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Center for Sustainable Systems
School of Natural Resources and Environment
University of Michigan
440 Church Street, Dana Building
Ann Arbor, MI 48109-1041
Phone: 734-764-1412
Fax: 734-647-5841
Email: css.info@umich.edu
Web: http://css.snre.umich.edu

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An Economic Analysis of the DTE Energy Hydrogen Technology Park

Authors
Edward M. Chao
Marshall Chase
Kristofer Jadd

A project submitted in partial fulfillment of the requirements for the degree of
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Faculty Advisors
Associate Professor Gregory A. Keoleian (Sustainable Systems)
Professor Thomas P. Lyon (Business Economics, Natural Resources)

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DTE Energy is a pioneer in the hydrogen infrastructure world, having committed substantial human and financial resources to the development of the Hydrogen Technology Park in Southfield, Michigan. The authors would like to thank the company for its support of this project. For the past twelve months, DTE Energy's employees have been generous with their time and have provided the team with critical data, insight, and ideas. We particularly acknowledge the efforts of Bruce Whitney who has tirelessly guided our team and opened the doors to DTE Energy's extensive resources.

We would also like to thank our advisors, Associate Professor Gregory Keoleian and Professor Thomas Lyon, for their support throughout this project. They have been provided valuable advice on project scope definition, analysis, recommendations, and client interaction.

Project Participants

The Project was carried out by Master of Science students at the University of Michigan School of Natural Resources and Environment in cooperation with DTE Energy. The students coauthored the study as follows:

Name	Topic
Edward M. Chao	Levelized costs of hydrogen and fuel cell electricity, financial estimates
Marshall Chase	Transportation demand
Kristofer Jadd	Distributed generation, energy storage, hydrogen market assessment

Abstract

Hydrogen has received great attention in recent years as an energy storage and transmission medium, given its potential environmental, national energy security, and performance benefits. DTE Energy and the United States Department of Energy have established the Hydrogen Technology Park ("Park") in Southfield, Michigan, a technology validation program consisting of an operating, demonstration facility with hydrogen electrolysers, compressed hydrogen storage, dispenser, and fuel cells. An engineering-economic analysis developed in this study, based on Park operating data and costs, estimates the current levelized cost of hydrogen ranging from \$12.33 to \$21.32/kg H_2 (for hypothetical Park-like facilities with output of 1,200 and 100 kg H_2/day, respectively), which is significantly higher than estimates made by other studies. Combining a fuel cell array with a neighborhood hydrogen filling station would result in an estimated current levelized cost of fuel cell electricity ranging from \$2.09 to \$2.13/kWh (for power generation of 5,000 kWh/day). The study concludes that the Park, with its current demonstration-stage technologies and costs, is not cost competitive in commercial hydrogen, utility-scale energy storage, or hydrogen vehicle markets.

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Note on terminology

In this study, we use the following terms:

- DOE – United States Department of Energy
- DOE-M – Modified fuel cell vehicle adoption scenario based on the scenario found in DOE's *Multi-Year Research, Development and Demonstration Plan*
- EIA – United States Energy Information Administration
- FCV – Fuel cell vehicle
- Forecourt – This term means filling station. The DTE Energy Hydrogen Technology Park, which produces and dispenses hydrogen in a single location, is an example of a forecourt hydrogen production system
- H_2ICE – Hydrogen-fueled internal combustion engine vehicle
- HEV – Hybrid electric vehicle (e.g. the Toyota Prius)
- HTP or HTPs – Any facility built in a design and underlying architecture similar to that of the DTE Energy Hydrogen Technology Park; i.e. a system utilizing distributed production of hydrogen via electrolysis, compressed storage in cylinders, dispensers, and possibly an array of fuel cells
- ICE – Internal combustion engine vehicle, most standard vehicles in existence today
- LDV – Light-duty vehicle, a car or truck under 8,500 pounds
- NAE – National Academy of Engineering which authored *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs*, a major reference used throughout this study
- NAE-M – Modified fuel cell vehicle adoption scenario based on the scenario found in NAE's *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs*
- NGV – Natural gas-fueled vehicle
- Off-peak / On-peak – In many electricity grid systems, including DTE Energy's and the Midwest Independent System Operator's ("MISO") systems, electric rates vary depending on the time of day and/or day of the calendar year when the electricity is consumed. In the DTE Energy's "D6" electric rate schedule, "on-peak" refers to hours between 11:00 AM to 7:00 PM on Monday through Friday, excluding legal holidays, and "off-peak" refers to the remainder of hours. In MISO, on-peak refers to hours between 6:00 AM to 10:00PM on Monday through Friday, excluding legal holidays.
- Off-taker – An off-taker is a party who enters into an agreement to purchase the output from a facility
- Park – The actual Hydrogen Technology Park in Southfield, Michigan
- Project team – The authors of this study
- VMT – Vehicle miles traveled

1 Executive Summary

1.1 DTE Problem Statement

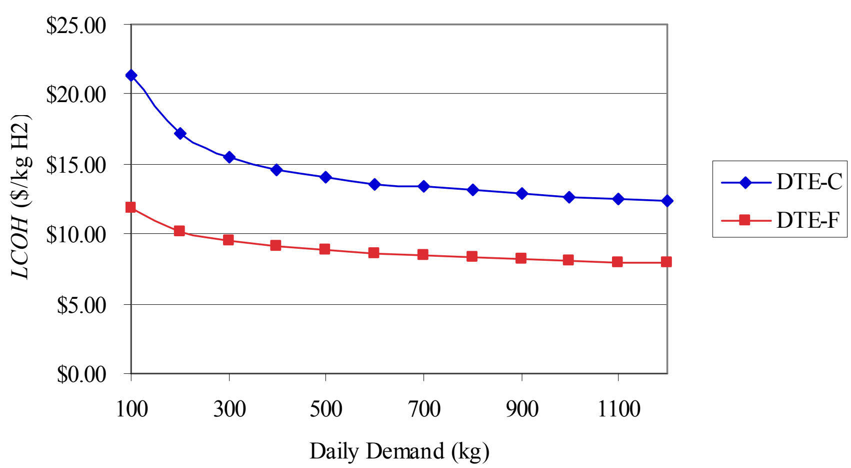
DTE Energy, a diversified energy holding company, has established an operating Hydrogen Technology Park ("Park") to demonstrate a potential avenue for the use of hydrogen in vehicle fueling and electricity generation. The Park produces hydrogen through electrolysis using electricity from the local grid, stores it in high pressure cylinders, and then either dispenses the hydrogen to vehicles or uses it in a fuel cell array to produce electricity. A major objective of the Park is to quantify the economic performance and drivers of hydrogen system performance for this type of system, and a team from the University of Michigan School of Natural Resources and Environment was tasked with performing this analysis.

1.2 Process

An engineering-economic Model, populated with the Park's actual performance and cost data, was created to estimate the levelized costs of producing hydrogen and fuel cell electricity of a set of hypothetical hydrogen technology parks ("HTP"). In addition, estimates were generated for demand from the transportation and electricity sectors. These estimates were used as inputs for the Model to determine the cost of producing hydrogen and electricity under various conditions.

1.3 Results

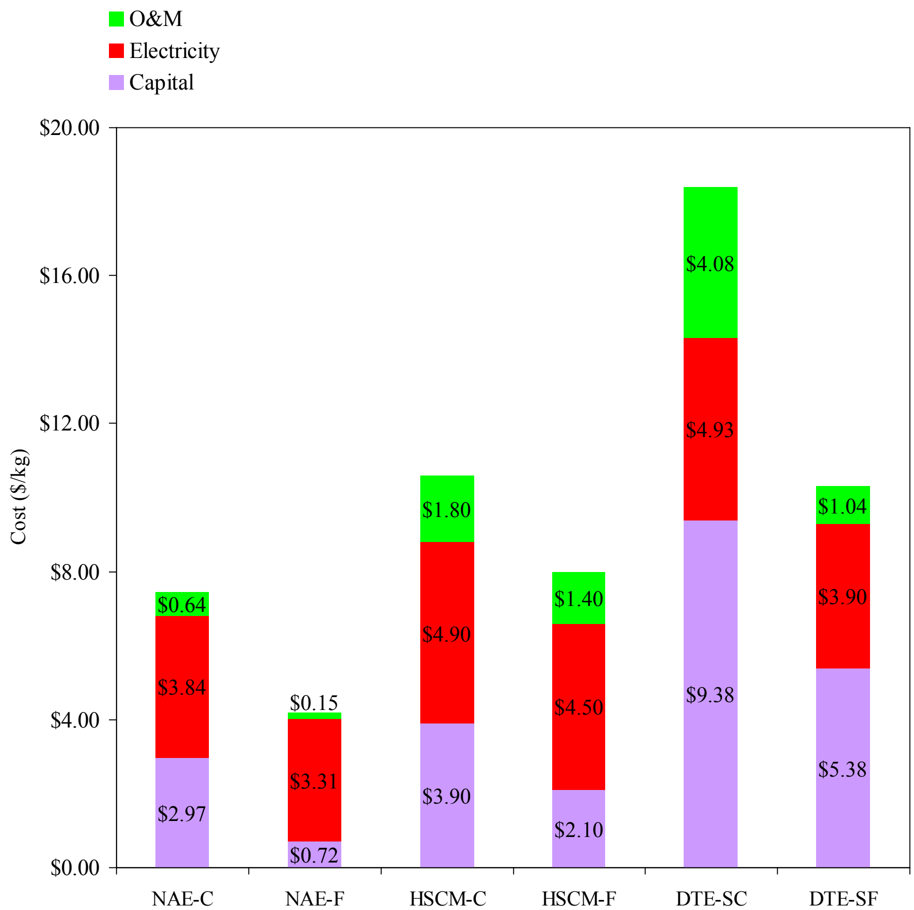
As shown in Figure 1-1, using current costs and technical assumptions ("DTE-C") the cost of hydrogen is estimated to range from \$12.33/kg H_2 for an HTP with the capacity to produce 1,200 kg H_2/day (approximately the amount required to serve as a neighborhood hydrogen filling station) to \$21.32/kg H_2 for a 100 kg H_2/day HTP, approximately twice the current Park's capacity of 44.8 kg H_2/day. Capital is 55% of the cost, followed by operations and maintenance, taxes, and electricity. The electrolyser is the single largest cost driver. In the future ("DTE-F"), with performance and cost improvements, the cost of hydrogen may fall to a range of \$7.90/kg H_2 for a 1,200 kg H_2/day HTP to \$11.91/kg H_2 for a 100 kg H_2/day HTP.



Source: Model calculations.

Figure 1-1: HTP Cost of Hydrogen Summary

These results are much higher than similar cost estimates by the National Academy of Engineering ("NAE-C" and "NAE-F" for NAE's current and future estimates) and Jonathan Weinert of the University of California, Davis ("HSCM-C" and "HSCM-F"), as shown in Figure 1-2. To facilitate comparisons, two "standardized" DTE Energy scenarios ("DTE-SC" and "DTE-SF") were created using the same cost of capital, electricity cost, and load factor assumptions as NAE and HSCM. Generally, the other studies use more recent data and optimistic assumptions for costs and technical performance, scaling factors, and O&M.

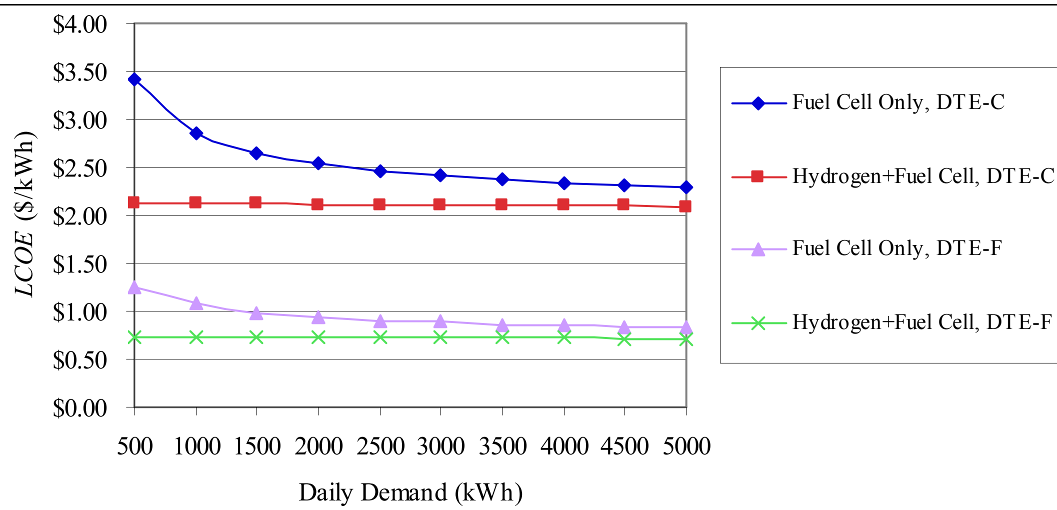


Note: All model runs assume a 100 kg H_2/day forecourt facility producing hydrogen via electrolysis.
Source: Weinert 2005, Project team runs on NAE model, and Model calculations.

Figure 1-2: Comparison of Hydrogen Costs

These results were derived from a single demonstration site installed in 2004. At the time this study went to press, Hydrogenics, the Park's electrolyser supplier, indicated that a new model of its HySTAT electrolyser would be available in 2006 with production rates up to 22x that of the electrolyser model used in the in the DTE-C and DTE-F scenarios. The Project team did not have an opportunity to estimate the cost of hydrogen using this new electrolyser, which could be lower than the estimates in this study.

The cost of fuel cell electricity varies depending on HTP design. The study considered a "Fuel Cell Only" configuration, where the Park produces hydrogen solely for fuel cells and not for dispensing to vehicles, and a "Hydrogen+Fuel Cell" configuration where an HTP doubles as both a hydrogen dispensing station and a fuel cell power generation system. As shown in Figure 1-3, for an HTP in the "Fuel Cell Only" configuration producing 5,000 kWh/day (eight on-peak hours at 625 kW power), the cost of electricity ranges from $0.83/kWh using future DTE-F assumptions, to $2.29/kWh using current DTE-C assumptions. For the "Hydrogen+Fuel Cell" configuration, which combines 5,000 kWh/day of fuel cell electricity with 1,200 kg H_2/day of hydrogen dispensing demand, the cost of electricity ranges from $0.71/kWh to $2.09/kWh with future and current assumptions, respectively. Hydrogen costs represent approximately half the cost of fuel cell electricity, followed by the expenses of replacing fuel cell stacks, a key consumable component. Regardless of configuration or assumptions, the results are consistently many multiples of the approximately $0.02/kWh marginal cost of on-peak electricity available from DTE Energy's commercial rate plans.



Source: Model calculations.

Figure 1-3: Comparison of Fuel Cell Electricity Cost Curves

From an environmental perspective, the Model estimates that, using current technologies and DTE Energy's grid as the source of electricity, HTP activities result in 55.1 kg CO_2 emitted per kg of H_2 produced, approximately 6.8x more carbon intensive than combusting motor gasoline. These results are high because of the energy intensive nature of hydrogen electrolysis using the Park's technology (70.4 kWh/kg H_2) and the high proportion (79.4%) of coal-fired electricity in DTE Energy's fuel mix.

Given the cost of hydrogen from an HTP, our analysis indicates that utilizing HTPs for energy storage and electricity production as well as selling hydrogen commercially is not cost competitive for DTE Energy. Additionally, the market for fuel cells in distributed generation applications is small and is not expected to experience significant growth during the 2006 to 2026 forecast period, according to Energy Information Administration ("EIA") projections.

Because the hydrogen vehicle transportation market is not expected to grow significantly before 2015 according to projections from the Department of Energy, the National Academy of Engineering, and other sources, future costs were also estimated based on anticipated technological improvements and the market size for hydrogen given by the transportation and electricity generation scenarios. Even in these circumstances, the anticipated cost of hydrogen produced at HTPs is between \$8.99/kg H_2 and \$10.11/kg H_2, depending on level of demand and year. Based on substantially lower cost estimates for alternative forms of hydrogen production or other alternative fuels, it is expected that these options will be much more attractive than hydrogen produced at HTPs should gasoline prices rise dramatically.

2 Introduction

2.1 The Hydrogen Economy

The "hydrogen economy" is defined as a future in which hydrogen is extensively adopted as a means for transporting and storing energy. It is increasingly touted by the United States government, environmental groups, and the business sector as a means to reduce dependency on foreign oil and reduce climate change and other environmental impacts associated with the heavy reliance of fossil fuels for energy generation and distribution. In 2004, for example, President George Bush proposed a $1.2 billion investment over five years to support a new Hydrogen Fuel Initiative (DOE 2004).

Many advocates of hydrogen believe that it promises more energy security for the U.S. and a "clean" energy source that will allow U.S. economic growth while significantly reducing pollution. In the future, supporters of the hydrogen economy believe that renewable energy sources ("renewables"), including solar and wind power, will generate pollution free hydrogen that can be utilized in a variety of energy applications.

While many see much promise in a hydrogen economy, there are many challenges that must be overcome if hydrogen is to become a viable energy carrier in the future. According to the U.S. Department of Energy ("DOE"), the current hydrogen production and distribution infrastructure is "insufficient to support the widespread use of hydrogen for energy." The current hydrogen industry does not produce hydrogen for use in energy applications with the exception of aerospace and rocket propulsion applications (DOE 2004). An appropriate infrastructure must be developed to produce and transport hydrogen for its widespread use in many energy applications.

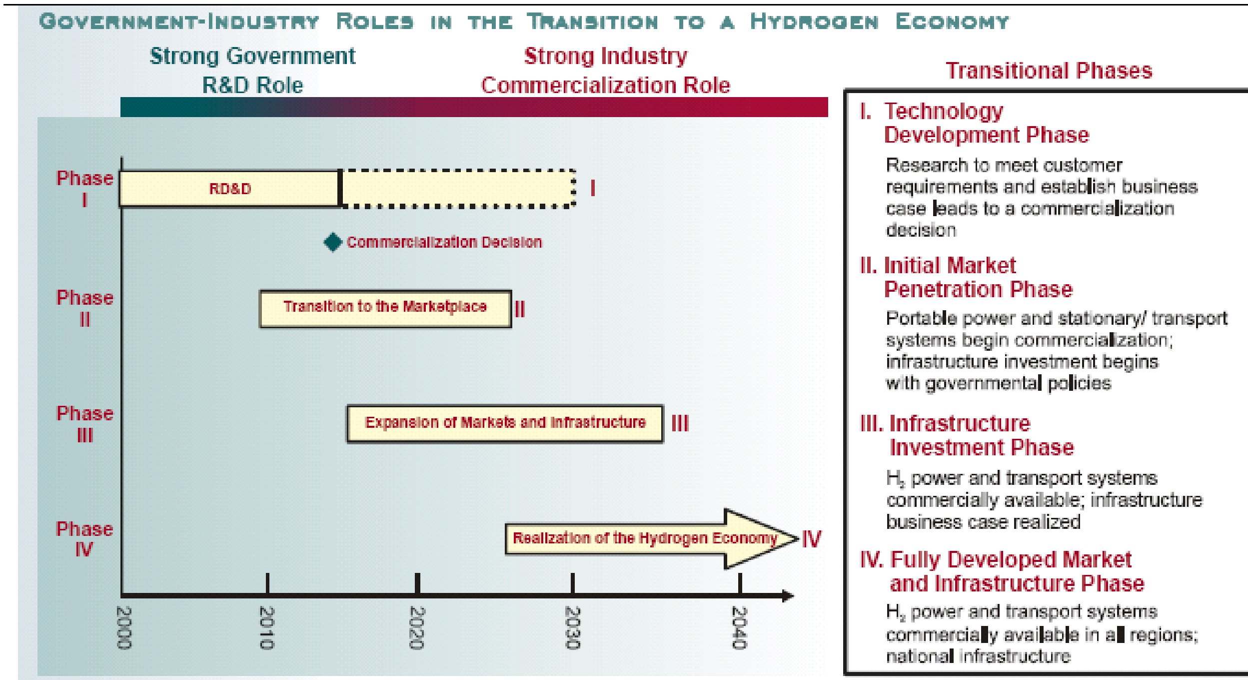
There are many questions about the design and feasibility of a hydrogen infrastructure, ranging from the energy source(s) used to produce hydrogen (e.g., renewables, fossil fuels, or nuclear power) and the source of the hydrogen itself (e.g., electrolysis of water, reformation of natural gas, or other methods), to how best to use hydrogen to produce energy (e.g., as a fuel carrier for cars or as a means of producing energy during peak electricity grid use). A viable hydrogen distribution system will be necessary to provide hydrogen for fuel cell vehicles. Additionally, there are questions regarding when operating this infrastructure will become commercially viable.

2.2 U.S. Department of Energy Hydrogen Program

The U.S. government is playing a major role in evaluating the hydrogen economy from both a technical and financial perspective. The U.S. government spends about $300 million annually on hydrogen and fuel cell programs.

The DOE Office of Hydrogen, Fuel Cells, and Infrastructure Technologies is overseeing much of the government investment and research into the hydrogen economy. The mission of the DOE Hydrogen Program is to "to research, develop, and validate fuel cells and hydrogen production, delivery, and storage technologies for transportation and stationary applications" (DOE 2006a). Demonstration projects are being developed by the DOE in conjunction with commercial partners to evaluate aspects of the hydrogen infrastructure. These demonstration projects are used to assist both the DOE and the business sector to evaluate a potential hydrogen economy.

The DOE envisions a four-phase process for achieving a viable hydrogen economy by 2030-2040 (Figure 2-1). Prior to widespread hydrogen infrastructure, the DOE wants to utilize this information to make a go/no go commercialization decision by 2015 (DOE 2004).



Source: DOE 2004.

Figure 2-1: Four Phases of Transition to Hydrogen Economy

2.3 DTE Energy background and business profile

DTE Energy Co., headquartered in Detroit, Michigan, is a diversified energy company involved in the development and management of energy-related businesses and services nationwide. DTE Energy's largest operating subsidiaries are its utilities: Detroit Edison (electric) and MichCon (natural gas). The non-utility businesses are focused in three areas: power and industrial projects, unconventional natural gas production, and fuel transportation and marketing (DTE Energy 2006).

DTE Energy Ventures is the technology investments subsidiary of DTE Energy. Their focus is on identifying and further developing emerging energy technologies. DTE Energy Ventures invests in and works with high potential energy technology companies to develop products and nurture businesses (DTE Energy Ventures 2006).

2.4 The DTE Energy Hydrogen Technology Park

Opened in 2004, the DTE Energy Hydrogen Technology Park ("Park") is a 50/50 cost-shared effort between the DOE and DTE Energy to develop, implement, and assess leading edge hydrogen energy technology. Figure 2-2 provides photos of the Park and the hydrogen dispenser. The Park's project sponsor is DTE Energy Ventures. Additional partners include Lawrence Technological University, which is providing testing design, data collection, analysis, and reporting support; DaimlerChrylser, whose hydrogen fuel cell vehicles will utilize the Park's hydrogen output, BP America, providing the dispenser and refueling technologies, and the University of Michigan School of Natural Resources and Environment, whose Project team is performing this economic analysis.

Located in Southfield, Michigan, the $3 million facility includes two Hydrogenics IGEN 30 electrolysers with a total of 2.7 kg H_2/hr output, ten 4 kW Plug Power GenCore 5B fuel cells, a hydrogen dispenser compatible with several makes of hydrogen vehicles, eight high pressure steel cylinders for hydrogen storage, and associated power electronics, control systems, and lighting. The system was sized to produce a maximum of 44.8 kg H_2/day.

The equipment and connecting piping and wiring are installed on a concrete base surrounded by park-like landscaping. The Park, located just across the street from residential housing, further demonstrates that distributed hydrogen production, using quiet, non-polluting technology (the only Park byproducts are oxygen and water), can be compatible with the environment and requirements of local neighborhoods. The Park is also the site of a DTE Energy photovoltaic system, which was not evaluated in this study.

Source: DTE Energy.

Figure 2-2: Photos of the DTE Energy Hydrogen Technology Park, Southfield, MI

According to DTE Energy, the objectives of the Park are to demonstrate an end-to-end, multi-use hydrogen energy station in order to:

- Test on-site, co-production of hydrogen for stationary fuel cell power and vehicle fueling applications;
- Identify the technical and economic drivers of system performance;
- Validate component and system technologies;
- Develop applications experience in hydrogen energy;
- Contribute to development of relevant safety standards and protocols for hydrogen-based power systems;
- Evaluate the market opportunities for hydrogen energy systems;
- Educate the public on hydrogen-based energy systems.

2.5 Project Research Goals

The purpose of this research project is to conduct an economic analysis of a distributed hydrogen production system using “real-world” data from the DTE Energy Hydrogen Technology Park. There have been a variety of academic, governmental, and experimental studies of hydrogen as an energy carrier attempting to answer these questions, but there have been few real-world operating projects designed to test practical applications. Currently, there are five DOE Demonstration Learning Projects that are used to demonstrate hydrogen production technologies. Each project differs in hydrogen production methods, equipment used, and other technical specifications.

In consultation with DTE Energy, the Project team focused on studying the following:

1. Hydrogen and electricity production costs of the Park;
2. Financial analysis of the Park utilizing real cost data and revenue projections;
3. Viability of the Park in current hydrogen and electricity markets;
4. Hydrogen demand forecasts in distributed generation and transportation markets;
5. Recommendations to achieve economic viability in current markets and to meet published DOE program goals.

Our analysis assists the DOE in examining the overall feasibility of a variety of hydrogen production and distribution methods and DTE Energy in evaluating the business prospects of distributed hydrogen production. This project is an economic analysis of hydrogen technology parks (“HTPs”) and not an analysis of the technical aspects associated with a hydrogen economy.

Since the Park is part of the DOE Demonstration Project program, we are relying on DOE data as a primary source for analyzing the long-term market conditions of hydrogen demand. This will assist in evaluating the Park with other DOE data and provide consistency for DOE analysis.

DTE Energy instructed the Project team to use the time frame of 2006 to 2026 for our analysis. This time frame is consistent with DOE goals and provides a time horizon that incorporates expected increased demand for hydrogen from fuel cell vehicles.

3 Cost of Hydrogen Estimates

3.1 *Introduction*

A major objective of the DTE Energy Hydrogen Technology Park is to quantify the economic performance and drivers of hydrogen system performance. The Project team developed a "supply side" analysis assessing the economics of producing hydrogen via electrolysis and fuel cell electricity. The analysis is based on data gathering, model building, and model validation with DTE Energy from March 2005 to March 2006. The team also utilized data collection results from a team led by Professor Rob Fletcher at Lawrence Technological University.

The cost of hydrogen is estimated to range from \$12.33/kg H_2 for a 1,200 kg H_2/day HTP with the capacity to serve as a neighborhood hydrogen filling station to \$21.32/kg H_2 for a 100 kg H_2/day HTP, approximately twice the current Park's capacity of 44.8 kg H_2/day (prices are expressed in 2005 dollars). Capital costs represent approximately 55% of the total cost, followed by operations and maintenance (primarily staffing), taxes, and electricity. The single largest cost driver is the electrolyser unit.

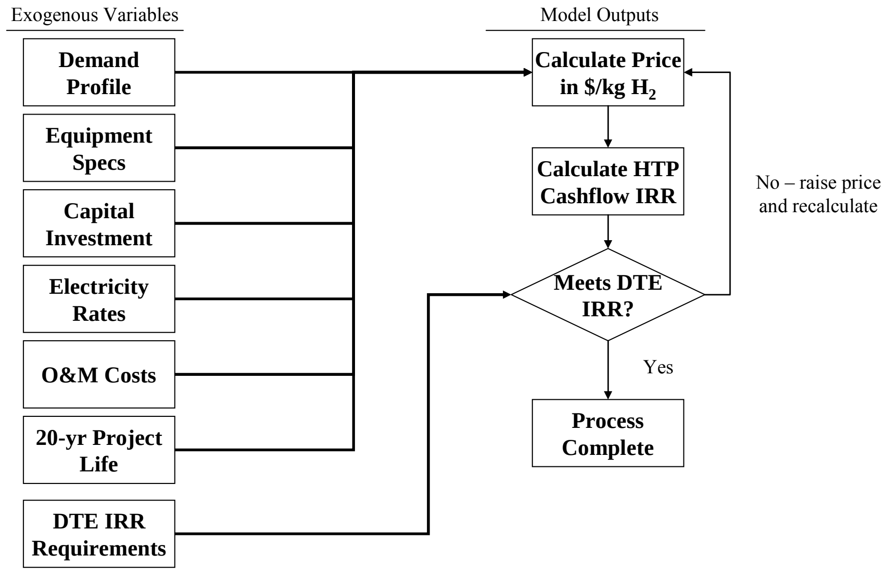
In the future, with performance and cost improvements, the cost of hydrogen may fall to \$7.90/kg H_2 for a 1,200 kg H_2/day HTP and \$11.91/kg H_2 for a 100 kg H_2/day HTP. Capital costs are still the largest component of the cost of hydrogen.

These results are much higher than estimates made by other similar studies, particularly the Hydrogen Station Cost Model by Jonathan Weinert of the University of California, Davis Institute of Transportation Studies and the National Academy of Engineering's distributed hydrogen electrolysis model.

3.2 *HTP Hydrogen Engineering-Economic Model Overview*

An engineering-economic model ("Model") was built in Microsoft Excel to estimate and analyze the economics of an HTP. The Model is divided into two major subsections: a hydrogen subsystem, discussed in this Chapter, and a fuel cell subsystem, discussed in Chapter 4. The hydrogen subsystem, which includes the electrolyser, storage, dispenser, balance of plant, and O&M, is utilized in all configurations of the Park. An instance of the spreadsheet can be found in the Appendix §13.1.

A levelized cost of hydrogen, *LCOH*, expressed in \$/kg H_2, is a value frequently used to compare the economic performance of alternative hydrogen producing systems. It is a single cost that, if used throughout an HTP's life (without including effects from inflation), will allow an HTP to earn its cost of capital. The Model estimates *LCOH* for an HTP. Figure 3-1 illustrates the estimation process at a high level.



Source: Project team.

Figure 3-1: Hydrogen Engineering-Economic Model Schematic

The process for estimating *LCOH* is:

1. Exogenous hydrogen demand forecasts, along with equipment specifications, are provided as inputs into the Model. The engineering portions of the Model determine the capital equipment requirements, such as number of electrolysers, storage cylinders, replacements, etc. to satisfy the demand forecast. The calculation of *LCOH* does not include fuel cells, which is modeled separately in the next chapter.
2. Based on actual and projected HTP costs provided by DTE Energy, the capital requirements are estimated. An initial estimate for *LCOH* is made by the Model, which results in a 20-year cash flow forecast.
3. The internal rate of return ("IRR") of an HTP's cashflows is calculated. If it does not equal the hurdle rate, the spreadsheet iteratively adjusts *LCOH* (via Goal Seek) and recalculates IRR until the hurdle is met.

Thus, the *LCOH* is the price at which the initial capital outlay is fully recovered through its cash flows, discounted at DTE Energy's hurdle rate. In formulae, *LCOH* is the price at which following identity holds:

$I_0 = PV\ (HTP\ Hydrogen\ Cashflows)$

or

$$I_0 = \sum_t \frac{(LCOH \times D_t) - E_t - M_t - C_t - T_t - K_t}{(1+r)^t}$$

I_0	Initial investment in capital, construction, design
E_t	Electricity costs for year t
D_t	Estimated annual demand for hydrogen
M_t	Operation and maintenance expenses

C_t	Carbon emission reduction credits
T_t	Corporate taxes (current obligations)
K_t	Ongoing capital expenditures (replacement of electrolysers)
r	DTE Energy hurdle internal rate of return (IRR)

The cost of hydrogen is often further broken down into its major subcomponents, such as $LCOH_E$, the cost of electricity per kilogram of hydrogen. The calculation employed for *LCOH* allows for variances in annual revenues and capital expenditures, and in turn, taxes and cash flows. Thus, a decomposition of *LCOH* into its constituents is calculated as discounted stream of individual flows, divided by the discounted number of kilograms of hydrogen sold over an HTP's life. For example, the part of *LCOH* attributable to electricity is:

$$LCOH_E = \frac{\sum_t \frac{E_t}{(1+r)^t}}{\sum_t \frac{D_t}{(1+r)^t}}$$

The portion attributable to the cost of capital is calculated as a residual:

$$LCOH_K = LCOH - LCOH_E - LCOH_M - LCOH_C - LCOH_T$$

3.3 Key Inputs

The robustness of the Model's results derives from its extensive use of real-world performance and cost data gathered by DTE Energy from the Park over its one and half years of operation. §3.3.1 through §3.3.11 detail the Model's key data inputs and formulae. In a few cases, estimates or assumptions were used in lieu of historic data where such substitution would produce results more applicable for future planning or comparison. Such substitutions are clearly identified in the respective sections below.

The basic Park architecture – distributed hydrogen production through electrolysis and storage in cylinders at 5,000-5,700 psi pressure – was assumed for all Model scenarios. A hydrogen dispenser is included in the Model calculations if there is demand for dispensing hydrogen, such as to hydrogen vehicles or merchant hydrogen sales. The Model did not evaluate alternative technologies for hydrogen production (such as methane reformation) or alternative distribution configurations (such as large scale centralized production with delivery via pipelines). The *LCOH* calculation does not include fuel cells, which are dealt as a separate subsystem in Chapter 4.

At DTE Energy's request, the analysis was performed assuming a 20-year project life. All capital equipment is assumed to be installed in Year 0 (2006 in the Model), and the system is sized to handle the peak demand encountered during the 20-year forecast period. This simplification may result in an *LCOH* higher than an alternative assumption where capital equipment is installed in phases to better match actual demand with capacity.

Two major sets of Model parameters have been created, a "Current" set called DTE-C, based largely on historic HTP data, and a "Future" set DTE-F. The future is not a set of expectations for costs and performance on a pre-determined date or time period, but a hypothetical case where certain expected improvements and cost savings have been realized by an HTP and its suppliers. Table 3-1 highlights the differences between DTE-C and DTE-F. A complete listing of parameters for DTE-C and DTE-F can be found in Appendix 13.1.

Table 3-1: Differences Between DTE-C and DTE-F Scenarios - Hydrogen

Parameter	DTE-C	DTE-F	Rationale for Difference
Electrolyser cost, before scaling ($/unit)	$225,000	$81,452	Learning effects
Electrolyser efficiency	47.2%	59.6%	Technological improvements
Dispenser ($/unit)	$55,000	$24,581	Learning effects
O&M ($)	$114,000	$14,000	No full-time staffing costs
Balance of plant ($), before scaling	$549,200	$407,200	No site design costs
Dispenser rate (kg/min)	0.39	2.00	Technological improvements

Source: Project team, DTE Energy.

3.3.1 Demand for Hydrogen

The Model can utilize any 20-year, annual forecast for hydrogen demand. Demand in each year of the Model is expressed as the average total daily demand D_{Daily} (kg H_2/day). D_{Daily} includes both hydrogen demanded through the dispensers, $D_{Daily\ D}$, and fuel cell subsystem, $D_{FC,H}$ (described in §4.3.3):

$$D_{Daily} = D_{Daily\ D} + D_{FC,H}$$

3.3.2 Electrolysers

The Model has two engineering calculations for electrolysers. It is assumed that the Hydrogenics IGEN 30 electrolyser installed at the Park is used in the Model. First, there is an estimate of the number of electrolysers required to satisfy the maximum load on the system:

$$\text{Electrolysers required} = \text{ROUNDUP}\left(\frac{D_{Daily}}{\lambda_E \times H_E \times A_E \times LF}\right)$$

D_{Daily} Estimated maximum daily demand for hydrogen (kg H_2) over the 20 year life of an HTP

λ_E Electrolysis production rate (kg/hr) per unit. The maximum rate of production observed at DTE Energy's facility has been 1.35 kg H_2/hr.

H_E Hours of hydrogen production per day. DTE Energy plans to operate an HTP for 16 hours of the day when off-peak electricity is available.

A_E Steady-state availability (percentage). This figure is an estimate of the percentage of the time the electrolyser operates according to specifications when requested and is determined by the unit's mean time to failure and mean time to reliability. The electrolyser is not expected to operate during scheduled maintenance hours - these are the off-line hours. In the remaining hours of the year, the on-line hours, the electrolyser is expected to perform when requested. An electrolyser with 90% availability should operate 90% of the on-line hours. An unscheduled repair is an example of an incident that would occur in the 10% unavailable time.

An estimate of 90% availability is used for both DTE-C and DTE-F scenarios in lieu of historic operating results. At the Park, availability has varied considerably, which is to be expected for a "first of a kind" demonstration system.

LF Targeted load factor (percentage). Given that the electrolysers come in fixed increments (e.g. 1.35 kg H_2/hr per unit), there will naturally be some overcapacity in the system. If *LF* is set to 100% (the default value), the Model will attempt to size a system capacity that is as close to daily demand as possible. If *LF* is set less than 100%, the number of electrolysers chosen will be sized to explicitly incorporate overcapacity.

Excel's ROUNDUP function is used to ensure an integer result.

The second engineering calculation places capital expenditures for replacement electrolysers at the appropriate point in the capital budget. We assume a ten year usable life for the electrolyser, and thus a new set of identical electrolysers is purchased in Year 10.

DTE Energy's IGEN 30 electrolyser cost approximately $225,000 per unit and produces at a maximum rate of 1.35 kg H_2/hr. This cost includes hydrogen purification and compression equipment and a gas control unit. At the Park, two electrolyser units were installed in a single enclosure, with a combined maximum measured production rate of 2.7 kg H_2/hr. This translates to a cost/production rate of $140,802/kg H_2/hr. Based on each electrolyser's maximum power demand of 99 kW, the electrolyser's cost/power is $1,920/kW.

The DTE-C electrolyser base cost is set to $225,000/unit for a 1.35 kg H_2/hr unit. In the DTE-F scenario, it is assumed that a large number of electrolysers have been produced and a learning curve effect reduces the base cost (see §3.4.1 for a discussion of how the learning curve is calculated). In both DTE-C and DTE-F cases, the base cost is adjusted by a scaling factor that reduces the per unit cost as total installed production capacity increases (see §3.4.2 for details on how the scaling factor is determined and calculated). Finally, a sensitivity analysis of ±10% changes in electrolyser costs on changes in *LCOH* is also performed, with results presented in §3.8.

Weinert 2005 provides results of a recent hydrogen equipment price survey, with manufacturers' estimates for electrolysers in Table 3-2 and compressor costs in Table 3-3. It is not possible to directly compare the IGEN 30's costs with the Weinert electrolyser studies, as a true comparison would require pairing electrolyser and compression equipment from the two tables to be comparable to the integrated IGEN 30 system. However, the data do show that the IGEN 30 costs are in line with comparable systems on the market. Weinert's survey also asked manufacturers about electrolyser production volumes. The production volume data show that electrolysers are emerging technologies produced in low volumes.

The National Academy of Engineering's ("NAE") estimated electrolyser and compressor costs are also presented in the same tables. This figure was obtained by running the NAE's spreadsheet model "Dist H2.xls", assuming an electrolyser sized for 100 kg H_2/day output capacity. NAE has neither reviewed, nor endorsed the use of their model with these inputs, but the results obtained illustrate the wide range of cost assumptions among the main studies.

Table 3-2: Comparison of Alkaline Electrolyser Costs

Cost/Rate ($/kg/hr)	Total Cost	$/kW	Capacity (kg/hr)	Production Volume (units/yr)	Study
$72,028	$600,000	$2,163	8.33	N/A	Weinert
74,149	308,953	1,413	4.2	N/A	NAE
83,426	450,000	2,505	5.4	10	Weinert
114,943	310,000	3,452	2.7	10	Weinert
124,212	670,000	3,730	5.4	1	Weinert
140,802	225,000	1,920	1.35	N/A	DTE
161,116	161,116	4,838	1.0	2	Weinert
166,852	450,000	5,011	2.7	1	Weinert
185,391	250,000	5,567	1.3	10	Weinert
200,013	686,044	6,006	3.43	2	Weinert
274,379	370,000	8,240	1.3	1	Weinert

Note: Table sorted in ascending order of $/kg H_2/hr. Number of significant digits reported varied. NAE production rate estimated by Project team, assuming 24 hr of production/day. N/A – Not available.
Source: Weinert 2005, NAE 2004, DTE Energy.

Table 3-3: Comparison of Diaphragm Compressor Costs

Cost/Rate ($/kg/hr)	Total Cost	Capacity (kg/hr)	Source
$2,738	$91,958	33.58	Weinert
4,016	245,222	61.06	Weinert
4,685	64,371	13.74	Weinert
9,072	62,327	6.87	Weinert
9,370	64,371	6.87	Weinert
9,914	41,310	4.2	NAE
16,447	125,000	7.6	Weinert
20,435	62,327	3.05	Weinert
25,658	195,000	7.6	Weinert

Note: Table sorted in ascending order of $/kg H_2/hr. Number of significant digits reported varied. NAE production rate estimated by Project team, assuming 24 hr of production/day.
Source: Weinert 2005, NAE 2004.

The IGEN 30 was originally manufactured and installed by Stuart Energy. Subsequent to the electrolyser's installation at the Park, Stuart Energy was acquired by Hydrogenics

Corporation. During the one and a half years that it has been installed on-site, Stuart and now Hydrogenics have made frequent equipment upgrades, replacements, and modifications. The equipment installed at the Park is best regarded as a "first of a kind" installation and not a commercial system. DTE Energy and Hydrogenics have begun discussions to replace the IGEN 30 with a new model. Therefore, the Model's cost and performance data may not be representative of future Hydrogenics products.

At the time this study went to press, Hydrogenics indicated that a new model of its HySTAT electrolyser would be available in 2006 with production rates up to 30 kg H_2/hr/electrolyser. Such a model would have a capacity approximately 22x that of the 1.35 kg H_2/hr IGEN 30 electrolyser evaluated in the DTE-C and DTE-F scenarios. With two of these electrolysers (costing a total of approximately \$3.5 million), an HTP could produce up to 1,440 kg H_2/day, which would meet the requirements for a neighborhood filling station. The Project team did not have an opportunity to estimate the cost of hydrogen of an HTP using this new electrolyser, which could be lower than the estimates in this study.

3.3.3 Storage

Compressed hydrogen produced from the electrolysers is stored in steel cylinder tanks. Three banks of cylinders, corresponding to low, medium, and high pressure, are used to provide a cascade refilling system. In order for hydrogen to flow from an HTP's cylinders into a hydrogen vehicle's tank, the pressure in an HTP's cylinders must exceed the pressure inside the vehicle's tank. In a cascade refilling system, hydrogen from the low pressure bank is discharged first, followed by the medium pressure bank, and finally the high pressure bank. DTE Energy has estimated that demand for low, medium, and high pressure stored hydrogen will be 75%, 15%, and 10% of production by volume, respectively.

There are two main cases where hydrogen storage is necessary. In the first case, hydrogen dispensing may take place at times when the electrolysers are not producing hydrogen. In DTE Energy's current operating procedure, hydrogen production is designated to occur in the 16 off-peak hours. If hydrogen vehicles arrive only in the other eight hours of the day, eight hours' consumption of hydrogen must be stored. The general formula to estimate the storage requirements for this case is:

$$S_1 = \frac{D_{Daily}}{H_D} \times \text{MINIMUM}(H_D, 24\text{ hrs/day} - H_E)$$

S_1	Storage required (kg H_2) to allow dispensing while electrolysers are not producing
D_{Daily}	Estimated maximum daily demand for hydrogen (kg H_2) (same value as in §3.3.2)
H_D	Hours of dispenser operation per day
H_E	Hours of hydrogen production per day (same value as in §3.3.2)

In the second case, hydrogen dispensing may occur during hours when electrolysers are operating. However, during this time, the dispensing rate may exceed the production rate. This may occur, for example, during rush hours when many hydrogen vehicles arrive to be refueled. Stored hydrogen will be needed to make up the difference. The formula to estimate the storage requirements for this case is:

$$S_2 = (Surge \times \frac{D_{Daily}}{H_D}) - \lambda_E$$

S_2	Storage required (kg H_2) to allow dispensing when dispensing rate exceeds production rate
Surge	Maximum surge rate of demand as a multiple of average hourly demand. For example, hydrogen may be dispensed at an average rate of 10 kg H_2/hr throughout the H_D dispensing hours. During the rush hour the required dispensing rate may be 40 kg H_2/hr, or four times as much as the average rate. In this example, *Surge* = 4.
D_{Daily}	Estimated maximum daily demand for hydrogen (same value as in §3.3.2)
H_D	Hours of dispenser operation per day
λ_E	Electrolysis production rate (kg/hr) per unit (same value as in §3.3.2)

The Model will select the greater of these two to determine the storage requirements:

$$S = \mathrm{MAX}(S_1, S_2)$$

In scenarios where there is little or no overlap between hydrogen production and dispensing hours, S_1 will determine the storage requirements *S*. In cases where there is 24 hour or near continuous production of hydrogen, S_2 will determine the storage requirements.

The Model integrates and extends an Excel worksheet developed by Prof. Rob Fletcher to translate the storage requirements *S* (measured in kg H_2) into volume requirements (measured in cubic feet), which then determines the minimum number of steel cylinders required. Fletcher's worksheet uses the Redlich-Kwong equation of state to determine the volume of storage necessary for each cylinder bank, assuming each bank is discharged daily. These equations are combined with specifications for a generic steel tank, and Excel's Solver determines the number of tanks required to meet demand while minimizing excess storage.

The cylinder specified for an HTP is an ASME-certified steel cylinder tank 12.75 inches in outer diameter and 32 feet long. This is similar to the cylinders installed at the Park, though not identical as such a model was not available in the market, as desired by DTE Energy, when the Park was installed. DTE Energy estimates such a cylinder can be purchased for approximately \$10,000. As steel cylinders are relatively mature technologies, it was assumed that there would be no price reductions due to learning effects, so the \$10,000 cost is used for both DTE-C and DTE-F scenarios. A sensitivity analysis of ±10% changes in cylinder prices on *LCOH* is presented in §3.8.

3.3.4 Dispensers

The Model estimates the number of dispensers required to satisfy the peak rate of dispensing during the day, defined as the *Surge* rate multiplied by the average hourly dispensing rate:

$$\text{Dispensers required} = \text{ROUNDUP}\left(\frac{Surge \times (D_{Daily} \div H_D)}{\lambda_D}\right)$$

Surge	Maximum surge rate of demand as a multiple of average hourly demand (same value as in §3.3.3)
$D_{Daily\ D}$	Estimated maximum daily demand for hydrogen through electrolysers
H_D	Hours of dispenser operation per day (same value as in §3.3.3)
λ_D	Dispenser rate (kg/hr) per unit (see below)

Dispensing rates can vary depending on how the hydrogen vehicle and dispenser are synchronized (also known as the "fueling protocol"). In cases where fueling protocols are well synchronized, fueling can be relatively fast. In other cases, a slower trickle rate is taken to prevent heat and pressure build-up in the hydrogen vehicle's tank.

The DTE-C dispenser rate λ_D was based on the following data. From 18 June 2005 to 7 September 2005 (corresponding to one of the Park's measurement periods), the Park performed 31 fill-ups of hydrogen fuel cell and internal combustion vehicles including various models of the Ford E-450, Inergy F-Cell, a hydrogen UPS van, and DCX F-cell. On average, these fill-ups occurred at an average rate of 0.39 kg H_2/min with standard deviation of 0.07784 kg H_2/min. The DTE-C dispensing rate is thus:

λ_D = 60 min/hr × 0.39 kg H_2/min = 23 kg H_2/hr

The DTE-F dispensing rate was assumed to be 2 kg H_2/min or 120 kg H_2/hr. In the future, dispensing rates will be higher as fueling protocols will be better synchronized. By way of comparison, NAE estimates the dispenser can fill at a rate of 48 kg/hr in both its current and future scenarios.

The Dispenser installed at the Park, and represented in the Model, is designed for a maximum pressure around 5,700 psi. There is much discussion within industry about moving towards higher pressure, higher dispensing rate systems that could decrease fueling time and more closely match the fueling rates for motor gasoline. For example, the DOE's 2010 FreedomCAR target is for the forecourt to deliver compressed hydrogen at 10,000 psi (DOE 2005a). Thus, the system modeled here may not be representative of future dispenser installations.

Based on the Park's budget and discussions with manufacturers, DTE Energy estimated the cost of purchasing a hydrogen dispenser at $55,000 per unit. $55,000 is used as the DTE-C dispenser price, and the DTE-F cost assumes price reductions due to learning effects from continuous, volume production (details on the learning curve is discussed in §3.4.1). A sensitivity analysis of ±10% changes in dispenser prices on *LCOH* is presented in §3.8.

3.3.5 Electricity

Electricity is the only feedstock modeled for an HTP. At DTE Energy's direction, the Project team did not model water consumption, though this can be a scarce and expensive input in other geographies. The amount of electricity energy demanded by hydrogen production $D_{H,E}$ is estimated using electrolysis efficiency figures obtained by measurement of the Park's performance. The current efficiency (with compression) is 47.2%, a figure obtained in the September 2005 period measurement.

$$D_{H,E} = \left(\frac{D_t}{\eta_E} \right)$$

η_E Efficiency of electrolyser (percentage).

The DTE-C η_E has been set to 47.2%, the maximum observed efficiency, including compression. For DTE-F, a 59.6% efficiency has been assumed, based on DTE Energy's discussions with Hydrogenics regarding future electrolyser performance. A sensitivity analysis of ±10% changes in electrolyser efficiency on *LCOH* is presented in §3.8.

It was assumed that an HTP would operate as a commercial entity purchasing electricity from DTE Energy on the terms of an arms-length, standard "D6" commercial rate schedule available in 2005. This rate schedule, which includes energy, demand, and fixed charges, is used for both DTE-C and DTE-F scenarios. DTE Energy's plans for an HTP are to operate it during the 16 hours when less expensive off-peak electricity is available. It was further assumed that the real prices would stay constant over the Project's life. A sensitivity analysis of ±10% changes in the marginal cost of off-peak electricity on *LCOH* is presented in §3.8.

For simplicity, the only use of electricity in the Model is for producing hydrogen by the electrolyser. In practice, a number of other loads are placed on the electrical grid, such as monitoring equipment, lighting, and a significant amount electric heating to prevent water from freezing in the electrolysers and fuel cells when they are not in operation. The exclusion of these loads has the effect of biasing *LCOH* downwards.

3.3.6 Operations and Maintenance (O&M)

O&M includes three costs. The first is the warranty expense for the electrolysers. As of this writing, warranty costs have not been finalized, so a DTE Energy estimate of $5,000/yr per unit has been used for warranty costs. Second is staffing. The Park is currently supervised and maintained by one staffer. For DTE-C, staffing costs are assumed to be $100,000 per year. In DTE-F, it is assumed that increased HTP reliability and fully automated operation will not require on-site staffing, and the $100,000 cost is eliminated. Thirdly, O&M includes $14,000 per year paid to DTE Energy's System Operations Center for monitoring, security, and remote management responsibilities. This appears in both DTE-C and DTE-F. A sensitivity analysis of ±10% changes in total O&M on *LCOH* is presented in §3.8.

3.3.7 Balance of Plant

The balance of plant includes equipment such as power electronics, supervisory control and data acquisition, and security infrastructure. It also includes site and system design and civil works. For simplicity, "balance of plant" includes all such supporting infrastructure for the fuel cell electricity subsystem. This was a simplification made on account of the fact that the Park was designed as an integrated system. Thus, *LCOH* is biased upwards compared to a system with no fuel cells.

The Park's actual budget for balance of plant was approximately $726,000: $64,000 for equipment, $520,000 for construction, and $142,000 for site and system design. These costs were for a system sized to produce a maximum of 44.8 kg H_2/day. The budget included "one-time" items such as system design costs and construction elements that enhance the aesthetic appearance of the facility (e.g., aluminum fences, concrete base, landscaping, etc.).

For the Model, lower cost construction is assumed (e.g., a less expensive chain link fence is used instead of an aluminum fence, a gravel base instead of concrete, and no landscaping). This construction cost is assumed to be $343,000 or 66% of the original $520,000 construction cost. Thus, the total DTE-C balance of plant estimate, for a 44.8 kg H_2/day HTP, is $549,200: $142,000 for system design, $64,000 for equipment, and $343,000 for construction. For the DTE-F estimate, it is assumed balance of plant costs are further reduced in that no costs for site and system design are needed as the initial designs can be replicated. The Model does not include permitting, lobbying, and other expenses incurred in the process of gaining proper approvals to build an HTP in a community, though such expenses can be expensive in terms of both time and money. A sensitivity analysis of ±10% changes in construction costs on *LCOH* is presented in §3.8.

When running the Model it is necessary to estimate the balance of plant costs for HTP with capacities larger than 44.8 kg H_2/day. The balance of plant cost is extrapolated using a scaling factor (see §3.4.2 for details).

3.3.8 Financial Assumptions

The Model's financial assumptions were set through consultation with DTE Energy's Treasury Department to ensure consistency with standards employed by DTE Energy for project evaluation. Key parameters include a 20-year life, 35% corporate tax rate (with no operating loss carryforwards), and seven year modified accelerated cost recovery system ("MACRS") depreciation. No working capital is assumed, and all free cash flows are paid as dividends to the parent immediately. No decommissioning expense was assumed. With the 20-year Project life and discount rate, this expense is not expected to be significant in present value terms.

In both DTE-C and DTE-F scenarios, the Model uses a real hurdle rate of return of 16%, which corresponds to DTE Energy's "mid-tier" risk level. By comparison, DTE Energy's hurdle rate is 11% for "lower risk" projects, such as those with a contracted off-taker, and 21% for "higher risk" projects.

Although the DOE's H2A model standards (DOE 2006b) were not used for the Model, Table 3-4 compares the financial assumptions between the Model and H2A. They show that the Model's inputs are generally consistent with those used in other studies. The major point of departure is the IRR. The H2A's 10% IRR reflects a "steady state situation in the future in which hydrogen is no longer a novel concept and a significant demand for hydrogen exists." The Model uses a 16% rate which is DTE Energy's standard, and in the view of the Project team, better reflects the riskiness of HTP cashflows than the 10% IRR.

Table 3-4: Comparison of DTE Energy and H2A Financial/Economic Assumptions

Variable	Model Assumptions	H2A Forecourt Assumptions
Discount rate/IRR	16% real – mix of 50% equity financed, 50% debt	10% real – 100% equity financed, sensitivity runs to be conducted using 0% and 25%
Depreciation schedule and period	7 years MACRS	7 years MACRS
Plant life and economic analysis period	20 years	20 years
Inflation rate	Constant real prices	1.9% inflation, but convert cash flows to real values
Tax rate	35%	38.9% including state and federal tax

Source: DOE 2006b, Project team analysis.

Due to the high sensitivity of *LCOH* to the cost of capital, sensitivity analyses have been run on a range of IRRs from 10% to 25% and presented in §3.8.

3.3.9 Clean Fuel Refueling Property Deduction

Federal law allows a tax deduction for "clean-fuel" refueling stations, as specified in Title 26 of the United States Code, Section 179A. This section was amended in the Energy Tax Incentives Act of 2005 (House of Representatives 2005). The deduction, which is applicable to the first year of operation, is the maximum of $30,000 or 30% of the facility's cost. This was included in the Model by reducing the tax basis for the first year of operation (2007) by $30,000.

3.3.10 Emissions

Hydrogen production at an HTP contributes to air pollution through the consumption of electricity from DTE Energy's grid, which is largely coal-fired, as indicated by Table 3-5.

Table 3-5: DTE Energy Grid Fuel Mix

Fuel Source	% of Fuel Mix
Coal	79.4%
Nuclear	17.9%
Gas	1.0%
Oil	0.7%
Biofuels	0.5%
Photovoltaic	0.4%
Hydroelectric	0.1%

Note: Data for June 2004-May 2005.
Source: DTE Energy.

The Model estimates the emissions attributable to hydrogen production, based on DTE Energy's emission factors as presented in Table 3-6. Emissions estimated by the Model include CO_2, NO_X, SO_2, and particulate matter. The system boundary for this analysis is defined as DTE Energy's system-wide grid. These estimates are based on the consumption of fossil fuels in the power plants for electricity generation and exclude emissions from 1) the extraction, processing, and distribution of fossil fuels to the power plants, and 2) the manufacturing, installation, and decommissioning of HTP equipment. These estimates do not deduct the emissions that would be avoided through the fuel switch from fossil-based vehicle fuels to hydrogen.

Table 3-6: DTE Energy Grid Average Emission Factors

Emission	2004 (tonne/MWh)	2012 Estimate (tonne/MWh)
CO_2	0.78275	0.77030
NO_X	0.00123	0.00069
SO_2	0.00399	0.00298
Particulate matter	0.00006	0.00004

Source: DTE Energy data converted to metric units by Project team.

In the Model, 2006-2011 emission factors were set equal to 2004 actual emission factors. By 2012, it is projected that DTE Energy will have installed additional emission reduction equipment and implemented at least one carbon sequestration project. Emissions from 2012 and thereafter are set equal to DTE Energy's 2012 emission factor estimates.

The total emissions attributable to HTP hydrogen production is calculated as follows:

$$E_H = EF_t \times D_{H,E}$$

E_H Emissions intensity for hydrogen production (e.g., tonnes of CO_2 equivalent/kg H_2) in year *t*

EF_t Emissions factor for electricity (tCO_2e/kWh) in year *t*, from Table 3-6

$D_{H,E}$ Electricity consumed per kg of H_2 produced (kWh/kg) in year *t*. This is calculated according to the formula in §3.3.5.

3.3.11 Carbon Credit Costs

CO_2 is the main greenhouse gas produced as a result of HTP activities. Acknowledging the potential for CO_2 to contribute to global climate change, DTE Energy has made a voluntary commitment to reduce the carbon intensity of its electricity by 3 to 5% over the next decade, in line with guidelines established by the Edison Electric Institute in 2003.

Under the Kyoto Protocol, a number of nations (the "Annex I" nations) have agreed to reduce their greenhouse gas emissions below specific targets. If emission limits are enforced, hydrogen producers will start treating carbon emissions as a cost of doing business, either by re-engineering industrial processes to reduce emissions or purchasing carbon emission reduction credits from another party who has achieved emission reductions. A fledging market for trading emission reduction credits has emerged. Through the interaction of supply and demand, the market sets a price for a tonne of carbon dioxide, as illustrated by Figure 3-2, which presents prices of carbon credit "forward allowances" (a promise to deliver a credit in the future) from the Nord Pool exchange.

Source: Nord Pool 2006.

Figure 3-2: Closing Price for CO_2 Allowance for Delivery in December 2007

At this time, a Kyoto Protocol-style carbon credit or carbon tax is not in place in the United States. Therefore, no carbon credits are included in either DTE-C or DTE-F scenarios. However, the Model has the ability to include such credits in the cost of hydrogen calculation, as carbon constraints could be implemented during the 20-years forecast horizon. The Model estimates an HTP's emissions and the cost of purchasing sufficient credits so that the HTP is carbon-neutral (i.e. it purchases one tonne of emissions reduction credit for every tonne emitted through the HTP). The amount spent on credits is then added to the costs in *LCOH*. An analysis quantifying the incremental cost to *LCOH* of carbon emission reduction credits is found in §3.8.2.

3.4 *Additional Modeling Considerations*

Consistent with other electrolysis models, the Model provides the ability to estimate capital costs using learning curves and scaling factors.

3.4.1 Learning Curve

Modeling an HTP's economics using the Park's budgeted costs has the strength of being grounded in real-world costs. The disadvantage is that such costs may be very high as the core technology is very young. There are many "first of a kind" costs that may not be repeated in the future. As more units are produced and installed, workers become more familiar with the manufacturing process, engineers are able to weed out bugs and optimize the design, and sales and marketing personnel become more adept at distributing the product.

The learning curve quantifies the concept that know-how translates into lower costs. An empirical relationship may be measured between experience (as measured through cumulative units produced to date) and unit cost. A similar effect may occur between increased output and higher product quality. Learning curves have been estimated for hundreds of products, and it may be reasonable to apply some form of the curve to HTP equipment to project what future capital costs may be.

There are three considerations when applying the learning curve to an HTP. First, a learning curve is a statistical measurement that may not directly identify the underlying learning process. The process improvements underlying other learning curves (say, those calculated in the airframe manufacturing industry) may not be applicable to hydrogen equipment.

Second, if one were to use the learning curve to project the cost of, say, the 4,000th cumulatively produced unit, one must assume that the first 3,999 units were produced and sold. This may occur in some industries where the manufacturer, sensing a strategic opportunity to develop a cost advantage, will be willing to assume temporary losses. Alternatively, this demand could come from government subsidy of electrolyser purchases, or customers willing to shoulder the higher costs of earlier units.

Third, the hydrogen industry is at a young, developmental stage. Products are constantly being re-engineered and the industry may not have reached a stage where large scale, serial production is occurring.

The basic form of the learning curve is:

$$P(t) = P(0) \times [\ Q(t) \div Q(0)\ ]^{-b}$$

$P(t)$	Price at time t
$Q(t)$	Cumulative quantity produced by time t
b	Learning coefficient

$$b = -\log_2 PR$$

PR	Progress ratio. Each doubling of production reduces costs by (1 – *PR*)

percentage

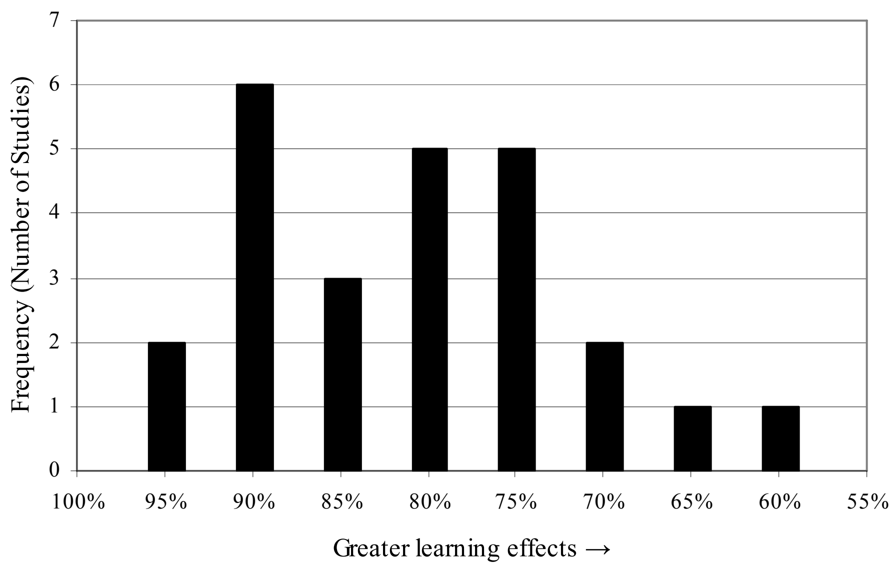
Thomas 1997 and Weinert 2005 have suggested using varying progress ratios for hydrogen-related equipment depending on technological maturity, as listed in Table 3-7. Less mature technologies exhibit stronger learning effects. For example, because storage cylinders are steel tanks that are already produced in large quantities for other applications, they will exhibit relatively little progress with additional cumulative production:

Table 3-7: Progress Ratios for Hydrogen Equipment

Cluster	Equipment	Progress Ratio
Nascent technology, "one of" production levels	Electrolyser, purifier, fuel cell	0.85
Mature equipment used primarily for H_2 stations	Compressor, dispenser, non-capital station costs	0.90
Mature equipment with high volume production levels	Storage cylinders	0.95

Source: Weinert 2005.

McDonald and Schrattenholzer 2001 compiled progress rates from studies in energy-related technologies ranging from wind turbines to oil extraction. As indicated in Figure 3-3, most studies reported progress rates around 80%-100%.



Note: Columns are sorted in the order of increasing savings from cumulative production. Lower *PR* values correspond to larger learning curve effects.
Source: McDonald and Schrattenholzer 2001.

Figure 3-3: Distribution of Progress Ratios

Finally, Tolley et al 2004 suggested a framework for predicting progress rates, based on data from the nuclear energy industry, reproduced in Table 3-8. Learning and cost reduction is most likely to happen when there is a constant pace of orders. A constant pace decreases the likelihood that engineering and construction crews will be reassigned to work on other projects or technologies.

Table 3-8: Progress Ratios for Nuclear Industry

Pace of Reactor Orders	Number of Reactors Built at a Single Site	Construction Market	Reactor Design Standardization	Regulation Impacts	Progress Ratio
Spread apart 1 year or more	Capacity saturated, no multiple units	Not highly competitive; can retain savings from learning	Not highly standardized	Some construction delays	0.97
Somewhat more continuous	Somewhat greater demand; multiple units uncommon	More competitive; most cost reductions from learning passed on to buyers	Narrower array of designs	Delays uncommon	0.95
Continuous construction	High capacity demand growth; multiple units common	Highly competitive; all cost reductions passed on	Several designs; sufficient orders for each to achieve standardization learning effects	Construction time reduced and delays largely eliminated	0.90

Source: Tolley et al 2004.

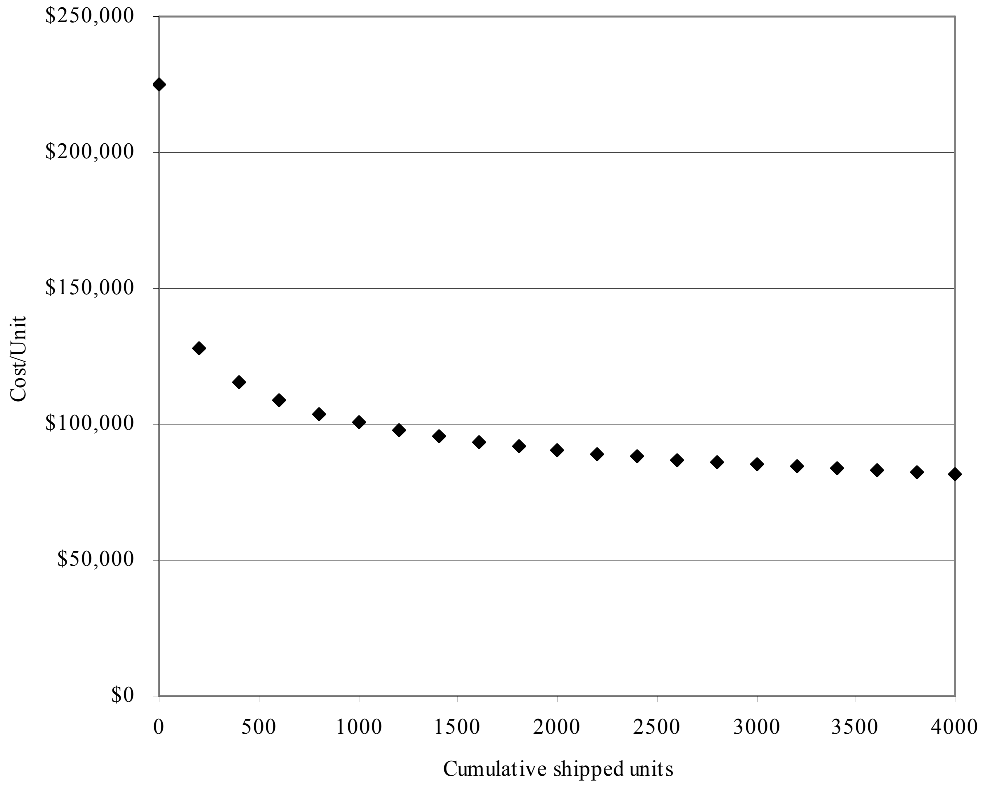
Based on the foregoing, the Model utilizes *PR* = 0.90 when modeling DTE-F future cases. On one hand, unlike nuclear plants, electrolysis is highly componentized, with most capital investment in discrete units or cells that can be assembled in a factory, trucked on site, and installed without major construction. There is much less site-specific engineering and regulatory risk than building a nuclear plant. Therefore the mid-0.90s range may be too conservative. On the other hand, at this time, the hydrogen industry is better characterized by "one of a kind" production than continuous production. The industry is likely to undergo rapid change and possibly mergers and acquisitions that could disrupt the continuity needed for learning. Without a continuous order stream, *PR* = 0.85 seemed aggressive.

For a conservative approach in the Model, the learning curve is applied only to the electrolyser and not to more mature technologies like the compressor, storage cylinders, or balance of plant.

The following parameters were used in estimating the DTE-F future price of the electrolyser *P(Future)*:

P(2005)	\$225,000 per electrolyser (DTE-C price)
Q(2005)	5
Q(Future)	4000
PR	0.90

The DTE-F estimate is *P(Future)* = \$81,452. Figure 3-4 illustrates the *P(Future)* as a function of cumulative shipped units:



Source: Model calculations.

Figure 3-4: Model Electrolyser Learning Curve

3.4.2 Scaling Factor

In addition to the learning curve effect are potential savings from scale. Like other complex systems, electrolysers and balance of plant may exhibit some scale economies; i.e. per unit cost (e.g., \$/kg H_2/hr) decreases as the aggregate installed capacity increases (e.g., total kg H_2/hr). This is because there are fixed costs that can be amortized over a larger base. For example, a single gas control unit can manage the flow of hydrogen from multiple electrolysers. In some cases, the inherent technical features of the system may mean that larger systems are less expensive.

Scaling is also a necessary analytical tool because the production rates of commercially available electrolysis units, typically under 5 kg/hr, are well under the required rate to support a neighborhood fueling station under normal usage patterns (closer to 50-60 kg/hr). Thus, some form of extrapolation must be made to the larger size.

The following formula is used to express the relationship between price and scale:

$$I_{DesignSize} = I_{BaseSize} \times \left[\text{BaseSize} \div \text{DesignSize}\right]^{(1-ScalingFactor)}$$

I	Investment cost per base size unit
DesignSize	Size of the designed system, in a measurement such as kg/hr
BaseSize	Standardized system size, such as a base system that produces 1.35 kg/hr

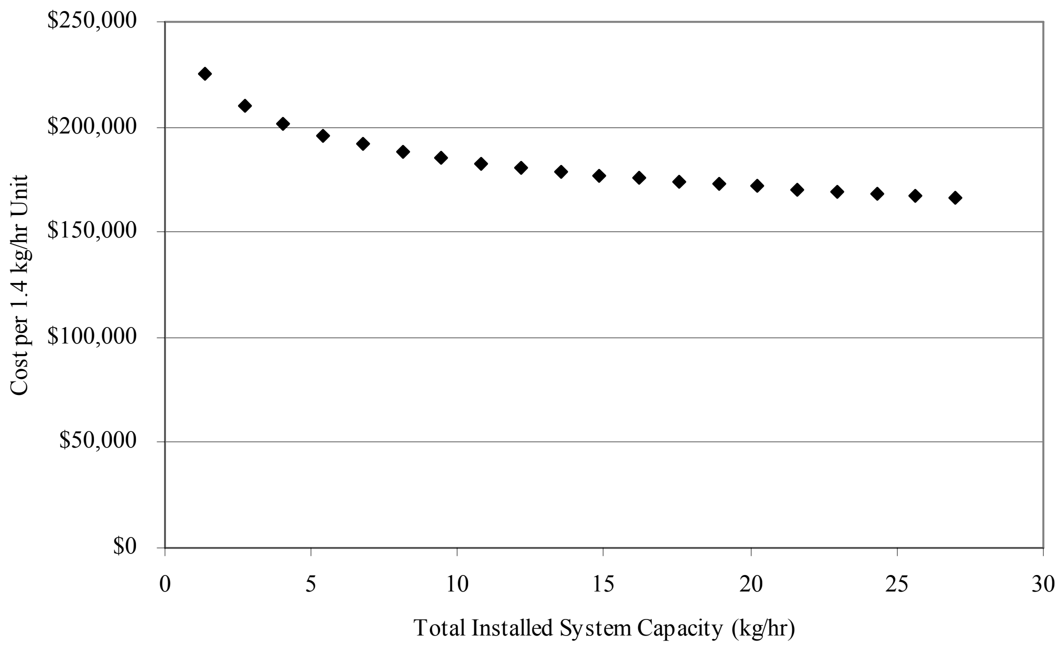
ScalingFactor A constant that relates greater size with reduced unit costs

Weinert 2005 obtained cost and production rate information for eight electrolyser models with hydrogen production rate specifications ranging from 1 to 5.4kg/hr. Through curve fitting, he estimated a 0.44 scaling factor, a number also used in his estimates of hydrogen costs (see §3.6 for a comparison between the Model and Weinert's results). The NAE's scaling factor assumption for electrolysers is 0.85.

For both DTE-C and DTE-F, the Model used a more conservative 0.90 scaling factor. The Project team felt this figure was appropriate as the IGEN 30 did not appear to have many "fixed cost" features or scalable components. The parameters used in the Model are:

$I_{BaseSize}$	The base cost is \$225,000 for DTE-C or the \$81,452 for DTE-F, as calculated above in §3.4.1
BaseSize	Base size is 1.35 kg H_2/hr
ScalingFactor	0.90. This assumption was believed to be conservative.

With a DTE-C base cost of \$225,000, the DTE-C estimate for $I_{6.3\ kg\ H2/hr}$ = \$193,580. Figure 3-5 illustrates the relationship between cost and scale:



Source: Model calculations.

Figure 3-5: Model Scaling Factor Effects on Electrolyser

Similarly, balance of plant is scaled with the following assumptions:

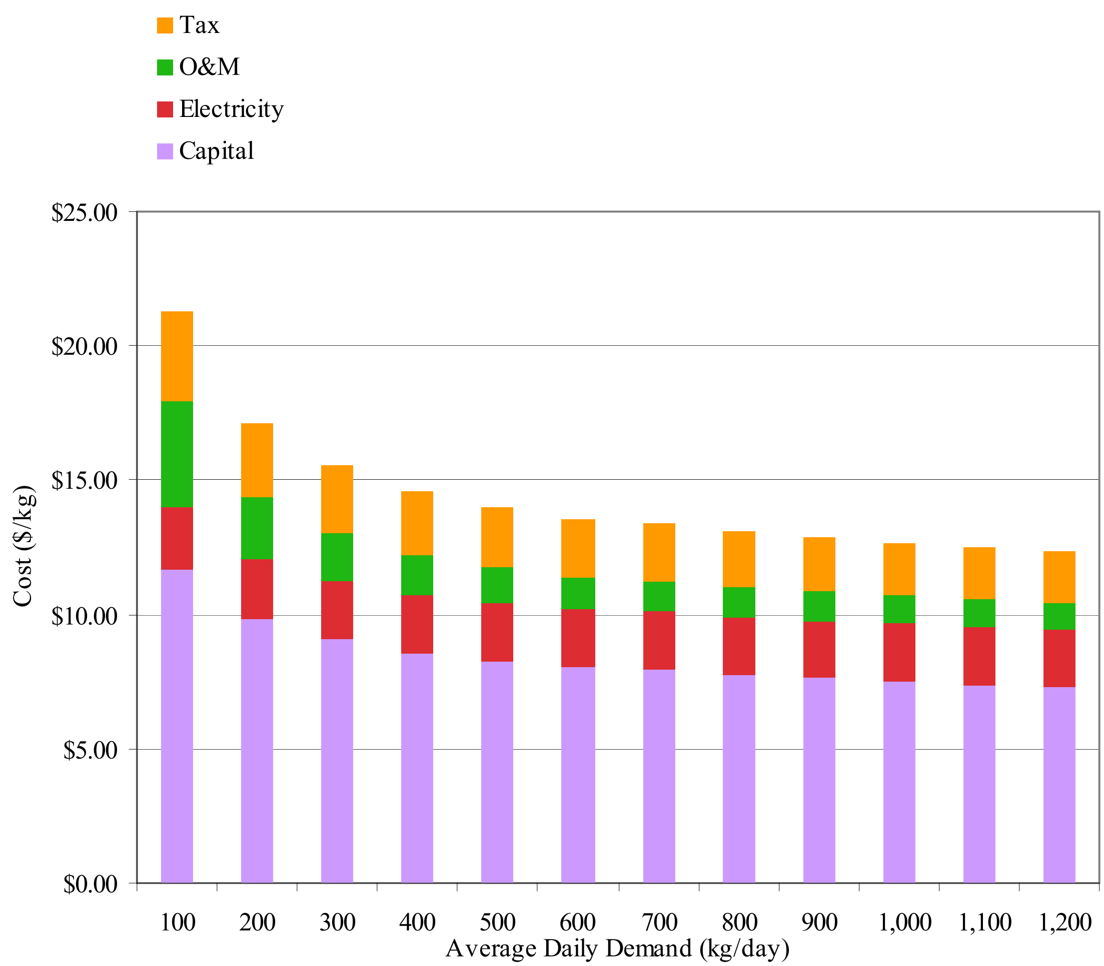
$I_{BaseSize}$	The base cost is the \$390,000 projected balance of plant as described in §3.3.7.
BaseSize	Base size is 44.8 kg H_2/day. This is how the Park is presently sized, with capacity of 2.8 kg H_2/hr × 16 hr/day = 44.8 kg/day production.

ScalingFactor   0.75. This figure was believed to be a reasonable assumption.

3.5 Levelized Cost of Hydrogen Estimates

3.5.1 Estimated Current Costs (DTE-C)

A number of Model runs have been made to derive estimates for *LCOH*. The first set of runs presented here utilize the DTE-C "current" assumptions for system sizes ranging from 100 kg H_2/day (approximately twice the size of the current Southfield facility) to 1,200 kg H_2/day, the size generally estimated to be sufficient to serve as a neighborhood filling station. A simplifying assumption, consistent with other cost of hydrogen studies, is uniform daily demand for hydrogen throughout the 20-year project life. This biases *LCOH* downwards as in a real-world scenario, as it is more likely that demand will take a few years to ramp-up to the maximum (a ramp-up scenario is considered in §9.6). Figure 3-6 and Table 3-9 depict the DTE-C Model run results.



Source: Model calculations.

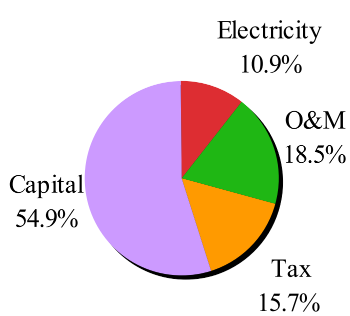
Figure 3-6: Levelized Cost of Hydrogen, Current (DTE-C)

Table 3-9: Levelized Cost of Hydrogen, Current (DTE-C)

D_{Daily}	Capital	Electricity	O&M	Tax	*LCOH*	*LCOH* Ex-Tax
100 kg	$11.70	$2.32	$3.95	$3.35	$21.32	$17.96
200	9.85	2.22	2.32	2.77	17.15	14.38
300	9.08	2.18	1.77	2.51	15.55	13.03
400	8.55	2.16	1.50	2.35	14.56	12.21
500	8.26	2.15	1.34	2.25	14.00	11.75
600	8.04	2.15	1.23	2.17	13.58	11.41
700	7.93	2.16	1.17	2.12	13.38	11.26
800	7.77	2.15	1.11	2.07	13.10	11.03
900	7.64	2.15	1.06	2.02	12.87	10.85
1,000	7.53	2.14	1.02	1.98	12.68	10.70
1,100	7.40	2.14	0.99	1.95	12.48	10.54
1,200	7.31	2.14	0.97	1.92	12.33	10.42

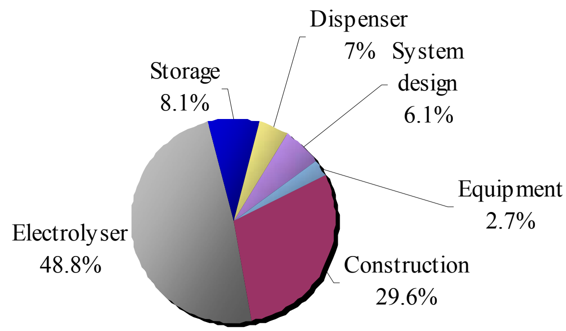
Source: Model calculations.

Figure 3-7 shows the Model's decomposition of *LCOH* for D_{Daily} = 100 kg H_2/day. Capital is the greatest component of cost of hydrogen, accounting for 55% of *LCOH*, followed by O&M at 19%. Figure 3-8 breaks the capital into its constituents, showing that electrolyser expense is the largest component at 49% of capital, followed by construction at 30%.



Source: Model calculations.

Figure 3-7: Cost of Hydrogen Breakdown, Current (DTE-C)



Source: Model calculations.

Figure 3-8: Initial Capital Investment, Current (DTE-C)

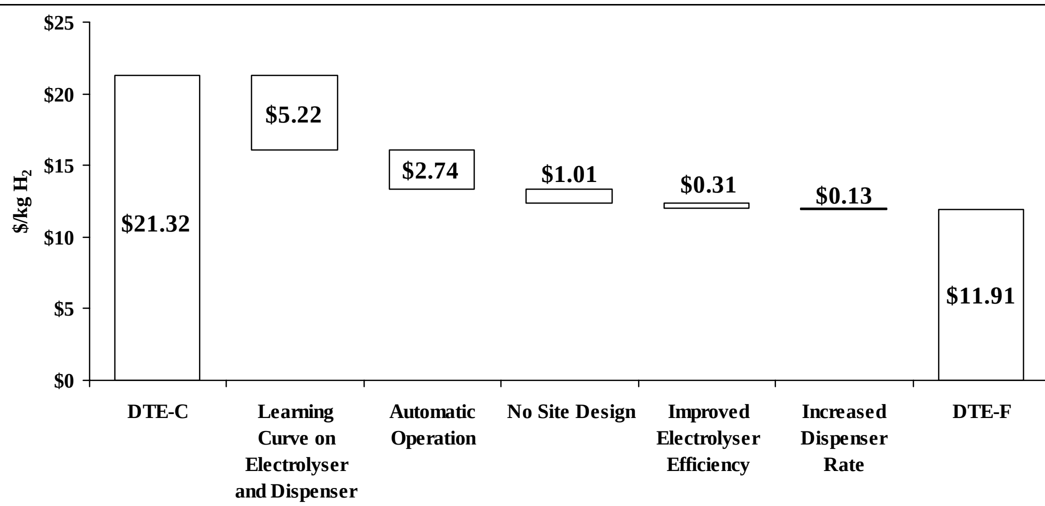
3.5.2 Estimated Future Costs (DTE-F)

The Model also projected the DTE-F "future" costs of hydrogen. The future is not a set of expectations for a pre-determined future date, but a hypothetical case where certain improvements and cost reductions have occurred. The differences between the current DTE-C to future DTE-F assumptions are:

- Application of the learning curve effect to the electrolyser, with *PR* = 0.90 (every doubling of cumulative output reduces unit costs by 10%) and cumulative production of 4,000 units (see §3.4.1 for details). This reduces the electrolyser cost from $225,000 per unit currently to $81,452 for each unit. This figure is further reduced by

applying the scaling factor with *ScalingFactor* = 90%, which is unchanged from the current scenarios. The final electrolyser cost used in this scenario is $68,812 for each unit (with 1.35 kg H_2/hr production capacity). Similarly, the dispenser's cost has been reduced at *PR* = 0.10, with no scaling;
- Completely automatic HTP operation, reducing O&M costs from $114,000 per year to $14,000 per year;
- Reducing balance of plant costs by eliminating system design costs;
- Improving the electrolyser efficiency from 47.2% (including compression) to an estimated future efficiency of 59.6%, a 26% improvement. This proportionally reduces electricity consumption per kg of hydrogen produced;
- Increased the dispenser rate from 0.39 kg H_2/min to 2.00 kg H_2/min. This is a result of technological improvements and will come about when hydrogen vehicles and dispensers' fueling protocols are well synchronized.

For a 100 kg H_2/day facility, the calculated DTE-F *LCOH* is $11.91/kg H_2. The breakdown of the cost savings from DTE-C to DTE-F is as follows:



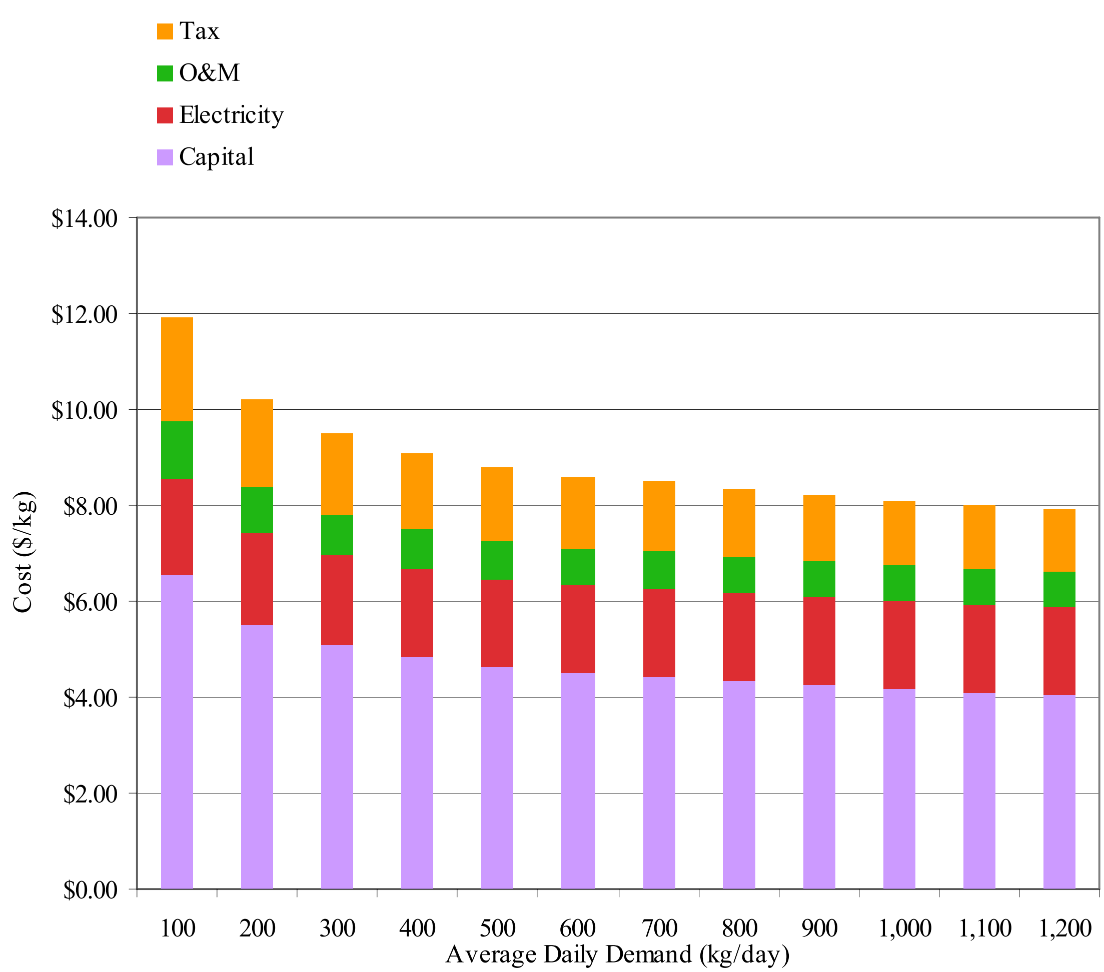
Source: Model calculations.

Figure 3-9: Cost Savings from DTE-C to DTE-F Hydrogen Scenarios

Reduction in capital costs due to the learning curve was the greatest contributor to reduced *LCOH* from DTE-C to DTE-F. Any initial investment savings will have a much greater effect on reducing LCOH than those realized over the course of 20 years. The next largest savings is automatic operation, in which no staffing costs are needed in O&M. This can happen only if equipment reliability rises to the point where only remote management and monitoring are needed.

Next, by re-using a library of site designs, initial costs can be lowered, improving *LCOH* by $1.01. Improved efficiency reduces electricity costs. Because capital costs greatly exceed electricity costs (see Figure 3-7), this result is expected. In other studies, electricity costs are greater than capital costs. In those studies, improving efficiency has greater effects on reducing the cost of hydrogen than in the Model. Finally, increased dispenser rates decrease costs slightly as only one dispenser needs to be installed in DTE-F, as opposed to two dispensers in DTE-C, to satisfy the same hydrogen demand.

The complete results for the DTE-F scenarios are presented in Figure 3-10 and Table 3-10.



Source: Model calculations.

Figure 3-10: Levelized Cost of Hydrogen, Future (DTE-F)

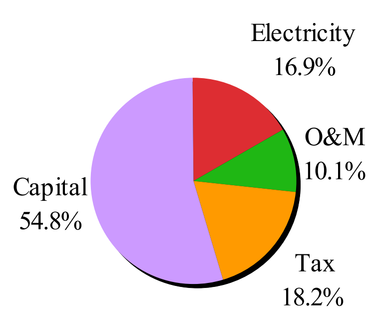
Table 3-10: Levelized Cost of Hydrogen, Future Values (DTE-F)

D_{Daily}	Capital	Electricity	O&M	Tax	*LCOH*	*LCOH* Ex-Tax
100 kg	$6.52	$2.01	$1.21	$2.17	$11.91	$9.74
200	5.51	1.90	0.95	1.85	10.21	8.36
300	5.07	1.87	0.86	1.69	9.49	7.80
400	4.82	1.85	0.82	1.60	9.08	7.48
500	4.63	1.84	0.79	1.53	8.79	7.26
600	4.49	1.83	0.77	1.47	8.57	7.09
700	4.42	1.85	0.78	1.44	8.48	7.05
800	4.32	1.84	0.77	1.40	8.33	6.93
900	4.23	1.84	0.76	1.37	8.19	6.83
1,000	4.17	1.83	0.75	1.34	8.10	6.76
1,100	4.10	1.83	0.74	1.32	7.99	6.68
1,200	4.04	1.83	0.74	1.29	7.90	6.61

Source: Model calculations.

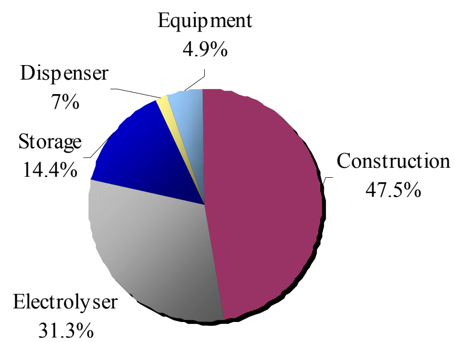
Figure 3-11 shows the Model's decomposition of *LCOH* for D_{Daily} = 100 kg H_2/day. As in DTE-C, capital is still the largest component of the cost of hydrogen, accounting for 55% of *LCOH*.

Figure 3-12 breaks the capital into its constituents. Unlike DTE-C, in which electrolyser costs were greatest, here construction costs are larger. In DTE-F, learning curve effects greatly reduced the cost of electrolysers and dispensers. In contrast, it was assumed that construction techniques, primarily civil works such as a gravel base, conduit, and piping, are unlikely to improve significantly over time. Therefore, no learning curve was applied to construction. Keeping this figure constant increased its proportion in total capital investment.



Source: Model calculations.

Figure 3-11: Cost of Hydrogen Breakdown, Future (DTE-F)



Source: Model calculations.

Figure 3-12: Initial Capital Investment, Future (DTE-F)

3.6 *Comparison with Electrolysis Cost Models*

3.6.1 Cost of Hydrogen Estimates

Cost estimates for electrolysis hydrogen have been made in a number of studies, including the National Academy of Engineering 2004 (the "NAE" model) and Weinert 2005 (the Hydrogen Station Cost Model, or "HSCM" model). For this study, the Project team compared the Model to NAE and HSCM because of the extensive documentation of these models' workings and assumptions. Table 3-11 provides an index to the models and their abbreviated names.

The NAE and HSCM used several different financial and operating assumptions from the DTE Energy default values. To control for these differences, two new scenarios DTE-SC and DTE-SF were created and run in the Model. These differences include:

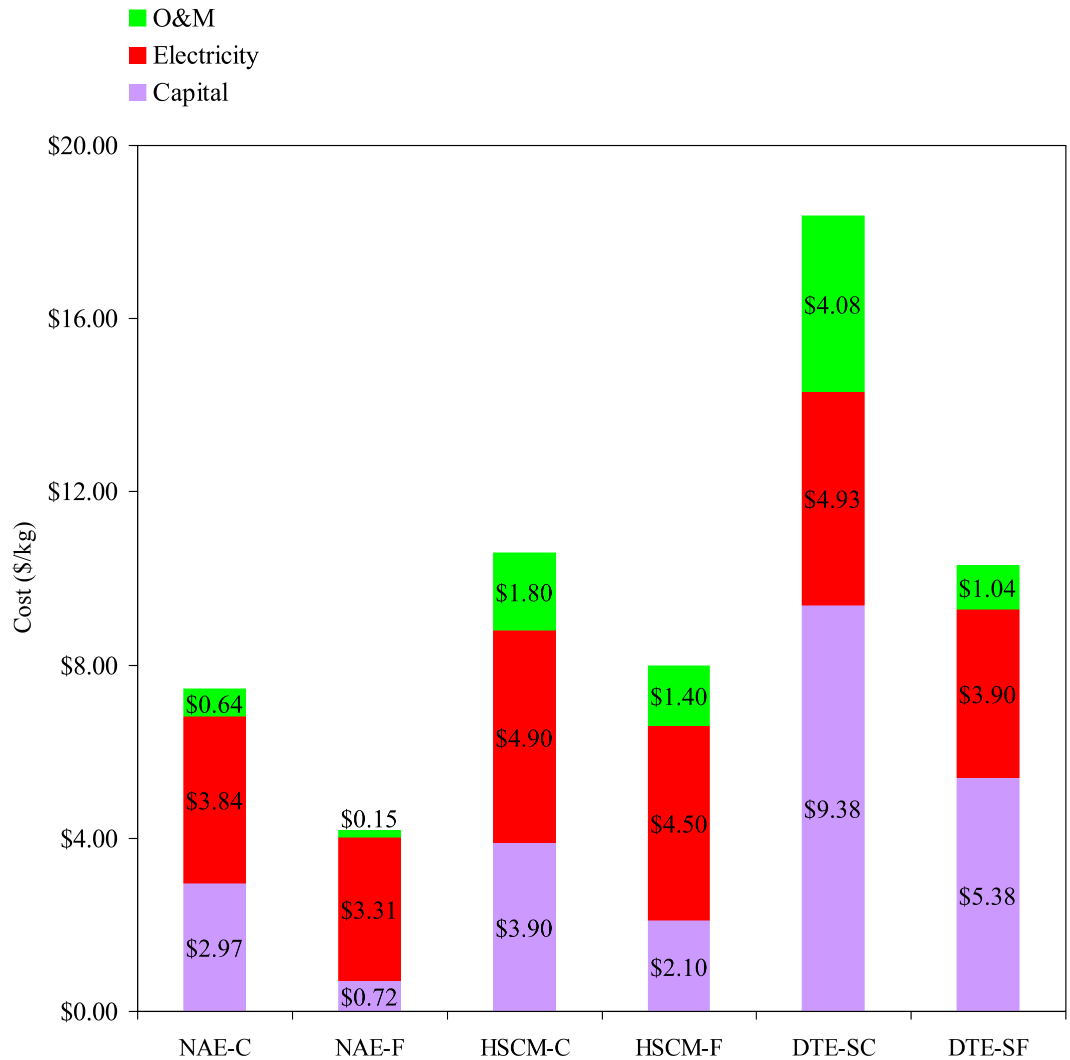
- System capacity of D_{Daily} = 100 kg H_2/day was used, and the hydrogen purchased by consumers is 90 kg H_2/day, resulting in an average load factor of 90%. Thus LF = 90% (versus DTE-C/DTE-F default of 100%). These were also standard inputs for HSCM. In NAE 2004, the NAE model is run on a system capacity of 480 kg H_2/day. To standardize the comparisons, we obtained the "Dist H2.xls" spreadsheet courtesy of NAE, and re-ran their Model with a system capacity of 100 kg H_2/day. NAE has not reviewed, and has not endorsed the use of their model with these inputs.
- Cost of capital was set to 14% (versus DTE default of 16%).
- The corporate tax rate was set to 0% (versus DTE default of 35%) as no separate corporate tax is included in the NAE and HSCM models.
- Electricity rates are at a flat $0.07/kWh, with no demand or fixed charges. This higher rate, and inspection of the NAE model, implies hydrogen production at all hours of the day. Thus, an HTP is also set to operate 24 hours/day (versus DTE Energy's D6 off-peak of 16 hours/day).

A full listing of changes in Model parameters is in Appendix §13.3.1. Results of the comparisons are provided in Figure 3-13 and Table 3-12. For additional comparison, the two original DTE scenarios presented earlier, DTE-C and DTE-F, are included in Table 3-12. These use the assumptions noted in §3.3, such as the 100% load factor, 16% IRR hurdle, 35% tax rate, and D6 electricity costs.

Table 3-11: Index to Hydrogen Cost Comparisons

Scenario Name	Description
Comparison Scenarios	
NAE–C	NAE forecast with current technology.
NAE–F	NAE forecast with future optimism
HSCM–C	HSCM model with current costs
HSCM–F	HSCM future model. Assumes 4,000 cumulative units produced.
DTE–SC	Model with current costs and performance specs, standardized assumptions
DTE–SF	Model with future costs and performance estimates, standardized assumptions. Assumes 4,000 cumulative units produced.
DTE Energy Scenarios	
DTE–C	Model with current costs and performance specs, and DTE Energy-specific capital, tax, and electric costs
DTE–F	Model with future costs and performance estimates, and DTE Energy-specific capital, tax, and electric costs

Source: Weinert 2005, NAE 2004, Project team.



Note: All studies assume a 100 kg H_2/day facility.
Source: Weinert 2005, Project team runs on NAE model and Model calculations.

Figure 3-13: Comparison of Hydrogen Costs

Table 3-12: Comparison of Hydrogen Costs

	NAE–C	NAE–F	HSCM–C	HSCM–F	DTE–SC	DTE–SF	DTE – C	DTE – F
Electrolyser capacity (kg/day)	100	100	100	100	100	100	100	100
Load factor	90%	90%	90%	90%	90%	90%	100%	100%
Annual capital recovery factor	14%	14%	14%	14%	14%	14%	16%	16%
Electricity marginal cost ($/kWh)	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.02	$0.02
Initial number of electrolysers needed	N/A	N/A	N/A	N/A	4	4	6	6
Electrolyser scaling factor	85%	85%	46%	46%	90%	90%	90%	90%
Storage capacity (kg)	53	53	149	149	91	91	192	192
H_2 Production (hr/day)	24	24	24	24	24	24	16	16
Capital Costs								
Electrolyser	$308,953	$34,076	$256,448	$94,253	$791,794	$286,638	$1,140,498	$412,872
Compressor	41,310	8,592	44,799	23,290	^	^	^	^
Storage	70,934	53,200	176,768	128,283	90,000	90,000	190,000	190,000
Dispenser	15,000	10,000	43,635	22,684	110,000	24,581	110,000	24,581
Balance of Plant*	259,537	62,992	340,059	155,932	832,742	690,742	832,742	690,742
Total Capital†	$695,734	$168,860	$861,709	$424,442	$1,824,536	$1,091,961	$2,273,240	$1,318,195
Cost of Hydrogen								
Electricity	$3.84	$3.31	$4.9	$4.5	$4.93	$3.90	$2.32	$2.01
O&M	0.64	0.15	1.8	1.4	4.08	1.04	3.95	1.21
Tax	-	-	-	-	-	-	3.35	2.17
Capital†	2.97	0.72	3.9	2.1	9.38	5.38	11.70	6.52
LCOH ($/kg H_2)	$7.44	$4.18	$10.7	$8.0	$18.39	$10.31	$21.32	$11.91

Note: All studies assume a 100 kg H_2/day facility. Numbers may not sum up due to rounding. N/A = Not available. HSCM total capital calculated, as figures do not add to "Capital Cost" in report. HSCM per kilogram figures reported to two significant digits. ^DTE scenarios include compressor cost in electrolyser cost. *NAE figures include their "Site Specific Factor". †HSCM figures include delivery and installation charge.
Source: Weinert 2005, Project team runs on NAE model and Model calculations.

3.6.2 Analysis of Differences

Electrolyser

The HTP's electrolyser costs are much higher than the other studies. First, HSCM and NAE utilize more optimistic and/or more recent electrolyser cost estimates. The DTE Energy electrolyser is based on the actual Park's electrolyser cost, which was purchased through a competitive bidding process in 2004. Secondly, HSCM uses a more optimistic scaling factor of 46% than the 90% value used by the Model. Thirdly, NAE (and possibly HSCM) estimates electrolyser costs by multiplying a per unit capacity cost by the design capacity. The NAE model prices electrolysers in \$/kW; its model estimates a 100 kg H_2/day facility will require 219kW. Thus:

NAE Electrolyser cost = \$1,413 / kW × 219 kW = \$308,953

It may not be possible to purchase electrolysers to meet the design target so exactly. As described in §3.3.2, the Model adds electrolysers in increments of 1.35 kg H_2/hr. In the comparison scenarios DTE-SC and DTE-SF, the Model determines a minimum of four electrolysers are required to meet demand. If operated at full capacity, the four electrolysers could actually produce 117 kg H_2/day, well over the 100 kg H_2/day capacity required in the comparison. Thus, DTE-SC and DTE-SF have much more capacity than NAE-C, NAE-F, HSCM-C, and HSCM-F.

Finally, in the "Capital" row of Table 3-12, the DTE Energy scenarios include the significant costs of purchasing replacement electrolysers in ten years. It appears the other models assume that the original electrolysers can last for 20 years.

Dispenser and Balance of Plant

Both NAE and HSCM have lower estimates for dispenser and balance of plant than the Model. NAE's cost for dispenser is \$15,000/unit, whereas DTE Energy believes it can purchase one for approximately \$55,000. It is not possible to pinpoint differences in balance of plant between the models, though it should noted that the DTE-SC and DTE-C scenarios include a significant cost for site and system design, a reality of implementing any hydrogen facility in the current time period.

Electricity

The source of divergence in electricity costs is due to varying estimates of electrolyser efficiency, as presented in Table 3-13. The NAE and HSCM models were based on an average of manufacturers' performance claims, while the Model uses the efficiency level observed at the Park. The models' estimates for future electrolyser performance are comparable.

Table 3-13: Comparison of Electrolyser Efficiency Assumptions

Model	Electricity Consumption with Compression (kWh/kg H_2)
NAE	54.83
HSCM	54.8
DTE-SC, DTE-C	70.4
DTE-SF, DTE-F	55.7

Note: Significant digits presented as originally reported.
Source: Weinert 2005, NAE 2004, Model calculations.

Operations and Maintenance
The NAE's O&M is calculated as 3% of total capital costs. HSCM's costs are higher than NAE because it includes insurance, real estate, property tax, and labor costs. The HTP estimated costs are the highest. While the DTE Energy scenarios do not include insurance, real estate, or property tax, they do include warranty expenses, which are $5,000/yr/electrolyser and a $100,000/yr cost for staffing (in the DTE-SC and DTE-C cases).

3.7 Emissions Estimates

In addition to the economic cost of hydrogen, the Model estimates environmental costs, defined in terms of emissions attributable to an HTP's power consumption. Based on the electrolyser's measured efficiency η_E of 47.2%, 70.4 kWh of electricity is needed to produce each kg of hydrogen:

$$70.4 \text{ kWh/kg } H_2 = 119.6 \text{ MJ/kg } H_2 \text{ (LHV)} \div 3.6 \text{ MJ/kWh} \div \eta_E$$

Based on the current levels of efficiency (DTE-C) and the emissions intensity of DTE Energy's power generation mix (Table 3-6), an HTP's emission factors are presented in Table 3-14.

Table 3-14: Emissions Intensity of HTP Hydrogen Production

	Intensity (kg/kg H_2)		Intensity (kg/million BTU)	
Emission	Current	2012	Current	2012
CO_2	55.1	54.2	485.8	478.1
NO_X	0.086	0.049	0.761	0.428
SO_2	0.281	0.210	2.480	1.851
Particulate matter	0.004	0.003	0.035	0.026

Source: Model calculations.

If electrolysis is adopted on a large scale, and the electricity utilized by electrolysis is supplied by fossil fuel-fired power plants, hydrogen production could result in substantial greenhouse gas emissions. Adding power generation capacity from renewable sources to satisfy electricity demand growth can help reduce the emissions intensity of HTP activities.

Hydrogen produced through an HTP is much more carbon intensive than directly burning fossil fuels, whose emissions intensities are listed in Table 3-15. This is partly due to the energy intensive nature of electrolysis, and partly due to the high percentage of coal in DTE Energy's generation mix.

Table 3-15: Emissions Intensity of Selected Fossil Fuels

Fuel	CO_2 Intensity (kg/million BTU)
Motor gasoline	71.0
Liquified petroleum gases	63.1
Jet fuel	70.9
Propane	63.1
Methane (natural gas)	52.3

Source: EIA 2006a.

The hydrogen will most likely be consumed in a fuel cell vehicle. As described in §9.2.3, fuel cell vehicles may have higher efficiency than internal combustion engines using fossil fuels. Assuming there is a 2.5x efficiency improvement, the adjusted emission intensities (obtained by dividing actual emission intensity by 2.5) are presented in Table 3-16.

Table 3-16: Adjusted Emissions Intensity of HTP Hydrogen Production

	Adjusted Hydrogen Intensity (kg/million BTU)		Multiple of Motor Gasoline Intensity	
Emission	Current	2012	Current	2012
CO_2	194.3	191.2	2.7x	2.7x

Source: Model calculations.

The adjusted emissions analysis assumes that the efficiency advantage of fuel cell vehicles over internal combustion engines stays constant between now and 2012. Historically, it has been observed that internal combustion engines have been able to make enormous strides in improving efficiency and reducing emissions as needed to meet the requirements of the market or regulatory authorities (Romm 2004).

3.8 Sensitivity Analysis

To assess the relative importance of the various inputs, a number of sensitivity analyses were carried out. In each case, a key DTE-C inputs were varied and *LCOH* compared to the base case 100 kg H_2/day *LCOH* of $21.32/kg.

3.8.1 Major input variables

A number of key DTE-C technical, cost, and demand inputs were varied by ±10% with results presented in Table 3-17.

Table 3-17: Cost of Hydrogen Sensitivity to Major Inputs

Assumption	-10% from default		+10% from default	
Cost Sensitivities				
Electrolyser cost	$(0.77)	-3.6%	+$0.76	+3.6%
Construction cost	(0.45)	-2.1%	+0.45	+2.1%
O&M cost	(0.39)	-1.9%	+0.39	+1.9%
Off-peak electricity marginal cost	(0.15)	-0.7%	+0.15	+0.7%
Cylinder cost	(0.10)	-0.5%	+0.10	+0.5%
Dispenser cost	(0.06)	-0.3%	+0.06	+0.3%
Technical Sensitivities				
Availability	+0.08	+0.4%	(1.48)	-6.9%
Electrolyser production rate	No change	No change	(1.42)	-6.6%
Electrolyser efficiency	+0.17	+0.8%	(0.14)	-0.6%
Demand Sensitivities				
Load factor	+0.53	+2.5%	N/A	N/A
Daily demand	+0.13	+0.6%	(1.35)	-6.3%

Note: All sensitivities compared to base case DTE-C cost of $21.32/kg H_2. N/A = Not applicable.
Source: Model calculations.

Cost-wise, reducing costs of the two largest capital investment components, the electrolyser and construction, have large effects on reducing *LCOH*. Technical improvements and learning effects over time will be needed to drive electrolyser costs down. For construction, improved architectures and designs will be needed. The Park was a "first of a kind" system and it is almost certain that systems optimization will be able to produce new designs that will decrease construction costs. Finally, O&M costs are very important. High O&M costs are the result of the need to assign staff to an HTP. If higher reliability and automated operation can reduce staffing, significant savings can be realized.

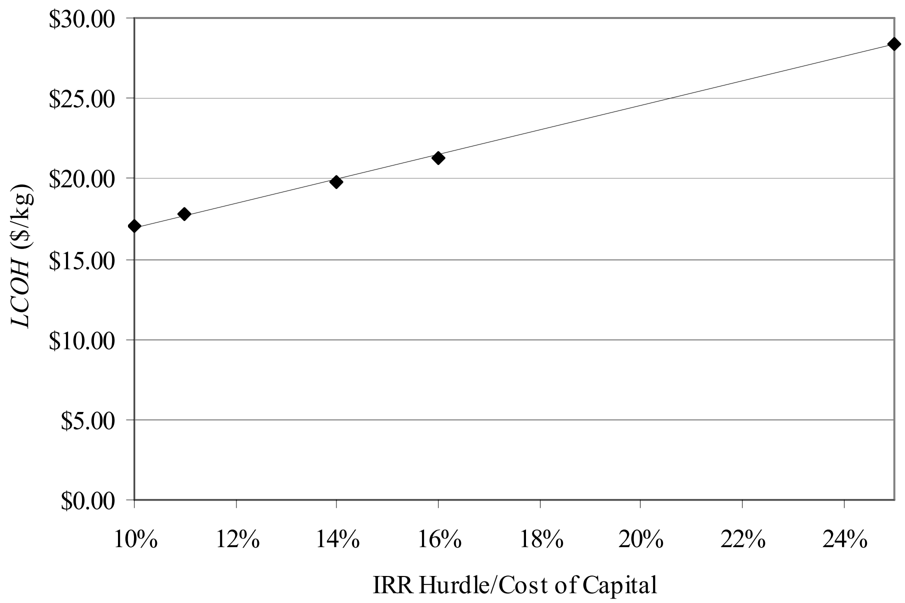
Technically, increasing the availability of the electrolysers has the greatest effect, though in this sensitivity case, increasing availability by 10% would result in a 99% availability, which may not be likely for some time. A more feasible goal may be increasing production rates. Given the equipment requirements of a 100 kg H_2/day HTP, a 10% increase in the production rate, from 1.35 kg H_2/hr to 1.49 kg H_2/hr, would mean that only five electrolysers would have to be purchased to meet demand, instead of six, resulting in substantial savings.

Demand-wise, increasing demand can reduce *LCOH*, by increasing the capacity utilization of an HTP. At the 100 kg H_2/day level, a demand increase of 10% would not require incremental investments in equipment.

3.8.2 Cost of Capital

The IRR hurdle, or the cost of capital, is one of the most important determinants of *LCOH*. Selecting the "right" cost of capital is an art and a science, and considerable debate surrounds the appropriate IRR for hydrogen projects. As described in §3.3.8, the DOE's H2A standard uses a relatively low 10% cost of capital, arguing such a rate would be appropriate in the long-term future, when hydrogen has become integrated into the national infrastructure. DTE Energy internally uses three costs of capital, depending on the riskiness of the project – 11% for "lower risk" projects, such as those with a contracted off-taker, 16% for "mid-tier risk", and 21% for "higher risk".

LCOH for varying levels of IRRs are plotted in Figure 3-14. The points on the figure correspond to five IRR levels found in hydrogen studies: the 10% H2A base case, 11% DTE Low Risk, 14% NAE, 16% DTE Energy standard, and 25% H2A high case. A linear trend line has been added to the figure.



Source: Model calculations.

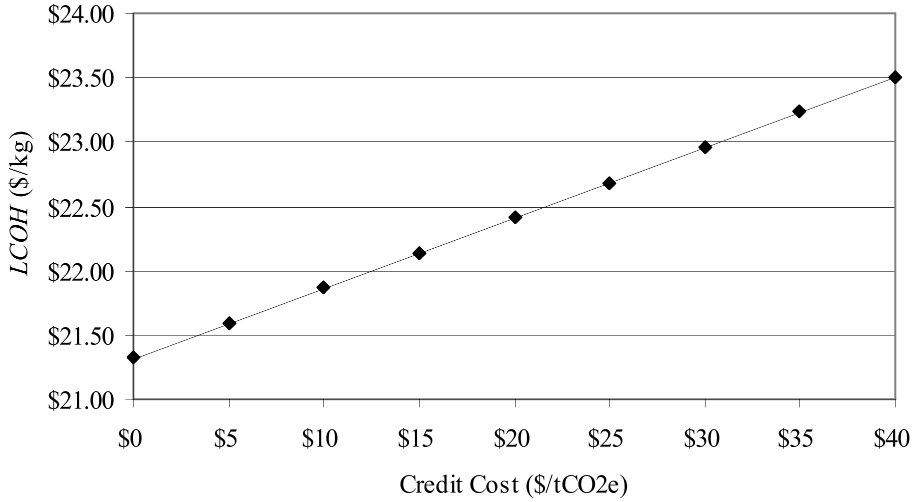
Figure 3-14: Cost of Hydrogen Sensitivity to Cost of Capital

Model calculations indicate a one percentage point decrease in IRR from 16% to 15% (equivalent to a 6.25% change) results in an *LCOH* decrease of $0.74 or -3.5%.

3.8.3 Carbon Credit Purchases

As discussed in §3.3.11, one way an HTP could offset its greenhouse gas impact on the environment is by purchasing carbon emission reduction credits. Based on the carbon emissions intensity calculated in §3.7, an HTP would need to purchase approximately 0.055 tonne CO_2 equivalent of credits for each kilogram of hydrogen produced. Over the last two years, the cost of credits have varied between €10 and €30 (Figure 3-2), or approximately $12.11 and $36.33, respectively.

Figure 3-15 plots *LCOH* as a function of carbon credit costs. Each $5 increase in the cost of credits increases *LCOH* by $0.27.



Source: Model calculations.

Figure 3-15: Cost of Hydrogen Sensitivity to Carbon Credit Costs

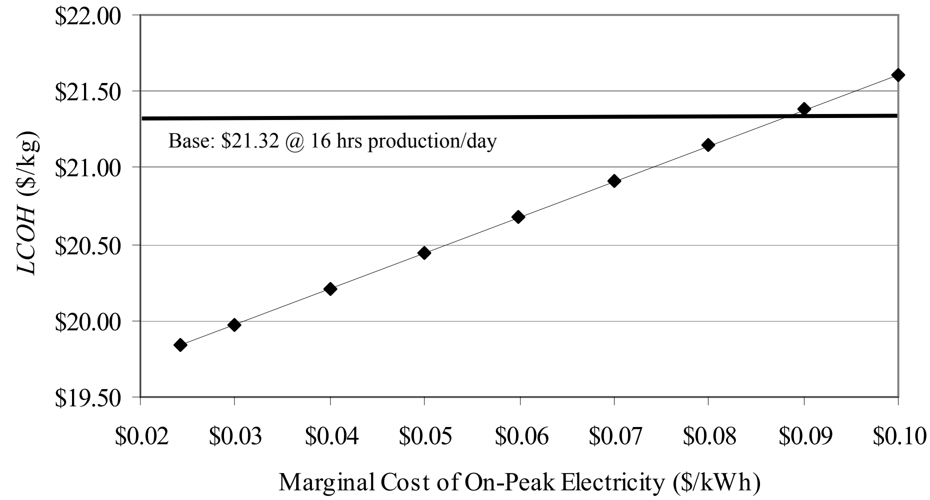
3.8.4 24 Hour Hydrogen Production

While DTE Energy's plans are to schedule hydrogen production during the 16 off-peak electricity hours, Model analysis indicates that it may more economical design an HTP to operate 24 hours a day, including on-peak hours. This conclusion holds even after including a higher on-peak demand charge.

There is a substantial gain to be made trading off capital versus electricity costs at the currently high DTE-C capital investment costs. Under the base case of a 100 kg H_2/day facility, it is necessary to purchase six electrolysers, each running 16 hours/day. If operations were extended to 24 hours/day, only four electrolysers would be required to produce the same amount of hydrogen. Instead of 19 cylinders of storage, a 24 hour HTP would need only 9 cylinders, since there would no longer be an eight hour gap during the day when no production occurs. The initial investment savings would total $448,704.

On the other hand, electricity costs would rise because an HTP would now have to pay both the higher marginal cost of on-peak electricity and the "maximum demand" and "on-peak billing demand" charges in the D6 rate schedule (please refer to the "Electricity" worksheet in Appendix §13.1 for a full listing of the charges). The cost of electricity, averaged over all HTP hours of production, would rise from $0.033/kWh in the case of no on-peak production to $0.0569/kWh with on-peak production.

Even with higher average electricity costs, the trade-off is in favor of 24 hour production. Figure 3-16 plots the costs of producing hydrogen 24 hours a day, varying the marginal cost of on-peak electricity.



Source: Model calculations.

Figure 3-16: Cost of Hydrogen with 24 Hour/day Production

If an HTP is configured to produce 24 hours a day at the current D6 on-peak marginal cost of $0.02431/kWh, *LCOH* would be $19.84. This is the point in the lower left hand corner of Figure 3-16. Even if the marginal cost of on-peak electricity were to rise, it would still be cost effective to operate the electrolysers 24 hours a day. The breakeven level is around $0.08/kWh; if the on-peak rate is at or less than this level then it is economical to run during on-peak hours, if the on-peak rate is higher then it is more economical to run only during off-peak hours.

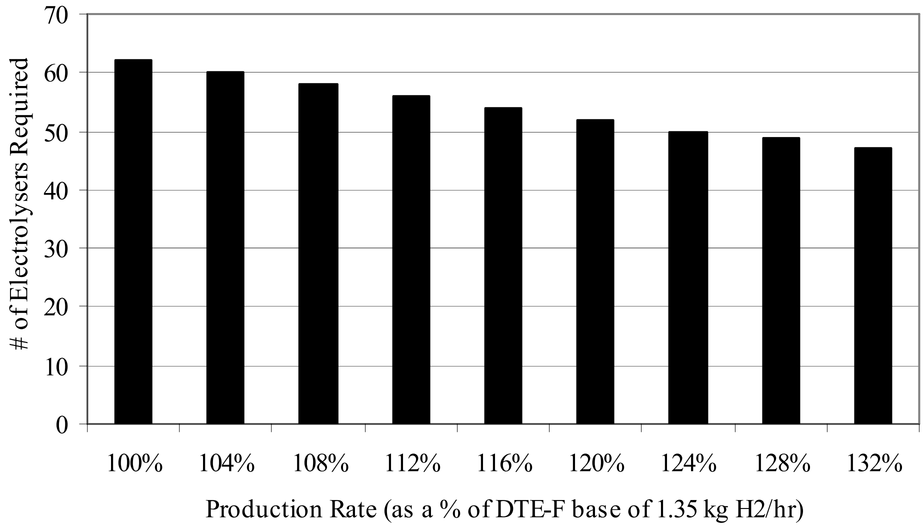
While 24 hour/day production may be advisable now, the recommendation does not hold in the DTE-F scenario. Producing only at off-peak hours, the DTE-F base *LCOH* is $11.91/kg H_2. If production were to be spread across 24 hour/day, *LCOH* would rise to $11.94/kg H_2. In the future, the cost of capital has fallen relative to the cost of electricity, and thus *LCOH* becomes more sensitive to electricity costs.

3.8.5 Increased Electrolyser Production Rate

This study assumed that electrolyser efficiency increased from 47.2% in DTE-C to 59.6% in DTE-F. The 26% efficiency improvement reduced electricity consumption per kg of H_2 produced. The hydrogen production rate λ_E was held constant at 1.35 kg H_2/hr/electrolyser (see §3.3.2). As production rates are a primary determinant of the number of electrolysers required, the total number of electrolysers required is the same in both DTE-C and DTE-F scenarios. Thus, efficiency improvements were used exclusively to reduce energy costs but not capital costs, which the Project team understands is a common assumption within the electric power industry.

It is possible that electrolyser manufacturers will also make technical improvements that increase production rates. If this occurs, an HTP could purchase fewer electrolysers to meet the same level of demand. In the DTE-F scenario, a future HTP with output of 1,200 kg

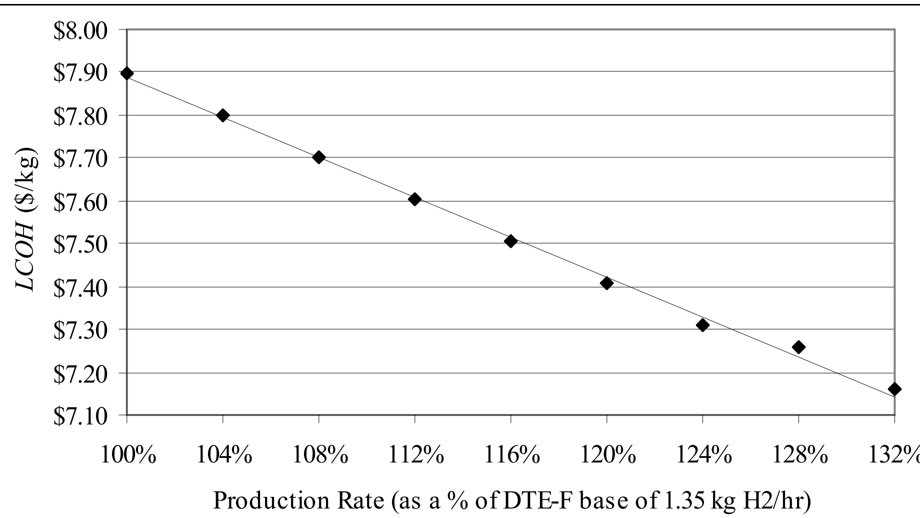
H_2/day will require 62 electrolysers. Figure 3-17 shows how the number of electrolysers decreases as production rates rise over the DTE-F default production rate of 1.35 kg H_2/hr.



Note: Assumes 1,200 kg H_2/day demand and DTE-F scenario.
Source: Model calculations.

Figure 3-17: Electrolyser Requirements Sensitivity to Electrolyser Production Rate

If it is assumed that electrolyser costs do not rise (that is, the DTE-F electrolyser cost of \$81,452 is held constant, as calculated in §3.4.1), the cost of hydrogen can decrease as lower capital investment is needed. Figure 3-18 shows the relationship between *LCOH* and increased production rates.



Note: Assumes 1,200 kg H_2/day demand and DTE-F scenario.
Source: Model calculations.

Figure 3-18: Cost of Hydrogen with Increased Production Rate

3.9 Model Limitations

As noted throughout this chapter, the Model contains a number of simplifying assumptions and omissions. In addition to those noted earlier, there are at least four other limitations with the Model that the reader should be aware of.

Hydrogen Industry Progress Since 2004

The Park's electrolyser and fuel cell technology were considered state-of-the-art when they were installed in 2004. This study utilizes only performance and cost data from the Park, so the cost of hydrogen and fuel cell electricity estimates should be interpreted as being representative of a demonstration system from that year. Hydrogen industry progress in electrolyser technology and costs since 2004 may change the economics for a new HTP.

System Physical Size

The vast physical space requirements of large HTP installations limit the extrapolation of current Park architecture and technology to meet the needs of a neighborhood filling station. For example, an HTP with a daily demand of 1,200 kg H_2 would require 62 electrolysers and 215 storage cylinders. If placed together, the cluster of cylinders alone would occupy approximately 691 m^3, a volume comparable to that of 20 standard 20-foot long shipping containers. These space requirements, along with associated costs like maintenance, security, and certification, may not be compatible with the requirements of areas zoned for residential or commercial use.

If the hydrogen economy is to develop using distributed hydrogen production via electrolysis, electrolysers with significantly greater scalability and production rates are needed. Alternative storage technologies are also needed. Instead of an inventory of "fixed" hydrogen whose purpose is to maintain high pressures, a system with piston or bladders to mechanically maintain pressure should be considered.

Electricity Prices and Infrastructure

The standard D6 schedule may be a less accurate predictor of electricity prices as the HTP system size scales up. At high levels of hydrogen production, an HTP's load on the DTE Energy electric grid becomes very substantial and may require additional investment in grid interconnection equipment that is not included in the Model. For example, using today's technology, an HTP producing 1,200 kg H_2/day would require 62 electrolysers. If operated concurrently at maximum production rates, the total peak power requirement could exceed 6 MW, potentially requiring special power lines and power electronics equipment to handle the high voltage and current. This may also require additional investments in property, operations and maintenance, safety procedures, permitting, and management of community concerns about high voltage transmission lines.

Park Reliability

One key issue affecting an HTP's costs is system reliability. This is represented in the Model by the availability variable which estimates the percentage of time the system will perform as specified when requested. It is assumed that scheduled maintenance occurs outside of these times, so maintenance does not affect availability. The reliability costs are also reflected in the need to maintain staffing for on-site maintenance. While these simple metrics help incorporate the concept of reliability into the cost of hydrogen, they may not fully convey the extent to which this area needs improvement.

Commissioning is a major milestone to be attained when validation and verification tests have confirmed that the Park's equipment is operating according to operational requirements. The Park, which opened in October 2004, has not reached commissioning as of writing (April 2006). According to DTE Energy's report in the *Hydrogen Program 2005 Annual Progress Report* (DOE 2005b):

> *During initial and follow-on system testing, several problems with vendor-supplied equipment were identified that required correction before system commissioning could be accomplished. These included: 1) hardwired safety system (HWSS) not supplied as control reliable; 2) diaphragm compressor mounting unsound; 3) electrolyzer control system code not reliable; and 4) electrolyzer heat management systems not properly engineered.*

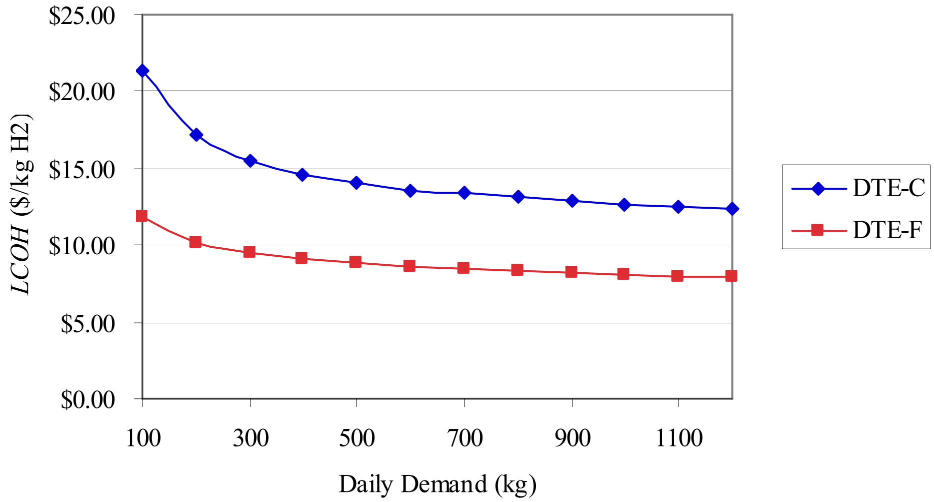
Furthermore:

> *To the extent possible, representative commercial units have been employed. However, the components, and system as a whole, should be considered prototypical vs. commercial, as indicated by the need for significant modifications/re-engineering once on-site to support the intended use.*

In the three month period from 1 July 2005 to 30 September 2005, the Park had 51 "unscheduled" issues, according to maintenance records disclosed to the DOE. These included issues with all of the Park's major subsystems, including such items as sudden system stops, overheated components, a door blown off in high winds, security camera problems, and computer lockups. While the Project team did not have access to more extensive reliability data and thus did not study this area in depth, our belief is that significant improvements in component and system availability must occur in order for an HTP to serve as a commercially viable system.

3.10 Conclusions

The Project team developed an engineering-economic model of an HTP based on pricing and performance data gathered over two years from the Park, a "first of a kind" demonstration facility in Southfield, Michigan. We estimate the current (DTE-C) levelized cost of hydrogen ranging from \$12.33/kg H_2 for a 1,200 kg H_2/day facility capable of serving as a neighborhood filling station (in 2005 dollars) and \$21.32/kg H_2 for an HTP facility producing and selling 100 kg H_2/day (approximately twice the capacity of the current Park). The Model's estimated costs of hydrogen as a function of facility size are plotted in Figure 3-19.



Source: Model calculations.

Figure 3-19: HTP Cost of Hydrogen Summary

Capital costs represent approximately 55% of the total cost, followed by operations and maintenance (primarily staffing), taxes, and electricity. The single largest cost driver is the electrolyser unit. In the future (DTE-F), with performance and cost improvements, the cost of hydrogen may range from \$7.90/kg H_2 for a 1,200 kg H_2/day HTP and \$11.91/kg H_2 for a 100 kg H_2/day HTP. Capital costs are still the largest component of the cost of hydrogen, but corporate taxes are now the second largest cost driver. Within the capital budget, construction costs now exceed electrolyser costs.

Even with adjustments to control for cost of capital, electricity rates, operating hours, and load factor, these results are much higher than estimates made in similar studies by the NAE (NAE-C, NAE-F) and Weinert (HSCM-C, HSCM-F), as shown in Figure 3-13. Generally, the other studies use more optimistic estimates and assumptions for electrolyser costs, scaling factors, learning curves, and O&M costs than data collected from the Park.

Reducing electrolyser cost and staffing costs (which is in turn a function of equipment and system availability) are likely to have the greatest effect on lowering the cost of hydrogen. With the Park's technology and costs, there is a gain trading off operating and capital costs, and in planning an HTP one should consider a 24 hour/day production schedule to minimize upfront capital investment.

Finally, the analysis suggests that the HTP concept and its demonstration-stage technologies may not be ready to serve a model for neighborhood hydrogen filling stations. The sheer physical size, enormous power consumption, reliability concerns, and comparatively high costs of hydrogen indicate significant technological and cost improvements will be required to make an HTP a feature of the American landscape.

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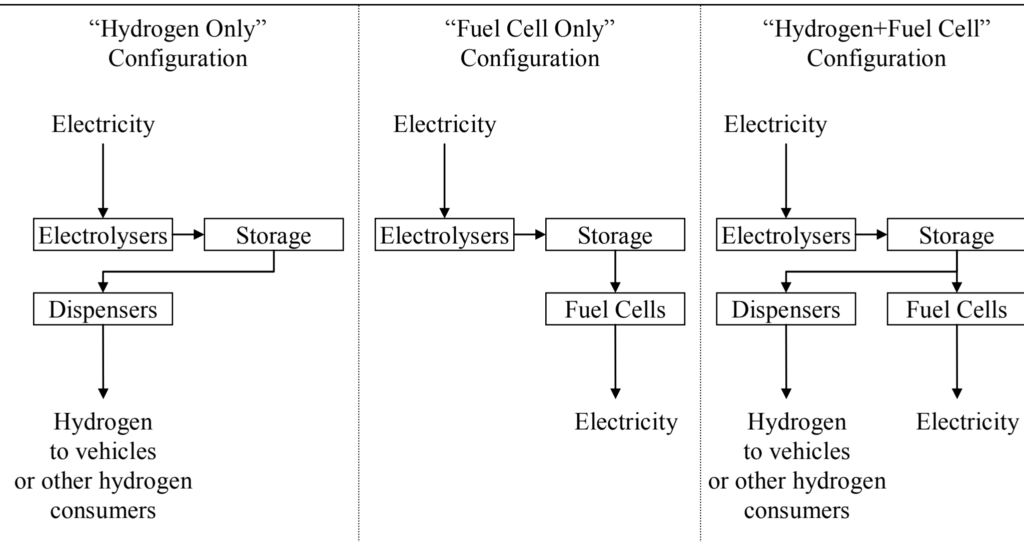
4 Cost of Fuel Cell Electricity Estimates

4.1 Introduction

As a multi-use demonstration system, the Park can produce hydrogen both for dispensing (for hydrogen vehicles, distributed generation, and other uses of hydrogen) and electricity through a fuel cell subsystem whose only capital equipment is an array of fuel cells. In the future, an HTP can be designed to incorporate some or all of the Park's subsystems. Figure 4-1 illustrates three possible ways of configuring an HTP.



Source: Project team.

Figure 4-1: HTP Configurations

The calculations in Chapter 3 provide the cost of hydrogen *LCOH* applicable for all three configurations. The "Hydrogen Only" configuration consists of all HTP equipment except for the fuel cell subsystem; only hydrogen production for dispensing to vehicles is possible in this configuration. In the "Fuel Cell Only" configuration, hydrogen is produced solely for consumption by the fuel cell array; only electricity is produced. The "Hydrogen+Fuel Cell" configuration most closely resembles the current Park, with both power generation and hydrogen output through dispensers. Both "Fuel Cell Only" and "Hydrogen+Fuel Cell" configurations include fuel cells and allow an HTP to be used for energy storage applications.

For the "Fuel Cell Only" configuration, the Model estimates the levelized cost of fuel cell electricity at $2.29/kWh for a "large" 625 kW installed capacity HTP facility producing hydrogen solely for energy storage applications, and $0.83/kWh with future cost and performance assumptions. For the "Hydrogen+Fuel Cell" configuration, the Model estimates the levelized cost of fuel cell electricity at $2.09/kWh with current assumptions, and $0.71/kWh with future assumptions.

Hydrogen costs represent approximately half of the cost of fuel cell electricity, followed by the expenses of replacing fuel cell stacks, a key consumable component. The results indicate that all combinations produce levelized costs of electricity well in excess of the $0.02431/kWh marginal cost of on-peak electricity on DTE Energy's D6 rate schedule.

4.2 HTP Fuel Cell Electricity Engineering-Economic Model Overview

The Model process for calculating the levelized cost of electricity *LCOE* is conceptually similar to that of hydrogen. The fuel cell subsystem is modeled as an incremental addition to the hydrogen subsystem described in Chapter 3. At a high level, the process to calculate *LCOE* is:

1. Exogenous fuel cell electricity demand requirements and fuel cell equipment specifications are provided as inputs into the Model. The engineering portions of the Model determine the daily hydrogen required by the fuel cells (which is incorporated into daily hydrogen demand D_{Daily} as described in §3.3.1), capital equipment requirements, such as number of fuel cells and the timing of replacement parts.
2. The Model estimates *LCOH* using the methodology described in Chapter 3.
3. Based on cost information provided by DTE Energy, the fuel cell capital investment is estimated. An initial *LCOE* is set by the spreadsheet and cash flows estimated.
4. The fuel cell subsystem's internal rate of return ("IRR") is calculated. If it does not meet IRR hurdle rate, the spreadsheet iteratively raises *LCOE* and calculates IRR until the hurdle is met.

The *LCOE* is the price at which the fuel cell subsystem's initial capital outlay is fully recovered through its cash flows, discounted at DTE Energy's IRR hurdle rate. In formulae, *LCOE* is the price at which following identity holds:

$I_{0\,FC} = PV(HTP\ Fuel\ Cell\ Electricity\ Cashflows)$

or

$$I_{0\,FC} = \sum_t \frac{(LCOE \times D_{FC}) - H - M_{FC} - T_{FC}}{(1+r)^t}$$

$I_{0\,FC}$	Initial investment in fuel cell capital
D_{FC}	Estimated annual demand for fuel cell electricity (kWh)
H	Hydrogen costs. It is assumed that all hydrogen is purchased from the hydrogen subsystem at a price of *LCOH* as determined through the process described in Chapter 3.
M_{FC}	Fuel cell operation and maintenance expenses
T_{FC}	Corporate taxes (assumed to be the same rate as that used in the cost of hydrogen analysis, as described in §3.3.8)
R	DTE hurdle IRR rate (assumed to be the same rate as that used in the cost of hydrogen analysis, as described in §3.3.8)

Costs such as balance of plant, staffing, and system design and construction are not directly used to calculate *LCOE*. They are included in *H*, which is a function of *LCOH*.

4.3 *Key Inputs*

The robustness of the Model's results derives from its extensive use of real-world performance and cost data gathered by DTE Energy from the Park over its one and half years of operation. Sections 4.3.1 through 4.3.6 detail the Model's key data inputs and formulae for the fuel cell subsystem.

Like the cost of hydrogen analysis in Chapter 3, two major sets of Model parameters have been created for the fuel cell subsystem, a "Current" set called DTE-C, based largely on historic HTP data, and a "Future" set DTE-F. The future is not a set of expectations for costs and performance on a pre-determined date or time period, but a hypothetical case where certain expected improvements and cost savings have been realized by an HTP and its suppliers. By incorporation, the DTE-C scenario includes all current DTE-C hydrogen-related parameters described in Chapter 3, and the DTE-F scenario includes both future hydrogen-related and fuel cell parameters. Table 4-1 highlights the differences between DTE-C and DTE-F for fuel cells. A complete listing of parameters for DTE-C and DTE-F can be found in Appendix 13.1.

Table 4-1: Differences Between DTE-C and DTE-F Scenarios – Fuel Cells

Parameter	DTE-C	DTE-F	Rationale for Difference
Fuel cost ($/unit)	$12,800	$6,000	Technological improvements
Fuel cell efficiency (%)	40%	50%	Technological improvements
Availability (%)	85%	95%	Reliability improvements
Useful life of proton exchange membrane stack (hr)	1,500 hr	6,000 hr	Technological improvements
Price of proton exchange membrane stack ($/unit)	$4,500	$2,000	Technological improvements

Source: DTE Energy.

4.3.1 Demand for fuel cell electricity

Demand in each year of the Model is expressed as the average daily energy demand $D_{Daily\ FC}$ (kWh/day). This simplification biases *LCOE* downwards because it assumes higher capacity utilization than what may occur in practice, as fuel cells may not be fully utilized on weekends and holidays. In addition to the energy demand, the Model requires the number of fuel cell operating hours per day H_{FC} and peak power output required of the fuel cell subsystem P_P, measured in kW. If not set by the user, by default, the Model assumes that power output is uniform during the hours that the fuel cells are operated:

$$P_P = D_{Daily\ FC} \div H_{FC}$$

In both DTE-C and DTE-F scenarios, it is assumed that H_{FC} = 8 hours. This means that the fuel cells produce electricity only during the eight on-peak hours according to DTE Energy's D6 rate schedule.

4.3.2 Fuel cells

The Model estimates the number of fuel cells required as a function of the maximum power demanded and availability:

$$\text{Number of fuel cells required} = \text{ROUNDUP}\left(\frac{P_P}{P_N \times A_{FC}}\right)$$

P_P	Peak power output required of the fuel cell subsystem.
P_N	Power output of fuel cell at normal operation. A fuel cell can be operated at varying levels of power output. However, sustained operation near the highest rated power output level may accelerate degradation of parts and require more frequent (and costly) replacement of consumables.
A_{FC}	Steady-state availability of fuel cell. This figure is an estimate of the percentage of the time the fuel cells operate according to specifications when requested, and is determined by the unit's mean time to failure and mean time to reliability. For example, a fuel cell is not expected to operate during scheduled maintenance hours - these are the off-line hours. In the remaining hours of the year, the on-line hours, the electrolyser is expected to perform when requested. A fuel cell with 85% availability (the DTE Energy estimate) should operate 85% of the on-line hours. An unscheduled repair is an example of an incident that would occur in the 15% unavailable time. An estimate of 85% availability is used for the DTE-C scenario in lieu of historic operating results. In practice, availability has varied considerably, which is to be expected for a "first of a kind" demonstration system. In the future DTE-F scenario, it is believed that fuel cell availability will increase to 95%.

The ROUNDUP function is used to ensure an integer result.

The current DTE-C price for the Plug Power Gen Core 5B fuel cell with maximum output of 4 kW is approximately \$12,800/unit, or \$3,200/kW[1]. Unlike the electrolyser analysis, the Project team did not use a learning curve to estimate the DTE-F future price of fuel cells. Instead, a DTE-F fuel cell cost of \$1,500/kW was estimated by DTE Energy based on discussions with Plug Power. No scaling factor has been applied to the fuel cell subsystem as it was believed that the costs of the fuel cells rose linearly with increases in power requirements.

The Model assumes there are two consumable inputs for the fuel cells: replacement proton exchange membrane ("PEM") cell stacks and batteries. Replacement cell stacks are purchased and expensed annually in proportion to the number of hours the fuel cells are operated each year:

[1] As of 1 April 2006, DTE Energy is a shareholder of Plug Power Inc. and a distributor of Plug Power products. An employee of Detroit Edison (a subsidiary of DTE Energy) is a member of the Board of Directors of Plug Power Inc.

Average number of stacks replaced = Hours of operation (hr/yr) ÷ PEM stack useful life (hr)

In DTE-C, the cost of the replacement stack is $4,500/unit and the stack's usable life is 1,500 hours, which is the duration currently warranted by the manufacturer, Plug Power Inc. This warranted life has been used in Model calculations instead of the actual stack life, which is confidential. In DTE-F, it is assumed that technological and reliability improvements have resulted in a less expensive stack of $2,000/unit lasting 6,000 hrs. In both scenarios, batteries used by the fuel cells are assumed to be replaced every three years.

4.3.3 Hydrogen

Hydrogen from an HTP is the only feedstock for the fuel cells. The amount of hydrogen consumed daily by the fuel cells $D_{FC,H}$ (kg) is calculated based on fuel cell efficiency.

$$D_{FC,H} = \left(\frac{D_{DailyFC}}{119.6\ MJ/kg \times \eta_{FC}} \right)$$

$D_{FC,H}$	Amount of hydrogen consumed daily by the fuel cell subsystem to meet electricity demand
η_{FC}	Efficiency of fuel cell

The current DTE-C fuel cell efficiency is 40%, a figure obtained in the September 2005 period measurement. For DTE-F, DTE Energy expected that improvements in fuel cell electricity could raise efficiency to 50%.

4.3.4 Emissions

Emissions attributed to fuel cell activities are calculated based on multiplying the hydrogen emissions intensity calculated in §3.7 and the amount of hydrogen consumed to produce the desired electrical energy.

$$E_{FC} = E_H \times D_{FC,H}$$

E_{FC}	Emissions intensity for fuel cell electricity (tCO_2e/kWh)
$D_{FC,H}$	Amount of hydrogen consumed daily by the fuel cell subsystem to meet electricity demand (same value as in §4.3.3)

4.3.5 Operations and Maintenance (O&M)

Three types of costs have been included in O&M: fuel cell warranty expenses, PEM stack replacements, and battery replacements. DTE Energy has not reached agreement on warranty expenses with Plug Power Inc., so the Model uses a DTE Energy estimated warranty cost of $528/unit/yr. DTE Energy estimated this warranty expense as the annual payment for an annuity with interest rate of 8.5%, 20-year life, and present value of $5,000. Stack replacement costs and schedules are described in §4.3.2.

4.3.6 Financial Assumptions

The fuel cell subsystem financial assumptions are the same as those for the hydrogen subsystem, described in §3.3.8. If there is demand for fuel cell electricity, the Model will add the resulting hydrogen demand to the overall demand placed on the hydrogen producing subsystem. Hydrogen is sold to the fuel cell subsystem at the transfer price *LCOH*. We have further assumed that all fuel cell electricity produced is dispatched and sold.

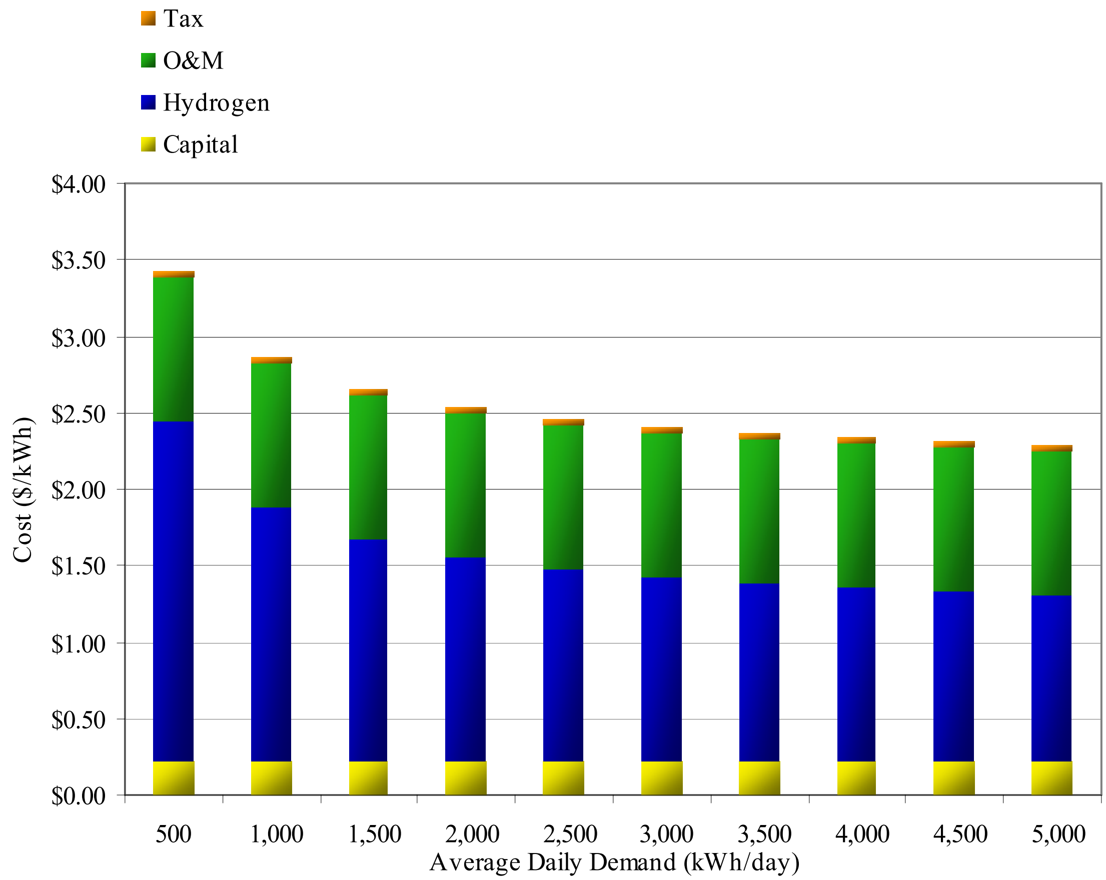
4.4 Levelized Cost of Fuel Cell Electricity Estimates

Four major Model runs were made to estimate the levelized cost of fuel cell electricity *LCOE*:

- "Fuel Cell Only" configuration with DTE-C parameters;
- "Fuel Cell Only" configuration with DTE-F parameters;
- "Hydrogen+Fuel Cell" configuration with DTE-C parameters; and,
- "Hydrogen+Fuel Cell" configuration with DTE-F parameters.

4.4.1 Fuel Cell Only Configuration with DTE-C Scenario

This run utilizes the "Fuel Cell Only" configuration as described in §4.1, for fuel cell electricity energy demands ranging from 500 kWh/day (approximately 1.6 times the 320 kWh/day design of the current Southfield facility) to 5,000 kWh/day, corresponding to a 625 kW capacity plant operating eight hours per day. Current DTE-C parameters were used. A simplifying assumption, is uniform daily demand for fuel cell electricity throughout the 20-year project life. Figure 4-2 and Table 4-2 depict the Fuel Cell Only, DTE-C results.



Source: Model calculations.

Figure 4-2: Levelized Cost of Fuel Cell Electricity, Fuel Cell Only, DTE-C

Table 4-2: Levelized Cost of Fuel Cell Electricity, Fuel Cell Only, DTE-C

D_{FC}	Capital	Hydrogen	O&M	Tax	Total *LCOE*	*LCOE* Ex-Tax
500 kWh	$0.22	$2.21	$0.94	$0.04	$3.42	$3.38
1,000	0.22	1.66	0.94	0.04	2.86	2.82
1,500	0.22	1.45	0.94	0.04	2.65	2.61
2,000	0.22	1.34	0.94	0.04	2.54	2.50
2,500	0.22	1.26	0.94	0.04	2.46	2.42
3,000	0.22	1.21	0.94	0.04	2.41	2.37
3,500	0.22	1.17	0.94	0.04	2.37	2.33
4,000	0.22	1.14	0.94	0.04	2.34	2.30
4,500	0.22	1.11	0.94	0.04	2.31	2.27
5,000	0.22	1.09	0.94	0.04	2.29	2.25

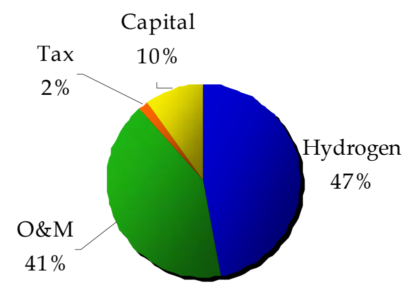
Source: Model calculations.

The Model assumes there are no economies of scale to the fuel cell subsystem, and no scaling factor was used to estimate fuel cell costs, and as a result, capital costs are constant in $/kWh terms, regardless of energy output. O&M costs are directly proportional to the hours of operation, which has been fixed at eight hours per day. O&M costs are also constant in

\$/kWh terms. Unlike capital and O&M, hydrogen costs do vary as a function of total energy demanded. In the Fuel Cell Only configuration, only the amount of fuel cell electricity produced (in kWh) determines the hydrogen consumption as there is no demand through dispensers. At D_{FC}=500 kWh, only 38 kg H_2/day are needed, and it is very expensive to produce such a small volume of hydrogen (\$29.43/kg H_2). On the other hand, at D_{FC}=5,000 kWh, 376 kg H_2/day are needed, which can be produced more economically at \$14.54/kg H_2.

The analysis shows that even if hydrogen (and balance of plant, which is incorporated in the cost of hydrogen) were supplied free to the fuel cells, the cost of fuel cell electricity would still be significant, approximately \$1.16/kWh, which is many times greater than the average on-peak electricity rates charged by DTE Energy's D6 rate schedule.

The breakdown of *LCOE* in Figure 4-3 is presented for larger D_{FC} = 5,000 kWh/day facility.



Source: Model calculations.

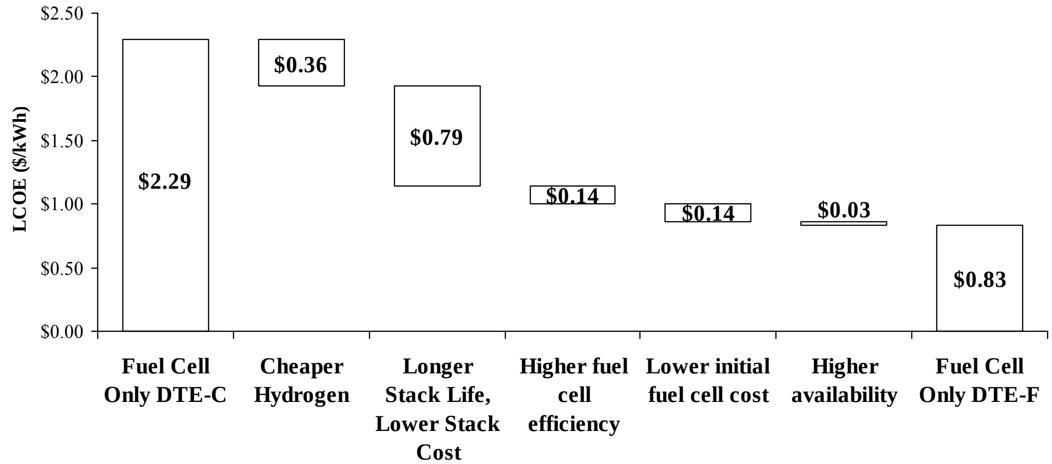
Figure 4-3: Cost of Electricity Breakdown, Fuel Cell Only, DTE-C

The fuel cell's feedstock (hydrogen) represents the largest cost driver at 47% of *LCOE*. O&M, which is dominated by replacement stack costs, is the next highest cost driver. The high costs attributable to replacement stacks means that the initial capital investment in purchasing fuel cells is relatively small, at 10% of *LCOE*.

Finally, unlike *LCOH*, taxes are very low as a percentage of *LCOE*. Unlike the hydrogen breakdown, capital costs do not dominate the cost of fuel cell electricity (please refer to Figure 3-7 for a comparison), O&M dominate in *LCOE*. Thus, the fuel cell subsystem does not have to generate much free cashflow to recover the initial investment. Revenues are thus set at a level resulting in relatively low profit margins, which results in low taxes.

4.4.2 Fuel Cell Only Configuration with DTE-F Scenario

This run combines the "Fuel Cell Only" configuration with future DTE-F parameters. The parameter differences between the DTE-C and DTE-F scenarios are listed in Table 4-1. This run quantified the effect of those differences on *LCOE*. For a 5,000 kWh/day facility, the calculated Fuel Cell future, standalone cost of fuel cell electricity is \$0.83/kWh. The breakdown of the cost savings from the Fuel Cell Only DTE-C to DTE-F is depicted in Figure 4-4.

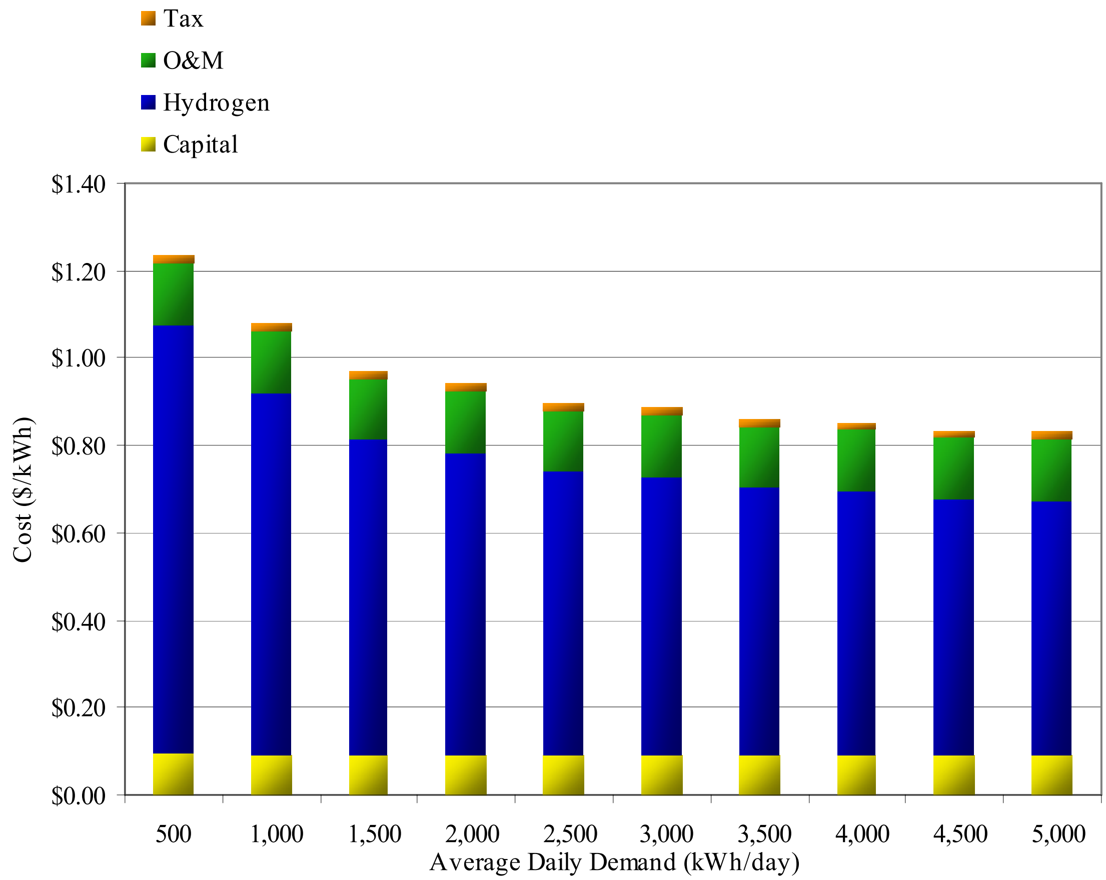


Source: Model calculations.

Figure 4-4: Cost Savings from DTE-C to DTE-F Fuel Cell Electricity Scenarios

The reduced cost of hydrogen plays a major part in reducing *LCOE*. The largest effect comes from improving the fuel cell stack due to its cost and replacement frequency. Both stack life and cost have significant (>$0.10/kWh) effects on *LCOE*. Because the sequence in which the two improvements are applied to the Model affect their estimated contribution, the cost and life effects are combined into a single "Longer Stack Life, Lower Stack Cost" category. Higher efficiency has some benefit, but because capital requirements are determined by peak power requirements (and not energy), it serves mainly to reduce feedstock consumption (hydrogen) without reducing capital requirements. To reduce capital requirements, one would need fuel cells with higher power output capacities. Finally, higher availability and lower initial fuel cell costs have smaller effects.

Figure 4-5 and Table 4-3 depict the Fuel Cell Only, DTE-F results for energy demands across the full range from 500 kWh/day to 5,000 kWh/day.



Source: Model calculations.

Figure 4-5: Levelized Cost of Fuel Cell Electricity, Fuel Cell Only, DTE-F

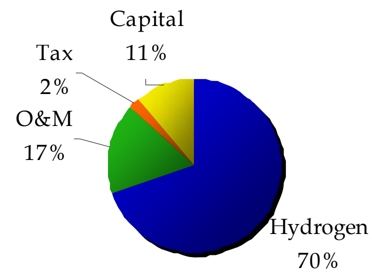
Table 4-3: Levelized Cost of Fuel Cell Electricity, Fuel Cell Only, DTE-F

D_{FC}	**Capital**	**Hydrogen**	**O&M**	**Tax**	**Total *LCOE***	***LCOE* Ex-Tax**
500 kWh	$0.09	$0.98	$0.14	$0.02	$1.24	$1.22
1,000	0.09	0.83	0.14	0.02	1.08	1.06
1,500	0.09	0.72	0.14	0.02	0.97	0.95
2,000	0.09	0.69	0.14	0.02	0.94	0.92
2,500	0.09	0.65	0.14	0.02	0.90	0.88
3,000	0.09	0.64	0.14	0.02	0.89	0.87
3,500	0.09	0.61	0.14	0.02	0.86	0.84
4,000	0.09	0.60	0.14	0.02	0.85	0.84
4,500	0.09	0.59	0.14	0.02	0.83	0.82
5,000	0.09	0.58	0.14	0.02	0.83	0.81

Source: Model calculations.

In the future DTE-F scenario, capital, hydrogen, and O&M costs (primarily replacement stack costs) have all fallen, but like the DTE-C scenario the capital and O&M costs are still fixed on a $/kWh basis. The analysis shows that even if hydrogen (and balance of plant, which is incorporated in the cost of hydrogen) were supplied free to the fuel cells, the cost of fuel cell electricity would still be significant, approximately \$0.25/kWh, which is many times greater than the average on-peak electricity rates charged by DTE Energy's D6 rate schedule.

The breakdown of *LCOE* in Figure 4-6 is presented for a D_{FC} = 5,000 kWh/day facility.



Source: Model calculations.

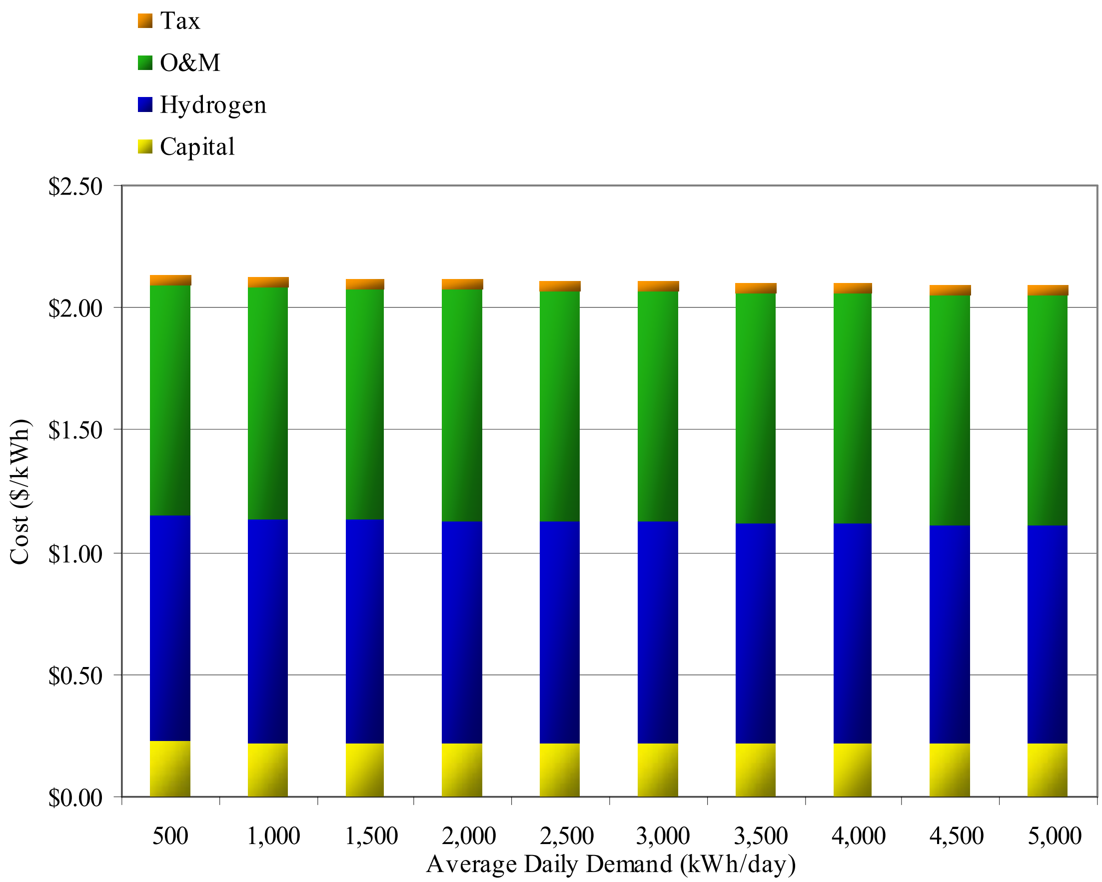
Figure 4-6: Cost of Electricity Breakdown, Fuel Cell Only, DTE-F

Hydrogen has now risen to 70% of *LCOE*, up from 47% in the DTE-C scenario. This is because the decline in O&M (dominated by replacement stack costs) was steeper than the drop in hydrogen prices (a 56% drop in replacement stack costs from \$4,500/unit to \$2,000/unit versus a 33% drop in hydrogen costs from \$14.54/kg H_2 to \$9.68/kg H_2). Tax and capital remained around 2% and 11% of *LCOE*.

4.4.3 Hydrogen+Fuel Cell Configuration with DTE-C Scenario

This run combines the "Hydrogen+Fuel Cell" configuration with current DTE-C parameters. This configuration assumes that a neighborhood filling station, with daily dispenser demand $D_{Daily\ D}$ of 1,200 kg H_2/day, is combined with a fuel cell subsystem. In the case where the large D_{FC} = 5,000 kWh/day fuel cell subsystem is used, the fuel cells will consume 376 kg H_2/day. Unlike "Fuel Cell Only", in the "Hydrogen+Fuel Cell" configuration the costs of the electrolysers, storage, and balance of plant are shared between hydrogen vehicles and fuel cell electricity customers, in proportion to their demand of the hydrogen produced. For Model simplicity, the *LCOH* charged to both customers includes dispensers, meaning that fuel cell users pay some of the costs of the dispenser, but the amount is less than 2% of *LCOE*.

Figure 4-7 and Table 4-4 present the Model results for the "Hydrogen+Fuel Cell" configuration with DTE-C scenario.



Source: Model calculations.

Figure 4-7: Levelized Cost of Fuel Cell Electricity, Hydrogen+Fuel Cell, DTE-C

Table 4-4: Levelized Cost of Fuel Cell Electricity, Hydrogen+Fuel Cell, DTE-C

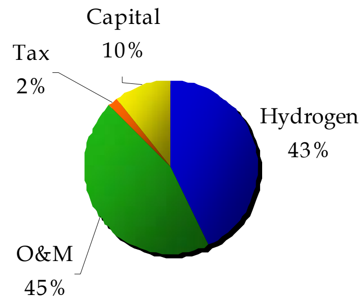
D_{FC}	Capital	Hydrogen	O&M	Tax	Total *LCOE*	Total Ex-Tax
500 kWh	$0.23	$0.92	$0.94	$0.04	$2.13	$2.09
1,000	0.22	0.92	0.94	0.04	2.12	2.08
1,500	0.22	0.92	0.94	0.04	2.12	2.08
2,000	0.22	0.91	0.94	0.04	2.11	2.07
2,500	0.22	0.91	0.94	0.04	2.11	2.07
3,000	0.22	0.90	0.94	0.04	2.11	2.06
3,500	0.22	0.90	0.94	0.04	2.10	2.06
4,000	0.22	0.90	0.94	0.04	2.10	2.06
4,500	0.22	0.90	0.94	0.04	2.10	2.05
5,000	0.22	0.89	0.94	0.04	2.09	2.05

Source: Model calculations.

To the fuel cell subsystem, the only difference between the “Fuel Cell Only” and “Hydrogen+Fuel Cell” scenarios is the cost of hydrogen. Therefore, capital and O&M are identical to the values derived earlier in the “Fuel Cell Only” DTE-C Table 4-2.

When combined with a neighborhood hydrogen filling station, the *LCOE* is much less sensitive to the size of the fuel cell substation, with the range between \$2.09/kWh and \$2.13/kWh. This is because even at the high 5,000 kWh/day level, the fuel cell substation's demand of hydrogen is 23% of the total daily hydrogen demand. Therefore, the fuel cell subsystem's effect on the cost of hydrogen is much smaller than the "Fuel Cell Only" scenarios, when the fuel cells were the only source of hydrogen demand.

The breakdown of *LCOE* in Figure 4-8 is presented for a D_{FC} = 5,000 kWh/day facility.



Source: Model calculations.

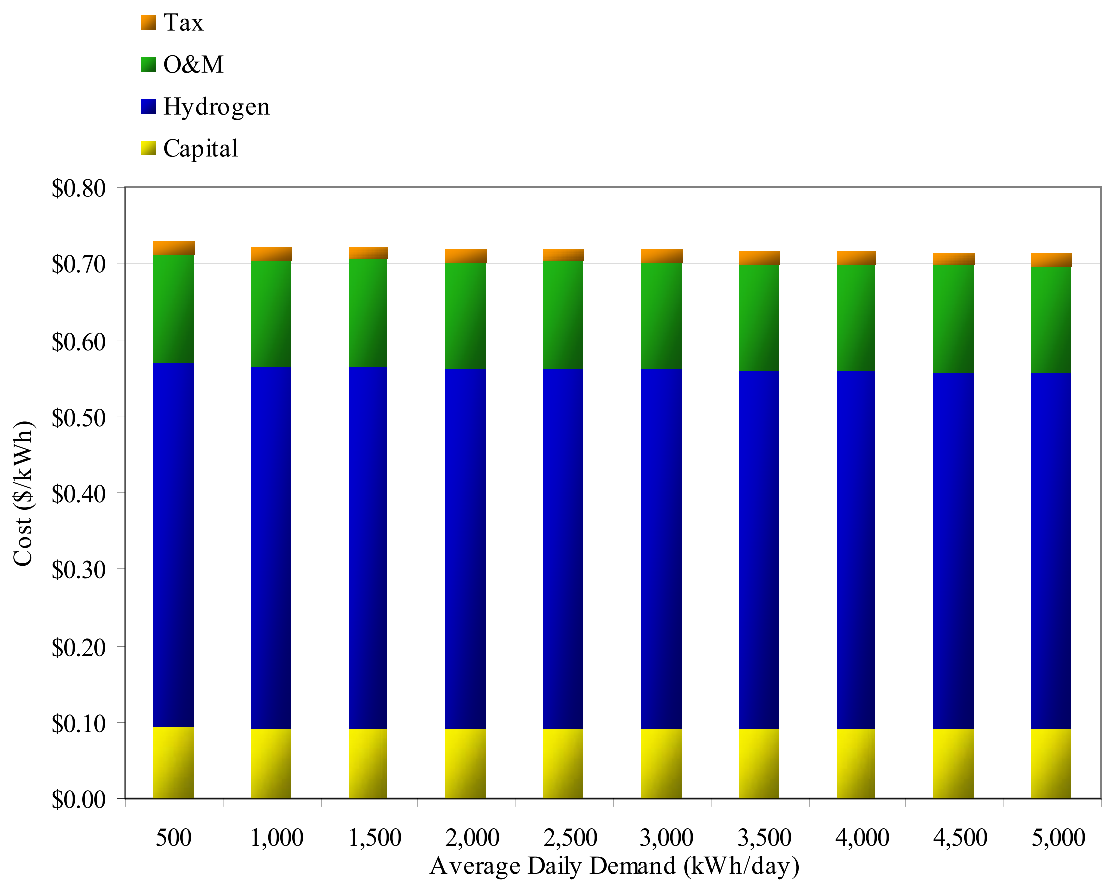
Figure 4-8: Cost of Electricity Breakdown, Hydrogen+Fuel Cell, DTE-C

The distribution of cost drivers is approximately the same as the "Fuel Cell Only" DTE-C Figure 4-3.

4.4.4 Hydrogen+Fuel Cell Configuration with DTE-F Scenario

This run combines the "Hydrogen+Fuel Cell" configuration with future DTE-F parameters. This is the most optimistic design for an HTP assessed in this study, and represents a future where HTPs are built to serve both hydrogen vehicle and energy storage applications. This configuration assumes that a neighborhood filling station, with daily dispenser demand $D_{Daily\ D}$ of 1,200 kg H_2/day, is built with a fuel cell subsystem. In the case where the large D_{FC} = 5,000 kWh/day fuel cell subsystem is used, the fuel cells will consume 301 kg H_2/day. The 301 kg H_2/day is lower than the 376 H_2/day in the DTE-C scenario (compare to §4.4.3) because higher fuel cell efficiencies result in reduced hydrogen demand.

Figure 4-9 and Table 4-5 present the Model results for the "Hydrogen+Fuel Cell" configuration with DTE-F scenario.



Source: Model calculations.

Figure 4-9: Levelized Cost of Fuel Cell Electricity, Hydrogen+Fuel Cell, DTE-F

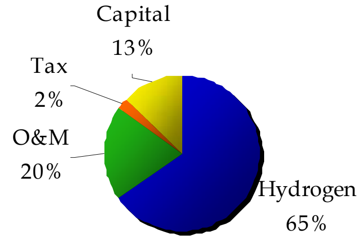
Table 4-5: Levelized Cost of Fuel Cell Electricity, Hydrogen+Fuel Cell, DTE-F

D_{FC}	Capital	Hydrogen	O&M	Tax	Total *LCOE*	Total Ex-Tax
500 kWh	$0.09	$0.48	$0.14	$0.02	$0.73	$0.71
1,000	0.09	0.47	0.14	0.02	0.72	0.70
1,500	0.09	0.47	0.14	0.02	0.72	0.71
2,000	0.09	0.47	0.14	0.02	0.72	0.70
2,500	0.09	0.47	0.14	0.02	0.72	0.70
3,000	0.09	0.47	0.14	0.02	0.72	0.70
3,500	0.09	0.47	0.14	0.02	0.72	0.70
4,000	0.09	0.47	0.14	0.02	0.72	0.70
4,500	0.09	0.47	0.14	0.02	0.71	0.70
5,000	0.09	0.46	0.14	0.02	0.71	0.70

Source: Model calculations.

Capital and O&M are identical to the values derived earlier in the "Fuel Cell Only" DTE-F Table 4-3. When combined with a neighborhood hydrogen filling station, the *LCOE* is much less sensitive to the size of the fuel cell substation, with the range between $0.71/kWh and $0.73/kWh. This is because even at the high 5,000 kWh/day level, the fuel cell substation's demand of hydrogen is 20% of the total daily hydrogen demand. Therefore, the fuel cell subsystem's effect on the cost of hydrogen is much smaller than the "Fuel Cell Only" scenarios, when the fuel cells were the only source of hydrogen demand.

The breakdown of *LCOE* is presented for a D_{FC} = 5,000 kWh/day facility in Figure 4-10.



Source: Model calculations.

Figure 4-10: Cost of Electricity Breakdown, Hydrogen+Fuel Cell, DTE-F

The distribution of cost drivers is approximately the same as the "Fuel Cell Only" DTE-F Figure 4-6.

4.5 Emissions Estimates and System Efficiency

Producing fuel cell electricity involves two major conversions of energy, from electricity to hydrogen and then from hydrogen back to electricity. Based on the electrolyser's measured efficiency η_E of 47.2% and fuel cell's efficiency of η_{FC} of 40.0%, 5.3 kWh of DTE Energy grid electricity is needed to produce each kWh of fuel cell electricity in the DTE-C scenario. This is consistent with the efficiency of an HTP system when used for energy storage:

$\eta_{HTP} = \eta_E \times \eta_{FC} = 18.9\%$
$1 \div \eta_{HTP} = 5.3x.$

Thus, an HTP's emissions intensity for all pollutants is also 5.3x the emissions intensity of the DTE Energy grid, as depicted in Table 4-6 (compare with Table 3-6).

Table 4-6: Emissions Intensity of HTP Fuel Cell Electricity Production

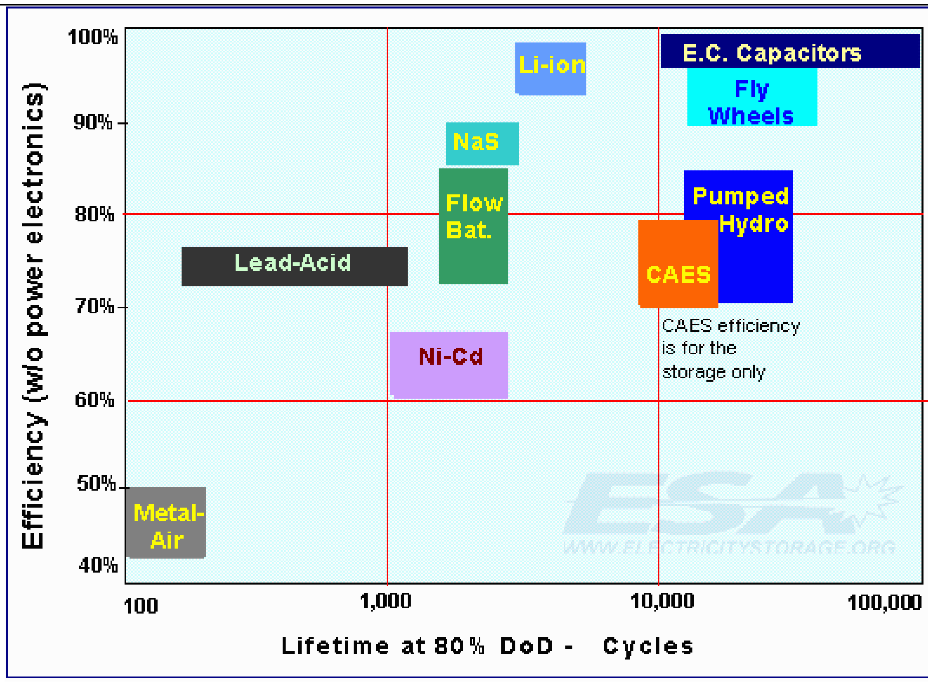
	Intensity (kg/kWh)	
Emission	Current	2012 Estimate
CO_2	4.15	4.08
NO_X	0.006	0.004
SO_2	0.021	0.016
Particulate matter	0.000303	0.000223

Source: Model calculation.

In the DTE-F scenario, efficiency rates for the electrolyser rises to 59.6% and to 50% for the fuel cells. The overall efficiency is:

$\eta_{HTP} = \eta_E \times \eta_{FC} = 29.8\%$
$1 \div \eta_{HTP} = 3.4x.$

Whether DTE-C or DTE-F efficiencies are used, the overall system efficiency is much lower than most other energy storage technologies, as shown in Figure 4-11, an industry survey by the Electricity Storage Association.



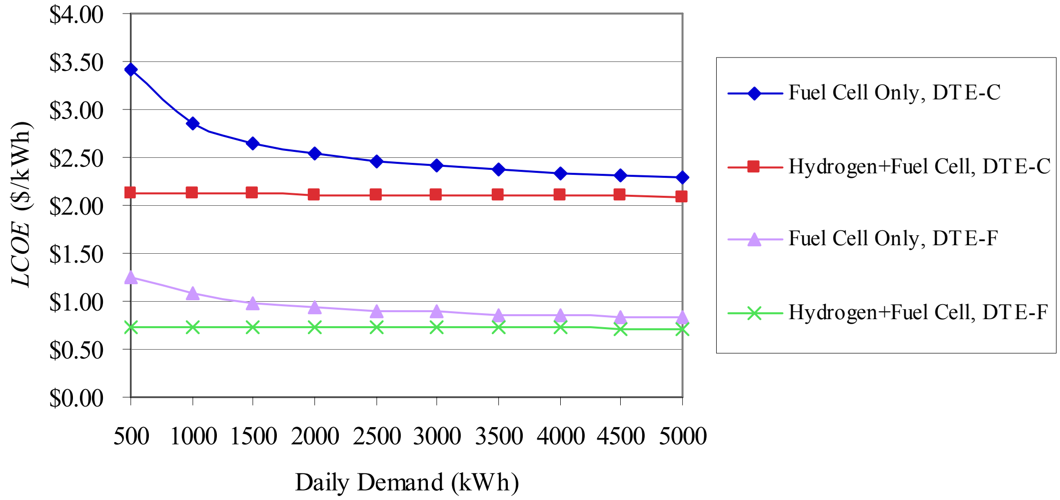
Source: Electricity Storage Association 2006.

Figure 4-11: Comparison of Energy Storage Technology Efficiency

To be sure, efficiency is only a single parameter used in evaluating energy storage solutions; other criteria may include technical performance criteria like quality of power, per cycle cost, and environmental impact. The results continue to demonstrate that fuel cell electricity from an HTP may not be cost competitive with other energy storage technologies.

4.6 Conclusions

With its array of fuel cells, the Park was designed to demonstrate and assess the concept of utilizing hydrogen in an energy storage application. The Model's results indicate that the cost of electricity from an HTP for such an application is many times greater than the electricity rates from DTE Energy's grid. This is true both for the "Fuel Cell Only" configuration, where no hydrogen dispensing occurs for vehicles, and for the "Hydrogen+Fuel Cell" configuration where the fuel cells share a common infrastructure with a neighborhood hydrogen filling station. Figure 4-12 summarizes Model runs on the two Model configurations, using both DTE-C and DTE-F scenarios. The results indicate that all combinations produce levelized costs of electricity well in excess of the $0.02431/kWh marginal cost of on-peak electricity on DTE Energy's D6 rate schedule.



Source: Model calculations.

Figure 4-12: Comparison of Fuel Cell Electricity Cost Curves

The key cost drivers for fuel cell electricity are hydrogen costs, which are determined by the levelized cost of hydrogen (via electrolysis) process described in Chapter 3, and proton exchange membrane replacement stacks, which at present are warranted for 1,500 hr (approximately 187 days at 8 hrs/day operation). Initial capital investment is relatively small.

The analysis indicates that making the "round-trip" from electricity to hydrogen and back using an HTP results in a system efficiency of 18.9% using current measured subsystem efficiencies, with the possibility of increasing to 29.8% system efficiency in the future. These levels of efficiency are below competing energy storage technologies and affirm the conclusion that an HTP is unlikely to be cost competitive as an utility-scale energy storage system.

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5 HTP Consolidated Financial Estimates

5.1 Introduction

To evaluate an HTP as a complete project, a set of consolidated pro forma financial estimates were prepared in accordance with DTE Energy standards, and reviewed by DTE Energy's Treasury department. Projections through the year 2016 are presented in Appendix §13.2. Results beyond 2016 were not presented due to space constraints.

5.2 Income Tax and Depreciation

Per DTE Energy's request, two sets of income statements have been prepared. The first does not include interest expenses and is intended to show the net operating profit after taxes (NOPAT). The second set includes interest expense using a standard DTE Energy interest rate of 7%. In both cases, the tax expense has been calculated by multiplying DTE Energy's 35% corporate tax rate by a taxable base that has been adjusted for the clean-fuel refueling property deduction (Title 26, Subtitle A , Chapter 1 , Subchapter B, Part VI, §179A), which as of writing was $30,000 in the first year of operations:

Tax Expense for Year 1 = Tax Rate × (Pre-Tax Income – Deduction)

In the Model, tax is set to $0 if pre-tax income is negative. There are no tax loss carryforwards.

For the capital equipment, the Model uses the Modified Accelerated Cost Recovery System of depreciation. A seven year recovery period is used with double declining balance depreciation in the first four years and straight line depreciation thereafter. As there is a difference between GAAP income tax and actual taxes paid, the Model will calculate deferred taxes, which net out to zero, as expected, by the end of an HTP's life.

5.3 Capital structure, dividend policy, and working capital

There are several financings in the Model. In period 0, an HTP's initial capital is financed 50% with debt, in the form of a 15 year maturity mortgage-style loan with 7% interest rate, and 50% with equity. In period 10, it is assumed that the electrolyser will need replacement, and will be financed entirely with a second issuance of debt, a 10 year maturity mortgage-style loan with 7% interest. At the end of year 20, when an HTP's useful life is complete, the only items on the balance sheet are the residual value of the balance of plant, which is not depreciated.

Note that the above is used only for presenting the consolidated HTP financials. While a changing debt to capitalization ratio should technically change an HTP's weighted average cost of capital yearly, the levelized cost of hydrogen and fuel cell electricity calculations are calculated to ensure free cash flows return a constant 16% IRR over an HTP's 20 year life.

Lastly, it is assumed that the Project dividends all excess cash and maintains a zero cash balance. For simplicity, it is assumed that an HTP requires no working capital and all costs are expensed in the same period, including fuel cell replacement stacks and batteries.

6 Energy Storage Applications

6.1 Introduction

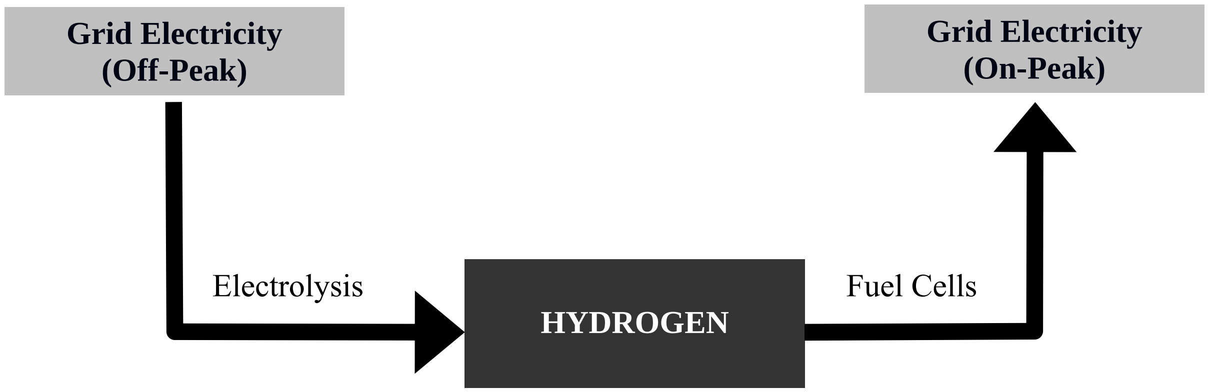
Electric utilities face a unique challenge as they attempt to match electricity supply with demand – once electricity is generated it must be transmitted and distributed immediately. As an energy carrier, hydrogen presents an electricity storage option for electric utilities. Hydrogen can be produced, stored and then converted into electricity through a fuel cell. In the future, hydrogen may be used to capture energy produced from renewable energy resources, such as wind and solar, which are intermittent in nature.

Electricity prices vary by time of day. Peak electricity is generally more expensive than off-peak electricity. The average daily price of electricity during on-peak hours from August 2005 to February 2006 in the Michigan Hub was 198% higher than off-peak hours – \$36.87/MWh during off-peak hours compared to \$73.12/MWh during on-peak hours (Table 6-1).

Electric utilities would have an opportunity to increase revenues/decrease costs, if electricity can be generated and stored when prices are lowest and released when prices are highest. Currently, DTE Energy uses a similar strategy at its Ludington, MI Pumped Storage Plant. DTE Energy owns a 49% stake of Ludington. The Ludington plant pumps water from Lake Michigan into a reservoir during off-peak hours at night and on weekends when electricity costs are lowest. The plant then releases the water through turbines to produce electricity during on-peak hours (Consumers Energy 2006).

6.2 Application to Hydrogen Technology Park

Given the ability of an HTP to produce both hydrogen and electricity, we examined the economic feasibility of utilizing the Park today to produce hydrogen during off-peak hours, store this hydrogen, and convert the hydrogen to electricity during on-peak hours (see Figure 6-1). The Park would purchase electricity during off-peak hours (when prices are cheapest) to produce hydrogen and convert this hydrogen into electricity during on-peak hours when DTE Energy would be able to receive a higher price for electricity. This would provide a similar business model to that at the Ludington Pumped Storage Plant.



Source: Project team.

Figure 6-1: Scenario for utilizing an HTP for Energy Storage Applications

6.3 Methodology

In addition to the data on electricity costs from the Park (see Chapter 4), an analysis of electricity prices from the Midwest Independent System Operator ("MISO") was performed to determine the economic feasibility of utilizing the Park for energy storage.

MISO is responsible for monitoring the electric transmission system that delivers electricity from generating plants to wholesale power transmitters in the Midwest. MISO tracks the clearing prices of electricity that is sold into the grid. Data is available for Day-Ahead prices for the Michigan Hub, which serves DTE Energy, from August 2005 through February 2006 (See Appendix 13.4 for an example of the MISO Day-Ahead Report).

Each Day-Ahead report contains the following information: Locational Marginal Pricing ($ per MW) for each hour of the day, low/high/average price for the entire 24-hour period, low/high/average price for the off-peak period (between 2201 and 0559 EST Monday through Friday, all hours for weekends and holidays) and low/high/average price for the peak period (between 6:00 AM and 10:00 PM EST Monday through Friday, excluding holidays). DTE Energy could sell electricity into the grid at the listed prices. Daily price information was converted to average daily prices per month and an average overall daily price for the August 2005 to February 2006 time period.

The MISO peak prices provide a target price for electricity produced from the Park. If the Park is able to produce electricity at prices lower than the MISO peak prices, DTE Energy could produce revenues from the sales of electricity into the grid. Other factors, including electricity quality, amount, and how quickly electricity can be produced, impact the ability to sell electricity to the grid. However, price is the single most important factor.

6.4 Results

6.4.1 Park Electricity Costs

The cost of producing electricity from the Park is calculated in §4.4.1 (Park hydrogen used solely for electricity production) and §4.4.2 (Park hydrogen used for both hydrogen vehicles and electricity production). As stated in §3.3.5, the Park would operate as a commercial entity purchasing off-peak electricity from DTE Energy on the standard D6 commercial rate schedule ($21.31/MWh). Projections assume that the real prices of electricity would stay constant over the Project's life. The cost projections in §4.4.1 and §4.4.2 incorporate the cost of purchasing electricity from the grid to produce hydrogen. Table 6-1 provides the levelized cost of electricity from the Park for both "Fuel Cell Only" and "Hydrogen+Fuel Cell" configurations at various electricity generation capacities ranging from 500 kWh to 5,000 kWh during on-peak hours.

Table 6-1: DTE Energy HTP Levelized Cost of Fuel Cell Electricity

Daily electricity production	Total *LCOE* ($/MWh)	
	Fuel Cell Only	Hydrogen + Fuel Cell
0.5 MWh	$3,420	$2,130
1.0	2,860	2,120
1.5	2,650	2,120
2.0	2,540	2,110
2.5	2,460	2,110
3.0	2,410	2,110
3.5	2,370	2,100
4.0	2,340	2,100
4.5	2,310	2,100
5.0	2,290	2,090

Source: Model calculations.

The costs listed in Table 6-1 provide a target point for Park electricity sales into the grid. In the best case scenario, prices for electricity must be greater than $2,090/MWh in order to provide revenue for DTE Energy.

6.4.2 MISO data

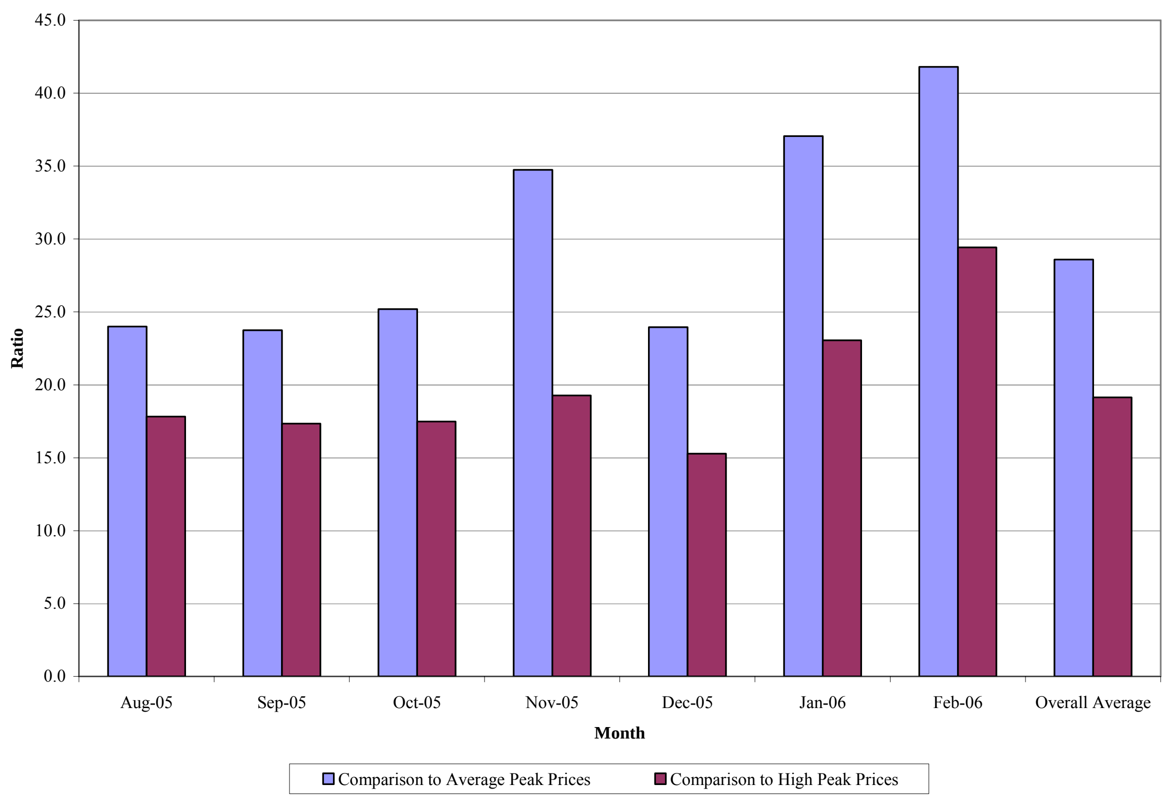
The average daily price for each month as well as the overall average daily price is shown below (Table 6-2). In every month, the average daily on-peak price is greater than the average daily off-peak price.

Table 6-2: Average daily prices of Michigan Hub electricity from August 2005 to February 2006

	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Overall Ave.
24-Hour Prices								
Low	$ 24.98	$ 24.24	$ 26.35	$ 28.64	$ 33.96	$ 27.50	$ 27.32	$ 27.57
Average	66.30	65.83	57.17	46.33	65.34	43.82	42.03	55.26
High	112.92	116.49	103.17	94.80	127.02	81.91	71.84	101.16
On-Peak								
Low	37.22	41.52	42.09	41.32	47.73	38.60	33.74	40.32
Average	87.08	88.01	82.94	60.15	87.28	56.40	49.99	73.12
High	117.23	120.52	119.60	108.43	136.79	90.63	71.02	109.18
Off-Peak								
Low	24.98	24.24	26.35	28.64	34.14	27.50	27.32	27.60
Average	40.68	36.98	35.66	33.69	46.30	32.63	32.13	36.87
High	65.32	66.57	64.95	49.51	77.23	45.87	44.90	59.19

Source: Midwest Independent System Operator 2006.

The levelized cost of electricity provides the minimum target price for using the Park to provide electricity for the grid. The cost of Park electricity is substantially higher than the clearing prices for the Michigan Hub electricity (Figure 6-2).



Source: Model calculations, Midwest Independent System Operator 2006.

Figure 6-2: Ratio of Park Electricity Price ($2,090/MWh) to Average and High Peak Electricity Prices from Michigan Hub

The difference between the levelized cost of electricity at daily generation levels of 5,000 kWh ($2,090/MWh) and the Average High Peak Daily Price ($109.18/MWh) is $1,980.82. Therefore, on-peak electricity prices would need to be 19.1 times higher than current prices for DTE Energy to economically store hydrogen and convert to electricity during on-peak hours at the Park.

6.5 Discussion and Conclusions

The analysis demonstrates the uneconomical nature of using the current Park configuration for electricity sales into the grid. Even the most favorable scenario (average high peak price of $136.79/MWh in December 2005 and HTP electricity price of $2,090/MWh) is far from economical. The December 2005 price would need to be at least 15.3 times greater to reach a breakeven point.

There are several reasons for the uneconomical nature of this function. Both hydrogen and O&M costs impact the high cost of Park electricity. In the "Fuel Cell Only" configuration for 5 MWh daily generation, hydrogen accounts for 47% of total electricity costs, while O&M accounts for 41%. In the combined use configuration for 5 MWh daily generation, "Hydrogen+Fuel Cell," hydrogen accounts for 43% of total electricity costs, while O&M accounts for 45% (see §4.4.1 and §4.4.2 for more detail). However, even if hydrogen costs were $0.00 this strategy would still be uneconomical given capital and O&M costs of $220/MWh and $940/MWh, respectively.

The underlying reason for the high costs is the inefficient nature of utilizing grid electricity to produce hydrogen and then use this hydrogen to produce electricity for the grid. According to the Model calculations, 5.3 kWh of electricity are required to produce 1 kWh of electricity through the fuel cells, which corresponds to a system efficiency of 18.9% (see §4.5). This makes the use of the Park for energy storage very difficult to achieve economic viability. Even if the costs for hydrogen production, storage, and conversion to electricity were $0.00, on-peak electricity prices would still need to be at least 5.3 times higher than off-peak hours to break even economically.

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7 Distributed Generation

7.1 Introduction

Definitions of distributed generation ("DG") vary by source. For this analysis, we define DG as small-scale (<60MW) energy generation located near the point of use. Numerous technologies are used in DG applications including reciprocating engine (internal combustion engine/generators), microturbines, gas turbines, solar photovoltaic systems, wind turbines, external combustion engines, and fuel cells.

Our analysis focuses on the application of fuel cells in DG applications and the projected growth of the DG fuel cell market. DTE Energy is interested in this market because it may provide a source of demand for hydrogen from HTPs. In this analysis, an HTP would not directly provide energy generation for DG applications, but would provide the hydrogen used for fuel cells in DG applications. The hydrogen would be dispensed from an HTP as a pressurized gas and transported in cylinders.

The market potential for fuel cells in DG applications may be significant. The DOE projects that an additional electricity generation capacity of 1.5 trillion kWh will be needed in the United States by 2020. If fuel cells provided 10% of the additional generation or 150 billion kWh, 10 million tons of hydrogen would be needed to power these fuel cells (DOE 2004).

Additionally, fuel cells may become commercially competitive in stationary applications before transportation uses (Chalk and Inouye 2003). The expected growth of fuel cell vehicles in the transportation sector is much greater than for stationary applications. However, given the technological limitations to fuel cell vehicles and the hydrogen infrastructure necessary to support fuel cell vehicles, this growth is not expected to occur for at least 10 years (See Chapter 9 for in-depth analysis of fuel cell vehicles). Fuel cells are commercially available for use in stationary applications today.

This Chapter will discuss the current market for distributed generation, the future market for fuel cells used in DG applications, and provide estimates of the total hydrogen needed to meet this future market demand in both the U.S. and Michigan.

7.2 Distributed Generation Market

7.2.1 Current Market Size

The various definitions of DG and lack of national data lead to a wide range of estimates of the current DG market size. Enerdynamics, an energy educator, estimates the total number of small stationary DG units in the U.S. at over 550,000 (Enerdynamics 2004), while NAE provides an estimate of 10.7 million (NAE 2004). NAE states that 85% of DG units in 2003 were reciprocating engines and used either distillate fuel oil or gasoline to power the units. Steam turbines and combustion turbines fueled by natural gas account for 9% and 5%, respectively, of total DG units. DG electricity generation capacity estimates also vary from 3% to 17% of total U.S. electricity generation capacity. This large discrepancy may be attributed to various definitions of DG used in estimates, including interconnection capability with the grid and size ranges.

DG is used in a variety of applications and may be connected to the grid or be independent of the grid. The majority of units are used as standby or emergency generators to provide backup power when needed. Peak shaving is the use of DG units during high-cost peak periods to reduce costs for users. Combined Heat and Power ("CHP") or co-generation involves using waste heat from on-site DG units to power heating-ventilation-and-air-conditioning ("HVAC") or provide heat. Electric utilities employ DG units for grid support in areas where transmission and distribution ("T&D") problems have arisen in the past. This may be a lower cost alternative than building new T&D infrastructure. Finally, DG units are used as stand alone electricity generators for buildings that are not connected to the grid (National Energy Technology Laboratory 2003).

7.2.2 Projected Market Size

The Energy Information Administration ("EIA") produces annual energy forecasts to provide projections on energy use in the United States. Both the 2005 Annual Energy Outlook ("AEO2005") and 2006 Annual Energy Outlook ("AEO2006") provide detailed forecasts on distributed generation, including fuel cells. A detailed analysis and discussion of distributed generation was included in AEO2005.

AEO2005 focuses on distributed generation projections in the commercial and residential building sectors. The AEO2005 forecasts a significant increase in building electricity generation. However, EIA does not expect distributed generation to provide a major portion of electricity requirements in both residential and commercial buildings. EIA believes the majority of future electricity generation capacity for buildings will continue to come from the grid.

EIA projections are based on forecasts of the economic returns of DG technology purchases to meet baseload electricity needs. This is a common method used to determine market penetration of several alternative technologies. The cash flow analysis includes annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) for a 30-year timeframe. The analysis assumes that any excess electricity above baseload levels can be sold into the grid. EIA uses data from the Department of Defense fuel cell demonstration program for the fuel cell portion of their analysis.

One of the major assumptions of EIA forecasts is that all fossil-fuel-fired systems are used in CHP applications to take advantage of waste heat produced in the generation process. CHP applications provide more economic benefit to end-users. Fuel cells are included in the fossil-fuel-fired system category, because EIA believes that the majority of hydrogen used in fuel cells will come from hydrogen reformation (Boedecker 2006).

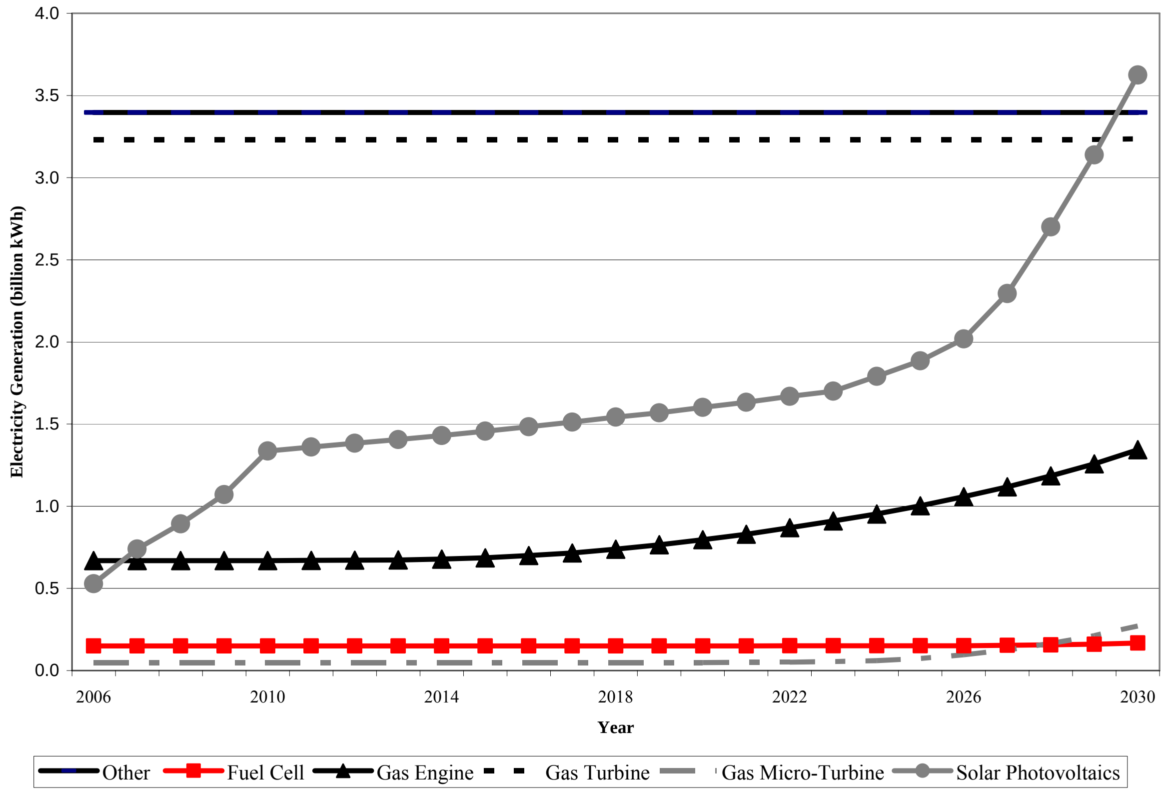
EIA identifies several key issues that will impact the DG market. These include the cost of purchasing electricity from the grid compared to investing in DG systems and fuel cost increases (primarily natural gas) that may limit the economic feasibility of DG systems.

Increased natural gas prices may provide an opportunity to make hydrogen powered fuel cells more economically attractive, if hydrogen is produced by methods excluding natural gas. A third issue is that only 5% of existing commercial buildings in US meet electrical demand and thermal loads to meet the criteria for CHP (EIA 2005). A final issue is that regulation surrounding DG systems vary by state, technology, fuel, and project size. Additional regulatory issues include emissions, siting regulations, and local utility interconnection.

7.2.3 AEO2006 Reference Case Projections

The AEO2006 reference case includes residential and commercial DG projections at the national level and for the nine regional districts. EIA does not forecast a significant market demand for DG for residential units. DG capacity currently used in residential buildings consists of electricity backup generators for use during power outages. Although DG is used primarily for backup power within the commercial building sector, EIA estimates that approximately 0.7% of DG units in commercial buildings are used for other purposes, including CHP.

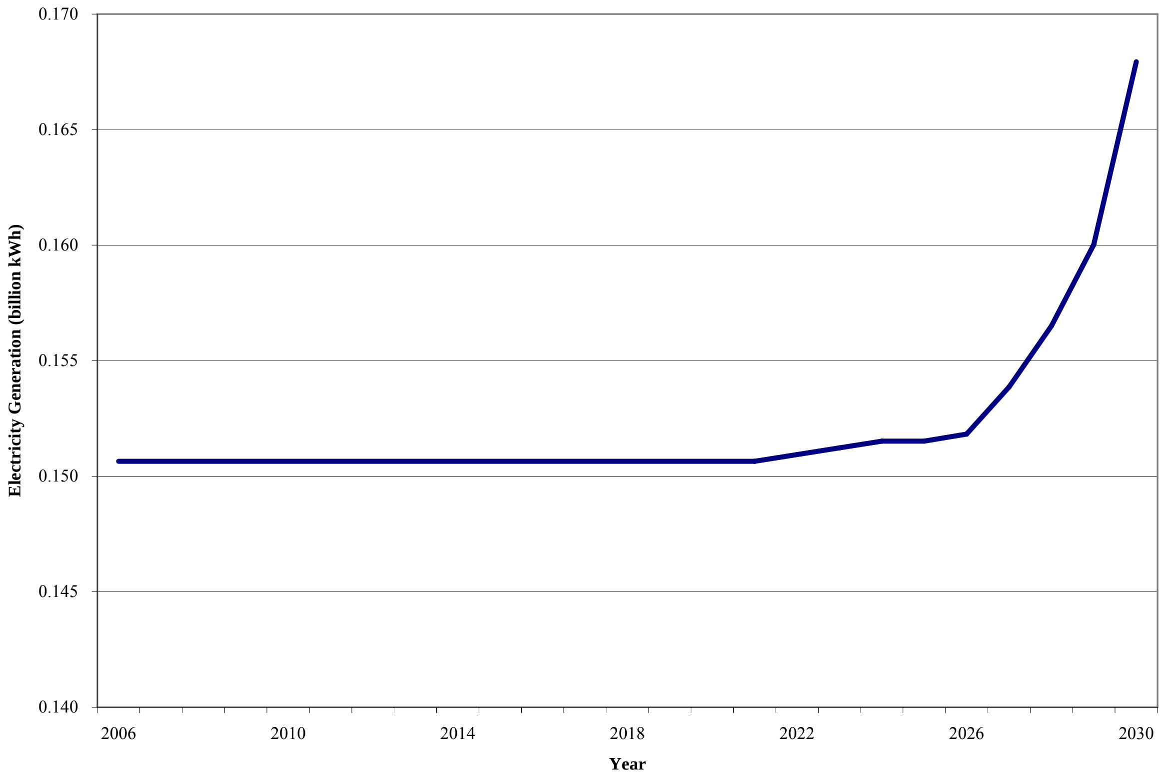
The reference case projects an 80% increase in electricity supplied annually by fossil-fuel-fired DG in the buildings sector (6.3 billion kWh in 2003 to 11.3 billion kWh in 2025). DG is expected to meet less than 1% of the electricity requirements for buildings nationally. Figure 7-1 provides AEO2006 forecasts for electricity generated from DG units associated with residential and commercial buildings. While the time period for our estimates is 2006 to 2026, data through 2030 is included to show the major growth in certain technologies occurring after 2026.



Note: Other includes conventional coal, conventional municipal solid waste, conventional oil, hydro, and wood. EIA predicts no growth in these sectors.
Source: EIA 2006c.

Figure 7-1: AEO2006 U.S. forecast for electricity generation from DG

Figure 7-2 provides electricity generation projections for only fuel cells. Please note the scale difference between Figure 7-1 and Figure 7-2.



Source: EIA 2006c.

Figure 7-2: Electricity generation forecasts from fuel cells in DG applications.

EIA views gas turbines as a mature technology and does not expect generation from natural gas turbines at commercial facilities to increase throughout the forecast period. Microturbines, fuel cells, and solar photovoltaic systems are expected to produce more electricity later in the forecast period. Projected cost reductions and technological advances that make these systems more efficient and cost effective lead to this increased generation.

Differences between geographic regions in the U.S. lead to different adoption rates of DG technologies. EIA predicts that DG technologies using fossil fuels in CHP applications will grow faster in regions with high electricity prices and moderate natural gas prices.

7.3 Methodology

7.3.1 Total U.S. Hydrogen Demand

As mentioned above, the 2005 and 2006 Annual Energy Outlooks published by the EIA provide forecasts of electricity generation from fuel cells in DG applications in the commercial sector. EIA also predicts fuel cell hydrogen to electricity conversion efficiency factors. This data was used to calculate annual hydrogen demand at a national level. This is referred to as "Scenario 1" or "Corresponding fuel cell efficiency" throughout the section. We also calculated hydrogen demand using a constant fuel cell efficiency factor of 40% to allow an understanding of how fuel cell efficiency affects hydrogen demand. This is referred to as "Scenario 2" or "Constant fuel cell efficiency." A sensitivity analysis was run based on several different electricity generation forecasts (-10%, 10%, 20%, and 50%) to determine how changes to electricity generation forecasts impact hydrogen demand forecasts.

The following formula was used to calculate annual hydrogen demand in kg:

Hydrogen (kg) = Electricity (kWh) ÷ [Energy Content in kWh of 1 kg of Hydrogen × Hydrogen to Electricity Conversion Efficiency of Fuel Cell]

7.3.2 Assumptions

For the energy content of hydrogen, we used the thermodynamic property of 33.2 kWh/kg H_2 at LHV (NAE 2004). The lifetime of fuel cells was assumed to be ten years throughout our calculations (EIA 2006c). We assumed that all new demand would be met through the addition of new fuel cells as opposed to increased utilization of existing fuel cells. Since EIA forecasts provide estimates back to 2000, we assumed that installation of fuel cells began in 2000. The hydrogen to electricity efficiency corresponds with the year of fuel cell installation. For example, in 2002 EIA estimated that 0.0027 billion kWh of electricity was generated by fuel cells. To meet this demand, we assume that fuel cells with an efficiency of 36% were installed in 2000. These fuel cells would meet this demand for the 10-year lifetime of the fuel cells until 2009.

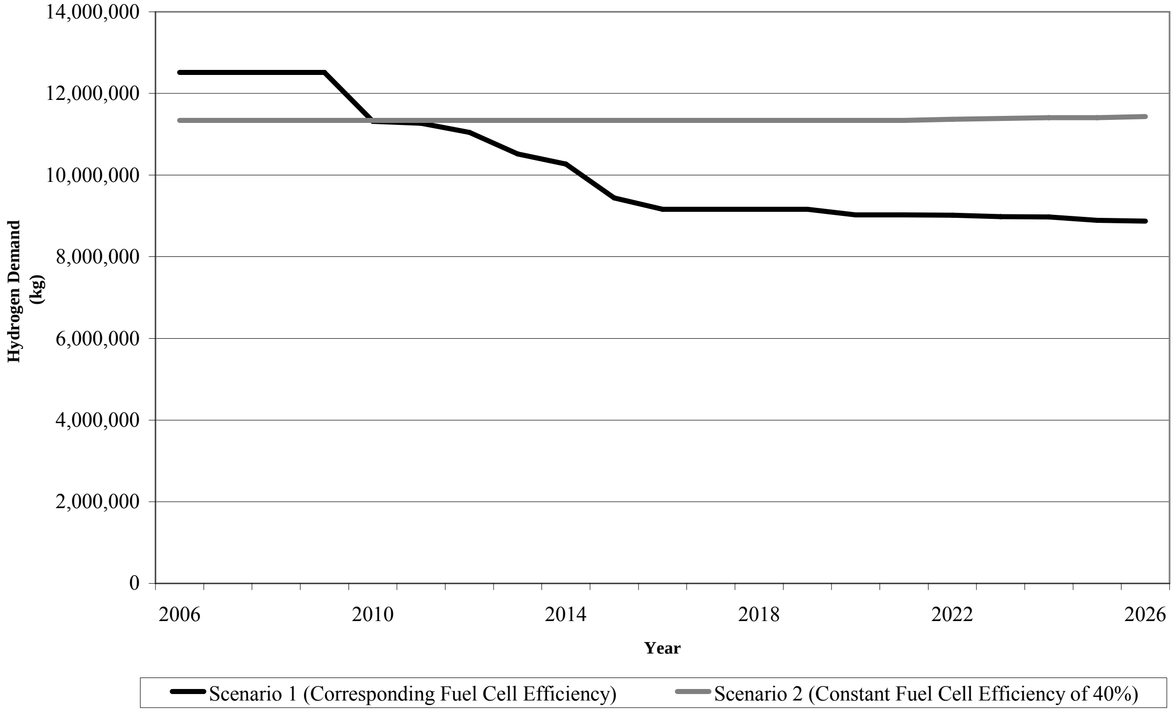
7.3.3 Total hydrogen demand in Michigan

Given the results from our calculations for hydrogen demand at a national level, DTE Energy asked us to determine the corresponding market size in the state of Michigan. The proportion of electricity generation in Michigan compared to the entire U.S. was used to estimate the market size for Michigan. Additionally, data from an EIA study on the market potential of commercial/institutional CHP by state was used to estimate the market size. The estimated Michigan market size was used in tandem with the results from the national hydrogen demand forecasts to calculate hydrogen demand for Michigan.

7.4 Results

7.4.1 Total U.S. Hydrogen Demand

The results from the calculations using corresponding fuel cell efficiency (Scenario 1) show a 29.1% decrease in total national hydrogen demand from 12,516,607 kg in 2006 to 8,873,472 in 2026. Total hydrogen demand increases slightly from 11,343,734 kg in 2006 to 11,432,012 kg in 2026 when a constant fuel efficiency factor of 40% is used in the calculations (Scenario 2). This amounts to a 0.78% demand increase (Figure 7-3). For complete results of the Model, see Appendix 13.5.



Source: Model calculations based on fuel cell electricity generation estimates from EIA 2006c.

Figure 7-3: Annual U.S. Hydrogen Demand of Hydrogen from DG Applications

7.4.2 Sensitivity Analysis

A sensitivity analysis was conducted for hydrogen demands with corresponding fuel cell efficiency and with constant fuel cell efficiency (40%). The sensitivity analysis shows that increases in electricity generation forecasts lead to higher hydrogen demand in both instances. However, electricity generation increases in the corresponding fuel cell efficiency scenario does not directly correlate to the same percentage of increased hydrogen demand. For example, a 50% increase in electricity generation demand translates to increased demand of 49.4% in 2026 (Table 7-1).

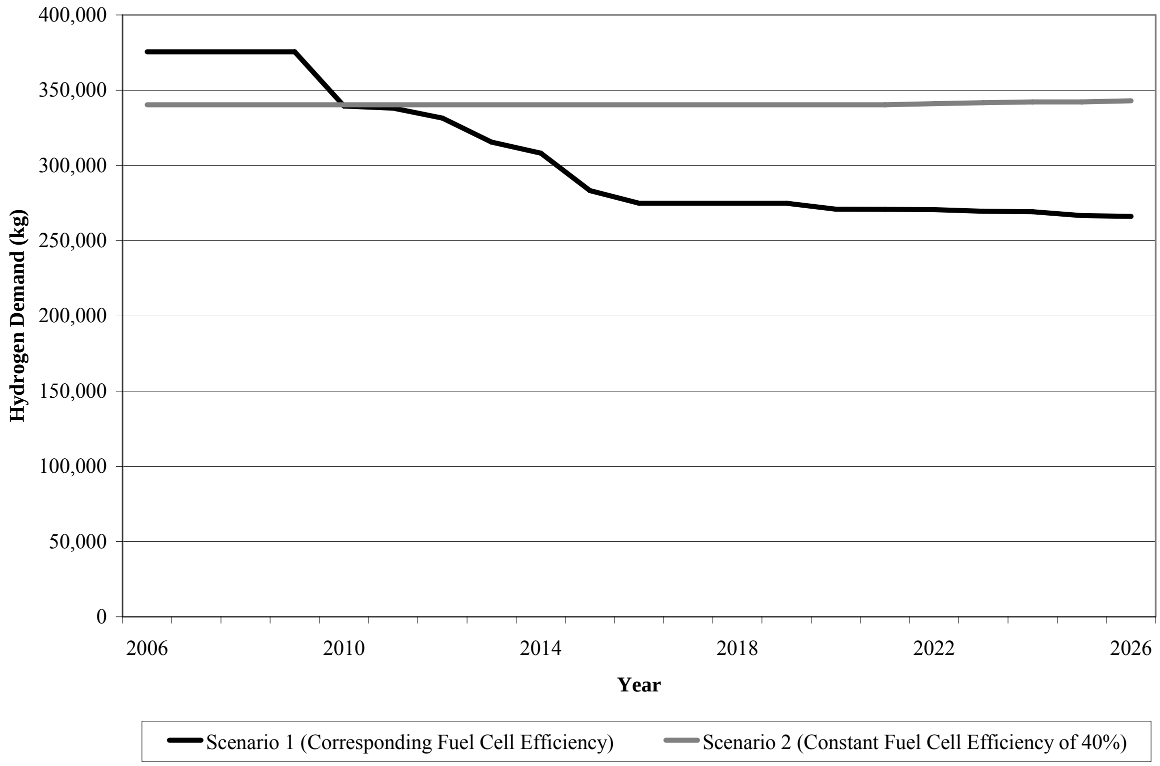
Table 7-1: Sensitivity Analysis: Change to Hydrogen Demand from Different Electricity Generation Forecasts

	2006		2016		2026	
	Amount (kg)	% Change from base case	Amount (kg)	% Change from base case	Amount (kg)	% Change from base case
Scenario 1 (Corresponding Fuel Cell Efficiency)						
Base Case	12,516,607	0.0%	9,160,805	0.0%	8,873,472	0.0%
Base Case - 10%	11,341,091	-9.4%	8,256,922	-9.9%	7,997,397	-9.9%
Base Case + 10%	13,692,124	9.4%	10,064,688	9.9%	9,749,548	9.9%
Base Case + 20%	14,867,640	18.8%	10,968,571	19.7%	10,625,623	19.7%
Base Case + 50%	18,394,190	47.0%	13,680,221	49.3%	13,253,849	49.4%
Scenario 2 (Constant Fuel Cell Efficiency of 40%)						
Base Case	11,343,734	0.0%	11,343,734	0.0%	11,432,012	0.0%
Base Case - 10%	10,209,360	-10.0%	10,209,360	-10.0%	10,288,811	-10.0%
Base Case + 10%	12,478,107	10.0%	12,478,107	10.0%	12,575,213	10.0%
Base Case + 20%	13,612,480	20.0%	13,612,480	20.0%	13,718,414	20.0%
Base Case + 50%	17,015,601	50.0%	17,015,601	50.0%	17,148,018	50.0%

Source: Model calculations based on electricity generation from EIA 2006c.

7.4.3 Market Potential in Michigan

Michigan generated 110,754 GWh of electricity from January to December 2005. This accounts for 3.00% of total U.S. electricity generation (EIA 2006c). The EIA forecast of commercial/institutional CHP market potential indicates a total U.S. market size of 77,920 MW of installed capacity. The EIA estimated Michigan market size is 2,560 MW or 3.31% of the entire U.S. market. A constant market size of 3.00% for fuel cell electricity was used to calculate hydrogen demand in Michigan. This estimate assumes that fuel cell electricity in Michigan is proportional to CHP market potential. Figure 7-4 shows the results for the total hydrogen demand in Michigan.



Source: Model calculations based on fuel cell electricity generation estimates from EIA 2006c.

Figure 7-4: Hydrogen Demand in Michigan from Fuel Cells

7.4.4 Number of Distributed Hydrogen Generation Facilities

We wanted to determine the number of distributed hydrogen production facilities necessary to meet the forecasted hydrogen demand in both the U.S. and Michigan. For this calculation, two park sizes were used: 100 kg/day of hydrogen production, roughly twice as large as the current Park and 1,200 kg/day, the approximate size of a neighborhood hydrogen filing station (similar sized HTPs are mentioned in Chapter 3). Additionally, since several hydrogen producers are available to meet this demand, four different market penetration sizes were incorporated: 100%, 75%, 50%, and 25%. For example, a 50% market penetration size means that distributed hydrogen production facilities serve 50% of hydrogen demand. Table 7-2 provides the calculations from this analysis.

Table 7-2: Number of HTPs Needed to Meet Projected U.S. and Michigan Demand

		Market Served	2006 Park Size		2016 Park Size		2026 Park Size	
			100 kg/day	1,200 kg/day	100 kg/day	1,200 kg/day	100 kg/day	1,200 kg/day
Scenario 1: Corresponding Fuel Cell Efficiency	United States	100%	343	29	251	21	243	20
		75%	257	21	188	16	182	15
		50%	171	14	125	10	122	10
		25%	86	7	63	5	61	5
	Michigan	100%	10	1	8	1	7	1
		75%	8	1	6	1	5	1
		50%	5	1	4	1	4	1
		25%	3	1	2	1	2	1
Scenario 2: Constant Fuel Cell Efficiency (40%)	United States	100%	311	26	311	26	313	26
		75%	233	19	233	19	235	20
		50%	155	13	155	13	157	13
		25%	78	6	78	6	78	7
	Michigan	100%	9	1	9	1	9	1
		75%	7	1	7	1	7	1
		50%	5	1	5	1	5	1
		25%	2	1	2	1	2	1

Source: Model calculations.

7.5 Discussion and Conclusions

7.5.1 Hydrogen Demand

The results show that whether electricity generation from fuel cells remains constant or increases during the forecast period, hydrogen demand decreases from 2006 to 2026. The major cause of this decline is the replacement of less efficient fuel cells to more efficient fuel cells after their 10-year usable life is over. More efficient fuel cells consume less hydrogen to produce the same amount of energy as less efficient fuel cells. While increased efficiency of fuel cells will help make the technology more desirable to consumers, it may reduce the total demand for hydrogen from fuel cells. This is especially true if the market demand for fuel cells does not experience significant growth. Based on our calculations, a 1% increase in fuel cell efficiency leads to a 2.5% decrease in hydrogen needed to power the fuel cell.

7.5.2 Model Limitations

While providing hydrogen demand estimates, the Model has several limitations. The Model relies exclusively on data provided by the EIA for fuel cell market penetration and electricity generation estimates. Therefore, the hydrogen demand estimates are skewed towards EIA projections. The Model assumes that all fuel cells installed in a given year have the same fuel cell efficiency. In reality, fuel cells from different manufacturers will have different efficiencies.

7.5.3 Major obstacles to widespread adoption of fuel cells in DG

Fuel cell costs are a major obstacle for widespread adoption in the DG marketplace. Current fuel cell capital costs are up to $4,000/kW. The fuel cells used in the Park today cost approximately $3,200/kW. These costs are approximately four times more than ICE generators and two times more than microturbines, both of which are competing technologies. Both cost and technological advancements are expected for fuel cells. However, competing technologies will also become more economically and technologically viable in the future.

According to NETL, costs must be reduced by a factor of ten to approximately $400/kW to allow fuel cells to "transcend niche market status and become a preferred option in a broad range of energy applications" (National Energy Technology Laboratory 2003).

A technical limitation to widespread market penetration today is the limited power output of fuel cells. The majority of fuel cells used for DG applications are under 1 MW. This prevents fuel cells from being used in larger scale DG applications. However, larger fuel cell systems are being developed for 5 MW applications (NAE 2004).

Reliability and durability issues surrounding fuel cells must be resolved to provide a viable market alternative to current DG technologies. One of the major reasons for use of DG units is to improve reliability (see §3.9 for discussion of reliability issues with Park). In backup/emergency power applications, users must be confident that their DG unit operates when needed. As fuel cell technology matures, reliability issues may be improved.

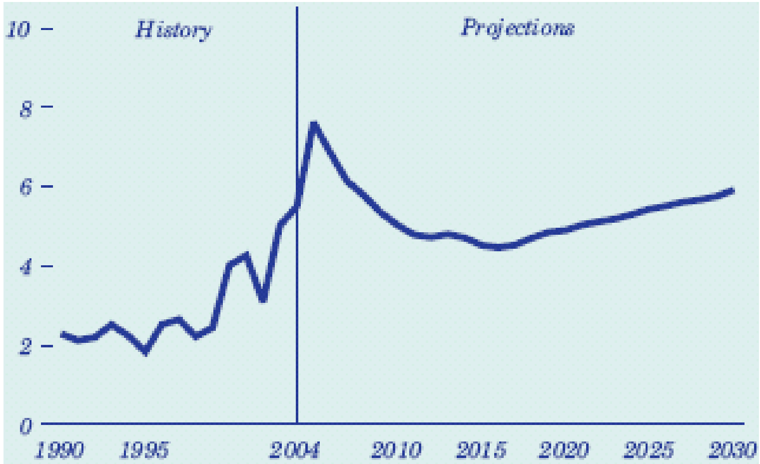
The number of competing technologies in the DG market presents a challenge for widespread adoption of fuel cells. The current market consists of both mature technologies and new technologies, such as fuel cells, microturbines, and solar photovoltaics. There are many factors that may impact the distribution of technologies in the DG market. These include the economic viability of technologies, performance ability of technologies, the availability of alternatives, such as utilizing grid electricity, and overall market conditions. This leads to uncertainty for both consumers and manufacturers and in evaluating market potential for each technology.

7.5.4 Limitations of EIA AEO Projections

There are many limitations to the EIA AEO projections of distributed generation. First, the model only examines DG in CHP applications. While CHP applications make DG more viable for consumers, the exclusion of non-CHP applications may underestimate the total market for DG. Second, the model suggests that natural gas will be used as the primary feedstock for hydrogen production. There is no discussion of hydrogen produced from electrolysis. Currently, hydrogen produced from natural gas is cheaper than electrolysis. However, this excludes potential increases to hydrogen production costs from higher natural gas prices, lower production costs of electrolysis-produced hydrogen, and implications of environmental regulation on hydrogen prices. Third, the AEO projects solar photovoltaics to provide a major source of growth for DG. Given the higher costs associated with PV, other sources may supersede PV. This may lead to higher usage of fuel cells.

7.5.5 Natural Gas Prices

Natural gas prices will influence the market growth of DG since natural gas is a primary fuel for many DG technologies. This has become a greater concern recently because of large increases in the price of natural gas. The entire DG market may be impacted by natural gas prices. EIA predicts natural gas prices to decrease from their current level over the next 9-10 years (Figure 7-5), a result of the development of new natural gas supplies and slower consumption growth (EIA 2006c).



Note: This figure and all projections in AEO2006 use 2004 as the reference point for future analysis.
Source: EIA 2006c.

Figure 7-5: Lower 48 states natural gas wellhead prices (2004$ per thousand cubic feet)

Fuel cells may gain market share if natural gas prices continue to rise in the future, assuming that natural gas is not used as a primary feedstock in hydrogen production. According to one study, a 4.9 to 22.4% increase in natural gas prices would reduce the DG market by 32%. On the other hand, if gas prices were to fall to historic 1990s levels, the DG market may increase up to 92% (McNamara 2005).

8 Hydrogen Market Analysis

8.1 Introduction

While Chapters 7 and 9 focus primarily on future demand forecasts, DTE Energy is also interested in examining the current market for hydrogen and determining the feasibility of entering the hydrogen production and distribution marketplace today. An analysis of the feasibility of entering the Southeast Michigan hydrogen market was conducted to determine if hydrogen produced from the Park could be sold today. DTE Energy would sell its hydrogen as pressurized gas in cylinders dispensed through the Park. Given our analysis of hydrogen costs from the Park, a major focus is a cost/price analysis to determine if hydrogen produced by the Park would be cost competitive in this market.

Hydrogen produced from the Park today is considered pure hydrogen because of its 99.995% purity levels. We analyzed both the market for hydrogen of any purity and pure hydrogen. For purposes of the study, any hydrogen produced through electrolysis is considered pure hydrogen, although purity levels vary depending on electrolysis source. Hydrogen produced through steam reformation is not as pure as hydrogen produced through electrolysis.

8.2 Merchant Market for Hydrogen

8.2.1 Market Overview

Approximately 8.165 billion kg (90 billion normal cubic meters or 3.2 trillion standard cubic feet) of hydrogen are consumed annually in the United States. Captive hydrogen, which is consumed at the place of manufacture, accounts for approximately 85% or 6.804 billion kg of the total hydrogen market. The remaining 15% or 1.361 billion kg is sold to consumers and is considered to be merchant hydrogen (National Hydrogen Association 2006). Although the future hydrogen economy focuses on the use of hydrogen in energy applications, the majority of hydrogen consumed today is for chemical applications rather than energy applications.

Hydrogen produced from electrolysis represents a small percentage (4%) of the total hydrogen market (Air Products 2006). This amounts to a total pure hydrogen market size of approximately 54 million kg. One of the major applications of pure hydrogen is to prevent oxidation in the manufacturing of semiconductors.

The major producers of merchant hydrogen in the U.S. are Air Products and Chemicals Inc., Air Liquide Group, Praxair Inc., and the BOC Group. These companies operate approximately 90 plants dedicated to the production of merchant hydrogen in the U.S. (DOE 2002).

8.2.2 Methodology

The price of merchant hydrogen to end consumers varies greatly depending on production method, hydrogen purity, geography, delivery method, and volume. We initially attempted to obtain price comparisons for pure hydrogen from major producers in Michigan to determine a target price point for DTE Energy. However, given the factors mentioned above and the unwillingness of companies to provide price data to a potential competitor, we were unable to gain this information. Therefore, a comparison of hydrogen production cost estimates will be used to provide a proxy for the market. Several government studies have examined the production costs of hydrogen from various methods. Two main studies used in this Chapter include: *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* authored by the National Academy of Engineering ("NAE") in 2004 and *Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis,* authored by Simbeck and Chang. Simbeck and Chang also authored portions of the NAE study.

For comparison, we used the DTE-C levelized cost of hydrogen (*LCOH*) of $21.32/kg from Chapter 3.

8.2.3 Cost of Merchant Hydrogen produced by natural gas reformation

The majority of hydrogen today is produced by steam methane reformation at large plants. Steam reformation utilizes steam to separate hydrogen from a hydrocarbon feedstock, such as natural gas. Natural gas reformation accounts for approximately 48% of reformation, followed by oil at 30% and coal at 18% (Air Products 2006).

NAE estimates that hydrogen produced by natural gas reformation at a central plant with a production capacity of 1,200,000 kg/day and distributed via pipeline to end consumers costs $1.99/kg including distribution and dispensing costs. This estimate uses a cost of $4.50/MMBtu for natural gas (NAE 2004). Natural gas costs represent $0.75/kg or approximately 37% of the total cost of hydrogen. Natural gas prices are significantly higher today. The industrial price for natural gas in January 2006 was $11.14/MMBtu or 2.5 times greater than the cost of $4.50/MMBtu used in the NAE estimates (EIA 2006c). If we raise the natural gas feedstock cost per kilogram from $0.75/kg by a factor of 2.475 to $1.86/kg and keep all other costs constant, the new cost of hydrogen would be $3.10/kg.

The cost of hydrogen produced at the Park ($21.32/kg) is 6.8 times higher than hydrogen produced from natural gas reformation at a centralized plant ($3.10/kg). Given the large economies of scale of major hydrogen producers and low hydrogen production costs, DTE Energy would not be able to compete in the traditional merchant hydrogen market. DTE Energy realizes this and instead wants to focus on the niche market segment of pure hydrogen.

8.2.4 Hydrogen produced by electrolysis

Simbeck and Chang's study estimates costs of electrolytic hydrogen based on production of 1,000 kg/day in a centralized plant vary from $8.27 to $9.92/kg (Table 8-1). The study utilizes 2002 US dollars and assumes natural gas prices of $5.50/MMBtu. The costs were adjusted to reflect 2005 US dollars by using an inflation conversion factor of 0.921, which was derived from the Consumer Price Index (Shari 2006).

Table 8-1: Costs of electrolysis produced hydrogen by various distribution methods from a centralized plant (2005$/kg)

	Liquid Tanker Truck	Gas Tube Trailer	Pipeline
Production	$6.70	$5.75	$5.57
Delivery	0.20	2.27	3.19
Dispensing	1.38	1.09	1.16
Total	**8.27**	**9.11**	**9.92**

Source: Simbeck and Chang 2002.

Simbeck and Chang also analyzed distributed production pathways, similar to the Park, to evaluate potential economic advantages of placing small modular units at fueling stations. In their analysis, each unit is designed to produce 470 kg/day of hydrogen with a 70% utilization rate. Their analysis shows that hydrogen produced from electrolysis is two to three times more expensive than methanol, natural gas, and gasoline feedstocks (Table 8-2). Although these numbers may be higher than estimated in Table 8-2 due to higher natural gas and gasoline prices, we still do not believe that electrolysis would be cost competitive with these traditional feedstocks.

Table 8-2: Costs of hydrogen produced at distributed facilities by feedstock

Feedstock	2005$/kg
Methanol	$4.92
Natural Gas	4.78
Gasoline	5.43
Water (using electrolysis)	13.16

Source: Simbeck and Chang 2002.

Ivy conducted a review of the electrolytic hydrogen production systems commercially available as of December 2003. The study was updated in 2005 to provide cost estimates in 2005 US dollars. Ivy estimated electrolytic hydrogen produced at a rate of 1,000 kg/day costs $4.15/kg (Ivy 2004). NAE provides a cost of $6.58/kg for distributed onsite production of electrolytic hydrogen (NAE 2004). §3.6 provides further discussion of electrolysis production cost estimates.

Table 8-3 summarizes the various costs estimates (excluding transportation and dispensing costs) and compares them to the cost of hydrogen production for the Park.

Table 8-3: Summary of cost estimates of electrolytic hydrogen

Source	Production Method	$/kg
Simbeck and Chang	Centralized production	$5.57-6.70
Simbeck and Chang	Distributed production	13.16
NAE	Distributed production	6.58
Ivy	Distributed production	4.15
Model calculations	Distributed production	21.32

Source: Ivy 2004, Model calculations, NAE 2004, Simbeck and Chang 2004.

8.3 DTE Energy Internal Hydrogen Use

DTE Energy wanted the Team to examine the potential for providing hydrogen produced from the Park for internal applications within DTE Energy. DTE Energy uses hydrogen internally for applications such as generator cooling. The Fermi 2 Nuclear Power Plant, located near Newport, MI, used approximately 3,254 kg of hydrogen for generator cooling in 2005. Data on hydrogen usage in other DTE Energy power plants was unavailable.

The production costs of hydrogen from the Park ($21.32/kg) are much greater than the purchase price of hydrogen at Fermi (the DTE Energy purchase price of hydrogen is not disclosed for confidentiality reasons). Therefore, this does not appear to be a potentially viable market at the current time. In the future, DTE Energy may look to strategic siting of future HTPs near demand sources to eliminate hydrogen transportation costs and provide a steady demand source of hydrogen.

8.4 Discussion

The above analysis demonstrates that DTE Energy would not be cost competitive in either the market for both hydrogen produced by natural gas reformation or pure hydrogen. The primary reason for this conclusion is the high cost of Park hydrogen compared to other cost estimates.

Cost is just one factor which limits the viability of market entrance. Another factor which would limit the viability is DTE Energy's unfamiliarity in the merchant hydrogen market. DTE Energy would have to identify customers in the Southeast Michigan region, determine price points, and develop an infrastructure for hydrogen distribution. DTE Energy may be able to gain expertise and lower costs in the future but at the current time this presents a major obstacle.

Another market barrier is the economies of scale of major hydrogen producers. The large-scale hydrogen providers have an established customer base, familiarity with hydrogen production, and an established distribution system. Even if the large-scale hydrogen production costs were comparable to those of DTE Energy, the lower distribution costs might provide a competitive advantage to these producers. Distribution costs of hydrogen may double the costs of hydrogen (DOE 2005c).

The Park design is also a limiting factor in market entrance. The Park was designed as a distributed hydrogen production system for on-site hydrogen dispensing, not as a centralized production facility. One of the major advantages of a distributed production system is the reduction of distribution costs. However, utilizing the Park as a central hydrogen generation system eliminates this advantage. Production costs are lowest at centralized plants because of economies of scale and lower feedstock and electricity prices. Simbeck and Chang state that "utilizing the hydrogen produced at the forecourt [distributed production] to fuel on-site power generation during initial low hydrogen demand does not make economic sense" (Simbeck and Chang 2002).

Additionally, larger scale electrolysers are commercially available, which would lead to lower hydrogen production costs. The largest commercially available electrolyser unit sold produces approximately 380,000 kg of hydrogen annually. The Hydrogenics IGEN 30 electrolyser installed in the Park is capable of producing approximately 24,000 kg of hydrogen annually. Capital costs will be lower for larger production units – ranging from 32% of total hydrogen costs in a 1,000 kg/day unit to 55% in a 100 kg/day unit (Ivy 2004).

A final market barrier to DTE Energy's entrance into the hydrogen market is the proximity of major hydrogen production plants of competitors. Air Products has a hydrogen production plant in Midland, MI (located 123 miles from the Park) that produces approximately 311,700 kg of hydrogen annually. Praxair operates a plant in Ecorse, MI (20 miles from the Park) that produces approximately 598,464 kg of hydrogen annually(The Innovation Group 2006). DTE Energy would have to compete directly with both Air Products and Praxair in the Southeast Michigan hydrogen market.

Although no opportunities currently exist for HTP hydrogen production and distribution in the merchant market, DTE Energy should continue to evaluate this market. If DTE Energy is able to reduce hydrogen production costs and demand for hydrogen increases, this may allow entry to the merchant hydrogen market.

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9 Transportation Applications

9.1 *Introduction*

Hydrogen use in motor vehicles is seen as a potential long-term solution to the environmental and national security concerns that arise from the use of petroleum as a transportation fuel. According to Energy Information Administration ("EIA") data, transportation accounts for 28% of total energy use and 68% of petroleum use in the US. Light duty vehicles (LDVs, defined as cars and trucks under 8,500 pounds), which have been the focus of research into hydrogen-fueled transportation, account for 58% of petroleum use in transportation (EIA 2006c). This petroleum use is a concern because finished motor gasoline produces 17% of U.S. greenhouse gas emissions and a significant percentage of other air pollutants (CBO 2002), while 65% of US oil is imported (EIA 2006c), and global dependence on oil from the Middle East and other unstable regions is expected to increase over time. If hydrogen replaces petroleum as a vehicle fuel, it has the potential to reduce greenhouse gas emissions because it emits no CO_2 when combusted or used in a fuel cell, and it can be produced from renewable energy sources that do not generate significant levels of CO_2. As a transportation fuel, hydrogen can also improve energy security because it can be produced using domestic energy sources such as coal, nuclear, and renewables.

Any transition to a hydrogen-dominated transportation market will be a long-term process, requiring substantial technology and infrastructure development. DTE Energy's Hydrogen Technology Park provides a potential design for hydrogen refueling stations, and is being used to test the viability of distributed electrolysis as a means of meeting transportation demand for hydrogen.

In this Chapter, vehicle types and relevant characteristics are reviewed, then several scenarios are examined for the adoption of hydrogen within the light duty vehicle market. Finally, the application of the scenarios, their outcomes, and implications are discussed.

9.2 *Vehicle types and characteristics*

Any future vehicles using hydrogen, such as fuel cell or internal combustion engine vehicles, will face competition from a range of other vehicle types including standard internal combustion engine vehicles, hybrid electric vehicles, and biofuel and natural gas vehicles.

9.2.1 Conventional Internal Combustion Engine Vehicle (ICE)

Conventional internal combustion engine vehicles currently account for virtually all light-duty vehicles on the road. They are generally fueled by gasoline or diesel fuel, which is combusted to create mechanical energy that is transferred to the wheels. Energy efficiency is relatively low, with gasoline engines converting only about 30% of the fuel's chemical energy into usable mechanical energy in the engine. CO_2 emissions per unit of fuel are 8.9 kg per gallon of gasoline (CBO 2002), so a vehicle with the fleet average fuel economy of 20.25 miles per gallon (EIA 2006c) would emit approximately 44 kg of CO_2 every 100 miles, or 5,274 kg of CO_2 yearly if driven 12,000 miles (approximately the average yearly mileage in the U.S.).

9.2.2 Conventional Hybrid-Electric Vehicles (HEV)

Hybrid-electric vehicles combine an internal combustion engine with a battery-powered electric motor and a variety of other technologies to improve fuel economy. Current HEVs have substantially better fuel economy than ICEs, but this comes at an additional $2,000-$4,000 cost per vehicle (Freeman 2005). Although the fuel savings typically do not make up for the additional purchase costs, hybrids have made substantial inroads into the U.S. automobile market. Nearly 200,000 hybrids (1.2% of the light duty vehicle market) were sold in 2005 (EIA 2006c), while Toyota, Honda, Ford, and other manufacturers plan to increase production dramatically by 2010. Currently, a variety of policymakers, businesses and individuals are advocating research into modified “plug-in” hybrid vehicles that will be able to go 30-50 miles before using the onboard internal combustion engine, thus increasing vehicle fuel efficiency to 80 or more miles per gallon but requiring additional energy from the electricity grid (The Economist 2006).

9.2.3 Hydrogen Fuel Cell Vehicles (FCV)

Hydrogen fuel cell vehicles use hydrogen to generate electricity, which is then used to run an electric motor to power the drive train. Current hydrogen fuel cell vehicles are produced at very small volumes and cost approximately ten times as much to produce as ICEs. With technological improvements and the use of mass production, however, it may be possible to bring costs down to levels similar to ICEs (Wee 2006). There are a range of hurdles that successful market entry of hydrogen fuel cell vehicles must overcome, from dramatic improvements in the durability and range of the vehicles themselves, to the development of a fueling infrastructure that can support FCVs. Assuming these improvements are made, FCVs may have dramatically better tank-to-wheels fuel efficiency and environmental impacts than ICEs. The only major direct emission of FCVs is water vapor as hydrogen fuel combines with oxygen in the fuel cell. If the hydrogen fuel is produced using renewable resources such as biomass, wind, or solar, then environmental impacts can be greatly reduced and greenhouse gas and other airborne emissions cut to virtually nothing. FCV tank-to-wheels fuel efficiency in production models is expected to be between 2 and 2.5 times greater than a conventional internal combustion engine (DOE 2006c). Total well-to-wheels energy efficiency and airborne emissions will depend on the source of the hydrogen. Efficiency and emissions specific to the HTP are discussed above in §3.7.

Currently, fuel cells require an extremely pure hydrogen supply to prevent damage to the fuel cell membrane. As noted in Chapter 8, this type of hydrogen is relatively expensive to obtain, and it is not widely distributed at present. In light of this, provision of pure hydrogen is an area where HTPs may have an advantage over other types of hydrogen production. The hydrogen stock produced by the Park is 99.995% pure H_2, cleaner than both the 99.9% DOE 2005 target and 99.99% 2015 target for microporous and dense metallic membrane hydrogen purification systems (DOE 2006c).

9.2.4 Hydrogen Internal Combustion Engine (H_2ICE)

A hydrogen-fueled internal combustion engine also uses hydrogen as a fuel, but burns it in a modified internal combustion engine. H_2ICEs are much easier and less expensive to produce than FCVs because they are based on established technology, and do not require the hydrogen fuel to be as pure as in FCVs. However, they are much less fuel efficient than

FCVs and emit more nitrogen oxides. The Ford Model U concept car, for example, is only 25% more fuel efficient than a gasoline ICE vehicle (Ford Motor Company 2006), compared with FCVs that are more than two times as efficient as conventional ICEs. H_2ICE vehicles can also be set up as "flex-fuel" vehicles like the BMW 745h, which can run on either conventional gasoline or hydrogen, although this requires two separate fuel systems within the car.

9.2.5 Biofuel Vehicles

Over 5% of LDVs sold in 2005 can use a mixture of gasoline and a biologically-based fuel such as ethanol (EIA 2006c). Vehicles can also use a mixture of conventional and bio-based diesel fuel. While vehicles running on E85 (a blend of 85% ethanol and 15% gasoline) are about 25% less fuel efficient than conventional ICEs, (DOE, cited in Lundegaard 2006) they emit fewer net greenhouse gases due to the renewable nature of the fuel, and fewer pollutants overall. For example, one study estimates that using E-85 instead of gasoline in a midsize passenger car can reduce life cycle greenhouse gas emissions by 41-61% (Kim and Dale 2005). As of this writing, General Motors has been particularly active in promoting vehicles that run on E-85.

9.2.6 Natural Gas Vehicles (NGV)

Alternative fuel vehicles may also use either compressed natural gas or liquefied petroleum gas. These NGVs currently comprise 0.5% of the total light-duty vehicle stock, and according to EIA projections may gradually increase to 1.1% of total vehicle stock by 2025 (EIA 2006c). Most of these vehicles are classified as "bi-fuel" vehicles that can use natural gas and another fuel. As a result, the market share of natural gas as a transportation fuel is actually smaller than the percentage of vehicles that can use it. Total natural and liquid propane gas consumed is projected to be only 0.31% of light-duty vehicle energy consumption in 2005, rising to 0.58% by 2025 (EIA 2006c). Because of this low anticipated adoption rate (due in part to the nature of refueling, expense of natural gas, and continued concerns about greenhouse gas emissions and other pollutants), these vehicles are not dealt with in this study.

9.3 Fleet Penetration Scenarios

9.3.1 Primary scenarios

One of the goals that the Department of Energy established in connection with the Park was to evaluate the feasibility of constructing 1,000 HTPs per year with each HTP ultimately serving 2,000 fuel cell vehicles, although there is no defined time by which these milestones should be reached (Gronich 2005).[2] This assumes as many as 2 million additional FCVs per year will enter the market, equivalent to 10-12% of total annual light-duty vehicle sales depending on year (EIA 2006c). For comparison, alternative vehicles (HEV, NGV, and biofuel) accounted for 7.65% of LDV sales in 2005 (EIA 2006c), although HEVs and biofuel

[2] 2,000 vehicles per refueling station is in line with current national average gasoline station vehicle service levels (Melaina 2005). However, it should be noted that vehicles served per gasoline station varies dramatically depending on station density, vehicle density and vehicle use patterns. This is discussed in further detail in Melaina (2005) and in §9.6.

vehicles do not require the substantial changes to fueling infrastructure necessary to service a large number of FCVs.

Rather than developing and defending an independent model for FCV adoption, the Project team elected to use FCV adoption rates established in other studies, with slight modifications (as discussed below in §9.4.1) to adjust for more recent data and the DOE 2,000 vehicles per HTP / 1,000 HTPs per year guideline. Of the limited number of scenarios available, we selected those in the Department of Energy's *Multi-Year Research, Development and Demonstration Plan* ("DOE scenario," or "DOE-M" for the scenario as modified for this Project) and the National Academy of Engineering's *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* ("NAE scenario," or "NAE-M" for the scenario as modified for this Project). The original Department of Energy scenario was chosen as a result of DTE Energy's interest in using DOE figures wherever possible to facilitate required reporting to the DOE. The original NAE scenario was chosen because it coincidentally fits the 2,000 vehicles per HTP / 1,000 HTPs per year guideline prior to the 2026 end date set by DTE Energy for this analysis. In addition to these scenarios, the Project team developed an analysis of the fleet vehicle and H_2ICE markets for hydrogen at DTE Energy's request.

It should be noted that both the DOE and NAE scenarios are "optimistic," as pointed out in NAE 2004:

> *In this analysis, it is assumed that many problems of hydrogen use in vehicles are solved: low-cost and durable fuel cells are available; high density of energy storage on vehicles allows reasonable range and quick refilling of the vehicles; vehicles have the same functionality, reliability, and cost associated with their gasoline-fueled competitors; hydrogen-fueled vehicles are as safe as gasoline-fueled vehicles.*

As a result, these scenarios predict that a substantially larger number of FCVs will be sold than is estimated by other baseline estimates, such as in the EIA's Annual Energy Outlook. For example, NAE projects that FCVs will account for 1% of new vehicle sales in 2015 and grow quickly after that, while EIA (2006) projections hold FCVs below 0.5% of new vehicle sales through 2030.

The original DOE and NAE scenarios contain a substantial number of assumptions that are not evaluated by this Project. The NAE points out that substantial problems must be overcome with fuel cell vehicle technology before its scenario becomes likely: "Costs are still a factor of 10 to 20 times too expensive, these fuel cells are short of required durability, and their energy efficiency is still too low for light-duty vehicle applications. Accordingly… the solutions to overcoming these challenges are uncertain" (NAE 2004). If hydrogen is stored onboard a vehicle at the current storage standard of 5,000 psi, for example, 6 kg of hydrogen (approximately the amount needed to provide a 300 mile driving range, which is a DOE goal (DOE 2004)) would require a 63-gallon tank:

120 MJ/kg H_2 * 6kg / 3 MJ/L H_2 = 270 L * .264 L/gal = 63.4 gallons (conversions from NAE 2004)

This would occupy approximately four times as much space as most existing LDV gasoline fuel tanks. Increased pressure tanks or alternative storage methods such as metal hydrides will be required if storage volume is to shrink, while costs for the overall vehicle fuel cell system will have to come down to the $50-100/kW range from nearly $5,000/kW in 2003 if this is to be a viable option (NAE 2004). If these problems are not overcome within the 20-year timeframe examined by this Project, then it is unlikely that significant adoption of hydrogen in the transportation market will occur during that time.

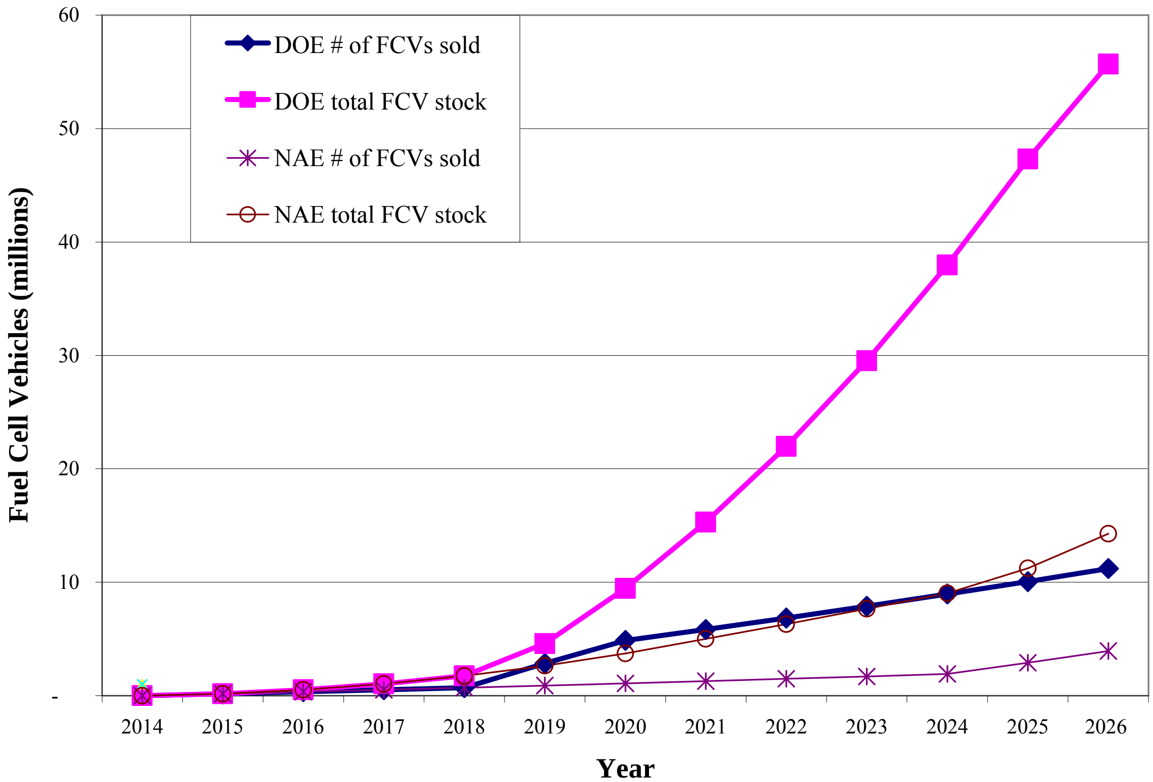
Both of these scenarios, and most of the other optimistic projections for hydrogen use in transportation, share several fundamental characteristics. First, the scenarios focus on the light-duty vehicle market for the environmental and national security reasons discussed in the introduction to this Chapter. Second, projections have assumed that penetration will occur through fuel cell vehicles rather than hydrogen internal combustion engines, because H_2ICEs are comparatively inefficient and have less potential for environmental benefit than FCVs, despite their lower cost. Third, projections rarely include attempts to model other alternative fuel vehicles, such as biofuels or natural gas, in competition with fuel cell vehicles. Finally, both scenarios assume that fuel cell vehicles will be competitive with ICEs, as discussed above, and will have similar usage characteristics such as range and annual VMT. As a result, there may be markets for hydrogen in fleet vehicles, H_2ICEs, or elsewhere that are not addressed by the DOE or NAE scenarios; and the introduction of other alternative fuel vehicles or inferior usage characteristics of FCVs (such as a shorter range, lower reliability, etc) may reduce projected demand for FCVs.

Neither the DOE nor the NAE claim that their scenarios are based on robust models of potential future markets for fuel cell vehicle sales. The DOE scenario assumed that vehicle penetration would begin in 2018 with 4% of light-duty vehicle sales, increasing linearly to 27% of sales in 2020 and again linearly to 52% of sales in 2025, as shown in Figure 9-1, below. It was assumed that hydrogen stations would be in place to meet this demand (DOE 2006c). In an Argonne National Laboratory analysis, this assumption was found to be “well within the range of transportation fuel switch transition rates that have occurred in the U.S. over the last two centuries” (DOE 2006c).

NAE 2004 assumes that an optimistic adoption rate for FCVs could be based on the adoption of HEVs:

> *HEVs provide a best case because the vehicle attributes were similar to those of a standard, high-volume gasoline ICE vehicle; no fueling infrastructure changes were required; the component technologies were relatively mature; the vehicles were viewed as high-tech and environmentally friendly; and tax benefits aided initial price reductions for the consumers*.

The study takes “the most optimistic scenarios” for HEV adoption, which place annual sales at approximately 2 million vehicles after a decade of production, and uses this as a potential FCV adoption scenario. It posits that “FCVs could reach 1% of US sales by 2015, increase by one percentage point per year until 2024 and by five percentage points per year thereafter…” (NAE 2004). NAE projections can be seen in Figure 9-1.



Source: Project Team analysis based on data from NAE 2004, DOE 2006c, EIA 2006c.

Figure 9-1: DOE and NAE Fuel Cell Vehicle Projections

9.3.2 Other scenarios

Although existing scenarios focus on hydrogen use in mass-market light-duty FCVs, there may also be an opportunity to use it in H_2ICEs or in fleet vehicles, particularly in the early years of a transition to a hydrogen economy. DTE Energy requested that the Project team explore these scenarios.

9.4 Methodology

9.4.1 DOE and NAE

This analysis used the annual FCV sales percentages that are applied in the original DOE and NAE scenarios to determine the number of FCVs on the road in a given year, then used these percentages to project demand for hydrogen and number of HTPs in modified scenarios. For the sake of simplicity and to present the best possible financial case, it was assumed that all stations constructed were of the HTP type, and that they would operate at the full anticipated capacity of 2,000 cars in their first year. The number and size of HTPs was then used to calculate hydrogen production cost in the DOE-M and NAE-M scenarios. Somewhat different approaches were taken to examine H_2ICE and fleet vehicle markets, as discussed in §9.4.2 and §9.4.3.

The annual sales percentages for fuel cell vehicles from the original DOE and NAE scenarios were taken as a given, with a modification of the DOE scenario so that FCV market penetration increases by one percent of total LDV sales between 2015 and 2018 (1% of LDV sales in 2015, 2% in 2016, etc.), rather than initiating market entry in 2018 at 4% of sales. For both DOE-M and NAE-M, the number of FCVs sold in a given year FS_t was calculated by applying the annual sales percentages to EIA (2006) projections for total new vehicle purchases in each given year, as shown below. The original DOE and NAE scenarios used earlier EIA fleet size projections, so EIA 2006c projections were used to provide an updated estimate.

$$FS_t = FS\%_t \times VS_t$$

FS_t	FCV annual sales for year *t*
$FS\%_t$	FCV % of total annual LDV sales in year *t*, from DOE 2006c or NAE 2004
VS_t	Total projected annual LDV sales for year *t*, from EIA 2006c

Using these sales numbers, the total number of FCVs on the road in a given year FT_t was calculated by adding the number of FCVs purchased over the previous seven years, assuming that an average FCV would be retired at the end of seven years. FCV vehicle stock $FT\%_t$ as a percentage of total vehicle stock was also calculated:

$$FT_t = FS_t + FS_{t-1} + FS_{t-2} + \ldots + FS_{t-6}$$

$$FT\%_t = FT_t \div VT_t$$

FT_t	Total FCV stock in year *t*
$FT\%_t$	FCV % of total vehicle stock in year *t*
VT_t	Total vehicle stock in year *t*

Next, the total number of FCVs on the road was used to calculate the number of HTPs, HTP_T_t, required to service those vehicles, using the DOE benchmark of 2,000 vehicles per HTP (Gronich 2005). The number of HTPs required to be constructed in a given year was calculated by subtracting the number of HTPs required the previous year from the number of HTPs required during the year in question.

$$HTP\_T_t = FT_t \div Capacity_{HTP}$$

HTP_T_t	Total number of HTPs required in year *t*
$Capacity_{HTP}$	Average total vehicle capacity of an HTP, given as 2,000 by DOE

The amount of hydrogen required per station per day (D_{Daily}, kg/day, as in §3.3.2, above) was then calculated as follows:

- Average FCV miles driven per kg of hydrogen in a given year, $mpkg_t$, was calculated assuming that FCV energy efficiency is a constant 2.25 times greater than in ICEs (DOE 2004) as ICE fuel efficiency increases at 1% per year from 21 mpg in 2002 to

26.7 mpg in 2026 (NAE 2004). The energy content of one kg hydrogen is approximately equal to the energy content of one gallon of gasoline, giving the following equation:

$$mpkg_t = mpg_t \times EFF$$

$mpkg_t$	Average FCV miles traveled per kilogram of hydrogen in year t
mpg_t	Average ICE miles traveled per gallon of gasoline in year t, from EIA 2006c
EFF	Energy efficiency of FCVs relative to ICEs, given as 2.25 in NAE 2004

- The average amount of hydrogen required per vehicle per year, $H_{Vt,}$ was then calculated with the following equation, using the original DOE and NAE scenario assumptions that FCVs will operate similarly to other cars on the road (between 12,000 and 13,000 miles per year in 2015-2025, per EIA 2006c):

$$H_{VT} = VMT_t \div mpkg_t$$

H_{Vt}	Average hydrogen required per vehicle in year t, in kg
VMT_t	Average vehicle miles traveled in year t, from EIA 2006c

- The annual amount of hydrogen per vehicle was multiplied by the 2,000 vehicle per HTP benchmark, then divided by 365 days per year to find daily demand per station:

$$D_{Daily} = H_{Vt} \times Capacity_{HTP} \div 365$$

In addition to the total number of HTPs and the annual and average daily hydrogen demand per HTP, total FCV vehicle miles traveled and market demand for hydrogen were calculated. Total FCV VMT was calculated by multiplying total FCVs by number of miles per vehicle in a given year (12-13,000 mi, as given above). Total annual FCV hydrogen demand was calculated by multiplying the amount of hydrogen required per vehicle by the total number of FCVs as estimated above.

The average daily demand for hydrogen per HTP was run as the demand input for the Model discussed in Chapters 3-5. Because the Project team assumed that each HTP would serve a full complement of 2,000 vehicles in its first year, the full amount of hydrogen demand per HTP was inserted into the first modeled year of HTP operations (Year 1). The targeted load factor (*LF*, discussed in §3.3.2) for the HTP was assumed to be 70%, to account for a 20% weekday to weekend surge, 10% seasonal surge, and a 10% statistical surge (Melaina 2005).[3] This represents "the upper limit of utilization under 'real-world' conditions, assuming a sufficient number of hydrogen vehicles are operating within the HTP's service area" (Melaina 2005). In addition, the Model's future scenario (DTE-F, see §3.5.2) was used because market demand does not develop until 2015. It was assumed that no hydrogen would be used for electricity generation, so the "Hydrogen Only" Model configuration was used.

[3] This does not include 17 days/year offline included by Melaina, which is assumed to be included in the "Availability" factor A_E included in the Model, as discussed in §3.3.2.

The learning curve and scaling factor included in the Model were applied assuming that 100 electrolysers and dispensers had been produced by 2015. The Model was then used to determine the number of electrolysers and hydrogen dispensers required per HTP given daily demand D_{Daily} in a specific year. These numbers were multiplied by the total number of stations HTP_T_t required that year to determine total number of electrolysers and dispensers required. These totals were then included in the scaling and learning curve components of the Model, and the Model was run to determine the *LCOH* for that year.

These calculations and model runs were repeated to determine the *LCOH* for each year between 2015 and 2026.

9.4.2 H_2ICE

To model potential H_2ICE demand for hydrogen, it was assumed that H_2ICEs would be the only hydrogen fueled vehicle to achieve market penetration, and best-case scenario H_2ICE sales would match NAE's projected FCV market penetration. In order to directly compare the results of this scenario with those of other scenarios, it was also assumed that the time scale for H_2ICE adoption is identical to that assumed for FCVs in the NAE scenario. All calculations are identical to those done in the previous scenarios, with the exception that H_2ICE efficiency vs. conventional ICEs is 1.25, rather than the 2.25 times greater efficiency used for fuel cells.

9.4.3 Fleet Vehicle Market

Rather than developing a scenario for hydrogen fuel cell use among centrally fueled fleet vehicles (such as corporate fleets), hydrogen costs were projected for individual centrally fueled fleets of various sizes with an estimated gasoline-equivalent mpg of 25.1 (identical to NAE 2004 estimate of average vehicle mpg in 2020). This method was chosen because fleets differ substantially in size, resulting in dramatically different HTP usage rates. Fleet demand for hydrogen was determined based on a 7-day driving week and 26,000 annual miles driven (Davis 2004). The cost of hydrogen was found using the Model's future scenario (DTE-F, see §3.5.2) with the assumption that the cumulative production of 1,000 electrolysers and dispensers have been factored into the learning curve. In addition, a 90% load factor (*LF*) was assumed because capacity utilization would be higher than for a neighborhood hydrogen fueling station.

9.5 Results

Table 9-1 provides select results from the above calculations for FCVs in the DOE-M and NAE-M scenarios, as well as H_2ICEs. Table 9-2 provides select results from fleet vehicle calculations.

Table 9-1: Select Results of DOE-M, NAE-M, and H_2ICE Scenarios - Future

	DOE-M			NAE-M – Base Case			H_2ICE		
	2015	2020	2026	2015	2020	2026	2015	2020	2026
Total # of H_2 vehicles	171,644	9.5M	55.7M	171,644	3.7M	14.2M	171,644	3.7M	14.2M
Total # of HTPs	86	4,732	27,841	86	1,860	7,137	86	1,860	7,137
Additional HTPs /yr	86	2,432	4,178	86	540	1,521	86	540	1,521
Total kg H_2 demand	38M	2,070M	11,845M	38M	813M	3,036M	69M	1,464M	5,465M
Annual kg H_2/HTP	448,402	437,391	425,437	448,402	437,391	425,437	807,122	787,303	765,786
Avg kg H_2/ day/HTP	1,228	1,198	1,166	1,228	1,198	1,166	2,211	2,157	2,098
H_2 cost/kg	$10.11	$9.06	$8.75	$10.11	$9.26	$8.99	$9.30	$8.55	$8.36
Annual fuel cost/vehicle	$2,266	$1,981	$1,861	$2,266	$2,026	$1,911	$3,753	$3,364	$3,200
Fuel cost/mi	$0.19	$0.16	$0.15	$0.19	$0.16	$0.15	$0.31	$0.27	$0.25

Source: Project team analysis based on DOE 2004 and NAE 2004; Model calculations.

Table 9-2: Select Results of Fleet FCV and Fleet H_2ICE - Future

	FCV				H_2ICE			
Fleet Size	10	50	100	500	10	50	100	500
Kg H_2 demand/yr	4,600	23,002	46,003	230,015	8,281	41,403	82,806	414,028
Kg H_2 demand/day	13	63	126	630	23	113	227	1,134
H_2 cost/kg	$24.44	$13.94	$12.07	$9.30	$20.20	$12.24	$10.55	$8.60
Annual fuel cost/vehicle	$11,245	$6,411	$5,554	$4,276	$16,729	$10,138	$8,738	$7,120
Fuel cost/mi	$0.43	$0.25	$0.21	$0.16	$0.36	$0.22	$0.19	$0.15

Source: Project team analysis based on NAE 2004; Model calculations.

9.6 Sensitivity Analysis

There is uncertainty about the future operating characteristics of FCVs and LDVs that were used as parameters of this analysis, such as vehicle miles traveled, fuel economy, and vehicle life. In light of this, an analysis was conducted to determine how different vehicle and demand characteristics would affect the cost of hydrogen.

Increasing vehicle life affects scenario outputs only for years 2022-2026, because FCVs do not enter the market until 2015 and have an assumed vehicle life of seven years. Increasing the assumed vehicle life to 12 years (approximately the average lifespan for conventional ICEs, per NAE 2004) and holding new vehicle sales and other factors constant increases the number of FCVs on the road in 2026 in the NAE-M scenario from 14.3 million to 16.9 million, and the total number of HTPs required that year from 7,137 to 8,456. The number of HTPs required to be built that year rises by 445 from 1,521 to 1,966. This increases the total amount of hydrogen demanded for transportation from 3.04 billion kg to 3.60 billion kg. The total number of FCVs in 2025 in the DOE-M scenario increases to 60.3 million, with a need for 30,141 HTPs (5,604 built that year) to meet a total hydrogen transportation demand of 12.82 billion kg. This compares with approximately 170,000 gasoline stations in the US today (Melaina 2005). However, these numbers do not change the amount of hydrogen demanded per HTP. They also have little impact on cost, reducing the cost of hydrogen per kg in 2026 by three cents per kg to $10.99/kg in the NAE-M scenario, and one cent to $8.74/kg in the DOE-M scenario as a result of diminishing returns to the learning curve at those already high levels of production.

The actual energy efficiency of fuel cell vehicles relative to ICEs in the next 10 to 20 years is also uncertain. This is in part because FCVs may be driven differently from conventional ICEs, and partly because FCVs may use more electricity-consuming accessories than ICEs (NAE 2004). For example, a higher proportion of FCVs may be driven in cities than ICEs, or have additional on-board navigation and other equipment. Most estimates range from 2 to 2.5 times as efficient as ICEs (see, for example, NAE 2004, DOE 2004, Arthur D. Little 2002). As shown in the chart below, the difference in efficiency has a noticeable effect on demand and cost of producing hydrogen.

Table 9-3: Future Sensitivity of Hydrogen Demand and Cost to FCV Efficiency

	2.0x ICE Efficiency		2.5x ICE Efficiency	
	2020	% change from base+	2020	% change from base+
Average daily kg H_2 per HTP	1,348	+12.5%	1,078	-10.0%
H_2 cost/kg	$9.12	-1.5%	$9.40	+1.5%
Annual fuel cost/vehicle	$2,244	+10.8%	$1,850	-8.7%
Fuel cost/mi	$0.18	+10.8%	$0.15	-8.7%

+Base = NAE-M results, year 2020: 1,198 kg H_2 per HTP, $9.26/kg, $2026/vehicle, $0.16/mi.
Source: Project team analysis based on NAE 2004; Model calculations.

Another area of uncertainty occurs because the number of vehicles per HTP will not be a uniform 2,000 vehicles per station, as assumed in the base DOE-M and NAE-M scenarios. In any future hydrogen transportation infrastructure, there will be a wide range of demand per station due to a varying number of vehicles per station, differences in vehicle miles traveled or other operating characteristics, and changing vehicle demand over time. In addition, there will be demand surges during the day (addressed in §3.3.3) and weekly and seasonal variation (addressed in §9.4.1), which have already been included in the base DOE-M and NAE-M transportation scenarios. We explore differing vehicle demand over time and differing demand per station in the paragraphs below.

The most significant change in FCV demand for hydrogen over time will likely occur because HTPs will be built prior to the existence of demand for hydrogen, in order to encourage demand growth. This will result in underutilization of HTPs for a period of time after construction (Melaina 2005). There is substantial uncertainty about the levels of underutilization that will be associated with HTP build-out in advance of demand, but for the case of a sensitivity analysis, it was assumed that HTPs will have a five year ramp-up to their full target capacity of 2,000 vehicles. It was assumed that they would reach 15% of this target (300 vehicles) in their first year, 35% (700 vehicles) in the second, 65% (1300 vehicles) in the third, 85% (1,700 vehicles) in the fourth, and 100% in the fifth year. This results in the cost of hydrogen in the NAE-M scenario increasing by about 1.3% in 2015, to $10.24/kg. Similarly, the cost for new stations will rise 1.2% in 2020, to $9.37/kg; and 0.4% in 2026 to $9.03. The primary reason why this cost increase is so small is that after ramp-up, the HTP operates at full capacity for 16 years of its 20-year life, so underutilization is relatively brief. Thus, the Model suggests that construction of HTPs in advance of demand will have only a small effect on the price of hydrogen.

Stations may also encounter demand that is substantially higher or lower than the 2,000 vehicles driving 12,000-13,000 miles annually assumed in the base DOE-M and NAE-M transportation scenarios above. Melaina (2005), for example, discusses early hydrogen fueling station sizes ranging from 100 kg per day to 2,500 kg per day. For this analysis, station sizes of 1,500 and 2,500 were evaluated for comparison to the NAE-M scenario base case. It was assumed that the total market size was identical to the base case, so a reduced number of vehicles served by one station would be compensated by an increased number at another station. As a result, the total number of electrolysers and fuel dispensers (and their resulting learning curve and scale effects) remained identical to the NAE-M scenario base case. As demonstrated by the results in Table 9-4 below, the substantial change in demand has a very limited effect on cost of producing hydrogen. This is primarily because at these high levels of output, the capital requirements for electrolysers and other equipment are largely varying in proportion with the number of vehicles the station is expected to serve.

Table 9-4: Future Hydrogen cost/kg variance with demand

	1,500 vehicles per station			2,500 vehicles per station		
	2015	2020	2026	2015	2020	2026
Daily kg H_2 demand	921	899	874	1,536	1,498	1,457
H_2 cost/kg	$10.42	$9.58	$9.31	$9.85	$9.04	$8.79
% change in cost from base	+3.1%	+3.5%	+3.6%	-2.6%	-2.4%	-2.2%

Source: Project team analysis based on NAE 2004; Model calculations (based on NAE-M, year 2020).

Finally, changes in vehicle miles traveled affect the amount of hydrogen demanded in a limited fashion. A 10% increase in annual VMT in 2020 from 12,360 mi to 13,596 mi results in a 2.9% reduction in the price of hydrogen, from $9.26/kg H_2 to $8.99/kg H_2. A 10% decrease in annual VMT in 2020 to 11,124 mi results in a 3.1% increase in the price of hydrogen to $9.55/kg H_2. This scenario assumes HTP inputs, such as electricity rate, remain constant

9.7 Discussion and Conclusions

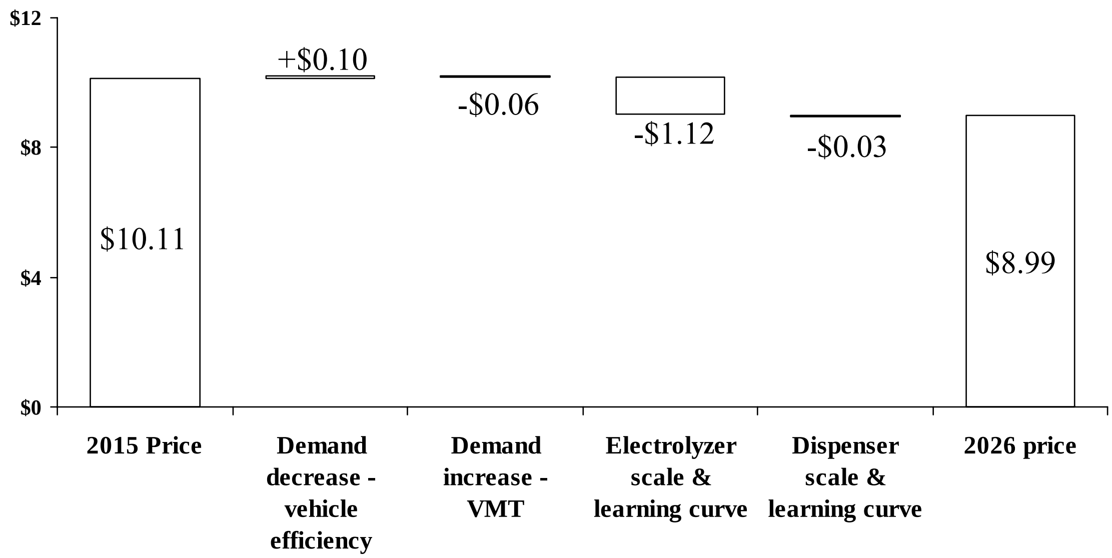
9.7.1 General

If the basic assumptions in these scenarios about energy costs and production costs of hydrogen hold true over time, then the cost of producing hydrogen in an HTP for transportation use appears infeasible. Assuming that FCVs are 2.25 times more energy efficient than ICEs, production costs of \$9.26/kg H_2 in 2020 equate to approximately \$4.12 per gallon of gasoline. This is well above the NAE assumed production costs of \$1.63-\$3.51/kg H_2 by 2020 (NAE 2004). Given this cost, even a substantial carbon tax of \$0.50 per gallon of gasoline does little to raise gasoline costs enough to make hydrogen competitive unless there is a substantial increase in the price of gasoline caused by other factors.

It may be unrealistic to assume that any imposed carbon tax would help narrow the gap between the cost of hydrogen and competing fuels, particularly given the results above in Table 3-16. This table demonstrates that using grid electricity at an HTP to produce hydrogen for FCVs results in approximately 2.7 times the CO_2 emissions of gasoline ICEs. This raises the concern that FCVs could actually contribute to additional climate change emissions unless carbon sequestration or renewable energy is used to address this concern. However, these alternatives would be likely to increase the cost of hydrogen production further.

Learning curve effects over time as modeled here are significant, resulting in approximately a 10% decrease in hydrogen production costs between 2015 and 2026. However, these reductions are not sufficient to bring hydrogen production costs down to where electrolysis-produced hydrogen may viably compete with gasoline. The individual factors affecting cost over time are broken out in Figure 9-2, which demonstrates that the single largest factor affecting the cost of hydrogen over time is the decline in costs due to electrolyser scale and learning curve efficiencies. This is primarily because of the large number of electrolysers required per HTP (86 per HTP in 2026), high cost per unit (\$24,465 per unit or \$2.1 million per station in 2026 under the NAE-M scenario), and number produced (625,000 by 2026).[4]

[4] It should be noted that in reality, a smaller number of higher-volume electrolysers is likely to be used. This was accounted for in the Model's scaling factor, as discussed in §3.4.2.



Source: Model calculations.
Note: Totals and segments do not add due to rounding.

Figure 9-2: Change in Cost of Hydrogen Due to Vehicle Demand, Scale and Learning Effects, 2015-2026 (NAE-M Scenario)

Note that the projection for hydrogen demand per HTP is identical between the DOE-M and NAE-M scenarios. This is because the number of vehicles per HTP is fixed at 2,000, so demand per HTP is dependent only on VMT and vehicle efficiency, which are identical between the two scenarios. In addition, demand remains fairly constant over time, declining by 5% per station between 2015 and 2026. This is because of the 2,000 vehicle peg and the fact that increasing demand due to growing VMT is more than countered by decreasing demand due to improved vehicle efficiency.

9.7.2 DOE-M

The rate of HTP construction in the DOE-M scenario reaches the DOE benchmark established in conjunction with the DTE Energy HTP project of 1,000 HTPs per year serving 2,000 vehicles each in about 2018, then rapidly exceeds the benchmark.[5] As a result, certain assumptions have to be relaxed: either HTPs must be able to serve as many as 4,000 vehicles (with construction at 1,000 HTPs/yr starting in 2014, the year before DOE expects to make a hydrogen commercialization decision per DOE 2004), construction must happen more rapidly than 1,000 HTPs per year (with a minimum of 3,000 to 4,000 HTPs constructed per year for several years prior to 2026), a lower growth rate must be considered, or some combination of these factors.

It is unlikely that the average number of vehicles per HTP will exceed 2,000 for several reasons. First, construction is likely to occur well in advance of demand in order to stimulate

[5] It should be noted that the DOE scenario is one hypothetical scenario for market adoption of hydrogen, while the 1,000 stations/2,000 vehicles benchmark was established independent of that scenario.

growth of the FCV market as noted above in §9.6, and actual demand is unlikely to be predicted well enough to permit construction immediately prior to the emergence of need (see Melaina 2005 for discussion of hydrogen infrastructure buildout). Second, physical plant space becomes a significant constraint when dispensing volumes above 1,000 kg of hydrogen per day, as noted above in §0, and HTPs serving 2,000 vehicles would already be over the 1,000 kg mark by 10-20%.

Exceeding the proposed construction rate by three to four times also may not be feasible. When producing enough hydrogen for 2,000 vehicles, the Model projects that a capital investment on the order of $11.1 million per HTP would be required in 2020 (using the NAE-M scenario), or a substantial $33.3 billion annual investment to construct 3,000 HTPs. Such an investment may be particularly difficult to justify in the early years of any transition to a hydrogen economy, given the likely uncertainties involved.

9.7.3 NAE-M

The lower growth rate explored in the NAE-M scenario meets the 2,000 vehicles/HTP and 1,000 HTPs/year construction rate criteria, while still "represent[ing] an optimistically fast rate of penetration of hydrogen vehicles into the marketplace" (NAE 2004). However, the NAE-M scenario still retains the problematically high cost of hydrogen and large capital influx for construction, as discussed above.

9.7.4 Other Scenarios – H_2ICE

Because of the low relative fuel efficiency of hydrogen internal combustion engines, particularly when electricity to hydrogen energy conversion efficiencies are included, H_2ICEs are substantially less attractive than FCVs both from a fuel cost and an environmental standpoint. If H_2ICEs are 1.25 times more efficient than conventional ICEs, then the functional equivalent to a gallon of gasoline will cost approximately $6.84 in 2020 (NAE-M scenario). In addition to being substantially more costly than fueling a FCV, high-purity hydrogen is unnecessary in H_2ICEs, so the one real advantage that an HTP has over competing forms of hydrogen production disappears.

9.7.5 Other Scenarios – Fleet Use

Due to the small amount of hydrogen demanded by fleets, cost per kg of hydrogen is greater than the broader market scenarios due to a lack of economies of scale. The costs for small fleets – $24.44/kg or more for fleets of 10 or fewer vehicles – appear to be extraordinarily prohibitive. Larger fleets of 500 LDVs see a substantial reduction in cost to $9.30/kg, but costs remain much higher than the cost of gasoline

10 Joint Electricity-Transportation demand

10.1 Introduction

One of the reasons why the DTE Energy HTP project was designed to create hydrogen for both vehicle fueling and electricity generation was that this joint use may reduce the average cost of producing hydrogen further than either application could do alone. Given the extremely high costs noted in Chapters 3 and 4 for both electricity and hydrogen fuel generation at the HTP, it was not expected that a joint application would reduce costs enough to make commercialization viable. Nonetheless, an effort to determine the cost effect of such a joint application given the above electricity and vehicle transportation scenarios was made.[6]

10.2 Methodology & Results

The NAE 2004 report and other scenarios suggest that there will be much greater demand for hydrogen in transportation applications than for hydrogen used to generate electricity. Given the limited projected demand for electricity generation from hydrogen, we assumed that approximately 100 HTPs would each be used to produce 5,000 kW of electricity per day in addition to transportation demand. This electricity generation component was added to the hydrogen demand in the NAE-M scenario in the Park Model, the total additional number of electrolysers required was calculated, and a weighted average targeted load factor (*LF*) of approximately 76% was calculated assuming a targeted electricity load factor of 100%, and a targeted vehicle load factor of 70% (see §9.4.1). This combined demand results in the following costs for hydrogen fuel and fuel cell-generated electricity:

Table 10-1: Future LCOH and LCOE for Hydrogen+Fuel Cell Configuration (NAE-M and DTE-F)

	2015	% change from base[+]	2020	% change from base[+]	2026	% change from base[+]
Fuel Cost/ kg H_2	\$9.19	-9.1%	\$8.47	-8.5%	\$8.24	-8.3%
Electricity cost/kWh	\$0.80	-3.6%	\$0.76	-8.4%	\$0.74	-10.8%

[+]Fuel base cost/kg from Table 9-1, NAE-M scenario. Electricity base cost/kWh of \$0.83/kWh, based on D_{FC} = \$0.83/kw 5,000 kWh and cumulative electrolyser production of 1,600. Cf. Table 4-3, Table 4-5.
Source: Model results.

10.3 Discussion

The combination of vehicle fueling and electricity production results in a 9.1% reduction in the cost of producing hydrogen fuel in 2015 (Model year 1), while the cost of fuel cell electricity

[6] Note that inputs for this scenario are based on the values given for transportation in Chapter 9, rather than the default values used to calculate costs under the Hydrogen+Fuel Cell Configuration with the DTE-F scenario in §3.5.2.

initially declines by 3.6%. This is primarily a result of the shift in *LF* for both fuel and electricity.

The percent reduction in cost of both electricity and vehicle fuel changes over time as a result of learning curve and scaling effects associated with the electrolyser. The hydrogen fuel cost shift from 9.1% lower than base cost in 2015 to 8.3% lower in 2026, for example, occurs because in 2015 the addition of electricity production increases the needed cumulative electrolyser production by 20% over the number needed for transportation, from 7,910 to 9,510. By 2026, however, cumulative production has increased by only 0.3%, from 625,105 to 626,705, because no additional electrolysers have been built for electricity production due to lack of demand growth. The opposite occurs with electricity production, where the dramatic growth in production of electrolysers to meet vehicle demand drives costs down over time.

Ultimately, however, the costs of both hydrogen vehicle fuel and fuel cell generated electricity remain much higher than the market is likely to bear. Substantial cost savings will have to be found in other areas if HTPs are to be competitive with other fuels and electricity sources.

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11 Conclusions

Conclusion 1: The HTP's cost of hydrogen is higher than costs estimated in other studies

This study estimates that using the DTE Energy Hydrogen Technology Park's costs and technical performance data, the cost of hydrogen ranges from \$12.33/kg H_2 for an HTP with the capacity to produce 1,200 kg H_2/day (approximately the amount required to serve as a neighborhood hydrogen filling station) to \$21.32/kg H_2 for a 100 kg H_2/day HTP (approximately twice the current Park's capacity). In the future, with technical and cost improvements, the cost of hydrogen may fall to a range of \$7.90/kg H_2 for a 1,200 kg H_2/day HTP to \$11.91/kg H_2 for a 100 kg H_2/day HTP. The results indicate that an HTP-style facility would need significantly improved cost structures, technologies, and design architectures to competitively supply the hydrogen economy. Advances in scalability will also be needed to ensure that the HTP's physical size requirements and electric grid demands are compatible with the constraints of residential neighborhoods.

These results, derived from a single demonstration site installed in 2004, are much higher than estimates derived from other electrolysis hydrogen engineering-economic models. Generally, the other studies use more recent data and optimistic assumptions for equipment performance and costs, scaling factors, and O&M. As newer electrolyser and hydrogen equipment become commercially available and are implemented and tested, this study should be updated with newer data to reflect the hydrogen industry's progress.

Conclusion 2: Distributed electrolysis production of hydrogen may create substantial greenhouse gas emissions

The Model estimates that, using current technologies and DTE Energy's grid as the source of electricity, HTP activities emit 55.1 kg CO_2 per kg of H_2 produced. This emission intensity is approximately 6.8x that of combusting motor gasoline. These results are high because of the energy intensive nature of hydrogen electrolysis using the Park's technology (70.4 kWh/kg H_2) and the high proportion (79.4%) of coal-fired electricity in DTE Energy's fuel mix. While technical progress in electrolyser efficiency will help reduce emissions, these results also highlight the important role renewable energy must play in any hydrogen economy scenario. Without significant investments in reducing the electricity grid's emissions intensity, electrolysis hydrogen production will not be environmentally sustainable.

Conclusion 3: Reducing capital costs and improving reliability are the highest development priorities

Model results indicate that greatest driver of lower cost of hydrogen are lower capital costs. Reliability is the often overlooked but second critical area for hydrogen equipment engineering. Current technologies require extensive human monitoring and intervention. These result in high O&M costs directly affect the cost of hydrogen. Progress in system reliability must be made to make hydrogen a viable fuel source. Model results suggest system efficiency, by itself, is of tertiary importance, if initial costs and reliability are not improved.

Conclusion 4: Using hydrogen for energy storage and electricity generation is not economical

Based on the current Park configuration, there is currently no economical application for utilizing the Park for energy storage and conversion to electricity during on-peak hours. The difference between the levelized cost of electricity at daily generation levels of 5,000 kWh ($2,090/MWh) and the Average High Peak Daily Price ($109.18) is $1,980.82. Therefore, on-peak electricity prices would need to be 19.1x higher than current prices in for DTE Energy to economically store hydrogen and convert to electricity during peak hours at the Park. Given the relative inefficiency of the current Park system in electricity conversion (5.3 kWh of electricity is needed to produce 1.0 kWh of fuel cell electricity in the Park), the use of the system for utility-scale electricity generation is not economically viable for the Park.

Conclusion 5: The hydrogen market is not attractive for DTE Energy's entrance through HTP applications

From our analysis of both the transportation and non-transportation sectors, the current market for hydrogen is not attractive for DTE Energy given the high costs of hydrogen produced through electrolysis based on the current Park configuration. The demand for hydrogen in the transportation sector is non-existent now for hydrogen prototype vehicles. According to NAE, commercialized hydrogen vehicles are not expected to gain significant market share until 2015. Although there is a larger market for hydrogen used by fuel cells in the distributed generation sector, this market is not expected to experience significant growth for about 20 years. EIA estimates that electricity generated from fuel cells in distributed generation applications will only increase from 0.151 billion kWh in 2006 to 0.152 billion kWh in 2026. This amounts to less than 1% of the total electricity generation predicted by EIA in the commercial and residential building sectors. Additionally, given the high costs of hydrogen produced at an HTP, DTE would not be able to compete in a competitive marketplace.

Conclusion 6: HTP costs of hydrogen production are prohibitively high for use in fuel cell vehicles and hydrogen internal combustion engine vehicles.

Based on market size projections from NAE, hydrogen costs reach $8.99/kg H_2 in 2026. This is approximately two and a half to five times larger than the cost of hydrogen for transportation use anticipated by DOE and NAE studies for fuel cell vehicle adoption. These costs suggest that the HTP model for distributed hydrogen generation by electrolysis will have limited use in the transition to a hydrogen economy unless there is substantial technological improvement.

Recommendations for further study:

The Park represents a "first of a kind" project integrating a number of hydrogen technologies. Engineering and economic optimizations of the HTP should be considered to improve future designs. For example, 24 hour/day hydrogen production may be advisable depending on the relative cost of capital versus operating costs.

The scenarios used to project hydrogen demand for vehicles anticipated that distributed electrolysis is likely to be one of the most expensive means of producing hydrogen. It may be worthwhile for DTE Energy to explore other hydrogen production technologies, such as centralized electrolysis and natural gas reformation.

Most scenarios for estimating hydrogen demand in the transportation market are incomplete because they do not include the effects of competition from biofuels. Because biofuels address many of the same environmental and national security concerns as hydrogen, the effects of biofuels on the adoption of hydrogen fuel should be studied.

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13 Appendices

13.1 DTE Hydrogen Technology Park Model

The pages are an extract of the Model's Excel spreadsheet with a daily hydrogen dispensing demand of 1,200 kg H_2 and daily demand of fuel cell electricity of 5,000 kWh/day. Due to the manner in which Excel recalculates the spreadsheet, it is possible that subsequent runs on the same input data may produce slightly different values for *LCOH* and *LCOE*, with variances of plus or minus a few cents. Because of space constraints, only the first ten years of the Model are presented.

Assumptions

CONTROLS / SUMMARY RESULTS

Scenario	0	0=DTE-C, 1=DTE-F	Hours of operation per day	
Use learning curves	0	1=Yes, 0=No	Off-peak	16
Use scaling factors	1	1=Yes, 0=No	On-peak	0
			Total	16

	Levelized Cost of Energy		Initial Capex		Efficiency (Output Energy/Electricity Input)	
Hydrogen	$11.86	/kg	$21,007,284		47.2%	70.4 kWh/kg H2
Electricity	$2.09	/kWh	$2,355,200	$3,765 /kW	18.9%	5.3 kWh/kWh fuel cell
	98	x off-peak	Total $23,362,484			

EQUIPMENT ASSUMPTIONS

	Model input	Scenario 0 DTE-C	Scenario 1 DTE-F	Notes
ELECTROLYSER				
Engineering				
Model	Hydrogenics IGEN 30			
Efficiency with compression (%)	47.2%	47.2%	59.6%	DTE measurement, Sept 2005 cycle
Power (kW/unit)	99			DTE measurement
Availability	90.0%	90.0%	90.0%	DTE estimate, % of time system functions when requested
Targeted load factor	100.0%	100.0%	100.0%	Annual load factor as % of installed capacity
Production rate (kg/h)	1.35	1.35	1.35	DTE measurement
Useful Life (yr)	10			Spec - note the Conversion sheet is hard-wired for 10 yrs useful life
Costs				
Price per 1.35 kg/h unit (base)	$225,000	$225,000	$225,000	DTE estimate. Price is before scaling/learning.
Warranty expense ($/yr/unit)	$5,000			DTE estimate
Learning Curve				
Current cumulative production	-		5	Assumption
Future cumulative production	-		4,000	Assumption
Decrease in cost	0%		-10%	Assumption
Progress ratio	1.00			
for every multiple of output	-		2.0	Assumption
Scaling Factor				
Scaling Factor	90%	90%	90%	Assumption

Assumptions (2 of 4)

STORAGE CYLINDERS				
Model	ASME-certified steel cylinder			
Capacity (cubic. ft water vol.)	14.5			Spec
Useful Life (yr)	20			Used for depreciation calc only, no replacement
Price per cylinder	$10,000			DTE estimate.
Minimum storage	30%			Assumption. % of daily production.
DISPENSER				
Average fill-up rate (kg/min)	0.39	0.39	2.00	LTU measurement from 6/18/05 to 9/07/05
Dispensing rate/dispenser (kg/h)	23			
Operational hours/day	10			Assumption
Maximum surge fill-up rate				
As a multiple of dispensing rate	4			Assumption, used in storage and dispenser calcs
Useful life (yr)	20			Value affects depreciation calculation only
Price per dispenser	$55,000			DTE estimate
Learning Curve				
Current cumulative production	-		20	Assumption
Future cumulative production	-		4,000	Assumption
Decrease in cost	0%		-10%	Assumption
Progress ratio	1.00			
for every multiple of output	-		2.0	Assumption
BALANCE OF PLANT				
Balance of Plant: Actual Park Costs			Projected Balance of Plant Costs (% of Actual)	
Equipment	$64,000		100.0%	DTE. Includes switchgear and system operation center equipment.
Construction	520,000		66.0%	DTE estimate, simplified design
Site and system design	142,000		100.0%	DTE.
Balance of plant	$726,000			
System design capacity	44.8	kg/day		
Balance of Plant: Projected Costs for 44.8 kg/day HTP				
Equipment	$64,000	$64,000	$64,000	No change
Construction	343,200	343,200	343,200	No change
Site and system design	142,000	142,000	-	No site and system design for future HTP.
Balance of plant	549,200	549,200	407,200	
BOP useful life (yr)	20			
Scaling Factor	75.0%	75.0%	75.0%	
OPERATIONS AND MAINTENANCE				
Staffing/monitoring costs	$114,000	$114,000	$14,000	DTE. Includes $14,000 of system monitoring costs and $100,000 staffing costs

Assumptions (3 of 4)

FUEL CELL					
Model	Plug Power GenCore 5B				
Hydrogen to Electricity Efficiency	40.0%	40.0%	50.0%	DTE measurement	50.0%
Peak power (kW/unit)	4				
Availability	85.0%	85.0%	95.0%	DTE estimate	95.0%
PEM stack useful life (hr)	1,500	1,500	6,000	Warranty spec. Figure may vary based on intensity of use.	6,000
Battery useful life (yr)	3			Spec	
Price per fuel cell unit ($/kW)	$3,200	$3,200	$1,500	DTE estimate	$1,500
($/unit)	$12,800				
Price of replacement stack ($/kW)	$1,125	$1,125	$500	DTE estimate	$500
($/unit)	$4,500				
Price per battery replacement	$200			DTE estimate	
Warranty expense ($/yr/unit)	$528			DTE estimate	

FINANCIAL		
Term (yr)	20	Note that spreadsheet is hard-wired for 20 years.
DTE hurdle IRR	16%	DTE low risk (contract off-take) 11%, mid 16%, higher tier 21%
DTE tax rate	35%	DTE standard value
Debt/capital ratio	50%	DTE standard value. "Mortgage-style" loan.
Cost of debt	7%	DTE standard value
Term of first loan (yr)	15	DTE standard value. Assumes one year grace period on loan.
Term of second loan (yr)	10	This second loan will be used for the electrolyser replacement
Clean-fuel refueling deduction	$30,000	2005 Energy Bill provides $30,000 deduction in first year of hydrogen equipment operation
No decommissioning reserve		Title 26, Subtitle A , Chapter 1 , Subchapter B, PART VI, §179A

GENERAL DEPRECIATION SYSTEM							
Method	200%	declining balance					
Recovery over	7	yr					
Straight line after year	5						
Year	1	2	3	4	5	6	7
Depreciation Rate	29%	29%	29%	29%	33%	50%	100%

Source: IRS, How to Depreciate Property, p. 40

CARBON CREDITS				
Carbon credits	$0	$0	$0	per tonne of CO_2

Assumptions (4 of 4)

CONSTANTS		
Minutes per hr	60	
Hrs per day	24	
Days per year	365	
Peak days per year	260	
MJ/kg of H2	119.6	LHV, Department of Energy (http://www.hydrogen.energy.gov/facts_figures.html)
BTU/kg of H2	113,400.0	LHV, Department of Energy
kg/million BTU	8.8	
MJ/kWh	3.6	
kWh/kg of H2	33.2	at 100% conversion

KEY DATES	
Fiscal year ending December 31	
Initial investment / Period 0	2006
Commissioning (+1 yr) / Period 1	2007
Forecast ends (+20 yr) / Period 20	2026

Electricity Costs and Emissions

	Fiscal year ending December 31, 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DTE ENERGY D6 RATE SCHEDULE (2005)											
Energy charge ($/kWh)											
Off-peak hours (h/day)	16	16	16	16	16	16	16	16	16	16	16
Off-peak energy charge	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131
On-peak hours (h/day)	8	8	8	8	8	8	8	8	8	8	8
On-peak energy charge	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431	$0.02431
Maximum demand charge ($/kW/yr)	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
On-peak billing demand ($/kWyr)	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00	$171.00
Fixed service charge ($/yr)	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300
Weighted average energy charge ($/kWh)		$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131	$0.02131
Total demand charge ($/kW)		$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
Emissions intensity (tonne/MWh)											
CO_2	0.78275	0.78	0.78	0.78	0.78	0.78	0.77030	0.77	0.77	0.77	0.77
NO_X	0.00123	0.00	0.00	0.00	0.00	0.00	0.00069	0.00	0.00	0.00	0.00
SO_2	0.00399	0.00	0.00	0.00	0.00	0.00	0.00298	0.00	0.00	0.00	0.00
Particulate matter	0.00006	0.00	0.00	0.00	0.00	0.00	0.00004	0.00	0.00	0.00	0.00

Source: DTE Energy. Emissions estimates are based on 2004 actual emissions and 2012 projections. Assumes same on-peak demand year-round.

Hydrogen Production and Storage

Cashflow forecast IRR	16%
Gap with hurdle IRR	0%

Fiscal year ending December 31,	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DEMAND											
Average Demand (kg/day) - Dispenser		1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Average Demand (kg/day) - Fuel Cell		376	376	376	376	376	376	376	376	376	376
Total (kg/day)		1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576
Required system capacity (kg/day)		1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576
Annual demand (kg)		575,333	575,333	575,333	575,333	575,333	575,333	575,333	575,333	575,333	575,333
Annual demand (MJ)		68,809,800	68,809,800	68,809,800	68,809,800	68,809,800	68,809,800	68,809,800	68,809,800	68,809,800	68,809,800
Electricity demand (MJ)		145,783,475	145,783,475	145,783,475	145,783,475	145,783,475	145,783,475	145,783,475	145,783,475	145,783,475	145,783,475
Electricity demand (kWh)		40,495,410	40,495,410	40,495,410	40,495,410	40,495,410	40,495,410	40,495,410	40,495,410	40,495,410	40,495,410
REVENUE											
Price of hydrogen ($/kg)		$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86
Annual revenues		$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472
SYSTEM SPECIFICATIONS - ELECTROLYSER											
Efficiency with compression (%)	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%	47.2%
Peak power (kW/park)		8,118	8,118	8,118	8,118	8,118	8,118	8,118	8,118	8,118	8,118
Availability	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Production rate (kg/h)	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35
Electrolysers required	0	82	82	82	82	82	82	82	82	82	82
CAPITAL EXPENDITURES											
Electrolysers											
Electrolysers installed	82	units									
Maximum production capacity	1,594	kg per day	99.6	kg per hr for	16	hrs/day					
Years to replacement		10	9	8	7	6	5	4	3	2	1
Units replaced this yr		-	-	-	-	-	-	-	-	-	-
Price per unit (scaled)	$146,345	per unit	$108,403	per kg/hr	$1,478	per kW					
Capital expenditure	$12,000,262										$12,000,262
Book depreciation		$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026	$1,200,026
Book asset value	12,000,262	10,800,236	9,600,210	8,400,184	7,200,157	6,000,131	4,800,105	3,600,079	2,400,052	1,200,026	12,000,262
Tax depreciation		3,428,646	2,449,033	1,749,309	1,249,507	1,041,256	1,041,256	1,041,256			
Tax asset value		8,571,616	6,122,583	4,373,273	3,123,767	2,082,511	1,041,256	-			

Conversion (2 of 3)

Storage cylinders											
Storage cylinders installed	283										
Price per unit	$10,000										
Capital expenditure	$2,830,000										
Book depreciation		$141,500	$141,500	$141,500	$141,500	$141,500	$141,500	$141,500	$141,500	$141,500	$141,500
Book asset value	2,830,000	2,688,500	2,547,000	2,405,500	2,264,000	2,122,500	1,981,000	1,839,500	1,698,000	1,556,500	1,415,000
Tax depreciation		808,571	577,551	412,536	294,669	245,557	245,557	245,557			
Tax asset value		2,021,429	1,443,878	1,031,341	736,672	491,115	245,557	-			
Dispenser											
Dispensers installed	21										
Price per unit	$55,000										
Capital expenditure	$1,155,000										
Book depreciation		$57,750	$57,750	$57,750	$57,750	$57,750	$57,750	$57,750	$57,750	$57,750	$57,750
Book asset value	1,155,000	1,097,250	1,039,500	981,750	924,000	866,250	808,500	750,750	693,000	635,250	577,500
Tax depreciation		330,000	235,714	168,367	120,262	100,219	100,219	100,219			
Tax asset value		825,000	589,286	420,918	300,656	200,437	100,219	-			
Balance of plant											
Equipment	$64,000										
Book depreciation		$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200
Book asset value	64,000	60,800	57,600	54,400	51,200	48,000	44,800	41,600	38,400	35,200	32,000
Tax depreciation		18,286	13,061	9,329	6,664	5,553	5,553	5,553			
Tax asset value		45,714	32,653	23,324	16,660	11,106	5,553	-			
Construction (scaled)	$4,958,022										
System design (expensed)	$142,000										
Total capital expenditure	$21,007,284	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,000,262
Total book asset value	21,007,284	19,604,808	18,202,332	16,799,856	15,397,379	13,994,903	12,592,427	11,189,951	9,787,475	8,384,998	18,982,784
Total book depreciation		1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476
Total tax depreciation		4,585,503	3,275,360	2,339,543	1,671,102	1,392,585	1,392,585	1,392,585	-	-	-
ELECTRICITY											
Energy charge		$862,957	$862,957	$862,957	$862,957	$862,957	$862,957	$862,957	$862,957	$862,957	$862,957
Demand charge		$365,310	$365,310	$365,310	$365,310	$365,310	$365,310	$365,310	$365,310	$365,310	$365,310
Service charge		$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300
Total electricity expense		$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567	$1,231,567
	Average cost of electricity:	$0.0304	/kWh								
CARBON CREDITS											
Carbon credits (at $0/tonne of CO2)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Conversion (3 of 3)

OPERATIONS AND MAINTENANCE											
Warranty expense		$410,000	$410,000	$410,000	$410,000	$410,000	$410,000	$410,000	$410,000	$410,000	$410,000
Fixed expense rate	142,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
Total operating expense	142,000	524,000	524,000	524,000	524,000	524,000	524,000	524,000	524,000	524,000	524,000
CASH FLOW FORECAST											
Revenues	$0	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472
- Electricity	-	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)	(1,231,567)
- Operations and maintenance	(142,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)	(524,000)
- Carbon tax	-	-	-	-	-	-	-	-	-	-	-
- Tax depreciation	-	(4,585,503)	(3,275,360)	(2,339,543)	(1,671,102)	(1,392,585)	(1,392,585)	(1,392,585)	-	-	-
Pre-tax cashflow	($142,000)	$481,401	$1,791,545	$2,727,362	$3,395,802	$3,674,319	$3,674,319	$3,674,319	$5,066,904	$5,066,904	$5,066,904
- Current tax obligation	-	(157,990)	(627,041)	(954,577)	(1,188,531)	(1,286,012)	(1,286,012)	(1,286,012)	(1,773,417)	(1,773,417)	(1,773,417)
After-tax cashflow	($142,000)	$323,411	$1,164,504	$1,772,785	$2,207,272	$2,388,308	$2,388,308	$2,388,308	$3,293,488	$3,293,488	$3,293,488
+ Tax depreciation	-	4,585,503	3,275,360	2,339,543	1,671,102	1,392,585	1,392,585	1,392,585	-	-	-
- Capital expenditures	(21,007,284)	-	-	-	-	-	-	-	-	-	(12,000,262)
Net cashflow	($21,149,284)	$4,908,914	$4,439,864	$4,112,328	$3,878,373	$3,780,893	$3,780,893	$3,780,893	$3,293,488	$3,293,488	($8,706,774)
GAAP INCOME STATEMENT											
Revenues	$0	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472
- Expenses	(142,000)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)	(1,755,567)
- Book depreciation	-	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)	(1,402,476)
EBIT	($142,000)	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428	$3,664,428
- Tax expense	-	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)	(1,282,550)
Net income	($142,000)	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878	$2,381,878
Deferred tax liability	-	1,124,560	1,780,069	2,108,042	2,202,061	2,198,599	2,195,137	2,191,675	1,700,808	1,209,942	719,075
EMISSIONS											
CO_2 (tonne)		31,698	31,698	31,698	31,698	31,698	31,194	31,194	31,194	31,194	31,194
Intensity (kg CO_2/kg)		*55.1*	*55*	*55*	*55*	*55*	*54.2*	*54*	*54*	*54*	*54*
Intensity (kg CO_2/million BTU)		*485.8*	*485.8*	*485.8*	*485.8*	*485.8*	*478.1*	*478.1*	*478.1*	*478.1*	*478.1*
NO_X (tonne)		50	50	50	50	50	28	28	28	28	28
Intensity (kg NO_X/kg)		*0.086*	*0.1*	*0.1*	*0.1*	*0.1*	*0.049*	*0.0*	*0.0*	*0.0*	*0.0*
SO_2 (tonne)		162	162	162	162	162	121	121	121	121	121
Intensity (kg SO_2/kg)		*0.281*	*0.3*	*0.3*	*0.3*	*0.3*	*0.210*	*0.2*	*0.2*	*0.2*	*0.2*
Particulate matter (tonne)		2	2	2	2	2	2	2	2	2	2
Intensity (kg PM/kg)		*0.004*	*0.0*	*0.0*	*0.0*	*0.0*	*0.003*	*0.0*	*0.0*	*0.0*	*0.0*

Fuel Cell Electricity

Cashflow forecast IRR	16%
Gap with hurdle IRR	0%

Fiscal year ending December 31,	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DEMAND											
Average daily demand (kWh/day)		5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average hours of operation (h/day)		8	8	8	8	8	8	8	8	8	8
Peak power requirement (kW/park)		625	625	625	625	625	625	625	625	625	625
Annual demand (kWh/yr)		1,825,000	1,825,000	1,825,000	1,825,000	1,825,000	1,825,000	1,825,000	1,825,000	1,825,000	1,825,000
Annual demand (MJ/yr)		6,570,000	6,570,000	6,570,000	6,570,000	6,570,000	6,570,000	6,570,000	6,570,000	6,570,000	6,570,000
REVENUE											
Price of electricity ($/kWh)		$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09
Annual revenues		$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011
SYSTEM SPECIFICATIONS (from Assumptions)											
Hydrogen to Electricity Efficiency	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Peak power (kW/unit)	4	4	4	4	4	4	4	4	4	4	4
Availability	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
Average power (kW/unit)	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Fuel cells required	-	184	184	184	184	184	184	184	184	184	184
CAPITAL EXPENDITURES											
Fuel cell unit											
Fuel cells installed	184	Maximum power:		626 kW							
Price per fuel cell unit	$12,800										
Capital expenditure	$2,355,200										
Book depreciation		$117,760	$117,760	$117,760	$117,760	$117,760	$117,760	$117,760	$117,760	$117,760	$117,760
Book asset value	$2,355,200	2,237,440	2,119,680	2,001,920	1,884,160	1,766,400	1,648,640	1,530,880	1,413,120	1,295,360	1,177,600
Tax depreciation		672,914	480,653	343,324	245,231	204,359	204,359	204,359			
Tax asset value		1,682,286	1,201,633	858,309	613,078	408,719	204,359	-			
FUEL											
Hydrogen demand (kg)		137,333	137,333	137,333	137,333	137,333	137,333	137,333	137,333	137,333	137,333
Average daily demand (kg)		376	376	376	376	376	376	376	376	376	376
Hydrogen cost ($/kg)		$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86	$11.86
Hydrogen expense ($/yr)		$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534	$1,628,534

Fuel Cell (2 of 3)

OPERATIONS AND MAINTENANCE											
PEM stack replacement											
Hours of operation (h/yr)		536,765	536,765	536,765	536,765	536,765	536,765	536,765	536,765	536,765	536,765
Average number of stacks replaced		358	358	358	358	358	358	358	358	358	358
Total expense		$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294	$1,610,294
Battery replacement											
Years to battery replacement		3	2	1	3	2	1	3	2	1	3
Batteries replaced this yr		-	-	-	184	-	-	184	-	-	184
Price per battery replacement		$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
Total expense		$0	$0	$0	$36,800	$0	$0	$36,800	$0	$0	$36,800
Warranty expense ($/yr/unit)		$528	$528	$528	$528	$528	$528	$528	$528	$528	$528
Fixed expense rate ($/yr)		$97,217	$97,217	$97,217	$97,217	$97,217	$97,217	$97,217	$97,217	$97,217	$97,217
Total operating expense		$1,707,511	$1,707,511	$1,707,511	$1,744,311	$1,707,511	$1,707,511	$1,744,311	$1,707,511	$1,707,511	$1,744,311
CASH FLOW FORECAST											
Revenues	$0	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011
- Hydrogen	-	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)	(1,628,534)
- Operations and maintenance	-	(1,707,511)	(1,707,511)	(1,707,511)	(1,744,311)	(1,707,511)	(1,707,511)	(1,744,311)	(1,707,511)	(1,707,511)	(1,744,311)
- Tax depreciation	-	(672,914)	(480,653)	(343,324)	(245,231)	(204,359)	(204,359)	(204,359)	-	-	-
Pre-tax cashflow	$0	($191,948)	$313	$137,642	$198,935	$276,607	$276,607	$239,807	$480,966	$480,966	$444,166
- Current tax obligation	-	67,182	(110)	(48,175)	(69,627)	(96,812)	(96,812)	(83,932)	(168,338)	(168,338)	(155,458)
After-tax cashflow	$0	($124,766)	$203	$89,468	$129,308	$179,794	$179,794	$155,874	$312,628	$312,628	$288,708
+ Tax depreciation	-	672,914	480,653	343,324	245,231	204,359	204,359	204,359	-	-	-
- Capital expenditures	(2,355,200)	-	-	-	-	-	-	-	-	-	-
Net cashflow	($2,355,200)	$548,148	$480,857	$432,791	$374,539	$384,154	$384,154	$360,234	$312,628	$312,628	$288,708
GAAP INCOME STATEMENT											
Revenues	$0	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011	$3,817,011
- Expenses	-	(3,336,045)	(3,336,045)	(3,336,045)	(3,372,845)	(3,336,045)	(3,336,045)	(3,372,845)	(3,336,045)	(3,336,045)	(3,372,845)
- Book depreciation	-	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)	(117,760)
EBIT	$0	$363,206	$363,206	$363,206	$326,406	$363,206	$363,206	$326,406	$363,206	$363,206	$326,406
- Tax expense	-	(127,122)	(127,122)	(127,122)	(114,242)	(127,122)	(127,122)	(114,242)	(127,122)	(127,122)	(114,242)
Net income	$0	$236,084	$236,084	$236,084	$212,164	$236,084	$236,084	$212,164	$236,084	$236,084	$212,164
Deferred tax liability	-	194,304	321,317	400,264	444,879	475,188	505,498	535,808	494,592	453,376	412,160

Fuel Cell (3 of 3)

EMISSIONS										
CO_2 (tonne)	7,566	7,566	7,566	7,566	7,566	7,446	7,446	7,446	7,446	7,446
Intensity (kg CO_2/kg)	4.15	4.15	4.15	4.15	4.15	4.08	4.08	4.08	4.08	4.08
NO_X (tonne)	11.856	11.856	11.856	11.856	11.856	6.670	6.670	6.670	6.670	6.670
Intensity (kg NO_X/kg)	0.006	0.006	0.006	0.006	0.006	0.004	0.004	0.004	0.004	0.004
SO_2 (tonne)	38.617	38.617	38.617	38.617	38.617	28.829	28.829	28.829	28.829	28.829
Intensity (kg SO_2/kg)	0.021	0.021	0.021	0.021	0.021	0.016	0.016	0.016	0.016	0.016
Particulate matter (tonne)	0.553	0.553	0.553	0.553	0.553	0.407	0.407	0.407	0.407	0.407
Intensity (kg PM/kg)	0.000303	0.000303	0.000303	0.000303	0.000303	0.000223	0.000223	0.000223	0.000223	0.000223

Storage Requirements

Adapted from spreadsheet by Prof. Rob Fletcher, Lawrence Technological University

Storage Demand		
Production hours/day	16	hrs
Consumption hours/day	10	hrs
At most	8	hrs of storage required
Daily demand	1,576	kg H_2
Storage requirement	80%	of daily demand
Total storage	2,871	kg H_2

Redlich-Kwong Equation Inputs		
MW =	2.0158	gm/mol
T_c =	33.2	°K
P_c =	12.830	atmosphers
V_c =	6.50E-05	m^3/mol
Z_c =	0.3061	

R = 8.206E-05 m^3-atm/mol-K

Redlich - Kwong Equations

$$P = \frac{RT}{V_m - b} - \frac{a}{\sqrt{T}V_m\,(V_m + b)}$$

$$a = \frac{0.42748 R^2 T_c^{2.5}}{P_c}$$

$$b = \frac{0.08664 R T_c}{P_c}$$

Redlich - Kwong Equation Values

a = 1.425E-06
b = 1.840E-05

Enter appropriate values into green cells

Starting high pressure =	5700	psi	393.00	atm
Starting medium pressure =	5700	psi	393.00	atm
Starting low pressure =	5000	psi	344.74	atm
Starting high pressure temp =	20	°C	293.15	°K
Starting medium pressure temp =	20	°C	293.15	°K
Starting low pressure temp =	20	°C	293.15	°K
Volume of high pressure tanks =	1769	ft^3	50.092	m^3
Volume of medium pressure tanks =	449.5	ft^3	12.728	m^3
Volume of low pressure tanks =	1885	ft^3	53.377	m^3
Ending high pressure =	5000	psi	344.74	atm
Ending medium pressure =	2000	psi	137.89	atm
Ending low pressure =	1000	psi	68.95	atm
Ending high pressure temp =	20	°C	293.15	°K
Ending medium pressure temp =	20	°C	293.15	°K
Ending low pressure temp =	20	°C	293.15	°K

Tanks (Solver)	
	122
	31
	130
Total	283

Total H_2 kg production =	**-1,271.48**	kg			Daily Demand (kg)	
		Installed Capacity			1,261	Excess capacity
Total H_2 kg production High Bank =	**-126.56**	126.56	10%		126.10	0.46
Total H_2 kg production Medium Bank =	**-194.38**	194.38	15%		189.15	5.23
Total H_2 kg production Low Bank =	**-950.54**	950.54	75%		945.75	4.78
						10.47

Start high pressure		
V m^3/mol	**mol**	**kg**
6.1209E-05	818,384.1	1,649.698676
7.7745E-05	644,313.3	1,298.806651
7.7925E-05	642,831.5	1,295.819746
7.7927E-05	642,815.6	1,295.787624
7.7927E-05	642,815.4	1,295.787278
7.7927E-05	642,815.4	1,295.787274
7.7927E-05	642,815.4	1,295.787274

End high pressure		
V m^3/mol	**mol**	**kg**
6.9778E-05	717,880.8	1,447.104102
8.6159E-05	581,393.1	1,171.972191
8.6359E-05	580,045.9	1,169.256555
8.6362E-05	580,030.3	1,169.225030
8.6362E-05	580,030.1	1,169.224663
8.6362E-05	580,030.1	1,169.224659
8.6362E-05	580,030.1	1,169.224659

Start medium pressure		
V m^3/mol	**mol**	**kg**
6.1209E-05	207,950.1	419.185729
7.7745E-05	163,718.9	330.024641
7.7925E-05	163,342.4	329.265673
7.7927E-05	163,338.4	329.257511
7.7927E-05	163,338.3	329.257423
7.7927E-05	163,338.3	329.257422
7.7927E-05	163,338.3	329.257422

End medium pressure		
V m^3/mol	**mol**	**kg**
1.7445E-04	72,964.9	147.082712
1.9004E-04	66,976.4	135.011057
1.9023E-04	66,911.5	134.880165
1.9023E-04	66,910.8	134.878719
1.9023E-04	66,910.8	134.878703
1.9023E-04	66,910.8	134.878703
1.9023E-04	66,910.8	134.878703

Start low pressure		
V m^3/mol	**mol**	**kg**
6.9778E-05	764,954.9	1,541.996174
8.6159E-05	619,517.2	1,248.822826
8.6359E-05	618,081.7	1,245.929116
8.6362E-05	618,065.0	1,245.895524
8.6362E-05	618,064.9	1,245.895133
8.6362E-05	618,064.9	1,245.895128
8.6362E-05	618,064.9	1,245.895128
Total in storage		2,870.94

End low pressure		
V m^3/mol	**mol**	**kg**
6.9778E-05	764,954.9	1,541.996174
3.5721E-04	149,428.7	301.218325
3.6424E-04	146,544.0	295.403302
3.6429E-04	146,522.7	295.360425
3.6429E-04	146,522.5	295.360109
3.6429E-04	146,522.5	295.360106
3.6429E-04	146,522.5	295.360106
Total in storage		1,599.46

13.2 HTP Pro Forma Financial Projections

HTP Pro Forma Financial Projections

	Fiscal year ending December 31,										
Year:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Period:	0	1	2	3	4	5	6	7	8	9	10
INCOME STATEMENT - No Interest Expense (For Presentation Only, Not Used in Pro Forma)											
Sales											
Hydrogen	$0	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472
Electricity	-	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011
Total sales	-	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483
Cost of goods sold											
Hydrogen	142,000	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567
Electricity	-	3,336,045	3,336,045	3,336,045	3,372,845	3,336,045	3,336,045	3,372,845	3,336,045	3,336,045	3,372,845
Total cost of goods sold	142,000	5,091,613	5,091,613	5,091,613	5,128,413	5,091,613	5,091,613	5,128,413	5,091,613	5,091,613	5,128,413
Gross profit	($142,000)	$5,547,870	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070
EBITDA	($142,000)	$5,547,870	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070
Depreciation											
Hydrogen	-	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476
Electricity	-	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760
Total depreciation	-	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236
EBIT	($142,000)	$4,027,634	$4,027,634	$4,027,634	$3,990,834	$4,027,634	$4,027,634	$3,990,834	$4,027,634	$4,027,634	$3,990,834
Tax expense	$0	$1,409,672	$1,409,672	$1,409,672	$1,396,792	$1,409,672	$1,409,672	$1,396,792	$1,409,672	$1,409,672	$1,396,792
Net operating profit after taxes	($142,000)	$2,617,962	$2,617,962	$2,617,962	$2,594,042	$2,617,962	$2,617,962	$2,594,042	$2,617,962	$2,617,962	$2,594,042

HTP Financials (2 of 4)

HTP Pro Forma Financial Projections

	Fiscal year ending December 31,										
Year:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Period:	0	1	2	3	4	5	6	7	8	9	10
INCOME STATEMENT - Including Interest Expense											
Sales											
Hydrogen	$0	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472	$6,822,472
Electricity	-	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011	3,817,011
Total sales	-	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483	10,639,483
Cost of goods sold											
Hydrogen	142,000	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567	1,755,567
Electricity	-	3,336,045	3,336,045	3,336,045	3,372,845	3,336,045	3,336,045	3,372,845	3,336,045	3,336,045	3,372,845
Total cost of goods sold	142,000	5,091,613	5,091,613	5,091,613	5,128,413	5,091,613	5,091,613	5,128,413	5,091,613	5,091,613	5,128,413
Gross profit	($142,000)	$5,547,870	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070
EBITDA	($142,000)	$5,547,870	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070	$5,547,870	$5,547,870	$5,511,070
Depreciation											
Hydrogen	-	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476	1,402,476
Electricity	-	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760	117,760
Total depreciation	-	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236
EBIT	($142,000)	$4,027,634	$4,027,634	$4,027,634	$3,990,834	$4,027,634	$4,027,634	$3,990,834	$4,027,634	$4,027,634	$3,990,834
Interest expense	$0	$789,920	$754,891	$717,410	$677,305	$634,393	$588,477	$539,347	$486,778	$430,530	$790,353
Pre-tax income	($142,000)	$3,237,715	$3,272,744	$3,310,225	$3,313,529	$3,393,241	$3,439,157	$3,451,487	$3,540,856	$3,597,105	$3,200,482
Tax expense	$0	$1,122,700	$1,145,460	$1,158,579	$1,159,735	$1,187,634	$1,203,705	$1,208,020	$1,239,300	$1,258,987	$1,120,169
Net income	($142,000)	$2,115,014	$2,127,283	$2,151,646	$2,153,794	$2,205,607	$2,235,452	$2,243,466	$2,301,556	$2,338,118	$2,080,313
Dividends	-	4,486,438	3,929,628	3,543,360	3,239,741	3,139,663	3,126,596	3,088,695	2,538,724	2,522,717	2,208,663

HTP Financials (3 of 4)

HTP Pro Forma Financial Projections

	Fiscal year ending December 31,										
Year:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Period:	0	1	2	3	4	5	6	7	8	9	10
CASH FLOW STATEMENT											
Operating activities											
Net income	($142,000)	$2,115,014	$2,127,283	$2,151,646	$2,153,794	$2,205,607	$2,235,452	$2,243,466	$2,301,556	$2,338,118	$2,080,313
Depreciation	-	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236	1,520,236
Change in deferred tax liability											
Hydrogen	-	1,124,560	655,509	327,973	94,019	(3,462)	(3,462)	(3,462)	(490,867)	(490,867)	(490,867)
Electricity	-	194,304	127,013	78,947	44,615	30,310	30,310	30,310	(41,216)	(41,216)	(41,216)
Total change in deferred tax liability	-	1,318,864	782,522	406,920	138,634	26,848	26,848	26,848	(532,083)	(532,083)	(532,083)
Cash from operating activities	($142,000)	$4,954,114	$4,430,041	$4,078,803	$3,812,664	$3,752,691	$3,782,536	$3,790,550	$3,289,710	$3,326,272	$3,068,467
Investing activities											
Capital expenditures											
Hydrogen	($21,007,284)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,000,262)
Electricity	(2,355,200)	-	-	-	-	-	-	-	-	-	-
Total cash from investing	($23,362,484)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,000,262)
Free cash flow	($23,504,484)	$4,954,114	$4,430,041	$4,078,803	$3,812,664	$3,752,691	$3,782,536	$3,790,550	$3,289,710	$3,326,272	($8,931,796)
Financing activities											
Proceeds from equity	$11,752,242	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,000,131
Proceeds from debt/(repayment) - 1st loan	11,752,242	(467,676)	(500,413)	(535,442)	(572,923)	(613,028)	(655,940)	(701,856)	(750,986)	(803,555)	(859,803)
Proceeds from debt/(repayment) - 2nd loan											6,000,131
Dividends paid	-	(4,486,438)	(3,929,628)	(3,543,360)	(3,239,741)	(3,139,663)	(3,126,596)	(3,088,695)	(2,538,724)	(2,522,717)	(2,208,663)
Total cash from financing	$23,504,484	($4,954,114)	($4,430,041)	($4,078,803)	($3,812,664)	($3,752,691)	($3,782,536)	($3,790,550)	($3,289,710)	($3,326,272)	$8,931,796
Increase/(decrease) in cash	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Beginning cash balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Ending cash balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

HTP Pro Forma Financial Projections

	Fiscal year ending December 31,										
Year:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Period:	0	1	2	3	4	5	6	7	8	9	10
BALANCE SHEET											
Assets											
Current Assets											
Cash	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property, plant and equipment, net											
Hydrogen	$21,007,284	$19,604,808	$18,202,332	$16,799,856	$15,397,379	$13,994,903	$12,592,427	$11,189,951	$9,787,475	$8,384,998	$18,982,784
Electricity	2,355,200	2,237,440	2,119,680	2,001,920	1,884,160	1,766,400	1,648,640	1,530,880	1,413,120	1,295,360	1,177,600
Total PP&E	$23,362,484	$21,842,248	$20,322,012	$18,801,776	$17,281,539	$15,761,303	$14,241,067	$12,720,831	$11,200,595	$9,680,358	$20,160,384
Total assets	$23,362,484	$21,842,248	$20,322,012	$18,801,776	$17,281,539	$15,761,303	$14,241,067	$12,720,831	$11,200,595	$9,680,358	$20,160,384
Liabilities and Shareholders' Equity											
Liabilities											
Long-term debt	$11,752,242	$11,284,566	$10,784,153	$10,248,710	$9,675,787	$9,062,759	$8,406,819	$7,704,964	$6,953,978	$6,150,423	$11,290,751
Deferred tax liability	-	1,318,864	2,101,385	2,508,306	2,646,940	2,673,787	2,700,635	2,727,483	2,195,400	1,663,318	1,131,235
Total	$11,752,242	$12,603,430	$12,885,538	$12,757,016	$12,322,727	$11,736,547	$11,107,455	$10,432,447	$9,149,378	$7,813,741	$12,421,986
Shareholders' equity											
Common stock	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$11,752,242	$17,752,373
Retained earnings	(142,000)	(2,513,424)	(4,315,768)	(5,707,483)	(6,793,429)	(7,727,486)	(8,618,630)	(9,463,858)	(9,701,026)	(9,885,625)	(10,013,975)
Total	$11,610,242	$9,238,818	$7,436,474	$6,044,759	$4,958,813	$4,024,757	$3,133,612	$2,288,384	$2,051,216	$1,866,617	$7,738,398
Total liabilities and shareholders' equity	$23,362,484	$21,842,248	$20,322,012	$18,801,776	$17,281,539	$15,761,303	$14,241,067	$12,720,831	$11,200,595	$9,680,358	$20,160,384

13.3 Model Scenario Parameters

13.3.1 Comparison of Hydrogen Costs

Table 13-1 lists the Model parameters used to generate the Model run results presented in Table 3-12.

Table 13-1: Model Parameters for Various Scenarios

Parameter	Worksheet	Cell(s)	DTE–SC	DTE–SF	DTE–C	DTE–F
Scenario	Assumptions	C6	0	1	0	1
Use learning curves	Assumptions	C7	0	1	0	1
On-peak hours	Assumptions	G8	8	8	0	0
Targeted load factor	Assumptions	D26:E26	90%	90%	100%	100%
DTE hurdle IRR	Assumptions	C99	14%	14%	16%	16%
DTE tax rate	Assumptions	C100	0%	0%	35%	35%
Off-peak energy charge	Electricity	D8	$0.07	$0.07	$0.02131	$0.02131
On-peak energy charge	Electricity	D10	$0.07	$0.07	$0.02431	$0.02431
Maximum demand charge	Electricity	D11	0	0	$45.00	$45.00
On-peak billing demand	Electricity	D12	0	0	$171.00	$171.00
Fixed service charge	Electricity	D13	0	0	$3,300	$3,300
Average demand – Dispenser	Conversion	E9:X9	100	100	100	100
Average demand – Fuel cells	Conversion	D10:X10	0	0	0	0

13.4 MISO Day-Ahead Report

Midwest ISO
We manage power.

Day-Ahead Pricing Report

Market Date: 11/03/2005

Peak Hour: HE 19 (EST)

Minimum Hour: HE 04 (EST)

Publish Date: 11/03/2005

Pricing Results	Dollars Cleared	Energy Cleared (MWh)
Fixed	$77,647,765.23	1,459,982.1
Price Sensitive	$2,860,306.88	51,397.0
Physical Total	$80,508,072.11	1,511,379.1
Virtual Bids	$17,108,865.33	332,114.7
Total	$97,616,937.44	1,843,493.8

LMP Prices ($ per MW)

	MISO System	Illinois Hub	Cinergy Hub	Michigan Hub	Minnesota Hub	First Energy Hub
Hour 01	29.81	31.79	31.86	33.06	20.00	32.75
Hour 02	28.35	30.78	30.63	32.00	17.46	31.70
Hour 03	26.96	29.54	29.02	30.71	15.68	30.42
Hour 04	26.03	28.92	28.91	30.05	13.94	29.77
Hour 05	26.21	29.49	28.62	30.72	13.48	30.44
Hour 06	29.26	32.01	32.55	33.27	17.35	32.97
Hour 07	45.23	46.59	46.55	48.47	35.21	48.04
Hour 08	59.50	59.38	50.00	62.47	56.26	61.27
Hour 09	61.45	49.46	44.62	60.79	68.16	58.35
Hour 10	63.42	51.98	58.51	61.45	72.94	59.62
Hour 11	61.26	51.24	53.51	57.42	69.04	55.68
Hour 12	56.32	48.46	49.31	52.94	61.02	52.01
Hour 13	54.70	51.48	50.15	56.43	51.34	55.91
Hour 14	49.98	49.68	42.81	51.75	47.08	51.28
Hour 15	46.33	46.17	38.81	48.10	43.75	47.65
Hour 16	41.71	41.29	36.71	43.02	39.13	42.62
Hour 17	45.19	43.96	40.83	46.46	43.07	46.02
Hour 18	75.08	61.79	66.00	75.79	78.79	70.98
Hour 19	109.28	87.54	97.26	102.25	134.64	99.26
Hour 20	86.77	60.05	68.06	76.58	117.94	71.73
Hour 21	75.37	63.41	68.89	72.83	89.35	69.80
Hour 22	59.45	57.15	48.96	60.65	59.76	59.54
Hour 23	42.15	42.21	36.86	43.98	40.01	43.57
Hour 24	35.74	34.76	34.79	36.21	32.94	35.88

Around the Clock

Low	26.03	28.92	28.62	30.05	13.48	29.77
Average	51.48	47.05	46.43	51.98	51.60	50.72
High	109.28	87.54	97.26	102.25	134.64	99.26

On-Peak (between 0600 and 2200 EST Monday through Friday, excluding holidays)

Low	41.71	41.29	36.71	43.02	35.21	42.62
Average	61.94	54.35	53.81	61.09	66.72	59.36
High	109.28	87.54	97.26	102.25	134.64	99.26

Off-Peak (between 2201 and 0559 EST Monday through Friday, all hours for weekends and holidays)

Low	26.03	28.92	28.62	30.05	13.48	29.77
Average	30.56	32.44	31.66	33.75	21.36	33.44
High	42.15	42.21	36.86	43.98	40.01	43.57

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13.5 *Hydrogen Demand Forecasts*

The following is a depiction of the Model's Excel spreadsheet that was used to calculate hydrogen demand in the U.S. and Michigan. The projections were based on EIA AEO2006 forecasts for fuel cell use in distributed generation applications. **Fuel Cell Electricity Forecasts** provides data on electricity generation from fuel cells directly from the AEO2006 forecast. **Hydrogen to Electricity Efficiency in Fuel Cells** shows data of fuel cell efficiency from AEO2006 forecast and the constant fuel cell efficiency of 40% that was used in Scenario 2. **Hydrogen Demand (in kg) by Fuel Cell Installation Date** shows the annual demand of hydrogen by year of fuel cell installation for the Base Case in Scenario 1. **Total Hydrogen Demand in kg** contains the annual hydrogen demand for all of the scenarios run in the Model.

Fuel Cell Electricity Forecasts (1 of 2)

(Billion kWh)	Reference	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Cell Electricity	1	0.151	0.151	0.151	0.151	0.151	0.151	0.151	0.151	0.151	0.151
Total DG Electricity		8.022	8.234	8.387	8.564	8.831	8.856	8.881	8.904	8.932	8.967
Fuel Cell as % of Total DG		1.88%	1.83%	1.80%	1.76%	1.71%	1.70%	1.70%	1.69%	1.69%	1.68%
Sensitivity Analysis											
Base Case - 5%	2	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143
Base Case - 10%	3	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136
Base Case + 5%	4	0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.158
Base Case + 10%	5	0.166	0.166	0.166	0.166	0.166	0.166	0.166	0.166	0.166	0.166
Base Case + 20%	6	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181
Base Case + 50%	7	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226
Michigan Fuel Cell Forecast											
% of Total U.S. Market		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Michigan Generation	8	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005

Notes

Fuel Cell Electricity Projections are from EIA AEO2006

Reference (B4) is used in Fuel Cell Usage to calculate electricity supplied by fuel cells

Fuel Cell Electricity Forecasts (2 of 2)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(Billion kWh)											
Fuel Cell Electricity	0.151	0.151	0.151	0.151	0.151	0.151	0.151	0.151	0.152	0.152	0.152
Total DG Electricity	9.008	9.053	9.106	9.159	9.224	9.288	9.366	9.442	9.580	9.739	9.950
Fuel Cell as % of Total DG	1.67%	1.66%	1.65%	1.64%	1.63%	1.62%	1.61%	1.60%	1.58%	1.56%	1.53%
Sensitivity Analysis											
Base Case - 5%	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.144	0.144	0.144	0.144
Base Case - 10%	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.137
Base Case + 5%	0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.159	0.159	0.159	0.159
Base Case + 10%	0.166	0.166	0.166	0.166	0.166	0.166	0.166	0.166	0.167	0.167	0.167
Base Case + 20%	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.182	0.182	0.182
Base Case + 50%	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.227	0.227	0.227	0.228
Michigan Fuel Cell Forecast											
% of Total U.S. Market	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Michigan Generation	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005

Hydrogen to Electricity Efficiency in Fuel Cells (1 of 1)

Source:		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2006 AEO EIA Assumptions	"Scenario 1"	39%	41%	44%	46%	49%	49%	49%	50%	50%	50%	50%
Constant Fuel Cell Efficiency	"Scenario 2"	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Source:		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2006 AEO EIA Assumptions	"Scenario 1"	50%	51%	51%	51%	51%	51%	52%	52%	52%	52%
Constant Fuel Cell Efficiency	"Scenario 2"	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Hydrogen Demand (in kg) by Fuel Cell Installation Date (1 of 3)

Fuel Cells Installed	2006	2007	2008	2009	2010	2011	2012	2013	2014
2000	4,536,513	4,536,513	4,536,513	4,536,513					
2001	171,652	171,652	171,652	171,652	171,652				
2002	809,216	809,216	809,216	809,216	809,216	809,216			
2003	1,937,213	1,937,213	1,937,213	1,937,213	1,937,213	1,937,213	1,937,213		
2004	882,781	882,781	882,781	882,781	882,781	882,781	882,781	882,781	
2005	2,967,124	2,967,124	2,967,124	2,967,124	2,967,124	2,967,124	2,967,124	2,967,124	2,967,124
2006	1,212,108	1,212,108	1,212,108	1,212,108	1,212,108	1,212,108	1,212,108	1,212,108	1,212,108
2010					3,332,948	3,332,948	3,332,948	3,332,948	3,332,948
2011						125,599	125,599	125,599	125,599
2012							589,712	589,712	589,712
2013								1,406,042	1,406,042
2014									638,155
2015									
2016									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
Total Hydrogen	12,516,607	12,516,607	12,516,607	12,516,607	11,313,043	11,266,990	11,047,486	10,516,315	10,271,689

Note: Based on Model assumptions, there is no additional fuel cell capacity added from 2007 to 2009 and 2017 to 2019.

Hydrogen Demand (in kg) by Fuel Cell Installation Date (2 of 3)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fuel Cells Installed										
2000										
2001										
2002										
2003										
2004										
2005										
2006	1,212,108									
2010	3,332,948	3,332,948	3,332,948	3,332,948	3,332,948					
2011	125,599	125,599	125,599	125,599	125,599	125,599				
2012	589,712	589,712	589,712	589,712	589,712	589,712	589,712			
2013	1,406,042	1,406,042	1,406,042	1,406,042	1,406,042	1,406,042	1,406,042	1,406,042		
2014	638,155	638,155	638,155	638,155	638,155	638,155	638,155	638,155	638,155	
2015	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330	2,136,330
2016		932,020	932,020	932,020	932,020	932,020	932,020	932,020	932,020	932,020
2020						3,202,244	3,202,244	3,202,244	3,202,244	3,202,244
2021							120,693	120,693	120,693	120,693
2022								583,941	583,941	583,941
2023									1,368,652	1,368,652
2024										630,558
2025										
2026										
2027										
2028										
2029										
2030										
Total Hydrogen	9,440,894	9,160,805	9,160,805	9,160,805	9,160,805	9,030,101	9,025,195	9,019,424	8,982,034	8,974,437

Note: Based on Model assumptions, there is no additional fuel cell capacity added from 2007 to 2009 and 2017 to 2019.

Hydrogen Demand (in kg) by Fuel Cell Installation Date (3 of 3)

	2025	2026
Fuel Cells Installed		
2000		
2001		
2002		
2003		
2004		
2005		
2006		
2010		
2011		
2012		
2013		
2014		
2015		
2016	932,020	
2020	3,202,244	3,202,244
2021	120,693	120,693
2022	583,941	583,941
2023	1,368,652	1,368,652
2024	630,558	630,558
2025	2,054,163	2,054,163
2026		913,222
2027		
2028		
2029		
2030		
Total Hydrogen	8,892,270	8,873,472

Note: Based on Model assumptions, there is no additional fuel cell capacity added from 2007 to 2009 and 2017 to 2019.

Total Hydrogen Demand in kg (1 of 3)

	2006	2007	2008	2009	2010	2011	2012
National Demand							
AEO2006 Projections in Scenario 1							
Base Case	12,516,607	12,516,607	12,516,607	12,516,607	11,313,043	11,266,990	11,047,486
Base Case - 5%	11,928,849	11,928,849	11,928,849	11,928,849	10,725,285	10,679,232	10,459,728
Base Case - 10%	11,341,091	11,341,091	11,341,091	11,341,091	10,137,526	10,091,473	9,871,970
Base Case + 5%	13,104,366	13,104,366	13,104,366	13,104,366	11,900,801	11,854,748	11,635,244
Base Case + 10%	13,692,124	13,692,124	13,692,124	13,692,124	12,488,559	12,442,506	12,223,002
Base Case + 20%	14,867,640	14,867,640	14,867,640	14,867,640	13,664,076	13,618,023	13,398,519
Base Case + 50%	18,394,190	18,394,190	18,394,190	18,394,190	17,190,625	17,144,572	16,925,068
AEO2006 Projections in Scenario 2							
Base Case	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734
Base Case - 5%	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547
Base Case - 10%	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360
Base Case + 5%	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920
Base Case + 10%	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107
Base Case + 20%	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480
Base Case + 50%	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601
Michigan Demand							
Base Case in Scenario 1	375,498	375,498	375,498	375,498	339,391	338,010	331,425
Base Case in Scenario 2	340,312	340,312	340,312	340,312	340,312	340,312	340,312

Total Hydrogen Demand in kg (2 of 3)

	2013	2014	2015	2016	2017	2018	2019	2020
National Demand								
AEO2006 Projections in Scenario 1								
Base Case	10,516,315	10,271,689	9,440,894	9,160,805	9,160,805	9,160,805	9,160,805	9,030,101
Base Case - 5%	9,928,556	9,683,930	8,853,135	8,708,863	8,708,863	8,708,863	8,708,863	8,578,159
Base Case - 10%	9,340,798	9,096,172	8,265,377	8,256,922	8,256,922	8,256,922	8,256,922	8,126,218
Base Case + 5%	11,104,073	10,859,447	10,028,652	9,612,746	9,612,746	9,612,746	9,612,746	9,482,043
Base Case + 10%	11,691,831	11,447,205	10,616,410	10,064,688	10,064,688	10,064,688	10,064,688	9,933,984
Base Case + 20%	12,867,347	12,622,721	11,791,927	10,968,571	10,968,571	10,968,571	10,968,571	10,837,867
Base Case + 50%	16,393,897	16,149,271	15,318,476	13,680,221	13,680,221	13,680,221	13,680,221	13,549,517
AEO2006 Projections in Scenario 2								
Base Case	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734	11,343,734
Base Case - 5%	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547	10,776,547
Base Case - 10%	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360	10,209,360
Base Case + 5%	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920	11,910,920
Base Case + 10%	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107	12,478,107
Base Case + 20%	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480	13,612,480
Base Case + 50%	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601	17,015,601
Michigan Demand								
Base Case in Scenario 1	315,489	308,151	283,227	274,824	274,824	274,824	274,824	270,903
Base Case in Scenario 2	340,312	340,312	340,312	340,312	340,312	340,312	340,312	340,312

Total Hydrogen Demand in kg (3 of 3)

	2021	2022	2023	2024	2025	2026
National Demand						
AEO2006 Projections in Scenario 1						
Base Case	9,025,195	9,019,424	8,982,034	8,974,437	8,892,270	8,873,472
Base Case - 5%	8,573,253	8,566,623	8,528,378	8,519,929	8,437,763	8,435,435
Base Case - 10%	8,121,312	8,113,823	8,074,723	8,065,421	7,983,255	7,997,397
Base Case + 5%	9,477,136	9,472,224	9,435,690	9,428,945	9,346,778	9,311,510
Base Case + 10%	9,929,078	9,925,024	9,889,345	9,883,453	9,801,286	9,749,548
Base Case + 20%	10,832,961	10,830,625	10,796,657	10,792,468	10,710,302	10,625,623
Base Case + 50%	13,544,611	13,547,427	13,518,591	13,519,515	13,437,349	13,253,849
AEO2006 Projections in Scenario 2						
Base Case	11,343,734	11,365,803	11,387,873	11,409,942	11,409,942	11,432,012
Base Case - 5%	10,776,547	10,797,513	10,818,479	10,839,445	10,839,445	10,860,411
Base Case - 10%	10,209,360	10,229,223	10,249,085	10,268,948	10,268,948	10,288,811
Base Case + 5%	11,910,920	11,934,093	11,957,266	11,980,439	11,980,439	12,003,612
Base Case + 10%	12,478,107	12,502,384	12,526,660	12,550,936	12,550,936	12,575,213
Base Case + 20%	13,612,480	13,638,964	13,665,447	13,691,931	13,691,931	13,718,414
Base Case + 50%	17,015,601	17,048,705	17,081,809	17,114,913	17,114,913	17,148,018
Michigan Demand						
Base Case in Scenario 1	270,756	270,583	269,461	269,233	266,768	266,204
Base Case in Scenario 2	340,312	340,974	341,636	342,298	342,298	342,960