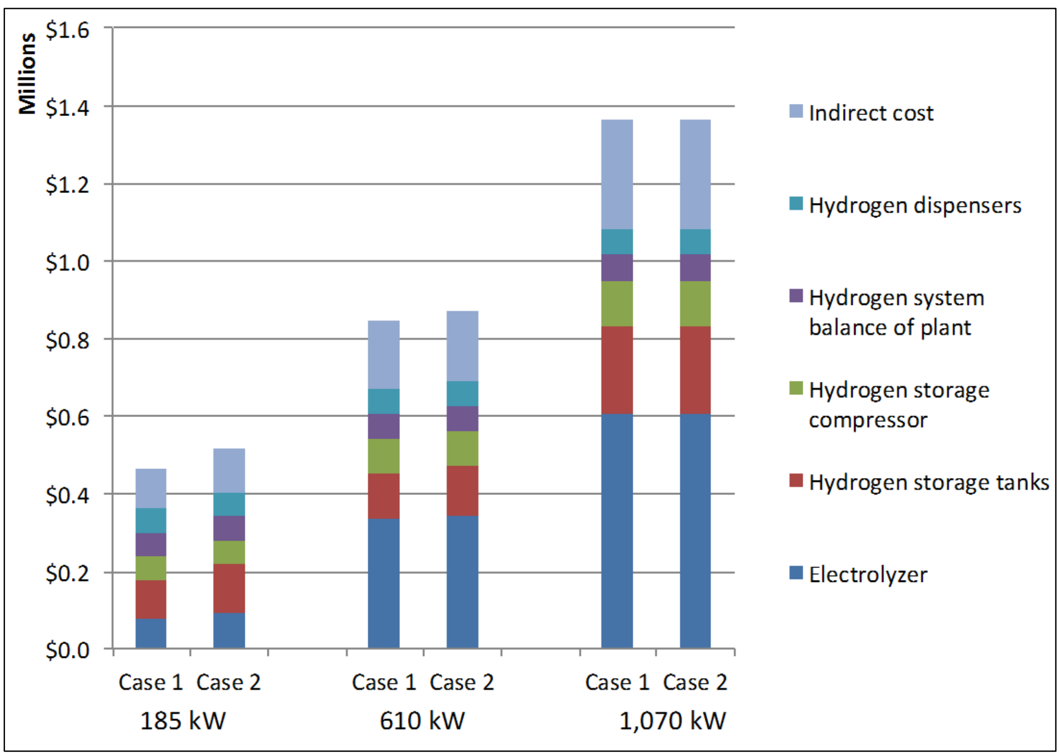

Figure 22. Comparison of hydrogen system capital costs between Case 1 and Case 2

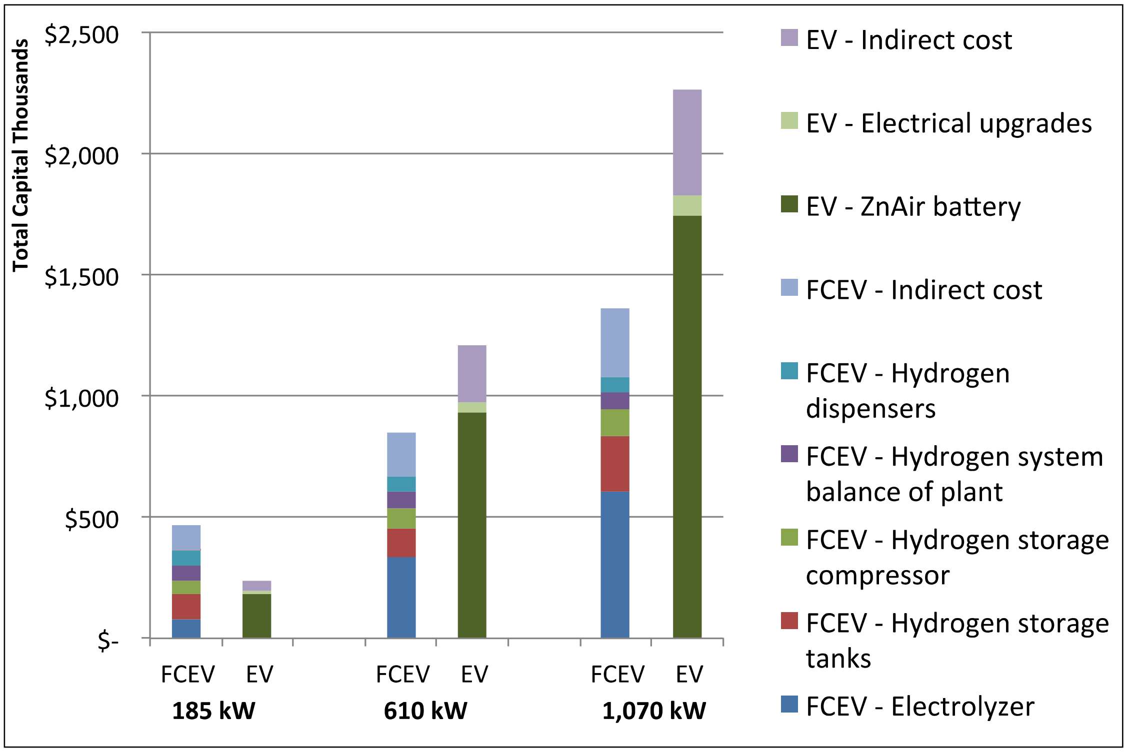

Figure 23. Capital costs of hydrogen (FCEV) and battery-electric (EV) systems—Case 1

Table 12. Summary of Vehicle-Refueling Cost Results

Hydrogen for Fuel Cell Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (kW)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)/ ($/kWh)	H_2 Cost (¢/mi)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)/ ($/kWh)	H_2 Cost (¢/mi)
185	1,804	9	34/1.01	56	3,541	17	22/0.66	38
610	14,564	72	13/0.39	22	16,985	84	12/0.37	21
1,070	29,274	146	12/0.35	20	31,898	159	11/0.34	19
Electricity for Battery-Electric Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (kW)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)
185	61,726	17	0.57	17	121,936	35	0.45	13
610	500,755	143	0.41	12	585,475	168	0.40	12
1,070	1,008,212	289	0.39	11	1,100,877	316	0.39	11

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system. For the 610 and 1,070 kW PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles vs. 55.6 kWh/100 miles for fuel cell electric vehicles [DOE 2013]) still results in a lower per-mile cost for the battery-electric vehicle system.

4 Conclusions

These simple analyses show the potential application of hydrogen production, storage, and electricity-generation technologies for community load leveling and vehicle refueling. Although the results do not show a clear advantage for hydrogen load leveling or vehicle refueling, the analysis does indicate that the economics could be improved, especially for larger systems.

The primary goal of the reconversion scenario was to evaluate storage systems for load leveling under the constraint of a limited grid/transformer size. The systems were sized to meet this goal, but not fully optimized for cost. The results of the analyses indicate that storage systems are more cost effective for higher penetrations of renewable electricity generation. In all cases, however, the electricity produced by the storage system was more expensive than grid electricity. Therefore, the storage system must provide benefits in addition to cost, such as relieving grid congestion and/or providing backup power, in order to be cost effective. A sensitivity analysis for equipment costs for the 610 kW energy storage case revealed that the LCOE of output electricity was most sensitive to the hydrogen storage tank cost (Figure 19). However, the overall system cost is also highly dependent on the configuration of the system and the relative sizes/capacities of the various pieces of equipment as shown by the wide variation in the relative sizes of equipment for the three PV system sizes analyzed (Figure 18).

In all scenarios, the storage system reduced peaks and valleys in grid demand and energy fed onto the grid (see Figure 15). The leveling effect was the most pronounced for the larger systems. However, the analysis also showed that additional optimization and/or control of the storage systems would be needed to completely eliminate large spikes in energy flow. For the 610 kW PV system case, which is most closely matched to the building demand, the storage system and vehicle systems reduced the daily fluctuations in grid demand by almost 80% and completely eliminated reverse flow of electricity to the grid. The 610 kW system storage scenario was also able to accommodate the seasonal variation in PV output, allowing for all of the energy produced by the PV system throughout the year to be used on site. Storage that can smooth seasonal variations as well as daily variations in PV system output may be advantageous for very high levels of PV penetration.

This brief analysis shows that community level hydrogen refueling using only renewably generated electricity could be accomplished. For the 610 kW PV system case, the number of fuel cell vehicles that could be refueled roughly matches the total number of vehicles expected for the community size modeled (100 households). The vehicle-refueling scenarios were configured so that the storage systems, either hydrogen or battery, were cycled approximately daily with a fairly generous “cushion” for expected fluctuations in demand over the course of a few days or a week. The analysis does not assume that the additional storage accounts for seasonal variations in hydrogen/electricity demand or production. Month-to-month variations in production are not large. However, the high and low production months (March and December, respectively) only roughly correspond to expected high and low demand months (June–August and November–January, respectively). There is also a predictable dip in PV output during the hottest part of the summer, when fuel demand is expected to peak. Although the analysis did not explicitly address seasonal variations in production or demand, it is likely that the additional storage modeled would be sufficient to accommodate them. The vehicle-refueling scenarios also provide as much smoothing of the PV system output/grid demand as the energy storage scenarios (see Figure 15). This smoothing of PV/grid interactions could be vital for integration of high levels of distributed PV.

The vehicle-refueling analysis shows the potential for community-level hydrogen refueling using only renewably generated electricity (Table 12). With the 610 kW PV system, the number of fuel cell vehicles served (70–80) roughly matches the modeled community size (100 households). The levelized hydrogen cost ranges from $34/kg ($1.01/kWh) for the 185 kW Case 1 system to $11/kg ($0.34/kWh) for the 1,070 kW Case 2 system. The cost of battery storage of electricity for electric vehicles ranges from $0.57/kWh to $0.39/kWh, also decreasing with increasing system size. The hydrogen system cost reduction for the larger systems, as for the reconversion system, is due to better utilization of the equipment. The hydrogen system configuration is also more flexible than the battery system because there are more independent pieces of equipment. For small systems, this is a disadvantage; but for larger systems, the increased flexibility reduces costs because an incremental increase in hydrogen storage capacity per kWh (hydrogen tank) is less expensive than an incremental (per kWh) increase in electrochemical storage. Even though the hydrogen system is lower cost than the battery system for the largest storage case, the electric vehicle is less expensive on a fuel ¢/mile basis because of its higher efficiency in comparison to the fuel cell vehicle.

5 Future Work

This analysis did not show a clear advantage for hydrogen load leveling or vehicle refueling. However, the analysis does indicate that the economics could be improved, especially for larger systems, with careful optimization of the system configuration and equipment. Several areas of further research that might enhance understanding of the economics of community level hydrogen energy include:

- Explore more realistic scenarios for dealing with seasonal variation in PV output
- Explore methodologies for optimizing hydrogen system configuration
- Explore the impact of incentives and net metering for economics.

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