Global Hydrogen Resource Analysis

Thomas E. Drennen and Susan M. Schoenung

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HYDROGEN IMPLEMENTING AGREEMENT

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Abstract

The International Energy Agency (IEA) established the Hydrogen Implementing Agreement (HIA) to pursue collaborative hydrogen research and development and information exchange among its member countries. The goal of Task 30 (Global Hydrogen Systems Analysis) is to “perform comprehensive technical and market analysis of hydrogen technologies and resources and supply and demand related to the projected use of hydrogen.” The overall objectives of Subtask A (Global Hydrogen Resource Analysis) are to: 1) Analyze potential hydrogen production and distribution pathways for participating countries; 2) Develop a user-friendly pathways analysis tool that allows users to understand the resource options and constraints to meeting future hydrogen demand and that estimates potential petroleum savings and greenhouse gas emission reductions associated with various scenarios; and 3) Collaborate with IEA analysts as appropriate to support global hydrogen resource analysis.

The Global Pathways Analysis Tool (GPAT) calculates least-cost pathways for H2 supply for eight participating countries: France, Germany, Norway, Spain, Sweden, Denmark, Japan, and the United States. The U.S. was further divided into eight regions to allow for additional regional analysis. Additional countries could be added as data becomes available. The pathways include consideration of feedstock, conversion, distribution (regional and long-distance), and carbon costs. For each country, hydrogen demand is calculated based on assumptions about future hydrogen vehicle market shares. Hydrogen production costs are calculated based on country-supplied data on feedstock availability for hydrogen production by type, cost, and quantity from 2010 to 2050, and assumptions about hydrogen production technology assumptions (efficiencies, costs, etc.).
GPAT was used to estimate the likely pathways for a range of scenarios and sensitivities for a wide-scale introduction of fuel cell electric vehicles (FCEV) by 2050. The results show that there are a large number of potential pathways for providing hydrogen to fuel significant FCEV fleet: resources are not the limiting factor to a hydrogen economy. Every country participating has identified multiple options for producing hydrogen domestically. In a low-natural-gas-cost world, it is difficult for other feedstocks to compete for a share of the hydrogen production in the absence of The analysis shows that there are a large number of potential pathways for providing hydrogen to fuel a significant vehicle fleet and that resource availability is not the limiting factor in a hydrogen economy. Using GPAT, each participating country has identified multiple options for producing hydrogen domestically.

GPAT also quantifies the potential reduction in greenhouse gas emissions from the transport sector. For a wide range of scenarios, we estimate that emissions could be lowered 40% – 44% from current levels. While a portion of this is due to expected efficiency improvements in traditional powertrains, FCEVs can lead to significant further reductions, especially for pathways that do not include coal as a feedstock for the hydrogen production.

A key feature of the Global Pathways Resource Analysis Tool is the ability for users to vary key assumptions, including resource availability and cost, vehicle shares and efficiencies, carbon taxes, and renewable portfolio standards, and view real-time results, making the tool ideal for policy-level discussions.
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<thead>
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<th>Acronym</th>
<th>Full Form</th>
</tr>
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<tbody>
<tr>
<td>BEV</td>
<td>Battery Electric Vehicle</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Sequestration</td>
</tr>
<tr>
<td>CARB</td>
<td>California Air Resources Board</td>
</tr>
<tr>
<td>CAFE</td>
<td>Corporate Average Fleet Economy</td>
</tr>
<tr>
<td>FCEV</td>
<td>Fuel Cell Electric Vehicle</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>GJ</td>
<td>Gigajoule</td>
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<tr>
<td>GPAT</td>
<td>Global Pathway Analysis Tool</td>
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<tr>
<td>H2A</td>
<td>Hydrogen Analysis Project</td>
</tr>
<tr>
<td>HDSAM</td>
<td>H2A Delivery Scenario Analysis Model</td>
</tr>
<tr>
<td>HIA</td>
<td>Hydrogen Implementing Agreement</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal Combustion Energy</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>kWh</td>
<td>kilowatt hour</td>
</tr>
<tr>
<td>mpge</td>
<td>miles per gallon equivalent</td>
</tr>
<tr>
<td>LDV</td>
<td>Light Duty Vehicle</td>
</tr>
<tr>
<td>MSM</td>
<td>Macro System Model</td>
</tr>
<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>PHEV</td>
<td>Plug-in Hybrid Electric Vehicle</td>
</tr>
<tr>
<td>ReEDs</td>
<td>Regional Energy Deployment System</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam Methane Reforming</td>
</tr>
<tr>
<td>DOE</td>
<td>United States Department of Energy</td>
</tr>
<tr>
<td>ZEV</td>
<td>Zero Emission Vehicle</td>
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EXECUTIVE SUMMARY

The International Energy Agency (IEA) established the Hydrogen Implementing Agreement (HIA) to pursue collaborative hydrogen research and development and information exchange among its member countries. The goal of Task 30 (Global Hydrogen Systems Analysis) is to “perform comprehensive technical and market analysis of hydrogen technologies and resources and supply and demand related to the projected use of hydrogen.” The overall objectives of Subtask A (Global Hydrogen Resource Analysis) are to: 1) Analyze potential hydrogen production and distribution pathways for participating countries; 2) Develop a user-friendly pathways analysis tool that allows users to understand the resource options and constraints to meeting future hydrogen demand and that estimates potential petroleum savings and greenhouse gas emission reductions associated with various scenarios; and 3) Collaborate with IEA analysts as appropriate to support global hydrogen resource analysis.

The Global Pathways Analysis Tool (GPAT) was developed as a tool for Task 30 participants to understand the resource options and constraints to meeting future hydrogen demand for a wide range of scenarios. GPAT calculates least-cost pathways for H₂ supply for eight participating countries: France, Germany, Norway, Spain, Sweden, Denmark, Japan, and the United States. The U.S. was further divided into eight regions to allow for additional regional analysis. Additional countries could be added as data becomes available. The pathways include consideration of feedstock, conversion, distribution (regional and long-distance), and carbon costs. For each country, hydrogen demand is calculated based on assumptions about future hydrogen vehicle market shares. Hydrogen production costs are calculated based on country-supplied data on feedstock availability for hydrogen production by type, cost, and quantity from 2010 to 2050, and assumptions about hydrogen production technology assumptions (efficiencies, costs, etc.), Figure ES - 1.

Figure ES - 1. Global Pathways Analysis Tool Structure.
A key feature of the Global Pathways Resource Analysis Tool is the ability for users to vary key assumptions, including resource availability and cost, vehicle shares and efficiencies, carbon taxes, and renewable portfolio standards, and view real-time results, making the tool ideal for policy-level discussions. This section discusses the model layout, highlighting user options.

To allow for the inclusion of additional countries, GPAT is organized by regions: North America, Europe, and the Pacific. The regional pages display aggregate projections of hydrogen demand and supply. The projected supply is shown by country and by pathway (natural gas, biomass, etc.). With the exception of carbon prices, the input assumptions are accessed from country level pages. The inputs include: regional distribution costs, feedstock sensitivities, a renewable or no CO2 policy requirement, and vehicle growth and scrappage rate assumptions. The outputs include: delivered H2 costs by feedstock option, feedstock availability and cost, projected hydrogen pathway to 2050, composition of the vehicle fleet, projected GHG emissions, vehicle cost estimates, and a comparison of the resource requirements for the hydrogen production with that country’s 2009 resource use.

GPAT was used to estimate the likely pathways for a range of scenarios and sensitivities for a wide-scale introduction of fuel cell electric vehicles (FCEV) by 2050. The results show that there are a large number of potential pathways for providing hydrogen to fuel a significant FCEV fleet (i.e. 40% of LDV sales by 2050): resources are not the limiting factor to a hydrogen economy. Every country participating has identified multiple options for producing hydrogen domestically. In a low-natural-gas-cost world, it is difficult for other feedstocks to compete for a share of the hydrogen production in the absence of CO2 prices or policies limiting its use. The results are also very sensitive to assumptions about distribution costs; transporting hydrogen can be expensive.

The analysis shows that there are a large number of potential pathways for providing hydrogen to fuel a significant vehicle fleet and that resource availability is not the limiting factor in a hydrogen economy. Using GPAT, each participating country has identified multiple options for producing hydrogen domestically.

GPAT results are presented at both the global, regional (i.e. Europe), and then country-level (France, Denmark, Sweden, Spain, Norway, and Germany) for the following two scenarios. For the U.S., results are shown at the national and regional level. Both scenarios assume that, with the exception of France, FCEVs capture 40% market share of new vehicles sales by 2050. The target for France is 20% market share by 2050.

1) Scenario 1: Each country produces sufficient H2 domestically to meet demand (no trading between countries)

2) Scenario 2: Interregional trading and 100 $/ton CO2e by 2025.

Figure ES - 2 summarizes global demand for the hydrogen required to fuel the projected number of FCEVs each year through 2050. By 2050, the total amount of H2 required is approximately 35 billion kg/year, with the majority of demand coming from the U.S. The least-cost pathways available domestically (Scenario 1) are summarized in Figure ES - 3. The largest pathway is hydrogen produced from locally distributed natural gas SMR facilities. In latter years, hydrogen produced from onshore wind, biomass, and

1 This was done at the request of the French experts.
centralized coal gasification without CCS capture a small percentage of the total supply. The H2 produced from biomass is produced largely in Germany and meets their requirement that 20% of all hydrogen come from renewable sources.

Figure ES - 2. Total demand for hydrogen, by country (Scenario 1 and 2).

Figure ES - 3. Total H2 production pathways (Scenario 1).

These results suggest that in a world of low-cost and abundant natural gas, it is difficult for other resource options to compete on economic grounds alone. Figure ES–4 shows the sensitivity of the results to the natural gas cost assumptions. Specifically, doubling
the cost of natural gas over the entire time of the model run results in a shift away from natural gas towards biomass.

For Scenario 2, which allows interregional transfers of H2 and includes a 100 $/ton CO2e tax by 2025, the H2 produced from biomass plays a much larger role, Figure ES - 5, although not as large as the case of doubled natural gas costs, Figure ES – 4.

In terms of resource use for the hydrogen production, supplying up to 40% of each country’s fleet will require additional consumption of natural gas, coal, and electricity over current consumption levels. While these additional resources are discussed in more detail at the regional or country level, the basic conclusion of this study is that there are sufficient resources available in each country for the wide-scale introduction of FCEVs. For example, for scenario 1, Germany’s consumption of natural gas and coal would
increase 2.9% and 18.5% over 2009 levels. In the U.S., natural gas use would increase 27% over 2009 levels. A limitation of this analysis is its ability to project the effect of increased demand on feedstock costs. For example, it seems likely that a 27% increase in natural gas demand in the U.S. would place upward pressure on U.S. natural gas costs. These effects are not further considered in this report.

The wide scale introduction of FCEVs will lead to significant lowered greenhouse gas emissions from this sector. Figure ES – 6 summarizes the projected emissions for the two scenarios analyzed here along with the case of no FCEVs. Even without the FCEVs, emissions are projected to decline 23% over 2015 levels due to the assumptions about improved efficiency of new vehicles in GPAT. This happens even though the total number of vehicles on the road increases. In Scenario 1, emissions are reduced an additional 23% over projected 2050 emissions, even though natural gas is the primary pathway for the hydrogen production. In Scenario 2, emissions would be 33% lower than the base case in 2050. Achieving larger reductions could be achieved if FCEVs capture an even greater market share.

![Figure ES – 6. Projected GHG emissions from LDVs.](image-url)
Additional integration of the results from this Task with the distribution cost results of Task 28 (Infrastructure) would be a useful next step. It would also be useful to integrate additional countries into GPAT as all participating countries found the iterative data collection and modeling approach used for this Task to be a useful exercise that provided insight into the range of potential options for supplying hydrogen for the transport sector.
INTRODUCTION

The International Energy Agency (IEA) established the Hydrogen Implementing Agreement (HIA) to pursue collaborative hydrogen research and development and information exchange among its member countries. The goal of Task 30 (Global Hydrogen Systems Analysis) is to “perform comprehensive technical and market analysis of hydrogen technologies and resources and supply and demand related to the projected use of hydrogen.” Task 30 includes four main subtasks. Subtask A, the focus of this report, focuses on the potential hydrogen production and distribution pathways for participating countries. Subtask B is developing a harmonized hydrogen technology database with detailed technical and economic assumptions. Subtask C is focused on collaboration with IEA analysts regarding the potential future role for hydrogen in a clean energy future. Subtask D seeks to analyze the value of hydrogen from renewable power to increase flexibility in the grid and other applications.

The overall objectives of Subtask 30A (Global Hydrogen Resource Analysis) are to: 1) Analyze potential hydrogen production and distribution pathways for participating countries; 2) Develop a user-friendly pathways analysis tool that allows users to understand the resource options and constraints to meeting future hydrogen demand and that estimates potential petroleum savings and greenhouse gas emission reductions associated with various scenarios; and 3) Collaborate with IEA analysts as appropriate to support global hydrogen resource analysis.

This report summarizes the methods, results, and conclusions from Subtask A and is organized as follows. The first section introduces the Global Pathways Analysis Tool (GPAT) developed to answer questions about potential hydrogen pathways, such as: How might pathways differ between countries or regions? Under what conditions might countries import hydrogen from other countries rather produce it themselves? What pathways lead to significant reductions in projected greenhouse gas emissions from the transport sector? How would different levels of CO₂ pricing change the projected pathways and likely greenhouse gas emission reductions? GPAT is an extremely flexible tool that can be easily modified to explore a wide range of alternative scenarios. The next section reviews country level plans for supporting and incentivizing the roll-out of fuel cell electric vehicles (FCEVs). This section includes overall goals, current or future incentives, potential sources for the hydrogen, current and future infrastructure, and key national studies. The results section summarizes possible hydrogen pathways for two scenarios. In each scenario, countries set targets for fuel cell electric vehicles (FCEVs) to capture 20% to 40% of new car sales by 2050. The first scenario assumes countries produce sufficient hydrogen domestically to meet the demand from the new vehicles. The second scenario allows for interregional trading of hydrogen and assumes a CO₂ price of 100 $/tCO₂e by 2050. The results are presented at both the aggregate and country level. Several key sensitivities are noted and explored.
THE GLOBAL PATHWAYS ANALYSIS TOOL

The Global Pathways Analysis Tool (GPAT) was developed as a tool for Task 30 participants to understand the resource options and constraints to meeting future hydrogen demand for a wide range of scenarios. The tool was developed by Sandia National Laboratories using Powersim, a dynamic simulation-modeling tool.2

The Global Pathways Analysis Tool calculates least-cost pathways for H2 supply for eight participating countries: France, Germany, Norway, Spain, Sweden, Denmark, Japan, and the United States. The U.S. was further divided into eight regions, modeled after the NERC electric regions, to allow for additional regional analysis. Table 1. Additional countries could be added as data becomes available. The pathways include consideration of feedstock, conversion, distribution (regional and long-distance), and carbon costs. For each country, hydrogen demand is calculated based on assumptions about future hydrogen vehicle market shares. Hydrogen production costs are calculated based on country-supplied data on feedstock availability for hydrogen production by type, cost, and quantity from 2010 to 2050, and assumptions about hydrogen production technology (efficiencies, costs, etc.). Where country-level data are not available, U.S.-based analysis estimates are derived from the Hydrogen Analysis (H2A) model, the Hydrogen Delivery Systems Analysis Model (HDSAM), and the Macro System Model (MSM). While this study had hoped to integrate results from Subtask B (Technology Database) and HIA Task 28 (Infrastructure) in this Subtask report, the data were not available in time for inclusion. Ideally, the completed results from Subtask B will be integrated in FY14. Regardless of whether this integration happens, GPAT is designed such that users can change key assumptions about a wide variety of inputs and view the subsequent results.

Table 1. Regional definitions used in GPAT.

<table>
<thead>
<tr>
<th>Region</th>
<th>Approximate NERC region</th>
<th>States</th>
</tr>
</thead>
<tbody>
<tr>
<td>Great Lakes + Mid Atlantic</td>
<td>RFC</td>
<td>DE, IL, IN, MD, MI, NJ, OH, PA, WV</td>
</tr>
<tr>
<td>Texas</td>
<td>TRE</td>
<td>TX</td>
</tr>
<tr>
<td>Midwest</td>
<td>MRO</td>
<td>IA, MN, NE, ND, SD, WI</td>
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<tr>
<td>New York and New England</td>
<td>NPCC</td>
<td>CT, ME, MA, NH, NY, RI, VT</td>
</tr>
<tr>
<td>Florida</td>
<td>FRE</td>
<td>FL</td>
</tr>
<tr>
<td>Southeast</td>
<td>SERC</td>
<td>AL, AR, GA, KY, LA, MS, MO, NC, SC, TN, VA</td>
</tr>
<tr>
<td>Kansas and Oklahoma</td>
<td>SPP</td>
<td>KS, OK</td>
</tr>
<tr>
<td>West</td>
<td>WECC</td>
<td>AZ, CA, CO, ID, MT, NM, OR, UT, WA, WY</td>
</tr>
</tbody>
</table>

2 Powersim is a commercially available dynamic software modeling tool. More information is available at: http://www.powersim.com/
This section discusses the basic model assumptions. The objective is to match country level demands for hydrogen with lowest cost supply options for each country, as shown in Figure 1. The delivered hydrogen costs include: 1) feedstock costs; 2) production (or conversion) costs; 3) distribution costs within regions, including refueling station costs; 4) long-distance transmissions costs between countries; and 5) carbon costs. All costs are calculated in 2010 U.S. $ and assume a Euro to U.S. dollar conversion of 0.71 €/$.

The feedstock component of delivered hydrogen costs is calculated from country-supplied information about costs and resource availability from 2010 to 2050 and assumptions about conversion efficiencies. Specifically, the feedstock costs are the feedstock cost ($/GJ_input) divided by the conversion efficiency (GJ_H2/GJ_input). For example, for coal costs of 4.28 $/GJ and an assumed conversion efficiency of 53.6%, the feedstock component of delivered H2 costs are 7.98 $/GJ.

A unique and integral part of this subtask and development of GPAT was the iterative approach used to gather data and assumptions. Country experts were asked to supply data on the available quantities and costs of resources expected to be available for the production of hydrogen from 2010 to 2050. This required experts to subtract projected demand due to all other uses from total available resources. This process also led to detailed discussion about whether to include potential imports in country estimates. As imports are an integral part of the global energy supply, the participants concluded that it was necessary to include the possible role of imports, especially of natural gas. In a few cases, countries provided supply curves for the resources. In most cases, countries were only able to supply static estimates of resource availability and cost in decadal increments. As GPAT runs on a monthly time step, linear interpolation was used to
estimate the availability and costs for the in-between periods. Ideally, supply curves would be used for all resources as a significant increase in demand for a resource, such as might be the case in these scenarios, would lead to increased supply costs, which could affect the results.
Feedstock Costs

The country-supplied feedstock cost assumptions are summarized in Table 2 and Table 3 and Figures 3 through 5. The costs for natural gas, coal, and biomass by country are summarized in Table 2. An “NA” indicates that country either does not have the resource or does not expect to use it for hydrogen production. The tables note whether supply curves were used rather than static costs. Figure 2 shows the biomass supply curves used for the U.S. analysis. Biomass supply curves were adapted from supplementary data of the U.S. Department of Energy’s “Billion Ton Update” study (DOE, 2011). Figure 3 show the regionally-differentiated U.S. supply curves for wind, derived from NREL’s Regional Energy Deployment Model (ReEDs) model (O’Connell, 2007). The regions correspond roughly to electric system regions in the U.S. and were summarized in Table 1. For the U.S. case, the cost of wind electricity is projected to decrease with research and learning; the combined improvements to both capital costs and capacity factor are modeled as an exponential learning curve with a long term 25% reduction in cost with a 15 year time frame. The Norwegian wind supply curves are shown in Figure 4 and Figure 5.3

There were several rounds of iterations with the feedstock data to ensure that countries were using the same criteria to report resource costs. Despite these iterations, there are still notable differences in costs between countries. Some of the differences are attributable to the existence of governmental incentives or subsidies; in other cases, the differences represent uncertainty about likely costs. These differences are most notable in the cost estimates of biomass and wind resources. For example, Spain’s estimated costs for onshore wind resources are almost one-half those estimated by Germany. Experts attributed at least some of this cost differential to labor and land costs and a portion are due to differences in remaining wind resources available for development. France reports a similar cost as Germany, but expect costs to increase over time, while all other countries expect costs will decrease. This difference reflects the French requirement that all grid-connected resources compete in the electricity market, which is probably how each of these resources would have to compete in reality. Another major difference is in reported biomass costs. Both Germany and France report fairly low costs for their biomass resources. And unlike the Germans, the French report very small quantities of resources available at those costs. By contrast, Norway, Sweden, and Spain report significantly higher costs. Norway and Sweden reconciled their numbers during the data review iterations to consistently account for existing governmental programs. These apparent remaining inconsistencies are explainable by how countries defined “resources available for hydrogen production.” Some countries, such as Germany, believe they have large quantities of biomass resources, either existing or that could be developed, available for hydrogen production.

3 Norwegian supply curves were derived by Kari Espegren, the Norwegian Task 30 country expert.
Table 2. Country-reported resource (natural gas, coal, and biomass) cost data in $/GJ. (“NA” indicates the country does not have, or does not expect to use, the resource)

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Table 3. Country-reported resource costs (onshore and offshore wind and hydro).
Blank cells indicate the resource is not available or used to produce hydrogen.

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</table>
Figure 2. Biomass supply curves for the U.S. (derived from DOE, 2011).

Figure 3. Regional wind supply curves for the U.S., including both onshore and offshore resources (derived from O’Connell, 2007).
Figure 4. Wind supply curve for Norway, 2020 (includes both onshore and offshore).

Figure 5. Wind supply curve for Norway, 2050 (includes both onshore and offshore).
**Production Costs**

The production costs include all conversion costs other than the feedstock costs. Consistent estimation of production costs for Task 30 participating countries is a major focus of the Subtask B effort. Similarly to Subtask A, country experts were asked to provide technical and financial assumptions for several production options. By applying a consistent economic methodology across all countries, including assumptions about technology maturity and debt/equity financing terms, the goal was to understand whether there was common agreement or whether there were varying estimates of production costs. Through a similar iterative approach used in Subtask A, it was hoped that production cost estimates would converge on values that all countries were comfortable with. This does not mean identical numbers across countries as certain inputs, such as land or labor costs, will naturally vary across countries. However, one would expect that the basic technology efficiencies should fall within a certain range. The Subtask B database is scheduled for completion in 2014. As the results were not yet available for integration into the GPAT for this analysis, this analysis relies on conversion efficiencies and production costs estimates from U.S. Department of Energy’s H2A Analysis.4 These estimates are for mature technologies, sized to supply sufficient quantities of hydrogen for the scenarios considered here (20-40% market share by 2050). In the initial years of the rollout, the conversion efficiencies will likely be lower. Production costs by technology and efficiency assumptions are summarized in Table 4.

Japan provided separate production cost estimates for several pathways, including: distributed SMR of natural gas, coal gasification with CCS in Australia, electrolysis by either solar PV or onshore wind, and byproduct hydrogen from oil refineries. These options are discussed in additional details below.

**Distribution Costs**

Distribution costs, or delivery costs, include all costs associated with getting the hydrogen from the production plant to the vehicle. As HIA Task 28 is charged with developing a consistent set of delivery costs for a range of scenarios (Figure 6), Task 30 did not want to duplicate their efforts. Unfortunately, the Task 28 estimates were not available in time for inclusion in this analysis. Therefore, with the exception of Japan, the delivery costs are derived from the U.S. Department of Energy’s H2A Analysis. The Japanese expert provided Japanese-specific estimates for distribution costs. GPAT allows the user to change these basic assumptions. Ideally, the results from Task 28 will be integrated into GPAT when they are available as the additional level of detail may significantly alter the results reported here.

For on-site production options (distributed H₂ production), the estimated costs include all compression, storage, and dispensing costs. The estimate is based on a 1500 kg/day H₂ onsite natural gas reforming system. The estimated delivery cost for this system is 13.75 $/GJ (1.65 $/kg).5 The cost breakdown includes capital (55%), fixed operating and maintenance (23%), and variable O&M including utilities (22%).

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4 http://www.hydrogen.energy.gov/h2a_analysis.html
5 H2A source file: 02D_Future_Forecourt_Hydrogen_Production_from_Natural_Gas_1500_kg_per_day_version_3.0.xls.
For the centralized options, the default delivery cost is 21.50 $/GJ (2.58 $/kg) and include compression (25%), storage (26%), pipeline transport (32%), liquefaction (8.3%), and refueling station (7.9%). This option assumes pipeline transport within an urban setting with more than one million people, market penetration of 50%, 700 bar cascade, and liquid storage. While GPAT allows these numbers to vary over time, these static estimates were used for this analysis for all countries, except Japan. Japan provided country-specific distribution estimates for on-site production options and centralized options with tube trailer transport of the hydrogen or even long-distance transport of the hydrogen produced by coal gasification with CCS in Australia. The Japanese estimates are significantly higher than the base case numbers assumed for other countries. For the onsite production, the delivery costs are 52.33 $/GJ in 2020, falling to 28.00 $/GJ in 2050. For the long distance transport option (coal gasification with CCS in Australia) centralized option, the costs are estimated at 72.42 $/GJ in 2025, falling to 44.90 $/GJ by 2035 and then remaining constant. For the other centralized options, H2 from solar and wind, the analysis used the GPAT default values (Table 4).

In the early stages of the hydrogen rollout, delivery will likely include truck transport. The costs here are associated with larger scale rollout. H2A source file: 06D_H2A_Future (2020)_Delivery_Scenario_Analysis_Model_Version_2.3.1.xls.
Table 4 summarizes the default production costs, distribution costs, conversion efficiencies, and well-to-tank GHG emissions for each technology used in the GPAT.

Table 4. Default production costs, distribution costs, conversion efficiency, and GHG emissions.

<table>
<thead>
<tr>
<th>Pathway</th>
<th>Production cost (excluding feedstock) $/GJ ($/kg)</th>
<th>Distribution cost$1 $/GJ ($/kg)</th>
<th>Feedstock conversion efficiency (MJ H2/MJ Feedstock)</th>
<th>Well-to-Tank GHG emissions (kg CO2e/kg H2)$2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas: Distributed SMR</td>
<td>6.67 (0.80)</td>
<td>13.75 (1.65)</td>
<td>71.9%</td>
<td>14.3</td>
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<td>Natural Gas: Centralized SMR</td>
<td>3.25 (0.39)</td>
<td>21.50 (2.58)</td>
<td>53.6%</td>
<td>14.7</td>
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<tr>
<td>Coal: Centralized gasification</td>
<td>10.75 (1.29)</td>
<td>21.50 (2.58)</td>
<td>53.6%</td>
<td>44.7</td>
</tr>
<tr>
<td>Coal: Centralized gasification with CCS</td>
<td>14.67 (1.76)</td>
<td>21.50 (2.58)</td>
<td>53.6%</td>
<td>7.5</td>
</tr>
<tr>
<td>Biomass: Centralized gasification</td>
<td>8.92 (1.07)</td>
<td>21.50 (2.58)</td>
<td>49.6%</td>
<td>3.1</td>
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<tr>
<td>Electrolyzer options (wind, solar, nuclear)</td>
<td>5.25</td>
<td>21.50 (2.58)</td>
<td>72.5%</td>
<td>2.9</td>
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</tbody>
</table>

$1$For onsite options (Natural Gas: Distributed SMR), distribution costs include compression, storage, and dispensing costs. For the centralized options, distribution costs include compression, storage, pipeline transport from centralized facility (excludes interregional distribution costs), and the refueling station.

$2$Well-to-tank greenhouse gas emission estimates for each source are from H2A.

For longer distance transport of H2, such as would be the case between regions or countries, we used a cost equation estimated for pipeline distribution using the H2A Delivery Scenario Analysis Model (HDSAM) model, Figure 7. Specifically, the cost is assumed to be a function of distance:

\[
\text{Costs ($/kg) = 0. 7982 + 0.00206*Distance (km)}
\]

Hence, moving H2 1,000 km through pipelines would add an additional 23.82 $/GJ (2.86 $/kg) to the delivered costs. For distances, GPAT uses geographic means to calculate the distances between included regions or countries. For example, the assumed distance between Germany and France is 759 km. Transporting H2 from Germany to France would add 19.68 $/GJ (2.36 $/kg) to the delivered cost. This simplifying assumption will not be valid in all situations and may skew the results away from interregional transport. It may be possible, for example, for a country to produce hydrogen close to the border for export. GPAT cannot currently capture this situation.
Japan provided cost estimates for the long-distance transportation of hydrogen from Australia. Specifically, the Japanese estimated the costs associated with the gasification of lignite in Australia along with CCS, with ship and then truck transport to pressurized H2 refueling stations. They assume this option will be available beginning in 20205, with declining production and distribution costs over time due to experience and economies of scale. They also assume the availability of low-cost lignite in Australia at a constant cost of 2.33 $/GJ. Their estimates suggest long distance of H2 by ship can be very inexpensive. In 2025, the estimated cost of ship transport is 6.87 $/GJ, dropping to 4.41 $/GJ by 2035. These Japanese specific estimates are incorporated into the results presented in this paper.

A study by Baumfume et al. (2011) for Germany also suggested that longer-distance transport costs could be lower than the default assumptions derived from HDSAM. Specifically, they estimate long-distance pipeline transport costs of 0.89 to 3.44 $/GJ for distances of 250 – 800 km, whereas the GPAT estimates are 10.94 and 20.39 $/GJ. Significantly lower long-distance pipeline transport costs would make interregional trading between countries more likely.

**Hydrogen Demand**

Hydrogen demand is based on assumptions about the passenger vehicle fleet. As the goal of this analysis is to determine potential pathways for a large-scale deployment of hydrogen vehicles, the default assumptions assume that new fuel cell vehicles capture 40% market share by 2050 in all participating countries except France. At the request of the French team, the default assumption for France is 20% market share by 2050. Because of the time required for existing vehicles to be replaced, fleet percentages by 2050 are lower than the new car market shares. A logistic growth curve is used to assign the expected sales fraction of new FCEVs in any year. For the assumed 40% market share by 2050, GPAT assumes a midpoint of 20% by 2030.

The composition of the fleet within each country is tracked by vehicle size, powertrain (gasoline or fuel cell), and age. Current and future light duty vehicles are categorized as
either compact, midsize, or light duty truck; each category has different fuel consumption efficiencies. Compact vehicles have an average fuel rating of 26.3 mpg in 2010; midsize cars average 21.3 mpg in 2010. For the U.S. future vehicles (both FCEVs and gasoline-fueled ICE), we use projected efficiencies from Argonne National Laboratories Autonomie model results, with linear interpolation between time points and fixed values after 2045 (Moawad, 2011). These values are shown in Table 5. Initial regional\textsuperscript{7} vehicle stocks in the U.S. are summarized in Table 7.

Table 5. FCEV fuel efficiency in miles per gallon equivalence (MPGe) in U.S. (Derived from Moawad, 2011).

<table>
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<tr>
<th>Size class</th>
<th>Compact car</th>
<th>Midsize car</th>
<th>SUV/ truck</th>
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<td>50</td>
<td>35</td>
</tr>
<tr>
<td>2015</td>
<td>62</td>
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<td>2030</td>
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<tr>
<td>2035</td>
<td>71</td>
<td>66</td>
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</table>

New sales are initially set at 6.7\% of the entire fleet with an average annual scrappage rate of 5.8\%, derived from U.S. transportation statistics for the period 2000-2009 (Davis, 2011). The sales and scrappage rates define an annual increase in fleet size by 0.9\% per year. The average U.S. based scrappage rate is used to determine the starting age distribution of the vehicle fleets for all countries. While the average scrappage rate is fixed, the actual rate increases as the vehicles age, Figure 8. For example, very few new vehicles are scrapped after just one or two years on the road and the rate is significantly higher than 5.8\% per year for older vehicles. Age-dependent annual mileage factors are applied to vehicle age to reflect decreasing annual miles as vehicles age (Barter, 2012). The annual mileage factors are normalized to produce an average annual mileage of 12,000 miles per year per vehicle. Users can quickly change the assumptions about market share, growth in vehicle stocks, and scrappage rates.

\textsuperscript{7} The included U.S. regions are summarized in Table 1.
Table 6. Initial vehicle size and distribution by U.S. region (Derived from FHWA 2012).

<table>
<thead>
<tr>
<th>Region</th>
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<th>Trucks</th>
<th>Total</th>
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<td>Great Lakes + MidAtlantic (RFC)</td>
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<td>37%</td>
<td>14%</td>
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<td>Texas (TRE)</td>
<td>41%</td>
<td>35%</td>
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<td>Midwest (MRO)</td>
<td>44%</td>
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<td>New York and New England (NPCC)</td>
<td>58%</td>
<td>33%</td>
<td>9%</td>
<td>21,881,286</td>
</tr>
<tr>
<td>Florida (FRCC)</td>
<td>46%</td>
<td>39%</td>
<td>15%</td>
<td>12,690,666</td>
</tr>
<tr>
<td>Southeast (SERC)</td>
<td>45%</td>
<td>34%</td>
<td>21%</td>
<td>55,397,852</td>
</tr>
<tr>
<td>Kansas and Oklahoma (SPP)</td>
<td>38%</td>
<td>33%</td>
<td>29%</td>
<td>9,556,107</td>
</tr>
<tr>
<td>West (WECC)</td>
<td>47%</td>
<td>35%</td>
<td>17%</td>
<td>53,874,771</td>
</tr>
<tr>
<td>U.S. total</td>
<td>47%</td>
<td>35%</td>
<td>18%</td>
<td>234,812,846</td>
</tr>
</tbody>
</table>

Figure 8. Vehicle survival rates by vehicle age (derived from Barter, 2012).

The initial vehicle stocks and future efficiencies by powertrain for the other countries are derived from the TREMOVE Economic Transport and Emissions Model (TREMOVE, 2010), Table 7 and Figure 9.
Table 7. Assumed vehicle efficiencies in non-U.S. countries in MPGe and liters/100 km. (Source: TREMOVE)

<table>
<thead>
<tr>
<th></th>
<th>ICE</th>
<th></th>
<th>Light Duty Trucks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Compact Car</td>
<td>Midsize Car</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>26.8 / 8.8</td>
<td>23.5 / 10.0</td>
<td>17.6 / 13.4</td>
</tr>
<tr>
<td>2030</td>
<td>38.6 / 6.1</td>
<td>35.3 / 6.7</td>
<td>23.1 / 10.2</td>
</tr>
<tr>
<td>2045</td>
<td>40.5 / 5.8</td>
<td>36.9 / 6.4</td>
<td>23.7 / 9.9</td>
</tr>
<tr>
<td>FCEV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>62.2 / 3.8</td>
<td>57.5 / 4.1</td>
<td>41.0 / 5.7</td>
</tr>
<tr>
<td>2030</td>
<td>68.7 / 3.4</td>
<td>63.8 / 3.7</td>
<td>44.4 / 5.3</td>
</tr>
<tr>
<td>2045</td>
<td>71.1 / 3.3</td>
<td>66.4 / 3.5</td>
<td>46.5 / 5.1</td>
</tr>
</tbody>
</table>

Figure 9. Initial vehicle distribution by non-U.S. country.
USING THE GLOBAL PATHWAYS ANALYSIS TOOL (GPAT)

The stated goal for GPAT is to help Task 30 participants understand the resource options and constraints to meeting future hydrogen demand and to estimate potential petroleum savings and greenhouse gas emission reductions associated with various scenarios. The tool includes consideration of inter-regional transfers of hydrogen based on total cost of producing and delivering hydrogen. GPAT was developed using the Powersim Dynamic Simulation Modeling platform. The Powersim platform is ideal for developing time-dependent scenarios incorporating a wide-range of input assumptions with feedback loops and for creating intuitive user interfaces to help navigate the input and output screens.8

A key feature of the Global Pathways Resource Analysis Tool is the ability for users to vary key assumptions, including resource availability and cost, vehicle shares and efficiencies, carbon taxes, and renewable portfolio standards, and view real-time results, making the tool ideal for policy-level discussions. This section discusses the model layout, highlighting user options.

To allow for the inclusion of additional countries, GPAT is organized by regions: North America, Europe, and the Pacific. The regional pages display aggregate projections of hydrogen demand and supply. The projected supply is shown by country and by pathway (natural gas, biomass, etc.). With the exception of carbon prices, the input assumptions are accessed from country level pages. Figure 10 shows a representative country-level page (Germany). Additional explanatory labels have been added to clearly show the inputs and outputs available for each country. This figure is included here for the sole purpose of explaining the layout and input and output options. Normally, it would be viewed in a much larger format. The outputs include: delivered H₂ costs by feedstock option, feedstock supply and cost, projected hydrogen pathway to 2050, composition of the vehicle fleet, projected GHG emissions, vehicle operating cost estimates, and a comparison of the resource requirements for the hydrogen production with that country’s 2009 resource use. The inputs include: regional distribution costs, feedstock sensitivities, a renewable or GHG policy requirement, and vehicle growth and scrappage rate assumptions.

When the model is running, it is possible and very interesting to view the demand, supply, cost components and GHG levels developing over time. The results shown in this report are for 2050.

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8 Although not used for this version of GPAT, Powersim has extensive Monte-Carlo and optimization capabilities.
Figure 10. Country-level screen layout of GPAT with labels explaining results and inputs.
The total delivered hydrogen cost ($/GJ) is broken down by feedstock costs (red); conversion or production costs including all capital and O&M costs (green); distribution costs, including the refueling stations (blue); and CO₂e cost (brown). Pull down menus at the bottom of each option allow the user to select which options to include and their order. The distribution costs can be altered to the right of this screen.

The feedstock supply and cost area shows the self-reported estimates of total resource by type available for hydrogen production and the associated cost. As these resource estimates are supposed to represent just the resource available for hydrogen production, they will likely underestimate the total feedstock base in a country, which might be set aside for other uses, such as electricity production. The user can adjust these estimates by applying supply and cost factors in the feedstock sensitivity area on the right. For example, to test the sensitivity of the German results to biomass cost, GPAT can be rerun with cost factors (1.1, 1.5, 2.0, etc.). In a similar fashion, the available supply can be moved up or down (0.5, 1.5, etc.).

The projected hydrogen pathways show the least cost solution for supplying the required hydrogen by feedstock type over time. The vehicle fleet graph shows the projected shares by powertrain type (ICE or FCEV) over time. The share of FCEVs in the fleet will, in most cases, be less than the assumed market share of new vehicle sales due to the assumptions about the life expectancies of vehicles already on the road. The greenhouse gas emission graph shows projected reductions in GHG emissions over time for the chosen scenario and will be affected by decisions about vehicle efficiencies and hydrogen pathways.

The resource requirement for hydrogen consumption box (resource increase over 2009) compares the estimated feedstock consumption requirements with a country’s consumption of that resource in 2009. This may be a good indicator of whether a particular pathway seems plausible. For example, if a projected pathway is dominated by natural gas, but represents a small change in 2009 consumption levels, it seems more plausible than a scenario requiring a country to double their electricity generation.

The cost per mile output shows the estimated fuel costs per mile and technology premium costs by powertrain option. The technology premium costs show the additional costs per mile of a vehicle costing an addition $2,000, $4,000, and $10,000 over a comparable ICE vehicle. This estimate assumes a four-year amortization period.

The renewable/no-GHG input box allows one to consider policies requiring a minimum percentage of renewable or non-GHG emitting sources for hydrogen production. For example, a country might specify that 20% of all hydrogen be produced using domestic renewable resources. The non-GHG option includes nuclear with the renewable options.

The GHG cost is located on the regional input screens and allows for consideration of different carbon prices and phase-in times, such as a 100 $/ton CO₂e by 2025 or one that starts at $100 and increases to $250 by 2050.

Obviously, there are many other input assumptions in GPAT, as noted throughout this report. While the developer can change these assumptions, they are not accessible to the general user. Future versions could include additional levels of screen inputs and outputs.
Hydrogen distribution costs between regions appear on the regional screens. Figure 11 shows an example of the projected total delivered hydrogen costs between regions in 2050. These costs include feedstock costs, production costs, regional and long-distance transport costs, storage and dispensing costs, and any associated externality costs. The columns show the estimated total cost from that country to each of the horizontal countries. The diagonal shows the in-country delivered cost. For example, the cost of H$_2$ production in Spain is 40.16 $/GJ; that H$_2$ delivered to France would cost 60.12 $/GJ.

![Figure 11. Total delivered cost ($/GJ) for H$_2$ within countries (diagonal) and traded between countries.](image)

<table>
<thead>
<tr>
<th>Delivered Cost</th>
<th>Germany</th>
<th>Norway</th>
<th>Spain</th>
<th>Sweden</th>
<th>Denmark</th>
<th>France</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>50.80</td>
<td>63.13</td>
<td>79.00</td>
<td>63.27</td>
<td>67.51</td>
<td>76.30</td>
</tr>
<tr>
<td>Norway</td>
<td>71.91</td>
<td>42.02</td>
<td>87.94</td>
<td>55.69</td>
<td>66.03</td>
<td>91.69</td>
</tr>
<tr>
<td>Spain</td>
<td>69.64</td>
<td>89.80</td>
<td>40.15</td>
<td>94.19</td>
<td>79.95</td>
<td>76.54</td>
</tr>
<tr>
<td>Sweden</td>
<td>76.23</td>
<td>56.95</td>
<td>91.50</td>
<td>42.84</td>
<td>66.77</td>
<td>94.72</td>
</tr>
<tr>
<td>Denmark</td>
<td>67.30</td>
<td>56.99</td>
<td>69.00</td>
<td>59.50</td>
<td>51.12</td>
<td>95.72</td>
</tr>
<tr>
<td>France</td>
<td>70.52</td>
<td>77.13</td>
<td>60.12</td>
<td>80.98</td>
<td>80.25</td>
<td>56.59</td>
</tr>
</tbody>
</table>

Columns are Supply and Rows are Consumption (Vertically it is the price supplied to the horizontal country).
PARTICIPATING COUNTRIES SUPPORT FOR FCEVS

A common theme amongst participating countries in this project is to understand the possible future role of FCEVs for reducing reliance on petroleum and to reduce greenhouse gas emissions. While similar assumptions are used in this analysis across countries, in reality there is considerable variation across the countries in terms of the existing and planned infrastructure, incentives for FCEV adoption, and even restrictions on possible pathways. For example, Germany expects that regardless of cost, 20% of H₂ will be produced by domestic, renewable options. Furthermore, Germany will not allow the use of coal gasification with CCS technologies.

The purpose of this section is to summarize national goals for adoption of FCEVs, likely policy mechanisms to promote FCEVs, restrictions on H₂ sources, and existing and planned infrastructure.

To solicit this information, each country expert was asked to provide answers to a series of questions about country goals for FCEV adoption, incentives for FCEVs, potential sources for hydrogen (including restrictions on certain sources), existing infrastructure, and references to key national studies. The following sections summarize their responses to this request.

**Norway**

*Goals for FCEV Adoption*

Norway does not have numerical goals for FCEVs, but they have set ambitious goals for reducing vehicular emissions in the Oslo region (50% below 1990 levels by 2030 despite projected population increase of 40%). To reach these goals, they have adopted strong incentives aimed at stimulating the demand for zero emission vehicles (ZEV), whether battery electric or FCEV. They have also announced ambitious plans for supporting the required infrastructure.

*Incentives for FCEVs*

Norway has several incentives to stimulate sales of zero emission vehicles (BEV and FCEVs), including:

- Exemptions on sales and value added taxes
- 90% discount on annual road taxes
- Exemptions on highway and ferry tolls and municipal parking fees
- Access to public transport lanes
- Access to thousands of public charging stations for BEVs

*Potential Sources for H₂ Supply*

Hydrogen is currently produced as an industrial byproduct and from electrolysis. Despite its abundant supplies of natural gas, Norway does not foresee using the natural gas as a
feedstock for H₂ production. Future H₂ production for the transport sector is expected to come from electrolysis powered by renewable resources, mainly hydro and wind. At present, approximately 96% of electricity produced in Norway comes from renewable resources. Norway and Sweden recently established the Green Certificate Market, which aims to increase the role of renewables in both countries.

**H₂ Infrastructure**

There are six operational hydrogen-refueling stations in Norway. Development of the refueling structure was initiated in 2004 with the HyNor project. The Ministry of Transport and Communications support the infrastructure development and recognize the need for further investment to support early adopters and to enable the H₂ economy.

**Key National Studies**

H₂OSL: Possibilities for utilization of hydrogen at Oslo Airport Gardermoen, April 2012 (In Norwegian).


**France**

**Goals for FCEV Adoption**

France does not have numerical goals for FCEVs. The French Environment and Energy Management Agency (Agence de l’Environnement et de la Maîtrise de l’Énergie) has developed a hydrogen roadmap that specifies needs for demonstration projects of low-carbon vehicles, whether electric or fuel cell. In addition, France launched the H₂ Mobility project in 2013. Objectives include development of a common roadmap for H₂ deployment in France and to support its implementation, including deployment of local fleets.

**Incentives for FCEVs**

France has not yet defined policy mechanisms for incentivizing the sales of FCEVs. Incentives will be addressed by the H₂ Mobility France project.
**Potential Sources for H₂ Supply**

Hydrogen is currently produced for industrial needs from natural gas (40%) and byproduct production (60%) (Le Duigou, 2011). Future H₂ production for the transport sector is expected to come primarily from electrolysis, using low-CO₂ intensive electricity.

**H₂ Infrastructure**

The current infrastructure is limited to a handful of private locations. The infrastructure necessary to support future transport-sector growth will be defined by the H₂ Mobility France project.

**Key National Studies**


Spain

Goals for FCEV Adoption

Spain has not adopted numerical goals for the introduction of FCEVs but has adopted a number of incentives aimed at promoting the introduction of zero emission vehicles, whether BEV or FCEV.

Incentives for FCEVs

At present, the main incentive is a subsidy of 7500 € – 21,000 € for the purchase of ZEV vehicles. Proposed additional incentives include parking discounts and exclusive access to city centers.

Potential Sources for H₂ Supply

Spain views H₂ production from wind as a possible solution to current problems associated with the intermittency of renewable energy. While the focus will likely remain on utilizing wind resources, other potential pathways may include using imported natural gas, coal, and biomass, depending on the economics.

H₂ Infrastructure

There are four operational hydrogen-refueling stations in Spain; three are designated for FC buses. Longer-term goals are based on the recent EU directive suggesting that countries develop networks of stations approximately 300 km apart.⁹

Key National Studies


**Italy**

*Goals for FCEV Adoption*

Italy has an overall goal of 10% renewable fuels in the transportation sector by 2020. This goal includes the possibility of H\(_2\) produced from renewable resources.

*Incentives for FCEVs*

FCEVs are eligible for subsidies available for vehicles emitting less than 50 gCO\(_2\)/km.

*Potential Sources for H\(_2\) Supply*

In order to meet renewable fuels goal, Italy expects that H\(_2\) production will come from renewable resources.

*H\(_2\) Infrastructure*

There is currently one operating H\(_2\) fueling station in Milan, producing H\(_2\) from solar.

**Japan**

*Goals for FCEV Adoption*

Japan has set a goal of two million FCEVs and 1,000 fueling stations by 2025. They expect FCEVs will be available to the public in 2015, requiring 100 refueling stations. The Fuel Cell Commercialization Conference of Japan is tasked with solving the challenges associated with the rollout and making the FCEV and fueling station business viable by 2025.

*Incentives for FCEVs*

The government will announce policy mechanisms for encouraging the purchase of FCEVs soon. Subsidies for construction of refueling stations were announced in 2013 and cover up to 50% of the construction cost of new stations.

*Potential Sources for H\(_2\) Supply*

While current H\(_2\) production comes from fossil fuels and as a byproduct of industrial processes, in the longer term, Japan expects H\(_2\) will come from reformation of either oil or natural gas with CCS, as well as renewable resources. They have not ruled out the possibility of imports from other countries in the longer term.
**H₂ Infrastructure**

As of 2012, there are 17 refueling stations in operation in Japan. Japan expects to have 100 stations by 2015 and 1000 by 2025.

**Key National Studies**


**Germany**

**Goals for FCEV Adoption**

Germany has established ambitious goals for the adoption of electric vehicles, whether BEV, PHEV, or FCEV. These goals are part of a master plan for sharply curtailing CO₂ emissions (40% below 1990 levels by 2020 and 80% by 2050). Specific targets for the transport sector include one million electric vehicles by 2020 and six million by 2030. The H₂Mobility Industry Initiative, which includes Air Liquide, Daimler, OMV, Shell and Total have agreed on a plan for the construction of a hydrogen refueling network that will have 100 stations within four years and 400 stations by 2023, pending FCEV market availability. Manufacturers expect to launch FCEVs beginning in 2015.

The National Innovation Program for Hydrogen and Fuel Cells (NIP II) established numerical goals for 2025 including: 500 filling stations, 500,000 FCEVs, 2,000 FC buses, 1500 MW of electrolysis capacity, 500,000 micro CHG PC units, and integration of hydrogen production into renewable energy systems as a way to increase flexibility and storage. Achieving these goals are expected to cost €3.9 billion between 2014 and 2023, with approximately 60% paid for by industry.

**Incentives for FCEVs**

Germany expects to use sales targets coupled with a wide range of incentives and subsidies to achieve the FCEV goals. The 2009 EU Directive limiting CO₂ emissions of new vehicles will drive Germany policy on transport options.

**Potential Sources for H₂ Supply**

The National Innovation Program for Hydrogen and Fuel Cells envisions hydrogen produced from renewable resources. The plan does not specify the percentage that should come from renewables. Germany will not allow the option of using coal gasification with CCS technologies.
**H₂ Infrastructure**

There are 15 operational hydrogen refueling stations in Germany. Plans call for a public hydrogen infrastructure that includes 100 stations over the next four years and 200 stations by 2023. Ideally, the refueling stations will be located within 90 km of each other. Vehicle companies plan on beginning sales of FCEVs by 2015.

**Key National Studies**

Clean Energy Partnership, 2013. Available at: [www.cleanenergypartnership.de](http://www.cleanenergypartnership.de)


**United States**

**Goals for FCEV Adoption**

The U.S. does not have numerical goals for the adoption of FCEVs. In 2013, the federal government launched a public-private partnership (H2USA), which is similar in spirit and principle to other public-private partnerships worldwide (UK Mobility, German Mobility, HySut, etc). The U.S. Department of Energy Fuel Cell Technology Office (FCTO) funds hydrogen-related research and development focused on addressing the barriers to getting significant quantities of hydrogen technologies, focusing on fuel cells, into the energy and transportation infrastructure (stationary power and on- and off-road vehicles). The many elements of the FCTO program can be found in the Multi-Year Program Plan (MYPP).

Although the U.S. does not have a stated goal for the adoption of fuel cell vehicles, several states have set goals for FCEVs, including California, South Carolina, Connecticut,
Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont. The California goals are highlighted in this report. The California Air Resources Board (CARB) has adopted a program for the introduction of zero-emission vehicles (ZEVs) in the state. Vehicle manufacturers are required to show increasing sales of ZEVs (including plug-in hybrid, battery electric and fuel cell electric vehicles) over time. California’s goal is for 1.5 million ZEVs by 2025. Targets from various automakers suggest a total of 53,000 ZEVs by 2017.

**Incentives for FCEVs**

The U.S. has adopted new corporate average fleet efficiency (CAFE) standards that will incentivize companies to adopt new technologies. Some states, including California, have policies in place to support the future role of H₂ in a wide range of vehicles. Eight state governors have signed an agreement to develop zero-emission vehicle mandates similar to California. As in California, this will create policy mechanisms (mandates) to improve market entry of ZEVs. Note, California recognizes a FCEV as a ZEV. Also, the new public-private partnership – H2USA – is focusing on advancing the development of the hydrogen infrastructure by coordinating research efforts and identifying cost-effective solutions to deploy infrastructure.¹⁰ Incentive funding is widely acknowledged as necessary to make the business case for investing in the early commercial stations.

California adopted legislation in 2013 to support the construction of up to 68 stations. In addition, CARB’s Clean Fuel Outlet regulation triggers the construction of up to 500 stations once over 20,000 FCEVs are deployed statewide or 10,000 in a designated air basin (California Fuel Cell Partnership, 2013).

**Potential Sources for H₂ Supply**

In the U.S., hydrogen will come from many sources, dependent primarily on costs. The most likely sources are natural gas, biomass and wind electrolysis. In some states, such as California, a percentage of the hydrogen must come from renewable resources, where the percentage and definition of “renewable” are currently being established.

Of the hydrogen stations currently operating in California, one is fueled entirely from a renewable source – digester gas from a Southern California wastewater treatment facility. Another, the AC Transit station in Oakland, is partially filled by PV electrolysis. Of the recently contracted stations, one will be supplied by electrolysis using 100% renewable or “green electrons,” as defined by the state. For the future stations, state law requires that 1/3 of the hydrogen be produced from renewable energy. New stations being proposed may also use California electricity, which must be at least 33% renewable by 2020, according to the Renewable Portfolio Standard. Whereas 100% renewable hydrogen is the ultimate goal, establishing an adequate and reliable infrastructure has higher priority in the near term.

H₂ Infrastructure

Approximately 14 publically-available H₂ refueling stations are currently operational in the U.S. at present\(^\text{11}\). The new public-private partnership – H₂USA – is focusing on options for advancing a cost-effective infrastructure. The California road map calls for 68 stations open to the public by 2016.

Key National Studies


\(^{11}\) The U.S. DOE maintains a database of all alternative fuels refueling locations. As of June, 2014, there are 14 hydrogen stations operating in the U.S.: http://www.afdc.energy.gov/fuels/hydrogen_locations.html.
RESULTS

The analysis shows that there are a large number of potential pathways for providing hydrogen to fuel a significant vehicle fleet and that resource availability is not the limiting factor in a hydrogen economy. Using GPAT, each participating country has identified multiple options for producing hydrogen domestically.\textsuperscript{12}

GPAT results are presented at both the regional (i.e. Europe) and then country-level (France, Denmark, Sweden, Spain, Norway, and Germany). For the U.S., results are shown at the national and regional level.

The following two scenarios are presented at the aggregate level for the included countries and then country level. Both scenarios assume that, with the exception of France, FCEVs capture 40\% market share of new vehicles sales by 2050. The target for France is 20\% market share by 2050\textsuperscript{13}.

1) Scenario 1: Each country produces sufficient H$_2$ domestically to meet demand (no trading between countries)
2) Scenario 2: Interregional trading and 100 S/ton CO$_2$e price by 2025.

After presentation of these two scenarios for each country, additional scenarios, as relevant to specific countries, are discussed.

Figure 12 summarizes total demand for the hydrogen required to fuel the projected number of FCEVs each year through 2050. By 2050, the total amount of H$_2$ required is approximately 35 billion kg/year, with the majority of demand coming from the U.S. The least-cost pathways available domestically (Scenario 1) are summarized in Figure 13. The largest pathway is hydrogen produced from locally distributed natural gas SMR facilities. In latter years, hydrogen produced from onshore wind, biomass, and centralized coal gasification without CCS capture a small percentage of the total supply. The H$_2$ produced from biomass is produced largely in Germany and meets their requirement that 20\% of all hydrogen come from renewable resources (see section on Germany for additional results).

\textsuperscript{12} The scenarios and optimization calculations presented in this report are based on data from literature (published prior to mid-2013) regarding potentials, technical parameters and costs for the supply of primary energy carriers, as well as energy conversion and end use technologies. The data are specified for different countries. A central and theoretical point of the research conducted for this study is the applicability of the quantitative Global Pathways Analysis Tool for different countries. Qualitative information that would be required to deliver an accurate and complete representation of any country's hydrogen supply situation can only be taken into account to a limited degree because the study is based on publicly available information and data. Whether generic in nature or specifically focused on hydrogen supply technology, factors such as national energy policy strategies or goals that would heavily influence the shape of hydrogen supply pathways in real-world situations are considered only to a limited extent. Therefore, the findings of this study are not to be understood as accurate empirical representations of the hydrogen supply regime in Germany.

\textsuperscript{13} This was done at the request of the French experts.
These results suggest that in a world of low-cost and abundant natural gas, it is difficult for the other resource options to compete on economic grounds alone. Figure 14 shows the
sensitivity of the results to the natural gas cost assumptions. Specifically, doubling the cost of natural gas over the entire time of the model run results in a shift away from natural gas towards biomass.

For Scenario 2, which allows interregional transfers of H2 and includes a 100 $/ton CO2e tax by 2025, the H2 produced from biomass plays a much larger role, Figure 15, although not as large as the case of doubled natural gas costs Figure 14.

In terms of resource use for the hydrogen production, supplying up to 40% of each country’s fleet will require additional consumption of natural gas, coal, and electricity over current...
consumption levels. While these additional resources are discussed in more detail at the regional or country level, the basic conclusion of this study is that there are sufficient resources available in each country for the wide-scale introduction of FCEVs. For example, for scenario 1, Germany’s consumption of natural gas and coal would increase 2.9% and 18.5% over 2009 levels. In the U.S., natural gas use would increase 27% over 2009 levels. A limitation of this analysis is its ability to project the effect of increased demand on feedstock costs. For example, it seems likely that a 27% increase in natural gas demand in the U.S. would place upward pressure on U.S. natural gas costs. These effects are not further considered in this report.

The wide-scale introduction of FCEVs will lead to significant lowered greenhouse gas emissions from this sector. Figure 18 summarizes the projected emissions for the two scenarios analyzed here along with the case of no FCEVs. Even without the FCEVs, emissions are projected to decline 23% over 2015 levels due to the assumptions about improved efficiency of new vehicles in GPAT. This happens even though the total number of vehicles on the road increases. In Scenario 1, emissions are reduced an additional 23% over projected 2050 emissions, even though natural gas is the primary pathway for the hydrogen production. In Scenario 2, emissions would be 33% lower than the base case in 2050. Achieving larger reductions could be achieved if FCEVs capture an even greater market share.

![Figure 17. Projected GHG from LDVs.](image-url)
European results with 100% domestic production of H₂ (Scenario 1)

Figure 18 shows the least-cost pathways for supplying the required hydrogen for the first scenario for the European countries. In the early years, hydrogen is produced using distributed onsite natural gas reformation. The share produced from natural gas declines after 2035 as onshore wind, biomass, coal, and hydro capture market share as their costs drop relative to natural gas. For example, projected natural gas costs in both Germany and Spain show significant increases in the later years. Continued lower natural gas costs would result in a longer-term reliance on natural gas. Total hydrogen demand reaches 8.3 billion kg H₂/year by 2050, equivalent to 165 million barrels of oil per year.

The amount of hydrogen produced and consumed in each European country is shown in Figure 19. Germany, Spain, and France are the largest consumers. The estimated production costs in 2050 by country are summarized in the country-level results.
The resources required to produce this hydrogen compared to 2009 resource use are summarized in Table 8. Meeting the additional H₂ demand requires significant increases in resource use in certain cases. For example, the amount of electricity used in Spain for H₂ production by 2050 is equivalent to approximately 34% of the amount of electricity consumed nationally in 2009. The additional coal resources required in Germany are 18.5% of those used in 2009. These resource numbers provide an overall idea of the amount of additional resources that would have to be used domestically for H₂ production.
Table 8. Additional resources required in 2050 compared to 2009 resource use for Scenario 1.

<table>
<thead>
<tr>
<th>% of 2009 Demand</th>
<th>NG</th>
<th>Coal</th>
<th>Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>2.90 %</td>
<td>18.52 %</td>
<td>10.87 %</td>
</tr>
<tr>
<td>Norway</td>
<td>0.00 %</td>
<td>0.00 %</td>
<td>9.21 %</td>
</tr>
<tr>
<td>Spain</td>
<td>4.01 %</td>
<td>0.00 %</td>
<td>34.27 %</td>
</tr>
<tr>
<td>Sweden</td>
<td>0.00 %</td>
<td>0.00 %</td>
<td>15.16 %</td>
</tr>
<tr>
<td>Denmark</td>
<td>0.00 %</td>
<td>0.00 %</td>
<td>25.50 %</td>
</tr>
<tr>
<td>France</td>
<td>16.45 %</td>
<td>0.00 %</td>
<td>0.52 %</td>
</tr>
</tbody>
</table>

Total GHG from passenger vehicles are expected to fall approximately 29% from 2015 to 2050 without the introduction of FCEVs due to the assumptions about increasing vehicle efficiencies, shown previously in Table 7. The wide scale introduction of FCEVs further reduces emissions in this sector; by 2050, emissions are reduced approximately 40% over 2015 levels. Limiting the production of H₂ from fossil fuels, particularly coal in Germany, would further reduce emissions.
European results with $100 per ton CO₂ (Scenario 2)

The inclusion of a tax on CO₂ drives out the use of coal gasification without CCS in favor of biomass gasification, Figure 20. As the assumptions about the market share for FCEVs are the same as in the first scenario, the total amount of H₂ produced is the same – 8.3 billion kg H₂/year by 2050, equivalent to 165 million barrels of oil per year. Greenhouse gas emissions are further reduced by the elimination of coal gasification; emissions are 44% below 2015 levels by 2050.

![Figure 20. H₂ Production pathways in Europe (Scenario 2).](image)
The resources required to produce this hydrogen compared to 2009 resource use levels are summarized in Table 9. Germany uses significantly more onshore wind, equivalent to 39% of 2009 total nationwide electricity usage. France, which would rely more on onsite natural gas for H₂ production, would use the equivalent of 16% of 2009 consumption of natural gas for H₂ production.

Table 9. Additional resources required over 2009 resource use levels to produce H₂ for Scenario 2.

<table>
<thead>
<tr>
<th>% of 2009 Demand</th>
<th>NG</th>
<th>Coal</th>
<th>Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>6.96%</td>
<td>0.00%</td>
<td>39.27%</td>
</tr>
<tr>
<td>Norway</td>
<td>0.00%</td>
<td>0.00%</td>
<td>9.21%</td>
</tr>
<tr>
<td>Spain</td>
<td>0.02%</td>
<td>0.00%</td>
<td>36.93%</td>
</tr>
<tr>
<td>Sweden</td>
<td>0.00%</td>
<td>0.00%</td>
<td>15.16%</td>
</tr>
<tr>
<td>Denmark</td>
<td>0.00%</td>
<td>0.00%</td>
<td>25.50%</td>
</tr>
<tr>
<td>France</td>
<td>16.45%</td>
<td>0.00%</td>
<td>0.52%</td>
</tr>
</tbody>
</table>

Delivered H₂ costs within and between countries in 2050 are summarized in Figure 21. For example, the estimated cost of H₂ production in Germany, Spain, and France are 50.80 $/GJ, 40.16 $/GJ, and 56.59 $/GJ, respectively. Despite the lower cost of H₂ production in Spain, it does not make economic sense for any other country to import Spanish H₂ because of the high delivery cost. For example, the delivered cost of Spanish H₂ in Germany is estimated at 79 $/GJ, significantly above the cost of domestic H₂ (50.80 $/GJ).
Country Level Results

This section summarizes country-level results for the two scenarios. For each country and scenario, the projected pathways and delivered H2 costs in 2050 are shown. Relevant sensitivities for each country are discussed.14

Germany

The German assumptions require that 20% of H2 is produced from renewable sources. In both scenarios, this 20% is produced using biomass. Prior to about 2035, the balance of the H2 demand is produced using onsite reformation of natural gas for both scenarios, Figure 22 and Figure 24. In the absence of CO2 prices, centralized coal gasification without CCS becomes the low-cost option for H2 production, Figure 22. This result is very sensitive to assumptions about CO2 price. With the 100 $/ton CO2 assumed in Scenario 2, H2 produced from biomass gasification replaces coal, Figure 24.

The projected costs of delivered H2 in 2050 for both scenarios are shown in Figure 23 and Figure 25. When running GPAT, these graphs are updated on an annual basis, making it possible to see the points at which the low cost option changes. The costs are broken down by feedstock costs (red), conversion costs (green), distribution costs (blue), and CO2 costs (brown). This allows the user to quickly understand the key sensitivities in the results. For the first scenario, delivered H2 produced from coal gasification without CCS is significantly cheaper than H2 produced from natural gas (45.30) or biomass (50.80).

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14 Please see footnote 12 for additional comments regarding limitations of country-specific results.
The addition of a CO₂ tax significantly increases the cost of H₂ produced from fossil fuels. By 2050, tax increases the cost of delivered H₂ from natural gas by 7.23 $/GJ (0.86 $/kg) and for coal by 16.42 $/GJ (1.97 $/kg).

Figure 22. Production pathways for Germany (Scenario 1).

Figure 23. Delivered H₂ costs for Germany in 2050 (Scenario 1).
These results are very sensitive to assumptions about the cost of the biomass resource. GPAT allows the user to easily test these sensitivities. For example, a 20% increase in the assumed cost of biomass relative to Scenario 2 results in a solution where natural gas captures the market share not required to come from renewables, Figure 26. As countries refine their estimates of future resource availability and costs, the likely pathways for low cost H₂ production will change. The results shown here reinforce our main conclusion that there are a large number of different pathways for H₂ production.
Spain reports the potential to greatly expand their wind capacity at relatively low cost. Even in the absence of CO₂ prices, wind resources capture a significant market share beginning around 2035, Figure 27 (Scenario 1). Prior to that time, H₂ production comes from onsite reformation of low-cost imported natural gas. By 2050, H₂ produced from wind is significantly cheaper than using onsite natural gas (40.16 $/GJ compared to 49.62 $/GJ). Small changes in the availability or cost of the natural gas results in earlier or later use of the wind resources. For example, a 30% increase in the assumed initial cost of natural gas drives the solution to wind from the beginning.
The addition of the CO₂ price (Scenario 2) makes onshore wind the low cost option for H₂ production by 2022, Figure 29. Prior to that point, natural gas is slightly cheaper. The layout and capabilities of GPAT make it easy to find the point at which such crossovers occur. Figure 30 shows the estimated costs in 2022. These results are fairly sensitive to the assumed costs of the wind resource. Small increases in assumed wind costs (10-40%), result in natural gas capturing a more dominant role before 2035. Figure 31 shows the production pathways for a 50% increase in assumed wind costs; hydro captures market share before wind and solar thermal become a small part of the solution in the latter years.
Figure 30. H₂ Production costs in Spain in 2022, when wind becomes the low-cost option (Scenario 2).

Figure 31. H₂ production costs in Spain in 2050 (Scenario 2)

Figure 32. H₂ Production pathways with wind resources 50% more expensive.
Norway

Norway expects governmental policy will limit options for H₂ production to renewable resources. Despite their abundant supplies of natural gas, they do not expect to use the natural gas for domestic H₂ production. Their self reported resource data is limited to renewable options. With the exception of the U.S., Norway was the only country to provide wind supply curves for both onshore and offshore wind resources.

Due to these constraints on available resources, the projected H₂ pathways for Norway are the same for both scenarios, Figure 33. Without significant changes in wind resource availability for H₂ production or cost, the solution does not change. Norway is likely to rely on wind resources for the production of hydrogen.

Figure 33. Production pathways in Norway for both scenarios.
In terms of the cost of the delivered H₂, H₂ produced from onshore wind are projected to cost approximately 42.04 $/GJ in 2050; the next lowest cost option is H₂ produced by hydro (53.95 $/GJ), Figure 34.

**Figure 34. Delivered H₂ costs in Norway for both scenarios.**

**Sweden**

Sweden expects to produce H₂ from renewable resources; hence their self-reported resources do not include any non-renewable resources. As is the case with Norway, the production pathways are the same for both scenarios, Figure 35. In early years, the hydrogen is produced by electrolysis using hydro resources. Beginning in about 2037, onshore wind becomes the dominant source as the assumed cost of onshore wind drops. By 2050, the cost of H₂ produced from onshore wind is approximately 5 $/GJ less expensive than from hydro, Figure 36.

**Figure 35. Production pathways in Sweden for both scenarios.**
France

The French data and base assumptions differ from other countries in two main areas. First, the French base case assumes market share for FCEVs of 20% by 2050, half that assumed for all other countries. Second, the French assume that all electricity-based options need to compete at grid prices, rather than at separate, stand-alone prices. The logic is that wind resources used for H2 production should not be priced lower than what the wind resource is valued at for the grid. Therefore, all of the electricity-based options (wind, solar, hydro, and nuclear) are given the same price initially. This means that if electrolyzer options are part of the solution, the electricity will come from a mix of generating sources determined by overall availability of that resource.

For the first scenario, in the absence of CO2 pricing, the lowest cost pathway for France is mainly onsite natural gas reformation, Figure 37. A small amount of H2 from biomass gasification is evident in the scenario; while the biomass option becomes cheaper in the out years than the natural gas option, Figure 38, its availability is limited; hence, it does not capture a larger role. Note that the various grid-based options are all more expensive to use and are not part of the projected pathway in this scenario. A key sensitivity in this scenario is the assumed biomass resource base. Any increase in assumed biomass availability means a larger role for biomass in the projected pathway.
The CO₂ prices of 100 $/tCO₂ by 2025 is not sufficient to alter the projected pathways from that of the first scenario; the natural gas option is still the low cost option, as shown previously in Figure 37. Increasing the assumed CO₂ price or increasing the cost of natural gas both result in large changes in the projected H₂ pathways.

Both of the following examples demonstrate the value of GPAT by capturing the dynamics of the developing H₂ markets in ways that might be overlooked otherwise. A visual inspection of the delivered H₂ costs (Figure 38) might suggest a higher CO₂ or natural gas cost would lead to a pathway with increased reliance on renewable options. The effect of the increased costs, however, leads France to import hydrogen from lower-cost countries. For example, in Scenario 2, increasing the assumed costs for natural gas by 50 percent results in France importing lower-cost H₂ from Spain, where the H₂ is produced from abundant and low-cost wind resources after 2040, Figure 40. Doubling the assumed CO₂ price results in a similar pathway. The assumption that any electrolytic production of hydrogen would be based on competing grid prices drives the solution to low-cost imported natural gas or alternatively, low cost imports from Spain. It is also worth noting the results are driven by the assumed costs for various feedstocks and that the differences in
assumptions about feedstocks should be further investigated. This conclusion does not detract from the basic message of the results though: there appear to be an abundance of pathways for countries to achieve a H₂ future. The exact pathways will likely evolve over time as assumptions are reviewed and standardized and costs change.

Figure 39. Delivered H₂ prices in 2050 in France (Scenario 2).

Figure 40. Production pathways in France with 50% higher natural gas costs. The “missing” supply after 2040 is provided by imports.

Specifying a percentage of H₂ that must come from domestically produced H₂ results in a projected pathway along the lines of Figure 41. In this example, 20% of H₂ comes from domestic, non-carbon emitting sources. Because of the assumption about grid prices discussed above, the 20 percent is split between the various electricity pathways, including wind (both onshore and offshore), solar PV, biomass, and hydro. The shares vary in size based on initial assumptions about availability of the resources over time. While France relies heavily on nuclear at present, the self-reported estimates available for H₂ production in the future were significantly smaller than those for renewables; hence nuclear is not part of this projected pathway.
Additional sensitivity analysis

For the most part, the assumptions about wind costs supplied by countries do not take into account the reality that there are times when wind power has very little value. Specifically, wind produced during non-peak electricity times may have little value on the grid; off peak production of hydrogen is one possible solution to increase the value of the wind resource during these times. While GPAT does not allow for varied time of day pricing, it does allow for changing the assumptions about initial resource and costs. Figure 42 demonstrates such an experiment. In this scenario, we assumed that 20 percent of the wind resource across Europe is available at just 10% of the initial cost. Despite expectations to the contrary, this does not result in the increased use of wind in the European markets. The basic explanation is that those countries that have wind resources (Norway, Spain, and Sweden) are already maximizing the amount of H₂ produced from this resource. As wind was already the low-cost option, supplying it at a cheaper cost does not change the solution.
Higher CO₂ Prices

Higher CO₂ prices will result in a shift away from natural gas towards renewable resources. For example, consider an example where the price of CO₂ is doubled (200 $/tCO₂e by 2025). The higher CO₂ prices result in larger reliance on non-CO₂ emitting resources, Figure 43. Relative to the baseline Scenario 2, the higher CO₂ price quickly makes the natural gas options more expensive than the renewable options; in this scenario biomass and onshore wind are the two dominant sources for hydrogen production. Germany relies almost solely on biomass; Spain and Norway use wind; and Sweden uses a similar mix of wind and hydro as in the lower CO₂ price case. The remaining natural gas use is in France; if trading between countries is allowed, then natural gas use in France is replaced with imported wind from Spain.

Solar PV does not capture a larger share in this or any of the scenarios as few countries reported significant likely future resources, assuming that it would be used more for residential use. The one country that reported significant potential resources is Spain; however, as the assumed costs from wind resources are lower, wind beats out solar. Higher wind costs would allow solar to play a more significant role in the scenarios.
European Portfolio Standard

This example considers a scenario where European countries require that 20% of all H₂ is produced from renewable resources. As in the doubled CO₂ price case, wind and biomass resources heavily dominate the pathways. As in the baseline Scenario 2 (see Figure 20), the peak in natural gas around 2040 and subsequent decline is caused by the switch to biomass in Germany once it becomes the cheaper option.
Reduced Distribution Costs

GPAT currently relies on U.S.-based estimates of distribution costs as the default values until the results from Task 28 are available. The projected pathways could change once these more specific, regionally-based distribution costs are included. For example, other published studies suggest lower values than included here.

McKinsey & Company (2010) completed a comprehensive study in 2010 analyzing how Europe could meet its goal of reducing carbon emissions by 80% by 2050. To reach that level, they assumed that the transport sector would need to reach a 95% decarbonization target by 2050. McKinsey assumed this required the wide-scale introduction of PHEVs, BEVs, and FCEVs. They analyzed nine possible production paths and assumed that while distribution will be initially by trucks, pipelines will dominate by 2025. They conclude that with a 25% market share of FCEVs, delivered H₂ costs will approach 52.50 $/GJ (6.30 $/kg) by 2030. McKinsey estimated distribution costs for onsite options of 6.20 $/GJ in 2030, dropping to 5.20 $/GJ by 2050. For centralized options, McKinsey estimates distribution costs falling rapidly and reaching 9.33 $/GJ in 2030. The distribution costs include the retail station. These costs are significantly less than assumed in GPAT, which were 13.50 $/GJ and 21.50 $/GJ, respectively.

An earlier analysis of nine alternative distribution pathways for the U.S. by Drennen and Rosthal (2007) found that for distribution options that include pipeline transport, costs range from 9.42 – 14.75 $/GJ with a total transport distance of 160 km and 22.16 – 24.83 $/GJ for transport distances of 800 km. Because the uncertainties regarding actual distances and quantities transported used by McKinsey, it is difficult to directly compare these results with those of McKinsey. However, they do support the general McKinsey conclusion that distribution costs could be lower than assumed in GPAT.

Using the McKinsey estimates for distribution costs does significantly change the results presented here. Figure 45 shows the projected pathways in the European countries for scenario 2 using the McKinsey numbers. The projected pathways shift away from onsite use of natural gas to centralized production of hydrogen from biomass and natural gas and onshore wind. At the country level, France shifts from onsite SMR to centralized SMR. Germany shifts from an early reliance on onsite SMR in favor of biomass gasification.

The delivered H₂ costs in 2050 in Germany are shown in Figure 46. This figure shows that with the lowered distribution costs, the biomass option becomes the low-cost option. It also shows how close the estimated costs for the two natural gas options are. This result shows the importance of the Task 28 efforts, as they are tasked developing a consistent set of infrastructure estimates. However, the basic message from Task 30 does not change: each country has a variety of options for supplying future their hydrogen demand and that the specific pathway may change as our understanding of delivery pathways evolve.
Figure 45. Sensitivity analysis on distribution costs (Scenario 2).

Figure 46. Delivered H2 costs in 2050 for reduced distribution cost.  

$^{15}$ Germany does not plan on allowing use of Coal with CCS. To handle this, an artificially high cost was input.
Japan

In addition to the data and scenarios considered for other countries, Japan provided estimates for both in-country and out-of-country production of hydrogen. Specifically, Japan provided cost estimates for production of H2 from abundant, low-cost Australian coal with long distance ship transport (9000 km) and then truck transport to the refueling stations. They assume that the coal gasification process includes CCS with a 95% CO2 capture rate, significantly higher than the 87.5% capture rate assumed for other countries. Since Australia was not included in the GPAT model, to accommodate this option, GPAT was modified in the Japanese case to represent the Australia coal gasification with CCS option. To ensure that coal gasification without CCS did not enter the solution as a lower-cost option, extremely high costs were assigned to the coal in that option.

For comparison purposes, we first consider the same two scenarios reported for the other countries (Scenario 1: No trading between countries; and Scenario 2: Trading and 100$/ton CO2e by 2025). Three additional scenarios requested as “more likely” by the Japanese team are then discussed. These three additional scenarios include:

- Base Case: No CO2 price and no domestic renewable requirements for H2 production.
- Base Case + 200 $/ton CO2e by 2050. No domestic renewable requirements.
- Base Case + 20% domestic renewables by 2050. No CO2 price.

If Japan does not consider the Australia option (Scenario 1), then 100% of their H2 would come from domestic use of natural gas, Figure 47. In this scenario, there are three options for producing hydrogen identified by the Japanese: centralized electrolysis using either wind or solar PV, or distributed SMR of natural gas, Figure 48. The high cost associated with the other options signifies they are not available for consideration in GPAT. Unfortunately, it is not possible to limit the display to only available options. The main sensitivity with the two renewable options is the distribution costs; achieving reductions in these expected costs could make the renewable options more viable.

Figure 47. H2 production pathways in Japan (Scenario 1).
Figure 48. Delivered H2 costs in 2050 (Scenario 1)\textsuperscript{16}.

The addition of a 100 $/ton CO\textsubscript{2}e by 2025 (Scenario 2), does not change the pathways. Natural gas SMR is still the lowest-cost option, Figure 49. Sensitivity analysis on the carbon price indicates that the carbon price would have to approach 200 $/ton CO\textsubscript{2}e before the renewable options are cost competitive, Figure 50. In this example, solar PV is the lowest cost option initially, with onshore wind becoming competitive in later years. The larger the carbon price, the larger the fraction of hydrogen produced from renewables.

\textsuperscript{16} Offshore wind and coal (with and without CCS) are not available in this Japanese scenarios; hence the very high delivered costs.
Once the Australian option is considered (three auxiliary scenarios), the projected pathways tend to favor the use of the H2 produced in Australia. For the first case – No CO2 price and no domestic requirements – prior to 2025 when the Australian option becomes an option, H2 production is comes from onsite natural gas SMR. Beginning in 2025, the coal gasification with CCS option in Australia is the lowest-cost option, Figure 51. These results are very sensitive to the assumptions about transport costs. As shown in Figure 52, in 2025, the year that the Australian option is first available, the Australian option (red circle added for clarity) is marginally less expensive than the domestic natural gas SMR option; note that both the feedstock and conversion costs for the Australian option are low. The transport costs are more than 50% of the total costs and any additional cost there could make the domestic option more attractive. By 2050, Figure 53, the Australian option is significantly cheaper than any of the other options. Based on the given assumptions about projected reductions in transport costs over time, the Australian option is likely to be a major source for the Japan; less certain is whether this will be the case immediately in 2025.
Figure 52. Delivered H2 costs in Japan in 2025. Coal with CCS is the Australian option.\textsuperscript{17}

Figure 53. Delivered H2 costs in Japan in 2050. Coal with CCS is the Australian option.\textsuperscript{18}

Additional Japanese Scenarios

For the next scenario, CO$_2$ prices are gradually increased, reaching 200 \$/ton CO$_2$\textsubscript{e} in 2050. As the Australia coal gasification option includes CCS, the result is exactly the same as the previous scenario – before 2025, the H2 is produced domestically using natural gas. After 2025, the Australia coal option is the low-cost option. As with the last scenario, this result is highly sensitive to the transport costs. If the transport costs are higher, domestic production of H2 from natural gas remains the least-cost option until such time as the CO$_2$

\textsuperscript{17} Neither coal gasification without CCS or offshore wind are options for Japan; costs have been set high to prevent them from consideration.

\textsuperscript{18} Neither coal gasification without CCS or offshore wind are options for Japan; costs have been set high to prevent them from consideration.
price becomes high enough to allow solar PV and onshore wind to compete, which happens around 2045 with a 200 $/ton CO$_2$e tax.

The final case considered requires that 20% of all hydrogen is produced domestically using renewable resources, Figure 54. In this case, H2 produced from solar PV is initially the low-cost renewable option. H2 produced from onshore wind first becomes economical around 2035. Australian coal gasification with CCS is the main non-renewable option after 2025. As shown in Figure 55, beginning in 2025, Australian H2 production from coal gasification with CCS is the low-cost option. The renewable mandate forces solar PV and then onshore wind into the solution. Note that onsite SMR of natural gas is close to competing with the Australia option in 2025, again emphasizing the sensitivity of these results to assumptions about the long-distance transport costs.

Figure 54. H2 production pathways for Japan with requirement that 20% of all hydrogen is produced from domestic renewable resources.
As is the case throughout this report, the results are not definitive. As should be clear from the discussion about the sensitivity around the long-distance transport costs in the Japanese analysis, small changes in assumptions can result in very different pathways. Nevertheless, the point of the analysis is still valid: many different pathways are possible and there are sufficient resources for each country to supply the hydrogen necessary for a significant FCEV fleet.

For Japan, the participating experts in this project noted that several other hydrogen pathways are possible under other conditions. For example, hydrogen refueling stations located near hydrogen production plants will benefit from locally supplied hydrogen rather than hydrogen shipped long distances. Further, in the early stage of hydrogen deployment, it may be that one dominant strategy, such as the Australian option, will not make economic sense and that many other supply strategies will evolve. Finally, the experts note that as advances in renewables lead to lower cost, it will become increasingly likely that hydrogen produced from renewable energy may be able to compete with the Australian option.

**United States**

The United States is modeled by sub-region, as described earlier, with results available at either the regional or aggregate level. In the absence of carbon prices, abundant, low-cost natural gas is used for hydrogen production Figure 56. Figure 57 shows the delivered costs by region; while there is variation across regions, interregional transport does not make economic sense in this analysis. We note, however, that these results are somewhat driven by the regional definitions. It is possible that a state within one region might border a state in another region, but as the distance between regions is based on a geographic mean for purposes of calculating transport distance, the actual distance may be overstated. Therefore, most of the U.S. results will focus on aggregate results.
Figure 56. H₂ production pathways for the United States (Scenario 1).

Figure 57. Delivered H₂ costs in the United States (Scenario 1).

<table>
<thead>
<tr>
<th>Delivered H₂ Price ($/GJ)</th>
<th>RFC</th>
<th>TRE</th>
<th>MRO</th>
<th>NPCC</th>
<th>FRCC</th>
<th>SERC</th>
<th>SPP</th>
<th>WECC</th>
</tr>
</thead>
<tbody>
<tr>
<td>RFC</td>
<td>29.18</td>
<td>69.13</td>
<td>50.04</td>
<td>52.88</td>
<td>58.77</td>
<td>53.21</td>
<td>59.44</td>
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<tr>
<td>TRE</td>
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<td>28.57</td>
<td>51.55</td>
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<td>58.31</td>
<td>45.22</td>
<td>85.23</td>
</tr>
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<td>MRO</td>
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<td>59.72</td>
<td>30.40</td>
<td>71.35</td>
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<td>69.40</td>
<td>49.32</td>
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<tr>
<td>NPCC</td>
<td>52.27</td>
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<td>71.97</td>
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<td>76.61</td>
<td>57.03</td>
<td>76.24</td>
<td>115.05</td>
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<td>FRCC</td>
<td>61.64</td>
<td>70.06</td>
<td>80.50</td>
<td>70.29</td>
<td>36.81</td>
<td>57.17</td>
<td>69.89</td>
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<td>SERC</td>
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<td>61.99</td>
<td>64.99</td>
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<td>53.60</td>
<td>34.89</td>
<td>57.06</td>
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<tr>
<td>SPP</td>
<td>59.95</td>
<td>46.12</td>
<td>51.05</td>
<td>77.36</td>
<td>77.53</td>
<td>63.28</td>
<td>28.67</td>
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<td>WECC</td>
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<td>114.03</td>
<td>124.32</td>
<td>108.92</td>
<td>82.40</td>
<td>30.81</td>
</tr>
</tbody>
</table>

Columns are Supply and Rows are Consumption (vertically, it is the price supplied to the horizontal country).

Figure 58 shows the delivered H₂ costs in the Western Region (WECC) in 2050. Similar dynamic graphs are available for each region. As is the case with all of the regions, for Scenario 1, onsite natural gas is the low cost option (30.81 $/GJ) followed by centralized natural gas (35.03 $/GJ) and centralized biomass gasification (35.27 $/GJ). The small difference in delivered cost suggests the results are sensitive to changes in the base case assumptions. For example, a 50% increase in assumed natural gas costs leads to significant H₂ production from biomass, with a small contribution from coal gasification without CCS, Figure 59, with significant regional differences. In this higher natural gas cost scenario,
certain regions still rely solely on natural gas (RPC, TRE, and NPCC), while others use some or mostly biomass (FRCC).

![Figure 58. Delivered H₂ prices in the Western Region in 2050 (Scenario 1).](image1)

The modified Scenario 1 is similar to the projected pathways for Scenario 2, Figure 60. CO₂ prices have the same effect as increasing the cost of natural gas. Coal gasification is not one of the pathway options. Doubling the carbon price further forces natural gas out of the solution; by 2050, H₂ production from natural gas is limited to about 10%. The remainder comes from the assumed abundant supplies of low-cost biomass.¹⁹

¹⁹ GPAT does not consider the possibility of other large-scale increases in demand for this biomass.
Figure 61 shows regional production of H₂ for Scenario 2. Regional (and total) greenhouse gas emissions from the transport sector are shown in Figure 62. Scenario 2 results in a 36.1% decrease in projected GHG emissions by 2050 from the case of no FCEVs. By doubling the CO₂ price, emissions would be 42.1% lower by 2050. For Scenario 1, GHG emissions are reduced by 24.6% by 2050. These results show the wide-scale introduction of FCEVs can significantly reduce GHG emissions from the transport sector. However, note in Figure 62 the leveling out of the emissions. A more dramatic move to FCEV will be needed to continue decreases in GHG emissions because the population of vehicles continues to rise.

**Figure 60. H₂ pathways for the United States (Scenario 2)**
Figure 61. Regional H₂ production in the United States (Scenario 2).
Scenario Summary

Delivered H2 costs by participating country and year are summarized for the two main scenarios in Table 10. Blank cells for certain countries in 2020 indicate no resources were identified as available for use in hydrogen production in 2020.

Projected GHG emissions from light duty vehicles for all of the scenarios discussed above are summarized in Figure 63. Emissions are expected to decrease even without the introduction of FCEVs as fuel efficiencies improve. The introduction of FCEVs can result in significant additional reductions, especially if countries require a certain percentage of the hydrogen is produced from renewable sources. For the scenario combining the 100 $/ton CO₂ tax and a 20% renewable hydrogen production requirement, emissions are 22% below the case of no FCEVs. GHGs begin increasing again for the case with no FCEVs as assumed improvements in vehicle efficiencies end. This is also the case for scenario 1 as coal captures an increasing share of hydrogen production. For the other scenarios shown, emissions stop declining in the latter years as the proportion of FCEVs reaches the 40% level. This result suggests it will be difficult for European countries to achieve further decarbonization of the transport sector without a larger scale introduction of FCEVs with hydrogen produced from non-carbon based sources or other non-CO₂ emitting vehicle options.
### Table 10. Delivered H2 costs by country and year for the two scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
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<td><strong>Scenario 1: No Trading, no CO2 price</strong></td>
<td></td>
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**Figure 63. GHG emissions from European transport sector.**
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CONCLUSIONS AND FUTURE DIRECTIONS

This global resource analysis work is a subtask of the IEA Hydrogen Implementing Agreement Task 30 (Global Hydrogen Systems Analysis). The main objective is to analyze potential hydrogen production and distribution pathways for participating countries. To accomplish this objective, we developed a user-friendly pathways tool to help participants understand the resource options and constraints to meeting future hydrogen demand for various scenarios. The results show there are a large number of potential pathways for providing hydrogen to fuel significant fuel cell fleets and that resource availability is not the limiting factor for a hydrogen economy.

For a wide range of scenarios, we estimate that greenhouse gas emissions from the transport sector could be lowered 41% – 48% from current levels. While a portion of this is due to expected efficiency improvements in traditional powertrains, FCEVs potentially lead to significant further reductions, especially for pathways that do not include fossil fuels as a feedstock for the hydrogen production. In a low-natural-gas-cost world, it is difficult for other feedstocks to compete for a share of hydrogen production in the absence of CO₂ prices or policies limiting natural gas use. For this reason, many countries expect their countries to require some percentage of their hydrogen production to come from low-carbon intensity fuels such as wind or biomass.

Each participating country has identified multiple options for producing hydrogen domestically. This report summarizes several scenarios and discusses the key sensitivities. While several key sensitivities are highlighted in this report, none of them change the basic conclusion that existing resources are sufficient to support a wide-scale introduction of fuel cell vehicles.
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*GermanHy Woher kommt der Wasserstoff in Deutschland bis 2050? Studie im Auftrag des Bundesministeriums für Verkehr, Bau und Stadtentwicklung (BMVBS) und in Abstimmung mit der Nationalen Organisation Wasserstoff- und Brennstoffzellentechnologie (NOW).*


H2OSL: Possibilities for utilization of hydrogen at Oslo Airport Gardermoen, April 2012 (In Norwegian).


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