1. Introduction

Hydrogen energy systems have been proposed as a means to increase energy independence, improve domestic economies, and reduce greenhouse gas and other harmful emissions from stationary and mobile sources. These systems, however, face technical and economic barriers that must be overcome before hydrogen can become a competitive energy carrier for the 21st century.

In a recent effort supported by the International Energy Agency (Annex 11 - Integrated Systems), design guidelines were developed for a large number of hydrogen-based and non-hydrogen-based components. These guidelines provide data on individual components to assist in the design of integrated energy systems. Included in the guidelines are measures of performance, which provide relevant means to compare systems. In addition, a tool was developed to assist in the design of hydrogen energy systems. Computer models were developed for a large number of hydrogen production, storage, distribution, and end use technologies, based on data collected from hydrogen demonstration projects throughout the world. These models can be linked through the use of a common integrating platform into integrated hydrogen systems. Renewable-based and fossil-based components are included in the component model library to assist in comparative analysis between advanced systems and commercial systems.

Comparison of different system configurations for a particular application requires a set of criteria on which the comparison can be made. This can include efficiency, environmental impacts, economic impact, capital and operating costs, and other measures of importance to the analyst. In all cases, these parameters can be reduced to a comparison of costs, given that appropriate value can be assigned to the individual criteria. It is important to develop consistent cost models for the various hydrogen components so that fair assessments can be made of alternative designs. This is particularly important when comparing dissimilar systems at very different levels of development and commercialization.

2. Objective

The overall objective of this task was to provide a means by which hydrogen energy systems could be compared to conventional energy systems. In order to meet this objective, existing, planned, and conceptual hydrogen demonstration systems were designed, optimized, and evaluated using a previously developed tool (see Annex 11). Emphasis was placed on comparative analysis of these integrated systems. The activities focused on near- and mid-term applications (3-10 years), with consideration of the transition to sustainable hydrogen energy systems.

3. Work Elements

3.1 Cost Model Development

The basis for the development of consistent cost models was established, including the appropriate size ranges, scaling factors, installation factors, operating and maintenance costs, etc. This basis was used to insure consistency and fairness. Cost models based on existing non-proprietary data and standard engineering procedures were developed. These models include non-proprietary projections for future costs based on cost-reduction parameters (such as mass production, market size, and technological advances) that were defined as part of this activity (based on literature values to the largest extent possible).

The Cost Model is based on standard engineering procedures while allowing variations specific to each application. The Cost Model has to meet the requirements of Annex 13 that include the following:

- Components may be at different levels of development and should be assessed appropriately,
Components of a given system may be purchased in different countries and have different output capacities, inputs and installation requirements, utilisation and scaling factors, etc …

Each component may be used in a country having a given currency, different taxation schedules and import duties on goods and services including utilities, different labour costs, etc …

Each system or application should be assessed on a commercial basis that may vary from country to country

To meet the above requirements, the Cost Model was segmented into different Sections presented in Figure 1.

![Figure 1: Cost Model Sections](image)

The Cost Model developed for this activity is an overlay on a spreadsheet program. It uses multiple data sheets such as Components, Local Conditions, Investments, Operations, Cost Model and Cash Flows. The User is guided through each sheet and is asked to provide data where appropriate.

The “Components” section of the Model provides information on the required system hardware: input and output requirements, costs, scaling factors etc… “Local Conditions” compiles data relative to the costs of various inputs in each country as well as prevailing economic conditions characterising business acceptability. The “Investment” section of the model details the required initial investment in each system as well as the future investment at the end of the life of the project. The “Operations” section compiles data relative to operating conditions of the system while the “Scaling” section adjusts the data to the size of the component for the project selected. Finally, the cash flow section determines if the selected project’s viability in the selected country.

Default values are included in the Cost Model in the form of a Project of a wind-electrolysis hydrogen generating system. A 4-MW windmill provides electricity to an electrolyser that in turns generates hydrogen. This project will serve as an example of usage of the Cost Model and is referred to as the Wind-electrolysis system. Costs developed for this application are realistic but are not in any way intended to represent the reality of a commercial project.

### 3.1.1 Components

Information on Components includes the following:

- Name of component, country of origin and name of component model
- Specifications of component such as annual capacity, maximum annual operating time, planned operating time or utilisation factor and scaling factor
- Input requirements of component and units used including feedstock, energy, labour, maintenance and other annual costs
- Output of component and units used such as main output, by-products including excess heat
- List of main equipment (black-box is also possible)

Component information is inserted on this sheet for each system to be analysed. The fictitious data relative to the Wind-electrolysis system are presented in Figure 2 for information.
3.1.2 Local Conditions

Local Conditions information is developed to allow for:
- The integration of information from different countries, and
- The comparison of different systems in different countries.

This information is specific to each system under evaluation and includes items such as:
- Relative value of each currency compared to a given common based unit such as the Canadian dollar
- Cost of materials required by each component in each country of use of the system such as: diesel, natural gas, gasoline, methanol, heating oil, de-mineralised water, process or cooling water, hydrogen at user site, etc...
- Cost of energy such as electricity and heat
- Cost of labour
- Land requirements (or footprint)
- Country’s specific financial information with regards to commercial projects such as amortisation rate, expected project recovery life, real after tax return on projects, yearly inflation rate, corporate income tax rate, applicable sales tax on goods and services as well as duty on imported goods.

An example of Local Conditions existing in Spain is presented in Figure 3. This information was developed with the cooperation of Annex 13 Participants. Data has been compiled for the following countries: Canada, Spain, Norway, the Netherlands, Japan, Sweden and the United States.

3.1.3 Investments

The Investment Section of the Cost Model is then developed for the Country where the component will be used. This sheet converts the “Components” section’s information in the currency of the country where the proposed system is to be used and applies appropriate duty or local taxes. The Investment Section using our fictitious example is shown in Figure 4.
**Figure 3: Annex 13 - Local Conditions in Spain**

<table>
<thead>
<tr>
<th>Local Conditions</th>
<th>Specify from pull-down menu in which country the System will be used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind / Electrolysis H₂</td>
<td>Spain</td>
</tr>
<tr>
<td>Country</td>
<td>Country Code</td>
</tr>
<tr>
<td>Monetary</td>
<td>Currency</td>
</tr>
<tr>
<td>Materials</td>
<td>Relative Value of Currency to SCA</td>
</tr>
<tr>
<td>Energy / Heat / Work</td>
<td>Total energy demand</td>
</tr>
<tr>
<td>Labor</td>
<td>Yearly labor rate</td>
</tr>
<tr>
<td>Others</td>
<td>Land area</td>
</tr>
<tr>
<td>Financial</td>
<td>Amortization rate</td>
</tr>
</tbody>
</table>

**Figure 4: Annex 13 – Investment Module – Spanish User**

### Initial Investment Costs for System

<table>
<thead>
<tr>
<th>Description of Cost</th>
<th>Quantity</th>
<th>Unit</th>
<th>Unit Cost</th>
<th>Amount</th>
<th>Currency</th>
<th>Relative Cost</th>
<th>How to use the Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind / Electrolysis H₂ Used in Spain</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Future Investment Costs for System

<table>
<thead>
<tr>
<th>Description of Cost</th>
<th>Quantity</th>
<th>Unit</th>
<th>Unit Cost</th>
<th>Amount</th>
<th>Currency</th>
<th>Relative Cost</th>
<th>How to use the Model</th>
</tr>
</thead>
</table>
The user of the model can input additional data relative to feasibility studies, engineering, development costs usually accompanying renewable energy projects such as site specific wind data development, permits and others. Investment credits can be allocated under miscellaneous to account for avoided costs of infrastructure when using a renewable based system.

To the above information, three (3) additional tables allow the user to account for information relative to the investment, such as:

- a construction schedule (up to five (5) years duration) allowing for the annual distribution of investments,
- a start up schedule (up to three (3) years duration) taking into account the (in some cases) slow ramp-up to full capacity, and
- a future investment estimate taking into account investments to be made at the end of the system's life such as the cost of dismantling the system, costs related to the return of the site to its original status and finally credits for sellable items at the end of the useful life of the system.

### 3.1.4 Operating Costs

An Operating cost section is also developed to account for items as described in Figure 5.

The resulting values are those of the system’s components developed in the Country where the system is proposed to be used (in this case - Spain). Should credits be available for renewable systems in that country, these can be incorporated in the module as negative values in “Other”. The user is invited to input data relative to the use of the electricity generated by either the wind mill or the local grid (in our example) and to input a percent contingency on the costs of the overall variable local supplies.

<table>
<thead>
<tr>
<th>Annual Costs for System</th>
<th>Wind / Electrolyte H2 Used in</th>
<th>Spain</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description of Cost</strong></td>
<td><strong>Quantity</strong></td>
<td><strong>Unit</strong></td>
</tr>
<tr>
<td>Operations</td>
<td>1441.94G</td>
<td>ton</td>
</tr>
<tr>
<td>Energy</td>
<td>7.40737kW</td>
<td>kW</td>
</tr>
<tr>
<td>Demand charge</td>
<td>3.077</td>
<td>kW</td>
</tr>
<tr>
<td>Labor</td>
<td>0.25</td>
<td>person-year</td>
</tr>
<tr>
<td>Maintenance</td>
<td>0.000</td>
<td>Pesetas</td>
</tr>
<tr>
<td>Other</td>
<td>574.555 Pesetas</td>
<td>0%</td>
</tr>
<tr>
<td>Contingencies</td>
<td>3.5</td>
<td>% of O&amp;M</td>
</tr>
<tr>
<td><strong>Total Annual Costs</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 5: Annex 13 – Operating Cost Module in User Country

### 3.1.5 Base Cost Model

Once all values for all sections of the system are available, a non-optimised Base Cost Model summarises the data for the module in the Country where the module will be used as in the example of Figure 6.
A method is proposed to the user to calculate the value of the Working Capital as part of the Investment and the system is ready for scaling. Using the scaling factor of the Component description allows the user to align the system's output to the appropriate level as the component may have had a different output when the system's data was compiled. The system is therefore scaled to meet the requirements of the system in the specific application as in Figure 7.

**System at Required Scale**

<table>
<thead>
<tr>
<th>Annual Production Requested</th>
<th>548 231 Nm$^3$ of Hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment Required</td>
<td>7 809 399 Peseta</td>
</tr>
<tr>
<td>Process efficiency improvement @ scale</td>
<td>-5%</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>1 304 094 Peseta</td>
</tr>
<tr>
<td>Amortization</td>
<td>1 335 540 Peseta</td>
</tr>
<tr>
<td>Total Production cost @ scale</td>
<td>2 639 634 Peseta</td>
</tr>
<tr>
<td>Unit Production Cost</td>
<td>4,81 Peseta</td>
</tr>
</tbody>
</table>

When a technology is in the development phase, its cost is usually high. Commercial production levels are accompanied by lower costs. Such lower costs can be incorporated in the Base Cost Model or the Component information used to develop the Base Cost Model of a given System. Improvements in process efficiency gains can also be included in the above Model's section as well as process inefficiencies as assumed in the fictitious example above.
3.1.6 Cash Flows

Finally, using the Financial Parameters of a given country, a Cash-flow analysis derives a price for the system’s output and if this price is lower or equal to the price of that commodity produced in a conventional system or otherwise generated in that country, then the renewable system is deemed competitive. If the price of the renewable system is higher, simulations can be performed to determine the conditions that will render the renewable system competitive. Figure 8 shows our example of the cash-flow analysis.

![Figure 8: Example of a cash-flow analysis](image)

The output of the Cost Models for each application is then used as input to develop the Life Cycle Analysis that will result in estimating the relative value of each application in terms of environmental impact.
3.2 Design and Optimization of Hydrogen Systems

Experts canvassed potential hydrogen demonstration project leaders in participant and non-participant countries to identify candidate configurations for analysis. Using information, tools, and methodologies developed in Annex 11 or otherwise available, the identified hydrogen demonstration projects were assessed and three selected for further evaluation. Potential demonstrations were evaluated and recommendations made as to optimum design and operation of the facility to meet the needs of the project.

3.2.1 Hydrogen Systems for Residential Developments

The development of “greenfield” communities is an important opportunity for hydrogen energy systems. In the Netherlands, new residential districts are being developed, with housing additions of 60,000 (1-2% of the total housing market of 6 million). There is an ambitious national plan to require the power generation mix to include 3% renewables (green energy) by 2010 and 10% renewables by 2020. The Dutch national energy policy includes price supports via an eco-tax of up to 30% on non-green energy. Given the requirement to integrate renewables in the national power mix, continued deregulation of utilities, and the desires by many communities to include “green” homes, hydrogen systems offer interesting opportunities for residential developments.

Introducing hydrogen as an energy carrier requires a different infrastructure from the existing infrastructure. Developing such an infrastructure for mobile applications is a much-debated issue. For stationary applications, the role of hydrogen is less defined but will likely depend strongly on the introduction strategies for fuel cells. The first large-scale application of fuel cells may well be small-scale combined heat and power (CHP) systems. One interesting starting point for developing a hydrogen infrastructure is the use of hydrogen as a fuel for CHP units based on fuel cells. To fully realize the ultimate clean-energy benefits, hydrogen energy systems will use hydrogen from renewable sources. However, in the nearer term, H2 will most likely be produced from fossil fuels. The availability of appropriate technologies to support a hydrogen energy system based on fossil fuels is one important aspect of this early-introduction strategy.

3.2.1.1 Introducing hydrogen in residential area

The natural gas grid in the Netherlands is very extensive. In the short term, therefore, demonstrations of fuel cells for household energy supply will focus on natural gas systems. For proton exchange membrane fuel cells (PEMFCs), the fuel requirement is a H2-rich gas that is, among other things, virtually free of CO. For micro-scale CHP systems operating on natural gas, each fuel cell system would have its own fuel processor system. However, producing hydrogen in a centralized location and distributing the hydrogen to the homes has advantages over the distributed natural gas fueled CHP systems. The advantages of the centralized system are:

- Reduced capital costs per unit of hydrogen generated: The cost of fuel processor is substantial, with the fuel processing unit expected to cost at least as much as the fuel cell itself. Generating hydrogen in a central location takes advantage of the economy-of-scale for the fuel processing.
- Higher efficiency: In the ‘centralized reforming’ concept the fuel provided to the PEMFC is pure hydrogen. The efficiency of the PEMFC operating on pure hydrogen is 20 - 30% higher than the efficiency of the fuel cell operating on a dilute stream of hydrogen.
- Simplicity: The system in the home will be relatively simple, the basis consisting only of the PEM fuel cell, the air supply subsystem and a subsystem for utilizing the heat from the fuel cell. The single hydrogen production plant is located in a controlled area and operated by trained professionals.

The introduction of hydrogen as an energy carrier brings with it a number of challenges, for both the centralized and decentralized production of hydrogen. These include:

- The Hindenburg Effect: Distributing hydrogen in a residential area involves technical, regulatory and social challenges;
• Initial investment: Hydrogen systems will likely require relatively large initial capital investments, by a community and/or the individual homeowner;
• Training: Maintenance of the reformer systems and the fuel cells requires special training that is currently not widely available.

Examining the trade-offs between centralized and distributed (decentralized) hydrogen systems for residential applications has been undertaken as a case study by the International Energy Agency Hydrogen Implementing Agreement’s Annex 13 – Design and Optimization of Integrated Systems. Eight participating countries (Canada, Japan, Lithuania, The Netherlands, Norway, Spain, Sweden, and USA) are cooperating to develop an understanding of the technical, economic, and social issues related to the introduction of hydrogen energy systems.

3.2.1.2 Objectives and scope of the study

Energy use of households makes up 20% of the Dutch energy consumption. Furthermore the relatively uniform market for heating appliances makes it an attractive market for the use of fuel cells as CHP units. In the underlying study, the application of decentralized \( \text{H}_2 \) production and use of this hydrogen in fuel cells for CHP is compared to other options for supplying energy to the homes. The objectives of this study are to identify which technological and economical barriers are important in the concept of using hydrogen as an energy carrier in a residential area. Once these barriers are identified, efforts can be made to reduce or eliminate them through:

• Identification of the research needs (technical and economical);
• Improvement in the design of such a concept; and
• Identification of possible demonstration projects.

The aim of this study is to compare the performance and cost of an energy system for a residential area based on centralized hydrogen production and distribution within the residential area with competing concepts. The assessment of the feasibility of introducing hydrogen into residential developments is particularly important because it can influence the choices that need to be made with respect to the infrastructure. Two factors make a thorough assessment very important:

• The choice of an infrastructure has long-term (50 years) consequences; and
• The decision to opt for one type of infrastructure may block emergence of, or exclude (lock out), other technological solutions.

3.2.1.3 Approach

The starting point for comparison of the competitive solutions to providing energy services to a residential development is to identify the services that the system must provide: electrical power (E) and heat (Q) for tap water and space heating for the households. Heat demand, in particular for space heating, depends strongly on the season. The performance of the energy system in supplying heat and electricity should take into account these seasonal variations. Therefore, the energy consumption and performance of the system in supplying these services in the residential district is simulated for an average year. Both electricity and heat vary significantly over a 24-hour period. To take these variations into account, the simulations have been carried out using a 15-minute time interval. This is sufficient for determining the main dimensions of storage components in the system. For the electricity demand, a smaller interval is required to take into account peaks in power demand. Such patterns were not available for Dutch households. Projects are underway to determine the electricity demand on a one-minute time interval. The results will be incorporated in future studies. For this study, a residential area of 1300 houses is considered. The heat and electricity demand patterns have been taken from an earlier ECN study [1]. These energy demand patterns, which represent the expected energy use for houses that will be built in 2010, are shown in Figure 9.

Different systems for supplying heat and electricity to the houses of the district were evaluated. These are schematically represented in Figure 10-a through 10-d:
II-a) Reference: Electricity is supplied from the grid, and heat is supplied by a conventional natural gas boiler, with a typical efficiency of 95% (LHV). This is the system used in nearly all Dutch residential areas.

II-b) Case B - Micro CHP: Using the same infrastructure (electricity grid and a natural gas grid), the boiler is replaced by a CHP unit to achieve higher efficiency. The most important natural gas CHP options are gas engines, Stirling engines, and fuel cells. For this study, CHP based on the solid oxide fuel cell (SOFC) was selected, based on the limited fuel processing requirements (compared to the PEMFC) and the high efficiencies projected for the longer term.

II-c) Case C - All-electric: Only the electricity grid is required if heat is produced using heat pumps. In this case an 'all-electric' infrastructure is postulated.

II-d) Case D - Hydrogen: A hydrogen grid within the district is used to distribute hydrogen. The hydrogen is produced from natural gas using small-scale (e.g. 2 MW NG input), centralized reforming.

Figure 9: Yearly demand patterns for a 1300 house district for heat (top) and electricity (bottom)

Figure 10: Systems to supply heat and electricity to households in a 1300-house residential district
For each of the systems of interest, simulations were carried out to compare performance. Three aspects (measures of performance) are calculated:

- **Primary energy consumption**: The district uses natural gas and electricity as energy carriers. The primary energy required for each kWh of electricity was calculated assuming an efficiency of 55% (LHV) for a natural gas-powered combined cycle plant, which represents the marginal generating power for the Netherlands.

- **Costs**: The total annual cost per household was calculated. The annual cost includes capital depreciation, operation and maintenance (O&M) costs, and energy/fuel cost. The capital costs were calculated using the data in Table 1 and are based on the assumption that these technologies represent mature technologies in the 5 to 10 year time frame. Energy costs are based on the current (2001) consumer costs for energy, including the Dutch energy taxes.

- **Emissions**: Carbon emissions were calculated using the same assumptions as for the primary energy. Because both calculations are based only on natural gas as primary energy carrier, the carbon emissions and primary energy are, in this case, proportional.

### Table 1: Data used in the calculation of investment costs

<table>
<thead>
<tr>
<th>Component</th>
<th>Size</th>
<th>US$/unit</th>
<th>Scaling factor n</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heater</td>
<td>12 kW th</td>
<td>75/ kW th</td>
<td>0.7</td>
<td>[2]</td>
</tr>
<tr>
<td>EHP</td>
<td>6.6 kW th</td>
<td>516/ kW th</td>
<td>0.5</td>
<td>[3]</td>
</tr>
<tr>
<td>PEMFC</td>
<td>5 kW e</td>
<td>1400/ kW e</td>
<td>0.7/0.85</td>
<td>[4]</td>
</tr>
<tr>
<td>SOFC</td>
<td>5 kW e</td>
<td>1080/ kW e</td>
<td>0.7/0.85</td>
<td>[5]</td>
</tr>
<tr>
<td>Heat buffer</td>
<td>10 MJ</td>
<td>45 /MJ</td>
<td>0.7</td>
<td>[6]</td>
</tr>
<tr>
<td>Hydrogen buffer</td>
<td>1000 Nm³</td>
<td>35.7 /Nm³</td>
<td>0.7</td>
<td>[7]</td>
</tr>
<tr>
<td>SMR</td>
<td>0.1 MSCF</td>
<td>3943 /kW H₂</td>
<td>0.3</td>
<td>[8]</td>
</tr>
</tbody>
</table>

### 3.2.1.4 Results

#### 3.2.1.4.1 Systems for the district with a natural gas infrastructure – Reference and Case B

##### 3.2.1.4.1.1 Reference system

The total heating demand for the 1300-house district is 6880 MWh (5290 kWh/house). Electricity consumption for the district is 4380 MWh (3370 kWh/house). The reference case demands are met using the conventional heating boiler and electricity from the grid. The total primary energy consumption to supply this heat and electricity and the total CO₂ emissions for the district were calculated and results are summarized in Table 2. For the electricity production, these calculations are based on the primary energy consumption and CO₂ emissions for a 55% (LHV) efficient natural gas plant (combined cycle) and assuming grid losses totaling 5.5% of the electricity supplied to the grid. The natural gas used for heating is calculated using an efficiency of 95% (LHV) for the boiler.

The carbon emissions for the district are the sum of the carbon emissions resulting from burning the natural gas for heating and from electricity production. The emissions per house are shown in Table 2. Annual CO₂ emissions for electricity production are slightly higher (355 kg/a carbon) than for heat production. The results of the energy calculations are shown in the energy flow diagram or Sankey diagram in Figure 11.

##### 3.2.1.4.1.2 Micro CHP SOFC system (Case B)

The schematic of the natural gas/micro CHP system (Case B) is shown in Figure 12. The main component is the SOFC system that delivers heat and electricity to the house. The electrical efficiency assumed for this unit is 45% (LHV) and the total efficiency (heat + electricity) is 80% (LHV).
For this case, the SOFC system is operated as a base load system. The fuel cell operates at a constant load during the whole year. If the fuel cell is sized to meet the heat demand, the system will be highly over-dimensioned with respect to the electricity demand. In view of the relatively low price that is expected for the electricity sold to the grid, this is not attractive. Therefore the system was sized using two different small stack sizes: 0.38 kW_e (Case B-1) and 1 kW_e (Case B-2) for each house. To be able to deliver the required amount of heat to the house, an additional burner is necessary, as shown in Figure 12. This burner supplies the difference between the heat demand and the heat supplied by the fuel cell if demand is higher than the heat produced by the fuel cell.

Table 2: Calculation results for the reference system

<table>
<thead>
<tr>
<th></th>
<th>District</th>
<th>House</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy use [MWh/a]</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>6880</td>
<td>5.29</td>
</tr>
<tr>
<td>Electricity</td>
<td>4380</td>
<td>3.37</td>
</tr>
<tr>
<td><strong>Carbon emission [kg/a]</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heating</td>
<td>849 000</td>
<td>661</td>
</tr>
<tr>
<td>Electricity</td>
<td>397 000</td>
<td>306</td>
</tr>
<tr>
<td></td>
<td>461 000</td>
<td>355</td>
</tr>
<tr>
<td><strong>Costs [USD/a]</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of capital</td>
<td>893</td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>106</td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>237</td>
<td></td>
</tr>
</tbody>
</table>

Figure 11: Energy flow in MWh/a (Sankey diagram) for the Reference Case showing the energy flows for the total district.
On the other hand, the result of operating in base load is that if the heat demand is low, the heat produced by the fuel cell cannot be utilized. Therefore, part of the heat that is generated by the fuel cell may be wasted. This can be partially overcome by using a heat buffer. The influence of such a buffer has been studied by simulating the system for different buffer sizes.

In Figure 13, the Sankey diagram for Case B-1 using the 0.38 kW SOFC is shown. This size was selected for the SOFC so that electricity production is approximately equal to the annual consumption of electricity. As a result, the net amount of electricity that is imported from the electricity grid is small.

Figure 12: Schematic representation of the natural gas fueled SOFC CHP system (Case B) with additional burner and heat buffer

Figure 13: Energy flow in MWh/a (Sankey diagram) for 0.38 kW SOFC (Case B-1)
The SOFC is operated as a base load unit. The annual electricity demand of the district is 4380 MWh/a, and the fuel cells produce slightly less (4150 MWh/a). Given the electricity demand patterns, the calculations indicate that 76% of electricity produced by the SOFC (3160 MWh/a) can be used directly. Therefore 24% of electricity produced by the fuel cell is exported to the grid and bought back at a later time and at a higher price (for these calculations the selling price is considered half of the price paid for the electricity). This is indicated in the Sankey diagram in Figure 13 by the loop through the electricity meter (990 MWh/a). Given the expected difference between the selling and buying prices, it is uneconomic to exchange large amounts of electricity through the grid. The design of the system should focus on maximizing the amount of electricity that is consumed directly. However, because the fuel cell produces heat and power at the same time, optimizing heat and electricity balances independently is not possible.

The heat balance for Case B-1 is shown in Figure 13. The total annual heat demand for the district is 6880 MWh/a. The fuel cells produce approximately half of this amount (3410 MWh/a). However, because the fuel cells operate in base load, only part of the heat that is produced in the fuel cell can be used, in this case, 1950 MWh/a. The remainder of the heat (1460 MWh/a) cannot be used and is lost through a cooling system. As a result, the fuel cells cover less than 30% of the heating requirements. The burners provide the remainder of the heat.

In principle, the efficiency of heat production through the CHP system is much higher than for a burner/boiler. Therefore, to increase the efficiency of the heat production, it is important to minimize the contribution of the burner. This can be achieved by using a larger fuel cell. Figure 14 shows the effect of increasing the fuel cell size from 0.38 kW to 1 kW (Case B-2) on the heat balance of the system. The larger fuel cell substantially decreases the portion of the heat that is produced by the burner, from 59% of the total heat production to 26%. However, the amount of heat produced in the fuel cell that cannot be used increases significantly. For the 0.38 kW SOFC (Case B-1), more than half of the heat produced in the SOFC can be used. For the 1 kW system (Case B-2), this drops well below half.

**Figure 14:** Comparison of the heat balances for Case B: SOFC system with a 0.38 kW fuel cell (Case B-1) and a 1 kW fuel cell (Case B-2)

The consequences of increasing the size of the fuel cell on the electricity balance are shown in Figure 15. The first bar represents the electricity production by the fuel cell, which is either used directly or exported to the grid. The second bar represents the electricity demand of the district that is satisfied.
either by the fuel cell or from the grid. The graph shows that for the 0.38 kW system (Case B-1), the fuel cell covers 75% of the electricity demand directly and 25% comes from the grid. The 1 kW system (Case B-2) covers the entire electricity demand. However, the result is also that, on an annual basis, the system produces much more electricity than required in the house.

Time is the essential element in optimizing both the electricity and the heat balance for the system. It is not only necessary to match average production and demand over a year, but also to match production and demand in time. There are several ways in which the match between demand and production can be improved, such as by varying the production to meet demand (load following) and by storing energy.

![Figure 15: Comparison of the electricity balances for the SOFC system with a 0.38 kW fuel cell (Case B-1) and a 1 kW fuel cell (Case B-2)](image)

There are a number of limitations in designing a system for load following operation. It is, for example, not possible to follow both the electricity and heat demand with a CHP unit as both are coupled. Furthermore, if a unit has high investment costs, base load operation is the most attractive option because the depreciation per kWh is minimized. In general optimization of design with respect to load following is not straightforward.

For the SOFC system, only base load operation has been considered because of the high investment costs. Furthermore, it is not clear if SOFC systems will be suitable for part-load operation, given the high temperature at which the system is operated. The effect of load following is considered for the PEMFC systems (Case D).

A second option for matching demand is the use of storage. To balance electricity production and demand, the grid is used as virtual storage. The economic penalty of using the grid as a buffer is the price difference between selling and buying (in this study we used a 50% penalty). On-site electricity storage is not considered as an alternative in these calculations (batteries could be used for only a small amount of storage). Heat storage is, however, feasible. For seasonal heat storage, the use of aquifers is possible. In this study, only simple heat storage in 50- or 100-liter hot water vessels is considered.

The Sankey diagram for the 0.38 kW SOFC system with heat buffer (Case B-3) is shown in Figure 16. The difference between the system without buffer (Case B-1, Figure 13) lies mainly in the unused
heat that is produced in the fuel cell but cannot be used (‘lost heat SOFC’ in Figures 13 and 16). Using a 50-liter buffer to store the heat that cannot be directly used at the specific moment reduces these losses by more than half (from 1460 MWh/a to 600 MWh/a for the district). Part of the gain is lost because of heat losses of the buffer (1% of max. capacity/h loss is assumed). However, the net effect of introducing the buffer is that the burner duty decreases by 15%. Increasing the buffer size to 100 liters is not effective. If the buffer size is doubled, the extra amount of heat that can be recovered only just compensates for the additional heat losses from the buffer.

In Figure 17, the difference in carbon emissions compared to the reference system is shown. The two systems with 0.38 kW fuel cells (Cases B-1 and B-3) perform better than the reference system. The Case B-3 system reduces the emissions by 45 kg/a (reference system = 661 kg/a). The system with the 1 kW SOFC (Case B-2) produces more carbon than the reference system. This is due to the large amount of heat produced in the fuel cell that goes unused.

Figure 16: Energy flow in MWh/a (Sankey diagram) for the system with 0.38 kW SOFC and a 50-liter heat buffer (Case B-3)
Figure 17: Carbon emission reduction [kg/a] relative to the reference system for Case B systems

Figure 18 shows the total annual cost per household, which consists of the energy cost and the cost of capital and O&M. The systems with the 0.38 kW SOFC (Case B-1 and B-3) could be economically attractive for the consumer, based on the assumptions with respect to investment costs for the SOFC. This is because these systems effectively minimize the amount of electricity to be bought from the grid. The larger system (1 kW – Case B-2) saves less and requires higher investments. As a result, the annual costs for this system are higher than for the reference system.

Figure 18: Annual cost for the reference system and for Case B systems

3.2.1.4.2 Systems for the all-electric district – Case C

Combusting natural gas in domestic boilers to produce heat leads to inefficiency. By eliminating heat production through combustion, CHP systems produce heat with high efficiency. Another way in which the combustion process can be avoided is by using a heat pump. In the all-electric systems
(Case C), an electrical heat pump is used to supply the heat. All electricity required, both for the heat pump and to satisfy the electricity demand of the household, is imported from the electricity grid.

The primary energy use and emissions for electricity have been calculated using the same data as in the previous section: a 55% (LHV) efficient NG-fueled power plant and 5.5% grid losses. The performance of the heat pump is characterized by the coefficient of performance (COP), which is the ratio between heat produced and electricity consumed. For these calculations the value of the COP is 2.5. This is an average value for combined production of heat for tap water and space heating.

The calculation results for the district are summarized in Figure 19, which shows the Sankey diagram for this system. To produce the required heat and power for the district, the reference system (shown in Figure 11) uses 15640 MWh/a of natural gas. The system with a heat pump uses only 13540 MWh/a of natural gas. In Case C-1, heat from the environment contributes 4200 MWh/a, reducing the consumption of natural gas by 13% from the reference case.

The investment costs for heat pumps are high. These high costs are evident in Figure 20, where the total yearly costs for the heat pump system without a heat buffer (Case C-1) and with a heat buffer (Case C-2), are compared to the reference system. The costs and efficiencies have been calculated assuming the heat pump system operates in a load-following manner. For Case C-2, a large buffer (320 liter) has been used to minimize the size of the heat pump. However, the total costs for this system do not differ significantly from Case C-1.

The emissions for the Case C systems relative to the reference case are shown in Figure 21. This figure shows that the emission reductions that can be achieved with the heat pump systems are substantial. The emission performance of the system with heat buffer (Case C-2) is lower due to heat losses from the buffer.

![Energy flow in MWh/a (Sankey diagram) for the district for the all-electric system with a heat pump (Case C-1)](Image)
3.2.1.4.3 Systems for the district with a hydrogen infrastructure – Case D

3.2.1.4.3.1 Description of the hydrogen based systems

The two main reasons for introducing hydrogen as an energy carrier in the residential area are the high efficiency of the PEMFC operating on pure hydrogen, and the economy of scale that can be achieved by producing hydrogen for a large number of houses in a centralized location. The system is shown schematically in Figure 22. Natural gas is delivered to the district and reformed at a central location in the district. This central plant includes a gas cleanup system that produces pure hydrogen that can be distributed to each house and used directly in the PEM fuel cells.
A number of configuration variations are considered for the hydrogen system. These are summarized in Table 3.

Table 3: Hydrogen configurations examined in Case D

<table>
<thead>
<tr>
<th>Case</th>
<th>PEMFC</th>
<th>H₂ Burner</th>
<th>H₂ Buffer</th>
<th>Heat Pump</th>
<th>Base-Load or Load-Following</th>
</tr>
</thead>
<tbody>
<tr>
<td>D-1</td>
<td>0.38 kW</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>BL</td>
</tr>
<tr>
<td>D-2</td>
<td>1 kW</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>BL</td>
</tr>
<tr>
<td>D-3</td>
<td>0.38 kW</td>
<td>N</td>
<td>N</td>
<td>Y</td>
<td>BL</td>
</tr>
<tr>
<td>D-4</td>
<td>0.38 kW</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
<td>LF</td>
</tr>
<tr>
<td>D-5</td>
<td>1 kW</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
<td>LF</td>
</tr>
<tr>
<td>D-6</td>
<td>0.38 kW</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
<td>LF</td>
</tr>
</tbody>
</table>

The Case D systems are similar to the Case B systems (SOFC CHP). The main component in Case D is the PEMFC, which delivers power and heat. As in the SOFC system, the PEM fuel cell does not provide all the heat demand and a second component is required to supply the remainder of this demand. Two possibilities have been considered. The first is a hydrogen-fueled burner (Cases D-1, D-2, D-4, and D-5), similar to the one in the Case B-1 system. The burner operates on hydrogen (as there is no natural gas grid in the district). As will be shown, the efficiency of the system is adversely affected by using a hydrogen burner. Therefore a second option has been considered, namely using a heat pump (Cases D-3 and D-6) to deliver the difference between the heat produced by the fuel cell and the heat demand.

For the Case B calculations, operation in base load was assumed because of the high investment cost for the SOFC and technical limitations of operating the high-temperature unit in a load-following mode. In Case D, part-load operation of the PEMFC is technically not an issue. However, producing additional heat to meet demand is more complex for the hydrogen-fueled system. Therefore the calculations for the PEMFC system have been made both for base-load (Cases D-1, D-2, and D-3) and for load-following operation (Cases D-4, D-5, and D-6). In the latter case, the control strategy for the fuel cell aims to minimize the production of heat in the fuel cell that cannot be used.
The Sankey diagram for the base case PEMFC system (Case D-1) is shown in Figure 23. The base case is a small fuel cell (0.38 kW), operated at constant power (base load) and with a small heat buffer. The centralized reformer efficiency used in the calculations is 75% (LHV), which is realistic for this scale (2 MW NG input). The hydrogen that is produced in the reformer is used in the fuel cell and in the hydrogen burner. Even using a small heat buffer to make better use of the heat produced in the fuel cell, the hydrogen burner in the base case still produces 2/3 of the heat demand and the fuel cell only 1/3. As in the natural gas system, combustion of fuel gas to produce heat is very inefficient. In the PEMFC system, this is even more so, since there are inefficiencies in the production of hydrogen. The losses in the reformer are therefore not compensated by the higher efficiency of the PEMFC (which has only a small contribution in heat generation) and as a result, the overall efficiency of the PEMFC system is slightly lower than for the reference system. The primary energy use increases from 15640 MWh/a (reference system) to 16390 MWh/a for Case D-1.

3.2.1.4.3.2 Using a heat pump to produce heat

The heat pump offers an efficient way to produce heat. In Figure 25, the calculated carbon emissions for the 0.38 kW PEMFC system with a burner (Case D-1) can be compared to the corresponding system with a heat pump (Case D-3). The carbon emissions for the systems with a heat pump (Cases D-3 and D-6) are significantly lower than the reference system.

However, the economics of the PEMFC/heat pump system is not very attractive (Figure 26). The total annual cost, composed of the energy costs and the capital and O&M costs, is almost twice as high for the system with heat pump (Case D-3) as for the reference system. This is mainly due to the high investment costs for the heat pump.
Figure 24: Heat balances for hydrogen-fueled PEMFC configurations

Figure 25: Carbon emission reduction [kg C/a] relative to the reference system for the six Case D hydrogen PEMFC system configurations
Capital cost contributions are shown in Figure 27. The hydrogen distribution grid contributes roughly 10% of the capital cost, based on the conservative estimate used (hydrogen distribution cost = 2 x natural gas distribution cost).

For the 0.38 kW system (Case D-1), more than half (51%) of the capital cost comes from the steam methane reformer (SMR). In this case, the SMR is very large (>10 MW) because it supplies hydrogen to both the fuel cell and the burner.

In the systems with a heat pump (Cases D-3 and D-6), the heat pump is responsible for approximately half of the capital cost. The fraction of the capital costs for the SMR drops below 20%, mainly because the SMR is much smaller in this case (no need to supply hydrogen to the burner).
3.2.1.4.3.3 Load following

The last option considered is operating in a load-following mode. In this case, the fuel cell is operated at part load if the heat demand of the system is low. The reformer operates at constant power and a hydrogen buffer is used to make up for the difference between demand and production.

Figure 28 shows the Sankey diagram for Case D-4, with a 0.38 kW load-following PEMFC with a hydrogen burner to supplement the heat production of the fuel cell. The main difference between this diagram and the corresponding diagram for the base-load configuration (Case D-1) in Figure 23 is that all the heat from the fuel cell is supplied to the heat buffer. As a result of this improvement, the carbon emissions of the load-following system are significantly lower than for the base-load system (see Figure 25). The best performance for the burner system is found for the load-following system with a larger (1 kW) fuel cell stack (Case D-5). This system combines a low contribution of the hydrogen burner and a high utilization of the heat produced in the fuel cell (see Figure 24). The comparison of costs in Figure 26 shows that the costs of the load-following systems are not higher than the corresponding base-load systems (Case D-1 vs Case D-4, and Case D-2 vs Case D-5).

Figure 28: Sankey diagram for the 0.38 kW load-following PEMFC system (Case D-4)

3.2.1.5 Discussion and Conclusions

3.2.1.5.1 Discussion

Combined generation of heat and power for household energy needs has the potential to substantially reduce primary energy consumption and emissions. This study shows specifically that the degree to which this potential can be realized depends strongly on effective generation of the required heat. Ideally the fuel cell produces exactly the amount of heat that is required in the household. If the heat production in the fuel cell is larger, part of the heat production cannot be utilized. On the other hand, if the heat production in the fuel cell does not cover the heat demand, producing the additional heat by
using a supplementary burner will lead to higher costs and/or lower energy and emissions savings. Therefore, sizing the system right is essential. However, as the calculations in this study show, if the changes in demand in time (day/night, summer/winter) and economic limitations are taken into account, it is not possible to size the fuel cell large enough to produce all the heat in the fuel cell and avoid dumping heat at the same time. Optimizing the CHP system therefore corresponds primarily to finding the balance between producing too much heat and having to generate additional heat.

Two types of CHP have been considered. The first type is a micro-CHP SOFC system using natural gas as a fuel. The second type is a PEMFC system using hydrogen as a fuel, where the hydrogen is produced in a centralized reformer that produces the hydrogen for the whole residential area (1300 houses). In both cases, the reduction in primary energy use and CO₂ emissions are very sensitive to the design of the system. Base load vs. load following, the size of the fuel cell, and the size of heat buffers are some of the design issues that determine if and how much the system performs better than the reference system. The reference system uses a natural gas heater to provide all of the home heating needs. Not only is the performance of the CHP sensitive to the design, the calculations also show that the savings in terms of primary energy and CO₂ emissions for the systems discussed here are substantially smaller than might be expected.

3.2.1.5.2 Meeting the objectives of the study

Three objectives were given for this study:

- Identification of the research needs (technical and economical)
- Improvement of the design of the concept of a hydrogen-based residential energy system
- Identification of possible demonstration projects

Technological improvements that could increase the system performance substantially are, for example, more efficient small scale reformers, cheaper small heat pumps, and efficient means of storing heat.

Based on the energy analysis of the hydrogen systems, there are several interesting options for improvement of the system design besides optimizing the design. Decreasing the heat losses in reforming or making use of the heat that is produced in the reformer would substantially improve the overall efficiency of the system. One way in which this could be achieved, is by combining hydrogen production with electricity production, for example by using a gas turbine to deliver heat to the reformer or by using high temperature fuel cells. Another way is to utilize the waste heat by supplying it to homes or other heat users in the residential area.

Analysis can show the potential of the concept of using hydrogen in a residential area, and the benefits in terms of efficiency and reduced emissions. Whether such a potential can be realized can only be determined in the end by bringing the concept to life. This calls ultimately for a demonstration project to determine the potential in a real environment, with real limitations to infrastructure, real regulations, and real consumer behavior and perception.

3.2.1.5.3 Conclusions

For the hydrogen systems examined here, specific conclusions can be drawn. The main difference between the hydrogen-based CHP (Case D) and the natural gas-based (reference and SOFC CHP) systems is the required conversion from natural gas to hydrogen in the Case D scenarios. As a result of the efficiency of this conversion, approximately 25% of the energy in the natural gas is lost. To achieve good performance of the total system, the high efficiency of the PEMFC should be put to work. The calculations show that to achieve better performance, the hydrogen system requires a smart system design. Specifically, the design should focus simultaneously on minimizing wasting heat produced in the fuel cell and on avoiding having to produce additional large amounts of heat using a burner. In particular when the fuel is hydrogen, produced with substantial losses from natural gas, using the burner is detrimental to the efficiency of the system.
3.2.2 Integrating Renewables for Remote Fuel Systems

3.2.2.1 Introduction

Hydrogen energy systems have been proposed as a means to increase energy independence, improve domestic economies, and reduce greenhouse gas and other harmful emissions from stationary and mobile sources. These systems, however, face technical and economic barriers that must be overcome before hydrogen can become a competitive energy carrier for the 21st century. A wind-H₂ system for a remote location was studied to determine the feasibility of producing hydrogen for transportation applications. This case study was initiated by STATKRAFT SF, Norway's largest producer of hydroelectric power and the second largest producer in the Nordic region. The modelling work was performed by the Institute for Energy Technology (IFE).

3.2.2.2 Background

In Norway, more than 99% of the electricity demand is supplied by hydropower. During the last 10 years, however, public resistance based on environmental issues has virtually brought the development of the remainder of these resources to a standstill. Because of the increase in power demand and good wind resources along a sparsely populated coastline (a potential of around 10 TWh/year is recognised), the focus on wind energy plants has grown over the last years. It seems that the public resistance, especially in the early phase of the introduction of large-scale wind energy development, is smaller than is the case for further hydropower development. In 2000, the Norwegian government has approved several applications for building of wind parks, in total amounting to some 300 MW peak power.

The selected locations for Norwegian wind parks are remote areas, such as islands, where the best wind resources are found. The wind parks will produce power for the small communities in these areas, but also for the common electricity grid as a complement to the existing hydropower. In this study, the production and use of hydrogen in fuel cells in relation to such wind parks is discussed. A wind/electrolyser-based hydrogen refuelling station taking the base power from one of the large windmills in a wind park is modelled. The hydrogen produced is assumed to be used in buses operating the public transport on the remote location. At a later stage, hydrogen for operation of ferries would also be an attractive alternative.

The existence of a low-voltage grid is assumed for this study. In practice, this enables testing under constant conditions during the commissioning period. In the modelling work, the assumption of a weak grid enables the identification of several cases of operation of the filling station. In addition to a
grid-connected case, two cases where the power from the renewable energy source (wind) is used to run the filling station autonomously are identified and discussed.

3.2.2.3 System Description

As mentioned above, the wind-H\textsubscript{2} energy system is connected to a low-voltage grid (22 kV). The H\textsubscript{2} system receives power from a 2 MW variable speed Wind Energy Conversion System (WECS). The produced hydrogen is stored as compressed gas at 300 bar. The simulations were done using the computer modelling code; TRaNsient SYStem simulation program (TRNSYS). TRNSYS is a modular simulation tool where components are connected much like in an actual system. For this study, detailed technical models developed at IFE since 1995 were applied. The models comprise the components: Alkaline electrolysers, hydrogen storage, power conditioning, compressors, WECS and system control units [10]. A schematic drawing of the wind-H\textsubscript{2} energy system is shown in Figure 29.

3.2.2.3.1 Wind resources

A three-year wind speed (m/s) data series with a time-step of 1 hour from a measurement station at a specific remote location along the Norwegian coastline was used as input to the simulation. The actual time period used in this study was:

- Start date/time: 1997-10-31, 00:00:00
- Stop date/time: 2000-10-31, 23:00:00
- No. of data points: 26304

![Figure 29: Schematic presentation of the wind-H\textsubscript{2} energy system](image-url)
Wind-speed data recorded mostly at a height of 50 meters (in smaller periods of time at 30 meters) where extrapolated to 67 meters, which is the hub height of the WECS used in the modelling. The wind data are presented in Figure 30.

3.2.2.3.2 WECS power output

The WECS is of the type VESTAS V80 with a maximum power output of 2 MW. In order to simulate the power contribution from this windmill, a linear extrapolation to the measured data of wind speed and power output, as supplied by VESTAS Wind Systems A/S (Denmark), was made. A representation of the power output from the WECS as a function of wind speed is shown in Figure 31.

3.2.2.3.3 Electrolyser and storage

In this study electrolyser technology from Gesellschaft für Hochleistungselektrolyseure zur Wasserstoffproduktion mbH (GHW) is chosen [11]. GHW develops alkaline electrolysers with a nominal operating temperature of 70-80°C and a working pressure of 30 bar. The GHW electrolysers are especially advantageous with the unpredictability of wind resources as they can take variations in power ranging from 20% up to 100% of maximum rated power. Figure 32 shows the voltage-current characteristics for the GHW electrolyser applied in the modelling.

![Figure 30: Wind speed (in m/s) as a function of time (in weeks) for the 3 years period. In order to visualise summer and winter variations, a smoothed curve is also presented. Three winter seasons with good wind resources are seen.](image-url)
Figure 31: Power/wind speed characteristics for the VESTAS V80 (2MW) WECS. The line represents the linear extrapolation used in the simulations. No hysteresis loop is assumed upon re-entering the valid wind speed range from wind speeds above 25 m/s.

Figure 32: Voltage-current (U-I) characteristics of the GHW electrolyser used in the simulation.
Hydrogen is stored at a pressure of 300 bar. A compressor is used to increase the hydrogen pressure from 30 bar (the operating pressure of the electrolyser) to the storage pressure. The size of the storage unit depends on the operating scenario.

3.2.2.3.4 Mini-buses

The hydrogen load is represented by three PEM fuel cell powered mini-buses. The fuel demand and other technical information on the fuel cell mini-buses are listed in Table 4.

<table>
<thead>
<tr>
<th>Vehicle type</th>
<th>16-seat mini-bus</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of vehicles</td>
<td>3</td>
</tr>
<tr>
<td>Onboard storage capacity</td>
<td>120 Nm³ @ 200 bar = ~10.7 kg</td>
</tr>
<tr>
<td>Fuel consumption</td>
<td>0.6 Nm³km⁻¹ [12]</td>
</tr>
<tr>
<td>Driving range</td>
<td>200 km</td>
</tr>
<tr>
<td>Filling frequency</td>
<td>day⁻¹</td>
</tr>
</tbody>
</table>

3.2.2.4. Definition of Cases

Three distinct cases with regard to the operation of the electrolyser are described: one case with constant operation (drawing electricity from the grid); and two cases with variable operation of the electrolyser (true stand-alone systems).

3.2.2.4.1 Electrolyser operated at constant power (Case 1)

The electrolyser can be operated at constant power. For a wind-H₂ system, however, this will require that power be supplied from the grid during times of poor wind resources. Based on the information in Table 4, 32 kg of hydrogen are required each day. We assume that the filling of all three mini-buses is possible within 1 hour (fast-fill). The size of H₂ storage unit and the electrolyser may then be easily calculated. Based on manufacturers’ data, the energy required by the electrolyser, when operated constantly at maximum power, is 4.4 kWh/Nm³ H₂ [11]. This gives a total energy demand per filling of 120 Nm³ x 3 x 4.4 kWh/Nm³ = 1584 kWh. In 24 hours this equals an electrolyser of capacity 1584 kWh / 24 h = 66 kW. The size of the storage is also easily estimated by taking the total amount of H₂ needed per day, 32 kg / 0.08988 kg/Nm³ = 360 Nm³. At 300 bar, this is around 1.7 m³ physical gas volume (adding a lower and upper dead-band of 20% + 20% = 40%). For comparison, this is equivalent to about 50 x 50-liter bottles of commercially available H₂ at 200 bar. The electrolyser and H₂ storage unit sizes for Case 1 are summarised in Table 5. The state of charge (SOC) of the H₂ storage unit is shown in Figure 33.

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyser</td>
<td>66</td>
<td>KW</td>
</tr>
<tr>
<td>Compressed H₂ storage unit</td>
<td>1.7</td>
<td>m³ (tank volume)</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>Nm³ H₂</td>
</tr>
<tr>
<td></td>
<td>45</td>
<td>kg H₂</td>
</tr>
</tbody>
</table>
Continuous operation of the electrolyser requires that power be supplied from the grid at times of low wind resources. For Case 1, 19% of the energy needed to operate the electrolyser continuously at 66 kW must be supplied from the grid for the 3-year period under study here. The power from the WECS is insufficient to operate the electrolyser at full power for about 24% of the time. For sake of illustration, the electrolyser power profile for a critical wind resource period (04.08.98-21.08.98) is shown in Figure 34.

Figure 33: Schematic representation of state of charge (SOC) of H₂ storage when the electrolyser is operated at constant power (Case 1)

Figure 34: Power distribution for the electrolyser in Case 1 for a critical wind resource period. Approximately 73 kW are directed to the electrolyser (includes 10% loss in the inverter)
3.2.2.4.2 Stand-alone operation (Cases 2 & 3)

In Cases 2 and 3, where the electrolyser receives power from the WECS only, the storage and electrolyser have to be somewhat over-sized. Figure 35 illustrates the fraction of the power from the WECS that is directed to the electrolyser. If the power output from the WECS is between the lower and upper power limit for the electrolyser (20 - 100% of maximum power), then all power from the WECS is directed to the electrolyser. If, on the other hand, the WECS produces more power than the electrolyser can utilise, then the over-shooting power is distributed to the grid. Also if the power from the WECS is lower than needed for operating of the electrolyser at 20%, the power is instead distributed to the grid.

3.2.2.4.2.1 Direct-connect Scenario (Case 2)

In Case 2, the electrolyser is operated whenever there are wind resources and the storage unit is over-dimensioned accordingly. To determine the appropriate electrolyser and storage unit sizes, optimisation calculations were performed to achieve a design where no hydrogen is dumped by ventilation to the surroundings and where the storage unit is never entirely drained. The electrolyser and storage unit dimensions are given in Table 6. Figure 36 shows the distribution of power from the WECS to the electrolyser in a selected ~4 days period. The optimal solution for Case 2 shows that the electrolyser will only need to be over-dimensioned by ~45% (from 66 to 98 kW). The SOC of the storage unit will reflect the variations in wind resources as a function of time and show peaks during wintertime and minima during summertime. The resulting storage unit SOC is shown in Figure 37.

This control strategy – electrolyser operation whenever there are wind resources – results in an operation profile as presented in Figure 38. Here we see that the electrolyser is operated at 80-100% of its maximum power for ~75% of the time and that it is idling ~10% of the time.

![Figure 35: Schematic presentation of power distribution from the WECS. The grey area represents power distributed to the electrolyser while the hatched areas represent the power sent to the grid](image-url)
Table 6: Summary of electrolyser and storage unit capacity for Case 2

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyser</td>
<td>98</td>
<td>KW</td>
</tr>
<tr>
<td>Compressed H₂ storage unit</td>
<td>50</td>
<td>m³ (tank volume)</td>
</tr>
<tr>
<td></td>
<td>11800</td>
<td>Nm³ H₂</td>
</tr>
<tr>
<td></td>
<td>1060</td>
<td>kg H₂</td>
</tr>
</tbody>
</table>

Figure 36: The distribution of power to the electrolyser from the WECS for a 100-hour period for Case 2. The horizontal dotted lines represent the upper and lower limits of electrolyser operation.
Figure 37: Storage state of charge (SOC) for Case 2 for a 50 m³ storage unit at 300 bar (11800 Nm³). The dashed line indicates fulfilment of energy conservation over the 3-year period.

Figure 38: Operation profile for the electrolyser of Case 2.
In Case 3, the electrolyser operation is guided by the SOC of the H₂-storage unit. This case represents a so-called top-charging scenario. The electrolyser and storage unit are dimensioned so as to keep the storage SOC within the dead-band when possible. This type of control routine is commonly used in stand-alone systems based on energy storage in batteries [10]. The lower and upper dead-bands were set to 0.80 and 0.94, respectively, for Case 3. Hence, the electrolyser is set to idling when the upper limit is reached and set to operate when the lower limit is reached. The aim of this strategy was to minimize the storage unit size. The storage unit size was set to 7.35 m³ at 300 bar. This is comparative to a commercially available storage solution comprised of a 20-feet container with 147 x 50 l bottles at 300 bar. In order to keep this storage unit from being exhausted at any time during the 3-year period, the electrolyser capacity had to be increasing to some 230 kW, an electrolyser capacity that is nearly 3.5 times that of the constant operation situation of Case 1. The electrolyser and storage unit dimensions for Case 3 are summarised in Table 7.

Table 7: Summary of electrolyser and storage unit size for Case 3

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyser</td>
<td>230</td>
<td>KW</td>
</tr>
<tr>
<td>Compressed H₂ storage unit</td>
<td>7.35</td>
<td>m³ (tank volume)</td>
</tr>
<tr>
<td></td>
<td>1743</td>
<td>Nm³ H₂</td>
</tr>
<tr>
<td></td>
<td>156</td>
<td>kg H₂</td>
</tr>
</tbody>
</table>

Figure 39 shows the distribution of power from the WECS in a selected one-week period. Figure 40 shows the SOC for the H₂ storage unit of Case 3. Dips in SOC will appear at times of continuously low wind resources and will set the storage unit size for a given electrolyser capacity.
Figure 40: Storage state of charge (SOC) for Case 3 for a 7.35 m³ storage unit at 300 bar (1743 Nm³).

Figure 41 shows the operation profile for Case 3. In the top-charging strategy of Case 3, the electrolyser operates at near full power ~30% of the time, while it is idling ~60% of the time. 

Figure 41: Operation profile for the electrolyser of Case 3.
3.2.2.5. Conclusions

Based on calculated component sizes, Case 1 will be the least costly in terms of capital investment. This is because both the electrolyser and the storage unit are held at the lowest possible size/capacity for this case.

Case 2 seems unrealistic in that it requires a storage unit with a capacity of 11800 Nm³, which is both practically difficult to achieve and also associated with high investment costs.

Case 3 also requires an over-dimensioning of the electrolyser and storage unit. To make Case 3 more realistic and avoid prolonged periods of idling, the electrolyser should be operated such that it is never switched off, but regulated between 20% and 100% power. This will, however, not contribute to a reduction in the electrolyser size given the size of the storage unit or vice versa. The storage-unit size will still be dependent on the length of the periods of low wind resources and the electrolyser size set.

The storage-unit size of Case 3 can be somewhat reduced by setting the lower limit of the dead-band to a higher value. This will have an impact on the average time of operation/idling for the electrolyser. With a very narrow bandwidth, the electrolyser will be switched between idling and H₂ production at a higher frequency. With regard to start-up time and handling of fast transients, this may not be an acceptable electrolyser operation control strategy. Depending on the electrolyser solution chosen, these possible restraints should be added to the modelling code.

3.2.2.6 Future Work

In this work, a known hydrogen load (3 mini-buses) was selected, but models with less stringent requirements should also be developed. One scenario of interest would include adding a small- to medium-sized fuel cell to the system, enabling distribution of electrical power to an application or to the grid in times of low consumption of hydrogen. This would make the system more flexible. In addition, cost models should be included in the model library to enable users to identify break-even points with regard to control strategies and type of technology installed. Finally, the potential for hydrogen energy systems for load levelling in weak grids should also be investigated.

3.2.2.7 References

[12] Communicated by R. Hamelmann at Proton Motor GmbH, Germany

3.2.3 Hydrogen Vehicle and Refueling Infrastructure Alternatives

3.2.3.1 Introduction

The transportation analysis discussed herein is not as geographically specific as the previous two case studies discussed above. It is, however, based on current U.S. experience with hydrogen fueling infrastructure. It is meant to contribute to the ongoing discussion, both in the U.S. and internationally, on the preferred choice for fueling options and hydrogen distribution alternatives.

3.2.3.2 Scope of Study

The overall scope of the transportation analysis includes a comparison of hydrogen passenger vehicle fueling options, including:

- Refueling alternatives, primarily various sources of gaseous or liquid hydrogen
Vehicle configuration and fuel alternatives, primarily various hydrogen storage and power plant selections, compared to other fuels, including methanol and gasoline

Cost variations for electricity, natural gas and hydrogen with economic conditions and over international boundaries

Future costs of upstream infrastructure

Figures of merit for the overall project include: Costs, both capital and operating, leading to the cost of hydrogen dispensed to a vehicle; Efficiency, primarily in terms of vehicle fuel economy; Footprints, primarily for refueling station alternatives; and Emissions, for each alternative system

The base case refueling station analysis, including all cost and footprint assumptions, has been reported previously [13-16]. This paper addresses the sensitivity of dispensed hydrogen costs to a number of assumptions regarding future supply and demand assumptions and end-use aspects of various vehicle configurations and alternative fuels. The sensitivity analysis addressed the following parameters:

- The utilization factor of the refueling station
- Number of vehicles served per day (or capacity of station)
- Natural gas and electricity prices
- Upstream costs of central reformers when demand exceeds existing supply
- Upstream costs of new hydrogen pipelines

The end-use analysis addressed tailpipe emissions of various vehicle configurations and local station emissions for various station and vehicle combinations.

The objective throughout the study has been to aid decision-making with respect to station type, thus guiding infrastructure development. The overall goal is to answer the question: Where are we headed? Some have suggested a trend from bulk hydrogen delivery, to on-site hydrogen production, and possibly to on-board reforming. But does analysis of the costs and emissions, particularly for hydrogen dispensed to hydrogen vehicles, justify this scenario? This study attempts to shed some light on this question.

3.2.3.3 Refueling Station Infrastructure Alternatives

Originally, six refueling station cases were selected for analysis. These give an estimate of the cost of hydrogen dispensed to the vehicle. These cases were:

- Bulk liquid hydrogen from an existing central reformer is transported to the refueling station by truck, stored as a cryogenic liquid and dispensed to the vehicle as a liquid.
- Bulk liquid hydrogen from an existing central reformer transported to the refueling station by truck, stored as a cryogenic liquid and dispensed to the vehicle as a gas.
- Bulk gaseous hydrogen transported to the refueling station by existing pipeline, stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas. This case is valid only where there is a nearby pipeline. (Pipeline construction costs were considered later.)
- Gaseous hydrogen generated at the refueling station from natural gas by steam methane reforming (SMR), stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas.
- Gaseous hydrogen generated at the refueling station from natural gas by a partial oxidation (POX) process, stored as a compressed gas and dispensed to the vehicle as gas.
- Gaseous hydrogen generated at the refueling station by electrolysis, stored as a compressed gas at 5000 psi and dispensed to the vehicle as a gas. (For the early analysis, grid electricity was assumed to power the electrolyser. Renewable electricity was considered later.)

System diagrams for these 6 alternatives are shown in Figure 42.
A number of initial assumptions were made regarding operation of the transportation and refueling system [13]. The most important ones are repeated here.

- The base case calls for capacity to refuel 100 vehicles per day.
- Each vehicle refueling event requires approximately 4 kg of hydrogen. As a result, at 100% utilization, 400 kg hydrogen is served per day. Storage is sized to serve the entire anticipated volume of customers, plus a buffer.
- A refueling station consists of the hydrogen production unit or receiving area, storage and its associated facilities, and the dispensing area with two dispensing units. These are the capital cost components considered in this study.
- Available dispensing hours are 24 hours per day, 365 days per year.
- On-site hydrogen production capacity is sized to fill the required storage once per day.
- Liquid delivery is scheduled once per week. An average round trip delivery distance of 1000 miles was assumed. The dewar is sized for one week's service plus 30%, to maintain proper conditions and reduce boil-off in the tank.

The costing and sizing approach are described elsewhere [13]. The cost analysis consists of computing both capital cost and the delivered cost of hydrogen for each alternative station case. The capital cost components include:

- Hydrogen generator (for on-site cases)
- Storage system and auxiliaries
- Storage compressor (for gaseous cases)
- Boost compressor (for gaseous cases)
- Dispensers and auxiliaries

The central SMR and pipeline were not costed for the base cases, as they were not part of the station. The cost of delivered hydrogen – liquid or gas – is included in the operation costs. The upstream systems were costed for the sensitivity analysis presented here.
The operating cost components include:
(a) Capital charge (cost of money)
(b) Natural gas (if purchased)  
(c) Hydrogen (if purchased)  
(d) Catalysts or other consumables  
(e) Electricity  
(f) Operations and Maintenance charges O&M  
(g) Labor  

The cost of delivered or dispensed hydrogen is calculated based on the annual operating costs divided by the amount of hydrogen delivered, in GJ.

\[
\text{Delivered cost of hydrogen ($/GJ)} = \frac{\text{Annual operating cost}}{\text{GJ hydrogen dispensed per year}}
\]

Figure 43 presents a comparison of delivered cost of hydrogen for the 6 base cases assuming 100% utilization factor for the refueling station, i.e., 100 cars are filled every day. Figure 44 presents the components of the fuel cost for each case. These charts are all presented in $/GJ. An equivalent value to consider would be $/gallon of gasoline equivalent. $30/GJ is approximately $3/gallon. A 300 mile fill-up for a hydrogen fuel cell vehicle would be about $16 on average.

3.2.3.4 Sensitivity Studies

The basic station model was used to study the effects of changing various parameters. These included the following parameters: number of vehicles, capital costs, and prices for gas and electricity. Upstream infrastructure costs were added later.

3.2.3.4.1 Sensitivity to Utilization Factor

The first sensitivity study was a look at the impact of under-utilization of the refueling station, as may be the case in the early years of operation. Figure 45 shows a comparison of the cost of delivered hydrogen for 100% and 50% utilization (i.e., 50 cars served per day) for the 6 base cases. Capital charges, O&M and labor are independent of utilization, whereas consumables (i.e. natural gas or bulk hydrogen) and electricity use depend on the number of vehicles served. Thus, the cases with greater up-front capital cost, i.e., the on-site generation cases, are more dramatically impacted by the utilization factor.

3.2.3.4.2 Sensitivity to Station Size

The original analysis was based on 100 passenger vehicles per day, or 400 kg of dispensed hydrogen. This corresponds to just over 165,000 scf/day. Some have questioned whether the conclusions would change if a larger station size were analyzed. The calculations for the 6 cases have been repeated assuming a larger number of vehicles: 200 per day and 500 per day. These correspond to 800 kg (330,000 scf/day) and 2000 kg (825,000 scf/day). The results, in Figure 46, show each station configuration for the 3 sizes. The overall cost of dispensed hydrogen decreases for a larger station, but the relative comparison between station types does not change significantly, although distinctions become less at larger sizes.

3.2.3.4.3 Sensitivity to Changes in the Cost of Natural Gas and Electricity

The base case analysis assumed costs for natural gas and electricity that were representative of recent historical values. The costs are highly volatile, however, and also vary internationally. The study team expressed an interest in seeing how sensitive the infrastructure results were to variations in the costs of these consumables. Tables 8 and 9 list the original and parametric assumptions for the sensitivity analysis, for natural gas and electricity, respectively. Natural gas costs were halved and doubled to show general sensitivity. These changes in natural gas cost flowed through to bulk hydrogen costs in the following way. Dividing the natural gas cost by 2 reduced the bulk liquid hydrogen cost by about 15%, whereas multiplying the natural gas cost by 2 increased the bulk liquid
hydrogen cost by a factor of 30%. This relationship was based on Ref. 18. Pipeline hydrogen from a central reformer is more directly impacted by changes in the cost of natural gas. As seen in Table 8, the resulting cost variations are greater.

Electricity costs were also halved and doubled. These variations also impact the cost of hydrogen from a central reformer, as shown in Table 9. Renewable electricity from wind is approximately represented by the higher, doubled costs. Renewable electricity from solar photovoltaics would be nearly ten times higher [19].

Figure 43. Delivered Cost of Hydrogen ($/GJ) for Base Cases, 100% Utilization Factor

Figure 44. Components of Hydrogen Cost for Base Cases, 100% Utilization Factor
Figure 45. Cost of Delivered Hydrogen for 100% and 50% Utilization Factors

Figure 46. Sensitivity of Dispensed Hydrogen Cost to Station Size

Table 8. Natural Gas Prices and Resulting Bulk Hydrogen Prices for Sensitivity Study

<table>
<thead>
<tr>
<th></th>
<th>Natural gas, $/MMBTU</th>
<th>Bulk liquid hydrogen*, $/GJ</th>
<th>Pipeline hydrogen, $/GJ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>6</td>
<td>25.6</td>
<td>10</td>
</tr>
<tr>
<td>Lower (× 1/2)</td>
<td>3</td>
<td>21.5</td>
<td>6</td>
</tr>
<tr>
<td>Higher (× 2)</td>
<td>12</td>
<td>33.5</td>
<td>18</td>
</tr>
</tbody>
</table>

*Assumes 500 mile one-way delivery distance
Table 9. Electricity Prices and Resulting Bulk Hydrogen Prices for Sensitivity Study

<table>
<thead>
<tr>
<th></th>
<th>Electricity, off-peak, cents/kWh</th>
<th>Electricity, on-peak, cents/kWh</th>
<th>Bulk liquid hydrogen, $/GJ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>3</td>
<td>7</td>
<td>25.6</td>
</tr>
<tr>
<td>Lower ($\times\ 1/2$)</td>
<td>1.5</td>
<td>3.5</td>
<td>23.6</td>
</tr>
<tr>
<td>Higher ($\times\ 2$)</td>
<td>6</td>
<td>14</td>
<td>29.4</td>
</tr>
</tbody>
</table>

The effect of changing the cost of consumables is to change the resulting cost of hydrogen dispensed at the pump. Figure 47a shows the sensitivity to natural gas prices. Only the on-site electrolyser case is insensitive to the cost of natural gas. The POX system is seen to become relatively expensive as gas prices rise. Figure 47b shows the sensitivity to electricity prices. Not surprisingly, the results for the on-site electrolyser are most affected by these changes. In fact, if the higher, doubled price represents wind power, then renewable electrolysis is not as attractive as it initially appeared, compared to other options.

![Figure 47a&b. Sensitivity of Dispensed H₂ Cost ($/GJ) to a) Natural Gas and b) Electricity Prices](image)

3.2.3.4.4 Sensitivity to the Costs of Upstream Infrastructure

The original base case analyses were built around an assumption that refueling stations would be served from hydrogen resources already in place. Therefore, the cost of dispensed hydrogen did not reflect the need for new, central hydrogen production facilities elsewhere. The study team considered this situation unrealistic for the long-term and wondered what the cost of building upstream infrastructure would mean to the conclusions regarding preferred station selection. As this was seen as an important policy issue, new cases were added to the study. These include the cost of building new large central reformers (when current capacity is exceeded) and the cost of building new hydrogen pipelines where none currently exist.

**Central Reformer Development** The cost of a central reformer has been estimated as $340 million for a 153 MSCF/day plant, which is representative of a very large scale plant [20]. If the proportional capital cost is included along with the capital cost of the station (i.e., the fraction corresponding to 100 vehicles per day, or 0.165 MSCF/day), this adds $368,000 to the capital cost for those systems using bulk hydrogen. When computing this addition, plus corresponding O&M, the additional cost of dispensed hydrogen is 3.4$/GJ. This represents about a 10% increase in the cost of dispensed hydrogen for the two scenarios using bulk liquid hydrogen.
Pipeline Development  Hydrogen pipelines exist in several places in the U.S., mostly in the vicinity of large refinery capacity [21]. Here, pipelines are used to ship by-product hydrogen short distances for industrial uses. Where pipelines do not exist, they could be built. Conversion of natural gas pipelines to hydrogen has also been proposed, but that option has not been evaluated in this study. It has been stated that construction of new hydrogen pipelines would be extremely expensive and such investment would not be made [22]. However, several studies and this estimate of pipeline installation costs seem to indicate that, within the larger picture of developing hydrogen fueling infrastructure, the construction of pipelines should not be categorically eliminated.

In this sensitivity study, the estimates of Ogden [23], Richards [24], and Amos [21] have been used to show the impact of including the construction of new hydrogen pipelines in the station infrastructure cost. Both Ogden and Richards have estimated a hydrogen pipeline cost for an urban area of $1M per mile. Amos’ estimates range from $200,000 to $2 million / mile, for a range of conditions. Ogden further estimates the marginal, addition to the cost of new pipeline using a formula based on distance and mass flow [20]:

$$$/GJ = 1.2 \times \text{distance in km} / \text{flow rate in million scf / day}.$$  

Ogden limited her estimate to the mass flow range of 1 to 20 MSCF/day. For the current modeling, a value of $1M / mile for the flow rate range 10 to 20 MSCF/day was adopted. The proportional share of the pipeline capital cost was then added to the station capital cost for the pipeline case.

Figure 48 shows the impact of including upstream infrastructure costs into the calculation for dispensed hydrogen cost for the 100-vehicle station. The calculation assumes there are enough stations to share the full cost of the new infrastructure. A central reformer producing 153 MSCF/day would supply over 900 stations. A pipeline carrying 10 MSCF/day would serve 15 stations.

The two cases using bulk delivered liquid hydrogen show an increased cost of 3.375 $/GJ or about 10%. This assumes the same delivery distance (500 miles, or 1000 miles round trip) as the base cases. The pipeline case has 3 new results:
- the case of including new reformer capacity into the system capital cost,
- the case of including a new 10-mile pipeline (but not the central reformer) into the system capital cost, and
- the case of including a new 100-mile pipeline.

The 10-mile pipeline adds approximately 2$/GJ or about 8%. The 100 mile pipeline adds 12$/GJ, or about 50%. Thus, the overall general conclusion is that adding this upstream infrastructure does not necessarily price bulk hydrogen options out of the market for future refueling stations. The pipeline case is probably limited to a regional or urban area, however, because of the strong cost sensitivity to distance.
3.2.3.5 Emissions Analysis

Although an analysis of hydrogen refueling infrastructure was the major emphasis of this study, the IEA Annex was also interested in looking at alternative end-use scenarios to hydrogen fuel cell vehicles. Other fuels and vehicle configurations have been proposed for a clean future. The primary figures of merit for this part of the study were fuel economy and emissions. Tailpipe and local or station emission results are reported here.

Alternative vehicle configurations fall into the following categories:
- Alternative hydrogen power plants: fuel cell or internal combustion engine (ICE)
- Alternative hydrogen storage types: compressed gas, cryogenic liquid, or metal hydride
- Alternative fuels for on-board storage (and reforming): hydrogen, methanol, or gasoline
- Alternative vehicle types: battery hybrid and advanced ICE, such as PNGV vehicles (The battery hybrid is considered the most likely competition for near-term clean vehicles.)

Fuel economy estimates were required in the analysis of tailpipe emissions. The fuel economy analysis was based primarily on other estimates, i.e., estimates from other sources were summarized and compared. Major sources were recent DTI studies [25, 26] and more recent PSI results [27]. Some parameters that were considered in an attempt to find consistency among the studies were: vehicle weight, vehicle driving range, and driving cycle. Vehicle weight is impacted by the type of power plant, type of storage system, and the fuel type. As an example, for a base case vehicle weight of 900 kg, each additional kg of storage weight contributes 1.5 kg of vehicle weight [25].

Emissions results are also based primarily on other studies. These were also surveyed and compared. To help illustrate the local environmental impact, tailpipe and station emissions were estimated independently, although it was difficult in some studies to separate fueling operations emissions from the total. For the methanol and gasoline fueled vehicles, results are based on previous work by Ogden [23] and The American Methanol Foundation [28]. Methanol and gasoline stations are assumed to be similar to the hydrogen station, i.e., they have the same vehicle refueling capacity and same typical urban location. The methanol and gasoline storage tanks are assumed to be filled by weekly truck delivery, as in the hydrogen case. The diesel delivery trucks and the delivery
process contribute to the local pollution; U.S. Environmental Protection Agency (EPA) data were used to estimate this impact.

Other specific assumptions for the emissions analysis included:
- Where available, actual vehicle data were used.
- Modeled vehicles were based on 900 kg PNGV Glider for DTI [26] and 650 kg Renault Twingo for PSI studies [27].
- The station was sized to serve 100 cars per day with 300-mile range per fill-up. Thus, the on-site storage capacity is a function of the assumed fuel economy of the vehicles.
- Fuel delivery trucks spend 3 hours per delivery (once per week) in the local, urban area, traveling an average of 20 mph, except for battery hybrid vehicle stations, which are serviced once every two weeks.
- Fuel delivery trucks are assumed to be powered by a heavy-duty diesel engines and have a fuel economy of 6.7 miles per gallon, based on Ref. [29].
- On-site POX generators produce emissions similar to the SMR, multiplied by 1.73, per Ref. [30].

Composite tailpipe emission results are shown in Figure 49. Details can be found in Ref. [17]. These give a graphical representation of the dramatic reduction in tailpipe emissions from hydrogen vehicles compared to all other alternatives.

Emissions from station operations or delivery of fuel to the station have been estimated for the various station configurations. These are primarily engine pollutants from diesel delivery trucks, fuel volatiles (so called “marketing emissions”) for gasoline and methanol delivery, and green house gases for the cases with on-site hydrogen production from natural gas. The two cases with virtually no local emissions are the pipeline delivery of hydrogen and hydrogen production by electrolysis. For these two cases the major emissions occur elsewhere - at the central reformer and/or electric power station. Only renewable production of hydrogen avoids real-time air emissions throughout the system. Local emission results (in kg of pollutant per year) are shown in Figures 50a for green house gases and volatile organic compounds, and in Figure 50b for CO, NOx, SOx, and particulates. Note the different scales for the two parts of Figure 50.
3.2.3.6 Summary

- The cost of dispensed hydrogen is generally greater for on-site production of hydrogen.
- When the station is underutilized, the cost of dispensed hydrogen from all sources is always greater because the capital, O&M, and labor charges are independent of the utilization factor. For on-site generation alternatives, where the capital investment is higher, the cost of dispensed hydrogen is even higher when the utilization factor is less than 100%.
- A larger station would serve less expensive hydrogen fuel if fully utilized, but the comparison of options does not change significantly, i.e., pipeline hydrogen is least expensive, where available.
- Increasing costs of natural gas increase the cost of dispensed hydrogen for all cases, except on-site electrolysis.
- On-site electrolysis is most significantly affected by changes in the cost of electricity. Doubling electricity costs, which might be representative of current wind power costs, makes on-site electrolysis unattractive compared to other cases.
- Including the cost of upstream infrastructure in the system cost does not necessarily make bulk delivered hydrogen noncompetitive. Building a very large central reformer adds only about 10% to the cost of bulk hydrogen options.
- Pipeline costs depend on distance and flowrate. Modest volumes of hydrogen can be delivered regionally (within about 100 miles) at an infrastructure cost that still keeps the dispensed cost of hydrogen competitive with other options.
- Tailpipe emissions for hydrogen vehicles are zero or negligible, making hydrogen vehicles the best choice for urban driving. Station emissions for hydrogen stations are lowest for pipeline hydrogen and on-site production by electrolysis.

3.2.3.7 Conclusions

This analysis has shown that various options for hydrogen infrastructure are possible, and that the least costly option may vary with location, local pricing of gas or electricity, and technology maturity. Near-term options using hydrogen delivered from existing sources are quite feasible. The longer-term options include building new central production and distribution facilities. On-site generation requires development of commercial subsystems. The urgency of reduced local emissions can be met with hydrogen-fueled vehicles and clean hydrogen brought in by pipeline or produced by electrolysis.

3.2.3.8 References

[17] S. Schoenung, "IEA Hydrogen Annex 13, Transportation Applications Analysis" final report to DOE, cooperative agreement no. DE-FC36-00GO10607, 2002
[22] Larry Watkins, South Coast Air Quality Management District, personal communication, October 2001
3.3 Life Cycle Assessments

The value of hydrogen energy systems are often linked to environmental improvements (greenhouse gas reductions, and CO, NOx, and SOx reductions, etc.) or other intangible benefits (job creation, energy independence, etc). Quantification of some of these benefits can be made using life cycle assessment (LCA) comparisons. LCA is a systematic analytical method to identify, evaluate, and help minimize the environmental impacts of a specific process or competing processes. Material and energy balances are used to quantify the emissions, resource depletion, and energy consumption of all processes between transformation of raw materials into useful products and the final disposal of all products and by-products. The results are then used to evaluate the environmental impacts of the process so that efforts can be focused on mitigating possible effects.

The scope of an LCA for hydrogen systems was defined, based on established (published) LCA methodologies. The measures included comparison of CO2 and other gaseous emissions, and determination of net energy ratio (amount of energy produced per unit of fossil fuel input).

3.3.1 LCA Case Study for a Residential Application

This application is to provide heat and electricity to a residential district in the Netherlands containing 1,300 houses. The heating and electricity requirement for the district is 6,880 MWh/yr and 4,380 MWh/yr, respectively. Two comparative systems were examined: (1) a central reformer produces hydrogen with a portion being supplied to the district where it is used in a proton exchange membrane (PEM) fuel cell to provide heat and power for each house (a small amount of electricity must also come from the grid and additional heat is provided by a heat pump), (2) natural gas is burned in a boiler to supply heat and a natural gas combined cycle power generation system provides the electricity.

The Sankey diagram showing the district energy flow for this conventional system is shown in Figure 51. A life cycle assessment of this system was performed.

ECN examined several hydrogen distribution systems that integrated a combination of several of the following: PEM fuel cells, solid oxide fuel cells, heat pumps, natural gas burners, hydrogen burners, heat storage, and hydrogen storage. The hydrogen system chosen for the life cycle assessment work uses a 0.38 kW PEM fuel cell integrated with a heat pump and hydrogen storage along with make-up electricity from the grid. The Sankey diagram showing the district energy flow for this hydrogen network system is shown in Figure 52.
3.3.1.1 LCA Results for Residential Application

Figure 53 is a comparison of the resource consumption and Figure 54 is a comparison of the major air emissions for the conventional and hydrogen systems examined. Because of its magnitude, CO₂ is shown on a different scale. Except for natural gas, the hydrogen system consumes slightly more resources than the conventional system per kWh of heat and electricity supplied to the district. Because of the design and efficiency of the district heating and electricity production, the amount of natural gas required by the hydrogen system is less than that for the conventional system. The hydrogen system also produces less air emissions per kWh of heat and electricity supplied to the district.

The resource consumption, air emissions, GWP, solid waste generated, and energy balance for the each system are given in Table 10. The GWP of the hydrogen system is 16% less than that for the conventional system. The CH₄ emissions, primarily from natural gas production and distribution, contribute about 12% to the each system's GWP. The energy consumption of the conventional system is higher than the hydrogen system, 6.3 MJ/kWh of heat plus electricity compared to 4.9 MJ/kWh of heat plus electricity. The difference between the net energy ratio and external energy ratio indicates that the conventional system consumes considerably more upstream energy than the hydrogen system for every kWh of heat and electricity supplied to the district. There is also slightly less solid waste produced from the hydrogen system.

Figure 52: Sankey Diagram for Hydrogen System (Energy Flow in MWh/yr)
Figure 53: Residential Application - Comparison of Resource Requirements

- Conventional system (boiler & NGCC)
- H2 system (PEMFC & heat pump)

- **Coal**: 128 g/kWh
- **Iron ore + scrap**: 104 g/kWh
- **Limestone**: 0 g/kWh
- **Natural Gas**: 128 g/kWh
- **Oil**: 0 g/kWh

Resource consumption (g/kWh of heat plus electricity)

---

Figure 54: Residential Application - Comparison of Major Air Emissions

- Conventional system (boiler & NGCC)
- H2 system (PEMFC & heat pump)

- **CO2**: 350 g/kWh
- **CO**: 0.5 g/kWh
- **CH4**: 2.0 g/kWh
- **NOx**: 1.5 g/kWh
- **NMHC**: 1.0 g/kWh
- **Particulates**: 0.5 g/kWh
- **SOX**: 0.5 g/kWh

Air emissions, except CO2 (g/kWh of heat plus electricity)
Table 10: Comparison of LCA Results for Residential Application

<table>
<thead>
<tr>
<th>Resource consumption</th>
<th>Conventional System (Boiler &amp; NGCC)</th>
<th>Hydrogen System</th>
<th>(g/kWh of heat plus electricity)</th>
<th>(g/kWh of heat plus electricity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>coal</td>
<td>1.0</td>
<td>1.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>iron (ore + scrap)</td>
<td>0.4</td>
<td>1.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>limestone</td>
<td>0.2</td>
<td>0.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>natural gas</td>
<td>127.5</td>
<td>103.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>oil</td>
<td>0.4</td>
<td>0.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water consumption</td>
<td>0.02</td>
<td>0.4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Air Emissions</th>
<th>(g/kWh of heat plus electricity)</th>
<th>(g/kWh of heat plus electricity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>338.5</td>
<td>285.4</td>
</tr>
<tr>
<td>CO</td>
<td>0.3</td>
<td>0.2</td>
</tr>
<tr>
<td>CH4</td>
<td>2.1</td>
<td>1.7</td>
</tr>
<tr>
<td>NOx</td>
<td>0.4</td>
<td>0.3</td>
</tr>
<tr>
<td>N2O</td>
<td>0.0012</td>
<td>0.0006</td>
</tr>
<tr>
<td>NMHC</td>
<td>0.5</td>
<td>0.4</td>
</tr>
<tr>
<td>particulates</td>
<td>0.065</td>
<td>0.057</td>
</tr>
<tr>
<td>SOx</td>
<td>0.22</td>
<td>0.20</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>(g of CO2-equivalent/kWh of heat plus electricity)</th>
<th>(g of CO2-equivalent/kWh of heat plus electricity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GWP (a)</td>
<td>383</td>
</tr>
<tr>
<td>% contribution from CO2</td>
<td>88.3%</td>
</tr>
<tr>
<td>% contribution from CH4</td>
<td>11.6%</td>
</tr>
<tr>
<td>% contribution from N2O</td>
<td>0.1%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Solid Waste (g/kWh of heat plus electricity)</th>
<th>(g/kWh of heat plus electricity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>waste generated</td>
<td>4.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy balance (MJ/kWh of heat plus electricity)</th>
<th>(MJ/kWh of heat plus electricity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>total energy consumed</td>
<td>6.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Life cycle efficiency</th>
<th>(Edist - Eu - En)/ (En) (b), (c)</th>
</tr>
</thead>
<tbody>
<tr>
<td>-53.8%</td>
<td>-29.6%</td>
</tr>
</tbody>
</table>

| External energy efficiency (Edist - Eu)/ (En) (c), (d) | 46.2%                                             | 70.4%                                            |

| Net energy ratio (Edist)/ (En) (c), (e)               | 0.6                                               | 0.7                                               |

| External energy ratio (Edist)/(En - En) (c), (d)      | 2.8                                               | 6.9                                               |

(a) The GWP system is considered to be a combination of CO2, CH4, and N2O emissions. The capacity of CH4 and N2O to contribute to the warming of the atmosphere is 21 and 310 times higher than CO2, respectively, for a 100 year time frame according to the Intergovernmental Panel on Climate Change (IPCC). Thus, the GWP of a system can be normalized to CO2-equivalence to describe its overall contribution to global climate change.

(b) This efficiency includes the fossil energy consumption of all process steps in the system.

(c) Edist = electric and heat energy delivered to the district; Eu = energy consumed by the upstream processes; En = energy contained in the natural gas to produce heat and power; En = total fossil energy consumed within the system (i.e., Eu + En)

(d) Excludes the natural gas to the hydrogen plant indicating the energy consumption from upstream processes.

(e) This term illustrates how much electric and heat energy is delivered to the district for each unit of fossil fuel energy consumed.
3.3.2 LCA Case Study for a Remote Application

For this application, hydrogen production and storage are required in order to fuel three PEMFC buses used for transportation on a remote island off the coast of Norway. The hydrogen requirement based on the fuel consumption and driving range of the buses is 32 kg/day of hydrogen. Two comparative systems were examined: (1) hydrogen is produced from wind/electrolysis and excess electricity is sent to the grid providing some power on the island, and (2) hydrogen is produced via a central steam methane reforming (SMR) plant then a portion of the hydrogen is shipped to the island.

3.3.2.1 Operation of Wind Turbine and Electrolyser

For all of the cases examined, the size of the wind turbine was kept constant at 2 MW. In one case, the electrolyser is operated at constant power to minimize the size of the electrolyser. This means that at times power must be supplied from the grid when the wind resources are poor and some hydrogen storage is required. Two stand-alone scenarios were also examined where the electrolyser only operates when there are adequate wind resources. In one stand-alone case, referred to as the direct-connect scenario, the electrolyser operates any time that the wind resources are adequate and the hydrogen storage is sized accordingly. The size of the electrolyser and storage unit were determined by optimization calculations to achieve a design where the hydrogen storage is never entirely depleted but there is adequate storage for periods of peak hydrogen production. For this case, the electrolyser is operated at 80-100% of its maximum power 75% of the time and is idling 10% of the time. This resulted in an electrolyser that is 48% greater and hydrogen storage that is 29 times larger than the constant power case. In the second stand-alone case, referred to as the top-charging scenario, the hydrogen storage is minimized and the operation of the electrolyser is guided by the amount of hydrogen in the storage vessel. The electrolyser is set to operate when the hydrogen storage reaches the lower dead-band limit and begins idling when the upper dead-band limit is reached. For this case, the electrolyser operates near full power 30% of the time and is idling 60% of the time. The electrolyser is not always operating when the wind resources are adequate, thus the electrolyser must be larger than that for the direct-connect stand-alone scenario. For the top-charging stand-alone scenario, the electrolyser is 248% greater and the hydrogen storage is 4 times larger than the constant power case. This means that the electrolyser is 135% greater and the hydrogen storage is 85% less than the direct-connect stand-alone scenario. Considering both the economics (higher costs for the larger electrolyzers and storage units for the two stand alone cases) and the best operating practice, the most logical wind/electrolysis scenario for this situation is the constant power operation case, therefore, a life cycle assessment was done for this case only.

3.3.2.2 Boundaries of Each System

Because the wind turbine produces more electricity than is required for hydrogen production, the excess electricity is sent to the grid. At those times when the wind resources are poor, electricity is required from another source. Although the majority of Norway’s electricity comes from hydro, new capacity is being generated from natural gas. Therefore, the electricity required during times of poor wind resources is assumed to come from a natural gas combined-cycle (NGCC) system via a sub sea cable. If the island were farther out in the ocean then the electricity would probably have come from diesel generators. Table 11 shows the electricity production and consumption of the wind/electrolysis system.

<table>
<thead>
<tr>
<th>Description</th>
<th>Electricity produced or required (GJ/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total electricity produced by the wind turbine</td>
<td>20,866</td>
</tr>
<tr>
<td>Electricity required for hydrogen production and compression</td>
<td>2,281</td>
</tr>
<tr>
<td>Electricity required during times when wind resources are poor</td>
<td>308</td>
</tr>
<tr>
<td>Excess electricity from wind turbine</td>
<td>18,892</td>
</tr>
</tbody>
</table>
The graphic in Figure 55 shows the processes that make up this system.

For comparison, a life cycle assessment was performed on a fossil based system, steam methane reforming. Hydrogen is assumed to be produced at a large central SMR plant then a portion of the hydrogen is compressed and shipped to the island in tube trailers over a distance of 100 km. Figure 56 shows the processes involved in hydrogen delivery from the SMR system.

3.3.2.3 LCA Results for Remote Application

Results of the remote system show that, in general, the resource requirement per kg of hydrogen is somewhat higher for the wind/electrolysis system than for the SMR system. This is due to the steel and concrete used in constructing the wind turbine. Figure 57 compares the resource consumption of each system. Natural gas, of course, is consumed at the highest rate for the SMR system.

Figure 58 compares the major air emissions of the two systems. Note that because of its magnitude, CO₂ is shown on a different scale.
Table 12 gives the resource consumption, air emissions, global warming potential (GWP), solid waste generated, and energy consumption for both the wind/electrolysis system and the SMR system.
Table 12: Comparison of LCA Results for Remote Application

<table>
<thead>
<tr>
<th>Resource consumption</th>
<th>SMR (g/kg of H(_2))</th>
<th>Wind/Electrolysis (g/kg of H(_2))</th>
</tr>
</thead>
<tbody>
<tr>
<td>coal</td>
<td>159</td>
<td>119</td>
</tr>
<tr>
<td>iron (ore + scrap)</td>
<td>21</td>
<td>227</td>
</tr>
<tr>
<td>limestone</td>
<td>16</td>
<td>261</td>
</tr>
<tr>
<td>natural gas</td>
<td>3,642</td>
<td>10</td>
</tr>
<tr>
<td>oil</td>
<td>16</td>
<td>31</td>
</tr>
<tr>
<td>Water consumption</td>
<td>33</td>
<td>21</td>
</tr>
<tr>
<td>Air Emissions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO(_2)</td>
<td>11,357</td>
<td>590</td>
</tr>
<tr>
<td>CO</td>
<td>8</td>
<td>0.6</td>
</tr>
<tr>
<td>CH(_4)</td>
<td>60</td>
<td>0.2</td>
</tr>
<tr>
<td>NOx</td>
<td>21</td>
<td>3</td>
</tr>
<tr>
<td>N(_2)O</td>
<td>0.1</td>
<td>0.02</td>
</tr>
<tr>
<td>NMHC</td>
<td>16</td>
<td>2</td>
</tr>
<tr>
<td>particulates</td>
<td>4</td>
<td>20</td>
</tr>
<tr>
<td>SOx</td>
<td>8</td>
<td>3</td>
</tr>
<tr>
<td>GWP (a)</td>
<td>12,665</td>
<td>602</td>
</tr>
<tr>
<td>% contribution from CO(_2)</td>
<td>89.7%</td>
<td>98.0%</td>
</tr>
<tr>
<td>% contribution from CH(_4)</td>
<td>10.0%</td>
<td>0.7%</td>
</tr>
<tr>
<td>% contribution from N(_2)O</td>
<td>0.4%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Solid Waste</td>
<td></td>
<td></td>
</tr>
<tr>
<td>waste generated</td>
<td>224</td>
<td>140</td>
</tr>
<tr>
<td>Total energy consumed</td>
<td>195 MJ/kg of H(_2)</td>
<td>5 MJ/kg of H(_2)</td>
</tr>
<tr>
<td>net energy ratio</td>
<td>(E(_{\text{H2}})/E(_f)) (b), (c)</td>
<td>0.7</td>
</tr>
<tr>
<td>external energy ratio</td>
<td>(E(_{\text{H2}})/(E(<em>f) - E(</em>{\text{ngfeed}})) (c), (d)</td>
<td>5</td>
</tr>
</tbody>
</table>

(a) The GWP is considered to be a combination of CO\(_2\), CH\(_4\), and N\(_2\)O emissions. The capacity of CH\(_4\) and N\(_2\)O to contribute to the warming of the atmosphere is 21 and 310 times higher than CO\(_2\), respectively, for a 100 year time frame according to the Intergovernmental Panel on Climate Change (IPCC). Thus, the GWP of a system can be normalized to CO\(_2\)-equivalence to describe its overall contribution to global climate change.

(b) This term illustrates how much hydrogen energy is produced for each unit of fossil fuel energy consumed.

(c) E\(_{\text{H2}}\) = the energy in the hydrogen produced; E\(_f\) = the total fossil energy consumed by the system

(d) E\(_{\text{ngfeed}}\) = the natural gas feedstock to the SMR plant; This term excludes the natural gas to the hydrogen plant indicating the fossil energy consumption from upstream processes.

As expected, the natural gas consumption per kg of hydrogen for the SMR system is considerably higher than that for the wind/electrolysis system. The air emissions show that the wind/electrolysis system has a considerable reduction in CO\(_2\) and CH\(_4\). Particulate emissions are higher for the wind/electrolysis system due to the concrete requirement. They come primarily from quarrying the sand and limestone needed for concrete production. The GWP is greatly affected by the use of natural gas, mostly because of the CO\(_2\) emissions released during combustion and partly because of the CH\(_4\) that is emitted to the atmosphere during natural gas production and distribution. The energy balance shows that the wind/electrolysis system produces 22 MJ of H\(_2\) are for every MJ of fossil energy consumed while the SMR system produces only 0.7 MJ of H\(_2\) for every MJ of fossil energy consumed. The upstream energy consumption for the SMR system is high because when the natural gas feedstock energy is excluded, the external
energy ratio is still low. Also, note that the energy ratio for the SMR system is lower than the wind/electrolysis system even after subtracting out the energy content of the natural gas, 5 versus 22.

3.3.3 Summary and Recommendations for LCAs

For the residential application, the resource consumption is higher for the hydrogen system compared to the conventional system. However, the air emissions, energy consumption, and solid waste generated are somewhat less for the hydrogen system. The hydrogen system in the residential application is fossil based but if this system were to use hydrogen produced from a renewable source, then the air emissions, especially CO₂ and CH₄, and the energy consumption will be even lower. For the remote application, in general, the renewable hydrogen system consumes more resources than the SMR system with the exception of the large amount of natural gas consumed by the SMR system. Apart from that, there is a considerable reduction in the air emissions, solid waste generated, and energy consumption by using wind/electrolysis.

The economics of these systems are being examined by Norway and the Netherlands. Putting this information together with the LCA results will give the cost of avoided emissions, waste, and energy consumption for the novel versus conventional system. It is recommended that this be done in the future. This is especially important for the residential application to determine if the small savings in emissions, waste, and energy consumption merit the anticipated higher cost of the hydrogen system. Additionally, in terms of the residential application, if the central SMR plant were located close to the district and some of the steam from this hydrogen production facility were available, it would be interesting to examine a scenario where steam is used instead of additional heat from a heat pump.