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Understanding the design and economics of distributed tri-generation systems for home and neighborhood refueling—Part II: Neighborhood system case studies

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ABSTRACT

The lack of a hydrogen infrastructure remains a major barrier for fuel cell vehicle (FCV) adoption. The high cost of an extensive hydrogen station network and the low utilization in the near term discourage private investment. Past experience of fuel infrastructure development for motor vehicles, indicates that innovative, distributed, small-volume hydrogen refueling methods may be required to refuel FCVs in the near term. Among small-volume refueling methods, home and neighborhood tri-generation systems stand out because the technology is available and has potential to alleviate consumer's fuel availability concerns. Additionally, it has features attractive to consumers such as convenience and security to refuel at home or in their neighborhood.

In this paper, we study neighborhood tri-generation systems in multi-unit dwellings such as apartment complexes. We apply analytical tools including an interdisciplinary framework and an engineering/economic model to a representative multi-family residence in the Northern California area. The simulation results indicate that a neighborhood tri-generation system improves the economics of providing the three energy products for the households compared with the two alternatives studied. The small capacity of the systems and the valuable co-products help address the low utilization problem of hydrogen infrastructure.

1. Introduction

Hydrogen fuel cell vehicles (FCVs) are slated for introduction in North America, Europe and Asia over the next few years. Hydrogen refueling infrastructure is a key issue for the rollout of these early fleets. Despite the rapid progress in FCV technology [1,2], lack of refueling infrastructure worldwide is still daunting to automobile companies. Several recent studies have proposed strategies for building early networks of public hydrogen refueling stations [3–5]. Although the proposed strategic station placement can improve consumer accessibility to fuel, the high cost of building an extensive hydrogen station network and the foreseeable low utilization in the near term are still issues, which discourage private investment. Based on past experience of fuel infrastructure development for motor vehicles including gasoline and compressed natural gas (CNG) vehicles, innovative, distributed, and small-volume hydrogen refueling methods may be required to refuel FCVs at least in the near term [6,7]. For instance, CNG is currently available at approximately 1300 refueling stations in 46 states in the US, which is less than 1% of the 170,000 gasoline stations that exist nationally [8]. Drivers of CNG vehicles have complained of access, billing, and location problems related to refueling their vehicles [9]. Lack of refueling infrastructure is an important reason that the number of CNG vehicles on the road grows only slowly, given the fact that the cost and performance of a CNG vehicle is comparable to gasoline vehicles (e.g., based on the official website of American Honda Motor Co., Inc., the 2011 Honda Civic CNG car is only about $1500 more expensive than the 2011 Civic Hybrid, $25,500 vs. $24,000, and has a fast refueling time and a range of 220 miles. CNG car also has less fuel cost). Some CNG car owners have adopted home refueling systems to refuel their cars for convenience [9–11].

Among small-volume refueling methods for FCVs, home and neighborhood tri-generation systems stand out because the technologies are available and have potential to alleviate the consumer's fuel availability concern. They also have other features attractive to consumers such as convenience and security to refuel at home or in their neighborhood. A typical tri-generation system produces electricity and heat for buildings as well as hydrogen for vehicles by converting a hydrocarbon such as natural gas (NG) or biomethane [12]. There are many ongoing demonstrations of tri-generation systems and fuel cell combined heat and power (CHP) systems [13]. In earlier work, we analyzed home tri-generation systems for single family residences [13].

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The results show that tri-generation for home refueling has the potential to be included in hydrogen infrastructure plans or portfolio infrastructure solutions in California and other states or countries. It is competitive with other early options for fueling hydrogen cars, although it is difficult to compete with the conventional system (grid electricity plus NG heat and gasoline), unless capital costs are reduced, gasoline price increases, or other factors such as relative prices for electricity and NG come into play.

In this paper, we study neighborhood refueling tri-generation systems, which serve 10–20 households in multi-unit dwellings such as apartment complexes and town houses. Neighborhood tri-generation systems can be installed at a community of single family houses as well, serving multiple households, as long as it is economical to install and operate these systems based on demand profiles and other inputs. Because the capacity of a neighborhood system is larger than a single-family home system, we expect that economies of scale would improve the economic performance of neighborhood systems compared with home systems.

We apply analytical tools including an interdisciplinary framework and an engineering/economic model (the HTS model) [13] to a representative multi-family residence in the Northern California Sacramento area. We model the yearly operation of a tri-generation system, explore the optimal design of the system, estimate the cost of electricity, heat, and hydrogen, and the system CO_2 emissions, and compare the results to alternatives. We conduct sensitivity analysis to evaluate the potential impacts of uncertainties in energy prices, capital cost reduction, government incentives and environmental cost. In addition, we explore the policy implications of the modeling results for multi-family tri-generation systems.

2. Description of neighborhood refueling and tri-generation systems

Neighborhood refueling systems are located near or in a community to offer convenience and security similar to home refueling. Neighborhood refueling systems are suitable for multi-family residences (e.g., apartment buildings and townhouses); they can serve a community of single family houses as well, as long as it is economical to install and operate these systems. Neighborhood refueling may be particularly important for densely populated areas, such as some cities in the east and west coast, Europe, and Asia, where individual garages, carports or other reserved parking are not available for home refueling.

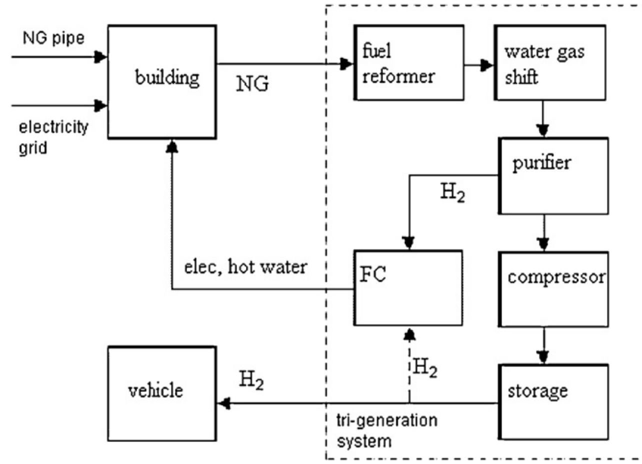

Fig. 1. The schematic of a typical tri-generation system.
Source: [13].

We consider neighborhood refueling systems sized for 10–20 households (averaging hydrogen output capacity of 10–20 kg d^{-1}), which are larger than individual home systems, but smaller than public hydrogen refueling stations that typically offer at least 100 kg d^{-1} of hydrogen. Compared to single family home tri-generation systems, the larger size of neighborhood systems has the potential to improve efficiency and lower costs through economies of scale.

A typical tri-generation system is shown in Fig. 1. A fuel reformer converts NG to a mixture of hydrogen and other gases including CO and CO_2. A water-gas shift processor converts most of the CO to hydrogen and CO_2. A purifier separates hydrogen from other gases. Pure hydrogen can be used by a PEMFC sub-system to generate electricity and heat, and can be compressed and used to refuel vehicles. More details can be found in [13].

3. Methods and data

3.1. Analytical tools

To model tri-generation systems, we developed the HTS model on the basis of the interdisciplinary framework illustrated in Fig. 2.

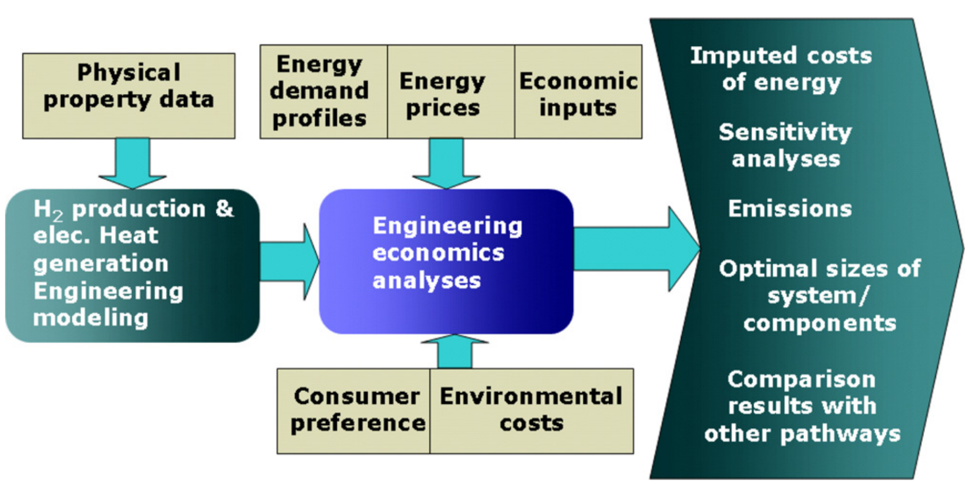

Fig. 2. Interdisciplinary framework for analyzing tri-generation systems.
Source: [13].

The model consists of two main stages: first, engineering modeling of hydrogen, electricity, and heat generation; and second, engineering/economic analysis incorporating engineering performance inputs, cost data, energy prices, and consumer preference and environmental cost information.

To assess the system economics, we estimate the levelized cost of energy products (electricity or hydrogen). The levelized cost of electricity (LEC) is compared to the price of grid electricity, and the levelized cost of hydrogen is compared to the price of transport fuel, as a metric when the tri-generation system is competitive with alternatives. Credits are taken for heat and transportation fuel provided by the tri-generation system. Eq. (1) is used to calculate the levelized cost of electricity [13].[1]

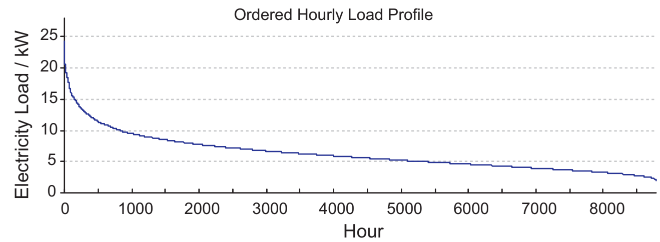

Fig. 3. Ordered annual hourly (8784 h) electricity load profile (the graph shows the number of hours per year the electricity load exceeds a certain value).

demand data for a representative multi-family residence in the Northern California Sacramento area, provided by the California

$$\bar{R}_{\mathrm{elec}} = \frac{CRF \times (CC - C_{\mathrm{credit}}) + C_{o\&m} + R_{\mathrm{NG}} n_{\mathrm{NG}} + \int R_{\mathrm{ele}}\theta_1(P)\,\mathrm{d}t + \int R_{\mathrm{ele}}\theta_2(P)\,\mathrm{d}t - c_{\mathrm{heat}} - c_{\mathrm{transport}} - t_{\mathrm{carbon}}}{\int P\,\mathrm{d}t} \qquad (1)$$

$\theta_1 = P$, when $P < (1/5)P_{\mathrm{FC,max}}$ (turn down ratio of the FC sub-system is 5); $\theta_1 = 0$, otherwise. $\theta_2 = P - P_{\mathrm{FC,max}}$, when $P > P_{\mathrm{FC,max}}$; $\theta_2 = 0$, otherwise. $\bar{R}_{\mathrm{elec}}$ is the LEC ($\$\,\mathrm{kWh}^{-1}$); *CRF* is the capital recovery factor; *CC* stands for the present value of life cycle capital cost of a system ($); C_{credit} represents various credits including feebate and tax credits ($); $C_{\mathrm{o\&m}}$ is fixed annual operating and maintenance cost (independent of the amount of energy produced) including labor, maintenance costs, and overhead ($\$\,\mathrm{y}^{-1}$); R_{NG}, is the price of NG ($\$\,\mathrm{GJ}^{-1}$); n_{NG} is the annual amount of NG consumed ($\mathrm{GJ\,y}^{-1}$); R_{elec} is the grid electricity price ($\$\,\mathrm{kWh}^{-1}$); *P* is the hourly average electricity demand load (kW), and $\int P\,dt$ is annual electricity demand ($\mathrm{kWh\,y}^{-1}$); c_{heat} represents the annual credit of hot water heat, based on what it would have cost to provide heat using a conventional NG based hot water system ($\$\,\mathrm{y}^{-1}$); $c_{\mathrm{transport}}$ represents the annual credit of transportation fuel (gasoline or hydrogen), based on what it would have cost to purchase gasoline or hydrogen from a public refueling station ($\$\,\mathrm{y}^{-1}$); t_{carbon} represents annual carbon tax ($\$\,\mathrm{y}^{-1}$).

An analogous equation can be developed for hydrogen. See [13] for more details on calculating the levelized cost of energy products and the HTS model. It is worth noting that model results vary with data inputs and the main assumptions. Table 1 presents a summary of main data sets and assumptions in this paper. More details on data and assumptions can be found in Section 3.2. Sensitivity analyses are conducted in case studies to evaluate the impacts of changes in assumptions that are subject to uncertainty such as system capital costs and energy prices.

3.2. Energy consumption data and key engineering/economic inputs

In this paper, we evaluate neighborhood tri-generation systems for multi-family residences such as apartment complexes and town houses. We assume that these systems can be designed as a vending machine-like unit in terms of size and installation, and can be easily installed in or near existing buildings [13].

Because tri-generation systems are designed to provide electricity, hot water, and transportation fuel to residences, three sets of energy consumption data are used in this paper: the hourly electricity demand profile, hourly hot water demand profile, and hourly transportation fuel consumption data. We employ electricity demand data for a representative multi-family residence in the Northern California Sacramento area, provided by the California Energy Commission [14]. The residence is assumed to be a 10-household apartment building. It is also assumed that passenger vehicles are driven 10,000 miles each year,[2] with a fuel economy of 25 mpg for a gasoline vehicle and 55 miles per kg of H_2 for a FCV. In recent years, hybrid electrical vehicles (HEVs) have gained some acceptance among consumers. To reflect the recent trend in the industry and research, we evaluate the impact of replacing the conventional gasoline vehicle with an HEV (the fuel economy of an HEV is assumed to be 40 mpg) as well. The fuel economy assumptions are approximately the same as in some other studies [1,18].

Fig. 3 shows the ordered hourly electricity load profile (also called a load duration curve); most of the time (80%), the electricity demand load is below 8 kW.

A 24-h hot water demand profile is used to represent the 366 days of the year (2008), which is derived from [19,20]. The data from [19,20] was directly used in the home tri-generation system case in an earlier study [13]. In this paper the data is multiplied with the ratio of total electricity consumption in a multi-family residence household to that of a single family residence household to reflect the difference in their hot water demand. Although there are weekly and seasonal variations in hot water demand, it is not expected that these variations would affect the modeling results significantly for a few reasons [13]. First, hot water heating daily demand pattern does not vary significantly with season and geographic locations. Second, for a typical residence the total electricity consumption is approximately double the hot water energy consumption, and the distribution and two peaks of electricity hourly profile (daily pattern) match that of the hot water profile. If tri-generation systems operate with an electricity load following strategy within its operation range, sufficient heat will be available for recovery for the majority of hours during a day [13,21]. Fig. 4 shows the 24-h electricity and hot water demand profiles of a particular day (January 1, 2008). Third, a hot water tank can be a buffer for small mismatch in electricity and hot water demand. The hot water tank is currently available in residences and can accommodate the variations in demand.

Table 2 summarizes the annual energy consumption of the aforementioned electricity profile, hot water profile, and transportation fuel demand for 10 households. The total annual energy consumption of electricity, hot water heat, gasoline, and fuel hydrogen is 54,939.3 kWh (electricity), 25,875.6 kWh (93.17 GJ

[1] *Note*: The difference in gasoline and FC vehicle costs is not considered in this analysis.

[2] Some studies [16] find that on average people in multi-family residences drive less compared with people in single family residences due to issues such as transportation cost burden and land use density. Therefore, we use lower annual miles driven range found in the literature [17] (10,000 miles per year in this paper, instead of the 15,000 miles per year used in an earlier paper on single family residences [13]).

Table 1
Main assumptions and data inputs.

Engineering performance data and assumptions	Components and system efficiencies are based on material and energy balance modeling and experimental data
Case study area	Northern California Sacramento area
Energy consumption data and assumptions	Hourly energy demand profiles (electricity, heat, and transportation fuel) for the entire year are used. We employ data for a representative multi-family apartment complex in Northern California Sacramento area, provided by the California Energy Commission [14]
Energy price data	Historical data is used for NG, electricity, and gasoline prices in the Sacramento area. Projected near-term hydrogen prices are from conceptual studies by other researchers [3]
Capital cost assumptions	The manufacturing cost of PEMFC systems varies significantly with different levels of production volume. Currently, a competitive market for FC systems is not well developed and FC systems are not mass produced. The current market price does not reflect the volume production manufacturing cost because it is for highly customized systems; the market price is different from the costs in this study and is not used. We choose to use a bottom-up mass production cost assessment in this study [15]. In addition, we assume that home and neighborhood tri-generation systems are designed as appliance type systems, and non-equipment costs such as site development and rent for landscape can be significantly reduced compared with current practice in installing public hydrogen refueling stations
Other economic assumptions	We assume a real discount rate of 8% and calculate the capital recovery factor (*CRF*) based on a 10-year equipment lifetime. *CRF* = 0.149

Source: [13].

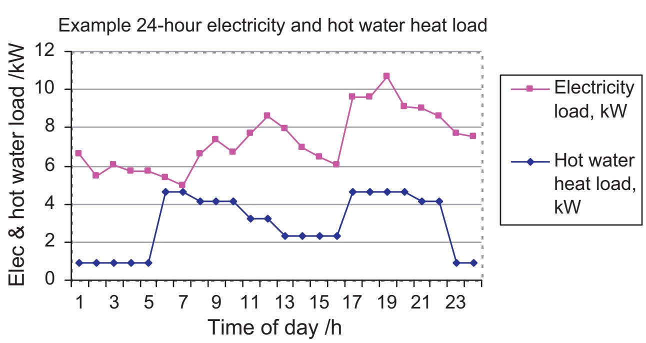

Fig. 4. Hourly electricity and hot water demand profiles (*source*: [19,20]). *Note*: Both electricity and hot water profiles are derived by multiplying the single residence profiles by ten (the number of households in the multi-family building). The actual aggregated demand for both would probably be less "peaky" (the maximum demand divided by the average demand would be less), because individual households' demands would not coincide exactly in time.

hot water), 134,780 kWh (4000 gal gasoline, based on LHV), and 60,598.2 kWh (1818.18 kg hydrogen), respectively. When replacing the conventional gasoline vehicle with an HEV, the total annual energy consumption of gasoline is 84,238 kWh (2500 gal gasoline).

In addition to energy demand data, model results also vary with key engineering/economic inputs including efficiencies of energy conversion processes, energy prices, and capital, operating and maintenance costs. Table 3 shows key engineering inputs used in this paper (Fig. 5). Tables 4 and 5 present key economic inputs and cost assumptions, respectively.

Table 3
Main engineering parameters.

Reformer efficiency [21]	75% (this parameter represents the combined efficiency of fuel reformer, water gas shift processor, and purifier in Fig. 1)
FC stack efficiency η_{FC} (also shown in Fig. 5) [21–23]	$\eta_{FC} = \{1-\exp[-0.5(P/P_{FC,max})^{1.2}]\} \times [0.622-0.002(P/P_{FC,max})]$, P is the hourly average electricity demand load (kW), and $P_{FC,max}$ is the capacity of the FC sub-system (kW) (this is LHV efficiency, and the function is derived by fitting the function to the measured performance of a 50 kW PEMFC stack delivered to the US Department of Energy [21])
Compressor efficiency [24]	80%
Parasitic load efficiency loss, the percentage of generated electricity used for parasitic load [22]	15%
AC/DC power conversion efficiency [21]	92%
H_2 utilization in fuel cell [21]	85%
Hot water tank efficiency (NG to hot water heat) [21]	75%
Rate of heat (by product of electricity generation) captured for hot water [21]	70%

Table 4
Key economic inputs (costs are in 2008 dollars).

Price of energy	Based on the PG & E (major utility company in Northern California) electricity and NG rate data for 2008, an electricity price of 16.8¢ kWh^{-1} and a residential NG rate of 3.72¢ kWh^{-1} (or \$10.33 GJ^{-1} and \$1.09 $therm^{-1}$) are used (this rate is for households with compressed NG vehicles and is appropriate for FCV owners). A gasoline price of \$3.12 gal^{-1} is used based on EIA data for California [25]
Cost assumptions	The capital cost of a system is the sum of component costs. The FC stack is assumed to be replaced every 5 years. The present value of these replacements is included in the capital cost CC

4. Case studies

4.1. *The optimal size of a tri-generation system for neighborhood refueling*

4.1.1. *Results and discussion*

Optimizing the size of a tri-generation system allows the system to meet the three household energy needs (electricity, hot water heat, and transportation fuel) with minimal cost under specified

Table 2
Summary of the energy demand data of the multi-family residence (10 households, annual data based on 366 days of 2008).

Energy form	Hourly average power (kW)	Annual end-use energy consumption (kWh)	Demand max (kW)	Demand min (kW)	Demand Stdev (kW)
Electricity	6.25	54,939.34	24.34	1.94	2.88
Hot water	2.95 (10.62 MJ h^{-1})	25,875.64 (93.17 GJ)	4.62	0.92	1.51
Hydrogen	n/a	60,598.18 (1818.18 kg)	n/a	n/a	n/a
Gasoline (a conventional gasoline vehicle)	n/a	134,780 (4000 gal)	n/a	n/a	n/a
Gasoline (an HEV vehicle)	n/a	84,238 (2500 gal)	n/a	n/a	n/a

Table 5
System component costs (in 2008 dollars).

Component	Cost
NG reformer	$6434.1 + 147.2P_{ref,max}$ ($P_{ref,max}$ is the capacity of the reformer in kW); this cost formula is developed in [15], the reformer cost calculated based on it is slightly lower than the cost estimate of the DOE H2A Production Analysis for 2005 [26], but higher than the cost projection of the DOE H2A Production Analysis for 2025 [27]
PEMFC sub-system	FC stack: $1.1 \times \{[(722.45 - 105.4)/10 + 17.56 \times 0.6] \times P_{FC,max} \times (1 + 0.06)^5/0.625 + 363.33\}$ ($P_{FC,max}$ is the capacity of the FC stack in kW); ancillary components: $3161.9 + 37.8 \times P_{FC,max}$; inverter/controller: $542 + 169 \times P_{FC,max}$; this cost formula is developed in [15], the PEMFC system cost calculated based on it is within the cost range presented in [28], and higher than the estimated cost in [29]
Storage system	$284N_t + 192H_{store}$ (N_t—the number of tanks in the cascade filling storage system, H_{store}—hydrogen stored, kg of hydrogen); this cost formula is developed in [15], the storage system cost calculated based on it is higher than the DOE cost target for onboard H_2 storage tanks [30], but slightly lower than the low end of the cost range of onboard H_2 storage tanks in a 2011 assessment of current technology [30]
Compressor	$5920 + 374.1P_{comp}$ (P_{comp} is the capacity of the compressor in kg h^{-1}); this cost formula is developed in [15], the compressor cost calculated based on it is higher than the cost estimate of the DOE H2A Production Analysis for current and future technology [26,27]
Dispenser	$856 + 79 \times P_{ref,max}$; this cost formula is developed in [15], the dispenser is assumed to be similar to the ones used in CNG home refueling systems, instead of dispensers used in public stations
Hot water tank and distribution system	0 (similar tank and distribution system is also necessary for the conventional NG heating system, so there is no incremental cost)
Replacement FC stack at the 5th year (present value)	Stack cost/$(1 + 0.08)^5$
Non-equipment (delivery and installation)	23% of total equipment capital cost [31] (we assume that home and neighborhood tri-generation systems are designed as appliance type systems, and non-equipment costs such as site development and rent for landscape can be significantly reduced compared with current practice in installing public hydrogen refueling stations)
Maintenance	1000 y^{-1}

Note: The cost estimation is based on a 1000 unit cumulative production volume.

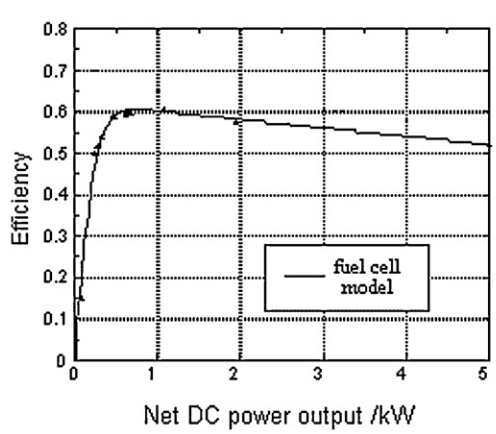

Fig. 5. Net DC power to hydrogen efficiency of the FC sub-system. Modified from [21].

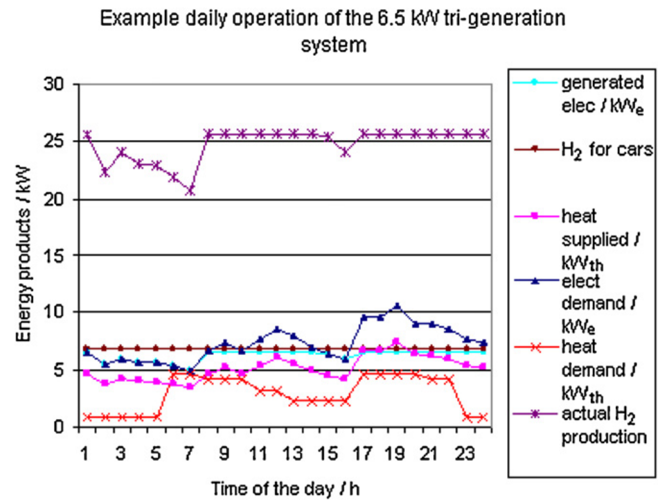

Fig. 6. Daily operation of a 6.5 kW tri-generation system (the FC system follows the electricity demand within its operation range).

energy prices. Given the assumptions on the operation strategy, refueling pattern, and fuel hydrogen production rate, the optimal size of a tri-generation system is determined by identifying the optimal size of the FC sub-system. In this paper, we study grid-connected systems with an electricity load following strategy. A hydrogen storage unit is configured to allow flexible, fast refueling. Vehicles can be refueled to a full tank within several minutes. A "brute force" exhaustive search algorithm is used to identify the optimal size.

Fig. 6 illustrates the operation of a tri-generation system by demonstrating the daily (24 h) energy production of a 6.5 kW system for a particular day (January 1, 2008). The system is grid-connected and operates mainly in an electricity load following mode; however, the electricity demand can be met from either the FC sub-system or the grid depending on the electricity demand at that particular time and the operation range of the FC sub-system. Using a turn down ratio of 1/5, the operation range of the FC sub-system is 1.3–6.5 kW. If the electricity demand is below 1.3 kW, the FC sub-system will be shut down because its efficiency is low (the reformer is still operating producing hydrogen fuel, which goes to a storage tank). If the electricity demand is higher than 6.5 kW, the FC sub-system will be operating at 6.5 kW, and the electricity demand above 6.5 kW will be purchased from the grid.

For this particular day, the electricity demand is within the 1.3–6.5 kW range for 8 h (2–7 am and 3–4 pm), but greater than 6.5 kW for the rest of the day. For hours when electricity demand is within the operating range of the system, the generated electricity and electricity demand curves are the same (load following). For hours when electricity demand is greater than the system capacity (6.5 kW), the FC sub-system is operating at 6.5 kW; the electricity demand above 6.5 kW is purchased from the grid. It is assumed that the reformer is constantly operating to produce hydrogen fuel in addition to hydrogen for electricity. Fuel hydrogen production (e.g., for use in vehicles) is conceptually shown in Fig. 6 as constant. The actual total production rate of hydrogen for transportation fuel plus electricity has a shape similar to the generated electricity curve plus the demand for hydrogen fuel. The curves for hot water heat generated and heat demand are presented as well.

Fig. 7 shows that when determining the optimal FC sub-system size to meet a specified power demand, there is a tradeoff between the capacity factor (capital utilization) and the fraction of electricity demand that can be covered. While a larger system size could meet a greater fraction of the electricity demand, increased capital cost and lower capital utilization also result. Fig. 7 also illustrates how

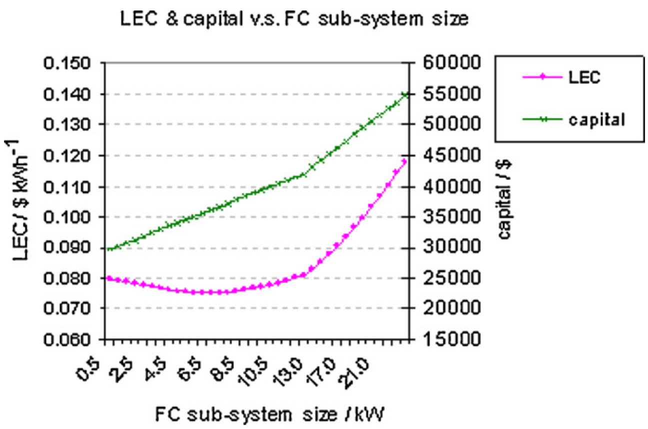

Fig. 7. LEC vs. FC sub-system size for tri-generation systems of different sizes.

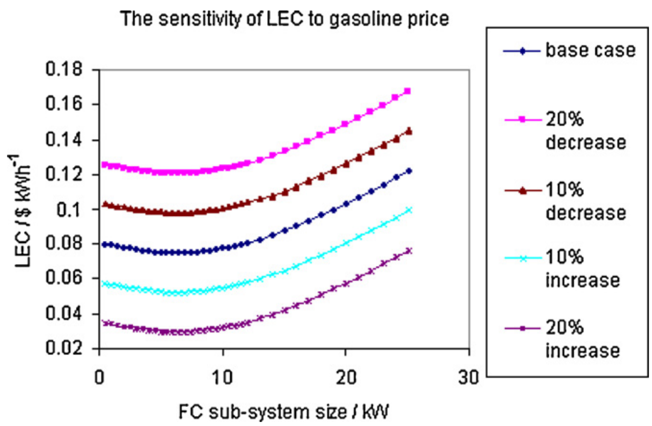

Fig. 8. The sensitivity of LEC to gasoline price (the base case gasoline price is $3.12 gal^{-1}).

Table 6
Specifications of the 6.5 kW tri-generation system.

	System specifications
Reformer capacity, kg of H_2 per day (kg d^{-1})	19.35
PEMFC stack capacity, kW	6.5
Number of vehicles supported	10
Fuel H_2 production capacity additional to electricity H_2 capacity, kg d^{-1} (the capacity factor used is 0.63 [15])	7.89 (this supports the average daily demand of 10 vehicles)
Hydrogen storage (kg of H_2) (determined using the formula: $N_{FCV} \times H_{FCV} \times S_f/U_c$, N_{FCV} is the number of FCVs supported by the system, H_{FCV} is the average daily hydrogen consumption by one FCV, S_f is the total cascade storage fraction of average daily demand, and U_c is the hydrogen utilization fraction [15])	12.62 (this capacity approximately allows 3 vehicles to be fast refueled one by one at any time)

the LEC and capital cost change with the size of the FC sub-system. Total system capital cost is approximately linear with the system power output, because the cost of main components is linear with component capacities. This is an approximation that neglects the availability of discrete off-the-shelf component sizes. The FC sub-system size that results in the lowest LEC is the optimal size given the energy prices in Table 4 and the Sacramento area energy consumption data.

As shown in Fig. 7, the optimal or lowest LEC point (7.52¢ kWh^{-1}) occurs when the capacity of the FC sub-system is around 6.5 kW. This is slightly above the 6.25 kW annual average electricity load. Table 6 illustrates the specifications of the 6.5 kW system.

The LEC shows low sensitivity to the FC sub-system size around a broad minimum centered at 6.5 kW. Even if the system is not optimally sized, the impact on the electricity cost is relatively small. For example, if the system is undersized or oversized by 1 kW, the electricity cost increases by less than 1%.

4.1.2. Optimal system size sensitivity analysis

Future capital cost and energy prices are subject to uncertainty. Therefore, a sensitivity analysis is conducted to show how the optimal size changes as a result of changes in capital cost and energy prices. The optimal size is insensitive to gasoline price. A 20% increase and decrease in gasoline price significantly change the value of LEC, but have no impact on the optimal FC sub-system size. Fig. 8 shows the sensitivity of LEC to gasoline price.

The optimal size is relatively sensitive to capital cost. A 10% and 20% increase in capital cost results in a 1 kW and 1.5 kW decrease in the optimal FC sub-system size, respectively. A 10% and 20% decrease in capital cost results in a 0.5 kW and 1 kW increase in the optimal FC sub-system size, respectively. Fig. 9 shows the sensitivity of LEC to capital cost.

The optimal size is quite sensitive to NG and electricity prices. A 10% and 20% decrease in NG price results in a 1 kW and 1.5 kW increase in the optimal system size, respectively. When there is a 10% and 20% increase in NG price, the shape of the LEC vs. FC sub-system size curves in Fig. 10 changes and the lowest value of LEC occurs when the system size is zero. (In this case, the tri-generation system would not be competitive with conventional options, so the optimal size is zero.) As shown in Fig. 11, similar impact occurs for the sensitivity of LEC to electricity price. A 10%

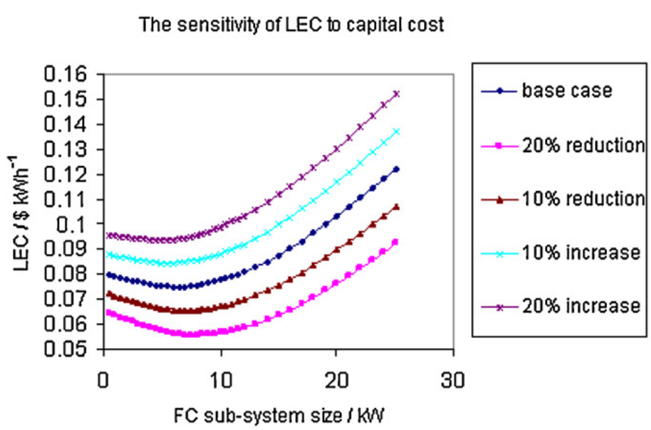

Fig. 9. The sensitivity of LEC to capital cost.

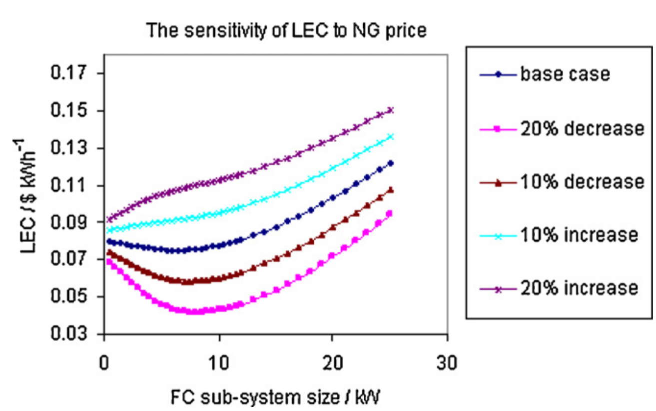

Fig. 10. The sensitivity of LEC to NG price (base case NG price is 3.72¢ kWh^{-1} or $10.33 GJ^{-1}).

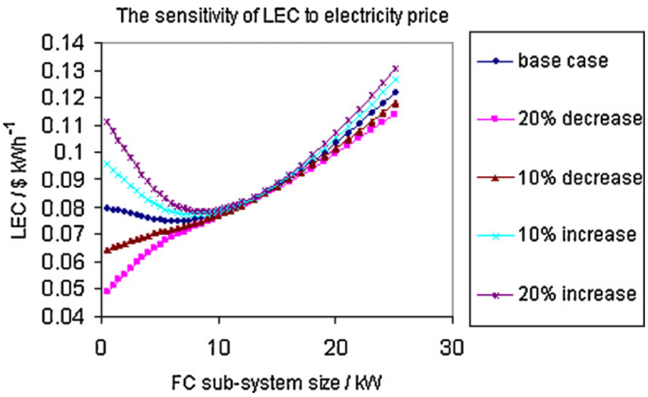

Fig. 11. The sensitivity of LEC to electricity price (base case electricity price is 16.8¢ kWh^{-1}).

and 20% increase in electricity price results in a 1.5 kW and 2 kW increase in the optimal system size, respectively. When there is a 10% and 20% decrease in electricity price, the shape of LEC vs. FC system size curves in Fig. 11 changes and the lowest value of LEC occurs when the system size is zero.

A higher NG price or lower electricity price decreases the economic attractiveness of a NG fueled tri-generation system. This is consistent with the well known fact that the competitiveness of NG based co-generation systems is sensitive to the gap between NG and electricity prices. The wider the gap (low NG price and high electricity price) the lower will be the payback period of the NG based co-generation systems. Consequently, the NG based co-generation systems are more likely to compete economically with the conventional system of grid electricity plus NG heat [32].

4.2. The economics of operating the 6.5 kW tri-generation system

4.2.1. Simulation results and discussion

This case study evaluates a 6.5 kW tri-generation system in detail because it is the optimal size identified in Section 4.1. As described in Section 4.1, the system is grid-connected with an electricity load following strategy. The HTS model is used to generate the LEC, annual energy cost, and annual CO_2 emissions for a tri-generation system. These results are compared with the results of two other pathways: purchasing grid electricity, NG heat, and gasoline (a gasoline vehicle is used in this pathway); and the projected pathway of purchasing grid electricity, NG heat, and hydrogen from an early public station (a FCV is used in this pathway). Details on system specifications and system capital cost are presented in Tables 6 and 7, respectively. As shown in Table 7, a NG reformer is the biggest contributor to total capital cost, followed by the PEMFC sub-system (including PEMFC stack, ancillary components and inverter/controller), compressor, and storage system. Table 8 presents all costs and credits associated with installing and operating the 6.5 kW tri-generation system, as well as the LEC and its components.

As can be seen, capital cost, NG cost and gasoline credit are major components of LEC. The economics of installing and operating a tri-generation system is expected to be sensitive to these three cost components.

The LEC of the 6.5 kW system is about 7.5¢ kWh^{-1}, which is 9.3¢ kWh^{-1} lower than the 16.8¢ kWh^{-1} electricity price. The annual electricity cost from the tri-generation system is $4131.6, while buying electricity from the grid is $9229.8. There is a 55% or $5098.2 decrease in the annual cost using the tri-generation system. In addition, there is a 25.8% or 19,658 kg reduction in annual CO_2 emission using the tri-generation system. Fig. 12 presents a comparison of CO_2 emissions in the two cases.

Table 7
System capital cost for a 6.5 kW tri-generation system (based on Table 5).

Component	Capital cost ($)
NG reformer	9282.4 (or $480 kg^{-1}, this is slightly higher than the $424 kg^{-1} cost estimate of the DOE H2A Production Analysis for 2005 [26])
PEM system cost (FC stack, 23.5%; ancillary components, 51.6%; inverter/controller, 24.9%)	6598 (FC stack: 1551.8, ancillary components: 3405.7, inverter/controller: 1640.5) (the FC stack cost is $239 kW^{-1}, and the FC system cost is $1015 kW^{-1}, the FC system cost is within the $465–1395 kW^{-1} cost range presented in [28], and higher than the estimated cost of $656 kW^{-1} in [29])
Compressor	6221.6 (or $7717 kg h^{-1}, this is significantly higher than the $4537 kg h^{-1} cost estimate of the DOE H2A Production Analysis [26,27])
Storage system	4127.5 (or $327 kg^{-1}, this is about 2.5 times the DOE cost target for onboard H_2 storage tanks [30], but slightly lower than the low end of the estimation of $353–656 kg^{-1} cost range of onboard H_2 storage tanks in a 2011 assessment of current technology [30])
Dispenser	$1369.5 per dispenser
Hot water cogeneration	0 (use the existing hot water storage and distribution system)
Stack (replaced at the fifth year, present value)	1056.2
Non-equipment (delivery and installation)	6505.6
Total installed capital cost	35,160.8 ($5409 kW^{-1})

We have focused so far on estimating the LEC based on Eq. (1). If we instead fix the electricity price, we can develop an analogous equation for estimating the levelized hydrogen cost. Using this approach the model results show that a levelized hydrogen cost of $4.06 kg^{-1} can be achieved using the tri-generation system given an electricity price of 16.8¢ kWh^{-1} and an NG price of $1.09 $therm^{-1}$ ($10.9 $MBTU^{-1}$). This is equivalent to a gasoline price of $1.85 gal^{-1} assuming a FCV has a fuel economy of 55 miles per kg of H_2 and the gasoline car fuel economy is 25 mpg. In other words, holding other inputs constant, if the gasoline price reaches higher than $1.85 gal^{-1}, the tri-generation system can be competitive with the pathway of grid electricity, NG heat and gasoline combination. This price is 40.7% lower than the $3.12 gal^{-1} gasoline price in 2008. Furthermore, the hydrogen cost of $4.06 kg^{-1} is highly competitive with purchasing hydrogen from an early hydrogen station (some research estimates that it can cost $13–77 kg^{-1} from an early hydrogen station) [3].

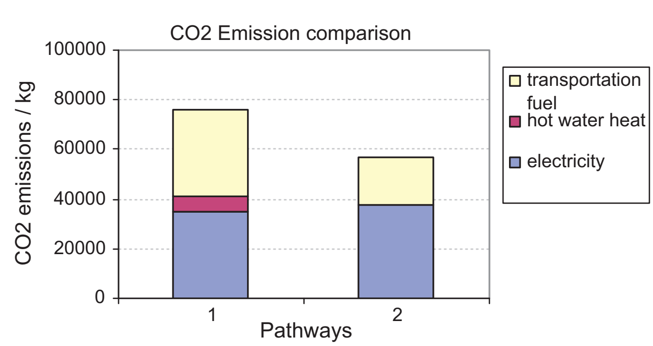

Fig. 12. CO_2 emission chart. *Note*: pathway 1—electricity + NG heat + gasoline; pathway 2—using a neighborhood tri-generation system with a hydrogen FCV.

Table 8
Costs and credits of installing and operating the 6.5 kW neighborhood tri-generation system.

Costs and credits		The LEC and its components	
System capital cost (including the FC stack replacement cost at the fifth year), $	35,160.9	Total electricity provided by the system (kWh)	54,939.3
System capital cost (annualized), $ y^{-1}	5239	System capital cost (annualized), ¢ kWh^{-1}	9.54
Fixed O&M costs, $ y^{-1}	1000	Fixed operating costs, ¢ kWh^{-1}	1.82
NG input, $ y^{-1}	10,215.3	NG input, ¢ kWh^{-1}	18.59
Grid electricity, $ y^{-1}	1440.8	Grid electricity, ¢ kWh^{-1}	2.62
Heat credit, $ y^{-1} (NG)	−1283.4	Heat credit (NG), ¢ kWh^{-1}	−2.34
Transportation fuel (gasoline) credit, $ y^{-1}	−12,480	Transportation fuel (gasoline) credit, ¢ kWh^{-1}	−22.72
Carbon credit, $ y^{-1}	0	Carbon credit, ¢ kWh^{-1}	0
System subsidy, $ y^{-1}	0	System subsidy, ¢ kWh^{-1}	0
CA average elec price, ¢ kWh^{-1}	16.8	LEC, ¢ kWh^{-1}	7.52
Annual cost for buying electricity from the grid at 16.8¢ kWh, $ y^{-1}	9229.8	Annual electricity cost with tri-generation system, $ y^{-1}	4131.6

4.2.2. Sensitivity analysis

From Table 8 we see that the major components determining the LEC are the system capital cost, NG cost, and transportation fuel cost. The HTS model allows us to evaluate the impact of uncertainty in capital cost and energy prices; it also allows us to explore the impact of various credits on the economics of tri-generation systems. These credits could be policy-driven, for example a feebate or tax incentive. HEVs have gained some acceptance among consumers in the past few years. Overall HEVs have better fuel economy than conventional gasoline vehicles. The HTS model enables us to evaluate the impact of replacing the conventional gasoline vehicle in the base case with an HEV.

To test the robustness of our results and address the uncertainty in capital cost and energy prices, we conducted a sensitivity analysis around the base case described in Tables 6 and 7. Sensitivity analysis for how the LEC varies with capital cost and energy prices is conducted by varying the capital cost and energy prices (electricity, NG, and gasoline price) by −20%, −10%, 10%, and 20% compared with the base case. We also evaluate the impact of replacing the conventional gasoline vehicle in the base case with a higher fuel economy gasoline vehicle such as an HEV. Sensitivity analysis results are summarized in Fig. 13. In each case, it is interesting to compare the cost of electricity from the tri-generation system with the price of grid electricity (16.8¢ kWh^{-1}).

As shown in Fig. 13, changes in the system capital cost have significant impact on the economics of tri-generation systems. A 10% and 20% reduction in total system capital cost results in a 12% (0.9¢ kWh^{-1}) and 25.3% decrease (1.9¢ kWh^{-1}) in LEC, respectively. A 10% and 20% increase in total system capital cost leads to a 13.3% (1¢ kWh^{-1}) and 25.3% (1.9¢ kWh^{-1}) increase in LEC, respectively. A 20% increase in the base case system capital cost leads to a $42,193 system capital cost, and with this increase in system capital cost the LEC is still 7.4¢ kWh^{-1} lower than the 16.8¢ kWh^{-1} grid electricity price.

A 10% and 20% decrease in gasoline price results in a 30.7% and 61.3% increase in LEC. A higher gasoline price allows more credit in Eq. (1), and thus improves the economics of tri-generation systems. A 10% and 20% increase in gasoline price (20% increase in price is equivalent to a gasoline price of $3.74 gal^{-1}) leads to a 30.7% and 60% decrease in LEC, respectively.

A 10% and 20% increase in NG price leads to a 21.3% and 44% increase in LEC, respectively. A 10% and 20% decrease in NG price leads to a 21.3% and 42.7% decrease in LEC, respectively.

Although changes in electricity price do not lead to significant changes in LEC, the economics of tri-generation systems is still sensitive to electricity price, since what matters is the difference between LEC and electricity price. A 20% increase in electricity price results in a 6.7% increase in LEC; the resulting LEC is 8¢ kWh^{-1}, which is 12.2¢ kWh^{-1} lower than the 20.2¢ kWh^{-1} grid electricity price. A 10% increase in electricity price results in a 4% increase in LEC; the resulting LEC is 7.8¢ kWh^{-1}, which is 10.7¢ kWh^{-1} lower than the 18.5¢ kWh^{-1} grid electricity price.

A 20% decrease in electricity results in a 6.7% decrease in LEC; the resulting LEC is 7¢ kWh^{-1}, which is 6.4¢ kWh^{-1} lower than the 13.4¢ kWh^{-1} grid electricity price. A 10% decrease in electricity

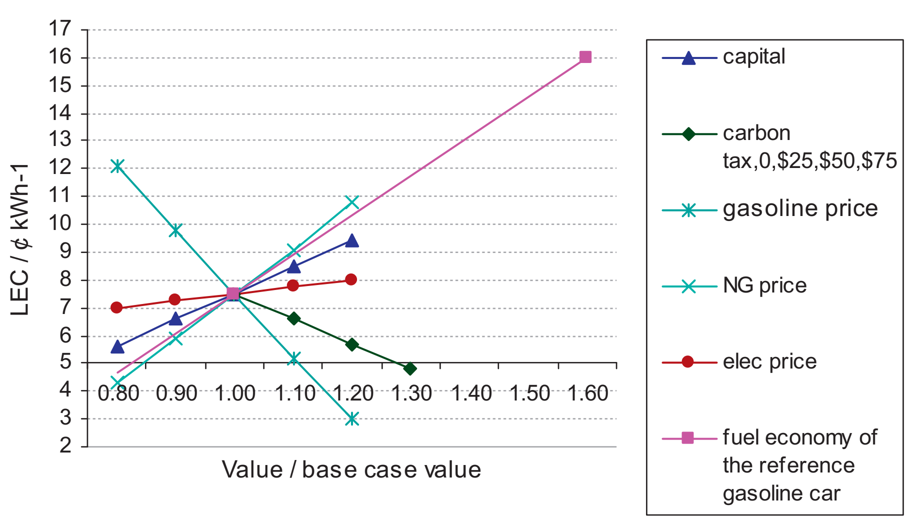

Fig. 13. The sensitivity of the LEC to capital cost, energy prices, carbon tax, and fuel economy of the reference gasoline car (shown for the 25 mpg base case and a 40 mpg HEV).

results in a 2.7% decrease in LEC; the resulting LEC is 7.3¢ kWh^{-1}, which is 7.8¢ kWh^{-1} lower than the 15.1¢ kWh^{-1} grid electricity price.

Replacing the conventional gasoline vehicle in the base case with a more efficient gasoline vehicle significantly changes the economics of a tri-generation system. For example, if we assume a gasoline vehicle with a fuel economy of 35 mpg (this is 1.4 times the base case value and meets the 2020 CAFÉ standard), the resulting LEC is 14¢ kWh^{-1}, which is 6.48¢ kWh^{-1} higher than that of the base case (7.52¢ kWh^{-1}). The annual CO_2 emission reduction decreases from 25.8% (base case) to 14.5%. If we consider a gasoline hybrid vehicle with a fuel economy of 40 mpg (1.6 times the base case value), the resulting LEC is 16¢ kWh^{-1}, which is 8.48¢ kWh^{-1} higher than that of the base case (7.52¢ kWh^{-1}). The annual CO_2 emission reduction decreases from 25.8% (base case) to 10.2% (with an HEV). Nevertheless, using tri-generation is still slightly cheaper than using grid electricity, NG heat, and gasoline for an HEV.

A carbon tax has positive impact on the economic performance of a tri-generation system, and the significance of the impact depends on the level of taxation. A $25, $50, and $75 per metric tonne CO_2 emission carbon tax results in a 12%, 24%, and 36% decrease in the LEC, respectively. The results in Section 4.2.1 demonstrate that the system is competitive without any feebate or tax incentive. As a result, we did not estimate the impact of credits on the LEC in this paper.

5. Conclusions

In this paper, an interdisciplinary framework and the HTS model are utilized to evaluate the design and the technical, economic, and environmental performance of a neighborhood tri-generation system. The system is designed to serve a 10-household multi-family residence in the Sacramento area in Northern California.

With the representative annual energy consumption data and energy prices from this area, the optimal FC sub-system size of the neighborhood tri-generation system is 6.5 kW, and the corresponding LEC is about 7.5¢ kWh^{-1}. The LEC shows low sensitivity to the FC sub-system size around a broad minimum centered at 6.5 kW. Even if the system is not optimally sized, the impact on the electricity cost is relatively small. For example, if the system is undersized or oversized by 1 kW, the electricity cost increases by less than 1%. The optimal FC sub-system size is insensitive to gasoline price, and relatively sensitive to capital cost. The optimal FC sub-system size is quite sensitive to NG and electricity price, but this sensitivity is not expected to be a concern to manufacturers and consumers since the LEC shows low sensitivity to FC sub-system size around a broad minimum centered at 6.5 kW.

A detailed assessment of the optimal size (6.5 kW) tri-generation system shows that neighborhood tri-generation is more economically competitive than the conventional grid electricity, NG heat, and gasoline combination. The LEC of a 6.5 kW system is about 7.5¢ kWh^{-1}, which is 9.3¢ kWh^{-1} lower than the 16.8¢ kWh^{-1} annual CA electricity price. The annual electricity cost from a tri-generation system is $4131.6, while buying electricity from the grid is $9229.8. There is a 55% or $5098.2 decrease in the annual cost using tri-generation systems. In addition, there is a 25.8% or 19,658 kg reduction in annual CO_2 emission using a tri-generation system.

Neighborhood tri-generation is also more economically competitive than the projected grid electricity, NG heat, and purchasing hydrogen from an early public hydrogen station combination. A levelized hydrogen cost of $4.06 kg^{-1} can be achieved, which is equivalent to a gasoline price of $1.85 gal^{-1} (assuming a FCV has a fuel economy of 55 miles per kg of H_2 and a gasoline car has a fuel economy of 25 mpg). The hydrogen cost is also highly competitive with the hydrogen cost from an early public hydrogen station (some research estimates that it can cost $13–77 kg^{-1} from an early hydrogen station).

Sensitivity analysis shows that capital cost and energy prices have a significant impact on the economics of tri-generation systems. Specifically, the LEC is most sensitive to gasoline price, followed by NG price, electricity price, and capital cost. For example, a 20% increase in gasoline price, a 20% decrease in NG price, a 20% increase in electricity price, and a 20% reduction in capital cost lead to a difference between LEC and electricity price (electricity price – LEC) of 13.8¢ kWh^{-1}, 12.5¢ kWh^{-1}, 12.16¢ kWh^{-1}, and 11.2¢ kWh^{-1}, respectively.

Replacing the conventional gasoline vehicle in the base case with an HEV results in a LEC of 16¢ kWh^{-1}, which is 8.48¢ kWh^{-1} higher than that of the base case (7.52¢ kWh^{-1}). The annual CO_2 emission reduction decreases from 25.8% (base case) to 10.2% (with an HEV). Nevertheless, using tri-generation is still slightly cheaper than using grid electricity, NG heat, and gasoline for an HEV (the grid electricity price is 16.8¢ kWh^{-1}).

A carbon tax has positive impact on the economic performance of a tri-generation system, but the significance of the impact depends on the level of taxation. A $25, $50, and $75 per metric tonne CO_2 emission carbon tax results in a 12%, 24%, and 36% decrease in the LEC, respectively.

The simulation results in this study indicate that a multi-family neighborhood tri-generation system improves the economics of providing the three energy products for the households compared with the two alternatives studied in this paper. The small capacity of the systems and the valuable co-products also help address the low utilization problem of hydrogen infrastructure when hydrogen vehicle demand is low. Compared with a home tri-generation system for single family residences, the economy of scale improves the economic performance of a neighborhood system for multi-family residences. Replacing the conventional gasoline vehicle in the base case with a more efficient gasoline vehicle significantly decreases the competitiveness of a neighborhood tri-generation system, although using tri-generation (with an FCV) is still slightly cheaper than using grid electricity, NG heat, and gasoline even for a 40 mpg gasoline HEV.

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