The Potential Role of Blue Hydrogen in Low-Carbon Energy Markets in the US

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Note on use of "hydrogen colors"

This report uses the term "blue hydrogen" to refer to hydrogen made from natural gas where most of the carbon dioxide produced by the hydrogen manufacturing process is captured and geologically stored or used to make chemicals, fuels, materials, or other products. The report also uses the term "green hydrogen" to refer to hydrogen that is made by electrolysis using renewable electricity.

These are commonly used terms that are employed here to make the report more readily understood. But these terms are not defined by US laws or regulations and neither ICF nor API is advocating that these terms be used in setting policies, laws, regulations, tax incentives, etc.

Key Takeaways

1. Hydrogen can have a large role in low-carbon energy markets in the US

Hydrogen can be a wide-spread and cost-effective resource for mitigating carbon emission in all end-use sectors (residential, commercial, industrial and transportation) and in the power sector. US demand for hydrogen by end-users and power plants could reach 9.9 to 12.9 quadrillion Btu by 2050 if policies were introduced based on a willingness to pay $150 to $250 per metric ton of CO2e reduced. These levels of hydrogen use would represent 12% to 15% of total US energy end-use consumption. [See **Section 7.2**]

2. Hydrogen's importance stems from its ability to facilitate the decarbonization of fossil fuels and make electricity more "useable" and "storable"

The main advantages of converting fossil fuels to hydrogen is that the fuels are decarbonized at a central location that can take advantage of economies of scale for carbon capture and transport and proximity to geologic storage. The main advantages of converting renewable electricity (or any type of electricity) to hydrogen is that hydrogen can be applied more effectively than electricity in certain end-uses (e.g., high temperature industrial process heating, long-haul trucking, large airplanes, etc.); can be combined with captured carbon dioxide to create synthetic methane, liquid fuels, and nonfuel chemicals; and can be stored in the form of hydrogen or one of its derived fuels.

3. Hydrogen made from natural gas may be the largest initial source of new hydrogen supply in the US

The results of this analysis suggest that blue hydrogen made from natural gas with CCUS could be considerably less expensive than green hydrogen from electrolyzers for the next two decades even when electrolyzers use dedicated solar/wind renewable electricity and there is an assumption of substantial continued technology improvements that reduce the cost of renewable electricity and the cost of conversion of electricity to hydrogen in electrolyzers. Given these economics over the study period through the year 2050, blue hydrogen is expected to make up over 90% of the US market to supply end-users from dedicated, continuous hydrogen production facilities. [See **Section 7.3**]

4. Hydrogen made from renewable electricity may also play a significant role

Large amounts of solar and wind generation will be needed to meet national climate goals. This is expected to lead to "excess electricity" when electricity load plus charging for electricity storage is less than generation from non-dispatchable/inflexible generation. Assuming that most of this excess electricity is not curtailed but is used to make hydrogen in electrolyzers, the resulting hydrogen could make up about 7% to 9% of projected hydrogen demand in the US from 2025 to 2050. An additional 2% of hydrogen supply might come from solar/wind generation that is "dedicated" to making hydrogen on a continuous basis. [See **Section 7.3** and **Section 7.4**]

5. Uniform incentives among sources could help achieve hydrogen's full benefits

The analytic conclusions stated above are based on economic modeling that assumes that climate mitigation policies will treat all technologies/fuels equally in terms of the incentives and disincentives offered in terms of $/metric ton of carbon dioxide equivalent that can be reduced. The importance of uniform incentives in ensuring that all sources of hydrogen can help realize hydrogen's benefits as a carbon mitigation resource was investigated in this study by modifying the $250/MT CO2e case to assume that blue hydrogen would bear a $12/MMBtu differential in incentives relative to green hydrogen. [See **Section 1.1.1** and **Section 7.2.4**] The important differences in results between the case with uniform incentives (that is, the same $/metric ton of CO2e reduced) and this "High Uneven Case" are:

- **There is a much bigger hydrogen market by 2050 (12.9 quads versus 3.7 quads) when incentives are provided equally.**
- **When each source of hydrogen gets the same incentives per unit of CO2 reduction, 5.5 billion more metric tons of GHG emission reductions are achieved through 2050. This difference is equivalent to eliminating 1½ years of average GHG emissions before 2050.**
- **The case with equal incentives shows better economic efficiency (measured as incremental dollars per metric ton of CO2e reduced). There is a 12% difference in economic efficiency averaged over the entire forecast period and a 17% difference in the year 2050 alone.**

6. Capital requirements for hydrogen infrastructure could total approximately $1 trillion through 2050

The realization of hydrogen's potential to contribute to GHG mitigation goals will require investments into several kinds of infrastructure including blue hydrogen manufacturing; electrolyzers to convert excess and dedicated solar and wind electricity; hydrogen pipelines; hydrogen storage; local hydrogen distribution systems; and facilities to convert, transport and dispense hydrogen for transportation markets. When all hydrogen sources are treated equally in terms of incentives and disincentive, investments in blue hydrogen manufacturing facilities could constitute the largest category of infrastructure, making up about 22% of the $950 billion to $1.27 trillion total requirement through the year 2050. [See **Section 7.2.5**]

Executive Summary

ES.1. Purpose and Scope

Given the high level of interest in the potential use of hydrogen as part of comprehensive carbon mitigation strategies in the US and around the world, this study was conducted at the request of the American Petroleum Institute to answer the following questions:

- How might hydrogen fit into a low-carbon future for the US?
- What productive role could be played by hydrogen made from natural gas with carbon capture and geologic storage ("blue hydrogen")?
- What benefits can be realized when all hydrogen supply options are on an equal footing and receive the same incentives (on a basis of $/metric ton of lifecycle CO2e avoided) versus policies that provide greater support for specific hydrogen supply options?
- What level of investment in hydrogen infrastructure will be needed for these anticipated contributions to be realized?

The analysis was conducted at a national level through the year 2050. All large residential, commercial, industrial, power and transportation markets in which hydrogen is expected to compete well are included in the analysis.

ES.2. Framing of Analytic Cases

The starting point for the study is the Energy Information Administration's (EIA) 2021 Annual Energy Outlook (AEO) Reference Case, which describes total energy use by technology/fuels through 2050 based on current laws and regulations. In this projection, hydrogen continues to be an important chemical used in petroleum refining, petrochemical and steel industries but does not play any significant direct role in fuel and power markets in the US.

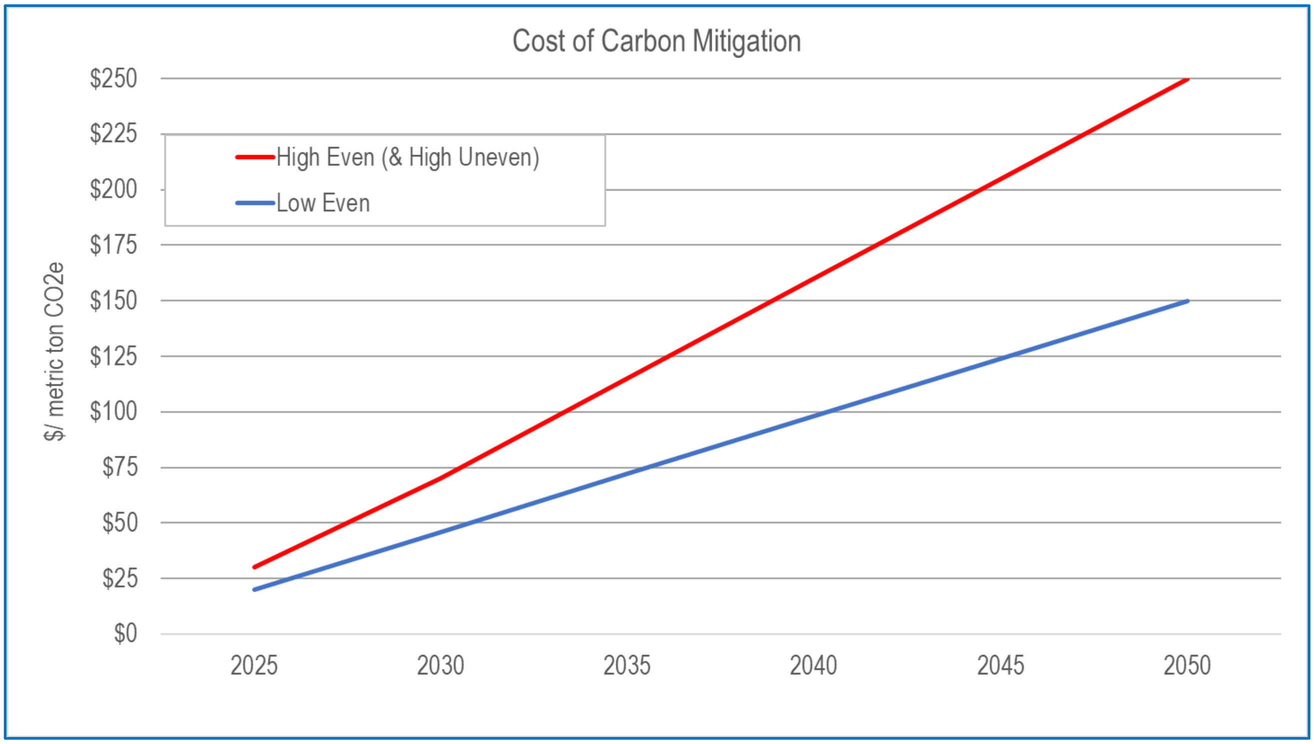
This study examines three Alternative Cases that assume US policies will be altered to significantly reduce GHG emissions and provide a potentially wider and larger market for hydrogen. For all Alternative Cases, the choices for technologies/fuels were determined by an economic competition within various markets and submarkets. These competitions were represented by market share equations that allocated portions of the market among competing technologies/fuels based on their relative "lifecycle costs" or "lifetime cost of ownership" which include capital, operating and maintenance, and fuel/energy expenditures plus the time value of money.

A cost of carbon mitigation in $/metric ton of CO2e was introduced into the economic competition to represent the effects of policies to move energy consumption toward GHG goals. The three Alternative Cases consist of:

- "Low Cost of Carbon Mitigation Applied Evenly" (Low Even Case) wherein the cost of carbon mitigation reaches $150 per metric ton of CO2e by 2050. All technologies/fuels receive incentives (or pay fees) based on the same $/metric ton of CO2e amount applied to their lifecycle GHG emissions.

- "High Cost of Carbon Mitigation Applied Evenly" (High Even Case) that reaches $250 per metric ton of CO2e by 2050. Here too, all technologies/fuels receive incentives (or pay fees) on an equal $/metric ton of CO2e basis.
- "High Cost of Carbon Mitigation Applied Unevenly" (High Uneven Case) which has the same cost of carbon mitigation as the High Even Case but assumes blue hydrogen does not receive incentives (or pay fees) on an equal basis with other forms of hydrogen. This is represented as a $12/MMBtu differential for blue hydrogen relative to the treatment of green hydrogen.[1]

Exhibit 1: Cost of Carbon Mitigation Assumed in Creation of Alternative Cases



Note: The cost of carbon mitigation represents the willingness to pay for reduced GHG emissions measured in dollars per metric ton of avoided carbon dioxide. It can be implemented through taxes/fees, mandates, performance standards, taxes credits, subsidies, etc. The High Uneven Case assumes the same cost of carbon mitigation as the High Even Case.

The concept of differential treatment between blue hydrogen and hydrogen from other sources is based on the November 2021 Build Back Better (BBB) bill passed by the House of Representatives. That bill would have created a $12/MMBtu differential in incentives for blue hydrogen relative to what it would get if treated on the same $/metric ton basis as green

[1] This differential could be achieved by offering more incentives to green hydrogen (e.g., larger tax credits), by creating more disincentives for blue hydrogen (e.g., higher taxes or fees) or by a combination of the two approaches. The economic modeling of the High Uneven Case was performed by adding an extra cost to blue hydrogen so as to make it less competitive in the wholesale, "composite" market for hydrogen supply without changing the relative economics of green hydrogen versus other fuels such as electricity, diesel, or gasoline.

hydrogen. The case with uneven treatment among sources of hydrogen was investigated to illustrate the potential economic inefficiencies that might occur if such policy were to be pursued.

Although policies to encourage low-carbon technologies/fuels are represented in the economic modelling as a tax or fee based on each option's lifecycle GHG emissions, the study does not investigate or recommend specific policy options to create incentives/disincentives to promote low-carbon energy technologies/fuels.

ES.3. Analytic Results: Hydrogen Supply

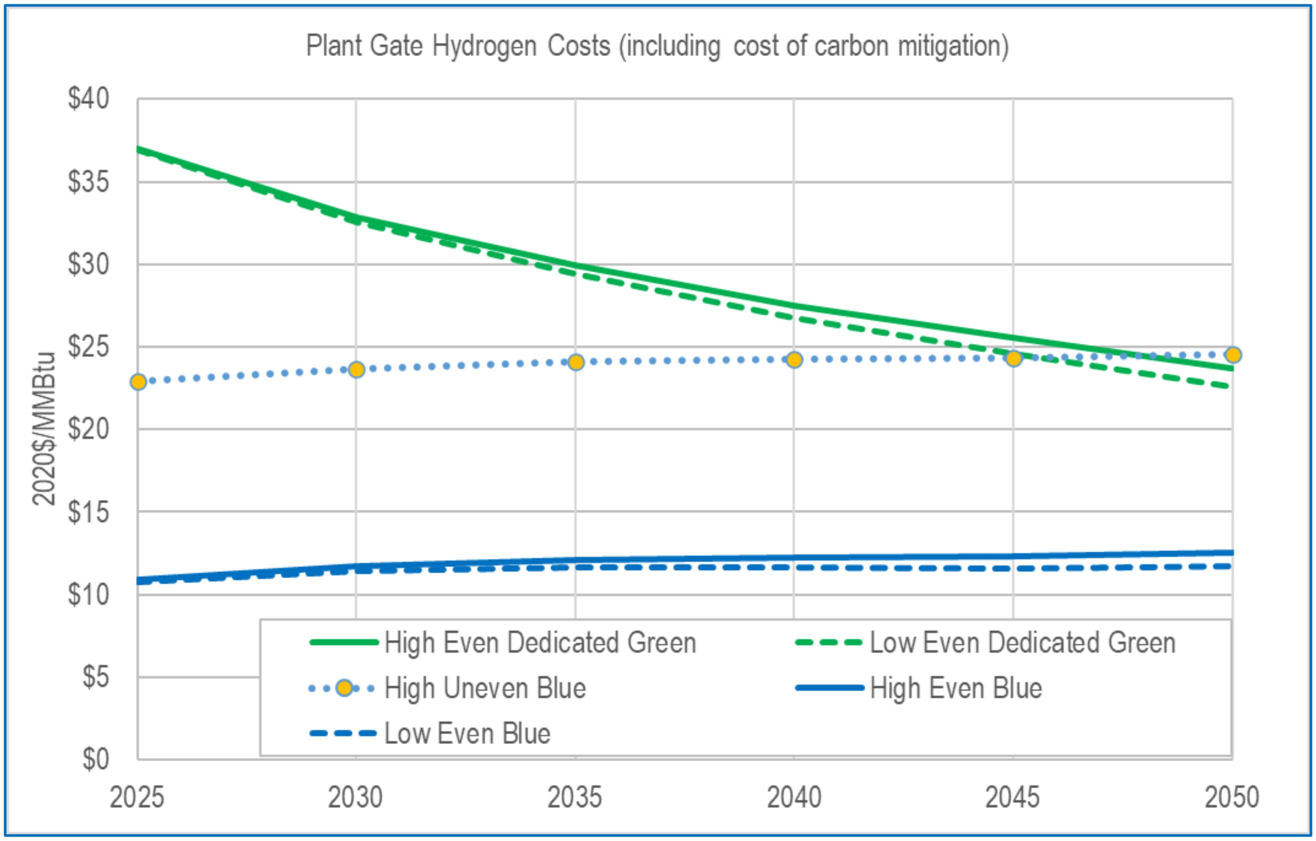
The economics of blue hydrogen evaluated here are based on autothermal reforming (ATR) with 97% carbon capture (of emissions at the production plant) and geologic storage. The price of natural gas used by the ATR plant is assumed to be the national average industrial price from the 2021 AEO Reference Case. This industrial natural gas price ranges from $3.81 to $4.52 and averages $4.29/MMBtu from 2025 to 2050.

The cost of making hydrogen from electricity and water in electrolyzers will depend, to a large degree, on what kind of electricity is used and how many hours in a year that electricity will be available (that is, the anticipated annual capacity utilization rate for the electrolyzer). The options for using electrolyzers to make hydrogen can be placed into three categories:

- Buy **electricity from the grid** and operate at a high load factor. For the economic modeling of this option the relevant electricity price is the average electricity price to industrial consumers from the AEO (about $65/MWh from 2025 to 2050). This would be appropriate for a dedicated hydrogen plant buying electricity from the grid and operating at high utilization rates of 70% or more. Production of hydrogen might cease for some hours in the year when electricity prices are very high. This option is not expected to be economic in the cases examined in this report because the average industrial electricity price is too high given the expected market clearing price for hydrogen.
- Use electricity from **dedicated solar/wind generators** and operate for all hours when electricity is available from those generators. For the economic modeling of this option, the relevant electricity price would be the cost of marginal new solar and wind power plants (roughly $49.50 to $33.50/MWh between 2025 and 2050). If such electrolyzers operated only whenever the dedicated renewable electricity is available, their annual capacity utilization rate might range from 25% to 60% depending on where they are located and the mix of solar and wind generation to which they are linked. In the cases examined here, this option is expected to be marginally economic. It would occur most likely in areas where sales from wind/solar generators to the electricity grid is bottlenecked by inadequate electric transmission capacity.
- Use only **"excess electricity"** that would be available only when electricity load plus charging for electricity storage is less than generation from non-dispatchable/inflexible generation. That is, when the market price for electricity would be lowest (zero to $20.00/MWh). Electrolyzers using only excess electricity would be most economic where large amounts of low-cost electricity are available for many hours in the year and high annual capacity utilization rates can be achieved. Sourcing "excess electricity" to make hydrogen is expected to be the primary method for the "uniform incentives" cases examined in this report.

For this analysis, the power plant capital costs, operating and maintenance cost and performance characteristics of wind and solar (including the effects of future technological improvements) are taken from the AEO modeling assumptions. As shown in Exhibit 2, the results of this analysis suggest that blue hydrogen made from natural gas could be considerably less expensive than green hydrogen from electrolyzers when electrolyzers use dedicated solar/wind renewable electricity. However, if policies were to create a $12.00/MMBtu differential in incentives for blue hydrogen relative to green hydrogen, green hydrogen could become less expensive than blue hydrogen after 2045.

Exhibit 2: Potential Costs of Producing Hydrogen



Note: Green hydrogen costs are based on dedicated solar and wind generation producing electricity at a lifecycle cost averaging $49.50/MWh in 2025 and declining to $33.50/MWh in 2050. The cost of grid electricity under average industrial electricity tariffs would be higher at approximately $65/MWh over that period. The cost of blue hydrogen in the High Uneven Case is represented as a $12/MMBtu increase relative to the High Even Case, which also has the cost of carbon mitigation rising to $250/MT of CO2e in 2050.

Given these economics, blue hydrogen is expected to make up most of the US market to supply end-users from dedicated, continuous hydrogen production facilities in the Low Even and High Even Cases. However, the large amounts of solar and wind generation expected in the Alternative Cases will lead to “excess electricity” when electricity load is less than generation from non-dispatchable/inflexible generation. Assuming that most of this excess electricity is not curtailed but is used to make hydrogen in electrolyzers, the hydrogen made from excess electricity in the High Even Case would total over 1,100 TBtu in 2050 and make up about 7% of project hydrogen demand in the US from 2025 to 2050 (See Exhibit 3). In the Low Even Case, overall hydrogen demand is lower and excess electricity is the source of 9% of hydrogen supplies over the forecast period while dedicated solar/wind is the source of just 2% of hydrogen supply – the same proportion as in the High Even Case.

In the High Uneven Case, the $12/MMBtu differential in incentives faced by blue hydrogen leads to a much smaller market for hydrogen (3.7 quads in 2050) and a substantial change in the mix of hydrogen supply sources. When blue hydrogen has lower incentives, its market share in hydrogen production drops from around 90% in the High Even and Low Even Cases to 54%. Hydrogen from dedicated solar/wind represents 27% of supplies and hydrogen from excess electricity is the final 18%.

Exhibit 3: Projected Market Shares for Modelled Hydrogen Production Options

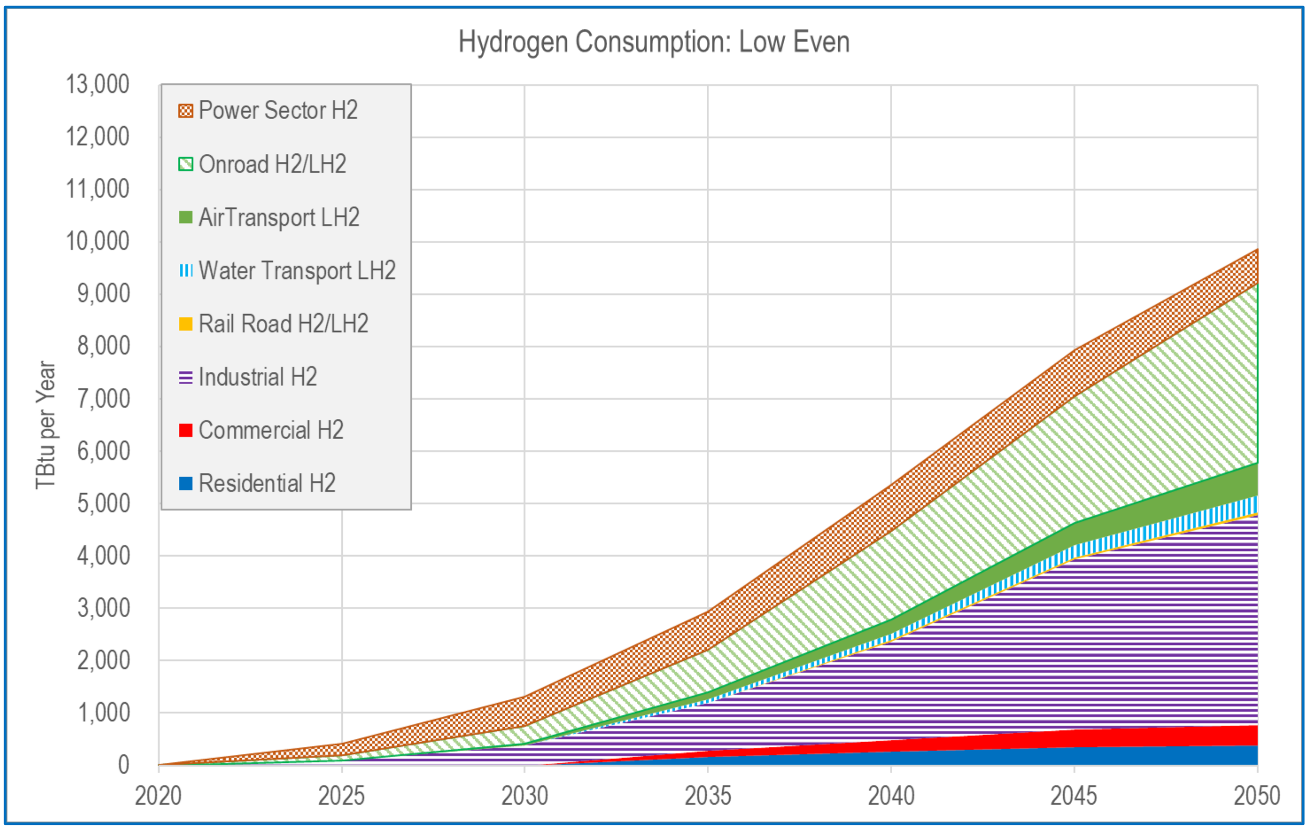
	Low Even Case (TBtu)				High Even Case (TBtu)				High Uneven Case (TBtu)			
Year	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply
2025	414	8	0	423	659	13	0	672	408	8	0	416
2030	1,290	26	1	1,317	2,291	47	1	2,339	639	13	1	652
2035	2,555	59	326	2,940	5,307	115	313	5,734	684	28	286	999
2040	4,781	107	475	5,364	8,352	182	546	9,080	986	192	500	1,679
2045	7,181	159	588	7,928	10,341	225	696	11,263	1,247	653	485	2,384
2050	8,661	197	995	9,853	11,468	258	1,181	12,908	1,389	1,773	547	3,709
average market share 2025-2050	*89%*	*2%*	*9%*	*100%*	*91%*	*2%*	*7%*	*100%*	*54%*	*27%*	*18%*	*100%*

Note: The study did not model all methods of producing hydrogen such as those using biomass, coal, or nuclear power. To the extent any of these prove to be economic, the market shares for blue hydrogen and electrolysis (using grid electricity, dedicated wind/solar, or "excess electricity") may be lower than shown here.

ES.4. Analytic Results: Hydrogen End-use Demand

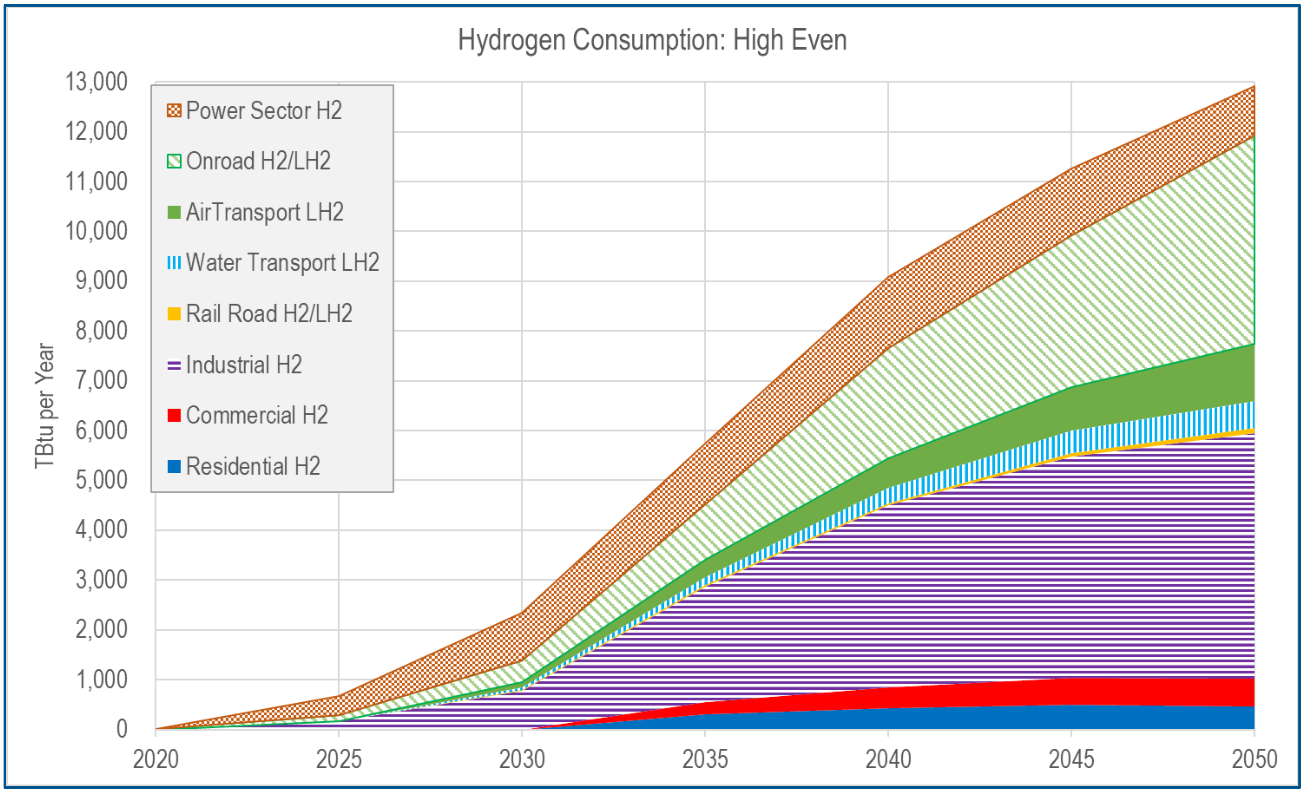
As with the supply-side modelling, the demand-side modeling conducted for this study assumed that policies could be implemented with a willingness to pay going up to $150 to $250 per metric ton of avoided CO2e by 2050. Under these hypothetical policies, energy consumers would be free to select technologies and fuels based on economics (wherein the lifecycle GHG emissions of each option are internalized at the targeted cost of carbon mitigation adopted by the policy for each year). Under such scenarios of "economic competition with uniform incentives," demand for hydrogen by end-users and power plants could reach 9.9 quadrillion Btu by 2050 (in the $150/MT cost carbon mitigation case shown in Exhibit 4) to 12.9 quadrillion Btu (for the $250/MT CO2e case shown in Exhibit 5). Hydrogen consumption in the Low Even Case is lower than in the High Even Case (when hydrogen is more expensive) because end-use sectors demand more hydrogen as a result of higher costs of competing energy sources under the higher willingness to pay for carbon mitigation. These levels of use of hydrogen in 2050 would include all end-use sectors (residential, commercial, industrial and transportation) and would represent 12% to 15% of total US energy end-use consumption (83.7 quads) as forecasted in the 2021 EIA Annual Energy Outlook.

Exhibit 4: Projected Hydrogen Consumption: Low Even Case



Some use of hydrogen in several end-use sectors could be achieved by the use of hydrogen blending into natural gas pipeline and distribution systems. If shown to be technically feasible and facilitated by regulatory approvals, this report concludes that such blending might represent up to approximately 0.5 quads of hydrogen use by 2050. (See Section 6.3).

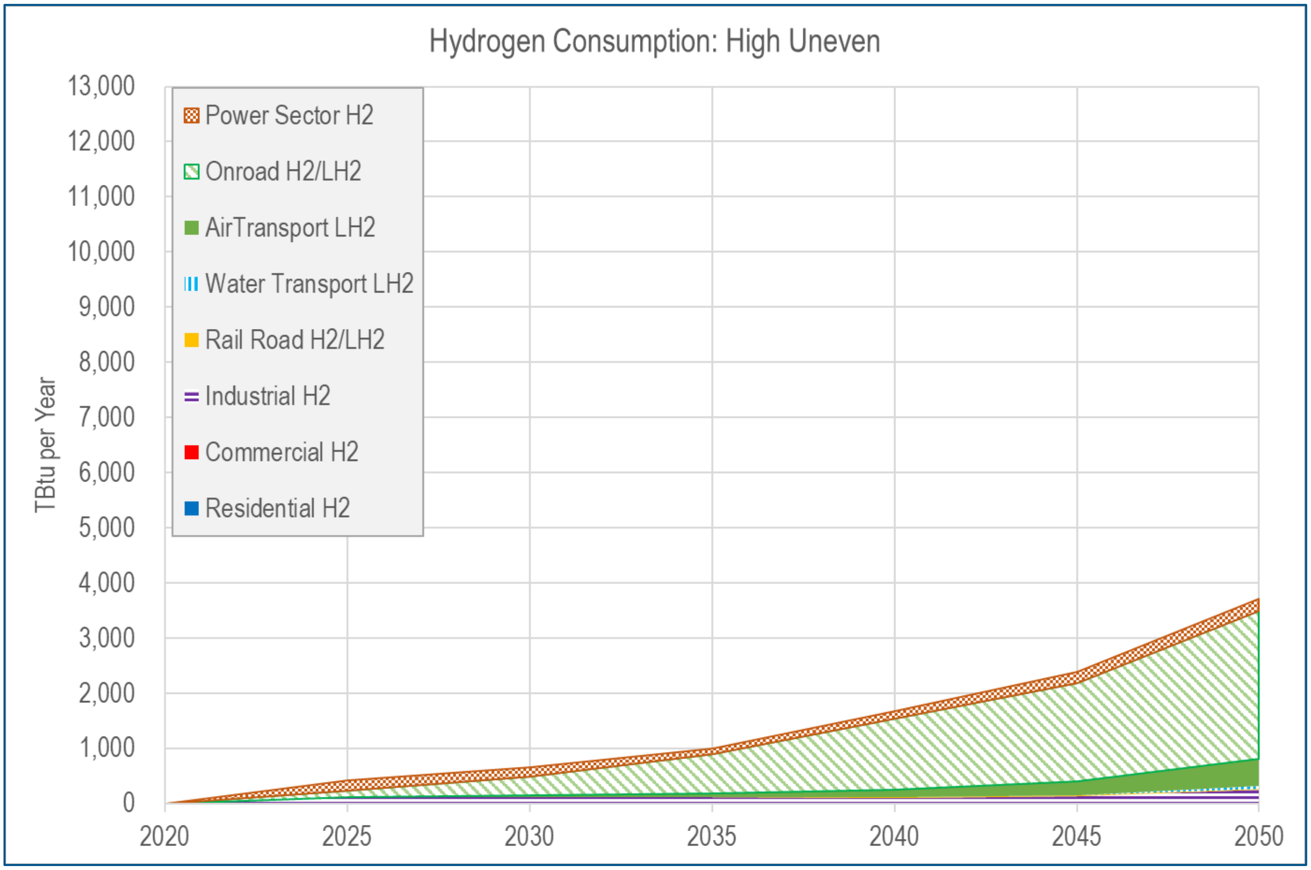
Exhibit 5: Projected Hydrogen Consumption: High Even Case



The importance of blue hydrogen in realizing the benefits of hydrogen as a carbon mitigation resource was investigated by modifying the \$250/MT CO2e case to assume that there was not a level playing field based on the potential to mitigate carbon emissions but rather that blue hydrogen would bear a \$12/MMBtu differential in incentives relative to green hydrogen. The "uniform incentives" case has a larger 2050 hydrogen end-use market (12.9 quads versus 3.7 quads) compared to the High Uneven Case. This loss of market in the High Uneven Case is a result of higher wholesale hydrogen prices as blue hydrogen is more expensive and the market must rely on higher cost green hydrogen. As discussed further below, compared to the High Uneven Case the Even Case also results in 5.5 billion more metric tons GHG emission reductions through 2050 (equivalent to 18.5 months of the average of all GHG emissions).[2] The High Even Case also has better economic efficiencies compared to the High Uneven Case when measured as incremental dollars per metric ton of CO2e reduced. There is a 12% difference in economic efficiency between the two cases averaged over the entire forecast period and a 17% difference in favor of the Even Case in the year 2050 alone.

[2] It is important to remember that these cases were constructed assuming there would be no overall CO2 cap limiting emissions. The incentives to reduce GHG emissions would come through internalizing an assumed willingness to pay for carbon mitigation. Therefore, the cases can result in different levels of carbon reductions.

Exhibit 6: Projected Hydrogen Consumption: High Uneven Case

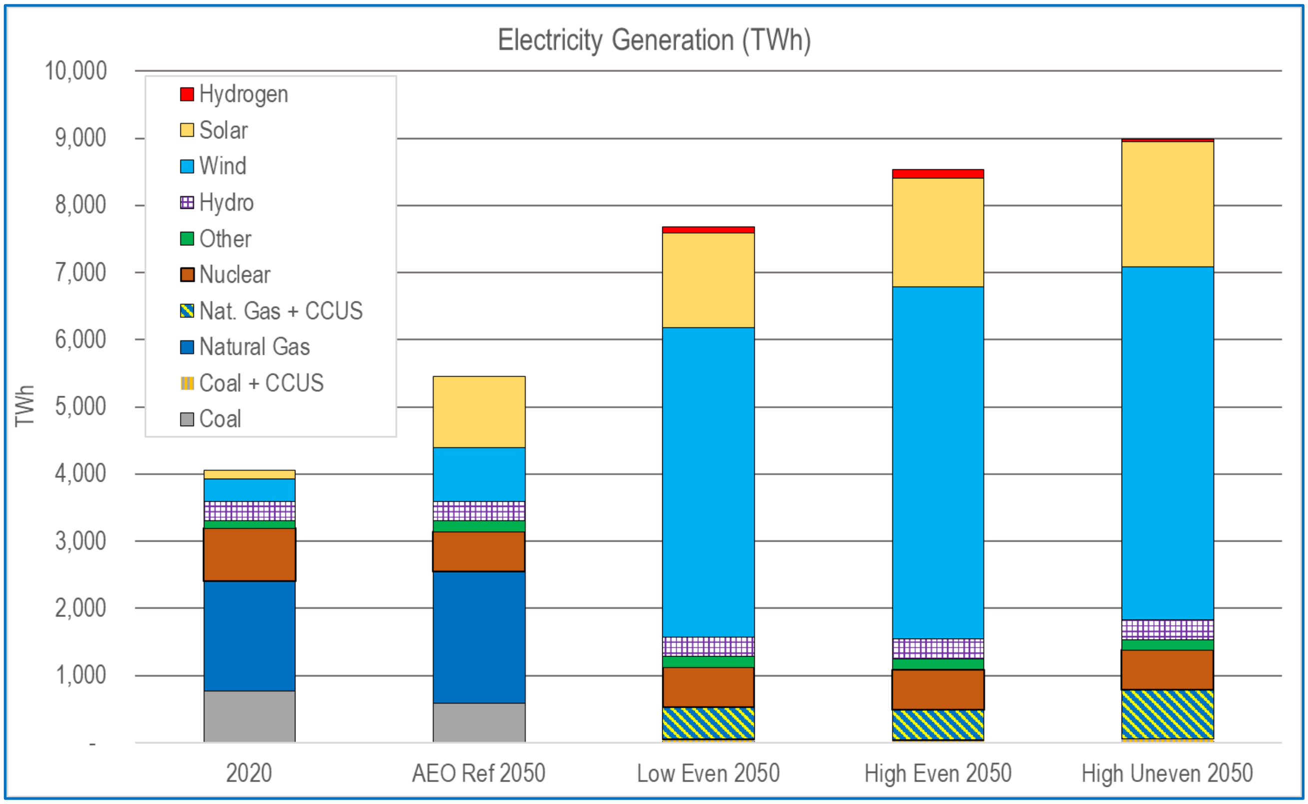


ES.5. Analytic Results: Power Sector

For the power sector, the differences between the AEO Reference Case and the Alternative Cases are significant. When an assumed willingness to pay for carbon mitigation is internalized into consumers decisions, electricity demand goes up substantially in the Alternative Cases due to shifts from fossil fuels to electricity in several end-use sectors (electrification). Electrification occurs because there are several relatively low-cost options to decarbonize electricity generation and so the price of electricity goes up less than the price of fossils fuels when a cost of carbon mitigation is introduced. This makes electric end-use technologies more competitive and increases electricity's market share in several submarkets. By 2050 the increase in demand for electricity is 1,970 terawatt hours (TWh) in the Low Even Case and 2,988 TWh in the High Even Case. These values are, respectively, 36% and 54% increases over the AEO Reference Case electricity demand for the year 2050. The High Uneven Case has even more electrification by 2050 (3,519 TWh or a 64% increase over the AEO) because consumers find hydrogen to be less economic and turn instead to electric options.

As shown in Exhibit 7, fossil fuel use for power generation is sharply reduced as fossil generation falls from 2,546 TWh in 2050 in the AEO Reference Case to 531 and 496 TWh in the Low Even and High Even Cases, respectively. The remaining use of fossil generators is shifted mostly to gas with carbon capture, use and storage (CCUS), hydrogen and to a small extent coal with CCUS. Hydrogen consumed as a fuel in power plants reaches as high as 886 TBtu and 1,423 TBtu in the Low Even and High Even respectively. Due to its higher cost under the High Uneven Case, hydrogen makes up only 210 TBtu of 2050 power plant fuel consumption in that case.

Exhibit 7: Electricity Generation by Fuel Type



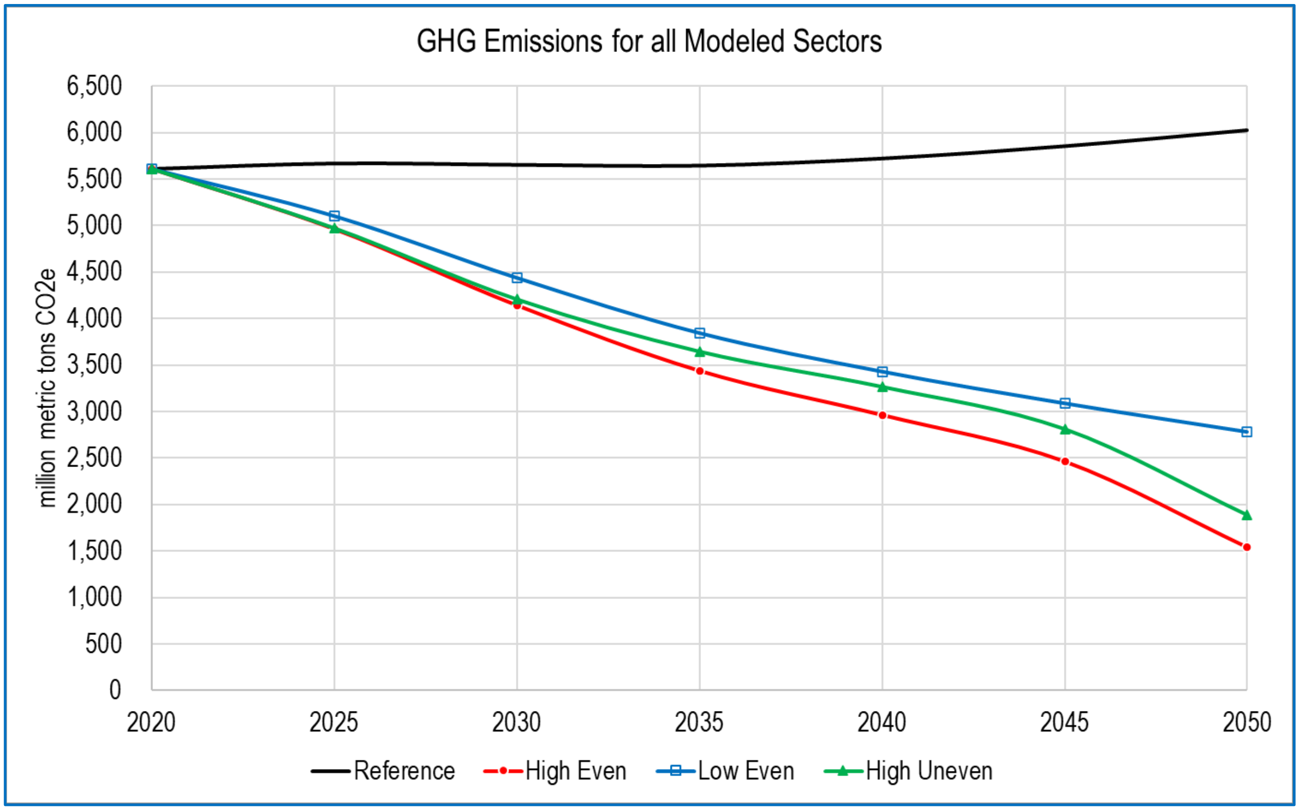
Generation from renewables (primarily wind) goes up sharply compared to the AEO, but substantial fossil capacity is preserved to maintain reserve margins. For this reason, capacity utilization of fossil plants falls below 15%. The intermittent renewable plants cannot follow load and so there is considerable "excess electricity" generation in hours when load is less than generation from non-dispatchable/inflexible generation. This excess generation occurs even after assuming a considerable portion of electric vehicle recharging (75% of light-duty and 50% of heavy-duty vehicles) can be shifted to hours when solar/wind generation is highest. It is generally not going to be economic to store this excess electricity for long periods. It would be cheaper to curtail it. This study assumes that this excess electricity is not curtailed but is mostly used to make hydrogen in electrolyzers. As shown earlier in Exhibit 3, this hydrogen made from excess electricity would total 546 to 1,181 TBtu or 7% to 18% of project hydrogen demand in the US through the year 2050.

The Alternative Cases result in generation from wind exceeding that from solar, which is a reversal of the relative market shares shown in the AEO Reference Case. This occurs because solar has a larger lifecycle GHG footprint compared to wind and so when a cost of carbon mitigations is added, wind becomes more economic relative to solar power.

ES.6. Analytic Results: GHG Emissions

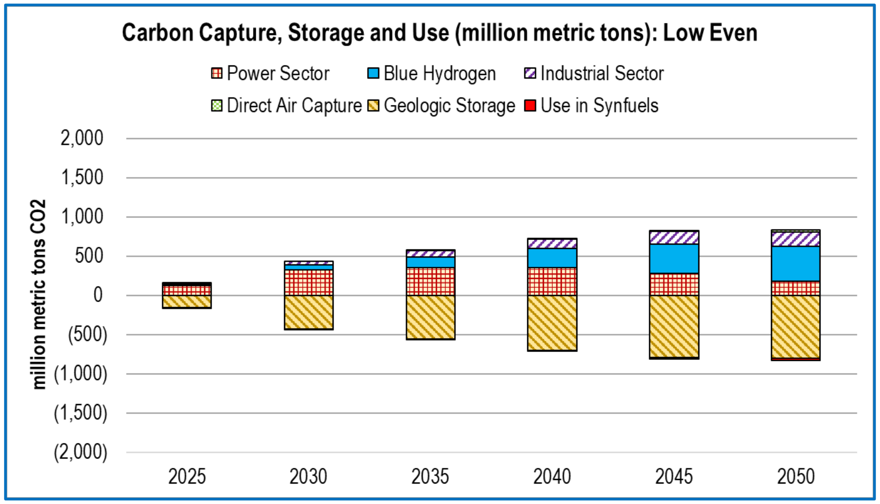
All three Alternative Cases achieve substantial reductions in GHGs relative to the AEO Reference Case by 2050. The cumulative reductions to GHG from 2020 to 2050 range from 37.3% for the High Even Case to 29.9% for the Low Even Case. The 2050 annual reductions are 53.8% for the Low Even Case and 74.4% for the High Even Case. For the High Uneven Case cumulative reductions are 34.1% and 2050 annual reductions are 68.6% versus the Reference Case. The High Even Case is more effective at reducing GHG emissions compared to High Uneven Case because hydrogen is available at lower cost when blue hydrogen does not face lower incentives. The availability of blue hydrogen at a low price creates a larger market for hydrogen and allows a greater degree of carbon mitigation to occur within the assumed willingness to pay $250/MT of CO2e by 2050.

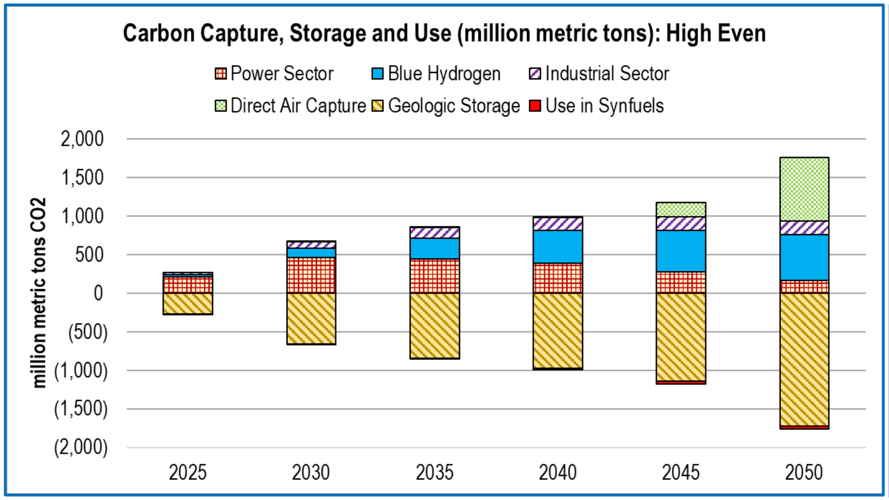
Exhibit 8: Projected GHG Emissions for AEO Reference and Alternative Cases

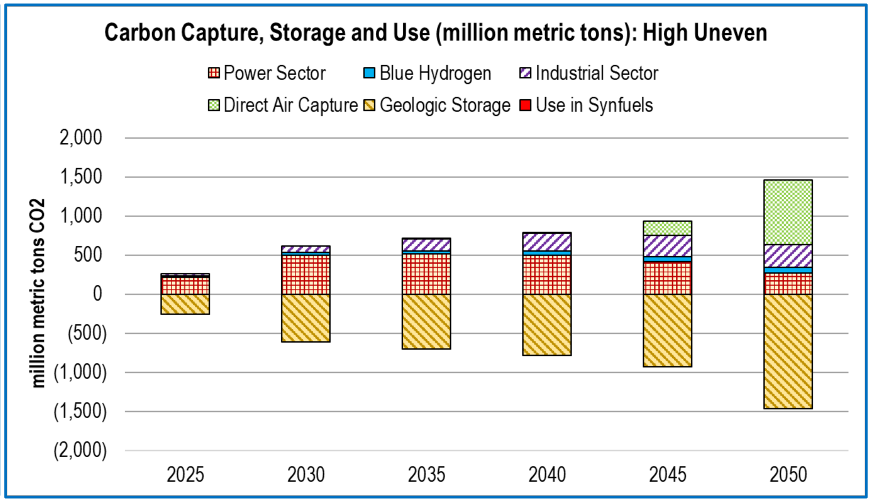


The reduction in GHG emissions results from electrification, switching to low carbon fuels such as hydrogen and the application of carbon capture, storage, and utilization. As shown in Exhibit 9, in the Low Even Case CCUS volumes are 801 million metric tons of CO2 per year by 2050. That volume increases to 1,724 million metric tons in the High Even Case. In the High Uneven Case, the use of CCUS goes up by over 60% in the industrial and power sectors due the fact that hydrogen becomes much less economic and CCUS becomes the best option. However, overall use of CCUS is only 1,464 million metric tons in 2050 because the CCUS associated with blue hydrogen declines substantially in the High Uneven Case.

Exhibit 9: CCUS Volumes in the Alternative Cases







Note: The volumes of carbon dioxide captured are shown by sector as bars above the x-axis. The disposal or use of the carbon dioxide is shown as bars below the x-axis. The total amount stored is equal to amounts disposed and used.

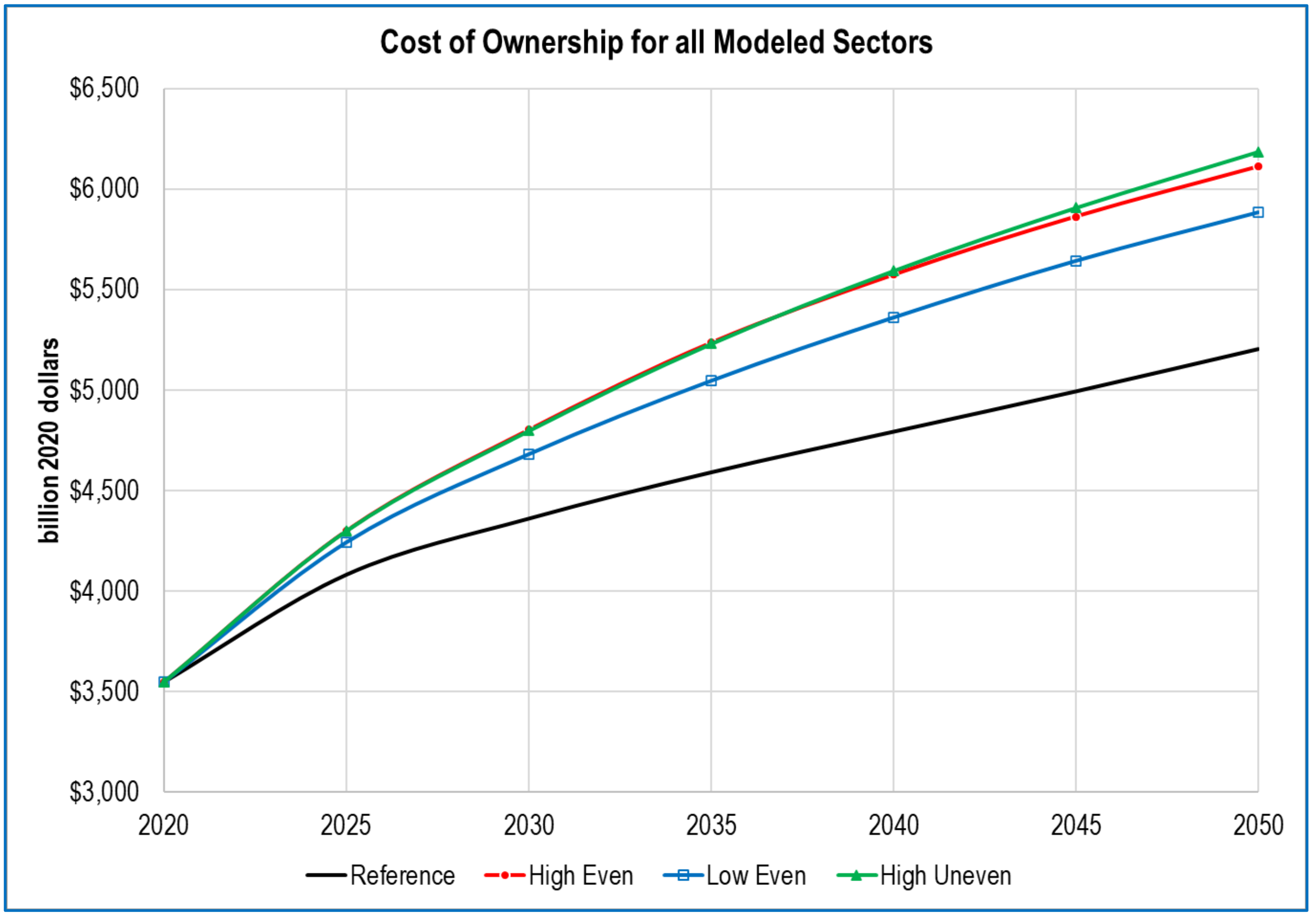
This underscores the fact that blue hydrogen provides an opportunity to decarbonize natural gas at large facilities that can take advantage of economies of scale and can benefit from being located near suitable geologic sequestration sites. When the option of low-cost blue hydrogen is removed due to policy choices, there are some additional power plants and industrial facilities that will adopt CCUS, but other facilities with poor economies of scale for CCUS, unfavorable geologic settings for underground CO2 storage, and onsite space constraints will have limited GHG mitigation options and overall US GHG emissions could be greater.

ES.7. Analytic Results: Costs

The competition models compute the cost of ownership of major technology/fuel alternatives for each kind of modeled vehicle, appliance or equipment including annualized capital costs, operating and maintenance costs, the cost of energy consumed, and the assumed internalized cost of carbon mitigation set by policy (that is, the willingness to pay for each metric ton of CO2e reduced). The pro forma comparisons of cost of ownership among technology/fuel alternatives are computed per-unit of energy services such as cents per passenger-mile traveled, cents per ton-mile transported, or MMBtu of process heat delivered. For all modeled sectors, this cost of ownership sums to $3.5 trillion dollars in 2020 and increases annually to $5.2 trillion in 2050 in the AEO Reference Case. There is no cost of carbon mitigation applied to the AEO Reference Case.

The Alternative Cases have costs of ownership that are cumulatively 9.2% to 12.9% higher through 2050. The High Even and High Uneven Cases have similar annual and cumulative cost of ownership but show an important difference when costs are measured in terms of incremental dollar spent versus metric tons of CO2e reduced. Because of the larger amount of CO2e reduced in the High Even Case, it is 12% more cost effective than the High Uneven Case over the whole forecast period and by the last year of 2050 is 17% more economically efficient.

Exhibit 10: Projected Energy Services Costs for AEO Reference and Alternative Cases



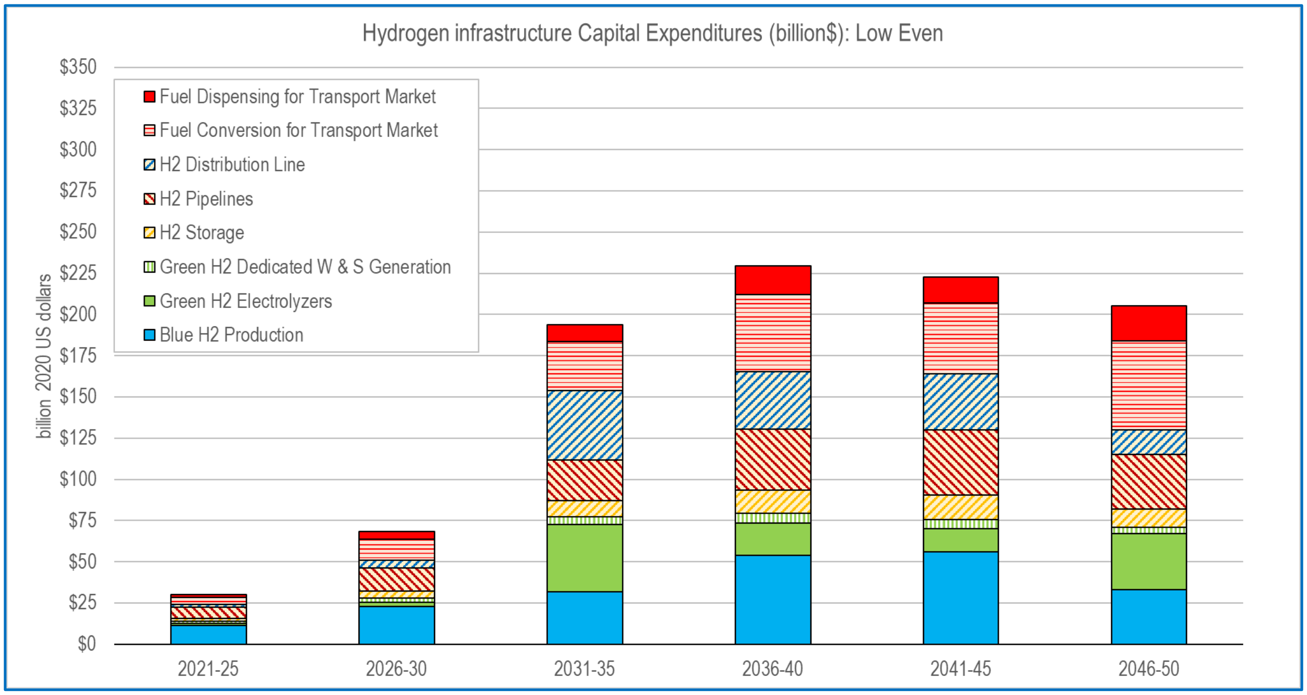
Note: Cost of ownership is the annual cost of energy-consuming vehicles, appliances, equipment, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

ES.8. Analytic Results: Capital Requirements

The realization of hydrogen's potential to contribute to GHG mitigation goals will require investments into several kinds of infrastructure including blue hydrogen manufacturing, electrolyzers to convert excess and dedicated solar and wind electricity; hydrogen pipelines; hydrogen storage; local hydrogen distribution systems; and hydrogen conversion, transport and dispensing for transportation market. The amounts, types and timing of these investments are shown for the three Alternative Cases in Exhibit 11, Exhibit 12, and Exhibit 13.

For the Low Even Case, investments in blue hydrogen manufacturing facilities constitute the largest category, coming to $209 billion or 22% of the $950 billion total requirement. The next largest components are conversion of hydrogen (that is, cryogenic liquefaction, compression to very high pressures, or conversion to derived fuels) for transportation markets, hydrogen pipelines, local hydrogen distribution systems, and electrolyzers. The physical amounts of infrastructure (both new and converted from natural gas or other service[3]) that could be needed by 2050 include 430 TBtu of hydrogen underground storage capacity; 50,500 miles of hydrogen transmission pipeline; 380,000 miles of customer laterals and LDC pipeline/service lines; and 18,300 hydrogen fuel dispensing stations/facilities for the transportation sector.

Exhibit 11: Projected Capital Expenditures of Hydrogen Infrastructure: Low Even Case



The High Even Case has greater demand for hydrogen compared to the Low Even Case (12.9 quads versus 9.9 quads in 2050) and also has a higher requirement for capital expenditures ($1.27 trillion versus $0.95 trillion). The percent allocation of expenditures among categories is similar with blue hydrogen manufacturing again being the largest category with about 22% of the total. The physical infrastructure to be needed by 2050 for the High Even Case is 560 TBtu of hydrogen underground storage capacity, 67,000 miles of hydrogen transmission pipeline, 500,000 miles of customer laterals and LDC pipeline/service lines, and 22,900 hydrogen fuel dispensing stations/facilities.

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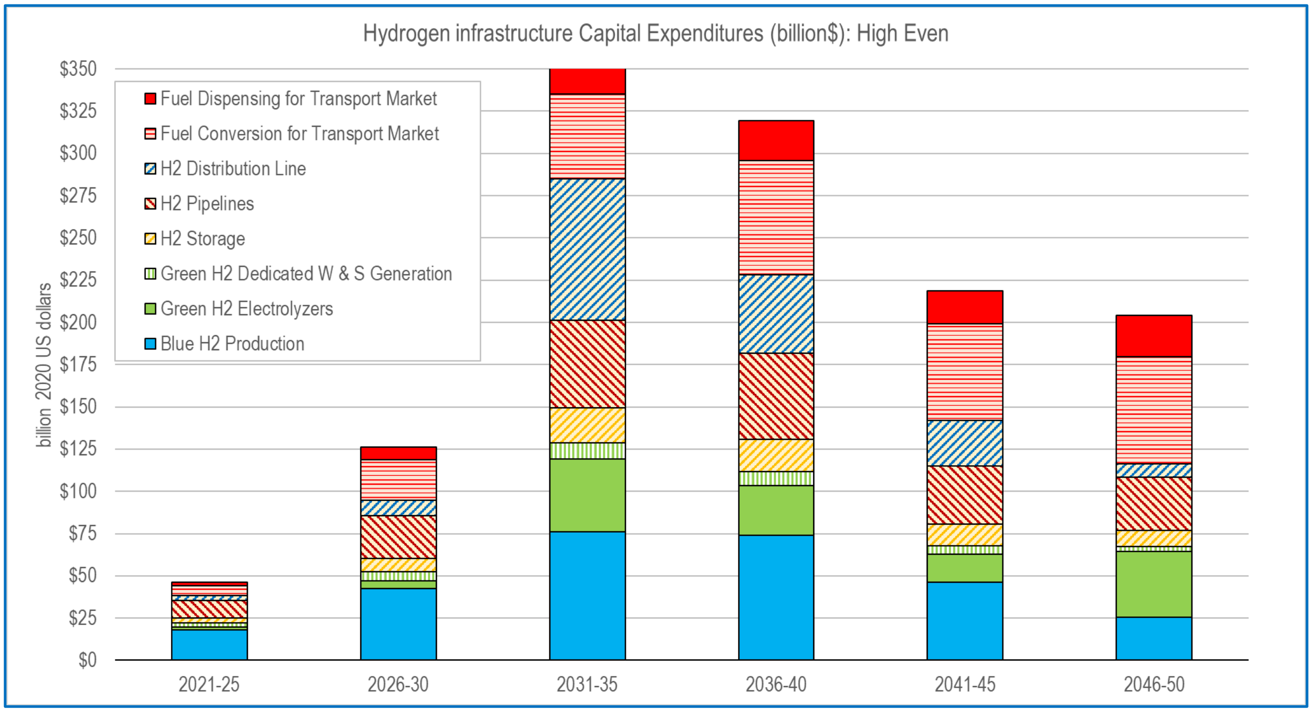
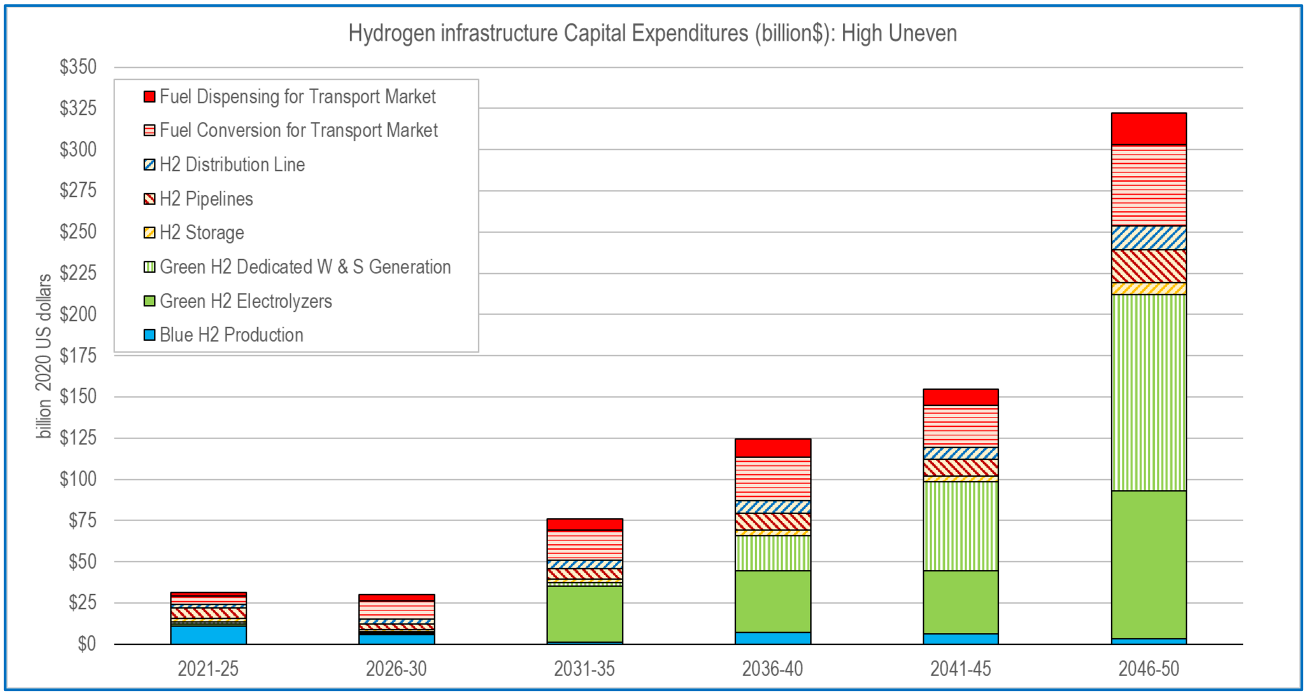
[3] For purposes of estimating costs, it was assumed that one-half of the infrastructure for underground storage, transmission pipeline, and lateral/distribution line would be natural gas systems converted to 100% hydrogen service. Cost of conversion is assumed to be one-fourth of the cost for new builds. All infrastructure for liquefying/pressurizing and dispensing hydrogen for the transportation sector uses was assumed to be newly built.

Exhibit 12: Projected Capital Expenditures of Hydrogen Infrastructure: High Even Case



The pattern of investment for the High Uneven Case is different from the other two cases in that electrolyzers are the largest category of investment, and the expenditure pattern is backloaded rather than peaking in the 2030's. Also, the overall level of investment is the lowest among the three Alternative Cases because the volume of hydrogen fuel use is much lower. Another point of note is that the high hydrogen prices associated with the High Uneven Case leads to the virtual elimination of hydrogen demand in the residential and commercial sectors. That consumption would have been served through local hydrogen distribution systems. The near elimination of residential/commercial demand in the High Uneven Case is why investment in local hydrogen distribution system is so low in that case relative to the other cases. For the High Uneven Case, the physical infrastructure estimated to be needed by 2050 is 150 TBtu of hydrogen underground storage capacity, 18,500 miles of hydrogen transmission pipeline, 35,000 miles of customer lateral and LDC pipeline/service lines, and 14,200 hydrogen fuel dispensing stations/facilities.

Exhibit 13: Projected Capital Expenditures of Hydrogen Infrastructure: High Uneven Case



ES.9. Conclusions

Hydrogen is not an energy source, but an energy “carrier” analogous to electricity. Hydrogen can be produced from many energy sources/carriers including fossil fuels, biomass, and electricity and through electro-chemical processes. When policies treat all sources equally in terms of incentives and disincentives to encourage reductions in GHG emissions, hydrogen can be a wide-spread and cost-effective resource for mitigating carbon emission in the US.

The main advantages of converting fossil fuels to hydrogen is that the fuels are decarbonized at a central location that can take advantage of economies of scale for carbon capture and transport and proximity to geologic storage and do not produce CO2 when consumed. The main advantages of converting renewable electricity (or any type of electricity) to hydrogen is that hydrogen can be applied more effectively than electricity in certain end-uses (e.g., high temperature industrial process heating, long-haul trucking, large airplanes, etc.); can be combined with captured carbon dioxide to synthesize ammonia, methane, liquid fuels, and non-fuel chemicals; and can be stored for extended periods in the form of hydrogen or one of its derived fuels.

The main disadvantages of hydrogen are that the infrastructure needed for its large-scale production and distribution do not exist and the vehicles and equipment needed for its use are not widely available. Moreover, distribution to mobile customers (automobiles, trucks, trains, ships, airplanes) and stationary consumers without access to hydrogen pipelines will require that the hydrogen be compressed to a high pressure; be liquefied; or converted to another form such as ammonia, synthetic fuel, or metal hydride. These conversion processes add to costs and consume energy. Another important consideration is that while a consumer’s use of hydrogen (by combusting it or running through fuel cells to produce electricity) does not generate GHGs, the production, transmission, conversion, and distribution of hydrogen does produce GHG's. Those lifecycle emissions are important considerations in determining the best uses of hydrogen for carbon mitigation.

Factoring in these considerations, this study concludes that hydrogen can be used economically to supply 9.9 to 12.9 quadrillion Btu of energy by 2050. This hydrogen would make up 12% to 15% of end-use consumption and would be used in all end-use sectors and to produce electricity. If all energy sources to produce hydrogen can receive incentives (or pay disincentives) commensurate with their carbon mitigation characteristics, hydrogen made from natural gas with CCUS could make up about 90% of supplies even after taking into account production from electrolyzers that would use "excess electricity" that is expected to become increasingly available as capacity and generation of intermittent renewable energy ramp up to meet climate goals. However, if blue hydrogen were to face lower incentives through policy decisions, the expected outcome likely would be higher hydrogen prices, smaller hydrogen markets, higher mitigation costs and greater overall GHG emissions. Based on the hypothetical scenarios presented in this report, the inclusion of hydrogen produced with natural gas utilizing CCUS in the clean energy transition on an equal footing with green hydrogen is expected reduce mitigation costs by 12% on a dollar-per-ton reduced basis and result in 5.5 billion metric tons fewer GHG emissions through 2050.

ES.10. Caveats

Many important factors that will determine how hydrogen will compete in multifaceted and interelated US energy markets over the next 28 years must be analyzed in simplifed manner to be tractable and, in some cases, cannot be known with any certainty. This particularly true for projections of the potential roles of hydrogen in US energy sector given that:

- Many of the modeled technologies that use or compete with hydrogen in end-use markets are nascent with uncertain cost and performance characteristics.
- The pace of future technology advances which are expected to reduce cost are not known with any certainty. The pace of technological advances will help determine the cost of the low-carbon transitioning and the mix of technologies and fuels that will be employed. For example, advances in battery and electric motor technologies and new design for high-temperature industrial processes may erode hydrogen's advantages in the "niche" markets where hydrogen is now expected to fare well.
- The future energy market environment and energy prices could be much different than envisaged in the 2021 AEO. Furthermore, the climate policies themselves might change the amounts of each primary energy source consumed, likely causing the prices received by energy producers (before the application of the cost of mitigation) to drop. In particular, the prices received by producers of coal, petroleum products and natural gas could be lower due to falling consumption levels, making the prices to consumer somewhat lower than assumed in this study.
- Although end-use markets have been modeled here in considerable detail, regional variations and differences among different classes of consumers within a sector have not been accounted for explicitly.

- Consumer behavior in terms of which technologies/fuels are purchased and how they are used may deviate from the simple cost-minimization model employed in this report.
- There also uncertainties related to the investment behavior of energy producers and suppliers of energy-consuming appliances, vehicles, and equipment. They may or may not see the GHG mitigation policies as being permanent and make the needed investments in R&D and product commercialization in a timely manner.
- The large-scale adoption of geologic storage forecasted here for the power, industrial, direct air capture, and blue hydrogen sectors here may be difficult to achieve in certain areas due to popular opposition, regulatory delays, and other factors. This may also be true of solar, wind and other technologies that sometimes engender land-use, environmental impact, public nuisance, and other conflicts.
- The form of market interventions that may be adopted to achieve carbon mitigation goals might well deviate from the "economic competition" model assumed here and might differ among states and regions.
- This study preserved the AEO's level of demand for "energy-related services" (e.g., vehicle miles traveled, airline passenger miles, gallons of domestic hot water consumed per household) and did not consider conservation beyond that already in the AEO Reference Case. Energy conservation might exceed levels expected in the AEO due to specific policy measures that could be adopted as part of climate policies or (depending on how incentives versus disincentives are applied) could be induced by changes in the cost of ownership of energy-using appliances, equipment, vehicles, etc.
- This study was focused on the US and did not incorporate international considerations such as the potential market for export of US hydrogen, trade issues (e.g., application of compensating tariffs on high-carbon-content imports to prevent their import from countries with weak climate policies) or negotiated climate obligations.

1. Background

This study was conducted to better understand how hydrogen might fit into a low-carbon/net-zero[4] future and what productive role could be played by hydrogen made from natural gas with carbon capture and geologic storage ("blue hydrogen"). Specifically, the study seeks to determine what market penetration hydrogen could achieve and what reductions in GHG emission could be realized by policies that incentivize all forms of hydrogen equally based on their carbon mitigation characteristics versus policies that support some forms more than others. For example, some of the policies being discussed now provide subsidies for hydrogen production but only for processes that are below a threshold CO2ekg/MMBtu that only some hydrogen production methods can meet. An alternative policy would be to have all processes be eligible for a subsidy that would be proportionate to the GHG reductions each can offer. In other words, all hydrogen production processes would receive the same $/ton CO2e benefit for reducing GHGs.

The study addresses the following questions:

- How might hydrogen fit into a low-carbon future?
- What productive role could be played by hydrogen made from natural gas with carbon capture and geologic storage ("blue hydrogen")?
- What benefits can be realized by policies that equally incentivize all supply options for hydrogen versus policies that provide greater support (on a basis of $/metric ton of CO2e avoided) for selected forms of hydrogen?
- What level of investment in hydrogen infrastructure will be needed for these anticipated contributions to be realized?

The study estimates what market penetration hydrogen could achieve and what reductions in greenhouse gas (GHG) emissions could be realized by policies that incentivize both blue and green hydrogen versus policies that support only green hydrogen. The analysis was conducted at a national level and covers the US energy markets through the year 2050 and includes all large residential, commercial, industrial, power, and transportation markets in which hydrogen is expected to compete well.

1.1 Scope

This study addresses the following issues in a logical and analytic manner. The analysis focuses on characterizing the competition in four market areas, the first of which is supply-related and the last three are demand-related:

- **Markets for Hydrogen Supply**: Competition for supplying hydrogen will exist among multiple options using various technologies and primary energy sources. Blue hydrogen

[4] 'Net zero' refers to achieving an overall balance between GHG emissions produced and emissions taken out of the atmosphere. Some amount of GHG from hard-to-decarbonize sectors (e.g., agriculture, aviation, shipping, certain industrial processes) would still occur, but would be offset through negative emission measures such direct air capture (DAC) or reforestation.

made from natural gas with carbon capture and storage would be one of the options for making hydrogen. One of its primary competitors will be electrolyzers supplied by solar, wind, nuclear and other types of low-carbon power plants. The competition to supply hydrogen is based on economics, environmental impacts, reliability, scalability, geographic availability, ability to use existing infrastructure, etc.

- **Markets for Electricity Generation & Storage Applications**: Hydrogen can play a role in the competition among technologies and fuels for power generation and electricity storage. Making hydrogen from fossil fuels or biomass with carbon capture, use, and storage (CCUS) is a form of pre-combustion carbon capture that will compete with post-combustion capture at power plants and other ways of making low-carbon or negative-carbon electricity. Hydrogen or fuels derived from hydrogen also could be used as a long-term storage medium for renewable electricity that might be carried over from months in which it can be produced most plentifully to months when electricity demand is high. Hydrogen infrastructure built for seasonal storage would also be available to provide short-term electricity storage (shifting supplies among hours within a day or among days within a week) and ancillary services (e.g., operating and spinning reserves, load following, voltage regulation, black start, etc.).
- **Markets for Feedstock & Synfuel Applications**: Hydrogen is currently used as a process feedstock in refineries, to make basic chemicals (primarily ammonia and methanol), and in the steel industry. Hydrogen for such industrial applications is now made primarily from natural gas using steam methane reforming without carbon capture (so called “grey hydrogen”). The transition toward a net-zero economy would likely include converting these applications to use blue and green hydrogen. A net-zero economy might also see wider application of hydrogen to synthesize materials, chemicals (ammonia), and fuels (methane, methanol, diesel fuel) driven by desire to utilized captured carbon or to obtain a more transportable, storable, and useable fuel form.
- **Markets for End-use Applications**: Hydrogen would compete in end-use markets against traditional fuels and end-use technologies (natural gas, petroleum products, and electricity used in appliances, equipment, vehicles, etc.), low-carbon fuels and emerging electric technologies. Hydrogen would most likely be used to substitute a low-carbon fuel in place of fuels currently in use in markets where the use of non-hydrogen fuels (such as low-carbon electricity) is impractical or uneconomic and the application of onsite carbon capture is impractical or too costly.

2. Methodology and Scenario Modeling

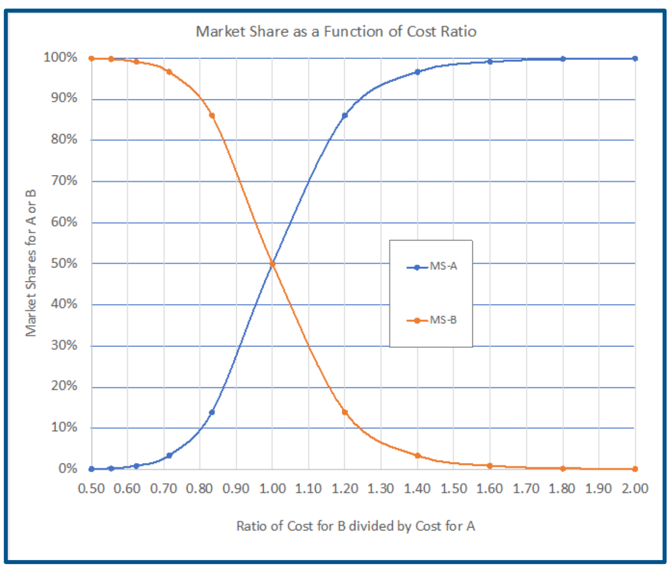
This section includes a general description of the methodology used to determine the future market potential for hydrogen and a description of each scenario considered in this study. More details on individual supply and end-use applications are included in Chapters 3 and 4.

2.1 Market Share Penetration Modeling

ICF created alternatives to EIA AEO Reference Case by creating pro forma economic competitions to characterize the markets and submarkets for various technologies/fuels. ICF first computed ownership costs for relevant alternative technologies/fuels in each submarket under AEO assumptions. Then to create the Alternative Cases, ICF incorporated a hypothesized willingness to pay for carbon mitigation into the competition (the $/metric ton of CO_2e cost which is assumed to be internalized to the consumer) and recomputed the market shares among technologies/fuels.

The calculated ownership cost for each relevant technology/fuel was computed on a basis of dollars per unit of energy services (e.g., dollar per ton-mile of freight transported by truck) and all options in a submarket were compared to each other in a “technology market penetration” model to estimate future market shares among the competing technologies/fuels for each five-year model period. Such market penetration models represent statistical distributions among consumers each of which may face different costs and each of which may have somewhat different preferences. As illustrated in Exhibit 14, technologies/fuels that are close in costs will share the market nearly equally. As one technology/fuel improves its cost relative to a competitor, it will smoothly increase its relative market share.

Exhibit 14: Market Share as a Function of Cost Ratio



Using these technology penetration algorithms, ICF computed how much of the market would shift based on the relative cost competitiveness. Results quantified the amount of fuel consumption expected across all applications and all markets/submarkets. The results were also aggregated to compare total costs and greenhouse gases (GHGs). For GHG impacts, ICF quantified the full lifecycle assessment (LCA) impact of the transportation and use of each fuel in each market. Fuels emit different levels of GHGs per MMBTU, so the implied mix determined by shifts in market share can significantly impact emission levels. For instance, in scenarios where a high willingness to pay for carbon mitigation (also referred to in the report as a high cost of carbon mitigation) is incorporated, the market is incentivized to adopt lower-carbon fuels and therefore a larger reduction in GHGs is expected over time.

ICF modeled results for every five years from 2025 through 2050. Projections in expected fuel consumption, energy prices, and improvements in technology costs and efficiencies were incorporated specifically for each end-use. ICF also generated all results across four scenarios including the Reference Case utilizing AEO assumptions which has a zero cost of carbon mitigation, two cases incorporating a cost of carbon mitigation (high and low) in a "uniform incentives" competition, and one case which disincentives blue hydrogen relative to green hydrogen (i.e., "uneven" playing field). Each scenario is discussed in more detail below.

2.2 Scenarios

The starting point for the study is EIA's 2021 AEO Reference Case, which describes total energy use by technology/fuels through 2050 based on current laws and regulations. ICF recreated the AEO Reference Case within its modelling system and also created three Alternative Cases that assume US policies will be altered to reduce GHG emissions:

- Low Cost of Carbon Mitigation Applied Evenly (Low Even Case) and reaches $150 per metric ton of CO2e by 2050. All forms of hydrogen receive the same $/metric ton of CO2e incentive or pay the same disincentive based on their lifecycle GHG emissions.
- High Cost of Carbon Mitigation Applied Evenly (High Even Case) and reaches $250 per metric ton of CO2e by 2050. Again, all forms of hydrogen are eligible for the same incentive/disincentives.
- The High Uneven Case is an alternative case similar to High Even, but in which blue hydrogen does not receive incentives (or pay fees) equal to its GHG characteristics. This is based on the November House Build Back Better (BBB) bill and creates a $12/MMBtu differential for blue hydrogen relative to the treatment of the lowest emitting hydrogen sources.

Although represented in the modelling as a tax or fee based on each fuel's lifecycle emissions, the study does not investigate or recommend specific policy options to create incentives/ disincentives to promote low-carbon energy technologies/fuels.

2.2.1 Derivation of Blue Hydrogen Differential in Incentives

The Build Back Better (BBB) bill passed in the House in November 2021 calls for a $3/kg ($22.26/MMBtu) subsidy for very-low GHG methods of making hydrogen. Methods with higher GHG emission per kilogram also get some subsidy, but it declines disproportionately to the increase in GHGs. In other words, the subsidies are designed to pay out much more per metric ton of CO_2e reductions for some sources of hydrogen versus others. Compared to a hypothetical alternative wherein everyone gets the same $/MT of reduction (based on the proposed $3/kg for the lowest emitter) then blue hydrogen made with the autothermal reforming (ATR) process would get about $12/MMBtu more than proposed in the House BBB. (See Exhibit 15.)

ICF's High Uneven Case assumes blue hydrogen bears a $12/MMBtu differential in incentives relative to methods of making hydrogen from solar and wind power. The study assumes that this differential will remain for the whole study period to 2050. The effects of this difference in incentives would be to:

- Increase the cost of making blue hydrogen
- Reduce the market share of blue hydrogen in the market and increase the "composite price" for wholesale hydrogen
- Reduce the use of hydrogen in end-use applications.

Exhibit 15: Supply Option Emission and Cost Comparison

	SMR	SMR + CCS	ATR + CCS
Total GHG in kg CO2e/kg of hydrogen	10.62	2.86	2.11
Credit in $/MMBtu per House BBB	$0.00	$4.45	$5.57
Credit in $/MMBtu per Alternative	$0.00	$14.49	$17.77
Difference	*$0.00*	*$10.04*	*$12.21*

Note: "SMR" refers to Steam Methane Reforming, a process of converting natural gas and water into hydrogen. "SMR+CCS" refers to steam methane reforming with the addition of carbon capture and storage (CCS) of approximately 90% of the carbon dioxide generated by the SMR process. "ATR+CCS" refers to autothermal reforming with carbon capture and storage. Like SMR, the ATR process converts natural gas and water into hydrogen but does so in a manner that make carbon capture more effective and less expensive.

3. Markets for Hydrogen Supply

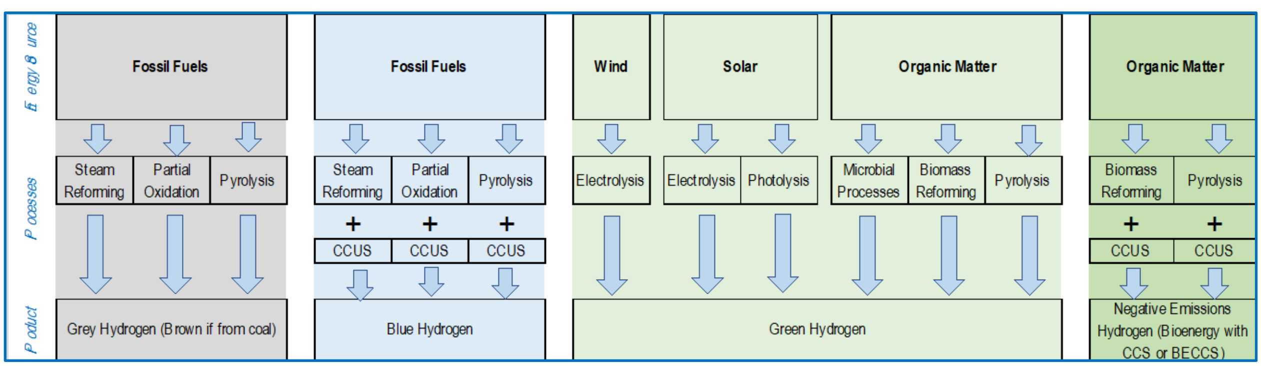
This section describes the technologies and costs associated with hydrogen supply.

3.1 Hydrogen Characteristics and Sources

Elemental hydrogen does not exist on earth in economically recoverable quantities. It must be produced using an energy source (e.g., fossil fuels, electricity, organic matter). As shown in Exhibit 16, steam methane reforming, pyrolysis and other methods can be used to produce hydrogen from hydrocarbons, organic matter, and water. Hydrogen can be produced from water alone by electrolysis using electricity from multiple sources including wind, solar and nuclear power. Biomass can be used to make green hydrogen and, when CCUS is included in the process, biomass can make negative emissions hydrogen.

The main advantages of converting fossil fuels to hydrogen is that the fuels are decarbonized at a central location that can take advantage of economies of scale in carbon capture and transmission and proximity to geologic storage. The main advantages of converting renewable electricity (or any type of electricity) to hydrogen is that hydrogen can be applied more effectively than electricity in certain end-uses (e.g., high temperature industrial process heating, long-haul trucking, large airplanes, etc.); can be combined with captured carbon dioxide to make ammonia, synthetic methane, liquid fuels, and non-fuel chemicals; and can be stored for an extended period in the form of hydrogen or a derived fuels.

Exhibit 16: Alternatives for Producing Hydrogen



The main disadvantages of hydrogen are that the infrastructure needed for its large-scale production and distribution do not exist and the vehicles and equipment needed for it use are not widely available. Moreover, distribution to mobile customers (automobiles, trucks, trains, ships, airplanes) and stationary consumers without access to H_2 pipelines will require that the H_2 be compressed to a high pressure; be liquefied; or converted to another form such as ammonia, synthetic fuels, or metal hydrides. These conversion processes add to costs and consume energy.

Another important consideration is that while a consumer's use of hydrogen (by combusting it or running through a fuel cell to produce electricity) does not generate GHGs, the production and distribution of hydrogen does produce GHG's. Those lifecycle emissions are important considerations in determining the best uses of hydrogen for carbon mitigation.

Exhibit 17: Physical Properties of Hydrogen

Property	Hydrogen Value	Unit	Condition	Comparison Notes
Density (gaseous)	0.089	kg/m3	0°C, 1 bar	1/10 of natural gas
Density (liquid)	70.79	kg/m3	-253°C, 1 bar	1/6 of natural gas
Boiling Point	-252.76	°C	1 bar	90°C below LNG
Energy per unit of mass (LHV)	120.1	MJ/kg	-	3x that of gasoline
Energy Density (ambient cond., LHV)	0.01	MJ/L	-	1/3 of natural gas
Specific Energy (liquefied, LHV)	8.5	MJ/L	-	1/3 of LNG
Flame Velocity	346	cm/s	-	8x methane
Ignition Range	4-77	%	in air by volume	6x wider than methane
Autoignition Temperature	585	°C	-	220°C for gasoline
Ignition Energy	0.02	MJ	-	1/10 of methane

Source: International Energy Administration (IEA)

An estimate of hydrogen uses and sources in the US are shown in Exhibit 18. The volumes are categorized as "captive" when the hydrogen is produced on purpose at the consuming industrial facility, typically using steam methane reforming. The largest captive producers are ammonia and methanol plants[5] and petroleum refiners. The category "byproduct" indicates that hydrogen is produced during an industrial process for which hydrogen is not the main product. For example, chlor-alkali plants in the chemical industry produce hydrogen as a by-product of the electro-chemical chlorine production process. Likewise, crackers in petrochemical plants release hydrogen as a by-product of their production of ethylene, propylene, and other olefins.

Hydrogen also is produced at petroleum refineries during the catalytic reforming of naphtha into higher value high-octane products. Refineries use hydrogen to lower the sulfur content of diesel fuel and other petroleum products and as a feedstock into hydrocrackers (to break large hydrocarbon molecules into smaller ones). The use of hydrogen at refineries is substantial and only about one-half of that need can be met by byproduct hydrogen production alone. Refinery demand for hydrogen has increased over the last several years as sulfur-content regulations have become more stringent, a larger proportion of heavier crudes have been refined and total refinery throughput has risen. The growth in hydrogen use at refineries has been met through hydrogen purchased from merchant suppliers, who manufacture the hydrogen in nearby SMR or petrochemical facilities and deliver an average of about 29% of refinery hydrogen needs "over the fence" through pipelines to the refineries.

[5] The hydrogen produced to make methanol is in a syngas mixture (mostly H2 and CO) that is not put through a water-gas shift step and purified. The same is true for the syngas used for direct reduction iron (DRI) production.

Exhibit 18: Hydrogen Use in US by Industry and Source

Use of Hydrogen by Industry and Source Category								Natural gas used for NG-sourced volumes (bcf/year)
Category	Use	Hydrogen Use in Million Metric Tons per Year	Hydrogen Use in Trillion Btu per Year	Sourced from Natural Gas (10^6 MT/Y)	Sourced from Oil/NGLs (10^6 MT/Y)	Electro-chemical Sourced (10^6 MT/Y)	Sourced from Coal/Coke (10^6 MT/Y)	
Captive	Ammonia	2.03	274	2.03	-	-	-	338
Captive	Refining	1.03	139	1.03	-	-	-	172
Captive	Methanol	0.43	58	0.43	-	-	-	72
Captive	Iron	0.25	33	0.25	-	-	-	41
Byproduct	Coke/Iron	0.38	51	-	-	-	0.38	-
Byproduct	Refining	3.52	474	-	3.52	-	-	-
Byproduct	Ethylene	1.47	198	-	1.47	-	-	-
Byproduct	Chloro-Alkali	0.30	40	-	-	0.30	-	-
Merchant	Refining	1.84	248	0.99	0.85	-	-	166
Merchant	Other	0.64	86	0.64	-	-	-	107
Total	**All**	**11.89**	**1,602**	**5.37**	**5.84**	**0.30**	**0.38**	**894**
Subtotal	Captive	3.74	503	3.74	-	-	-	622
Subtotal	Byproduct	5.67	764	-	4.99	0.30	0.38	-
Subtotal	Merchant	2.48	334	1.63	0.85	-	-	272
Total	**All**	**11.89**	**1,602**	**5.37**	**5.84**	**0.30**	**0.38**	**894**
Subtotal	Ammonia	2.03	274	2.03	-	-	-	338
Subtotal	Refining	6.39	861	2.02	4.37	-	-	337
Subtotal	Methanol	0.43	58	0.43	-	-	-	72
Subtotal	Iron	0.25	33	0.25	-	-	-	41
Subtotal	Coke/Iron	0.38	51	-	-	-	0.38	-
Subtotal	Ethylene	1.47	198	-	1.47	-	-	-
Subtotal	Chloro-Alkali	0.30	40	-	-	0.30	-	-
Subtotal	Other	0.64	86	0.64	-	-	-	107
Total	**All**	**11.89**	**1,602**	**5.37**	**5.84**	**0.30**	**0.38**	**894**

Source: ICF approximations derived from multiple sources including DOE/EIA MECS 2018, DOE/EIA Petroleum Supply Annual 2020, and Pacific Northwest National Laboratory 2015. Values are representative of the 2015-18 period and should be considered to be approximate.

Across all industries and sources, natural gas makes up 45% of the fuel sources that are converted to hydrogen while oil and NGLs add up to 49%. Coal and electro-chemical processes make up 3% each. The production of hydrogen (including hydrogen-rich syngases that are not purified) consumes roughly 894 Bcf of natural gas each year. (See last column in Exhibit 18.)

It would be feasible to use blue or green hydrogen to substitute for all hydrogen now made from natural gas and coal.[6] That adds up to 5.75 million tons (775 TBtu) of hydrogen per year. Hydrogen volumes derived from oil/NGLs and from electro-chemical processes (making up 6.14 million metric tons or 827 TBtu of hydrogen) are byproducts and, therefore, should not be considered as a target market for blue and green hydrogen.

3.2 Supply Technology Characteristics

Hydrogen production methods can vary significantly in terms of energy requirements and related GHG emissions generated. To delineate distinct types of hydrogen supply, volumes are referred to by different colors which refer to the specific production configuration. Hydrogen is

[6] The CO in the syngas used to make methanol can be replaced by captured carbon dioxide. The CO in the syngas used for direct reduction of iron is not needed since hydrogen on its own can be used as reducing agent.

currently produced mostly through steam methane reforming (SMR). This process introduces a hydrocarbon feedstock such as natural gas and steam into high temperatures furnace where an endothermic reaction in the presence of a solid catalyst forms a synthesis gas containing carbon monoxide and hydrogen. Then an exothermic water-gas shift reaction assisted by a catalyst is used to convert the carbon monoxide to free H_2 and CO_2. (See Exhibit 19 which shows that under ideal reactions 50% of the hydrogen coming out of the SMR process is derived from water molecules and 50% from natural gas.) In a final step, a pressure swing adsorption process is used to produce a pure H_2. Thermal energy for the SMR process usually comes from burning natural gas and "tail gas" containing unreacted methane and carbon monoxide. Traditional SMR hydrogen where the byproduct CO_2 is mostly emitted to atmosphere is referred to as "grey" hydrogen.

Exhibit 19: Steam Methane Reforming Reactions

Process	Reaction Equation
Steam reforming (SR)	(1) $CH_4+H_2O \rightarrow CO+3H_2$ (2) $CO+H_2O \rightarrow CO_2+H_2$

"Blue hydrogen" can utilize the same SMR process, but rather than releasing the produced CO_2, the volumes are captured from one or more process streams and the flue gas steam from the generator (boiler or combined cycled cogeneration). There are two refinery SMR plants that were retrofitted for carbon capture: the Shell Canada "Quest" project and the Air Products SMR Retrofit project at Port Arthur, TX. Blue hydrogen can also be produced through autothermal reforming (ATR), which produces the same hydrogen and carbon monoxide syngas by partially oxidizing a hydrocarbon feed with oxygen and steam and subsequent catalytic reforming. ATR requires an air separation unit (ASU) to produce oxygen, but carbon dioxide can be more easily and cost-effectively captured from the ATR process because the CO2 is contained in a single, more concentrated, and higher-pressure stream.

The CO2 captured from an SMR or ATR process can be sent by pipeline to an oil field for use in enhanced oil recovery, to a geological storage location where it can be permanently sequestered or to a location that can utilize the carbon dioxide to produce a new product such as cement or a synthetic fuel. Because the CO_2 is captured, blue hydrogen has significantly less associated released GHGs per kg of H_2 produced compared to grey hydrogen. Emissions can vary pending on the process used, the size of the production facility and the source of electricity utilized in the process. Additionally, both blue and grey hydrogen have associated lifecycle emissions from the wellhead production and transportation of the feedstock natural gas.

3.2.1 Blue Hydrogen Costs

ICF evaluated the economics and GHG footprints of hydrogen production from natural gas based on three process configurations: SMR, SMR+CCS and ATR+CCS. The ATR+CCS configuration is shown first for a plant size of 100,000 cubic meters per hour of hydrogen output (the same size as the two SMR examples) and then for a 500,000 cubic meter per hour facility. The key input assumptions and results of these analyses are shown in Exhibit 20 for the year 2030. ICF developed the underlying capital costs, operating and maintenance cost, and performance characteristics based on review of several recent reports.[7] However, ICF adjusted facility sizes and financial parameters to maintain internal consistency among competing technologies, to utilize the AEO energy prices, and to apply the relevant case assumptions for the cost of carbon mitigation.

In the ICF analysis, the economics of hydrogen production change from year to year to reflect:

- Each model year's energy costs from the AEO Reference Case.
- The technology improvements that can reduce costs and improve efficiencies over time
- The GHG emission factors for electricity that reflect the power sector modeling done for each of this study's three cost of carbon mitigation cases.

The AEO Reference Case average industrial electricity and natural gas prices are used to estimate H2 costs for each modeled year (2025, 2030, 2035... 2050). One set of plant gate costs are estimated under the AEO prices and then a second set are estimated under each of the three "alternative case" in which a trajectory for the price of carbon mitigation is assumed. As shown in the orange-colored row of Exhibit 20, the cost of hydrogen made from a large facility using an ATR+CCS process in 2030 is $10.76/MMBtu before the application of any cost of carbon mitigation. Applying the relevant cost of carbon mitigation for the year 2030 under the High Even Case ($70/metric ton of CO2e) produces the $11.70/MMBtu cost estimate shown in the yellow-colored row. Note that the cost of carbon mitigation is applied to the emission estimated for the plant itself as well as to the feedstocks, materials, energy, etc. consumed by the plant. The emission factors for electricity inputs to the hydrogen production plants reflect the mitigation that is expected to be applied in the electricity sector in response to the assumed cost of carbon mitigation. (See Exhibit 68 for data on how GHG emissions from electricity generation decline over time for the Reference and Alternative Cases.)

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[7] "Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis," Cristina Antonini, Karin Treyer, Anne Streb, Mijndert van der Spek, Christian Bauer and Marco Mazzotti, Royal Society of Chemistry, Sustainable Energy Fuels, 2020, 4,2967–2986, https://www.rsc.org/journals-books-databases/about-journals/sustainable-energyfuels/?utm_content=&utm_source=shortcut&utm_medium=printed&utm_campaign=mkt-rab-rp16097

Clean Air Task Force (CATF) comments on SB100 draft results, Docket Number: 19-SB-100, SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future, contains report from Hensley Energy Consulting LLC entitled "Estimate of Likely Performance and Cost for Hydrogen Production by Auto-Thermal Reforming of Natural Gas with Very Low CO2 Emissions Based on Literature Review of Recent Project Proposals," September 14, 2020 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-SB-10

BEIS Hydrogen Supply Programme, "HyNet Low Carbon Hydrogen Plant Phase 1 Report for BEIS" https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866401/HS384_-_Progressive_Energy_-_HyNet_hydrogen.pdf

Exhibit 20: Pro Forma Economics of Hydrogen from Natural Gas

Hydrogen Production from Natural Gas: 2030

	SMR	SMR + CCS	ATR + CCS	Large ATR + CCS
H2 output condition	99.9%+ purity, dense phase compressed gas	99.9%+ purity, dense phase compressed gas	99.9%+ purity, dense phase compressed gas	99.9%+ purity, dense phase compressed gas
Output capacity in cubic meters of H2 per hour	100,000	100,000	100,000	500,000
Output capacity in kilograms of H2 per hour	8,929	8,929	8,929	44,645
Output capacity in MMBtu (HHV) of H2 per hour	1,203	1,203	1,203	6,016
Output capacity in MMBtu (LHV) of H2 per hour	1,017	1,017	1,017	5,087
Output capacity Mscf of H2 per hour	3,508	3,508	3,508	17,541
Natural gas inputs in MMBtu (HHV) per hour	1,487	1,638	1,430	7,149
Thermal efficiency excluding purchased electricity (HHV)	80.9%	73.5%	84.2%	84.2%
Natural gas inputs in MMBtu (LHV) per hour	1,339	1,474	1,287	6,434
Thermal efficiency excluding purchased electricity (LHV)	76.0%	69.0%	79.1%	79.1%
Natural gas inputs in kg per hour	29,821	32,844	28,666	143,330
Natural gas inputs in kg of natural gas per kg H2 output	3.34	3.68	3.21	3.21
Natural gas inputs in Btu HHV of natural gas per kg H2 output	166,581	183,470	160,130	160,130
Water use in kg per kg of H2	12.7	14.3	10.6	10.6
Carbon dioxide generated in kg per hour	81,411	89,665	78,258	391,290
Carbon capture percent	0.0%	90.0%	97.0%	97.0%
Carbon dioxide captured in kg per hour	-	80,698	75,910	379,552
Amine regeneration fuel use MMBtu per hour	-	270	254	1,268
Air Separation Unit elec. use in kWh/kg H2	-	-	0.62	0.62
H2 plant, offsites, BOP elec. use in kWh/kg H2	0.57	0.63	1.28	1.28
CO2 compression elec. use in kWh/metric ton of CO2	-	*107*	*80*	*80*
CO2 compression elec. use in kWh/kg of H2	-	0.97	0.67	0.67
All purchased electricity use in kWh/kg H2	0.57	1.59	2.57	2.57
Purchased electricity in kW	5,081	14,223	22,948	114,738
Total Capex				
Capital cost in $mm	$285	$505	$353	$1,271
Total investment cost in $/kg annual capacity	$3.64	$6.46	$4.51	$3.25
TIC in $/MMBtu HHV annual capacity	$27.02	$47.92	$33.48	$24.11
TIC in $/Mscf annual capacity	$9.27	$16.44	$11.48	$8.27
Financial & Operations				
Annual operating and maintenance cost as % of Capex ex. feedstock & elec.	4.7%	3.0%	5.2%	4.7%
Cost of CO2 transport and storage in $ per metric ton	$15.00	$15.00	$15.00	$15.00
Cost of electricity in $/kWh	$0.067	$0.067	$0.067	$0.067
Cost of natural gas in $/MMBtu	$4.23	$4.23	$4.23	$4.23
Water cost $/metric ton	$0.79	$0.79	$0.79	$0.79
Capacity utilization rate	92.3%	92.3%	92.3%	92.3%
Output (kg per year)	72,201,268	72,201,268	72,201,268	361,006,338
Output (MMBtu per year HHV)	9,729,980	9,729,980	9,729,980	48,649,901
Output (Mscf per year)	28,367,289	28,367,289	28,367,289	141,836,446
Weighted average real cost of capital	6.5%	6.5%	6.5%	6.5%
Plant life in years	20	20	20	20
Annual Costs in $million				
Annual capital charge	$24.3	$43.0	$30.0	$108.2
O&M	$13.4	$15.2	$18.4	$59.6
Purchased natural gas	$50.9	$56.1	$49.0	$244.8
Purchased power	$2.7	$7.7	$12.4	$61.9
Purchased water	$0.7	$0.8	$0.6	$3.0
CO2 trans., storage	$0.0	$9.8	$9.2	$46.0
Total Annual Costs	$92.0	$132.5	$119.6	$523.6
Costs per Unit Produced at Plant Gate				
Cost in $/kg of H2	$1.27	$1.84	$1.66	$1.45
Cost in $/MMBtu HHV of H2	$9.46	$13.62	$12.29	$10.76
Cost in $/Mscf of H2	$3.24	$4.67	$4.22	$3.69
GHG Emission Factors				
Construction & material for this facility (kg CO2e/kg H2)	0.02	0.03	0.02	0.01
Combustion/venting CO2 emissions by this facility (kg CO2e/kg H2)	9.12	1.00	0.26	0.26
"Upstream" GHG for purchased fuels & feedstocks (kg CO2e/MMBtu NG)	7.29	7.29	7.29	7.29
GHG for purchased electricity (kg CO2e/MWh) NATIONAL AVERAGE	137.17	137.17	137.17	137.17
Total GHG in kg CO2e/kg of hydrogen	10.43	2.59	1.80	1.80
Annual GHG Emissions in Metric Tons per Year				
Construction & material for this facility	1,182	2,096	1,464	5,274
Combustion/venting CO2 emissions by this facility	658,299	72,504	18,984	94,921
"Non-combustion" GHG for purchased fuels & feedstocks	87,704	96,596	84,308	421,538
GHG for purchased electricity	5,635	15,777	25,454	127,268
Total GHG	752,821	186,973	130,210	649,001
Cost of GHG Emissions				
Cost of methane mitigation for this year ($/MT CO2e)	$70	$70	$70	$70
Carbon Cost ($mm)	$52.70	$13.09	$9.11	$45.43
Carbon Cost in $/kg of H2	$0.73	$0.18	$0.13	$0.13
Carbon Cost in $/MMBtu HHV of H2	$5.42	$1.35	$0.94	$0.93
Carbon Cost in $/Mscf of H2	$1.86	$0.46	$0.32	$0.32
Costs per Unit Produced at Plant Gate Including Cost of Carbon				
Cost in $/kg of H2	$2.00	$2.02	$1.78	$1.58
Cost in $/MMBtu HHV of H2	$14.88	$14.97	$13.23	$11.70
Cost in $/Mscf of H2	$5.10	$5.13	$4.54	$4.01

3.2.2 Green Hydrogen Costs

Another way to produce hydrogen is through electrolysis. This process utilizes a type of electrolyzer (such as proton-exchange membrane or PEM) which separate H_2 molecules from water by introducing electricity. The color variants for this supply process are determined by the source of the electricity used. “Green” hydrogen is hydrogen produced through electrolysis where the utilized electricity is produced from renewable sources such as wind and solar. Cost effective green hydrogen is of particular interest for decarbonization as there are no direct emissions from the production of feedstocks or the process itself.

The pro forma economics of producing hydrogen through electrolysis are shown in Exhibit 21 for three sizes of PEM facilities. The economic modeling done for this report assumes that the largest (and economically most efficient) electrolyzer will be used. As with the blue hydrogen pro forma analysis, the orange-colored row shows the cost before the effects of applying the cost of carbon mitigation and the yellow-colored row shows the cost after those effects are considered. The GHG emissions associated with solar (55.2 kg CO2e/MWh) and wind (15.4 kg CO2e/MWh) come from the construction and maintenance of the generating facilities. Since wind makes up about 60% of incremental renewable generation (that is, the amounts forecast in the Alternative Cases as compared to the AEO Reference Case), the weighted average GHG emission factor for renewable electricity that can be used to make green hydrogen is approximately 31.3 kg CO2e/MWh. These GHG estimates are from a meta-analysis compiled by National Renewable Energy Laboratory called “Life Cycle Assessment Harmonization.”[8] In this project, NREL reviewed and harmonized life cycle assessments of all major electricity generation technologies from around the world to reduce uncertainty around estimates for environmental impacts and increase the value of these assessments to the policymaking and research communities. The harmonization process included standardizing assumptions related to generator size and operating characteristics and recomputing LCA’s with common system boundaries and units of measure. ICF has used the medians of the harmonized data to characterize solar, wind, hydro, and nuclear power in this and other studies.

[8] These data are periodically updated by NREL. See Life Cycle Emissions Factors for Electricity Generation Technologies | NREL Data Catalog

Exhibit 21: Pro Forma Economics of Hydrogen from Electricity

Hydrogen Production Using Electrolyzers: 2030

	PEM Electrolysis Small	PEM Electrolysis Medium	PEM Electrolysis Large
Capacity (kW electricity input)	1,000	20,000	100,000
Electricity consumption kWh/kg H2	48	48	48
Capacity (kg H2 output/ hour)	21	413	2,064
Capacity (MMBtu H2 output LHV/ hour)	2.4	47.0	235.2
Capacity (MMBtu H2 output HHV/ hour)	2.8	55.6	278.2
Capacity (Mscf H2 output/ hour)	8.1	162.2	811.0
Thermal efficiency % LHV	68.9%	68.9%	68.9%
Thermal efficiency % HHV	81.5%	81.5%	81.5%
Electrolyzer Capital Cost			
Direct Capital Expenditure ($/kW)	$1,035	$641	$495
Total Capital Expenditure ($/kW)	$1,615	$1,000	$773
O&M (% of Capex)	3.0%	3.0%	3.0%
Water consumption (kg water/kg H2)	23	23	23
Water cost $/metric ton of water	$0.79	$0.79	$0.79
Electricty cost $/MWh RenewOnly	$43.80	$43.80	$43.80
Annual capacity utilization	30.0%	30.0%	30.0%
Output (kg per year)	54,250	1,084,998	5,424,989
Output (MMBtu HHV per year)	7,311	146,216	731,082
Output (Mscf per year)	21,314	426,287	2,131,434
Annual Costs in $million			
Annual capital charge	$0.18	$2.32	$9.10
O&M	$0.05	$0.63	$2.48
Purchased water	$0.00	$0.02	$0.10
Purchased power	$0.12	$2.35	$11.74
Total annual costs	$0.35	$5.32	$23.42
Costs per Unit Produced at Plant Gate (before any cost of carbon)			
Cost in $/kg of H2	$6.49	$4.90	$4.32
Cost in $/MMBtu HHV of H2	$48.16	$36.38	$32.03
Cost in $/Mscf of H2	$16.52	$12.48	$10.99
GHG Emission Factors			
Construction & material for this facility (kg CO2e/kg H2)	0.18	0.11	0.09
Combustion/venting CO2 emissions by this facility (kg CO2e/kg H2)	-	-	-
"Non-combustion" GHG for purchased fuels & feedstocks (kg CO2e/MMBtu NG)	-	-	-
GHG for purchased electricity (kg CO2e/MWh) RenewOnly	31.34	31.34	31.34
Total GHG in kg CO2e/kg of hydrogen	1.72	1.66	1.64
Annual GHG Emissions in Metric Tons per Year			
Construction & material for this facility	10	121	474
Combustion/venting CO2 emissions by this facility	-	-	-
"Upstream" GHG for purchased fuels & feedstocks	-	-	-
Upstream GHG for purchased electricity RenewOnly	84	1,680	8,398
Total GHG	94	1,800	8,872
Cost of GHG Emissions			
Cost of methane mitigation for this year ($/MT CO2e)	$70	$70	$70
Carbon Cost ($mm)	$0.01	$0.13	$0.62
Carbon Cost in $/kg of H2	$0.12	$0.12	$0.11
Carbon Cost in $/MMBtu HHV of H2	$0.90	$0.86	$0.85
Carbon Cost in $/Mscf of H2	$0.31	$0.30	$0.29
Costs per Unit Produced at Plant Gate Including Cost of Carbon			
Cost in $/kg of H2	$6.61	$5.02	$4.43
Cost in $/MMBtu HHV of H2	$49.06	$37.24	$32.88
Cost in $/Mscf of H2	$16.83	$12.77	$11.28

3.2.3 Technology Improvements for Hydrogen Supply

As stated above, the cost of hydrogen supplies from each technology may change each year based on the assumed rate of technology advances that can reduce capital cost per unit of output capacity or improve efficiency (energy output per unit of energy input). The key assumptions used in this report related to blue and green hydrogen are shown below in units of percent change per year. The pace of advancement for electricity generation from solar and wind is adopted directly from the AEO Reference Case. The other assumptions were made by ICF after review of various forecasts which show expectations for little improvement in the relatively mature SMR technology, modest improvements in ATR and CCS technologies, and the largest improvement for electrolyzers that are expected to benefit from improved designs and increasing economies of scale in manufacturing.

Exhibit 22: Assumed Annual Rates of Technology Advances for Hydrogen Supply

Technology	Reduction in Capital Costs per Unit of Output Capacity (% p.a.)	Improvements to Efficiency (% p.a.)
Electricity generation from solar	2.23%	NR
Electricity generation from wind	1.11%	NR
PEM Electrolysers	2.50%	0.36%
Hydrogen from NG, SMR	0.00%	0.00%
Hydrogen from NG, SMR+CCS	0.34%	0.00%
Hydrogen from NG, ATR+CCS	0.75%	0.00%

Note: "NR" indicates parameter is not relevant to a specific technology.

3.3 Hydrogen Wholesale Pricing

The cost of making hydrogen from electricity and water in electrolyzers will depend, to a large degree, on what kind of electricity is used and how many hours in a year that electricity will be available. Hours of operation will determine the anticipated annual capacity utilization rate for the electrolyzer and capital cost contribution to the $/MMBtu plant gate cost of the hydrogen. The calculations presented here for the cost of making hydrogen using electrolysis are based on three possible business strategies:

- Buy **electricity from the grid** and operate at a high load factor. For the economic modeling of this option the relevant electricity price is the average electricity price to industrial consumers from the AEO (averaging about $65/MWh from 2025 to 2050). This would be appropriate for a dedicated hydrogen plant buying electricity from the grid and operating at high utilization rates (75% is assumed in the ICF pro forma for this option). Production of hydrogen might cease for some hours in the year when electricity prices are very high. This option is not expected to be economic in the cases examined in this report because the average industrial electricity price is too high given the expected market clearing price for hydrogen that is likely to be set by blue hydrogen production costs.
- Use electricity from **dedicated solar/wind generators** and operate for all hours when electricity is available from those generators. For the economic modeling of this option,

the relevant electricity price would be the cost of marginal new solar and wind power plants (roughly $49.50 to $33.50/MWh between 2025 and 2050). If such electrolyzers operated only whenever the dedicated renewable electricity is available, their annual capacity utilization rate might range from 20% to 40% depending on where they are located and the mix of solar and wind generation to which they are linked.[9] In the cases examined here, this option is expected to be marginally economic. Favorable economics would occur most likely in areas with excellent solar/wind potential but where sales from wind/solar generators to the electricity grid is bottlenecked by inadequate electric transmission capacity. In such cases the electrolyzers and their solar/wind electricity sources might choose not to connect to the grid at all and thus avoid interconnect costs.

- Use only **"excess electricity"** that would be available during hours when electricity load plus charging for electricity storage is less than generation from non-dispatchable/ inflexible generation. That is, when the market price for electricity would be lowest (zero to $20.00/MWh). Electrolysers using only excess electricity would be most economic where enough low-cost electricity is available to achieve over 20% annual capacity utilization rates for the electrolyzers. Sourcing "excess electricity" to make hydrogen is expected to be the primary method electrolyzers will use in the cases in which all sources of hydrogen face the same incentive or disincentives per unit of CO2e reduction.

The expected cost of producing hydrogen using each of these options is shown in Exhibit 23 for the Low Even Case and in Exhibit 24 for the High Even Case. Note that the two exhibits look very similar because they depict the costs for low-carbon options for making hydrogen and so are changed only slightly when a willingness to pay for carbon mitigation is introduced in the Low Even Case and then made higher in the High Even Case. The blue lines near the bottom of each of these exhibits represent the cost of blue hydrogen, which is expected to be the lowest cost option overall. The red line represents the option of buying electricity off the grid at the average industrial electricity price and operating the electrolyzer at a 75% capacity utilization factor.

The option of using dedicated solar/wind generation and operating at a 30% capacity utilization factor is represented as the solid green line. (This is the basis for the pro forma case earlier shown in Exhibit 21.) If a dedicated solar/wind facility could operate at a higher 40% capacity utilization factor, it would have lower production costs indicated by the dashed green line. On the other hand, if the capacity utilization factor were only 20% for the dedicated solar/wind facility, the production costs would be higher as indicated by the dash-and-dot green line.

The purple lines on the exhibits show the production cost expected for facilities that pursue a strategy of using only excess electricity and pay an average price of $15.00/MWh for electricity. These facilities could be connected anywhere on the grid in pricing zones expected to frequently have excess generation and low prices. For the strategy of buying excess electricity, the pro forma case (solid purple line) assumes a 20% annual capacity utilization factor. The more optimistic case (dashed purple line) assumes a 30% capacity utilization factor and the more pessimistic case (dash-and-dot purple line) assumes a 10% utilization.

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[9] By way of comparison, the AEO Reference Case annual capacity utilization rates for solar averages 23.5% and wind averages 37.4% in 2050.

Exhibit 23: Cost of Hydrogen from Various Sources 2025-2050 Low Even Case

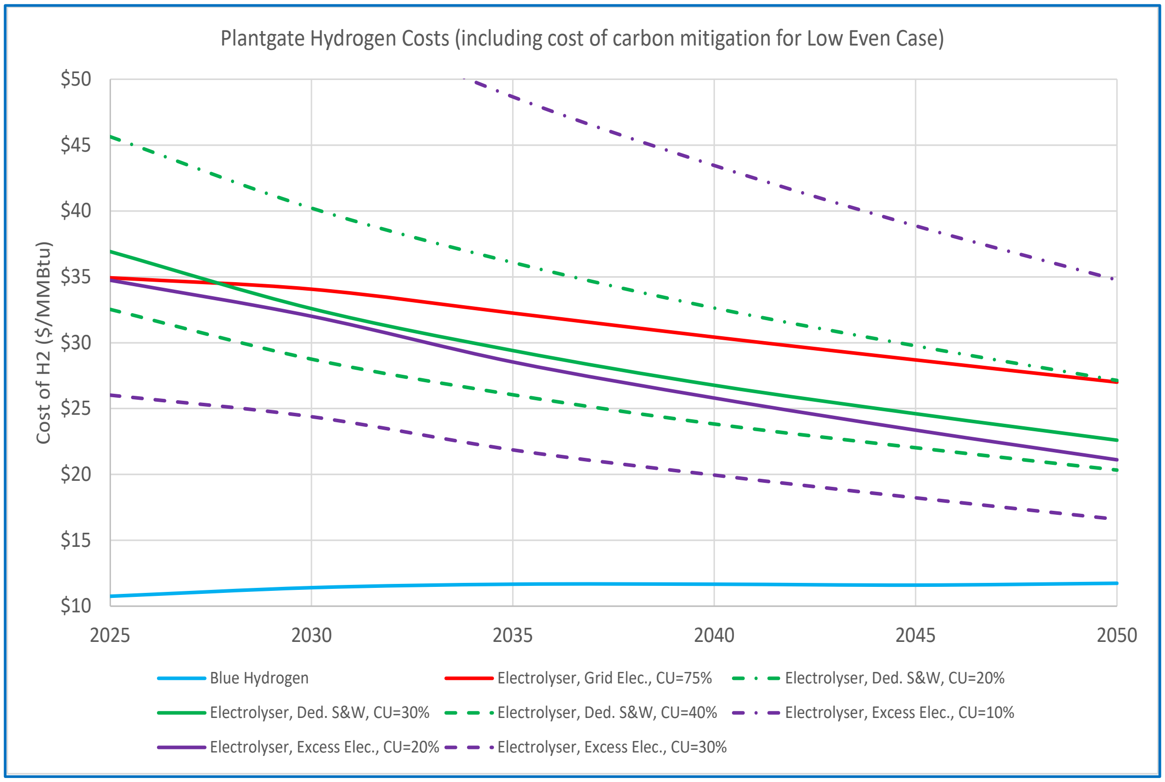


Exhibit 24: Cost of Hydrogen from Various Sources 2025-2050 High Even Case

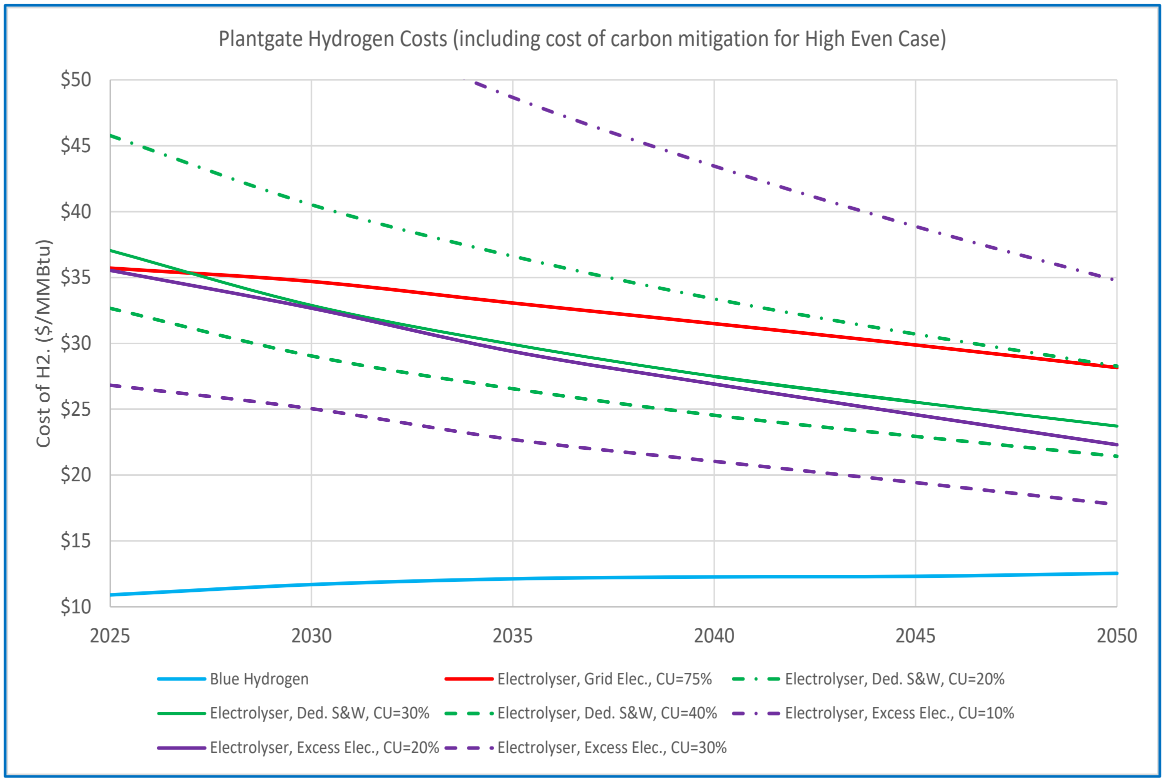


Exhibit 25 shows the cost of producing hydrogen for the High Uneven Case, where it is assumed that blue hydrogen would face a $12/MMBtu differential in incentives relative to green hydrogen. The lines representing electrolyzers using dedicated solar/wind generation (the three green lines) and excess electricity (the three purple lines) are in the same position as in the previous exhibit for the High Even Case. The red line representing electrolyzers purchasing grid electricity at average industrial rates, is slightly higher than in the High Even Case because the average cost of electricity generation is about one percent higher. The only large change in the High Uneven Case relative to the High Even Case is the blue line representing blue hydrogen. That line now intersects with the pro forma cost of dedicated solar/wind operating at 30% annual capacity utilization (solid green line) around the year 2045. The crossover point with blue hydrogen for dedicated electrolyzer plants operating at a higher 40% annual capacity utilization rate is about five years earlier in 2040.

The exhibit for the Uneven High Case shows that the year in which electrolyzers buying excess electricity at $15/MWh may be able to match blue hydrogen prices is approximately 2032 for the operating at 30% capacity utilization rates and around the year 2045 for those operating at 20% capacity utilization rates. However, in comparison the hypothetical $15/MWh price used to draw the charts, the actual market price at which they can buy the excess electricity is likely to be set by market forces and will fluctuate by pricing period (e.g., by hour or 15-minute intervals). Likewise, the hours of operation for the electrolyzers will not be the hypothetical 30% or 20% used to draw the chart but will be set by market factors.

US electricity markets have shown that in periods of excess generation market prices for electricity can fall to zero and even negative values.[10] If a substantial number of non-dedicated electrolyzers (that is, those without committed solar/wind generation capacity) are built, they could use up that excess electricity and help prevent near-zero electricity prices. In such instances, the market clearing price for electricity during hours of excess electricity would be set by the wholesale price of hydrogen minus the marginal operating cost of the electrolyzer adjusted for the conversion efficiency. Examples of this calculation are shown in Exhibit 26 for electrolyzers that operate at a 30% capacity utilization factor. Online electrolyzers that consider their capital costs as being sunk, should be willing to pay from $30 to $32 per MWh of electricity under the Low Even and High Even Cases. If capacity utilization were 20%, the willingness to pay would decline to $27 to $29 per MWh. The willingness to pay value for the High Even Case is much higher at $53 per MWh because wholesale hydrogen prices are higher.

When the total capacity of electrolyzers in an area is insufficiently large to use up all of the excess electricity, the market clearing electricity price again could fall to zero and below. Therefore, throughout the year one can expect periods in which market clearing electricity prices and the operating level of electrolyzers will vary. See Exhibit 27 for representation of such possible varying market conditions that could lead to fluctuating electricity prices to be paid by electrolyzers without dedicated solar/wind electricity supply.

[10] Negative wholesale electricity market prices can occur when solar and wind generators bid negative prices into day-ahead and real-time energy markets in ensure they can dispatch to earn tax credits.

Exhibit 25: Cost of Hydrogen from Various Sources 2025-2050 High Uneven Case

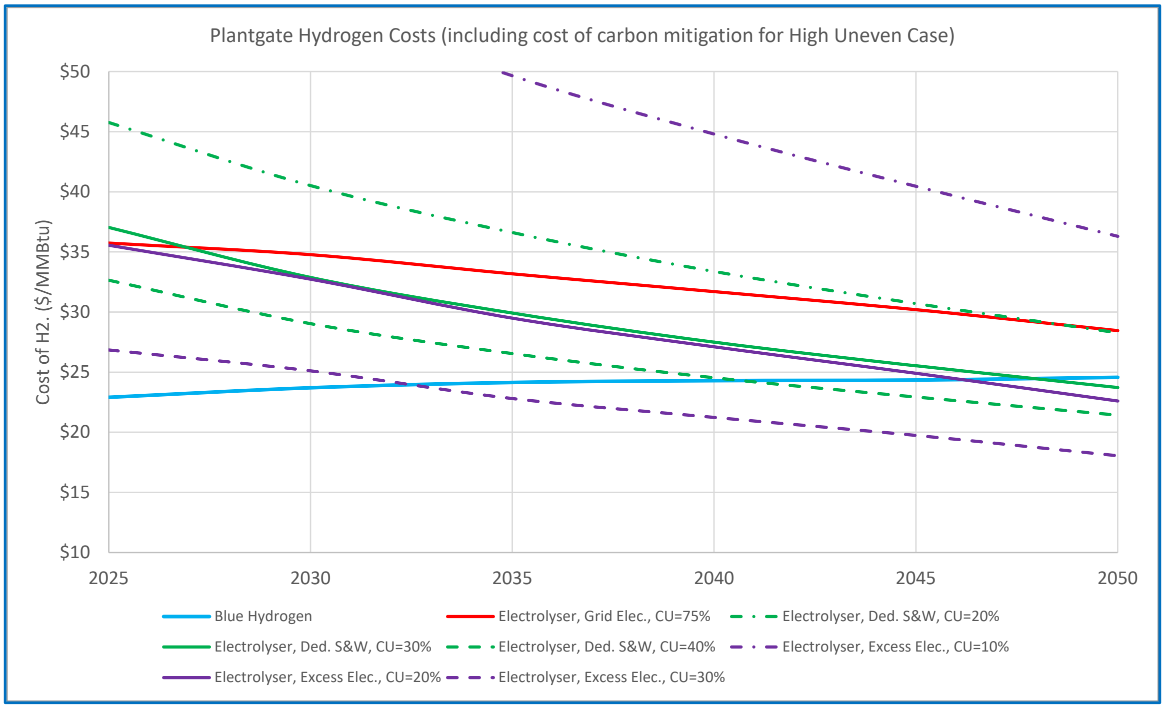


Exhibit 26: Willingness to Pay for Electrolysers Purchasing Excess Electricity

	Variable Cost Basis (30% CU)			Full Cost Basis (30% CU)		
	Low Even Case	High Even Case	High Uneven Case	Low Even Case	High Even Case	High Uneven Case
Average hydrogen wholesale price 2025-2050 ($/MMBtu)	$11.78	$12.25	$19.79	$11.78	$12.25	$19.79
Average hydrogen wholesale price 2025-2050 ($/kg)	$1.59	$1.65	$2.67	$1.59	$1.65	$2.67
Avoidable Costs ($/kg)	$0.15	$0.15	$0.15	$1.32	$1.32	$1.32
Revenue minus avoidable cost ($/kg)	$1.43	$1.50	$2.51	$0.27	$0.33	$1.35
Electricity consumption kWh/kg H2	47.2	47.2	47.2	47.2	47.2	47.2
Maximum electricity price that could be paid by electrolyzers for excess electricity $/MWh (willingness to pay amount)	$30.38	$31.74	$53.27	$5.67	$7.02	$28.56

Note: "Variable cost basis" assumes the electrolyzer has been built and so Capex is a sunk cost. "Avoidable costs" are computed as consumables (water and chemicals) plus half of other non-fuel O&M. The "full cost basis" considers all costs including Capex as being avoidable, as might be the case for an electrolyzer that has not yet been built.

Exhibit 27: Possible Electricity Pricing Conditions for Non-dedicated Electrolysers

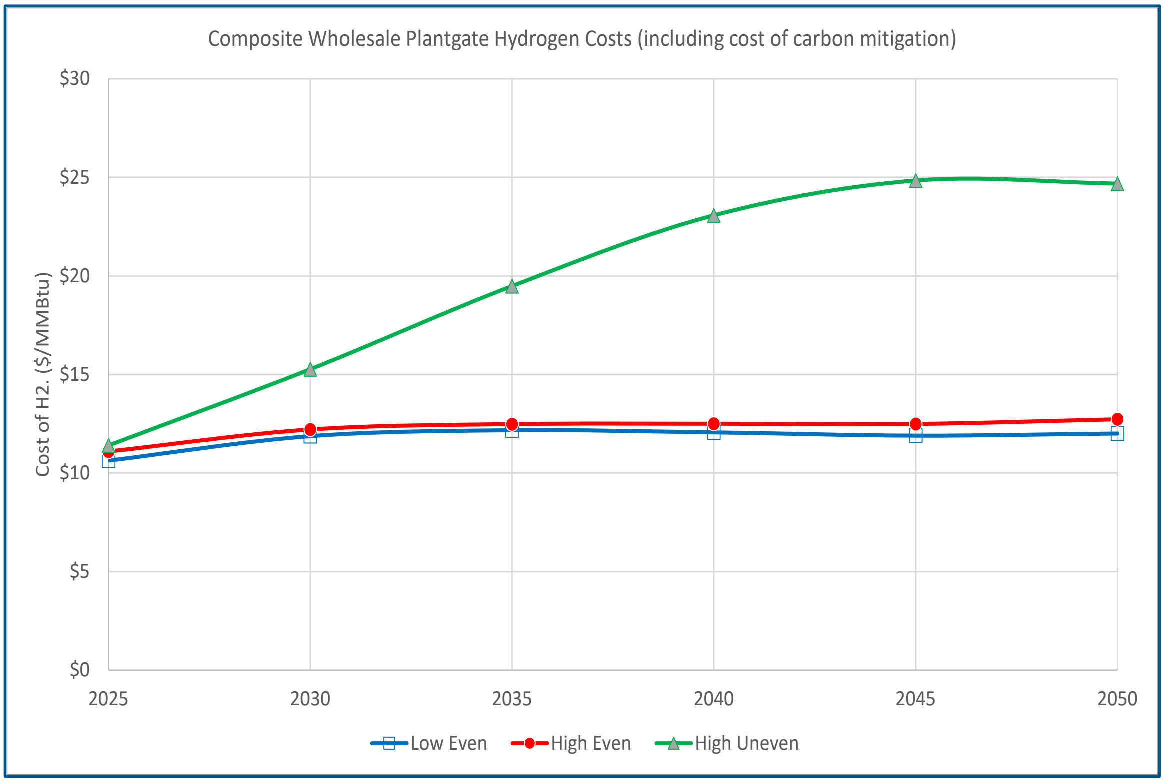
Electricity Market Condition	Electricity Price	Electrolyser Operation
Excess electricity is greater than the input needs of non-dedicated electrolyzers	Near zero electricity prices for these hours	All operable non-dedicated electrolyzer capacity will be online
Excess electricity is above zero but less than the input needs of non-dedicated electrolyzers	Electricity price for these hours will be at the marginal willingness to pay amount given price of hydrogen	Only those electrolyzers willing to pay market clearing electricity prices will be online
Excess electricity is at or below zero	Price will be set by marginal dispatchable generator and will be above what non-dedicated electrolyzers are willing to pay.	Few if any non-dedicated electrolyzer capacity will be online during these hours

Note: Excess electricity is defined as generation from solar/wind/nuclear, plus inflexible hydro, minus load, minus charging of electric storage. For any given period, market conditions can vary among electricity control areas and pricing zones. Therefore, hours of operation of the non-dedicated electrolyzers will not be the same in all locations.

For a non-dedicated electrolyzer to be economic to build in the first place, the expected average electricity price it pays must be low enough for it to have operating margins (revenue minus variable O&M minus cost of energy inputs) sufficiently large to pay its capital costs (depreciation plus cost of debt plus cost of equity) and fixed O&M. Those maximum electricity prices are shown at the bottom of Exhibit 26 under the heading “Full Cost Basis (30% CU).” Planned electrolyzers seeking investors would want to demonstrate that they will be able to procure electricity for 30% of the hours in a year at an average price from $5.70 to $7.00 per MWh under the Low Even and High Even Cases. The willingness to pay for investing in a new non-dedicated electrolyzer for the High Even Case is much higher at $28.60 per MWh because the facility can expect higher revenues due to the higher wholesale hydrogen prices in that case. These values for willingness to pay for electricity for new electrolyzers represent the results of modelling using national average assumptions for the Alternative Cases. The value for actual projects under consideration may differ from this based on the quality of solar/wind resources, local electricity market conditions and other factors.

Exhibit 28 shows the annual wholesale composite hydrogen prices that are computed as the weighted average cost of producing hydrogen from natural gas and from electrolysis using electricity from dedicated solar and wind. The market shares from each production technology are computed using the same market share equation employed for energy end-user markets see Exhibit 14: Market Share as a Function of Cost Ratio). The cost of making hydrogen produced from excess electricity does not enter into the calculation of composite wholesale hydrogen cost because it is assumed that such production would be a price taker (with the price paid for the excess electricity used as an input to make hydrogen roughly reflecting the composite hydrogen price found in the market adjusted for the avoidable operating cost of the electrolyzer and for conversion efficiency. This calculation was shown above in Exhibit 26: Willingness to Pay for Electrolysers Purchasing Excess Electricity).

Exhibit 28: Composite Wholesale Hydrogen Prices 2025-2050



Note: The composite wholesale hydrogen price is the weighted average plant gate price wherein the market shares are computed based on the cost of production of blue hydrogen and green hydrogen from dedicated electrolyzers. For the Low Even and High Even Cases, the composite prices are approximately the same as the blue hydrogen production costs due to blue hydrogen high market share. For the High Uneven Case, the composite price exceeds the blue hydrogen production costs (due to the differential in incentives assumed for that source) and over time, as the cost of carbon mitigation goes up, approach the production cost of green hydrogen from dedicated electrolyzers operating at 30% capacity utilization rates.

3.4 Cost of Delivered Hydrogen and Hydrogen Infrastructure

As described above, ICF performed a market share calculation for grey, blue, and green hydrogen production technologies to reflect the production costs and GHG impacts in future years. These are the market shares depicted in Exhibit 3: Projected Market Shares for Modelled Hydrogen Production Options. The "composite" wholesale hydrogen price shown directly above in Exhibit 28 is the weighted average plant gate cost which is used to computed all delivered end-use prices. The retail price of delivered hydrogen to each end-user sector and submarket reflects that composite wholesale cost plus the cost of delivering the hydrogen to consumers in the required form (pipeline, highly compressed gas, liquid).[11] Charts of the retail hydrogen and other energy prices for each end-used sector will be shown in Section 5 for each year through 2050 for the Reference and Alternative Cases.

For residential and commercial customers, hydrogen delivery is assumed to be by pipelines from production areas to the city gate and by local distribution companies from the city gate to

[11] Other methods of storing and delivering hydrogen to consumers may prove to be economic. These options, which might include converting hydrogen to ammonia or storing and transporting it as a metal hydride, are not explicitly modeled in this study but are implicitly part of cost distributions underlying the market share equations.

consumers. For residential hydrogen consumers, this markup from wholesale costs to delivered costs is \$10.45/MMBtu and for commercial customers \$6.60/MMBtu. The corresponding markup in the AEO for natural gas delivered through transmission pipelines and local distribution companies to residential customers is \$7.82/MMBtu and \$4.93/MMBtu for service to commercial natural gas customers. For the industrial sector, hydrogen is assumed to be overwhelmingly delivered directly from pipelines with a markup of \$1.19/MMBtu over composite wholesale plant gate costs. This compares to an average markup in the AEO for natural gas industrial consumers of \$0.89/MMBtu.

For the transportation sector there are additional costs for converting hydrogen to a high-pressure gas or liquid and dispensing the fuel. As an example, for hydrogen-powered vehicles, ICF assumed hydrogen was delivered as a liquid to refueling stations where it could be loaded into trucks and buses as a liquid or regasified at the pump for sales as a high-pressure gas for light-duty vehicle. Therefore, the delivered fuel price used in end-use market share calculations includes the composite wholesale hydrogen price, a cost to pipeline the gaseous hydrogen from the production location to the city gate, the liquefaction fee, the transportation of liquid hydrogen to the refueling station via truck delivery, and onsite regasification at the pump. The hydrogen price used in this sector of the analysis also includes retail markup, which reflects separate pricing for on-road vehicle and off-road options. See Exhibit 36: Transportation Sector Compression and Refueling Costs (\$/MMBtu HHV) for the values of these costs and markups for hydrogen and other fuels in transportation markets.

The ICF analysis assumes that new and converted pipelines would be built at costs similar to natural gas pipelines and operated at the same pressures and pressure drops per mile (see Exhibit 29).[12] The cost per unit of throughput is computed considering the lower heat content of hydrogen but also that the lower density and frictional characteristics would allow higher fluid velocities. The net effect is hydrogen pipeline transmission costs are 134% of the \$/MMBtu natural gas markups for the same pipeline diameter and distance.

To estimate infrastructure capital requirements, ICF assumed that one-half of the infrastructure for transmission pipeline, underground storage, and lateral/distribution line would be newly built and the remaining half would be natural gas systems converted to 100% hydrogen service. (The option of blending hydrogen into natural gas pipeline or distribution systems is a separate issue and is discussed in section 6.3) Cost of conversion is assumed to be one-fourth of the cost for new builds. All infrastructure for liquefying/pressurizing and dispensing hydrogen for the transportation sector uses was assumed to be newly built.

[12] Although operating new hydrogen pipelines at higher pressures could reduce \$/MMBtu transmission costs, the dangers of embrittlement would increase. Embrittlement occurs when the small hydrogen molecules are absorbed by metal. This reduces the metal's ductility and load bearing capability and can cause cracks and fractures at stresses less than the original yield strength of the metal.

Exhibit 29: Estimated Cost of New Natural Gas and Hydrogen Pipelines

NATURAL GAS PIPELINES (compressor inlet and outlet pressures of 770 and 1,000 psi)

Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Flow Capacity in MMscf per day (60 degrees F and 14.73 psi)	Flow Capacity in metric tons/day	Flow Capacity in MMBtu/day	Pipeline Cost for 75 Miles ($mm)	Compressor Cost for 75 Miles ($mm)	Annual Cost of Service for 75-mile Segment ($mm)	Cost of Service for 75 miles ($/Mcf)	Cost of Service for 75 miles ($/metric ton)	Cost of Service for 75 miles ($/MMBtu)
12.75	12.0	0.4	$188,939	70	1,446	71,748	$180.7	$2.9	$19.0	$0.94	$45.13	$0.91
16	15.3	0.4	$196,787	128	2,651	131,569	$236.1	$5.3	$25.3	$0.68	$32.65	$0.66
24	23.0	0.5	$211,911	361	7,497	372,093	$381.4	$15.1	$42.4	$0.40	$19.37	$0.39
30	28.8	0.6	$217,654	635	13,184	654,385	$489.7	$26.5	$56.2	$0.30	$14.59	$0.29
36	34.5	0.8	$223,397	1,008	20,911	1,037,915	$603.2	$42.0	$71.5	$0.24	$11.71	$0.24
42	40.3	0.9	$229,140	1,488	30,885	1,532,983	$721.8	$62.0	$88.4	$0.20	$9.81	$0.20

kWh/MMscf-mile 4.187 HP compressor capacity per MMscf for 75 mile spacing 16.67

HYDROGEN PIPELINES (compressor inlet and outlet pressures of 770 and 1,000 psi)

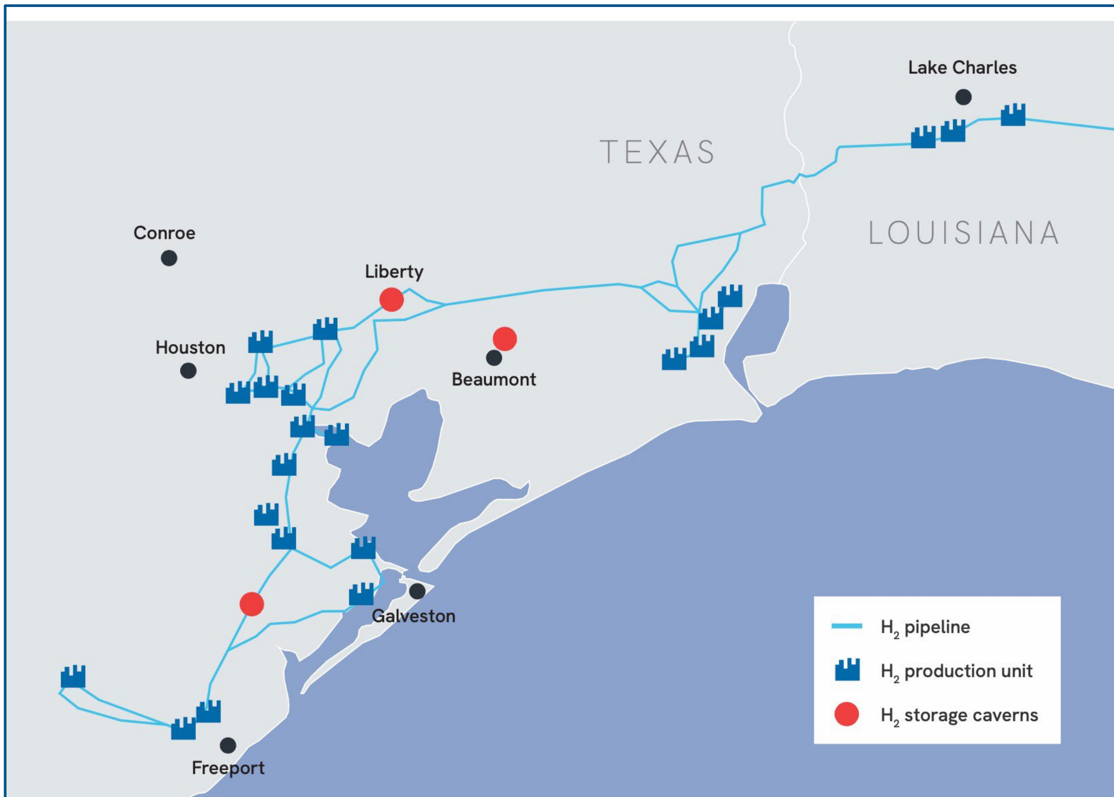
Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Flow Capacity in MMscf per day (60 degrees F and 14.73 psi)	Flow Capacity in metric tons/day	Flow Capacity in MMBtu/day	Pipeline Cost for 75 Miles ($mm)	Compressor Cost for 75 Miles ($mm)	Annual Cost of Service for 75-mile Segment ($mm)	Cost of Service for 75 miles ($/Mcf)	Cost of Service for 75 miles ($/metric ton)	Cost of Service for 75 miles ($/MMBtu)
12.75	12.0	0.4	$188,939	182	464	62,552	$180.7	$7.7	$20.2	$0.38	$149.14	$1.11
16	15.3	0.4	$196,787	334	851	114,706	$236.1	$14.1	$27.4	$0.28	$110.28	$0.82
24	23.0	0.5	$211,911	946	2,407	324,403	$381.4	$39.8	$48.4	$0.18	$68.92	$0.51
30	28.8	0.6	$217,654	1,663	4,234	570,515	$489.7	$70.0	$66.8	$0.14	$54.05	$0.40
36	34.5	0.8	$223,397	2,638	6,715	904,890	$603.2	$111.0	$88.4	$0.11	$45.07	$0.33
42	40.3	0.9	$229,140	3,897	9,918	1,336,507	$721.8	$163.9	$113.3	$0.10	$39.14	$0.29

Electricity kWh/MMscf-mile 4.227 HP compressor capacity per MMscf for 75 mile spacing 16.83

Source: ICF estimates based largely on new natural gas and oil pipeline costs filed at FERC and published annually in the Oil and Gas Journal.

Exhibit 30 shows the location of the approximately 1,600 miles of hydrogen pipelines currently operating in the US Gulf Coast. The pipelines are owned by merchant hydrogen producers and serve large hydrogen users, such as petroleum refineries and chemical plants. Much of the initial development of blue hydrogen in the US is expected to occur in the Gulf Coast area and may use this existing infrastructure.

Exhibit 30: Current Hydrogen Pipelines and Underground Storage in US Gulf Coast



Sources: H2Tools, USDOT–PHMSA, Air Liquide, Air Products, Praxair

The amount and cost of new infrastructure needed to meet the anticipated hydrogen consumption is based on “rule of thumb” factors derived from natural gas. These rules of thumb relate pipeline, storage and distribution systems capacities and miles to volumes of consumption and numbers of customers. For example:

- Hydrogen transmission pipelines are computed as five pipeline miles per one trillion Btu of annual hydrogen consumption versus the average of 11 miles per TBtu for natural gas systems. The lower pipeline factor compared to natural gas is due to the expectation that hydrogen will be produced at a limited number of facilities (as opposed to hundreds of thousands of gas and oil wells) and will serve a limited number of (mostly) nearby communities.

- The factor for storage working gas capacity is computed as 30 days of hydrogen consumption for residential and commercial consumption plus 15 days of consumption for other sectors. These factors are much less than corresponding values for natural gas

(65 days of storage overall) because hydrogen consumption will not be as winter-peaking as natural gas consumption and because it is expected that most hydrogen will be produced at blue hydrogen facilities which will backed up by existing natural gas storage capacity.

- The rule-of-thumb factor for miles of customer laterals and local distribution line vary by customer class and average 300 feet per hydrogen customer. This is about three times the corresponding value per natural gas customer. More hydrogen distribution feet are needed compared to natural gas because the market penetration for hydrogen is expected to be lower than what it has been for natural gas and so more distance will exist between customers.
- Fuel dispensing for the on-road transportation market is based on having relatively few high-volume stations (4,000 gallon-equivalents per day) as compared to gasoline/diesel stations.

For the High Even Case, which has the largest market for hydrogen among the Alternative Cases, these rule-of-thumb factors lead to year 2050 physical infrastructure estimates of 560 TBtu of hydrogen underground storage capacity, 67,000 miles of hydrogen transmission pipeline, 500,000 miles of customer laterals and LDC pipeline/service lines, and 22,900 hydrogen fuel dispensing stations/facilities. The corresponding hydrogen end-use customer counts are 8.4 million residential customers, 122,000 commercial customers, and 48,000 industrial customers.

4. Markets for End-Use Applications

For each market segment, ICF developed pro forma economic comparisons of hydrogen competitive economics versus major technology/fuel alternatives. This chapter discusses comparisons made for the utilization of hydrogen in end-use markets and for electricity generation and storage. The pro forma comparisons represent the direct cost for each option (initial or capital costs, nonfuel operating costs, and fuel costs) and translate those components into "per-unit cost of energy services" such cents per passenger-mile traveled, cents per ton-mile transported, or MMBtu of process heat delivered. The comparisons were calculated separately for each year to reflect the willingness to pay for carbon mitigation increasing over time, changing AEO fuel prices, and improving technologies that can increase conversion efficiencies and reduce capital cost per unit of output. These factors change over time and usually lead to higher market shares for hydrogen and other low-carbon fuels and technologies in the Alternative Cases. More detail on how this competition is represented in each sector is presented below.

4.1 Power Sector

4.1.1 Overall Methodology for Modelling the Power Sector

As with all energy sectors, the Reference Case for the power sector is based on the 2021 AEO Reference Case, for which generating capacity, power plant dispatch, fuel consumption, generation cost and average consumer electricity prices by sector are reported. The power sector model used for this study will reproduce the AEO Reference Case results if the inputs for electricity demand, generation capital and O&M cost, fuel prices and cost of carbon mitigation are left at AEO Reference Case values. The Alternative Cases for the power sector are produced using this model by:

- Adding demand for electricity from electrification in the residential, commercial, industrial and transportation sectors.
- Introducing annual values for cost of carbon mitigation in units of $/metric tons of CO2e.

Other inputs to the AEO Reference Case including generation capital and O&M cost and fuel prices are not changed. The power sector model does not change generating capacity and dispatch for nuclear and hydro power but does recalculate generation capacity and dispatch for other types of generation. The methodologies and data used to analyze the power sector are discussed further below.

4.1.2 Historical Hourly Profiles for Demand and Generation

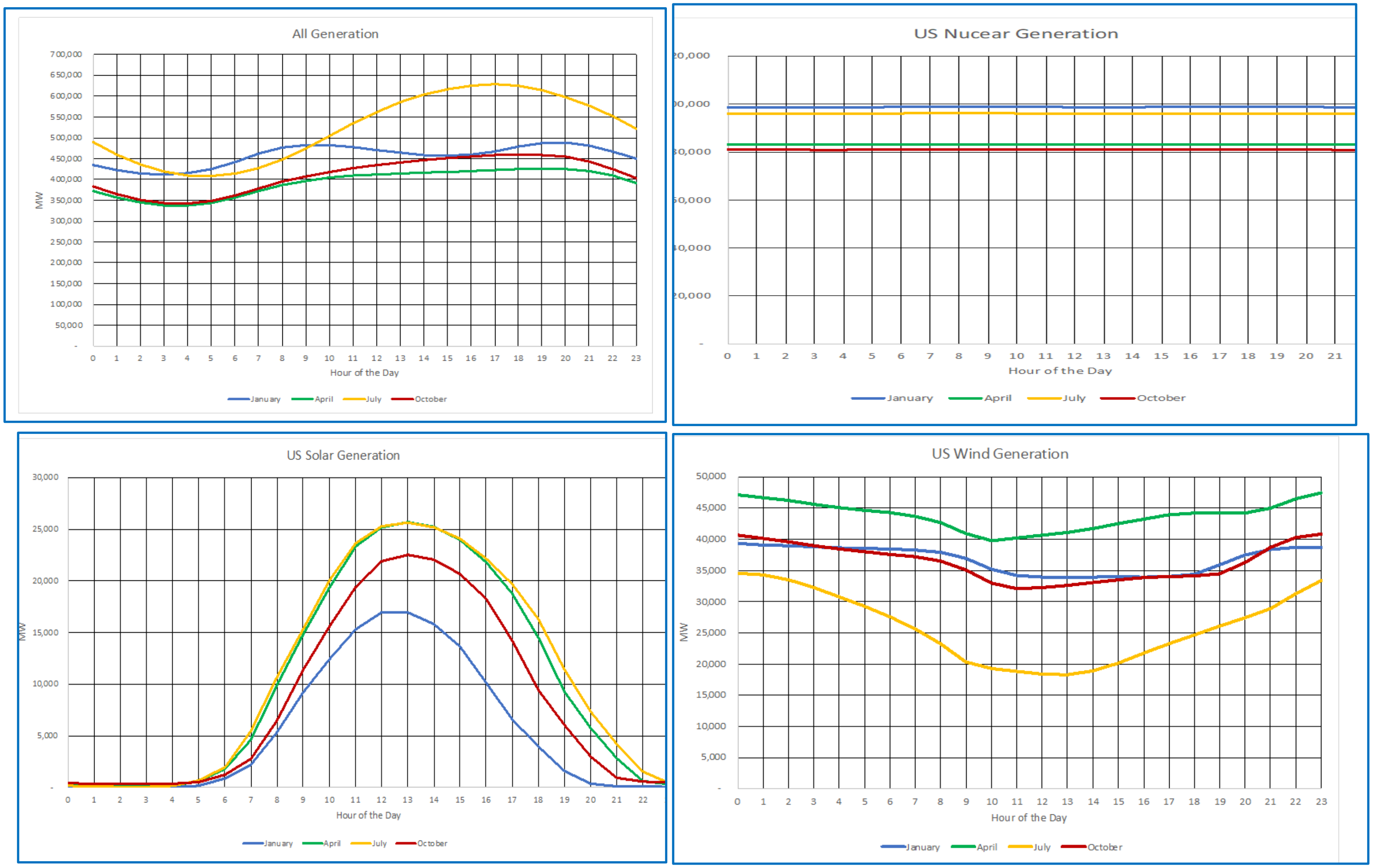
The model uses iterative processes and optimization to find an approximately optimum solution for capacity and "hourly" dispatch at a national level. Patterns for electricity supply and demand are represented for 24 hours in each day for weekdays and weekends each month. In other words, there are 24 x 2 x 12 = 576 hourly periods in a year. The model solves for the years 2025, 2030, 2035, 2040, 2045 and 2050.

Hourly electricity demand profiles for the Reference Case (that is, before electrification) are based on historical total generation data collected by EIA from the ISOs/RTOs. These generation data (which are presented by EIA in terms of eastern time zone hour of the day) have been “time shifted” so that the model’s “noon” and “midnight” represent an aggregation of “noons” and “midnights” in each US time zone. Hourly patterns for generation from solar, wind, hydro and nuclear are aggregated in the same manner to get the relative values for the 576 model hours. (See Exhibit 31.) Such time shifting produces more logical-looking patterns where, for example, solar generation is roughly symmetric around the noon-1 PM period.

Incremental demands for electricity in each sector are computed in the end use models. For the residential, commercial, and industrial sectors, these incremental demands are aggregated into space heating and non-space heating components. (See Exhibit 32 for examples of hourly patterns.) For light duty and heavy-duty vehicles, the electrification total TWh come in from the end-use models and are broken out into “fixed” versus “flexible” components based on user inputs for the power model case being run. The recharging pattern among the 576 model hours for the fixed portion is specified separately for light duty vehicles (LDVs) and for medium and heavy-duty vehicles (MDVs and HDVs).[13] The flexible portion of recharging is computed in each of the 24 modeled days (weekdays for 12 months plus weekends for 12 months = 24 modeled days). The logic for flexible recharging is to shift recharging to the hours that will minimize and flatten the dispatch of fossil energy within the day. This will reduce the need for fossil generation capacity. The cases shown in this report all assume that the portion of vehicle recharging that is flexible will grow overtime and by 2050 will reach 75% for LDV and 50% for HDV.

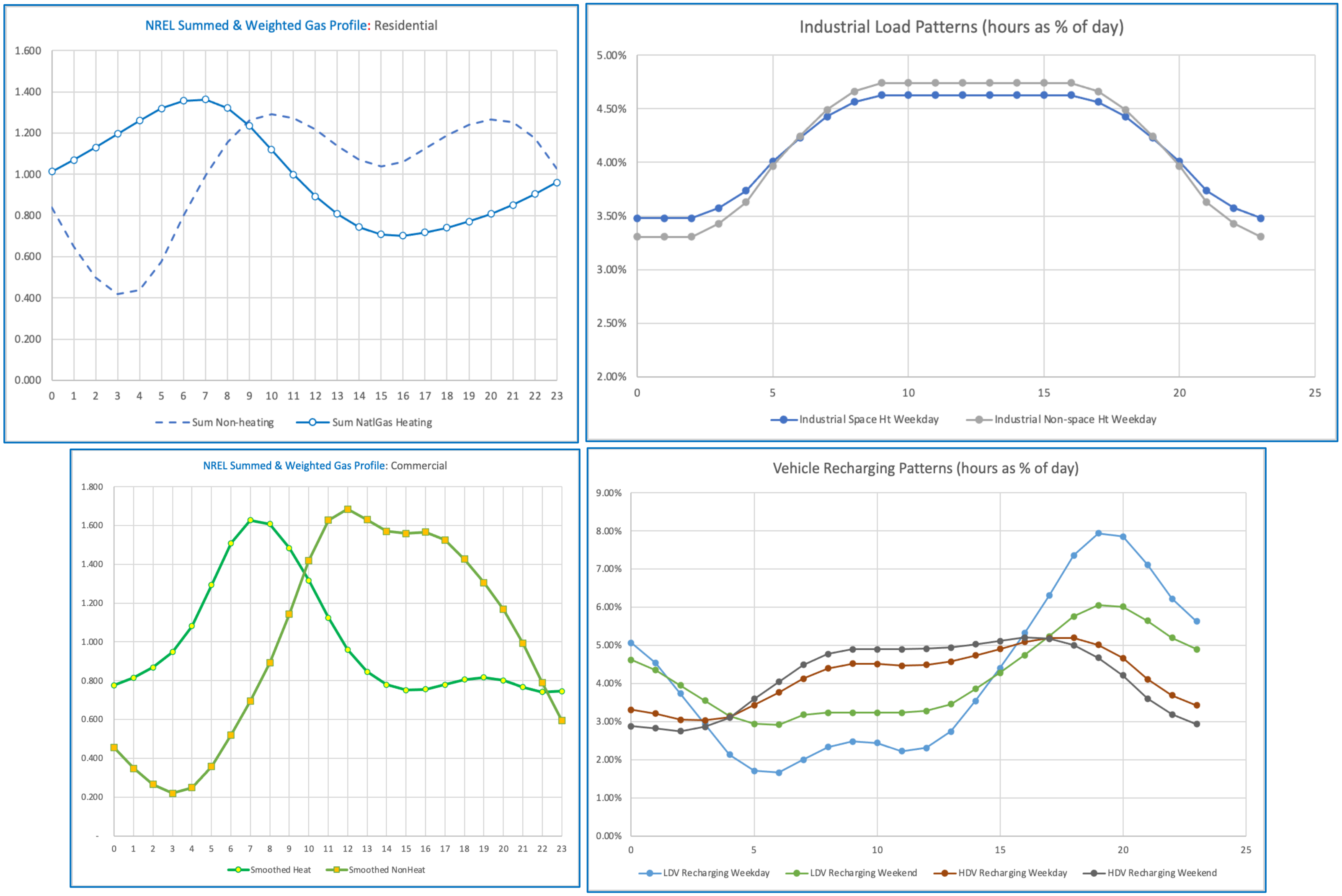
[13] Light-duty vehicles include cars, vans, SUVs, and pickup trucks. Medium-duty vehicles are smaller buses and trucks with gross vehicle weight ratings (GVWR) typically defined as ranging from 6,000 or 8,500 pounds up to 14,000 pounds. Heavy-duty vehicles includes large trucks and buses with GVWR above 14,000 pounds.

Exhibit 31: Hourly Profiles for Electricity Generation



Source: Average hourly generation over several years compiled by EIA from ISOs/RTOs historical data.

Exhibit 32: Examples of Hourly Profiles for Incremental Electrification Loads



Source: ICF estimate derived from NREL residential and commercial building simulations for various states and EPRI industrial electricity consumption surveys. These patterns are applied to monthly consumption which varies for heating loads based on heating degree days. Vehicle recharging patterns are ICF assumptions and reflect "consumer convenience" patterns before load management programs shift recharging to hours with surplus renewables generation. The modelling results presented in this report assume that 75% of LDV recharging and 50% of HDV will participate in load shifting programs by 2050.

4.1.3 Solution Method for Power Sector

The overall solution method for the model is to minimize each year's generation costs by finding the best values for three unknowns:

- Additional solar capacity (beyond the AEO forecast)
- Additional wind capacity (beyond the AEO forecast)
- The maximum hourly dispatch of fossil needed to fill the gaps between load and non-fossil generation.

This is done iteratively each year as the model adjusts certain parameters that determine the hourly demand patterns (that is, time shifting for vehicle recharging) and the need for capacity to meet reserve margin. The objective is to minimize costs while meeting loads for each model period and maintaining the target reserve margin.

Generation of nuclear and hydro are fixed to the AEO Reference Case values for each year and their hourly levels are fixed to the historical patterns. For any given level of wind and solar capacity, their annual generation is determined by the AEO's annual capacity factors and their hourly patterns are determined by the historical solar/wind hourly profiles. Therefore, as the model's optimization process tests alternative values of solar and wind capacity, the model has the hourly generation of all sources except for fossil (and any electricity storage). For the first pass each year, the model assumes all vehicle recharging is on a fixed profile so that all electricity demand is set for each hour. In subsequent passes the recharging patterns are shifted to flatten fossil generation as much as possible within each model day. This minimizes the overall need for fossil generation.

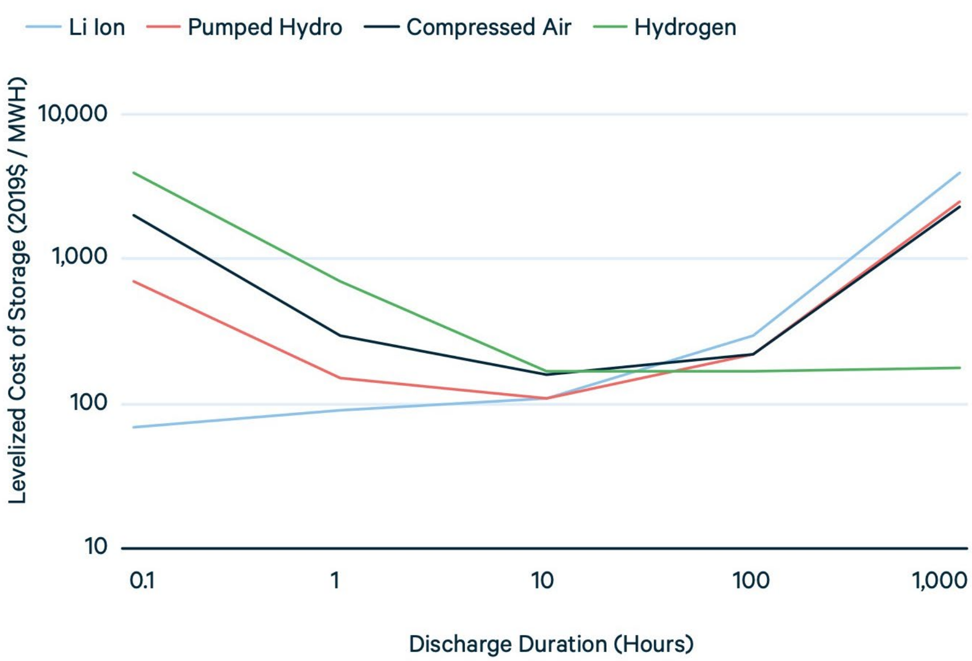
4.1.4 The Use of Electricity Storage to Balance Electricity Supply and Demand

The model's solution process simultaneously looks for the best values for additional wind capacity, additional solar capacity, and peak hour generation from fossil. It would have been possible to solve the model by assuming that the maximum hourly fossil generation would be equal to the largest hourly gap defined as load minus non-fossil generation. With such a solution there would be no need for electric storage discharge since the sum of non-fossil and fossil generation would always be the equal to or exceed loads. However, the model does not do this, but rather (when economic) allows the maximum fossil generation to be lower than the gap with difference being made up by electric storage withdrawals.

Generation can exceed loads when non-dispatchable/fixed hourly generation sources are greater than loads (and fossil generation is zero). When such "excess electricity" occurs, the model classifies it as "storage charging/curtailments/other uses." Depending on how the model is run and economics under a modelling scenario, such excess electricity might be stored and then discharged whenever load exceeds sum of nuclear + hydro + solar + fossil generation. Alternatively, this excess electricity can be thought of as being curtailed or used for some other purpose such as making hydrogen in electrolyzers.

When excess electricity is stored and then discharged, the sum of discharged electricity measured in MWh must be equal to annual MWh charge * (1-Losses). Losses for short-term storage (charging and discharging occurring in the same day or week) using batteries is modeled as having a 10% loss factor. Long-term storage (charging during spring and fall months and discharging during winter and peak summer hours) would have a loss factor of 55% if the electricity were converted to hydrogen, stored underground and then made back into electricity in a combined cycle power plant. With such a large loss factor and high capital costs for long-term electricity storage, the modelling results shows that it will not be economic to store electricity for long periods of time. (See Exhibit 33 for IEA economic analysis on alternative electricity storage options and Exhibit 34 for details of long-term electricity storage cost using underground hydrogen storage caverns.) With forecasted marginal generation cost of renewables being $49.50 to $33.50/MWh over the 2022 to 2050 period and long-term storage costs being approximately $200/MWh, it would be cheaper to build more renewables to meet winter and summer peak loads, even if the resulting excess electricity were curtailed (that is, the excess electricity is assigned a zero value).[14] Such excess electricity is assumed in the modelling to be available to make hydrogen.

Exhibit 33: Economics of Various Electricity Storage Technologies



Source: IEA 2019.
Note: Levelized costs of storage reflect an input electricity price of $50/MWh as well as other assumptions from IEA (2019).

[14] For example, if the renewable electricity were used only one-third of the time it is available and curtailed two-thirds of the time, its cost could triple, increasing to $150 to $100/MWh, but still would be cheaper than long-term storage. The amount of potential curtailment forecasted in the modelling conducted for this report (if hydrogen were not made from the excess electricity) is much less than this. For example, the expected excess supply in 2050 as a percent of solar and wind generation is as high as 13% in the High Even Case (see Exhibit 67) before considering short-term electricity storage and 6.5% after accounting for battery charging for short-term storage.

Exhibit 34: Long-term Electric Storage Cost Details

Long-term Electricity Storage using Underground Hydrogen Storage (UHS) with Combined Cycle (CC) Generation (100 MW, 2,000 hours per year discharge)							
	Capex ($mm)	Capex ($/kW discharge)	Annual Capital $/yr.	Fixed O&M $/yr.	Var. O&M $/yr.	Total Ann. w/o elec. $/yr.	$/MWh discharge
Electrolyser	$110.0	$1,100	$11,691,624	$3,198,757	$214,736	$15,105,117	$75.53
Pipeline Electrolyser to UHS	$30.0	$300	$2,295,010	$750,000		$3,045,010	$15.23
Underground Hydrogen Storage	$80.8	$808	$6,041,367	$3,125,562	$161,526	$9,328,456	$46.64
Pipeline UHS to Generator	$30.0	$300	$2,295,010	$750,000		$3,045,010	$15.23
Electricity Generator (CC)	$108.4	$1,084	$8,188,077	$1,466,964	$530,604	$10,185,645	$50.93
Total	$359.2	**$3,592**	$30,511,088	$9,291,283	$906,866	$40,709,237	$203.55
		$/MWh discharge	$152.56	$46.46	$4.53	$203.55	

Source: ICF estimates. Costs do not include the cost of the electricity used to make the hydrogen. If electricity going into storage was priced at $20/MWh and round-trip losses were 55%, that would make total cost for the discharged electricity $20/ (1-.55) + 203.55 = $247.99/MWh

4.1.5 Minimum Amount of Short-term Storage

Since the model employs "smooth" national average demand and supply hourly profiles and does not model weather and mechanical disruptions, the model understates the need for short-term storage. New solar and wind projects often have storage included in the projects design to help smooth out weather variations and shift sales to higher priced hours of the day. Therefore, the current model provides for a minimum amount of short-term storage that will be employed even if the optimization process (based on "smooth" supply and demand profiles) says storage is not needed. The model results reported in here assume that solar and wind projects added by the model in excess of the AEO forecast will include storage withdrawal capacity equal to 16.7% of their nominal generating capacity and that in the long-run withdrawals from storage will be 5.91% of solar and wind generation.

These factors were computed from an EIA design and cost example where a 150 MW solar project was paired with 50 MW battery discharge capacity and 4 hours of battery storage capacity (i.e., 50 MW x 4 hours = 200 MWh of battery capacity.) The modelling factors (16.7% of capacity and 5.91% of generation) were computed assume such a storage configuration will apply to 50% of new solar and wind projects (beyond the AEO levels) and that the capacity will be used at a 50% utilization rate. The result of adding 16.7% of incremental solar and wind capacity as battery storage results in short-term storage capacity equal to about 11% of total 2050 solar and wind capacity.

The amount of short-term electricity storage has little effect on the overall generation and fuel use result because whatever goes into storage (less a 10% loss) comes out again. The biggest effects are that (a) the capital cost for the storage is added to the cost of service and (b) less fossil fuel capacity is needed to meet peaks. The second effect stems from the fact that the storage withdrawal capacity is assumed to have a contribution to peak factor of 0.85, so having more storage reduces the need to keep fossil generating capacity to meet reserves requirements. The model has a reserve margin target (15%) and uses the "contribution to peak" values for each fuel to determine how much of each type of capacity to counted toward achieving that reserve margin. The net result is that the capacity utilization factor for fossil (and hydrogen) is driven below 15% by 2050 because keeping fossil plants is the cheapest way to provide reserve margin.

4.1.6 Fossil Fuel and Hydrogen Mix

The AEO's capacity and generation for hydro, nuclear and other/imports are not changed by the power sector model in creating the Alternative Cases. Incremental solar + wind capacity is added by the model in the process described above, whereby the ratio of solar versus wind capacity can be different from the AEO.

The model also adjusts the total fossil generation capacity and dispatches it by hour to meet load. Both the capacity mix and dispatch for fossil capacity is determined using a market share equation. (The same market share methodology as used in the end-use models.) For capacity decisions, the market share is computed using the $/MWh levelized full cost of production (sum of capital, fixed operating, and maintenance costs (FOM), variable operating and maintenance costs (VOM), fuel, carbon mitigation cost). For the dispatch decision, the $/MWh dispatch costs (VOM, fuel, carbon mitigation cost) is used. The market share is computed for each option as its cost raised to the power of -7.0 divided by the sum of each options cost raised to -7.0. When a cost of carbon mitigation is assumed, this market methodology shifts capacity and generation toward natural gas with CCS and to a lesser extent hydrogen and reduces fossil use overall all. The capital cost, O&M costs and heat rates assumed in this competition are derived largely from the AEO. The AEO does not have a hydrogen fueled power plant, but ICF has assumed such plants will have costs and heat rates that are the same as natural gas.

4.2 Industrial Sector

As the sector which includes the most existing uses of hydrogen, industrial consumption is a strong candidate for hydrogen market growth. Hydrogen is currently used as a process feedstock for hydrotreating and hydrocracking in refineries (to remove sulfur, break hydrocarbon chains, etc.), in the petrochemical industry to make basic chemicals (chiefly ammonia and methanol) and hundreds of derivatives, and in the steel industry.

Potential new markets for hydrogen would include expanding the application of the direct reduced iron (DRI) process in the iron and steel industry to use hydrogen instead of carbon (coke) as a reducing agent to remove oxygen from iron ore (iron oxide). DRI now is sometimes used in mini mills to maintain the desired chemistry of the scrap steel but is usually too expensive to use to make raw pig iron (mostly made in basic oxygen furnaces using coke). Other options might also see wider application of hydrogen to synthesize materials, chemicals, and fuels (methane, methanol) driven by desire to utilize captured carbon or to obtain a more useable fuel form (for instance through methanation or the creation of ammonia for transportation fuels). Hydrogen could also be used as an alternative fuel in general heating applications. Lime and cement kilns, medium and high temperature process heating, and space heating applications could be supported by hydrogen fuel use given certain pricing scenarios.

Demand for these applications is expected to increase in the future, creating need for additional volumes of fuels. ICF reviewed the economics of utilizing the existing and alternative fuels in each industrial application including the capital conversion and maintenance costs required. ICF quantified volumes as future market potential where the use of hydrogen becomes more cost competitive over time.

4.3 Residential Sector

The residential energy sector is comprised of fuels used to provide water heating, cooking, clothes drying, and residential space heating and cooling. These applications are typically supported by utilizing natural gas or electricity. Providing alternative fuel options for each technology requires a consideration on pricing, applicability, and available infrastructure. Conversion to hydrogen fuels can be done through various means, with varying investment requirements. One potential option would be increased hydrogen blending. Local distribution companies in the US and Europe are considering blending natural gas with up to 5-20% hydrogen by volume. They hope to continue to utilize existing natural gas infrastructure without additional investment or detrimental effect to natural gas consumers. Utilizing pure hydrogen as fuel for heating applications would require more investment, both to construct adequate infrastructure and to convert or install new equipment with the appropriate configuration to utilize the fuel.

To analyze this sector, ICF first utilized the EIA AEO for the expected demand of fuels in each application in future years. To quantify the market potential applicability of hydrogen, ICF determined applicable costs associated with various processes utilizing different fuels. This included pro forma examples of each application and market share, including the cost of heat pumps, air conditioning units, and furnaces. ICF assumed a certain amount of conversion to each fuel when costs are more competitive, including additional hydrogen demand in applications with favorable economics.

4.4 Commercial Sector

The commercial sector has many similarities to the residential sector, with end use applications including providing building space heating and cooling, water heating, and cooking. Similar options for hydrogen utilizations also exist in this sector, including additional hydrogen blending and conversion to technologies which support 100% hydrogen fuel use. ICF also utilized the EIA AEO for expected future volumes of all fuels in the applications in this sector and applied capital and maintenance cost assumptions to quantify the market potential for additional hydrogen use in future years.

4.5 Transportation Sector

The transportation sector encompasses all modes of transit, including for both passenger and freight. This sector represents a source of emissions which is difficult to decarbonize, generating significant amounts of CO_2 emissions from combusted fuel. Hydrogen can serve as a potential fuel option to reduce these impacts as it creates no emissions through traditional combustion. The technology used to utilize hydrogen as a transportation fuel in vehicles is via an onboard proton-exchange membrane fuel cell system. This system converts gaseous or liquid hydrogen to electricity to power vehicle drivetrain components.

To quantify the potential for hydrogen use as a fuel in the transportation sector, ICF modeled the cost of ownership for a vehicle in each market utilizing different fuel systems. The cost comparison includes considerations relevant to each market such as ease of use, availability/ease of refueling, and performance characteristics. All costs were calculated a related “service” basis, meaning a representative unit associated with that transportation market’s application. Each market is described in more detail in the following sections.

4.5.1 On Road Vehicles

The on-road sector is comprised of light duty, medium duty, and heavy-duty vehicles. These markets represent vehicle types which are generally defined by their gross vehicle weight rating (GVWR). Light duty vehicles include 4-door sedans and standard automobiles, passenger pick-up trucks, and motorcycles. Medium duty refers to heavier vehicle options such as parcel trucks or commercial box trucks. Heavy duty vehicles include medium and long-haul truck and trailers.

For each on-road submarket, ICF determined the cost of ownership for a newly purchased, standard size vehicle within that class. All submarket vehicle configurations were compared on a per-mile basis, represented by the total cost over the distance traveled in the first purchase life (typically 5 years). Costs were determined for vehicles utilizing various powertrains, including a traditional fossil fuel combustion engine, compressed natural gas (CNG), battery powered electric vehicle (BEV), hybrid electric vehicle (HEV), plug-in hybrid (PHEV), and a hydrogen powered fuel-cell electric vehicle (FCEV).

Capital, maintenance, and fuel costs were determined for all vehicle types by combining assumptions from sources including National Renewable Energy Laboratory (NREL)[15], International Energy Administration (IEA)[16], EIA, and market research. For on-road fuel costs, ICF primarily relied on EIA AEO transportation prices.[17] For electric vehicles, light duty vehicles can be charged at home using smaller, less efficient plugs, while heavy duty vehicles are typically charged with more efficient chargers and when not in service. These configurations amount to different costs per-kWh. This study utilized assumptions on the amount of time spent utilizing each type of charger across both vehicle types to arrive at weighted average price used for all fuel costs. Exhibit 35 shows the assumed retail cost of electricity for each vehicle type over time.

Exhibit 35: Transportation Electric Recharging Costs (2020$/kWh)

Vehicle Recharging Costs in 2020$/kWh to be used in vehicle competition models								
		2020	2025	2030	2035	2040	2045	2050
Ref	LDV	$0.192	$0.193	$0.193	$0.193	$0.190	$0.188	$0.184
Ref	HDV	$0.214	$0.213	$0.212	$0.211	$0.208	$0.205	$0.200
Alt High CoCM	LDV	$0.192	$0.206	$0.215	$0.216	$0.214	$0.210	$0.203
Alt High CoCM	HDV	$0.214	$0.226	$0.234	$0.234	$0.231	$0.227	$0.219
Alt Low CoCM	LDV	$0.192	$0.202	$0.210	$0.211	$0.209	$0.206	$0.199
Alt Low CoCM	HDV	$0.214	$0.222	$0.229	$0.230	$0.227	$0.223	$0.215
Alt HiCoCM BH dis	LDV	$0.192	$0.206	$0.214	$0.216	$0.214	$0.211	$0.204
Alt HiCoCM BH dis	HDV	$0.214	$0.226	$0.233	$0.234	$0.231	$0.228	$0.220

[15] National Renewable Energy Laboratory (NREL), Spatial and Temporal Analysis of the Total Cost of Ownership for Class 8 Tractors and Class 4 Parcel Delivery Trucks; September 2021
[16] International Information Agency (IEA), The Future of Hydrogen; June 2019
[17] Energy Information Administration (EIA), 2021 Annual Energy Outlook

Certain fuel types (such as CNG or hydrogen) have significantly less refueling stations available for public transit. This requires owners of vehicles which utilize these fuel types to travel further and longer each time they need to refuel. Also, electric and other alternative fuel vehicles take longer to “refuel” than traditional vehicles. Therefore, ICF included in the economic competition models the expected costs associated the time spent searching for refueling stations and the time spent refueling.

When purchasing a vehicle, buyers also have other considerations such as the amount of available usable space within the passenger cab. To quantify this concept, ICF determined the size and weight of the equipment used in each powertrain option including the engine, electric motor, battery, and fuel storage system to determine “penalties” in the form of costs for alternative vehicles versus traditional combustion engines. The penalties associated with the alternative fuel equipment vary and sometimes also create a negative (i.e., beneficial) cost when weight or sizing decreases versus traditional fossil fuel technology.

4.5.2 Off Road Vehicles

ICF modeled off-road vehicle types as described below.

4.5.2.1 Aircraft

ICF modeled costs to determine the viability of liquid hydrogen as fuel in air travel. ICF determined costs for a 165 passenger, domestic aircraft utilizing traditional jet fuel, liquid hydrogen, and synthetic fuel produced via the Fischer-Tropsch process. All aircraft types were compared on a total cost per passenger seat-mile basis. Capital and maintenance costs were determined for each aircraft type by utilizing a study produced by McKinsey.[18] Fuel costs were quantified by applying a price of fuel to the average fuel efficiency of narrow body aircraft in the US.[19]

4.5.2.2 Waterborne Transit

To determine the viability of liquid hydrogen as a fuel in waterborne shipping, ICF calculated the cost of a panamax size container ship utilizing low sulfur marine gas oil, residual fuel oil, liquid hydrogen, and liquefied natural gas (LNG). Each type of containership was compared on a per twenty-foot equivalent unit (TEU)-nautical mile basis. Capital and operating costs were determined for each vessel based on various assumptions on sizing and average trip characteristics. Fuel costs were derived through a combination of ICF analysis and assumptions from an Argonne study of hydrogen use in off-road transportation.[20]

4.5.2.3 Rail Transportation

ICF determined the potential for hydrogen transportation fuel adoption across three types of rail travel: freight transportation, regional passenger transportation, and switcher trains. Freight rail transportation delivers goods and cargo over long distances, while switcher trains can move cars containing goods within a rail yard. Regional trains offer alternative transportation options for passengers to travel between metropolitan areas.

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[18] Hydrogen-Powered Aviation; McKinsey, May 2020
[19] Energy Information Administration (EIA), 2021 Annual Energy Outlook
[20] Rail and Maritime Metrics, US DOE Hydrogen and Fuel Cells Program; Argonne National Laboratory

ICF calculated the cost of various transportation fuel applications within each of these submarkets, including diesel-powered, electric-powered, liquid hydrogen (via proton-exchange membrane, LH2-PEM), and liquified natural gas (LNG) powered rail cars. Total costs were compared on a per-kWh of operating hour(s) basis. Capital and operating costs were determined for each rail type based on assumptions from Argonne.[20] Fuel costs were derived through a combination of ICF analysis and assumptions from the same study. The ratio of efficiencies between fuel types was assumed to be comparable to heavy duty on-road vehicles.

For electric-powered freight railcar options, ICF also included the cost to install electric infrastructure in the ownership comparison. Because freight rails are not fully electrified, choosing this alternative technology requires additional investment. This amounts to a cost of between $2 and $5 million dollars per route-mile.[21]

4.5.3 Additional Transportation Fuel Cost Considerations

For most fuel costs in the above sectors, ICF utilized transportation pricing from the EIA AEO. However, for compressed natural gas (CNG) and liquefied natural gas (LNG) ICF first utilized natural gas pricing to industrial customers and determined additional costs related to the transportation of those fuels to local retail stations. For delivered CNG prices, ICF determined additional costs for natural gas LDC pipeline transport to a refueling station from industrial customers, as well as costs for the compression to convert to CNG. For LNG, ICF applied a liquefaction cost to the industrial natural gas price, as well as a cost of truck delivery to the refueling station from the industrial customer. ICF also included a retail markup which reflects the cost at the pump for on-road vehicles, or at the fueling location for each off-road option.

For hydrogen-powered vehicle refueling station costs, ICF assumed hydrogen was delivered as a liquid before regasification at the pump. Therefore, the price used in fuel cost calculations includes the composite wholesale hydrogen price, a cost to pipeline the gaseous hydrogen from the production location to the city gate, the liquefaction fee, the transportation of liquid hydrogen to the refueling station via truck delivery, and onsite regasification at the pump. The hydrogen price used in this sector of the analysis also includes retail markup, which reflects separate pricing for on-road vehicle and off-road options.

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[21] http://reasonrail.blogspot.com/2015/09/a-cost-to-benefit-analysis-of-railroad.html

Exhibit 36: Potential Costs for Transportation Sector Compression and Refueling ($/MMBtu HHV)

Related Product	Cost Parameter	2020	2025	2030	2035	2040	2045	2050
CNG	Industry NG Price ($/MMBtu)	$3.06	$3.78	$4.20	$4.37	$4.36	$4.32	$4.48
CNG	LDC Markup Delivered to Gas Station ($/MMBtu)	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00
CNG	Wholesale Conversion to CNG ($/MMBtu)	$1.11	$1.09	$1.06	$1.03	$1.00	$0.96	$0.93
CNG	Retail Markup for CNG ($/MMBtu)	$2.95	$2.94	$2.94	$2.94	$2.93	$2.93	$2.93
CNG	Total Cost ($/MMBtu)	$11.11	$11.81	$12.19	$12.34	$12.30	$12.22	$12.34
LNG	Industry NG Price ($/MMBtu)	$3.06	$3.78	$4.20	$4.37	$4.36	$4.32	$4.48
LNG	Wholesale Conversion to LNG ($/MMBtu)	$2.94	$2.89	$2.81	$2.74	$2.65	$2.57	$2.49
LNG	LNG Truck Delivery to Gas Station ($/MMBtu)	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.75
LNG	Cars and Trucks Retail Markup for LNG ($/MMBtu)	$3.98	$3.98	$3.98	$3.97	$3.97	$3.97	$3.96
LNG	Ships, Rail, and Planes Retail Markup for LNG ($/MMBtu)	$1.00	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99
LNG	Total Cars and Trucks Cost ($/MMBtu)	$10.72	$11.38	$11.73	$11.83	$11.73	$11.61	$11.68
LNG	Total Ships, Rail, and Planes Cost ($/MMBtu)	$7.74	$8.40	$8.74	$8.85	$8.76	$8.63	$8.70
H2/LH2	Industry H2 Price ($/MMBtu)	$10.57	$10.57	$11.03	$11.22	$11.14	$11.06	$11.18
H2/LH2	Wholesale Conversion to liquid H2 ($/MMBtu)	$14.24	$13.98	$13.61	$13.27	$12.84	$12.43	$12.03
H2/LH2	Transportation from Liquefaction Plant to Refueling Station ($/MMBtu)	$1.38	$1.39	$1.39	$1.39	$1.39	$1.40	$1.40
H2/LH2	Cars and Trucks Retail Markup for H2 ($/MMBtu)	$5.91	$5.83	$5.81	$5.80	$5.76	$5.72	$5.69
H2/LH2	Ships, Rail, and Planes Retail Markup for H2 ($/MMBtu)	$1.48	$1.46	$1.45	$1.45	$1.44	$1.43	$1.42
H2/LH2	Total Cars and Trucks Cost ($/MMBtu)	$32.10	$31.77	$31.84	$31.69	$31.15	$30.61	$30.30
H2/LH2	Total Ships, Rail, and Planes Cost ($/MMBtu)	$27.67	$27.39	$27.48	$27.34	$26.82	$26.32	$26.04

Note: These potential costs are for the AEO Reference Case and are based on the commodity costs of that case.

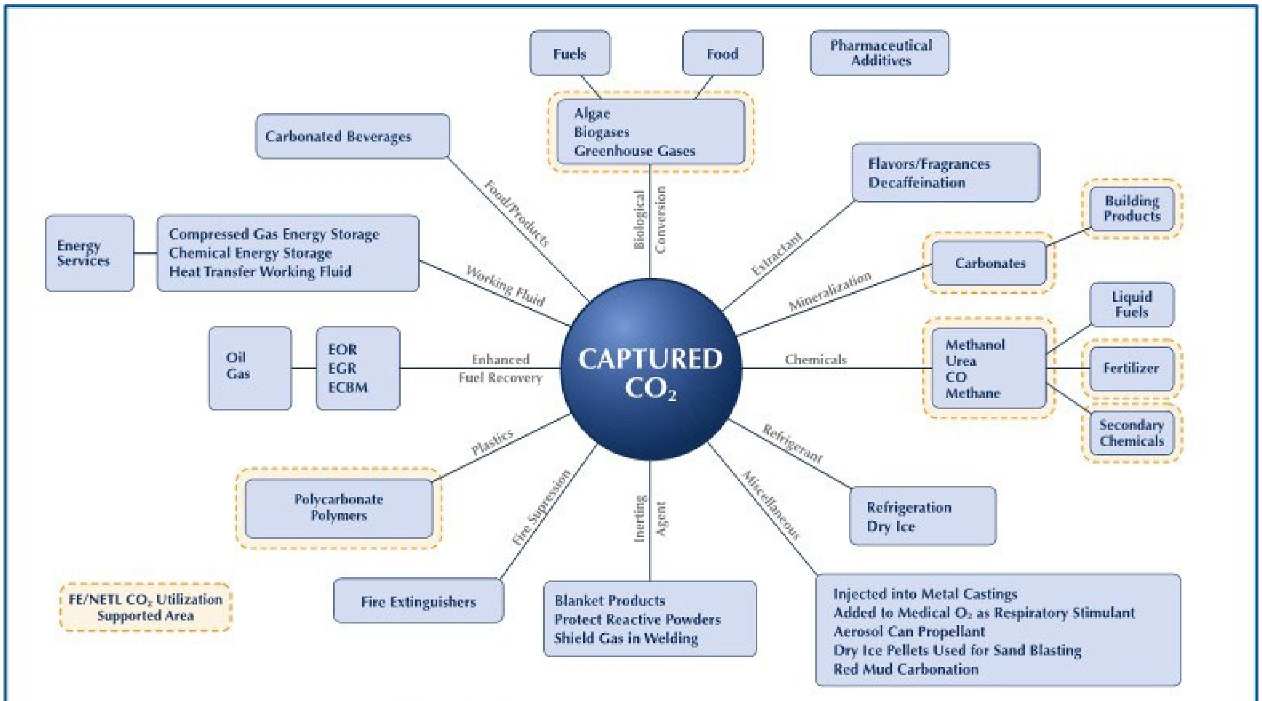
5. Carbon Capture, Use, and Storage

Carbon capture, use, and storage (CCUS) begins by capturing the CO_2 from several types of sources including:

- Flue gases of power plants and industrial facilities burning fossil fuels or biomass/biofuel,
- Process gas streams from industrial facilities (natural gas processing plants, ammonia plants, petroleum refineries, steel mills, cement plants, ethanol plants, etc.)
- Blue hydrogen plants using fossil fuels or biomass as feedstocks
- Air (through the application of direct air capture).

After capturing CO_2 from one of these sources, the next steps are to purify and dehydrate the CO_2, compress it for transportation and then either (a) inject it 800 meters or more underground into an appropriate geological storage site, where it is trapped and permanently stored in porous rock or (b) utilize it in one or more of the ways listed in Exhibit 37.

Exhibit 37: Options for CO_2 Utilization



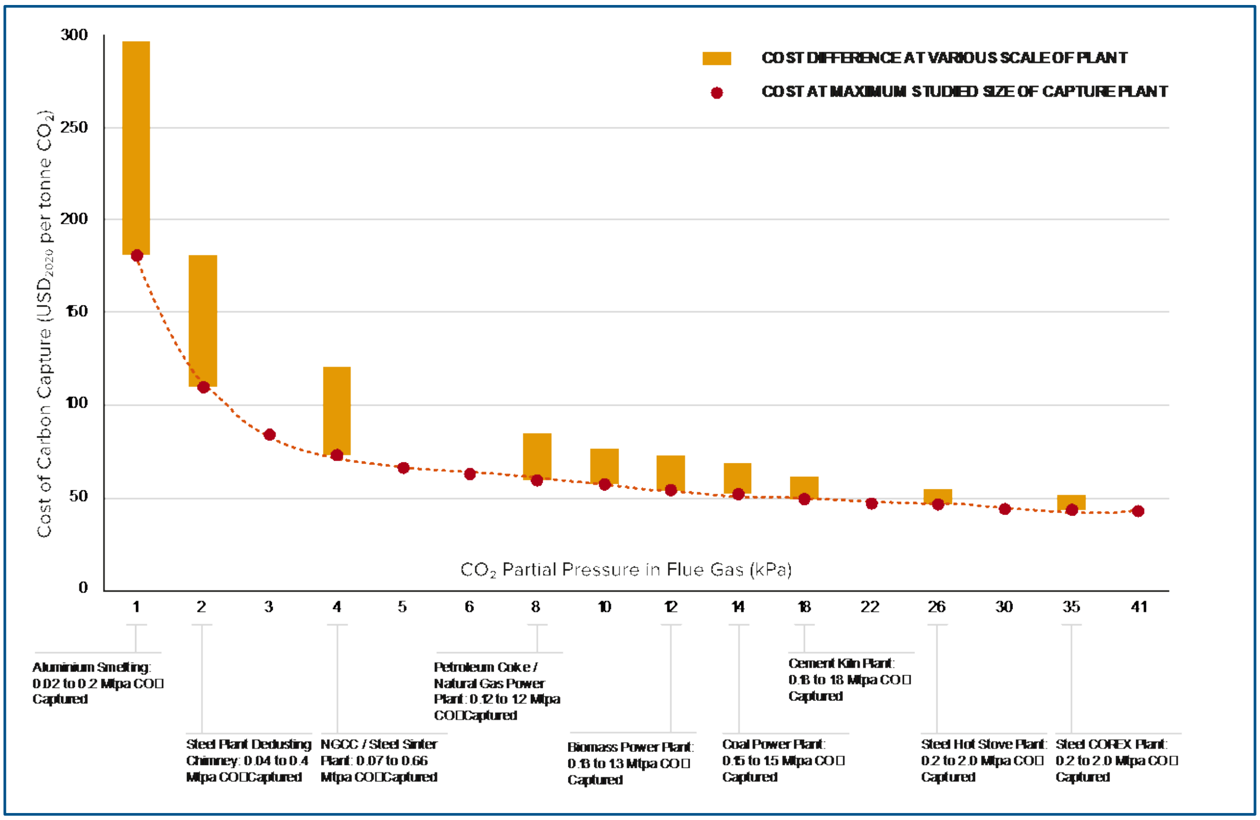
Source: National Energy Technology Laboratory www.netl.doe.gov

5.1 Carbon Capture Costs

The economic modeling of carbon capture costs for this study was largely adapted from the Global CCS Institute's March 2021 report entitled "Technology Readiness and Costs of CCS." Capture costs were modelled as largely a function of CO_2 partial pressure[22] and the volume of CO_2 being captured. The GCCSI cost estimate was based on an aqueous solution of 30% by weight of monoethanolamine (MEA). MEA is a chemical solvent that has wide commercial availability and performs well over a range of CO_2 partial pressures.

The cost of capturing CO_2 as calculated by GCCSI is shown in Exhibit 38 in units of dollars per metric ton of captured CO_2. These costs include annualized capital costs, operating and maintenance cost, costs for consumables, and energy costs. The exhibit indicates that high-volume gas streams with high CO_2 partial pressures can be captured at a cost of under $50/MT of CO_2, while gas stream gas with lower partial pressures and/or smaller stream volumes will have higher capture costs of $50 to $100/MT of CO_2 or more.

Exhibit 38: CO_2 Capture Cost from Industrial and Power Plant Flue Gas and Process Gas Streams



Source: GCCSI. Costs are for capture only and exclude dehydration and compression, transportation, and geologic storage.

The costs shown above are only to capture the CO_2 and do not include costs for dehydration, compression, transport, and storage. GCCSI also estimated these as shown below in Exhibit

[22] Partial pressure is measured as the percent concentration of CO_2 (or any other gas) in a gas stream times the pressure of that gas stream. A gas stream with high partial pressure of CO_2 means that it will be easier and less expensive to capture the CO_2 because less external energy is required compared to streams with lower CO_2 concentrations and/or lower pressures.

39. Costs after the capture step will add an additional $16 to $69 per metric ton of stored carbon dioxide. This brings total CCS cost for many industrial and power combustion flue gas streams and industrial process gas streams to $60 to $150 per MT. As shown earlier, cost of decarbonizing natural gas via blue hydrogen is about $140 to $160/MT CO_2e delivered to industrial and power plant consumers. This suggests that where CCS is feasible for a particular industrial facility or power plant, CCS might be selected instead of hydrogen in large facilities. Therefore, the best industrial markets for hydrogen would be among facilities far from geologic storage sites, with many scattered and low-volume, low-pressure flues and process gas streams and limited options for electrification.

Exhibit 39: CO_2 Compression, Dehydration, Transport, and Storage Costs as Estimated by GCCSI

CCS Costs to be Added to Capture Costs ($/metric ton)			
Step	Low	High	Middle
Compression & Dehydration	$10.00	$22.50	$16.25
Pipeline Transport 300km	$2.50	$24.00	$13.25
Injection & Geologic Storage	$2.00	$18.00	$10.00
Monitoring & Verification	$2.00	$4.00	$3.00
Sum	$16.50	$68.50	$42.50
Source: GCCSI			

5.2 Geologic Storage Capacity

Reducing carbon emissions from the energy sector is likely to require large volumes of CCUS. In the three cases examined in this report, the volume of CCUS in the year 2050 ranges from 801 to 1,464 million metric tons of carbon dioxide. The Low Even Case CCUS volumes are 801 million metric tons per year by 2050 while the High Even Case results in 1,724 million metric tons of CCUS for that year. In the High Uneven Case, the use of CCUS goes up by over 60% in the industrial and power sectors due the fact that hydrogen becomes much less economic and CCUS becomes the best option. However, overall use of CCUS is only 1,464 million metric tons in 2050 because the CCUS associated with blue hydrogen declines substantially in the High Uneven Case.

Exhibit 40 shows the estimate storage capacity in the Lower 48 state sums to 8,215 billion metric tons. At the maximum CCUS projected among the three cases (1.724 billion metric tons per year – even if it were all to be stored geologically) that capacity would last for over four thousand years.

Exhibit 40: Geologic Storage Capacity by State

NATCARB US Geologic Storage Capacity Allocated to States (gigatons)

	EOR CO2 Storage	Depleted Oil Fields	Unmineable Coal	Saline Aquifers - Non Basalt	Sum of All Types
Alabama	0.07	0.02	2.98	307.34	310.41
Arizona	-	-	-	0.42	0.42
Arkansas	0.08	0.10	2.46	21.20	23.84
Atlantic Offshore	-	-	-	202.00	202.00
California Onshore	1.24	3.61	-	147.55	152.40
Colorado	0.20	2.15	0.65	131.11	134.11
Delaware	-	-	-	0.04	0.04
Florida	0.13	0.03	1.95	246.45	248.56
Georgia	-	-	0.02	148.70	148.72
Idaho	-	-	-	0.15	0.15
Illinois	0.10	0.10	2.38	80.75	83.33
Indiana	0.02	0.02	0.14	66.67	66.85
Iowa	-	-	0.01	-	0.01
Kansas	0.41	0.84	-	34.40	35.65
Kentucky	0.01	1.74	0.18	46.43	48.36
LA Onshore	1.36	4.35	12.89	734.55	753.14
LA. Offshore	1.46	12.70	-	1,240.00	1,254.16
Maryland	-	-	-	1.88	1.88
Michigan	0.08	0.18	-	45.56	45.82
Minnesota	-	-	-	-	-
Mississippi	0.13	0.32	8.46	459.15	468.06
Missouri	-	-	0.01	0.10	0.11
Montana	0.25	0.13	0.33	335.74	336.45
North Carolina	-	-	-	6.51	6.51
North Dakota	0.32	0.59	0.54	136.50	137.95
Nebraska	0.02	0.01	-	54.47	54.50
Nevada	-	-	-	-	-
New England States	-	-	-	-	-
New Jersey	-	-	-	-	-
New Mexico	0.90	8.81	0.16	129.29	139.16
New York	-	0.08	-	4.37	4.45
Ohio	-	1.08	0.12	9.91	11.11
Oklahoma	1.41	2.99	0.01	76.87	81.28
Oregon	-	-	-	33.15	33.15
Pacific Offshore	-	0.05	2.63	37.00	39.68
Pennsylvania	-	1.34	0.27	17.34	18.95
South Carolina	-	-	-	31.07	31.07
South Dakota	-	-	-	7.04	7.04
Tennessee	-	-	-	1.85	1.85
Texas Onshore	7.55	130.05	21.80	1,505.79	1,665.19
Texas Offshore	-	2.97	-	798.00	800.97
Utah	0.28	2.11	0.07	88.65	91.11
Virginia	-	0.01	0.37	0.86	1.24
Washington	-	-	0.92	175.26	176.18
West Virginia	-	9.84	0.37	11.19	21.40
Wisconsin	-	-	-	-	-
Wyoming	0.42	0.17	6.64	570.92	578.15
Lower 48 US Sum	16.45	186.38	66.36	7,946.23	8,215.41

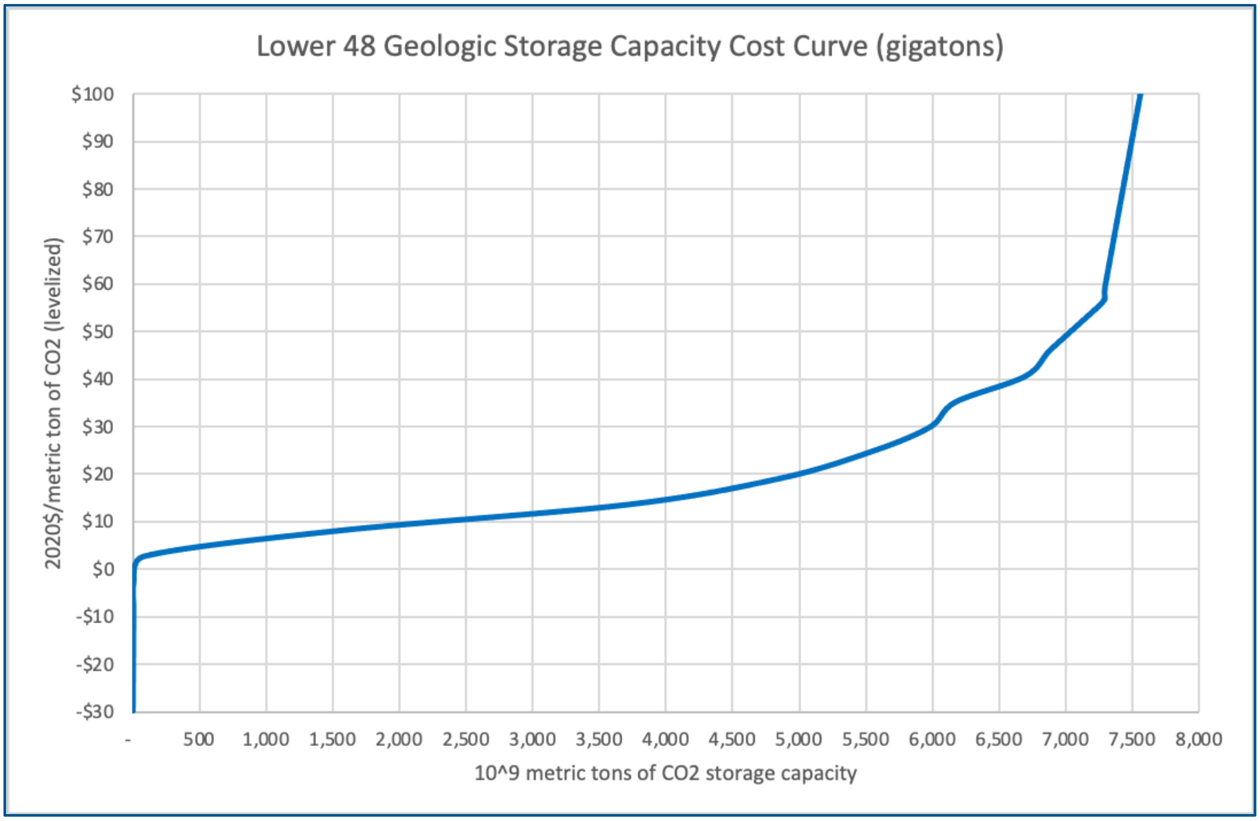
These storage capacity estimates were derived by ICF from the most recent DOE analysis of the lower-48 states CO_2 sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5."[23] The analysis of storage volumes is conducted by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The vast majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the most recent version of the Atlas, offshore storage volumes have also been broken out by DoE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF conducted a separate analysis to break out CO_2 EOR storage potential from the total potential in oil and gas reservoirs reported in NATCARB.

ICF builds onto the NATCARB assessments to include additional details needed for economic modeling such as the distribution of capacity by state, drilling depth, injectivity, etc. The outputs of the economic model are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 price points. The economic model includes 120 unit-cost elements grouped into categories such as geologic site characterization, monitoring, and injection well construction. Depending on the nature of each cost element, it is specified as cost per site, per square mile, as a function of well depth, per labor hour, or other specification. These individual cost specifications are combined to represent pro forma project-level costs. Each pro forma project has specifications for volume of CO_2 injected, depth, number of injection and monitoring wells, and other factors. Based on the timing of expenses and financial assumptions, these costs are translated in the model into levelized dollars per metric ton of CO_2 injected using standard discounted cash flow techniques.

The aggregate geologic storage cost curve for the Lower 48 is shown in Exhibit 41. The low end of the curve includes storage capacity with negative costs, representing the fact that the 16.45 billion tons of storage capacity for use in enhance oil recovery for which oil producers will be willing to pay for the CO_2. The largest portion of the curve represents saline aquifers with costs ranging from \$3 to \$20 or more per metric ton of CO_2. These are roughly in line with the GCCSI (generalized worldwide) cost estimates (for geologic storage, monitoring, and verification) that go from \$4 to \$22 per metric ton.

[23] See https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas

Exhibit 41: Geologic Storage Cost Curve



5.3 CO_2 Pipelines

ICF's costs of pipeline transportation are based on standard engineering calculations for what diameter of pipeline is needed to transport a given volume of CO_2 and certain assumptions about how CO_2 volumes from individual power plants and other sources get aggregated into larger pipelines for long-distance, inter-regional transportation. The capital cost of the CO_2 pipelines is represented in the ICF cost model in terms of dollars per inch-mile (for example $188,939 per inch-mile translates into $2.41 million per mile for a 12.75-inch diameter pipeline). The tariff rate is calculated using standard discounted cash flow techniques given these capital costs plus some assumptions about operating and maintenance costs for the CO_2 pipelines.

As shown in Exhibit 42 , total costs come to over $7 per metric ton for 12.75-inch pipeline of a nominal 75-mile length. There are considerable economies of scale, with the largest pipeline having cost of under $2 per metric ton for a 75-mile distance. These ICF cost estimates are roughly $4 to $18 per metric ton for the 300-kilometer distance used by GSSI as a nominal pipeline distance shown earlier in Exhibit 39. GCCSI showed costs of $2.50 to $24 per metric ton for 300 kilometers which is somewhat lower than the ICF estimates and might reflect lower pipeline construction costs outside the US and/or other differences in assumptions.

Exhibit 42: CO_2 Pipeline Costs

CARBON DIOXIDE PIPELINES (transported in dense phase at operating pressure of 1,600 to 2,200 psi)												
Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Flow Capacity in MMscf per day (60 degrees F and 14.73 psi)	Flow Capacity in metric tons/day	Flow Capacity in MMBtu/day	Pipeline Cost for 75 Miles ($mm)	Pump Cost for 75 Miles ($mm)	Annual Cost of Service for 75-mile Segment ($mm)	Cost of Service for 75 miles ($/Mcf)	Cost of Service for 75 miles ($/metric ton)	Cost of Service for 75 miles ($/MMBtu)
12.75	12.0	0.4	$188,939	165	8,762	NR	$180.7	$2.3	$18.9	$0.39	$7.39	NR
16	15.0	0.5	$199,965	294	15,563	NR	$240.0	$4.2	$25.4	$0.30	$5.58	NR
24	22.5	0.7	$221,212	819	43,412	NR	$398.2	$11.6	$43.3	$0.18	$3.41	NR
30	28.2	0.9	$229,281	1,440	76,347	NR	$515.9	$20.4	$57.4	$0.14	$2.57	NR
36	33.8	1.1	$237,349	2,284	121,093	NR	$640.8	$32.4	$73.0	$0.11	$2.06	NR
42	39.4	1.3	$245,417	3,373	178,853	NR	$773.1	$47.8	$90.2	$0.09	$1.73	NR

Electricity kWh/metric ton-mile *0.027*

Electricity kWh/MMscf-mile *1.425* *HP compressor capacity per MMscf for 75 mile spacing* *5.67*

Elec. Btu/1000 miles for 1 MMsc. *4,862,853*

6. Additional Fuel Considerations

6.1 Introduction

This section of the report discusses low-carbon fuel options that might be produced with the help of hydrogen and/or which might compete with hydrogen among end-users. The first fuel option discussed is renewable natural gas and the second is hydrogen blending in pipelines and distribution systems. The last two options are synthetic natural gas and synthetic liquid fuels that could be made from hydrogen and captured carbon dioxide.

6.2 Renewable Natural Gas

Renewable natural gas (RNG) is a gaseous fuel derived from biogenic or other renewable sources that is natural gas pipeline compatible quality. RNG has lower lifecycle carbon dioxide equivalent emissions than conventional natural gas when the RNG is made from biological feedstocks that have first absorbed carbon to grow or be produced.

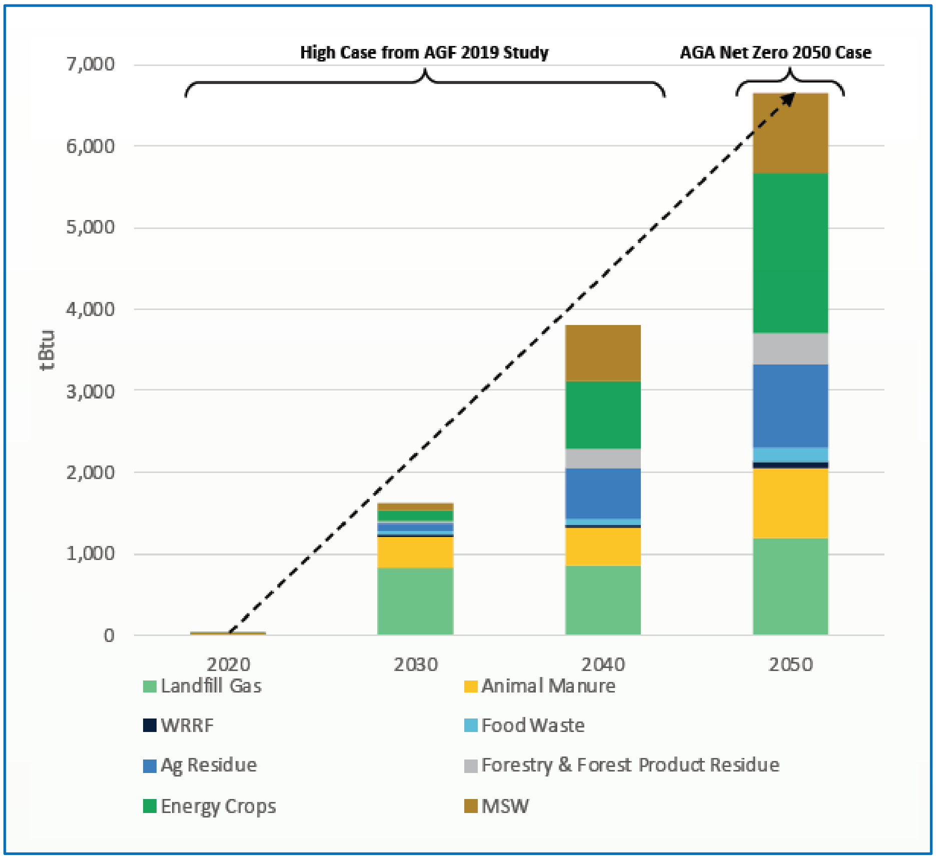
There is a wide array of potential RNG feedstocks and multiple production technologies. The most common way to produce RNG today is via anaerobic digestion, whereby microorganisms break down organic material (i.e., animal manure, organic waste in landfills, wastewater sludge, food waste) in an environment without oxygen. When organic material is introduced to the digester, it is broken down over multiple days by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide, sometimes referred to as biogas. The biogas is subsequently upgraded and conditioned to yield biomethane and can be injected into natural gas pipelines or distribution systems.

RNG can also be produced through thermal gasification of biomass, which includes processes where a carbon containing feedstock (i.e., agriculture residue, forestry residue, energy crops, municipal solid waste [MSW]) is converted into a mixture of gases referred to as synthetic gas or syngas, including hydrogen, carbon monoxide, steam, carbon dioxide, methane, and trace amounts of other gases. This process generally occurs at high temperatures.

ICF calculated estimates for potential maximum volumes of RNG in the U.S. for pipeline injection, showing significant growth over time. (See Exhibit 43 based on ICF studies conducted for the American Gas Foundation [AGF] and the American Gas Association [AGA].) ICF estimates that potential RNG supply could move from very low production volumes in 2020 to 1,600 trillion Btu (TBtu) in 2030, to 3,800 TBtu in 2040, and up to 6,600 TBtu in 2050. This analysis used reasonable assumptions for utilization of feedstocks and the rate of project development.[24] In the same report, ICF also reports a technical resource potential scenario of nearly 13,960 TBtu—an estimate intended to reflect the RNG production potential without any technical or economic constraints.

[24] The sources of renewable natural gas included in the exhibit include “MSW” referring to municipal solid waste and “WRRF” referring to water resources recovery facilities tied to sewage systems.

Exhibit 43: RNG Supply Potential Through 2050



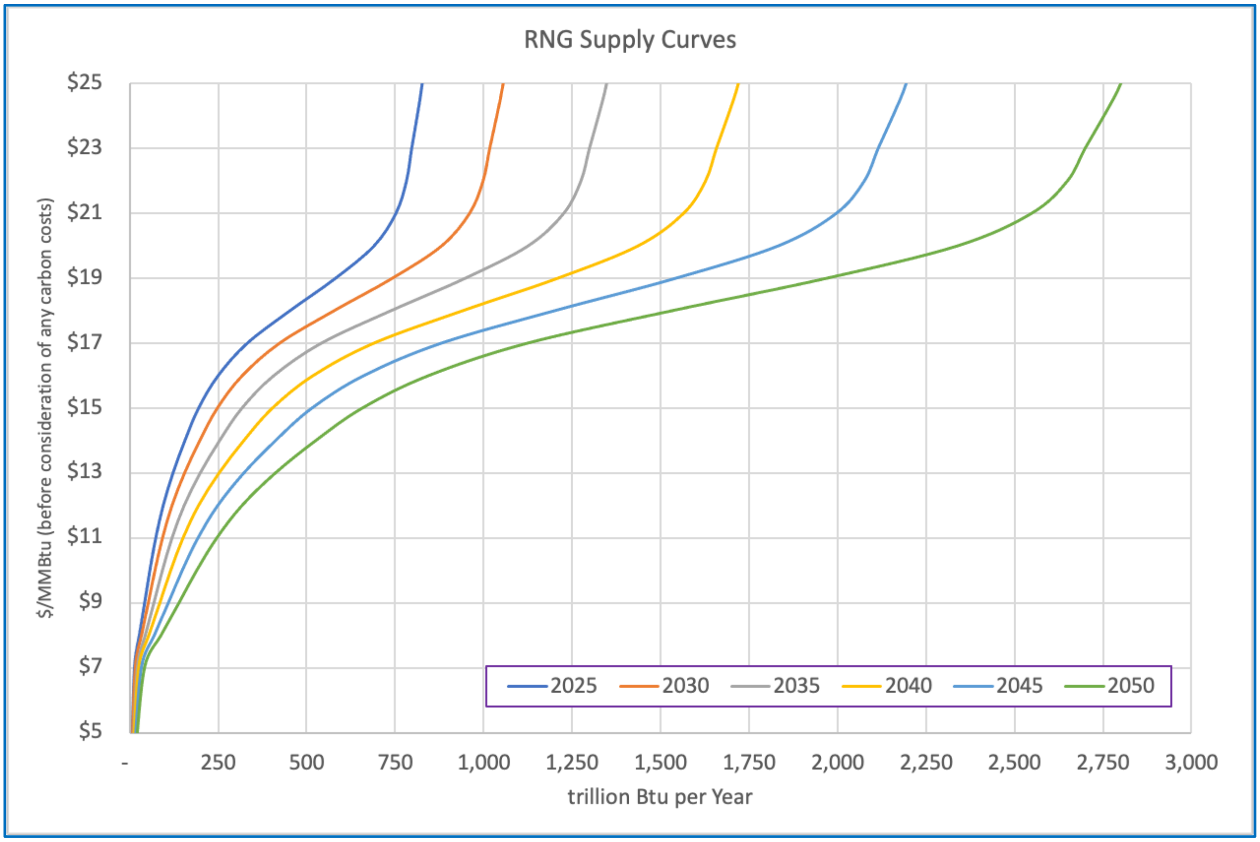
The table below presents ranges of lifecycle greenhouse gas (GHG) emissions for different RNG feedstocks up to the point of pipeline injection. These estimates are primarily based on ICF's analysis of a combination of Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) Model, and California Air Resources Board's modified California GREET model. The range captures differences between factors for different regions of the U.S. Feedstocks that prevent releasing fugitive methane, such as the collection and processing of dairy manure, enable RNG to be a negative emissions fuel source, since the global warming potential of methane is many times higher than the carbon dioxide produced through RNG combustion.

Exhibit 44: GHG Footprint of RNG Supply Options

RNG Feedstock	GHG (kg/MMBtu)
Landfill gas	14 - 36
Animal manure	
Dairy	(327) – (301)
Swine	(433) – (406)
Beef/Poultry	33 - 49
Water resource recovery facilities (WRRF)	14 - 36
Food Waste	(114) – (72)
Agriculture residue	26 - 58
Forestry residue	
Energy crops	
Municipal Solid Waste	

ICF estimates that more than half of the RNG production potential in the high resource potential scenario would be available at less than $20/MMBtu, as shown in Exhibit 45. ICF finds the front end of the supply curve to be landfill gas projects and water resources recovery facilities (WRRFs) that are poised to move towards RNG production. As the estimated costs move to higher costs, the supply curve includes some of the larger animal manure projects and the well-positioned food waste projects. The tail end of the curve, showing the upward sloping to the right, captures some thermal gasification projects that are assumed to exceed $20/MMBtu.

Exhibit 45: Combined RNG Supply-Cost Curve, in 2040-2050



The weighted average lifecycle GHG emissions for RNG for the volumes expected to be economic by 2050 under the assumed cost of carbon mitigation of $150 or $250 per metric ton of CO2e is -20.4 kg/MMBtu. As shown in Exhibit 46, the amount of RNG that would be expected in 2050 ranges from 657 TBtu to 2,547 TBtu. At those volumes, the use of RNG would reduce US annual GHG emissions by 51 to 177 million metric tons of CO2e relative to the continued use of natural gas.

Exhibit 46: Projected RNG Supply Volumes and GHG Mitigation Impacts

Renewable Natural Gas: Low Even Case													
Year	Cost of Carbon Mitigation $/MT CO2e	NG "Combustion" GHG kg CO2e/MMBtu	NG "Upstream" LCA GHG kg CO2e/MMBtu	NG "Pipeline" LCA GHG kg CO2e/ MMBtu	NG LCA GHG kg CO2e/ MMBtu	NatGas HH (BCoC)	NatGas HH (AftCoC)	RNG Average GHG kg/MMBtu	RNG Avr CoCM $/MMBtu	Willing to Pay for RNG $/MMBtu	RNG TBtu @ WtP Price	GHG Mitigation kg/MMBtu	GHG Mitigation 10^6 MT
2025	$20.00	52.93	5.88	2.34	61.14	$2.88	$4.10	(20.4)	-$0.41	$4.51	4	81.54	0.34
2030	$46.00	52.93	5.22	2.07	60.22	$3.34	$6.11	(20.4)	-$0.94	$7.05	16	80.62	1.29
2035	$72.00	52.93	4.63	1.84	59.40	$3.53	$7.81	(20.4)	-$1.47	$9.28	67	79.80	5.38
2040	$98.00	52.93	4.11	1.63	58.67	$3.55	$9.30	(20.4)	-$2.00	$11.30	151	79.07	11.97
2045	$124.00	52.93	3.65	1.45	58.02	$3.51	$10.70	(20.4)	-$2.53	$13.23	323	78.42	25.31
2050	$150.00	52.93	3.24	1.29	57.45	$3.69	$12.31	(20.4)	-$3.06	$15.37	657	77.85	51.15

Renewable Natural Gas: High Even and High Uneven Cases													
Year	Cost of Carbon Mitigation $/MT CO2e	NG "Combustion" GHG kg CO2e/MMBtu	NG "Upstream" LCA GHG kg CO2e/MMBtu	NG "Pipeline" LCA GHG kg CO2e/ MMBtu	NG LCA GHG kg CO2e/ MMBtu	NatGas HH (BCoC)	NatGas HH (AftCoC)	RNG Average GHG kg/MMBtu	RNG Avr CoCM $/MMBtu	Willing to Pay for RNG $/MMBtu	RNG TBtu @ WtP Price	GHG Mitigation kg/MMBtu	GHG Mitigation 10^6 MT
2025	$30.00	52.93	5.88	2.34	61.14	$2.88	$4.71	(20.4)	-$0.61	$5.33	4	81.54	0.34
2030	$70.00	52.93	5.22	2.07	60.22	$3.34	$7.56	(20.4)	-$1.43	$8.99	34	80.62	2.71
2035	$115.00	52.93	4.63	1.84	59.40	$3.53	$10.36	(20.4)	-$2.35	$12.71	153	79.80	12.20
2040	$160.00	52.93	4.11	1.63	58.67	$3.55	$12.94	(20.4)	-$3.26	$16.20	518	79.07	40.96
2045	$205.00	52.93	3.65	1.45	58.02	$3.51	$15.40	(20.4)	-$4.18	$19.58	1,541	78.42	120.87
2050	$250.00	52.93	3.24	1.29	57.45	$3.69	$18.06	(12.1)	-$3.03	$21.09	2,547	69.58	177.20

Notes: AftCoC=after cost of carbon is applied, NG=natural gas, BCoC=before cost of carbon is applied, GHG=greenhouse gas, H2=hydrogen, HH=Henry Hub, LCA=lifecycle analysis, MT=metric ton, TBtu=trillion British thermal units, WtP=willingness to pay for RNG. The High Even and High Uneven Case have the same willingness to pay for carbon mitigation and will result in similar economics for RNG relative to geologic natural gas.

6.3 Hydrogen Injection into Natural Gas Pipelines and Distribution Systems

One option for using hydrogen to reduce GHGs is to blend it into the natural gas going to consumers. The blending could occur anywhere along the natural gas supply chain including at gas processing plants, along transmission pipeline, at local distribution system or at end-user facilities (power plants and industrial sites). Blending allows for the immediate use of hydrogen without the need for new and separate infrastructure.

The concept is that a small enough amount of hydrogen would be added so that (a) the physical integrity and operations of the natural gas infrastructure would not be adversely affected and (b) the gas blend could be used in existing natural gas furnaces, stoves, water heaters, boilers, turbines, and other equipment with little or no adjustment and no loss of utility. The injection volumes contemplated in recently announced demonstrations and deployments range up to 30% by volume. As shown in Exhibit 47 because hydrogen has about one-third of the heat content of natural gas (343 Btu per standard cubic foot versus about 1,037 Btu/scf for natural gas), blending hydrogen at 30% by volume will yield a mixture wherein hydrogen contributes just 12.4% of the heat content.

The approximate economics of blending hydrogen into pipeline or LDC gas supplies for the Alternative Cases is shown in Exhibit 48. Given the considerable technical uncertainty regarding how much hydrogen can be injected safely and without disrupting existing gas consumers, the exhibit was created assuming the maximum practical blending limit will be 15% by volume and 5.5% by heat content. Blending would become fully economic once the price of natural gas including the cost of carbon mitigation exceeds the price of hydrogen including its cost of carbon mitigation. This takes place around the year 2050 for the Low Even Case and near the year 2040 for the High Even Case as the cost of carbon mitigation approaches $150/metric ton.

The calculations shown in the exhibit use the standard market share methodology to determine what portion of the available market would be served by blending. This yields a year 2050 market size of 391 TBtu for the Low Even and 546 TBtu for the High Even Case. These levels of blending would reduce GHG by 18.8 million metric tons in the Low Even Case and 26.8 million metric tons in the High Even Case. Note that the potential market for blending is smaller in the High Even Case compared to the Low Even Case because natural gas use in the residential, commercial, and industrial sectors because more consumers are expected to switch from natural gas to electricity and 100% hydrogen.

The market for blending hydrogen into pipeline and LDC supplies is reduced to near zero in the High Uneven Case because the high price of hydrogen expected for that case makes blending uneconomic.

Exhibit 47: Implications for Hydrogen Blending with Natural Gas

Implications for Hydrogen Blending with Natural Gas						
H2 Fraction of Blended Volume	CH4 Fraction of Blended Volume	H2 Btu/scf of blend	CH4 Btu/scf of blend	All Btu/scf of blend	H2 Fraction of Btu in blend	CH4 Fraction of Btu in blend
0%	100%	-	1,037	1,037	0.0%	100.0%
1%	99%	3	1,027	1,030	0.3%	99.7%
2%	98%	7	1,016	1,023	0.7%	99.3%
3%	97%	10	1,006	1,016	1.0%	99.0%
4%	96%	14	996	1,009	1.4%	98.6%
5%	95%	17	985	1,002	1.7%	98.3%
6%	94%	21	975	995	2.1%	97.9%
7%	93%	24	964	988	2.4%	97.6%
8%	92%	27	954	981	2.8%	97.2%
9%	91%	31	944	975	3.2%	96.8%
10%	90%	34	933	968	3.5%	96.5%
15%	85%	51	881	933	5.5%	94.5%
20%	80%	69	830	898	7.6%	92.4%
25%	75%	86	778	864	9.9%	90.1%
30%	70%	103	726	829	12.4%	87.6%

Exhibit 48: Potential Hydrogen Blending Volumes and GHG Mitigation Impacts

Potential Hydrogen Blending: Low Even Case										
Year	Cost of Carbon Mitigation $/MT CO2e	NatGas LCA GHG kg CO2e/MMBtu	NatGas HH (AftCoC)	kg/MMBtu GHG Alt. Case H2 Comp.	Composite H2 AftCoC	H2 MS total vol. (use * max Btu%)	NG Market Size in TBtu	Hydrogen demand for blending TBtu	GHG Mitigation kg/MMBtu substituted	GHG Mitigation 10^6 MT
2025	$20.00	61.14	$4.10	50.56	$10.63	0.0%	20,024	1	10.6	0.0
2030	$46.00	60.22	$6.11	31.97	$11.87	0.1%	19,365	10	28.2	0.3
2035	$72.00	59.40	$7.81	20.45	$12.18	0.2%	17,857	42	39.0	1.6
2040	$98.00	58.67	$9.30	14.46	$12.07	0.8%	16,031	123	44.2	5.4
2045	$124.00	58.02	$10.70	11.20	$11.90	1.8%	14,033	249	46.8	11.7
2050	$150.00	57.45	$12.31	9.31	$12.01	3.0%	13,037	391	48.1	18.8

Potential Hydrogen Blending: High Even Case										
Year	Cost of Carbon Mitigation $/MT CO2e	NatGas LCA GHG kg CO2e/MMBtu	NatGas HH (AftCoC)	kg/MMBtu GHG Alt. Case H2 Comp.	Composite H2 AftCoC	H2 MS total vol. (use * max Btu%)	NG Market Size in TBtu	Hydrogen demand for blending TBtu	GHG Mitigation kg/MMBtu substituted	GHG Mitigation 10^6 MT
2025	$30.00	61.14	$4.71	44.03	$11.09	0.0%	19,784	3	17.1	0.0
2030	$70.00	60.22	$7.56	23.37	$12.21	0.2%	19,566	36	36.8	1.3
2035	$115.00	59.40	$10.36	14.53	$12.48	1.2%	17,764	209	44.9	9.4
2040	$160.00	58.67	$12.94	11.21	$12.50	3.1%	14,249	440	47.5	20.9
2045	$205.00	58.02	$15.40	9.49	$12.49	4.5%	12,215	547	48.5	26.6
2050	$250.00	57.45	$18.06	8.36	$12.73	5.1%	10,754	546	49.1	26.8

Potential Hydrogen Blending: High Uneven Case										
Year	Cost of Carbon Mitigation $/MT CO2e	NatGas LCA GHG kg CO2e/MMBtu	NatGas HH (AftCoC)	kg/MMBtu GHG Alt. Case H2 Comp.	Composite H2 AftCoC	H2 MS total vol. (use * max Btu%)	NG Market Size in TBtu	Hydrogen demand for blending TBtu	GHG Mitigation kg/MMBtu substituted	GHG Mitigation 10^6 MT
2025	$30.00	61.14	$4.71	78.58	$11.40	0.0%	19,784	-	(17.4)	-
2030	$70.00	60.22	$7.56	74.77	$15.27	0.0%	19,616	-	(14.6)	-
2035	$115.00	59.40	$10.36	65.99	$19.48	0.1%	18,365	-	(6.6)	-
2040	$160.00	58.67	$12.94	49.84	$23.07	0.1%	16,263	15	8.8	0.1
2045	$205.00	58.02	$15.40	31.57	$24.83	0.2%	14,900	28	26.4	0.7
2050	$250.00	57.45	$18.06	18.95	$24.67	0.6%	14,223	79	38.5	3.1

Notes: AftCoC=after cost of carbon is applied NG=natural gas, BCoC=before cost of carbon is applied, GHG=greenhouse gas, H2=hydrogen, HH=Henry Hub, LCA=lifecycle analysis, MT=metric ton, TBtu=trillion British thermal units.

6.4 Synthetic Natural Gas

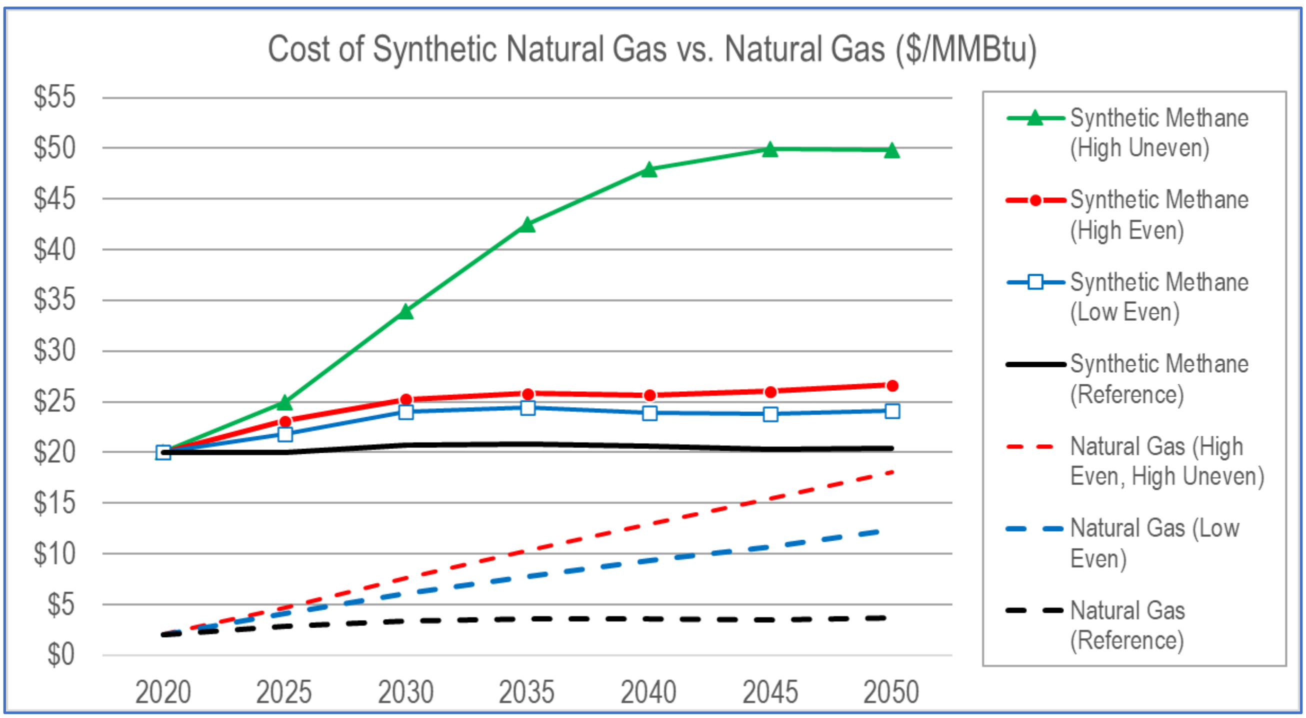
Synthetic natural gas (SNG) is produced from fossil fuels like coal, naphtha or from biofuels, or using electricity in power-to-gas systems. The production process, called methanation, is a chemical reaction aided by a catalyst (typically nickel-based) at high temperatures to turn carbon dioxide, carbon monoxide, and hydrogen into methane. Depending on the source of the feedstocks, SNG can be a low carbon or carbon-free substitute for conventional natural gas. The production of SNG typically requires a CO_2 separation unit, CO_2 compressor, CO_2 storage, a methanation reactor, an upgrading unit, a SNG compressor, and SNG storage.

Coal is gasified with steam and oxygen, producing CO, H_2, CO_2, and CH_4 and higher hydrocarbons like ethane and propane. The concentration of H_2 is increased typically in a water-gas shift reaction and then cleaned before entering the methanation process.[25] Synthetic natural gas can also be made through the gasification of biomass, such as forestry residues or energy crops.

A power to gas system takes renewable energy to produce hydrogen and oxygen via electrolysis, whereby the electric energy is stored in the H_2. The electrolysis technologies available on the market on an industrial scale are alkaline electrolysis and proton exchange membrane electrolysis. The main benefit of SNG is that this gas allows renewable energy to be stored in natural gas form and transported through the existing natural gas system with less restriction than injecting H_2. SNG also has a higher volumetric energy density than H_2, requiring less storage space to transport the same amount of energy.

Various cases were modeled to estimate the cost of SNG made from captured CO_2 and green hydrogen through 2050 varying the cost of carbon mitigation and hydrogen, shown in Exhibit 49. This study's Reference Case uses EIA's Annual Energy Outlook (AEO) 2021 price data for hydrogen and electricity with no cost of carbon mitigation. In this case alone, there is assumed to be no surplus CO_2, so the commercial price must be paid. The Alternative Cases incorporate various levels of a price on carbon. If a differential in incentives is applied to blue hydrogen, it quickly accelerates the cost of SNG to nearly $50/MMBtu in 2050, nearly double that of the equivalent High Even Case. Depending on the assumptions, SNG is expected to cost $7-15/MMBtu more than conventional natural gas in 2050. Even under the High Even Case, SNG does not become cost advantageous.

Exhibit 49: Comparison of Potential Costs for SNG 2020-2050, in $/MMBtu



Note: Commodity costs are based on the AEO Reference Case with adjustments for the Alternative Cases.

6.5 Synthetic Liquid Fuels

In addition to the production of SNG, hydrogen can be produced and combined with other compounds to produce synthetic liquid fuels. Hydrogen can be combined with CO_2 to produce synthetic liquid fuels such as methanol, diesel, gasoline, and jet fuel. The environmental impact of hydrogen-based synthetic hydrocarbon fuels depends on the GHG intensity of both the hydrogen and the CO_2. Ammonia can also be made from hydrogen, in combination with nitrogen.

To produce synthetic distillates, CO_2 is first converted into carbon monoxide, and the resulting mixture of carbon monoxide and hydrogen is then converted via Fischer-Tropsch (FT) synthesis to raw liquid fuels. This is then further upgraded into synthetic diesel or kerosene that can be used in combination with fossil-based fuels in conventional applications. FT synthesis is relatively slow and requires costly investment. Methanol can be used as a fuel or a chemical feedstock. Methanol can also be produced by reacting pure CO_2 and H_2 at appropriate temperatures and pressures.

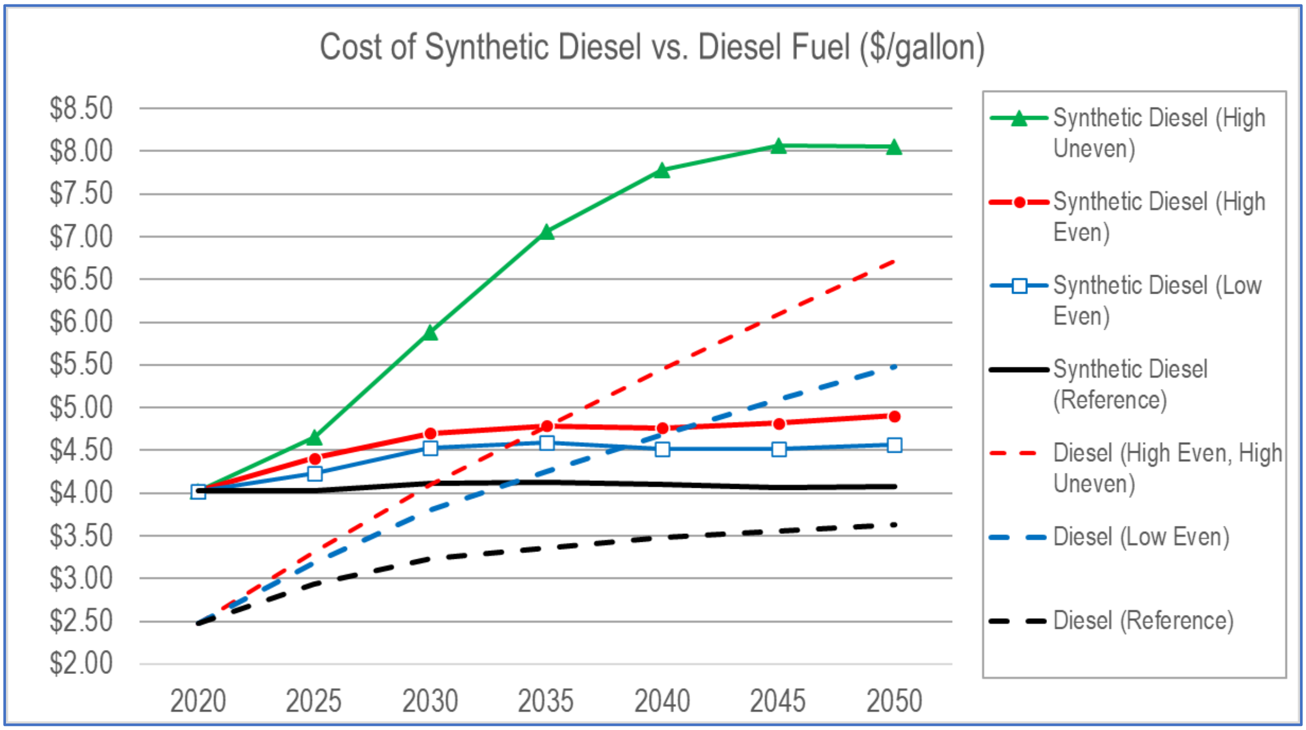
CO_2 can be produced or acquired via various processes, including from the combustion of fossil fuels, from various industrial process waste gases (e.g. cement production), from the production of biogas and bioethanol. CO_2 also can be captured from the atmosphere in a process referred to as known as direct air capture (DAC). Although DAC would greatly increase the availability of CO_2, DAC is more energy-intensive than CO_2 capture from gases formed at power plants or industrial facilities due to the low atmospheric concentration. However the CO_2 is produced or captured, it needs to be transported to or co-located with the synthetic fuel process to be combined with H_2.

Ammonia can, in principle, be used as a fuel in various energy applications (e.g., for co-firing in coal power plants), but none of these applications is being commercially used today. Ammonia is made typically in the Haber-Bosch process where atmospheric nitrogen is reacted under high temperature and pressure with hydrogen in the presence of a metallic catalyst.

The main cost components for the production of ammonia and synthetic hydrocarbons are the CAPEX, the hydrogen costs (which is driven by high electricity costs if the hydrogen is produced through electrolysis), and the CO_2 feedstock costs (for synthetic hydrocarbons). CO_2 feedstock costs can vary significantly, depending on the availability of suitable CO_2 sources. High CO_2 prices and low electricity costs in conjunction are needed to make synthetic hydrocarbons economically competitive with fossil crude oil and natural gas.

The same Reference Case and Alternative Case cost of carbon mitigation values were modeled to estimate the cost of synthetic diesel made from captured carbon and hydrogen through 2050, shown in Exhibit 50. Synthetic diesel moves from being about $1.60/gallon more expensive than conventional diesel in 2020, shifting to a cost advantage under both Low Even and High Even Cases between 2035 and 2040. Because of the high cost of hydrogen under the High Uneven Case, synthetic diesel made from captured carbon dioxide and hydrogen never becomes economic.

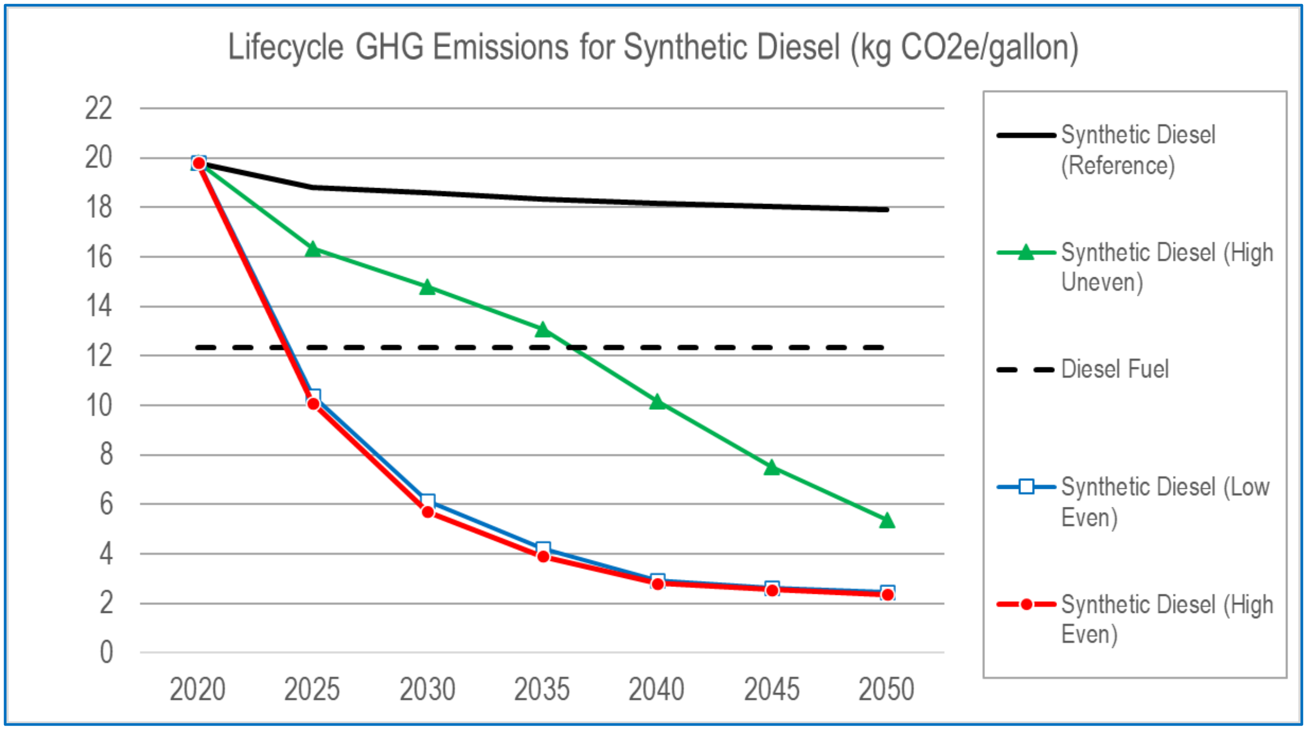
Exhibit 50: Comparisons of Potential Costs of Synthetic Diesel vs. Conventional Diesel 2020-2050, in $/gallon including taxes



Note: Commodity costs are based on the AEO Reference Case with adjustments for the Alternative Cases.

A lifecycle assessment of GHG emissions of synthetic diesel concludes that it emits less than 20 kg CO2e/gallon. Shown in Exhibit 51, the emissions decline over time, especially under the two cost of carbon mitigation cases to less than 3 kg CO2e/gallon as the electric grid and hydrogen become cleaner. By 2025, synthetic diesel is expected to be a lower emitter than conventional diesel under the high and low cost of carbon mitigation cases. The lifecycle analysis incorporates emissions for facility construction, facility operations, purchased H_2, CO_2 transport and electricity, although the two feedstocks are the main contributors.

Exhibit 51: Lifecycle GHG Emissions for Synthetic Diesel 2020-2050, in kg CO2e/gal[26]



[26] https://nicholasinstitute.duke.edu/sites/default/files/publications/natgas-paper.pdf

7. Analytic Results of Alternative Cases

7.1 Scope of Analysis and Description of Alternative Cases

This chapter presents the analytic results of the Reference Case and three Alternative Cases which analyze possible climate mitigation policies intended to shift US energy consumption toward low-carbon technologies and fuels. The study's Reference Case is based on the 2021 AEO Reference Case produced by the Energy Information Administration. The Alternative Cases were created by keeping most of the assumptions from the AEO but then introducing a willingness to pay the cost of carbon mitigation (stated as in \$/metric ton of CO2e reduced) into the economic competition among technologies/fuels in each sector. The three Alternative Cases consist of:

- Low Cost of Carbon Mitigation Applied Evenly: This "Low Even Case" has mitigation costs that reach \$150 per metric ton of CO2e by 2050. All technologies/fuels receive incentives (or pay fees) based on the same \$/metric ton of CO2e mitigation value applied to their lifecycle GHG characteristics.
- High Cost of Carbon Mitigation Applied Evenly: This "High Even Case" has mitigation costs that reach \$250 per metric ton of CO2e by 2050. Here too, all technologies/fuels receive incentives (or pay fees) on an equal \$/metric ton of CO2e basis.
- High Cost of Carbon Mitigation Applied Unevenly: This "High Uneven Case" has the same cost of carbon mitigation as the High Even Case but assumes blue hydrogen does not receive incentives (or pay fees) equal to its GHG characteristics. This is represented as a \$12/MMBtu differential for blue hydrogen relative to the treatment of hydrogen made from solar and wind energy.

The main objective of these cases is to determine where and how much hydrogen would be used when there is "economic competition with uniform incentives"" whereby the value of reduced carbon emissions is internalized equally for all technologies/fuels based on their lifecycle GHG characteristics. This is done under the Low Even Case assuming policies are adopted valuing carbon reductions up to \$150/MT by 2050 and the High Even Case wherein the cost of mitigation is assumed to reach \$250/MT.

The second objective of the cases is to determine what role blue hydrogen, specifically, will play and how that role might be impacted if blue hydrogen received fewer incentives or paid higher fees relative to green hydrogen. The High Uneven Case provides a point of comparison to determine how unequal treatment among sources of hydrogen could affect the overall role hydrogen could play in reducing GHGs.

The final objective of these cases was to estimate what hydrogen production, transmission, storage, conversion, and distribution infrastructure would be needed to supply the amounts of hydrogen consumption anticipated in the three Alternative Cases.

This chapter presents the analytic findings first in terms of the energy mix across all sectors and then in terms of what is expected within each sector. The results are presented at a national level through the year 2050.

7.2 Overall Results Across All Sectors

To estimate the effects of an introduction of a cost of carbon mitigation, ICF developed pro forma economic comparisons of the competitive economics of major technology/fuel alternatives in various end-uses sectors, markets, and submarkets. The pro forma comparisons represent the direct cost for each option (initial or capital costs, nonfuel operating costs, and fuel costs) and translate those components into “per-unit cost of energy services” such as cents per passenger-mile traveled, cents per ton-mile transported, or MMBtu of process heat delivered. The comparisons were calculated given various assumptions over time, allowing for the potential for the growth in hydrogen consumption and other shifts in the use of technologies/fuels to be quantified under different scenarios in the future. The net effects of introducing the cost of carbon can be grouped into three categories:

- Shifts away from fossil fuels toward electricity (electrification)
- Increases in the use of low-carbon fuels (including hydrogen, synfuels and renewable natural gas) in place of fuels with higher carbon content
- The application of carbon capture, utilization, and storage as means of reducing carbon emissions at power plants and industrial facilities. CCUS also plays a vital role in the production of blue hydrogen.

7.2.1 Electrification Across All Sectors

Electricity demand goes up substantially in the Alternative Cases due to shifts from fossil fuels to electricity in several end-use sectors. This electrification occurs because there are several relatively low-cost options to decarbonize electricity generation and so the price of electricity goes up less than the price of fossils fuels when a cost of carbon mitigation is introduced. This makes electric technologies more competitive and increases electricity’s market share in several submarkets.

By 2050 the increase in demand for electricity in Low Even Case is 1,970 terawatt hours (TWh) or 36% of AEO Reference Case electricity demand. (See Exhibit 52.) For the High Even Case, electrification increases end-use electricity demand by 2,988 TWh or 54% for the year 2050. The High Uneven Case has even more electrification by 2050 (3,519 TWh or a 64% increase over the AEO) because consumers find hydrogen to be less economic and turn instead to electric options.

These incremental demands for electricity in each sector are computed in the market-share models for specific individual end-uses (e.g., space heating, space cooling, water heating, cooking, clothes drying, etc.). For the residential, commercial, and industrial sectors, these incremental demands are aggregated into space heating and non-space heating categories so that seasonal and hourly load profiles can be applied. For light duty and heavy-duty vehicles, the terawatt hours of electrification come in various transportation end-use models and are divided into “fixed” versus “flexible” components based on inputs by the model user for the power sector case being run.

The cases shown in this report all assume that the portion of vehicle recharging that is flexible will grow overtime and by 2050 will reach 75% for LDV and 50% for HDV. The “fixed” recharging occurs in hours that are most convenient to consumers. For example, for light duty vehicles, the most convenient time for recharging as assumed to be during "after-work" hours of 5 PM to midnight. The logic for "flexible" or "smart" recharging is to that energy management programs and hourly pricing incentives will shift recharging to the hours that will minimize and flatten the dispatch of fossil energy within the day. This will increase the ability of the grid to accommodate higher levels of renewable energy and reduce the need for fossil generation and electricity storage capacity.

7.2.2 Fuel Mix Shifts toward Low Carbon Fuels Across All Sectors

7.2.2.1 Consumption of Hydrogen

Under the two alternative scenarios of "economic competition with uniform incentives," demand for hydrogen by end-users and power plants could reach up to 9.9 quadrillion Btu by 2050 (in the $150/MT cost carbon mitigation case (see Exhibit 53) or up to 12.9 quadrillion Btu for the $250/MT CO2e case. These levels of use of hydrogen in 2050 would include all end-use sectors (residential, commercial, industrial, and transportation) and would represents 12% to 15% of total US energy end-use consumption (83.7 quads) as forecasted in the 2021 EIA Annual Energy Outlook.

The third alternative case Illustrates the importance of blue hydrogen in realizing the benefits of hydrogen as a carbon mitigation resource. The High Uneven Case assumes that blue hydrogen would suffer a $12/MMBtu disincentive relative to green hydrogen. Relative to the corresponding "uniform incentives" case with the same assumed cost of carbon mitigation, this High Uneven Case shows a 71% loss of the potential hydrogen end-use markets by 2050 (3.7 quads versus 12.9 quads).

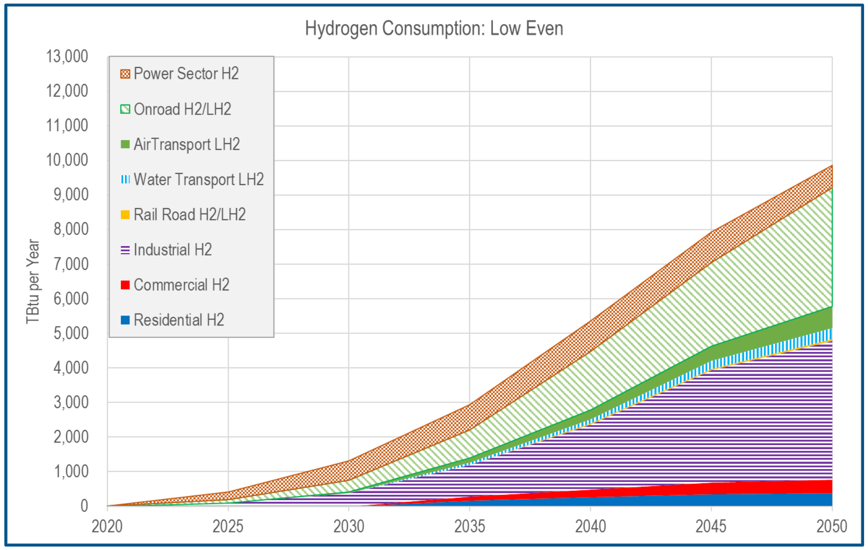
This loss of market is a result of higher wholesale hydrogen prices as blue hydrogen is more expensive and the market must rely on higher cost hydrogen sources. The High Uneven Case also results in 5.5 billion more metric tons GHG emissions through 2050 compared to the High Even and displays poorer economic efficiency. That is, economic efficiency measured as incremental dollars per metric ton of CO2e reductions was 12% worse over the entire forecast period and 17% worse by 2050.

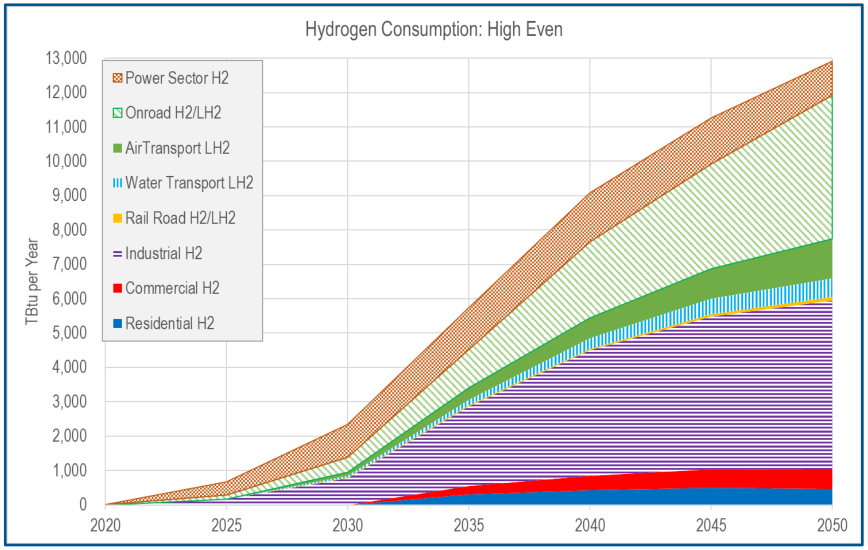
Exhibit 52: Estimates for Electrification (TWh beyond values in the Reference Case)

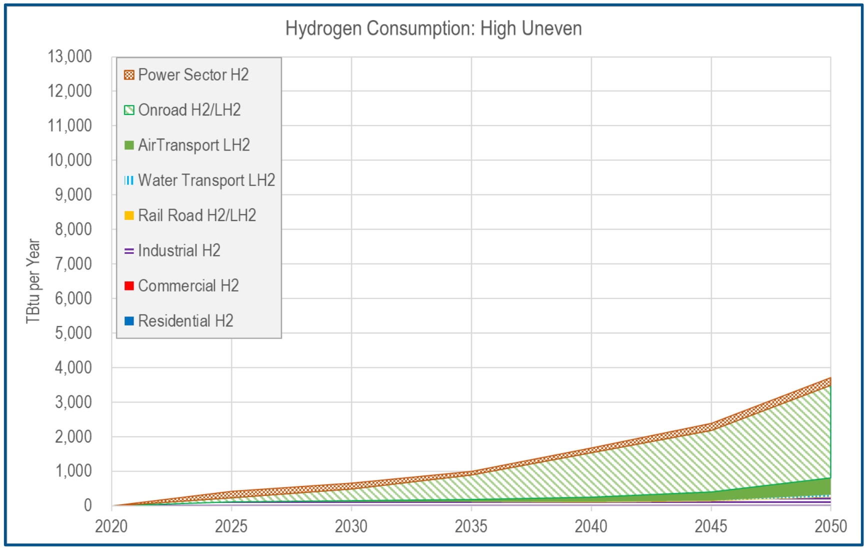
	Low Even							High Even							High Uneven						
TWh of Elec. (above AEO Ref. Case)	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Residential Space Heating	0.0	13.4	36.6	73.7	114.1	151.2	197.1	0.0	17.4	57.3	113.3	161.9	206.8	259.4	0.0	17.8	58.1	128.8	188.0	240.3	295.6
Residential Non-space Ht	0.0	8.2	22.3	44.9	69.4	92.0	119.9	0.0	15.0	49.1	97.2	138.8	177.3	222.4	0.0	14.4	47.2	104.5	152.6	195.1	239.9
Commercial Space Heating	0.0	20.2	37.8	64.7	95.6	128.5	169.8	0.0	23.4	48.4	88.9	133.6	178.0	224.4	0.0	23.9	48.7	89.3	138.0	195.0	254.1
Commercial Non-space Ht	0.0	12.3	23.0	39.4	58.2	78.2	103.3	0.0	20.0	41.5	76.2	114.6	152.7	192.4	0.0	19.4	39.5	72.5	112.0	158.2	206.3
Industrial Space Heating	0.0	5.5	37.6	126.5	231.8	340.3	417.8	0.0	12.9	82.3	232.2	304.6	370.8	448.5	0.0	13.6	90.1	279.9	458.8	547.9	640.7
Industrial Non-space Ht	0.0	3.4	22.9	77.0	141.0	207.1	254.2	0.0	11.0	70.6	199.1	261.2	318.0	384.6	0.0	11.0	73.1	227.2	372.4	444.7	520.0
LDV Recharging	0.0	94.4	206.4	315.1	427.5	535.1	628.9	0.0	101.0	231.2	367.0	504.9	636.4	745.1	0.0	101.2	232.1	369.1	512.2	653.0	774.9
HDV Recharging	0.0	3.0	11.4	23.9	40.6	73.1	64.9	0.0	3.9	16.2	36.2	59.6	102.3	87.9	0.0	3.9	17.2	42.9	86.4	168.6	164.6
Direct Air Capture	0.0	0.0	0.0	0.0	0.1	2.9	14.4	0.0	0.0	0.0	0.1	4.3	92.6	423.3	0.0	0.0	0.0	0.1	4.3	92.6	423.3
Sum New Loads	0.0	160.5	397.9	765.1	1,178.3	1,608.4	1,970.3	0.0	204.6	596.6	1,210.4	1,683.5	2,234.8	2,988.1	0.0	205.3	605.9	1,314.1	2,024.6	2,695.6	3,519.3
AEO Electricty generation	4,107	4,379	4,527	4,702	4,921	5,188	5,501	4,107	4,379	4,527	4,702	4,921	5,188	5,501	4,107	4,379	4,527	4,702	4,921	5,188	5,501
Electrification as % of AEO	0.0%	3.7%	8.8%	16.3%	23.9%	31.0%	35.8%	0.0%	4.7%	13.2%	25.7%	34.2%	43.1%	54.3%	0.0%	4.7%	13.4%	27.9%	41.1%	52.0%	64.0%

Source: These are estimates made by the end-use models based on the assumptions used to define each case.

Exhibit 53 Hydrogen Consumption to 2050







7.2.2.2 Consumption of Natural Gas

As shown in Exhibit 54, in the Reference Case demand for natural gas in the US goes up an average of 0.5% per year starting from 2020 and reaches 36.7 quads by 2050. Among the end-use sectors, the residential sector is the only with a negative growth rate, -0.1% per year. Natural gas consumption in the commercial sector grows by 0.4% per year in the Reference Case and by 0.6% in the industrial sector. Natural gas consumption in the power sector increases at an average rate of 0.5% in the Reference Case.

All three of the Alternative Cases show declines in total natural gas consumption ranging from -0.7% per year in both the Low Even and High Even Cases to -1.56% in the High Uneven Case. While the decline in total natural gas use is similar in the Low Even and High Even Cases, the composition of that demand is different. The High Even Case loses more end-use consumption than does the Low Even Case (-2.34% versus -1.38% per year), but the High Even makes up for that loss with greater use of natural gas to make blue hydrogen.

The largest drop in the natural gas market occurs in the High Uneven Case in which consumption falls to 19.9 quads by 2050, an average change of -1.6% per year. The sector accounting for most of difference is the manufacturing of blue hydrogen, which consumes 1.5 quads in 2050 in High Uneven Case as compared to 9.9 quads in the Low Even Case and 13.2 quads in the High Even Case.

The use of CCUS helps maintain the market for natural gas in both the industrial sector and power generation sectors for the three Alternative Cases. As shown in Exhibit 55, by 2050 97% to 99% of the natural gas used in the power sector is combined with CCUS. In the industrial sector, the percent of natural gas use with CCUS ranges from 43% to 61% by 2050. If the volume of natural gas used for industrial process feedstocks is removed from consideration, the percent of industrial natural gas consumed that involves carbon capture in 2050 increase to 51% to 70%.

Exhibit 54: Natural Gas Consumption to 2050

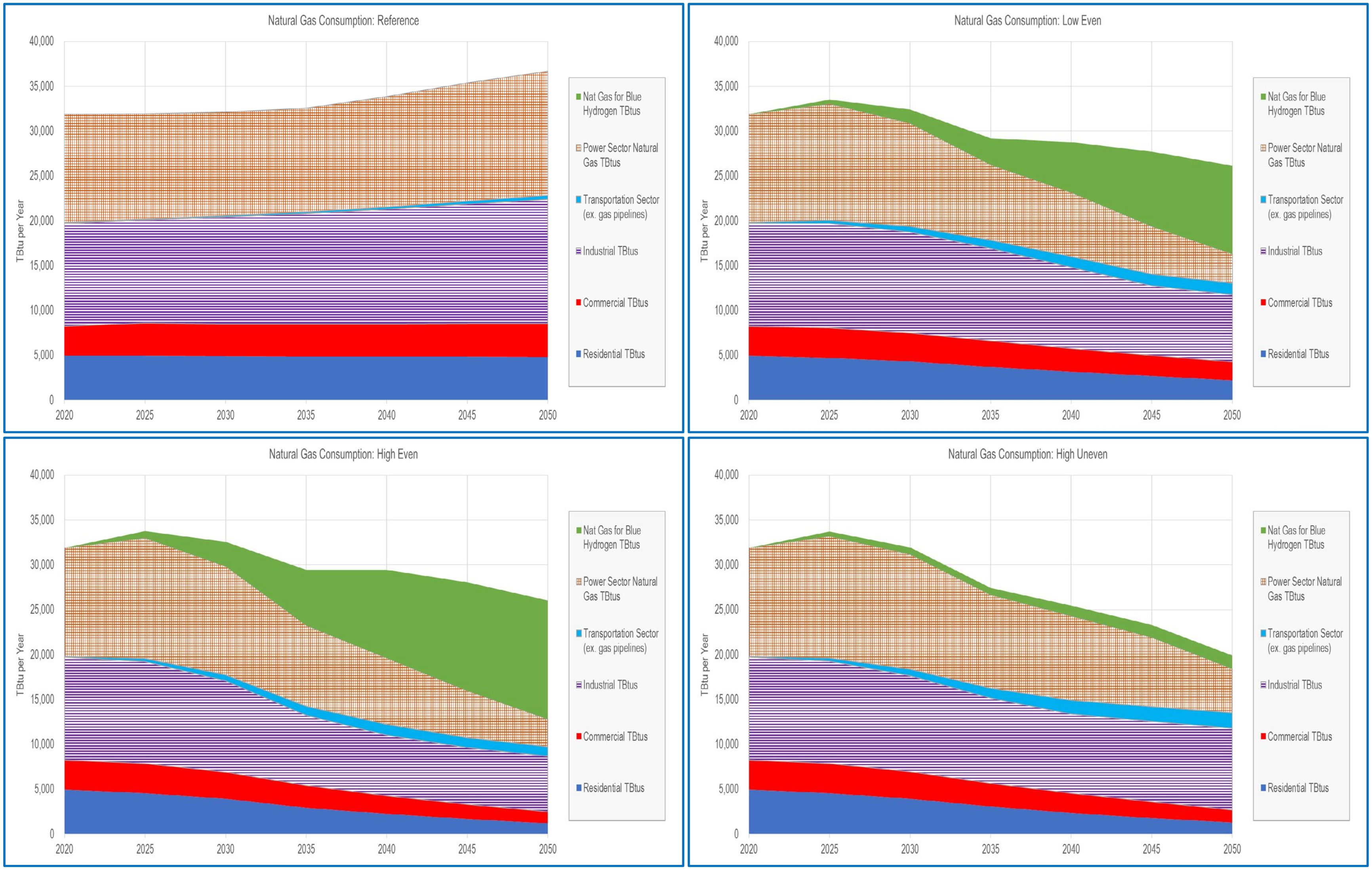


Exhibit 55: Industrial and Power Sector Natural Gas Use with and without CCUS

Natural Gas Used in Industrial Sector (TBtu)

Industrial	AEO 2030	AEO 2040	AEO 2050
w/o CCUS	11,943	12,789	13,868
with CCUS	-	-	-
All Natural Gas	11,943	12,789	13,868
Percent CCUS	*0%*	*0%*	*0%*
Industrial	**Low Even 2030 (TBtu)**	**Low Even 2040 (TBtu)**	**Low Even 2050 (TBtu)**
w/o CCUS	10,423	6,858	4,259
with CCUS	844	2,191	3,242
All Natural Gas	11,267	9,049	7,501
Percent CCUS	*7%*	*24%*	*43%*
Industrial	**High Even 2030 (TBtu)**	**High Even 2040 (TBtu)**	**High Even 2050 (TBtu)**
w/o CCUS	8,770	3,775	2,894
with CCUS	1,390	3,000	3,282
All Natural Gas	10,160	6,775	6,176
Percent CCUS	*14%*	*44%*	*53%*
Industrial	**High Uneven 2030 (TBtu)**	**High Uneven 2040 (TBtu)**	**High Uneven 2050 (TBtu)**
w/o CCUS	9,270	4,689	3,512
with CCUS	1,435	4,114	5,611
All Natural Gas	10,705	8,803	9,123
Percent CCUS	*13%*	*47%*	*61%*

Natural Gas Used in Power Sector (TBtu)

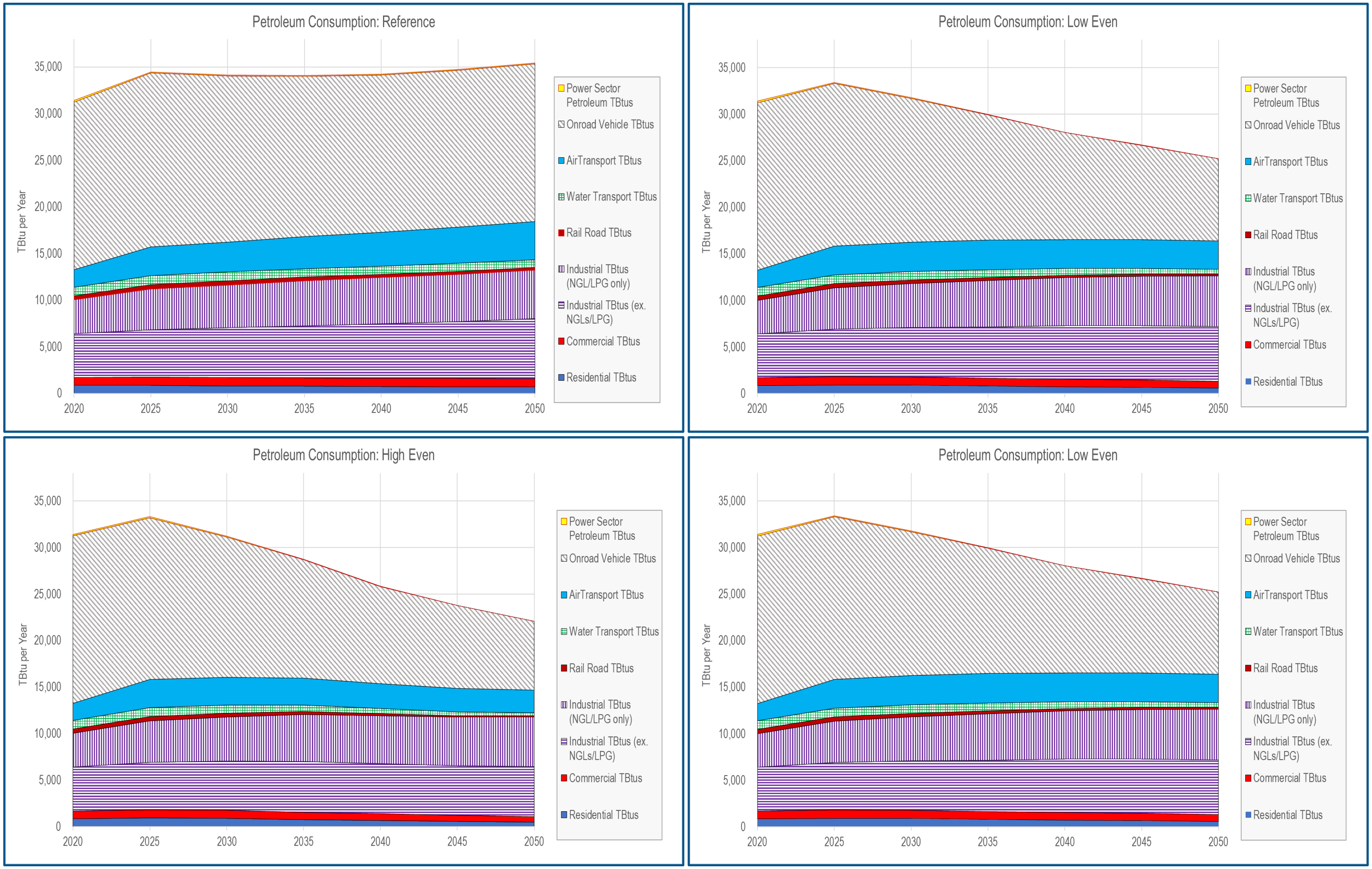
Power Sector	AEO 2030	AEO 2040	AEO 2050
w/o CCUS	11,527	12,306	13,874
with CCUS	-	-	-
All Natural Gas	11,527	12,306	13,874
Percent CCUS	*0%*	*0%*	*0%*
Power Sector	**Low Even 2030 (TBtu)**	**Low Even 2040 (TBtu)**	**Low Even 2050 (TBtu)**
w/o CCUS	5,612	843	101
with CCUS	5,887	6,276	3,161
All Natural Gas	11,499	7,119	3,263
Percent CCUS	*51%*	*88%*	*97%*
Power Sector	**High Even 2030 (TBtu)**	**High Even 2040 (TBtu)**	**High Even 2050 (TBtu)**
w/o CCUS	3,441	315	41
with CCUS	8,624	7,077	3,025
All Natural Gas	12,065	7,391	3,066
Percent CCUS	*71%*	*96%*	*99%*
Power Sector	**High Uneven 2030 (TBtu)**	**High Uneven 2040 (TBtu)**	**High Uneven 2050 (TBtu)**
w/o CCUS	3,605	358	51
with CCUS	9,199	9,059	4,824
All Natural Gas	12,804	9,417	4,875
Percent CCUS	*72%*	*96%*	*99%*

Note: Industrial gas consumption without CCUS includes various feedstock uses that average about 1,100 TBtu from 2020 to 2050.

7.2.2.3 Consumption of Petroleum Products

The consumption of petroleum products in the Reference Case grows 0.4% per year from 2020 to 2050 and reaches 35.4 quads. (See Exhibit 56). The markets showing growth include air transportation (2.7% per year), industrial use of NGL/LPGs for feedstocks and fuel (1.2% per year), other industrial petroleum product (1.0% per year), and the commercial sector (0.3% per year). The markets in which petroleum products decline in the Reference Case include rail (-1.5% per year), residential (-0.8% per year), and water transportation (-0.3% per year).

Exhibit 56: Petroleum Consumption to 2050



As was seen with natural gas, the imposition of a cost of carbon under the three Alternative Cases leads to decline in the consumption of petroleum products in favor of relatively lower-carbon fuels such as electricity, hydrogen, CNG, and synthetic or renewable diesel/jet fuels. In contrast to the 0.4% per year growth in the Reference Case, the Low Even Case shows an annual change in consumption of all petroleum products of -0.7%, with the largest absolute losses in 2050 among on-road vehicles (-8.1 quads), air transportation (-1.0 quads) and industrial non-NGL/LPG petroleum fuels (-0.5 quads).

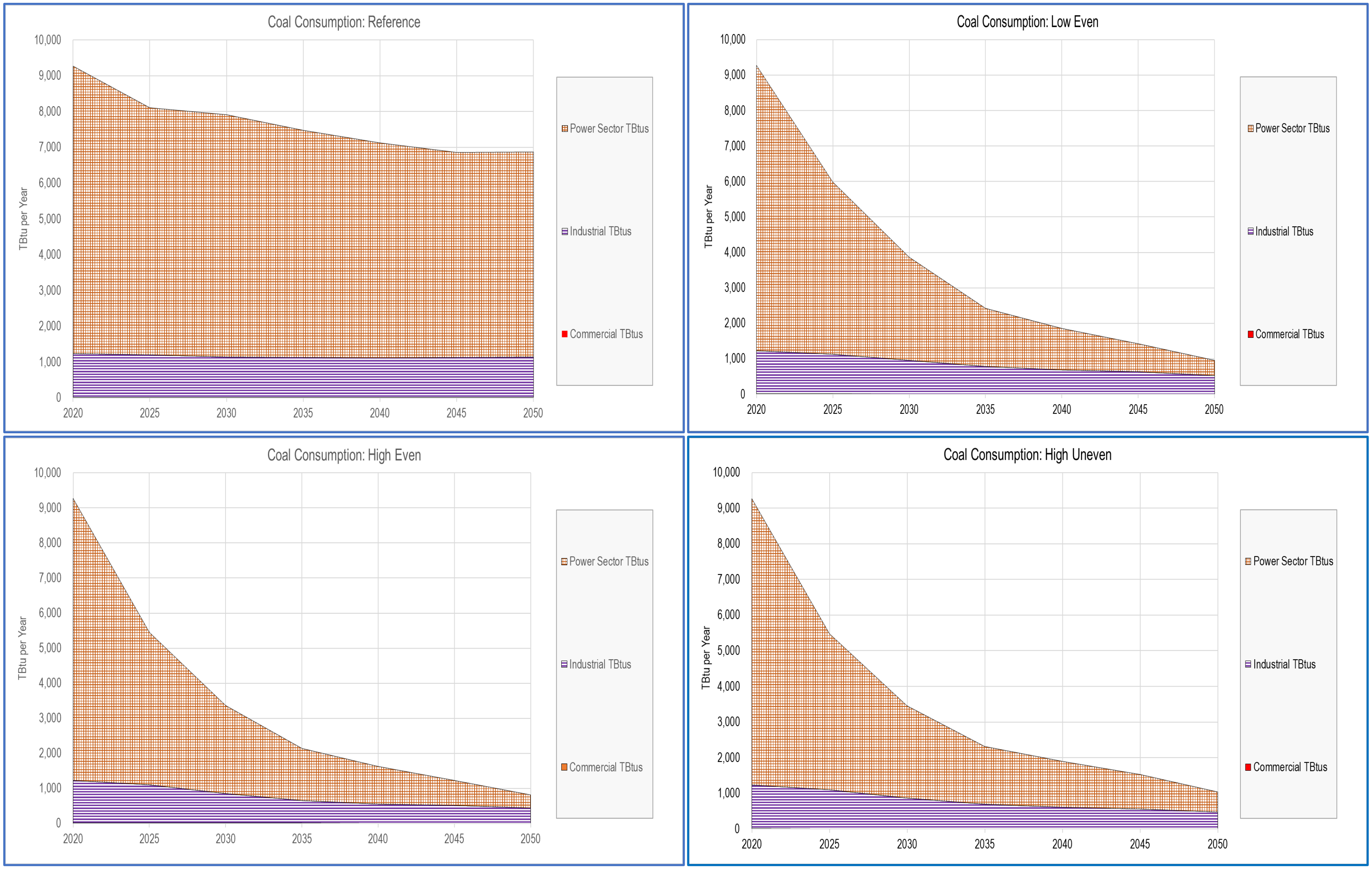
The High Even has an even steeper rate of decline of -1.2% per year and exhibits the largest absolute losses in the same markets as the Low Even Case. The 2050 consumption of petroleum products changes in the High Even Case by -9.5 quads for on-road vehicles, by -1.7 quads for air transportation, and by -1.0 quads among industrial non-NGL/LPG petroleum.

Because hydrogen is more expensive in the High Uneven Case as compared to the High Even Case (which has the same assumed annual $/MT of CO2e cost of carbon mitigation), hydrogen is less successful in competing against petroleum products – particularly in air, on-road, and waterborne transportation markets. Therefore, petroleum products decline less in the High Uneven Case (-0.8% per year) as compared to the High Even Case (-1.2% per year). The 2050 consumption of petroleum products in the High Uneven Case changes by -9.0 quads for on-road vehicles, by -0.5 quads for air transportation, and by -0.7 quads among industrial non-NGL/LPG petroleum products.

7.2.2.4 Consumption of Coal

In the Reference Case coal consumption declines at a rate of -1.0% per year and reaches 6.9 quads in 2050. (See Exhibit 57) Most of that decline is in the power sector, which declines at a rate of -1.1% per year. The only other significant markets for coal consumption are steam coal and metallurgical coal in the industrial sector, which together decline gradually at a rate of -0.3% per year in the Reference Case.

Exhibit 57: Coal Consumption to 2050



Because coal has relatively high lifecycle GHG emissions and has many potential lower-carbon substitutes, its consumption levels are significantly impacted by the cost of carbon mitigation added in the three Alternative Cases. In the Low Even Case, coal consumption declines at rate of -9.3% per year to 1.0 quad in 2050. A steeper annual rate of decline (-9.7%) is produced in the High Even Case, which ends with 0.8 quads of consumption in 2050. The High Uneven Case results in slightly higher market for coal in 2050 (1.0 quads in absolute level and 0.2 quads bigger than in High Even) because hydrogen is a less competitive fuel against coal and the electricity generation market, where coal best competes, is larger due to more electrification.

As with natural gas, the application of CCUS helps coal preserve market shares. By 2050 in the power sector, CCUS is used for between 75% and 81% of coal consumption. In the industrial sector, CCUS is employed with just 7% to 9% of coal consumption in 2050. The low use of CCUS for coal in the industrial sector occurs because the boiler and other combustion market most likely to employ CCUS switch to lower-carbon fuels rather than use CCUS which enjoys fewer economies of scale at industrial facilities relative to power plants. By 2050 some 75% of the industrial use of steam coal without CCUS is a feedstock to produce coal tars, chemicals, briquettes, etc. and only 25% is combusted as fuel in boilers, kilns, furnaces, etc.

7.2.3 Application of CCUS to Reduce GHG Emissions Across All Sectors

Exhibit 58 shows the lifecycle GHG emissions estimates for the modelled energy markets through the year 2050. Negative emissions expected to come from direct air capture in the Alternative Cases are shown as bars below the x-axis and the net emissions after DAC are shown as red lines. Note that the emissions from the power sector have been allocated to the end-use sectors which consume electricity and, therefore, are not shown separately.

All three Alternative Cases achieve substantial reductions in GHGs relative to the AEO Reference Case, but do not reach net-zero by 2050. The cumulative reductions to GHG from 2020 to 2050 are -37.3% for the High Even Case and -29.9% for the Low Even Case. The 2050 annual reductions are -53.8% for the Low Even Case and -74.4% for the High Even Case. For the High Uneven Case cumulative reductions are -34.1% and 2050 annual reductions are -68.6% versus the Reference Case. The High Even Case is more effective at reducing GHG emissions compared to High Uneven Case because hydrogen is available at lower cost when blue hydrogen is treated equally with other forms of hydrogen in terms of valuing each ton of CO2e mitigated.

Exhibit 58: GHG Emission to 2050

7.2.3.1 Carbon Capture, Use, and Storage

As discussed above, the employment of CCUS allows natural gas and coal to maintain some of their market shares in the industrial and power sectors. In the Low Even Case, CCUS volumes are 801 million metric tons of CO2 per year by 2050. (See Exhibit 59) That volume increases to 1,724 million metric tons in the High Even Case. In the High Uneven Case, the use of CCUS goes up by over 60% in the industrial and power sectors due the fact that hydrogen becomes much less economic and CCUS becomes the best option. However, overall use of CCUS is only 1,464 million metric tons in 2050 because the CCUS associated with blue hydrogen declines substantially in the High Uneven Case.

This underscores the fact that blue hydrogen provides an opportunity to decarbonize natural gas at large facilities that can take advantage of economies of scale and can benefit from being located near suitable geologic sequestration sites. When the option of low-cost blue hydrogen is removed due to policy choices, there are some additional power plants and industrial facilities that will adopt CCUS, but other facilities with poor economies of scale for CCUS, unfavorable geologic settings for underground CO2 storage and onsite space constraints will have limited GHG mitigation options and overall US GHG emissions will be greater.

Exhibit 59: CCUS Volumes in the Alternative Cases

Carbon Capture, Storage and Use (million metric tons): Low Even							
Year	Carbon Dioxide Captured					Storage and Use	
	Power Sector	Industrial Sector	Blue Hydrogen	Direct Air Capture	Sum All Sectors	Use in Synfuels	Geologic Storage
2020	0	0	0	0	0	0	0
2025	125	15	21	0	161	-1	-160
2030	320	48	66	0	434	-4	-431
2035	353	85	131	0	569	-9	-560
2040	348	124	245	0	717	-17	-701
2045	282	160	369	6	816	-24	-793
2050	179	178	445	28	830	-29	-801
2025-2050 %	*46%*	*17%*	*36%*	*1%*	*100%*	*-2%*	*-98%*

Carbon Capture, Storage and Use (million metric tons): High Even							
Year	Carbon Dioxide Captured					Storage and Use	
	Power Sector	Industrial Sector	Blue Hydrogen	Direct Air Capture	Sum All Sectors	Use in Synfuels	Geologic Storage
2020	0	0	0	0	0	0	0
2025	210	26	34	0	269	-1	-268
2030	467	80	118	0	665	-6	-659
2035	446	136	272	0	855	-14	-840
2040	389	169	429	8	995	-26	-969
2045	283	180	531	181	1,175	-34	-1,141
2050	168	177	589	829	1,762	-39	-1,724
2025-2050 %	*34%*	*13%*	*34%*	*18%*	*100%*	*-2%*	*-98%*

Carbon Capture, Storage and Use (million metric tons): High Uneven							
Year	Carbon Dioxide Captured					Storage and Use	
	Power Sector	Industrial Sector	Blue Hydrogen	Direct Air Capture	Sum All Sectors	Use in Synfuels	Geologic Storage
2020	0	0	0	0	0	0	0
2025	212	26	21	0	259	0	-259
2030	499	82	33	0	614	0	-614
2035	518	152	35	0	705	0	-705
2040	499	226	51	8	783	0	-783
2045	417	272	64	181	935	0	-935
2050	269	294	71	829	1,464	0	-1,464
2025-2050 %	*51%*	*22%*	*6%*	*21%*	*100%*	*0%*	*-100%*

7.2.4 Cost of Ownership Across All Sectors

The competition models compute the cost of ownership of major technology/fuel alternatives for each kind of modeled vehicle, appliance or equipment including annualized capital costs, operating and maintenance costs, the cost of energy consumed and the assumed internalized cost of carbon mitigation. The pro forma comparisons of cost of ownership among technology/fuel alternatives are computed per-unit of energy services such as cents per passenger-mile traveled, cents per ton-mile transported, or MMBtu of process heat delivered. For all modeled sectors, this cost of ownership sums to $3.5 trillion dollars in 2020 and increases annually to $5.2 trillion in 2050 in the AEO Reference Case. (See Exhibit 60.) There is no cost of carbon mitigation applied to the AEO Reference Case.

The Alternative Cases have higher costs of ownership than the Reference Case. By 2050 the Low Even Case reaches $5.9 trillion or 13.1% higher than the Reference Case. The High Even Case reaches $6.1 trillion in 2050, an increase of 17.5% over the Reference Case. The High Uneven Case has the highest cost for 2050 among the cases, reaching $6.2 trillion in 2050 or 18.9% more than the Reference Case.

Exhibit 60: Projected Energy Services Costs for AEO Reference and Alternative Cases

	Cost of Ownership All End Uses $billion			
Year	Reference	Low Even	High Even	High Uneven
2020	$3,549	$3,549	$3,549	$3,549
2025	$4,083	$4,244	$4,301	$4,301
2030	$4,361	$4,682	$4,803	$4,798
2035	$4,591	$5,047	$5,236	$5,231
2040	$4,793	$5,362	$5,574	$5,595
2045	$4,993	$5,644	$5,864	$5,908
2050	$5,203	$5,885	$6,112	$6,187
Cumulative $B 2021-50	135,981	148,480	153,049	153,507
% Increase in Cum vs. Ref.		*9.2%*	*12.6%*	*12.9%*

Note: Cost of ownership is the annual cost of energy-consuming vehicles, appliances, equipment, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

7.2.4.1 Cost Effectiveness

Measured in terms of incremental dollars paid by consumers versus reduced metric tons of CO2e, the High Even is 12% more cost effective than the High Uneven Case over the whole forecast period and by the last year of 2050 is 17% more economically efficient. (See Exhibit 61.) This occurs because in the High Uneven Case the $12/MMBtu differential in incentives faced by blue hydrogen leads to large drop in blue hydrogen's market share of hydrogen production and higher hydrogen prices. Without low-cost hydrogen energy, consumers must turn to more costly and less effective GHG mitigation options and the ratio of increased costs divided by reduced GHG emissions is higher.

Exhibit 61: Economic Efficiency of GHG Mitigation

	Change in Cost of Ownership per Change in GHG Emissions ($/MT CO2e)			Increase High Uneven vs High Even
Year	Low Even	High Even	High Uneven	
2025	$285	$310	$314	1.1%
2030	$264	$293	$303	3.4%
2035	$254	$293	$321	9.5%
2040	$248	$284	$327	15.3%
2045	$235	$257	$301	17.2%
2050	$210	$203	$238	17.4%
Average 2021-50	$244	$267	$300	12.4%

7.2.5 Infrastructure Requirements Across All Sectors

The realization of hydrogen's potential to contribute to GHG mitigation goals will require investments into several kinds of infrastructure including blue hydrogen manufacturing, electrolyzers to convert excess and dedicated solar and wind electricity, hydrogen pipelines, hydrogen storage, local hydrogen distribution systems and hydrogen conversion, transport and dispensing for transportation market. The amounts, types and timing of these investments are shown for the three Alternative Cases in Exhibit 62, Exhibit 63, and Exhibit 64.

For the Low Even Case, investments in blue hydrogen manufacturing facilities constitute the largest category, coming to $209 billion or 22% of the $950 billion total requirement. The next largest components are conversion of hydrogen (that is, cryogenic liquefaction or compression to very high pressures) for transportation markets, hydrogen pipelines, local hydrogen distribution systems, and electrolyzers.

The High Even Case has greater demand for hydrogen compared to the Low Even Case (12.9 quads versus 9.9 quads in 2050) and has a higher requirement for capital expenditures ($1.27 trillion versus $0.95 trillion). The percent allocation of expenditures among categories is similar to High Even with blue hydrogen manufacturing again being the largest category with about 22% of the total.

The pattern of investment for the High Uneven Case is different from the other two cases in that electrolyzers are the largest category of investment, and the expenditure pattern is backloaded rather than peaking in the 2030's. Also, the overall level of investment is the lowest among the three Alternative Cases. Another point of note is that the high hydrogen prices associated with the High Uneven Case leads to the virtual elimination of hydrogen demand in the residential and commercial sectors. That consumption would be served through local hydrogen distribution systems. The near elimination of residential/commercial demand in the High Uneven Case is why investment in local hydrogen distribution system is so low in that case relative to the other cases.

Exhibit 62: Projected Capital Expenditures of Hydrogen Infrastructure: Low Even

Hydrogen infrastructure Capital Expenditures (billion$): Low Even									
Period	Blue H2 Production	Green H2 Electrolyzers	Green H2 Dedicated W & S Generation	H2 Storage	H2 Pipelines	H2 Distribution Line	Fuel Conversion for Transport Market	Fuel Dispensing for Transport Market	All Categories
2021-25	$11	$1	$1	$2	$6	$2	$4	$2	$30
2026-30	$23	$2	$3	$4	$14	$5	$13	$5	$69
2031-35	$32	$41	$5	$10	$25	$42	$30	$10	$194
2036-40	$54	$19	$6	$14	$37	$35	$47	$18	$230
2041-45	$56	$14	$6	$15	$39	$34	$43	$16	$223
2046-50	$33	$34	$4	$11	$33	$15	$54	$21	$205
Sum over 2021-2050	$209	$111	$25	$56	$154	$133	$190	$71	$950
Percent of All H2-related Capex	*22.0%*	*11.7%*	*2.6%*	*5.9%*	*16.2%*	*14.0%*	*20.0%*	*7.5%*	*100.0%*

Exhibit 63: Projected Capital Expenditures of Hydrogen Infrastructure: High Even

Hydrogen infrastructure Capital Expenditures (billion$): High Even									
Period	Blue H2 Production	Green H2 Electrolyzers	Green H2 Dedicated W & S Generation	H2 Storage	H2 Pipelines	H2 Distribution Line	Fuel Conversion for Transport Market	Fuel Dispensing for Transport Market	All Categories
2021-25	$18	$2	$2	$3	$10	$3	$6	$2	$46
2026-30	$43	$4	$5	$8	$25	$9	$24	$7	$126
2031-35	$76	$43	$10	$21	$52	$84	$50	$16	$351
2036-40	$74	$29	$8	$19	$51	$46	$68	$24	$319
2041-45	$46	$16	$5	$13	$35	$27	$57	$19	$219
2046-50	$25	$39	$3	$9	$31	$8	$64	$24	$204
Sum over 2021-2050	$282	$135	$33	$73	$204	$177	$269	$93	$1,266
Percent of All H2-related Capex	*22.3%*	*10.6%*	*2.6%*	*5.8%*	*16.1%*	*14.0%*	*21.3%*	*7.3%*	*100.0%*

Exhibit 64: Projected Capital Expenditures of Hydrogen Infrastructure: High Uneven Case

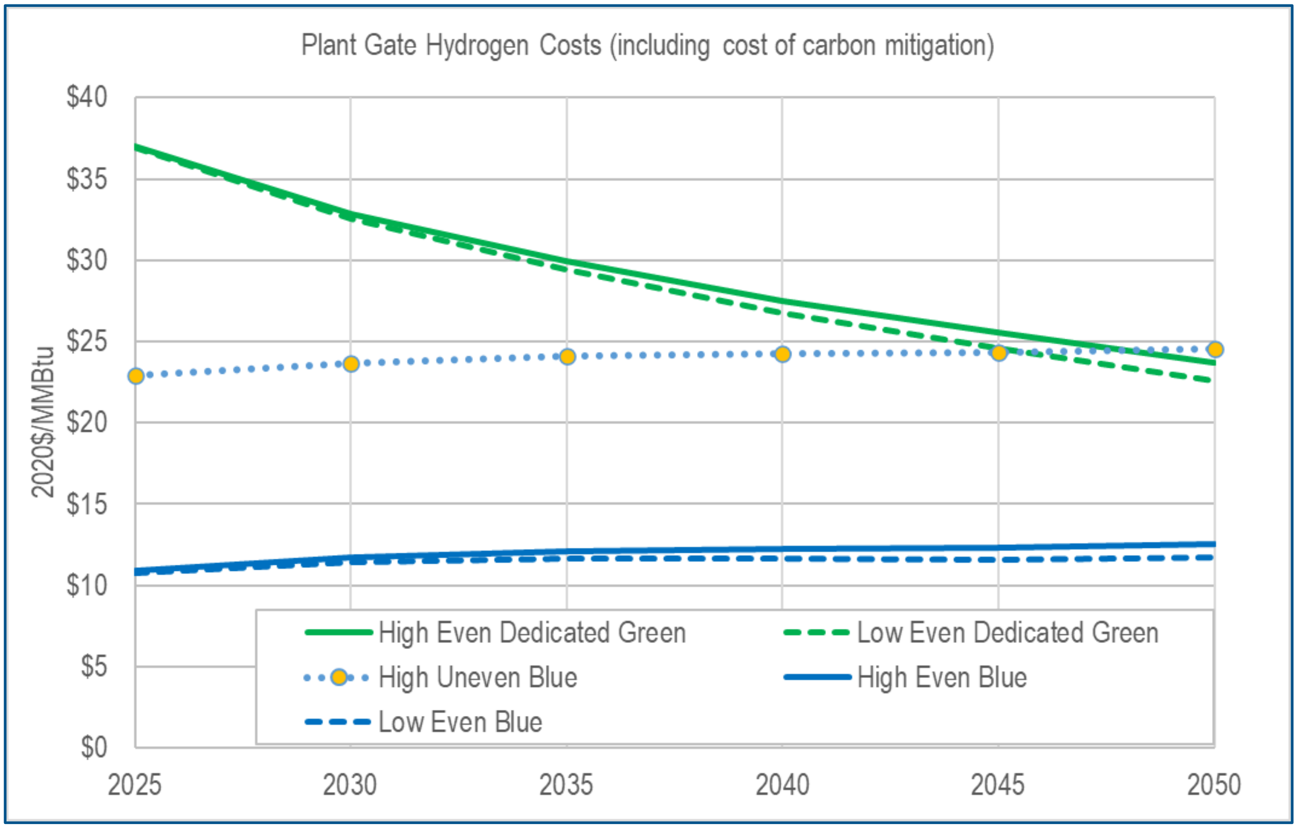
Hydrogen infrastructure Capital Expenditures (billion$): High Uneven									
Period	Blue H2 Production	Green H2 Electrolyzers	Green H2 Dedicated W & S Generation	H2 Storage	H2 Pipelines	H2 Distribution Line	Fuel Conversion for Transport Market	Fuel Dispensing for Transport Market	All Categories
2021-25	$11	$1	$1	$2	$6	$2	$5	$2	$31
2026-30	$6	$1	$1	$1	$4	$3	$11	$4	$30
2031-35	$1	$34	$2	$2	$6	$5	$18	$7	$76
2036-40	$7	$37	$21	$4	$10	$8	$26	$11	$125
2041-45	$6	$38	$54	$4	$10	$7	$26	$10	$155
2046-50	$3	$90	$119	$7	$20	$15	$49	$19	$322
Sum over 2021-2050	$35	$202	$198	$20	$57	$40	$135	$54	$739
Percent of All H2-related Capex	*4.7%*	*27.3%*	*26.8%*	*2.6%*	*7.7%*	*5.4%*	*18.3%*	*7.3%*	*100.0%*

7.3 Sector Details: Hydrogen Production

The economics of blue hydrogen evaluated here are based on autothermal reforming (ATR) with 97% carbon capture (of emissions at the production plant) and geologic storage. The price of natural gas used by the ATR plant is assumed to be the national average industrial price from the 2021 AEO Reference Case. This industrial natural gas price ranges from $3.81 to $4.52 and averages $4.29/MMBtu from 2025 to 2050. The price of electricity used in electrolyzers can be modelled as the average electricity price to industrial consumers from the AEO or the cost of marginal new solar and wind power plants that would be dedicated to serving the electrolyzers. The power plant capital costs, operating and maintenance cost and performance characteristics of wind and solar (including the effects of future technological improvements) are taken from the AEO modeling assumptions. As shown in Exhibit 65, the results of this analysis suggest that blue hydrogen made from natural gas may be considerably less expensive than green hydrogen from electrolyzers even when electrolyzers use dedicated solar/wind renewable electricity. However, if policies were to create a $12/MMBtu differential in incentives for blue hydrogen relative to green hydrogen, green hydrogen would become less expensive than blue hydrogen after 2045.

Given these economics, blue hydrogen is expected to make up nearly all of the supply from dedicated, continuous hydrogen production facilities in the Low Even and High Even Cases. However, the large amounts of solar and wind generation expected in the Alternative Cases may lead to “excess electricity” when electricity load is less than generation from non-dispatchable/inflexible generation. Assuming that this excess electricity is not curtailed but mostly is used to make hydrogen in electrolyzers, the hydrogen made from excess electricity in the High Even Case could total over 1,100 TBtu in 2050 and make up about 7% of project hydrogen demand in the US from 2025 to 2050 (See Exhibit 66). In the Low Even Case, overall hydrogen demand is lower and excess electricity is the source of 9% of hydrogen supplies over the forecast period while dedicated solar/wind is the source of just 2% of hydrogen supply – the same proportion as in the High Even Case.

Exhibit 65: Cost of Producing Hydrogen



Note: Green hydrogen costs are based on dedicated solar and wind generation producing electricity at a lifecycle cost averaging $49.50/MWh in 2025 and declining to $33.50/MWh in 2050. The cost of grid electricity under average industrial electricity tariffs would be higher at approximately $65/MWh over that period. The cost of blue hydrogen in the High Uneven Case is represented as a $12/MMBtu cost increase relative to the High Even Case, which also has the cost of carbon mitigation rising to $250/MT of CO2e in 2050.

Exhibit 66: Projected Market Shares for Modelled Hydrogen Production Options

	Low Even Case (TBtu)				High Even Case (TBtu)				High Uneven Case (TBtu)			
Year	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply	Blue H2	Dedicated Green H2	Green H2 from Excess Electricity	Total H2 Supply
2025	414	8	0	423	659	13	0	672	408	8	0	416
2030	1,290	26	1	1,317	2,291	47	1	2,339	639	13	1	652
2035	2,555	59	326	2,940	5,307	115	313	5,734	684	28	286	999
2040	4,781	107	475	5,364	8,352	182	546	9,080	986	192	500	1,679
2045	7,181	159	588	7,928	10,341	225	696	11,263	1,247	653	485	2,384
2050	8,661	197	995	9,853	11,468	258	1,181	12,908	1,389	1,773	547	3,709
average market share 2025-2050	*89%*	*2%*	*9%*	*100%*	*91%*	*2%*	*7%*	*100%*	*54%*	*27%*	*18%*	*100%*

Note: The study did not model all methods of producing hydrogen such as those using biomass, coal, or nuclear power. To the extent any of these prove to be economic, the market shares for blue hydrogen and electrolysis (using grid electricity, dedicated wind/solar or "excess electricity") may be lower than shown here.

In the High Uneven Case, the $12/MMBtu differential in incentives faced by blue hydrogen leads to a much smaller market for hydrogen (3.7 quads in 2050) and a substantial change in the mix of hydrogen supply sources. When blue hydrogen has lower incentives its market share in hydrogen production drops from around 90% in the High Even and Low Even Cases to 54%. Hydrogen from dedicated solar/wind represents 27% of supplies and hydrogen from excess electricity is the final 18%.

7.4 Sector Details: Power Sector

The power sector modelling conducted for this study was intended to address the following questions:

- How would the electricity sector respond to the assumed policies to encourage low-carbon generation up to a willingness to pay (cost of carbon mitigation) of $150 to $250 per metric ton of CO2e by 2050? How will generating capacity and the fuel use change and will there be demand for hydrogen as a low-carbon fuel in power plants?
- What changes in overall electricity demands and load profiles (that is, the shape of hourly demands) would occur due to electrification in end-use sectors?
- What might be the effects of managing the hourly recharging patterns of electric vehicles to better integrate large amounts of solar and wind generation and reduce the needs for peak generation capacity and electric storage?
- Will there be a demand for hydrogen as an intermediate carrier to store electricity for a short-term (within one day or one week) or long-term (seasonal) basis?
- How would the operation of electrolyzers be integrated into the operation of electrical systems to balance supply and demand and utilize “excess electricity” that might occur in hours when intermittent renewable and nuclear power generation exceeds loads?
- What will be the impact of all these changes to the price of electricity paid by consumers?
- What will be the impact of all these changes to the level of GHG emitted by the power sector?

While the analysis conducted for this study did not delve into all aspects of these questions or go into great depths for each, the study does conclude that the power sector may make many significant adjustments:

- By 2050, electricity demand may go up by 36% to 64% in the Alternative Cases as end-use consumer shifts from fossil fuels to electricity. Load shapes may be altered by the increases in wintertime space heating loads in the residential, commercial, and industrial sectors and electric vehicle recharging.
- Fossil fuel use for power generation may be sharply reduced and the remaining use of fossil fuels may be shifted mostly to gas with CCUS, hydrogen and to a smaller extent coal with CCUS.
- Hydrogen consumed as a fuel in power plants may reach as high as 886 TBtu and 1,423 TBtu in the Low Even and High Even Cases, respectively.
- Generation from renewables (primarily wind) may go up sharply compared to the AEO, but substantial fossil capacity may have to be preserved to maintain reserve margins.

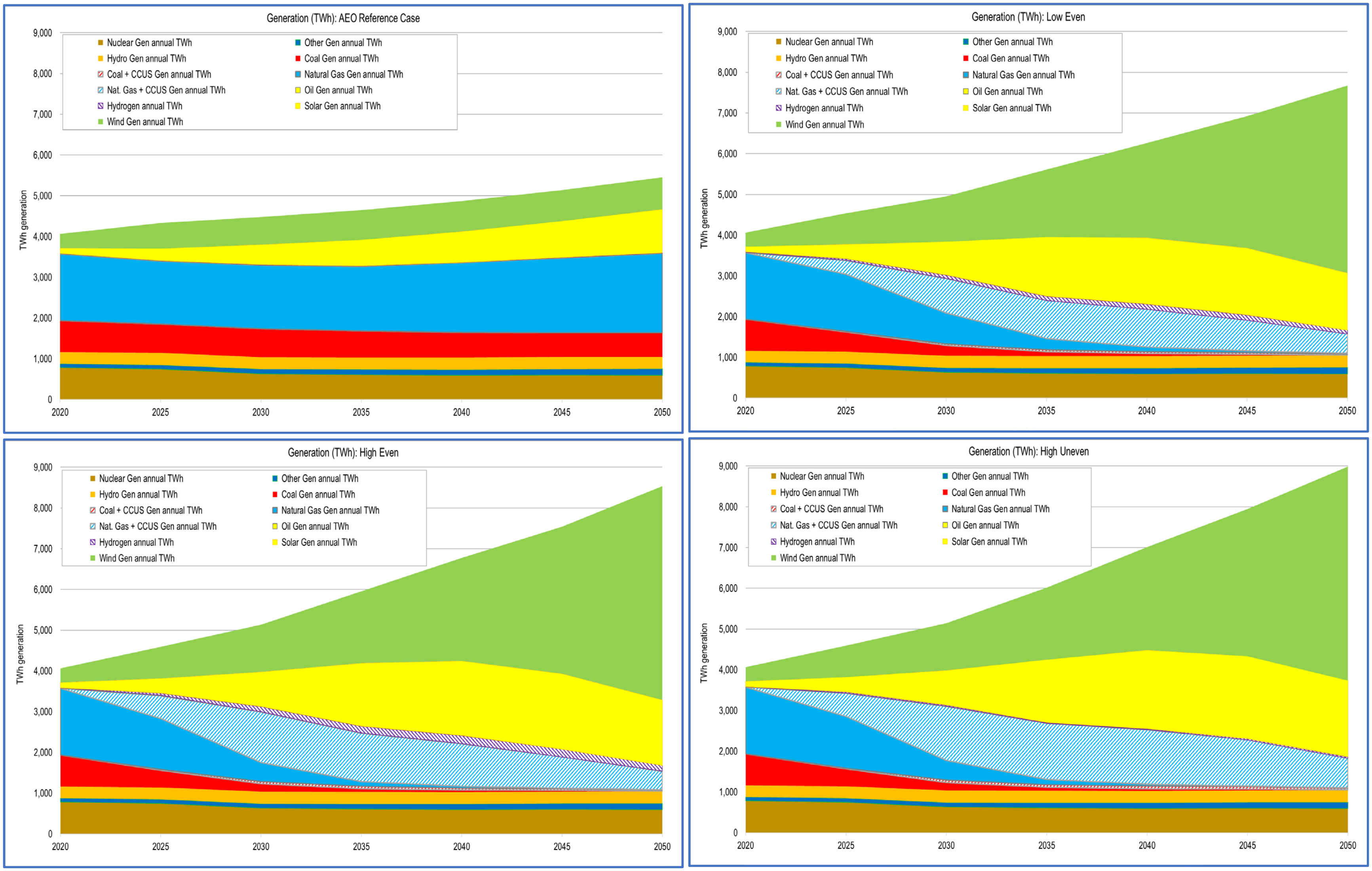
- The intermittent renewable plants cannot follow load and so there may be considerable "excess electricity" generation in hours when load is less than generation from non-dispatchable/inflexible generation.
- This excess generation is expected to occur even after assuming a considerable portion of electric vehicle recharging (75% of light-duty and 50% of heavy-duty vehicles) is shifted to hours when solar/wind generation is highest.
- Given this study's assumptions for the cost and performance of storage technologies, it may not be economic to store this excess electricity for long periods. Most likely this excess electricity will not be curtailed but may be used to make hydrogen in electrolyzers. In 2050, the hydrogen that could be made from excess electricity may total 546 to 1,181 TBtu or 7% to 18% of project hydrogen demand in the US.
- Despite the higher electricity consumption caused by electrification, 2050 GHG LCA emissions from the power sector may go from 1,597 million metric tons CO2e in the AEO Reference Case to 287 to 351 million metric tons in the Alternative Cases – reductions of 78% to 82%.
- The AEO Reference Case projects declining real wholesale electricity generation costs, which go from $67.04/MWh in 2025 to $52.19/MWh in 2050. The Alternative Cases developed here project wholesale electricity generation costs that are 24% to 30% higher than the AEO Reference Case averaged from 2025 to 2050.

7.4.1 Electricity Generation by Type

The AEO's capacity for hydro, nuclear and other/imports are not changed in creating the Alternative Cases. However, the amounts of solar, wind, and fossil capacity are adjusted by the model to meet incremental electricity demands and maintain reserve margins at the lowest possible costs. The annual and hourly generating patterns for solar, wind, hydro, and nuclear power are determined by the annual capacity utilizations rates from the AEO with generation allocated to hours based on historical generating data. Both the capacity mix and dispatch for fossil capacity is determined using a market share equation. For capacity decisions, the market share is computed using the $/MWh levelized full cost of production (sum of capital, FOM, VOM, fuel, carbon mitigation cost). For the dispatch decision, the $/MWh dispatch costs (VOM, fuel, carbon mitigation cost) is used. When a cost of carbon mitigation imposed, this market methodology shifts capacity and generation toward renewables, natural gas with CCS and to a lesser extent hydrogen and reduces fossil use overall all. The capital cost, O&M costs and heat rates assumed in this competition are derived largely from the AEO. The 2021 AEO modelling system did not have a representation of hydrogen-fueled gas turbine and combined cycle power plants, but ICF has assumed such plants will have costs and heat rates that are the same as their natural gas counterparts.

The results of this process for electricity generation by energy source is shown in Exhibit 67. The cases differ in terms of total generation in that the Alternative Cases have large amounts of electrification that increase generation by 36% to 64% by 2050. In addition, the Alternative Cases show a dramatic change in the mix of generation with much greater amounts of wind and solar generation and lesser amounts of coal and natural gas generation. The amounts of coal and natural generation that remains is mostly shifted to power plants employing CCUS.

Exhibit 67: Projected Power Generation to 2050



The Alternative Cases result in generation from wind exceeding that from solar, which is a reversal of the relative market shares shown in the AEO Reference Case. This occurs because solar has a larger lifecycle GHG footprint compared to wind and so when a cost of carbon mitigations is added, wind becomes more economic relative to solar power.

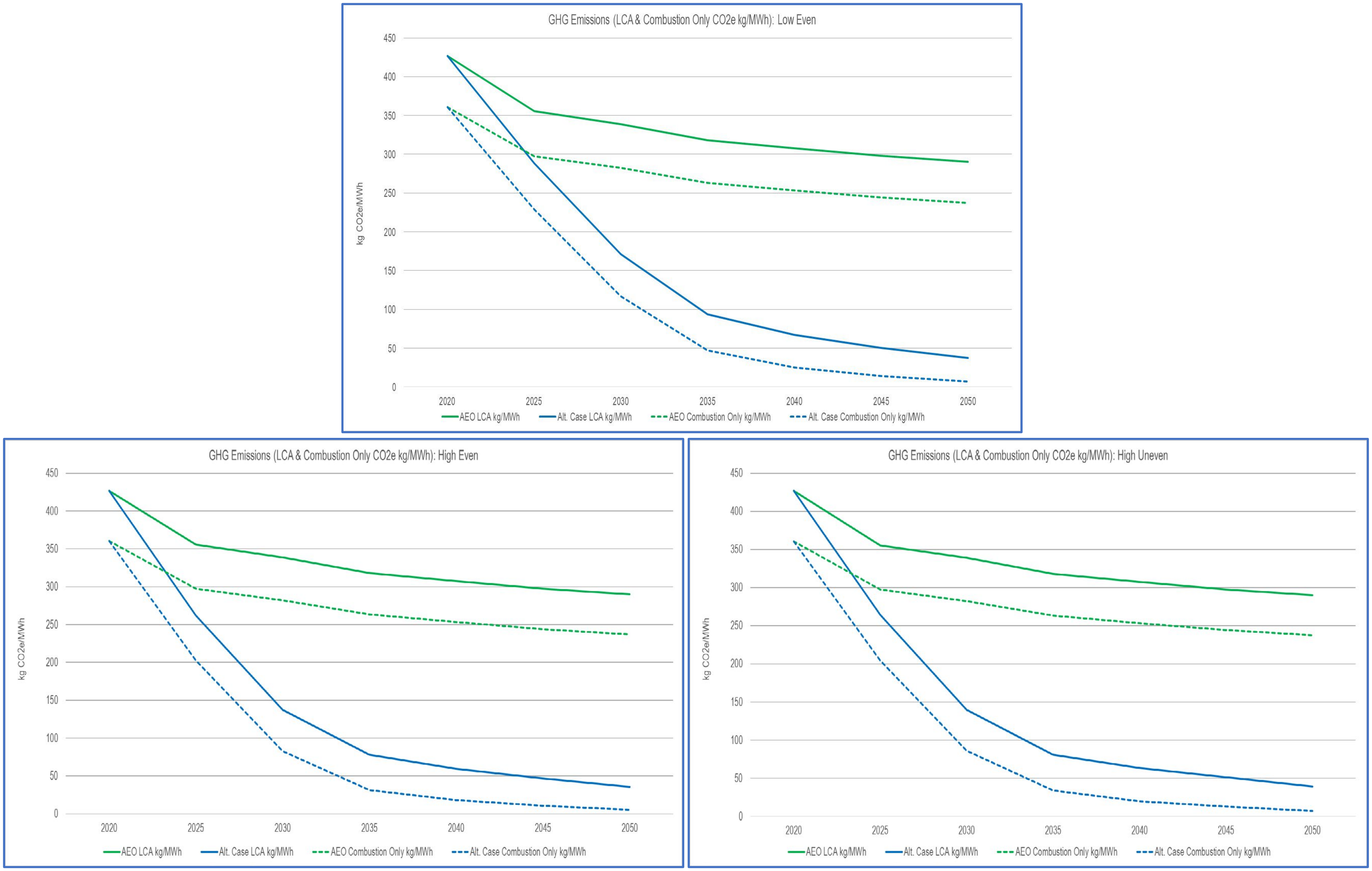
7.4.2 GHG Emissions in the Power Sector

GHG emissions from the power sector are computed by multiplying the forecasted generation for each technology/fuel by the appropriate emission factor. Using emission factors computed on lifecycle basis and summing across all energy sources, 2050 emissions from the power sector are projected to be about 1,597 million metric tons CO2e in the AEO Reference Case. The shift in the Alternative Cases toward greater portions of generation coming from wind, solar and fossil with CCUS may lead to reductions of LCA GHG's of 78% to 82% and bring totals to 287 to 351 million metric tons CO2e in 2050.

GHG emissions per megawatt-hour are shown in Exhibit 68 on an LCA basis and on a "combustion only" basis which counts just the CO2 generated by use of the fuel by end-users (and not any GHG emissions along the supply chain that produces the fuel and delivers it to the end-user). On an LCA basis, GHG emission start at 427 kg/MWh in 2020 and go down to 290 kg/MWh in the Reference Case. The reduction in LCA emissions by 2050 are greater in the Alternative Cases, reaching 37 kg CO2e/MWh in the Low Even Case, 36 kg CO2e/MWh in the High Even Case and 39 kg CO2e/MWh in the High Uneven Case

The same pattern is seen in the "combustion only" emissions which are measured in kilograms of carbon dioxide rather than kilograms of CO2-equivalent. The "combustion only" emissions start at 361 kg CO2/MWh in 2020 and reach 237 in 2050 in the Reference Case. The "combustion only" GHG emissions in the Alternative Cases reach 6 to 7 kg CO2/MWh and consist of a small amount of fossil fuels used without CCUS and the uncaptured portion (10%) of emission from fossil fuel used with CCUS.

Exhibit 68: Per-unit GHG Emissions from the Power Sector to 2050



7.4.3 Excess Electricity and Use of Electric Storage

The solution process to forecast power sector capacity and dispatch allows for total generation in any hour to exceed load. Under an economically optimum solution, generation would be expected to exceed loads only when non-dispatchable/inflexible hourly generation sources are greater than loads (and dispatchable fossil generation is zero). When such “excess electricity” occurs, the model classifies it as “storage charging/curtailments/other uses.” Depending on how the model is run and economics under a modelling scenario, such excess electricity might be stored and then discharged whenever load exceeds the sum of nuclear + hydro + solar + fossil generation. Such storage can be either “short-term” (the charge-discharge cycle occurs within one day or one week) or long-term electric storage (charge-discharge cycle occurs over two or more months). Alternatively, this excess electricity can be thought of as being curtailed or used for some other purpose such as making hydrogen in electrolyzers.

When excess electricity is stored and then discharged, there is a “roundtrip loss” that is modelled as 10% for short-term storage (assumed to be batteries) and 55% for long-term storage (assumed to be a process where electricity is converted to hydrogen, stored underground and then made back into electricity in a combined cycle power plant). With such a large loss factor and high capital costs for long-term electricity storage, the modelling results show that it may not be economic to store electricity for long periods of time as it would be cheaper to build more renewables to meet winter and summer peak loads, even if the resulting excess electricity were curtailed (that is, the excess electricity is assigned a zero value). However, such excess electricity is assumed in the modelling to mostly be used to make hydrogen which can be used as a fuel or industrial feedstock.

As shown below in Exhibit 69, electricity storage capacity in these case ranges from 221 GW to 292 GW and represents 20% to 24% of peak capacity. Additional results related to electricity storage capacity and annual charging and discharging are shown in Exhibit 70, Exhibit 71, and Exhibit 72 for the three Alternative Cases.

Exhibit 69: Electricity Storage versus Peak Loads in 2050

Case	2050 Electric Storage Capacity (GW)	2050 Peak Load (GW)	Storage Capacity as % of Peak Load
Low Even	221	1,094	20%
High Even	270	1,191	23%
High Uneven	292	1,227	24%

After accounting for the charging of electricity storage capacity, there still will be considerable "excess electricity" generation in hours when load is less than generation from non-dispatchable/ inflexible generation starting in the 2035 model year. This excess generation is expected to occur despite the cases assuming that a considerable portion of electric vehicle recharging (75% of light-duty and 50% of heavy-duty vehicles) is shifted to hours when solar/wind generation is highest. By 2050 the excess electricity (after accounting for storage charging) in the Low Even Case is 377 TWh or 4.9% of all generation. The excess electricity total for the High Even Case is 447 TWh and for the High Uneven Case 389 TWh. If all the excess electricity in 2050 were to be made into hydrogen, the amount of hydrogen would total 546 to 1,181 TBtu or 7% to 18% of project hydrogen demand in the US.

Exhibit 70: Electricity Storage and Excess Generation: Low Even Case

Year	2025	2030	2035	2040	2045	2050
ST Storage Disch. Capacity GW	12.7	50.4	114.8	151.1	187.2	221.0
ST Storage Charge Capacity GW	14.1	56.0	127.5	167.9	208.0	245.5
ST Storage Discharge TWh	33.1	114.4	184.1	233.8	288.9	355.2
ST Storage Charge TWh	36.8	127.2	204.6	259.7	321.1	394.6
ST Storage CU	29.9%	25.9%	18.3%	17.7%	17.6%	18.3%
ST Storage Losses	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
LT Storage Disch. Capacity GW	-	-	-	-	-	-
LT Storage Charge Capacity GW	-	-	-	-	-	-
LT Storage Discharge TWh	-	-	-	-	-	-
LT Storage Charge TWh	-	-	-	-	-	-
LT Storage CU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LT Storage Losses	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Total Charge+Curt+Other TWh	36.8	127.6	328.1	439.7	543.7	771.3
LT+ST Charge Losses TWh	3.7	12.7	20.5	26.0	32.1	39.5
Avr. Storage Losses	10.0%	10.0%	6.2%	5.9%	5.9%	5.1%
Excess for other uses in TWh	-	0.5	123.5	180.0	222.7	376.7
Excess for other in TBtu elec.	-	1.6	421.5	614.1	759.7	1,285.3
Excess for other in TBtu of H2	-	1.3	332.9	485.1	600.1	1,015.3
Exc. for other kilotonnes of H2	-	9.6	2,470.6	3,599.7	4,453.1	7,534.0
ST & LT Store as %S&W gen.	*3.28%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*
ST & LT Store as %all gen.	*0.80%*	*2.55%*	*3.62%*	*4.13%*	*4.62%*	*5.14%*
Excess elec. as %S&W gen.	*0.00%*	*0.02%*	*3.96%*	*4.55%*	*4.55%*	*6.27%*
Excess elec. as %all gen.	*0.00%*	*0.01%*	*2.19%*	*2.86%*	*3.21%*	*4.90%*

Notes: ST=short-term, LT=long-term, CU=capacity utilization rate, GW=gigawatt, TWh=terawatt-hours, S&W=solar and wind

Exhibit 71: Electricity Storage and Excess Generation: High Even Case

Year	2025	2030	2035	2040	2045	2050
ST Storage Disch. Capacity GW	13.7	55.3	127.7	177.9	223.0	270.4
ST Storage Charge Capacity GW	15.2	61.4	141.9	197.7	247.7	300.4
ST Storage Discharge TWh	33.6	118.8	195.7	257.7	323.1	405.4
ST Storage Charge TWh	37.3	132.0	217.5	286.3	358.9	450.5
ST Storage CU	28.0%	24.5%	17.5%	16.5%	16.5%	17.1%
ST Storage Losses	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
LT Storage Disch. Capacity GW	-	-	-	-	-	-
LT Storage Charge Capacity GW	-	-	-	-	-	-
LT Storage Discharge TWh	-	-	-	-	-	-
LT Storage Charge TWh	-	-	-	-	-	-
LT Storage CU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LT Storage Losses	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Total Charge+Curt+Other TWh	37.3	132.3	336.0	492.9	622.6	897.7
LT+ST Charge Losses TWh	3.7	13.2	21.7	28.6	35.9	45.0
Avr. Storage Losses	10.0%	10.0%	6.5%	5.8%	5.8%	5.0%
Excess for other uses in TWh	0.0	0.3	118.5	206.6	263.7	447.3
Excess for other in TBtu elec.	0.0	1.0	404.4	704.8	899.6	1,526.0
Excess for other in TBtu of H2	0.0	0.8	319.4	556.7	710.6	1,205.4
Exc. for other kilotonnes of H2	0.0	6.1	2,370.2	4,131.4	5,273.1	8,945.2
ST & LT Store as % S&W gen.	*3.28%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*
ST & LT Store as % all gen.	*0.81%*	*2.55%*	*3.63%*	*4.21%*	*4.75%*	*5.27%*
Excess elec. as % S&W gen.	*0.00%*	*0.02%*	*3.58%*	*4.74%*	*4.82%*	*6.52%*
Excess elec. as % all gen.	*0.00%*	*0.01%*	*1.98%*	*3.04%*	*3.49%*	*5.24%*

Notes: ST=short-term, LT=long-term, CU=capacity utilization rate, GW=gigawatt, TWh=terawatt-hours, S&W=solar and wind

Exhibit 72: Electricity Storage and Excess Generation: High Uneven Case

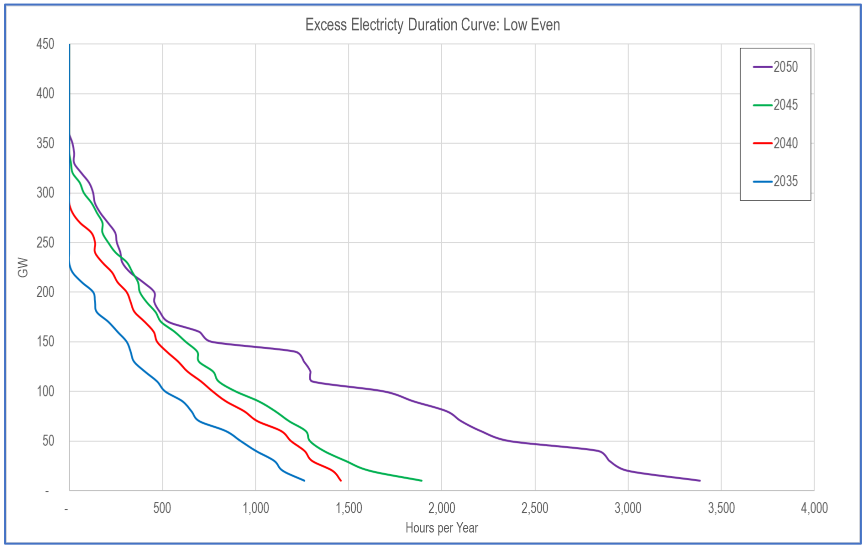
Year	2025	2030	2035	2040	2045	2050
ST Storage Disch. Capacity GW	13.7	55.3	127.7	186.1	237.1	291.8
ST Storage Charge Capacity GW	15.2	61.4	141.9	206.8	263.4	324.2
ST Storage Discharge TWh	33.6	118.8	195.7	263.7	333.3	421.1
ST Storage Charge TWh	37.3	132.0	217.5	293.0	370.3	467.9
ST Storage CU	28.0%	24.5%	17.5%	16.2%	16.0%	16.5%
ST Storage Losses	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
LT Storage Disch. Capacity GW	-	-	-	-	-	-
LT Storage Charge Capacity GW	-	-	-	-	-	-
LT Storage Discharge TWh	-	-	-	-	-	-
LT Storage Charge TWh	-	-	-	-	-	-
LT Storage CU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LT Storage Losses	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Total Charge+Curt+Other TWh	37.3	132.3	326.7	502.6	618.0	856.6
LT+ST Charge Losses TWh	3.7	13.2	21.7	29.3	37.0	46.8
Avr. Storage Losses	10.0%	10.0%	6.7%	5.8%	6.0%	5.5%
Excess for other uses in TWh	-	0.3	109.3	209.6	247.6	388.7
Excess for other in TBtu elec.	-	1.0	372.8	715.1	845.0	1,326.3
Excess for other in TBtu of H2	-	0.8	294.5	564.9	667.4	1,047.6
Exc. for other kilotonnes of H2	-	5.8	2,185.4	4,191.9	4,952.8	7,774.3
ST & LT Store as % S&W gen.	*3.28%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*	*6.57%*
ST & LT Store as % all gen.	*0.81%*	*2.55%*	*3.60%*	*4.17%*	*4.65%*	*5.21%*
Excess elec. as % S&W gen.	*0.00%*	*0.01%*	*3.30%*	*4.70%*	*4.39%*	*5.46%*
Excess elec. as % all gen.	*0.00%*	*0.01%*	*1.81%*	*2.98%*	*3.11%*	*4.33%*

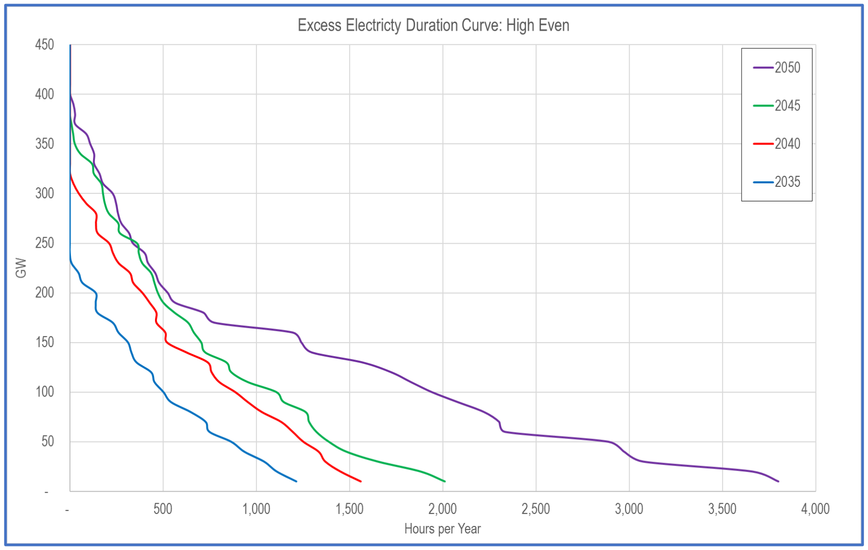
Notes: ST=short-term, LT=long-term, CU=capacity utilization rate, GW=gigawatt, TWh=terawatt-hours, S&W=solar and wind

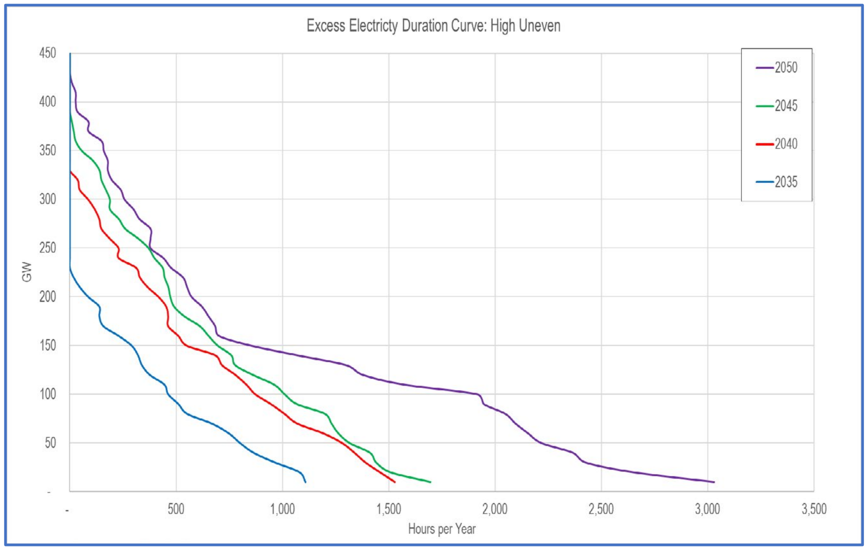
Another way of looking at excess electricity generation is through "duration curves" indicating how many hours in a year may have excess generation above a given gigawatt level. (See Exhibit 73.) These duration curves can be used to determine the feasible capacity utilization rates for electrolyzers or other means of using the excess generation. All three Alternative Cases show a similar pattern in that the amount of excess generation (height on the y-axis) grows each model year from 2035 to 2050 and that the maximum number of hours of duration of excess load (distance to the right on x-axis) also increases. The three cases show the maximum duration of excess generation reaching 3,000 to 3,800 hours each year which would translate into an annual capacity utilization rate of 34% to 43% for electrolyzers or other uses. However, high rates of capacity utilization can only apply to a portion of the excess generation (that is, the corresponding gigawatt amount on the y-axis.) For example, if one assumes that the minimum economically viable annual utilization rate for using the excess generation is 15% (1,314 or more hours per year), then 140 GW of excess generation could be used economically in the High Even Case in 2050. This amounts to 78% of the total available MWh of excess generation (that is, the area under the duration curve starting from a horizontal line at y=140 GW is 78% of the total area under the curve).

There are strong seasonal patterns to when generation from solar, wind, nuclear, and hydro is expected to exceed load. The months of March, April, May, which are characterized by springtime high winds and relatively low, "shoulder month" electricity demand, are expected to produce about 75% of the generation above load in 2050 in the High Even Case. The next largest seasonal contributor to generation above load is the fall (September, October, November) with 12% of the annual total.

Exhibit 73: Excess Generation Duration Curves



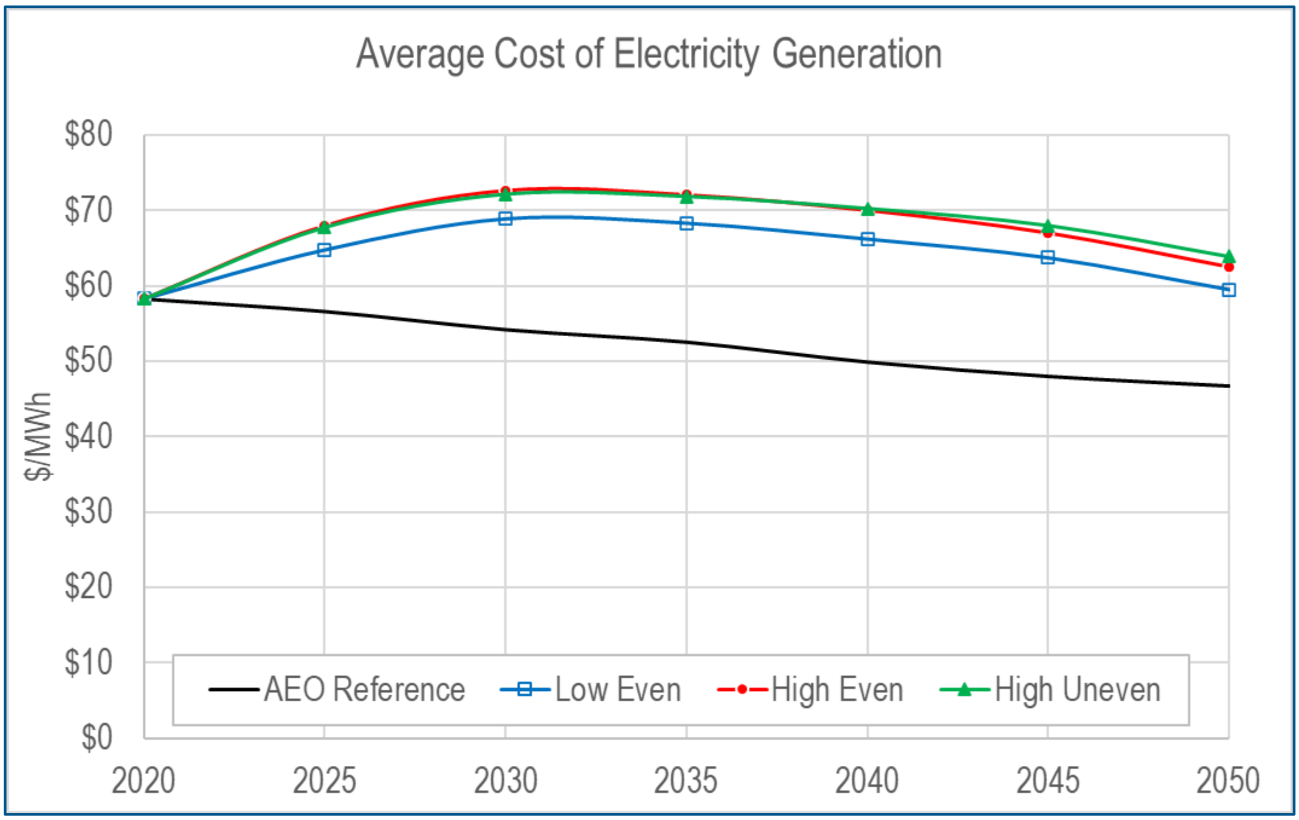




7.4.4 Cost of Electricity Generation

As shown in Exhibit 74, the AEO Reference Case projects declining real wholesale electricity generation costs, which go from $67.04/MWh in 2025 to $52.19/MWh in 2050. The decline is due to an increasing reliance on wind and solar power, which benefit from continued technology advances that drive down their costs. The average electricity generating costs over the 2025 to 2050 period is $58.26/MWh for the Reference Case. The Alternative Cases have wholesale electricity generation costs that are 24% to 30% higher during the 2025 to 2050 period including the cost of carbon mitigation. If transmission and distribution markups remain the same as the AEO per unit of electricity consumed (as is assumed in the Alternative Cases), these wholesale cost increases will translate to 12.8% to 16.3% increases to retail electricity prices paid by consumers across all end-use sectors in the Alternative Cases.

Exhibit 74: Average Cost of Electricity Generation (real 2020$)



7.5 Sector Details: Industrial Sector

The industrial sector is characterized by a wide variety of production processes, fuels, and energy-consuming equipment. In the AEO Reference Case projection for the years 2020 to 2050, the industrial sector accounts for approximately 38.8 percent of US end-use energy consumption (including petrochemical and other feedstocks) and 32.6% percent of projected GHG emissions (including allocated emissions from the power sector). The Alternative Cases examined here suggest that industrial GHG emission could be reduced by 54% to 60% by 2050 with the cost of carbon mitigation going up to between $150 and $250 per metric ton of CO2e.

Hydrogen consumption in the industrial sector might be as high as 4,931 TBtu and would take place in (a) process heat applications, (b) feedstock uses where blue and green hydrogen can substitute for hydrogen and syngases made from natural gas using a conventional SMR process, (c) several other applications where natural gas is now used including boilers, turbine/combined heat and power, and space heating.

7.5.1 Delivered Prices for the Industrial Sector

The average delivered fuel prices for industrial energy users in the Reference and Alternative Cases are shown in Exhibit **75**. The Reference Case fuel prices are those reported by EIA for the AEO 2021 Reference Case. The Reference fossil fuel prices have been adjusted upward in each Alternative case by an amount equal to each fuel's lifecycle GHG emissions times the assumed cost of carbon mitigation for each model year. The Low Even Case assumes a 2050 cost of carbon mitigation of $150 per metric ton of CO2e and the High Even and High Uneven Cases both assumes a 2050 cost of carbon mitigation of $250 per metric ton of CO2e.

The wholesale generation prices for electricity are estimated in the electricity sector model discussed earlier in this chapter and are marked up to produce retail prices for each end-use sector using the annual national-average transmission and distribution (T&D) markups from the AEO Reference Case. For the industrial sector, the average electricity T&D markup from 2020 to 2050 is 1.32 cents per kilowatt-hour ($13.20/MWh).

The annual wholesale composite hydrogen prices are the weighted average cost of producing hydrogen from natural gas and from electrolysis using electricity from dedicated solar and wind. The market shares from each production technology are computed using the same market share equation employed for energy end-user markets. The cost of making hydrogen produced from excess electricity does not enter into the calculation of composite wholesale hydrogen cost because it is assumed that such production would be a price taker (with the price paid for the excess electricity roughly reflecting the composite hydrogen price found in the market minus the capital and O&M cost of the electrolyzer). The retail price of delivered hydrogen to each end-user sector and market reflects the cost of delivering the hydrogen to consumers in the required form (pipeline, highly compressed gas, liquid). For the industrial sector, delivery is assumed to be overwhelmingly from pipelines with a markup of $1.19/MMBtu.

Exhibit 75: Industrial Sector Fuel Prices

7.5.2 Fuel Mix Results for the Industrial Sector

The projected fuel mix in the industrial sector is shown on a percentage basis in Exhibit 76. The Reference Case shares for each fuel type shows little change over the 2020 to 2050 forecast period. In comparison, the Low Even and High Even Cases show substantial declines in the use of natural gas and coal and increased consumption of electricity, hydrogen, and biomass/biofuels. The increases and decreases are more severe in the High Even Case as compared with the Low Even Case because the fuel prices differences are larger between high-carbon fuels versus low-carbon fuels.

The High Uneven Case has the same cost of carbon mitigation as the High Even Case and generally the same fuel prices, except that blue hydrogen is assumed to have a $12/MMBtu differential in incentives compared to green hydrogen. This causes the composite wholesale cost of hydrogen to be much higher and results in a much smaller market for hydrogen in all end-use sectors. For the industrial sector, hydrogen market share goes from 14.5% in the High Even Case to just 0.7% in the High Uneven Case. This lost market share is made up by increased use of natural gas (often with CCUS) and electricity.

The consumption of fuels and feedstocks in the industrial sector are shown in units of trillion Btus per year in Exhibit 77 and in Exhibit 78. The possible impacts of an uneven playing field for supplying hydrogen can be seen by comparing the green lines (High Uneven Case) with the red lines (High Even Case). By 2050 hydrogen use in lower by 4,678 TBtu, while natural gas increases by 2,947 TBtu and electricity gains by 1,051 TBtu.

Exhibit 76: Industrial Sector Fuel Mix

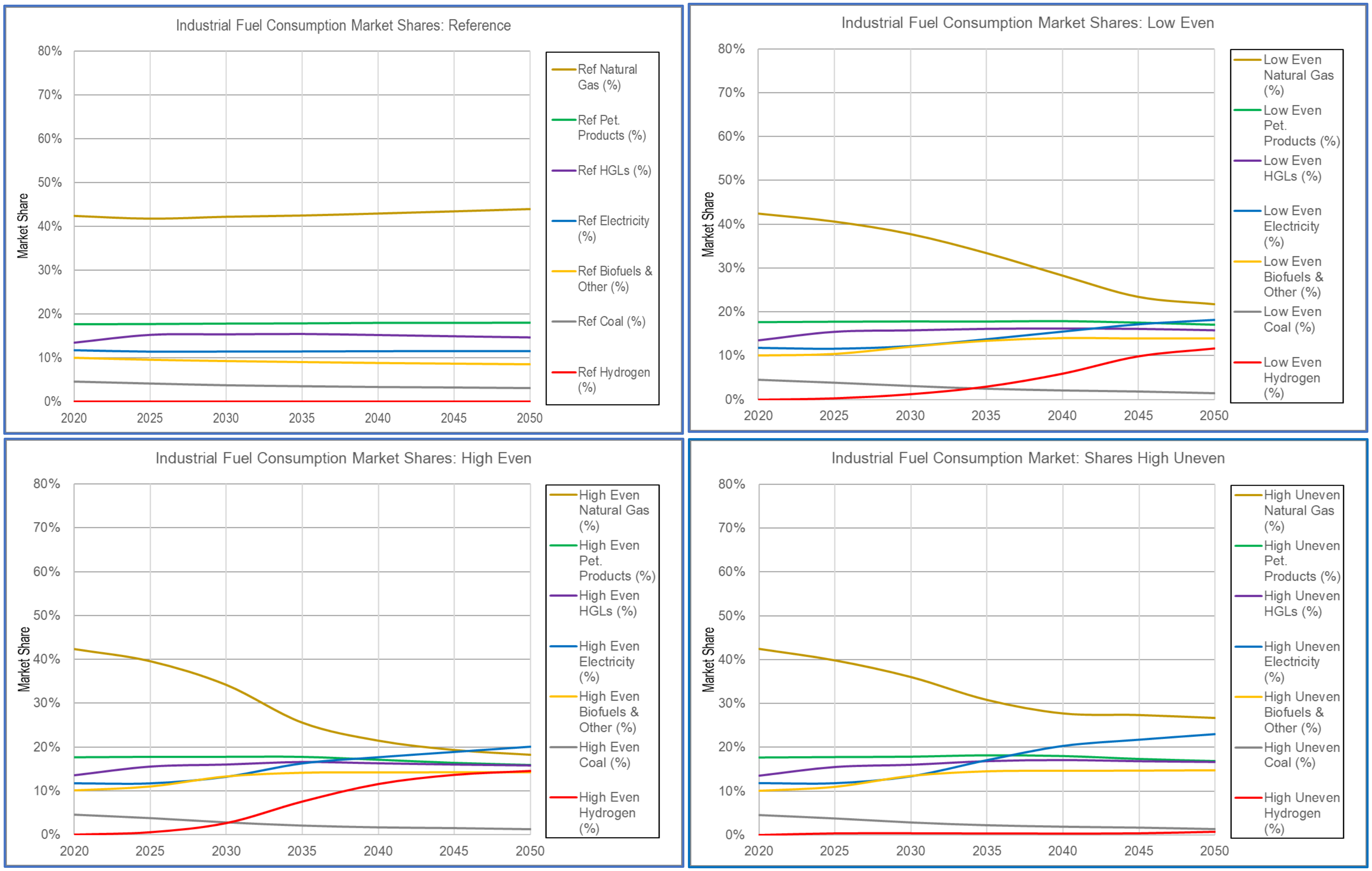


Exhibit 77: Industrial Sector Fuel Use Comparisons Among Cases

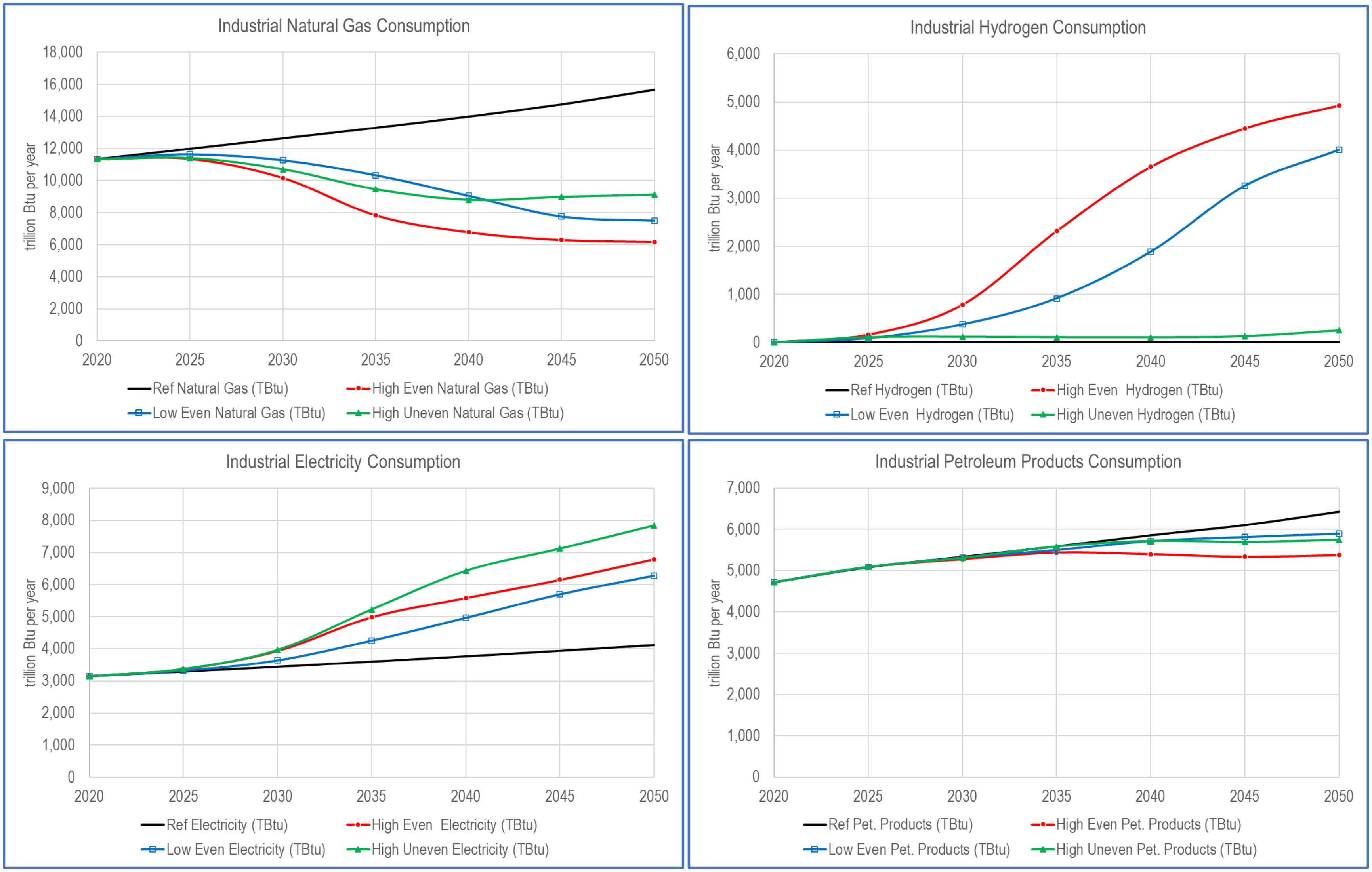
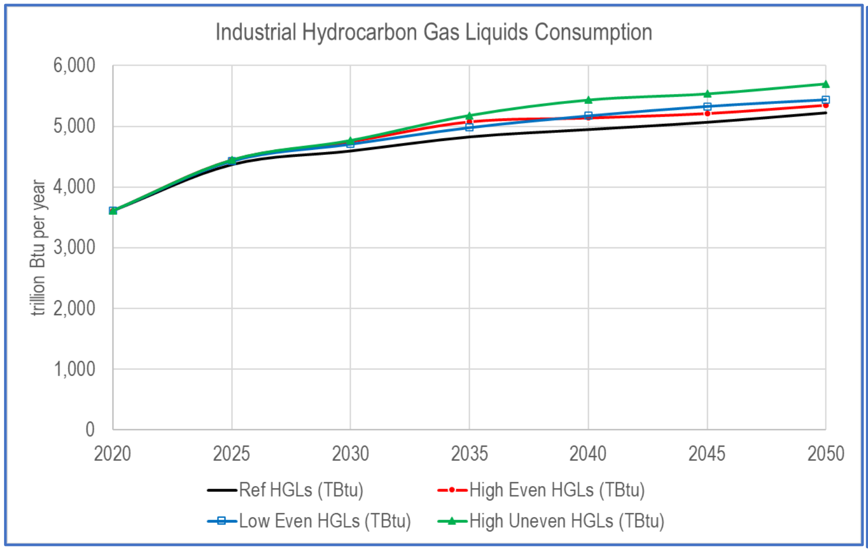
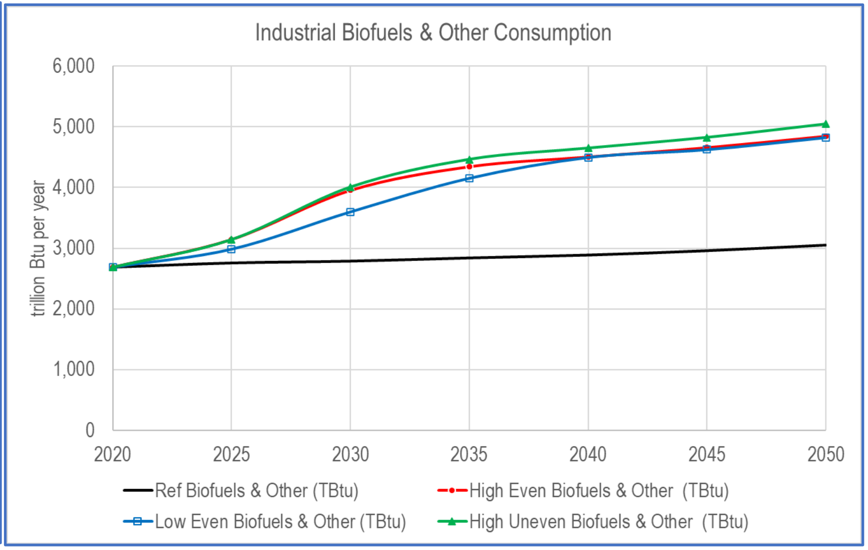
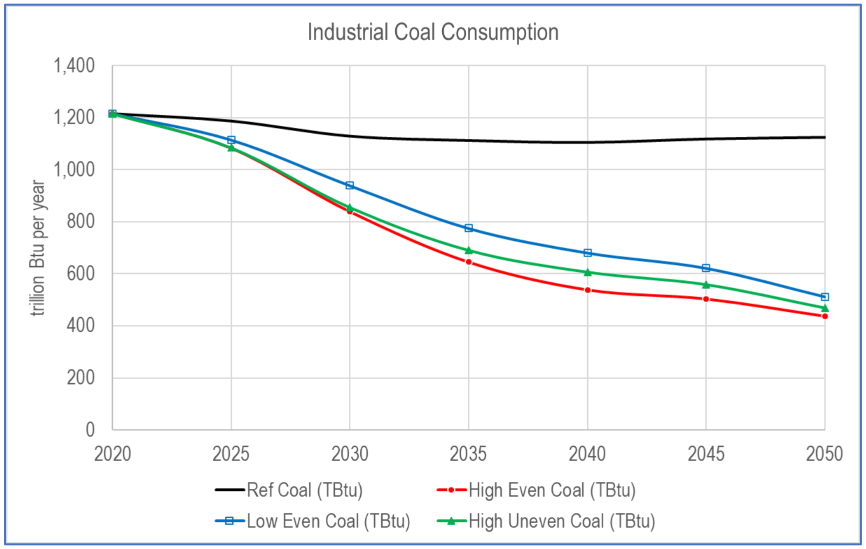


Exhibit 78: Industrial Sector Fuel Use Comparisons Among Cases (continued)







The specific industrial end-use application in which some of the major changes in fuel consumption take place are shown in the next two exhibits. Exhibit 79 shows electricity consumption in 2050 by end-use for the Reference Case and the three Alternative cases. Electrification in the industrial sector at the expense of natural gas may occur most significantly in low and medium temperature process heat applications, heating ventilation and cooling, and in machine drive applications in the natural gas supply chain (field gas compressors, gas processing plants, gas pipelines[27] and LNG liquefaction plants). Electrification at the expense of petroleum products/LPG/and other fossil fuels may occur in manufacturing machine drive, onsite transportation, and (small) boilers.

Exhibit 79: Industrial Sector Electricity Consumption by End-use in 2050 (TBtu)

Electricity Use in TBtu	Technology	Reference	Low Even	High Even	High Uneven
Standalone Boiler	-	72.1	215.4	219.4	262.5
Process Heating	Furnace/ Heater Low Temp	158.9	250.5	222.3	421.9
Process Heating	Furnace/ Heater Medium Temp	238.2	450.8	378.1	983.3
Process Heating	Furnace/ Heater High Temp	0.0	4.8	8.5	23.1
Process Heating	Cement & lime kilns	4.6	2.9	2.9	3.1
Process Heating	Ethanol plants	48.7	75.2	81.5	88.4
Process Cooling & Refrig.	-	333.8	334.2	334.1	335.0
Machine Drive	-	2,031.3	2,202.7	2,212.7	2,220.2
Electro-Chemical Processes	-	204.2	204.2	204.2	204.2
Other Process Use	-	108.1	146.2	221.9	216.5
Facility HVAC	-	395.7	853.9	932.3	1,054.4
Facility Lighting	-	295.4	295.4	295.4	295.4
Other Facility Support	-	110.9	181.1	192.6	192.4
Onsite Transportation	-	65.4	260.3	423.5	485.4
Other Nonprocess Use	-	56.0	56.0	56.0	56.0
Field gas compressor	-	0.0	368.5	497.4	495.2
Natural gas processing	-	0.0	116.4	158.2	157.1
Gas P/L compressors	-	0.0	129.2	175.1	174.1
Liquefy natural gas	-	0.0	131.0	179.0	177.6
	Total	4,123.2	6,278.6	6,795.2	7,845.9

Exhibit 80 shows the 2050 end-use applications where hydrogen can be used in the Low Even and High Even Cases where blue hydrogen has the same incentive (in terms of $/metric ton of CO2e reduction) as other sources of hydrogen. The largest industrial markets for hydrogen are expected to be in process heat uses (particularly high-temperature and medium-temperature applications) and in feedstock uses where blue and green hydrogen can substitute for hydrogen

[27] Energy use by gas pipelines is reported under the "transportation sector" in EIA historical statistical data and in the AEO forecast while energy use by field gas compressors and natural gas processing plants are part of the mining portion of the "industrial sector." Energy use by gas pipelines is categorized as "industrial" for the purposes of this report so that it can be modeled and reported together with other parts of the natural gas supply chain.

and syngases made from natural gas using a conventional SMR process. Hydrogen is also expected to compete in other applications where natural gas is now used including boilers, turbine/combined heat and power, space heating, and onsite transportation (a designation that includes offroad farm and construction equipment).

Exhibit 80: Industrial Sector Hydrogen Consumption by End-use in 2050 (TBtu)

Hydrogen Use in TBtu	Technology	Reference	Low Even	High Even	High Uneven
Standalone Boiler	-	0.0	276.9	295.2	0.0
Boiler & steam turbine CHP	-	0.0	273.5	324.2	0.0
Gas turbine & WHRB CHP	-	0.0	164.0	237.9	0.0
Recip CHP	-	0.0	28.5	48.1	4.9
Process Heating	Furnace/ Heater Low Temp	0.0	252.5	294.5	3.6
Process Heating	Furnace/ Heater Medium Temp	0.0	1,646.3	1,809.3	26.7
Process Heating	Furnace/ Heater High Temp	0.0	495.1	793.0	7.7
Process Heating	Cement & lime kilns	0.0	11.4	14.1	0.0
Process Heating	Ethanol plants	0.0	67.6	90.5	0.0
Process Cooling & Refrig.	-	0.0	2.0	2.1	0.0
Machine Drive	-	0.0	15.6	16.7	0.0
Facility HVAC	-	0.0	120.1	150.0	0.0
Onsite Transportation	-	0.0	107.8	195.8	66.1
Hydrogen Production	*refineries*	0.0	99.6	103.9	23.0
Ammonia Production	*bulk chemicals*	0.0	347.0	371.1	110.1
Iron Reduction	*iron & steel*	0.0	97.9	184.6	10.5
	Total	0.0	4,005.8	4,930.9	252.6

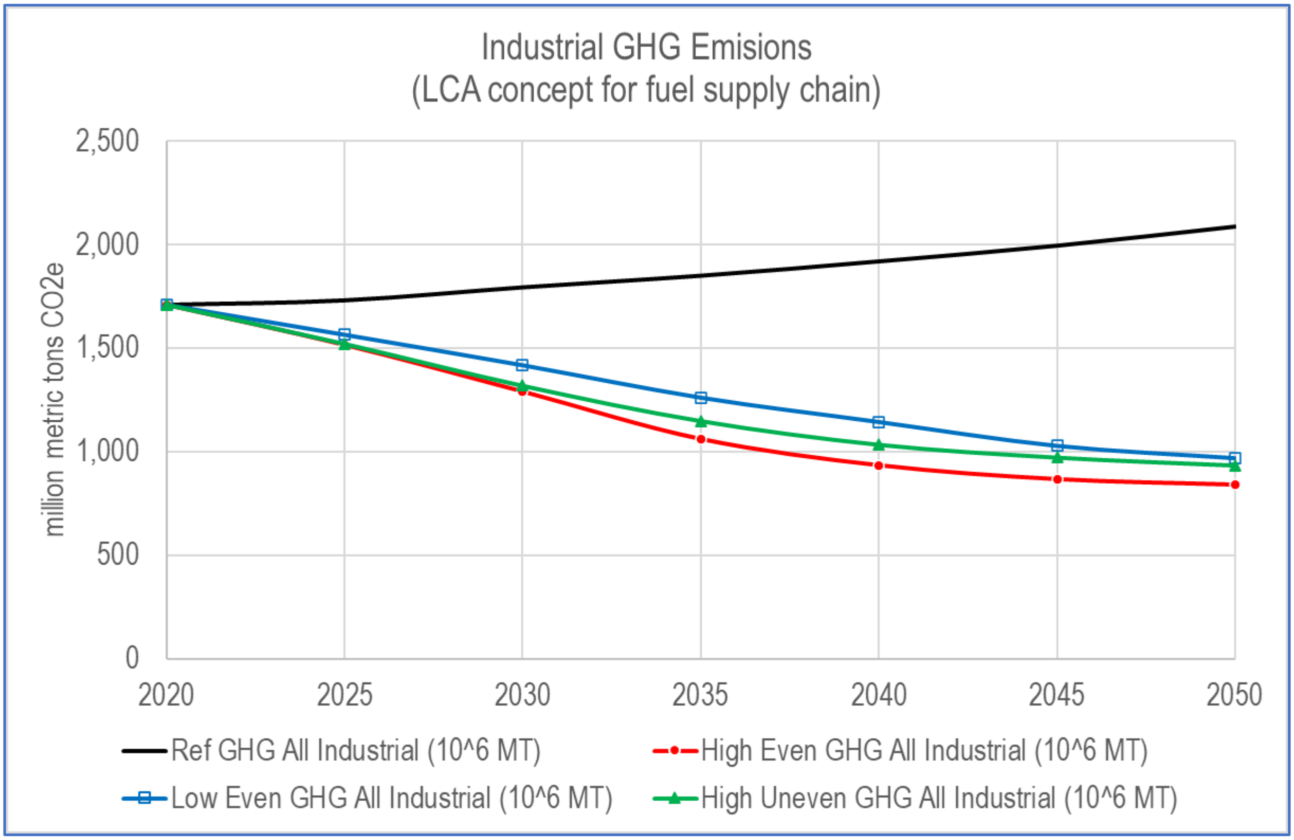
Note: Historical use of natural gas or other fossil fuels to make hydrogen or syngas is recorded as natural gas or other fossil fuel consumption in EIA's MECS and in the NEMS industrial forecasting model used to produce the AEO. Therefore, Reference Case use of "hydrogen" is zero. When these uses are displaced by blue or green hydrogen in ICF's forecasting model, they are recorded as hydrogen consumption.

7.5.3 GHG Emissions in the Industrial Sector

The industrial sector lifecycle GHG emissions for the Reference Case and the three Alternative Cases are shown in Exhibit 81. The Reference Case GHG emissions start at 1,709 million metric tons in 2020 and grow 0.7% annually to 2,087 million metric tons in 2050. In contrast, all the Alternative Cases have downward trends in emissions ranging from -1.9% to -2.3% per year. By 2050, the Low Even Case has emissions that are 54% below the Reference levels while the High Even Case results in emissions that are 60% below the Reference levels.

The High Uneven Case does not achieve the same level of GHG reductions as the High Even Case even though they both assume the same $/metric ton cost of carbon mitigation: 2050 reductions relative the Reference Case are down by 55% versus 60% for the High Even Case. The High Even Case is more effective at reducing GHG emissions compared to High Uneven because hydrogen is available at lower cost when blue hydrogen does not face disincentives. By 2050 industrial use of hydrogen is 4,931 TBtu in the High Even versus just 253 Btus in the High Uneven Case. The availability of blue hydrogen at a low price allows a greater degree of carbon mitigation to occur within the assumed willingness to pay because blue hydrogen provides an opportunity to decarbonize natural gas at large centralized facilities that can take advantage of economies of scale and can benefit from being located near suitable geologic sequestration sites. As was shown earlier in Exhibit 77 and Exhibit 78, when the option of low-cost blue hydrogen is removed due to policy choices, there will be some industrial facilities that will increase electrification or adopted CCUS and continue to burn natural gas. But other facilities with technical limits to electricity substitution and unfavorable CCUS economic (poor economies of scale, unfavorable geologic settings for underground CO_2 storage and onsite space constraints) will face more limited GHG mitigation options and overall industrial GHG emissions will be greater.

Exhibit 81: Industrial Sector GHG Emissions



7.5.4 Cost of Ownership GHG for the Industrial Sector

As with all end-use sectors, the industrial competition models compute the cost of ownership of major technology/fuel alternatives for each kind of application including annualized capital costs, operating and maintenance costs, the cost of energy consumed and the assumed internalized cost of carbon mitigation. The comparisons of cost of ownership among technology/fuel alternatives are computed per-unit of energy services such as dollars per MMBtu of process heat delivered. The cost of ownership in the industrial sector sums to $497 billion dollars in 2050 for the Reference Case, for which no cost of carbon mitigation is applied. (See Exhibit 82) The 2050 cost of ownership increases by 47% to $729 billion in the Low Even Case and by 61% to $802 billion in the High Even Case. The greatest cost increase occurs with the High Uneven Case which shows a 68% increase over the Reference Case to $836 billion. The difference in cost between the High Even and the High Uneven Case comes about because low-cost hydrogen is not available as a mitigation strategy to the industrial sector and higher-cost options must be adopted.

Exhibit 82: Industrial Sector Cost of Ownership in 2050

Fuel	Industrial Sector Energy Services Total Costs for 2050 ($mm/year)			
	Reference	Low Even	High Even	High Uneven
Electricity	$84,186	$181,222	$218,253	$249,841
Natural Gas	$148,566	$93,360	$81,033	$98,321
Natural Gas w/CCS	$0	$45,314	$49,797	$84,807
HGL	$57,912	$84,907	$96,116	$108,535
Still Gas	$12,472	$19,997	$27,570	$24,999
Still Gas w/CCS	$0	$6,474	$6,318	$8,429
Naptha/ gasoil	$8,182	$10,580	$12,178	$12,178
BTX	$5,147	$6,654	$7,660	$7,660
Motor Gasoline	$21,430	$21,762	$16,776	$19,065
Distillate FO/ Diesel	$84,515	$73,770	$60,589	$72,668
Residual FO	$3,140	$10,008	$12,367	$15,134
Asphalt & RO	$9,152	$12,216	$14,259	$14,259
Petroleum Coke	$8,240	$14,192	$19,948	$21,051
Petroleum Coke w/CCS	$0	$94	$56	$70
Steam Coal	$5,648	$4,904	$5,566	$5,920
Steam Coal w/CCS	$0	$515	$450	$549
Met Coal	$7,411	$3,767	$3,006	$3,479
Met Coal w/CCS	$0	$132	$170	$293
Synfuels	$0	$2,604	$4,033	$0
Biofuels	$15,860	$24,923	$26,623	$26,748
Other fs & mat.	$24,940	$44,242	$47,469	$50,485
Hydrogen	$0	$67,067	$91,387	$11,794
Total	**$496,801**	**$728,705**	**$801,624**	**$836,286**

Note: Cost of ownership is the annual cost of energy-consuming vehicles, appliances, equipment, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

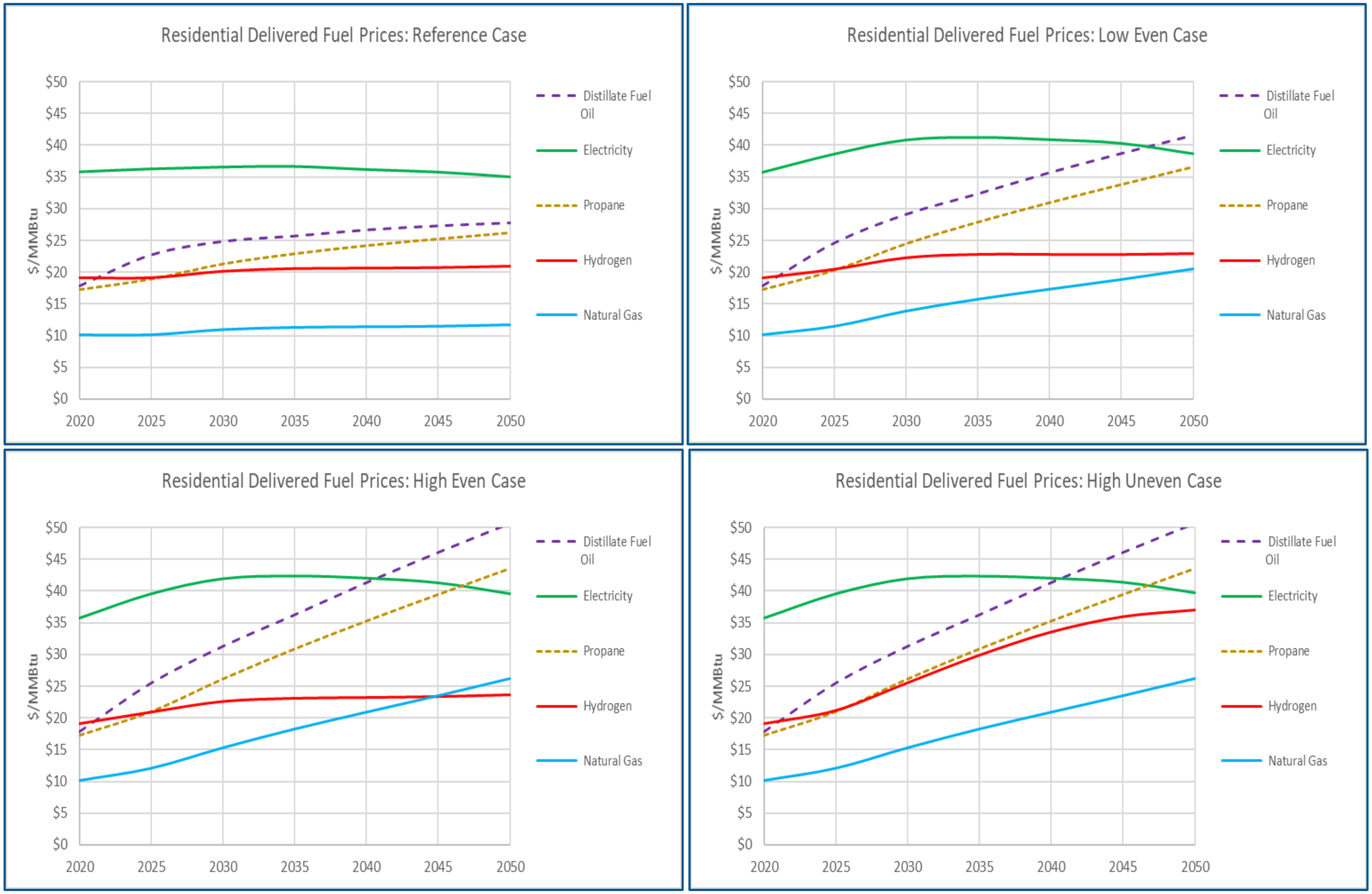
7.6 Sector Details: Residential

In the AEO Reference Case projection for the years 2020 to 2050, the residential sector accounts for approximately 14.9% of US end-use energy consumption and 17.4% percent of projected GHG emissions. The Alternative Cases examined here suggest that residential GHG emission could be reduced by 73% to 80% by 2050 with the cost of carbon mitigation going up to between $150 and $250 per metric ton of CO2e. Annual hydrogen consumption in the residential sector might be as high as 492 TBtu and would take place primarily in space heating and water heating applications.

7.6.1 Delivered Prices for the Residential Sector

The potential delivered fuel prices for the residential sector under the Reference and Alternative Cases are shown in Exhibit 83. The Reference Case fuel prices come directly from national average prices estimated by EIA for the AEO 2021 Reference Case. For the Alternative Cases, the Reference fossil fuel prices have been adjusted upward by an amount equal to each fuel's lifecycle GHG emissions times the assumed cost of carbon mitigation for each model year. For the Low Even Case, the 2050 cost of carbon mitigation is $150 per metric ton of CO2e and for the High Even and High Uneven Cases the 2050 cost of carbon mitigation is $250 per metric ton of CO2e.

Exhibit 83: Residential Sector Fuel Prices



The annual wholesale composite hydrogen prices are the weighted average cost of producing hydrogen from natural gas and from electrolysis using electricity from dedicated solar and wind. The retail price of delivered hydrogen to each end-user sector and market reflects the cost of delivering the hydrogen to consumers. For the residential customers, delivery is assumed to be by pipelines from production areas to the city gate and by local distribution companies from the city gate to consumers. For residential hydrogen consumers, this markup from wholesale prices is $10.45/MMBtu. The corresponding markup for natural gas delivered through transmission pipelines and local distribution companies to residential customers is $7.82/MMBtu.

Electricity prices for the residential sector are computed as the wholesale generation prices (estimated in the electricity sector model for the Alternative Cases) plus the transmission and distribution markups from the AEO Reference Case. For the residential sector, the average electricity transmission and distribution from 2020 to 2050 is 7.07 cents per kilowatt-hour ($70.70/MWh).

7.6.2 Fuel Mix Results for the Residential Sector

The projected fuel mix in the residential sector is shown on a percentage basis in Exhibit 84. The Reference Case shows a gradual erosion of the share for natural gas in favor of electricity. This occurs partly because the uses of energy where electricity dominates (appliances, electronics) grow faster than energy use for space heating and water heating (where natural gas use is most competitive). Also, electric technologies including heat pumps make inroads in space and water heating applications. When a cost of carbon mitigation is added in the Alternative Cases, the price differential between natural gas and electricity moves in favor of electricity causing the electric technologies to gain further market share. In the Reference Case electricity provides 53% of residential energy in 2050, while in the Low Even Case that percent grows to 67%, and in the High Even Case it grows to 75%. Because hydrogen prices increase in the High Uneven Case, the market share for hydrogen in the residential sector stays at near zero to the benefit mostly of electricity. By 2050 the electricity market share in the High Uneven Case is at 78%.

The consumption of energy in the residential sector is shown in units of quadrillion Btu in Exhibit 85. Relative to the Reference Case, natural gas loses between 2.6 and 3.6 quads of annual consumption by 2050 in the Alternative Cases. The gains for electricity are between 1.0 and 1.7 quads. The difference in these values stem from the fact that electricity is more efficient than natural gas in space and water heating applications (measured as Btu of energy services divided by Btu of energy consumed by the equipment).

Exhibit 84: Residential Sector Fuel Mix

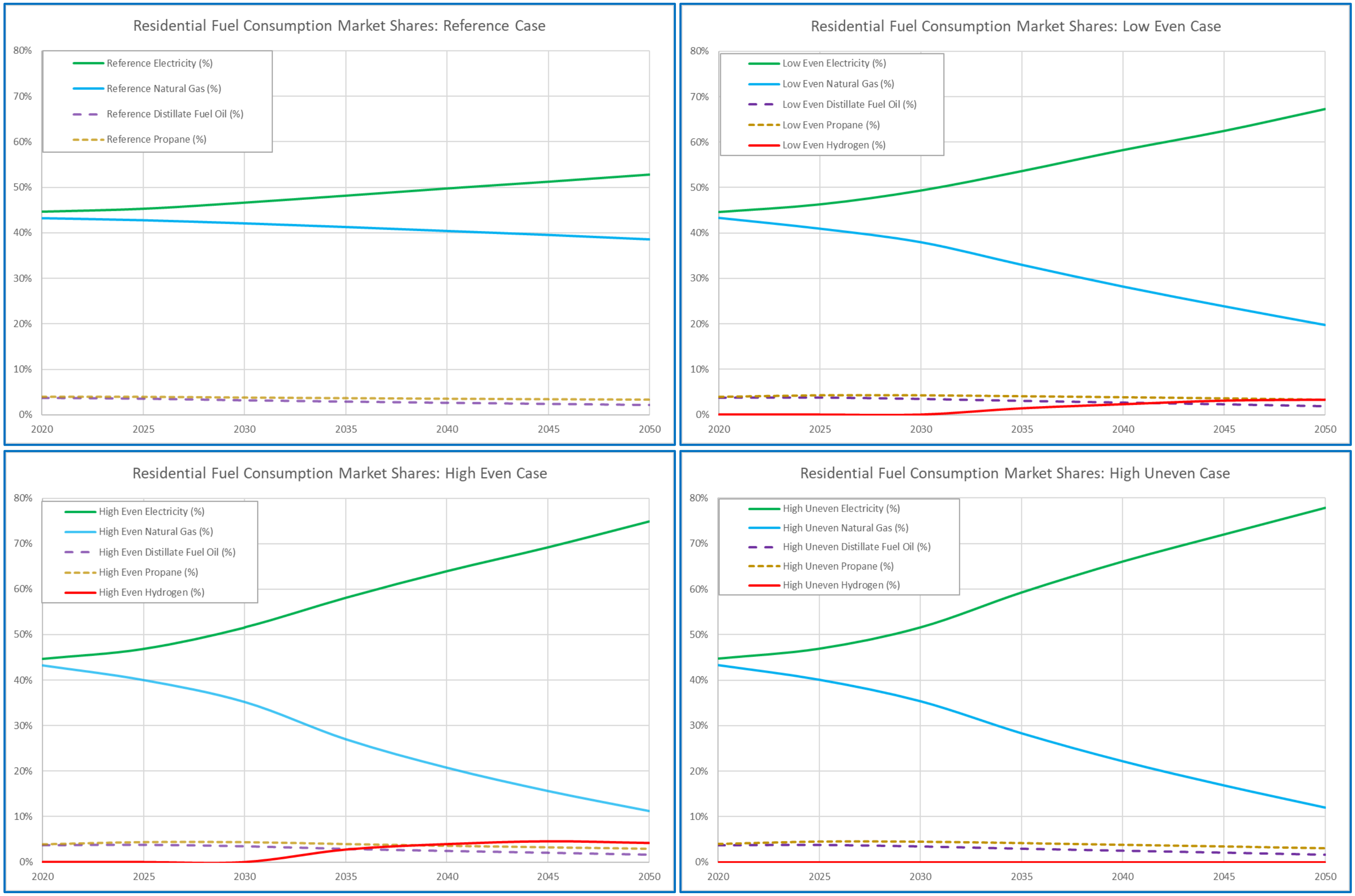
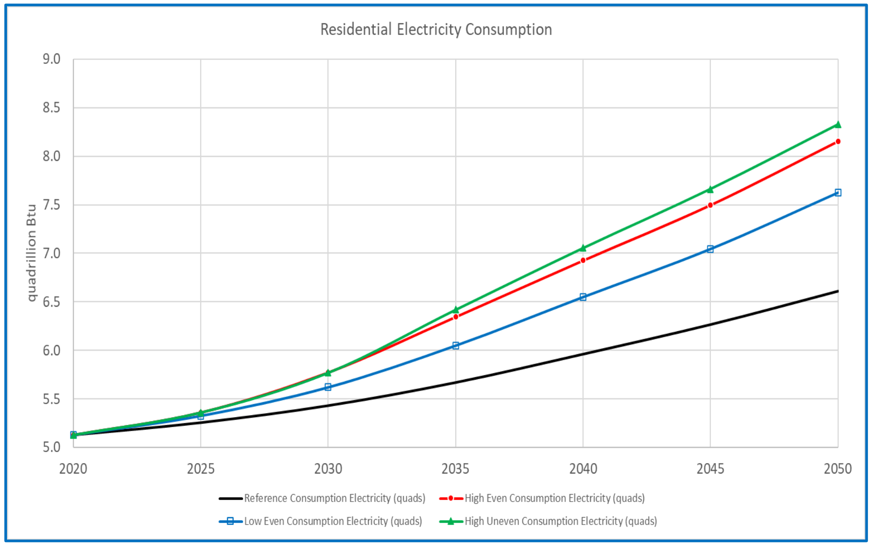
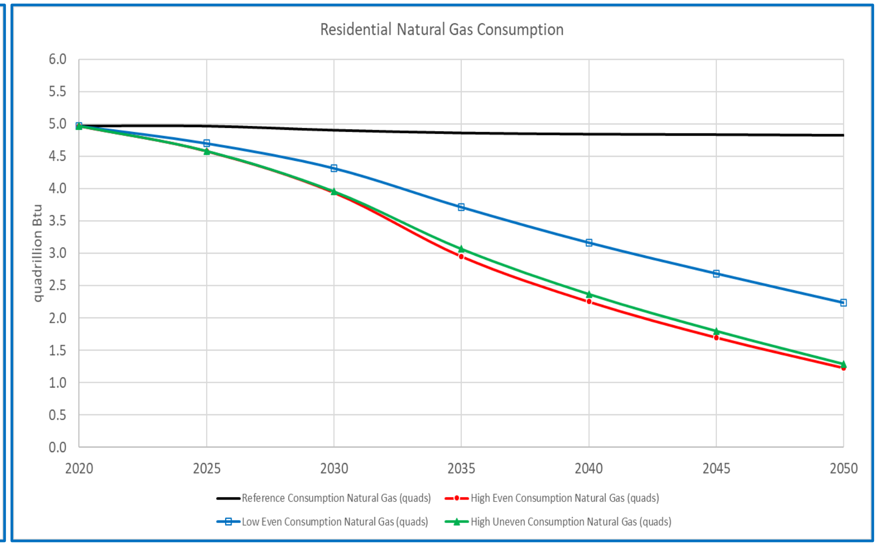
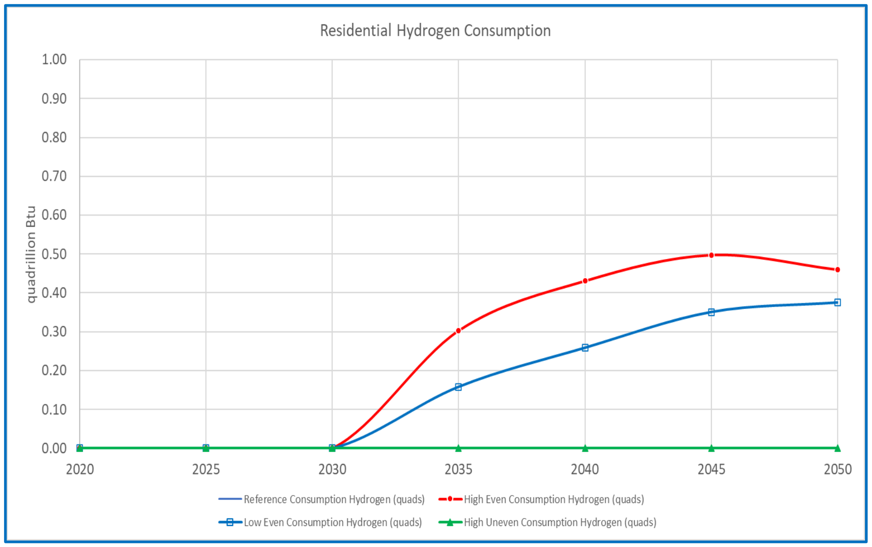


Exhibit 85: Residential Sector Fuel Use Comparisons Among Cases



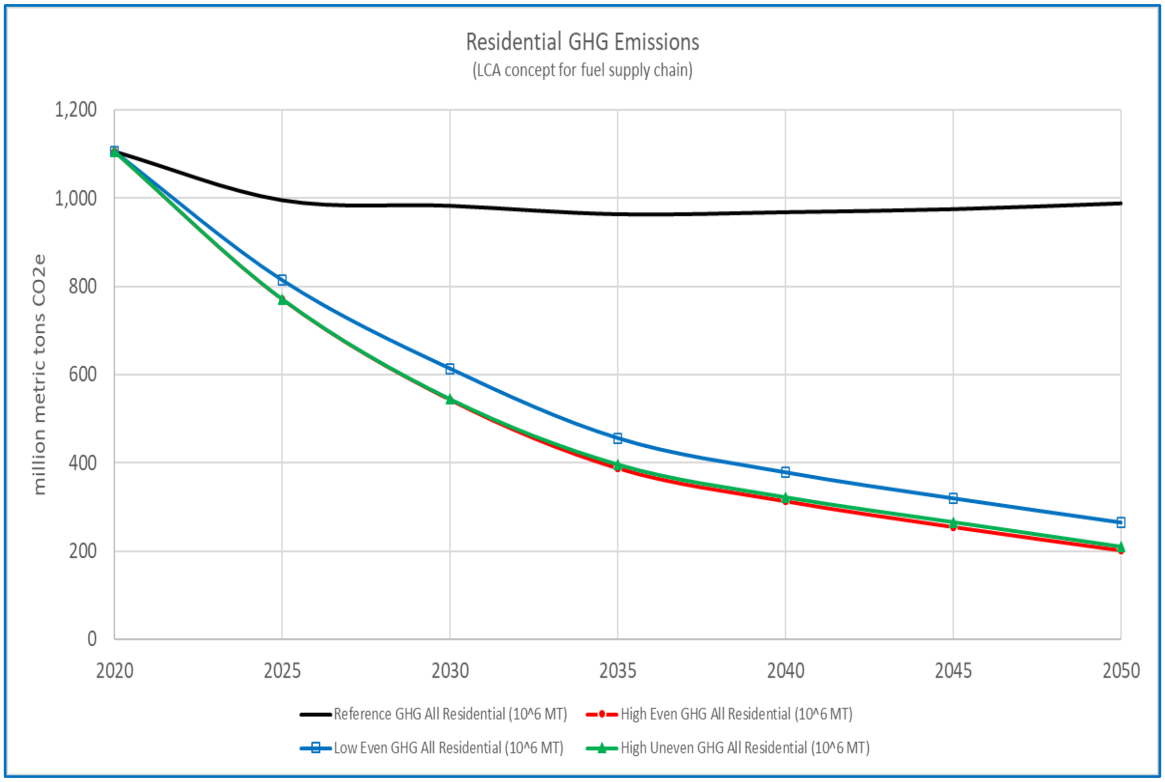




7.6.3 GHG Emissions in the Residential Sector

The residential sector lifecycle GHG emissions for the Reference Case and the three Alternative Cases are shown in Exhibit 86. The Reference Case GHG emissions decline 11% from 1,105 million metric tons in 2020 to 988 million metric tons in 2050. There is a much steeper decline in all the Alternative Cases. By 2050, the Low Even Case has emissions of 264 million metric tons of CO2 and the High Even Case has emissions of 202 million metric tons of CO2e. Relative to the Reference Case levels these are declines of -73% and -80%.

Exhibit 86: Residential Sector GHG Emissions



Because of the high cost of delivering hydrogen to the residential sector and the favorable economics of electric technologies, the overall market share for hydrogen does not get much above 4% and total consumption stays below 0.5 quads. Therefore, when the economics for hydrogen are made worse in the High Uneven Case there is not a big market to lose and GHG emissions do not change very much. The residential GHG emissions for the High Uneven Case are 209 million metric tons by 2050, only slightly higher than the 202 million metric tons for the High Even Case.

7.6.4 Cost of Ownership for the Residential Sector

The cost of ownership for residential energy consuming appliances and equipment is shown in Exhibit 87 for the Reference and the Alternative Cases. This includes the cost of buying and maintaining the appliances and equipment plus the cost of energy. The total increase in costs over the entire forecast period is 9.7% in the Low Even Case and 13.0% in the High Even and

High Uneven Cases. The number of households projected to exist over this period starts at 123.4 million in 2020 and increase to 151.6 million by 2050. Therefore, the average ownership cost per household would increase by $372 per year per household for the Low Even Case and by about $490 per year per household in the two High Cases.

Exhibit 87: Cost of Ownership for Residential Sector

Cost of Ownership ($billion): Residential				
Year	Reference	Low Even	High Even	High Uneven
2020	$460	$460	$460	$460
2025	$479	$502	$512	$512
2030	$505	$551	$567	$567
2035	$531	$590	$611	$610
2040	$553	$622	$646	$645
2045	$576	$652	$674	$674
2050	$598	$671	$692	$693
Cumulative 2021-50	$15,870	$17,411	$17,926	$17,925
% Increase in Cum vs. Ref.		*9.7%*	*13.0%*	*13.0%*

Note: Cost of ownership is the annual cost of energy-consuming appliances, equipment, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

7.7 Sector Details: Commercial

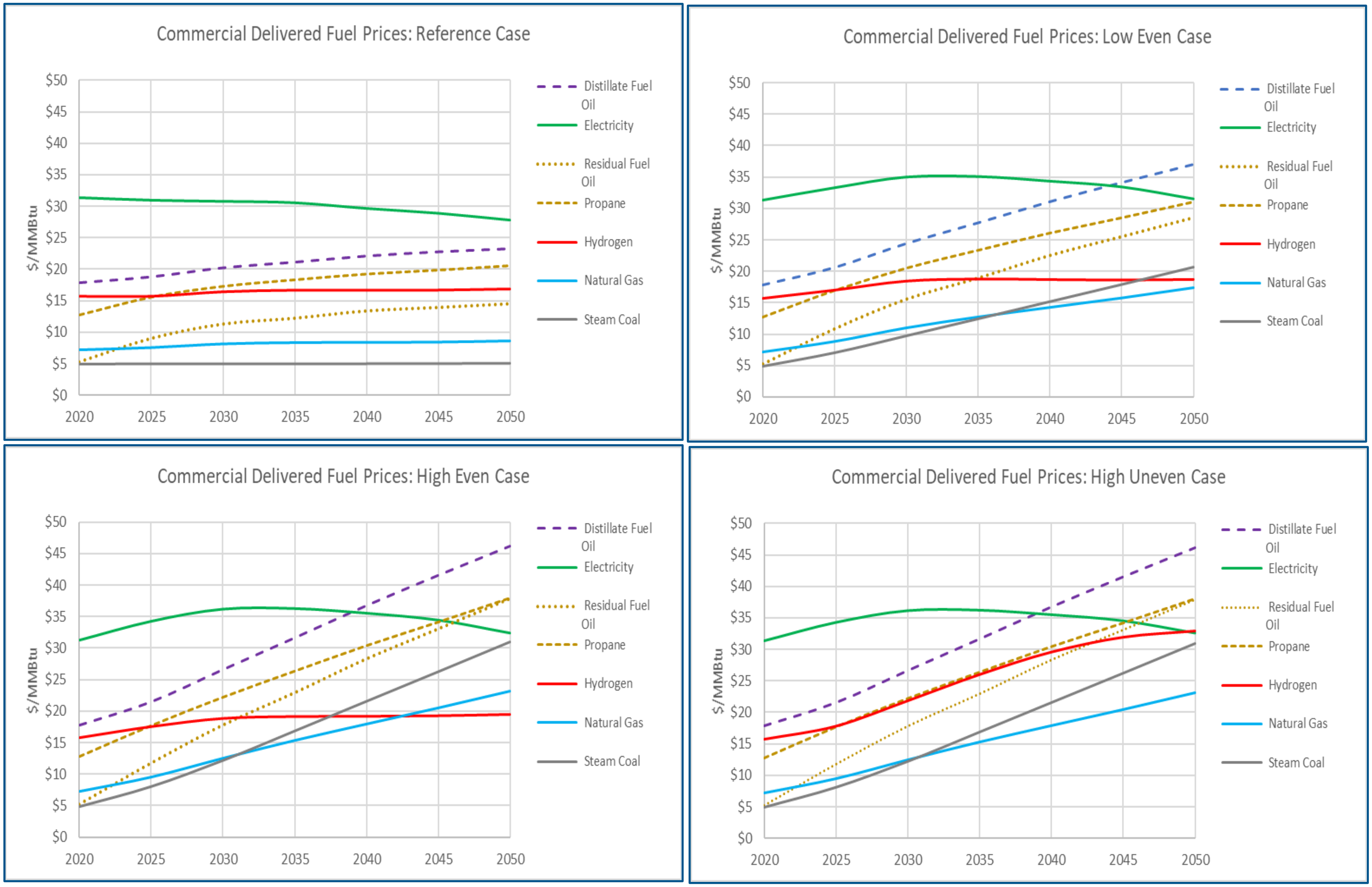
In the AEO Reference Case projection for the years 2020 to 2050, the commercial sector accounts for approximately 12.3% of US end-use energy consumption and 14.7% percent of projected GHG emissions. The Alternative Cases examined here suggest that commercial GHG emission could be reduced by 70% to 76% by 2050 with the cost of carbon mitigation going up to between $150 and $250 per metric ton of CO2e. Annual hydrogen consumption in the commercial sector might be as high as 559 TBtu and would take place primarily in space heating, water heating, and cogeneration applications.

7.7.1 Delivered Prices for the Commercial Sector

Delivered fuel prices for the commercial sector under the Reference and Alternative Cases are shown in Exhibit 88. The Reference Case fuel prices come directly from national average commercial sector prices estimated by EIA for the AEO 2021 Reference Case. As with the residential sector, the Reference fossil fuel prices have been adjusted upward in the Alternative Cases by an amount equal to each fuel's lifecycle GHG emissions times the assumed cost of carbon mitigation for each model year. The delivered hydrogen prices are computed as the annual wholesale composite hydrogen prices plus the cost of delivering the hydrogen to consumers. For the commercial customers, delivery is assumed to be by pipelines from production areas to the city gate and by local distribution companies from the city gate to consumers. For commercial hydrogen consumers, this markup from wholesale prices is $6.60/MMBtu. The corresponding markup for natural gas delivered through transmission pipelines and local distribution companies to commercial customers is $4.93/MMBtu.

Electricity prices for the commercial sector are computed as the wholesale generation prices, as estimated in the electricity sector model, plus the transmission and distribution markups from the AEO Reference Case. The average electricity transmission and distribution from 2020 to 2050 is 5.00 cents per kilowatt-hour ($50.00/MWh) for the commercial sector.

Exhibit 88: Commercial Sector Fuel Prices



7.7.2 Fuel Mix Results for the Commercial Sector

The projected fuel mix in the commercial sector is shown on a percentage basis in Exhibit 89. The Reference Case shows a small market share loss for natural gas in favor of electricity. This occurs in the commercial sector for the same reasons that a similar, but larger loss, occurs in the residential sector: (a) uses of energy where electricity dominates grow faster than energy use for space heating and water heating (where natural gas use is most competitive) and (b) electric technologies including heat pumps make inroads in space and water heating applications.

When a cost of carbon mitigation is added in the Alternative Cases, the price differential between natural gas and electricity in the commercial sector moves in favor of electricity causing the electric technologies to gain further market share. In the Reference Case electricity provides 51% of commercial energy in 2050, while in the Low Even Case that percent grows to 62% and in the High Even Case it grows to 68%. The electricity market share in the High Uneven Case is even higher (72%) in 2050 because the high hydrogen prices in that case cause the market share for hydrogen in the commercial sector to remain near zero boosting electricity consumption.

The consumption of energy in the commercial sector is shown in units of quadrillion Btu in Exhibit 90. Relative to the Reference Case, natural gas loses between 1.7 and 2.4 quads of annual consumption by 2050 in the Alternative Cases. Hydrogen gains zero to 0.6 quads of which 62% is spacing heating and the remainder is water heating and other uses. The gains for electricity are between 0.9 and 1.5 quads. As was the case for the residential sector, electricity is more efficient than natural gas in space and water heating applications (measured as Btu of energy services divided by Btu of energy consumed by the equipment) so the net loss for natural gas plus hydrogen is less than the gain in electricity.

Exhibit 89: Commercial Sector Fuel Mix

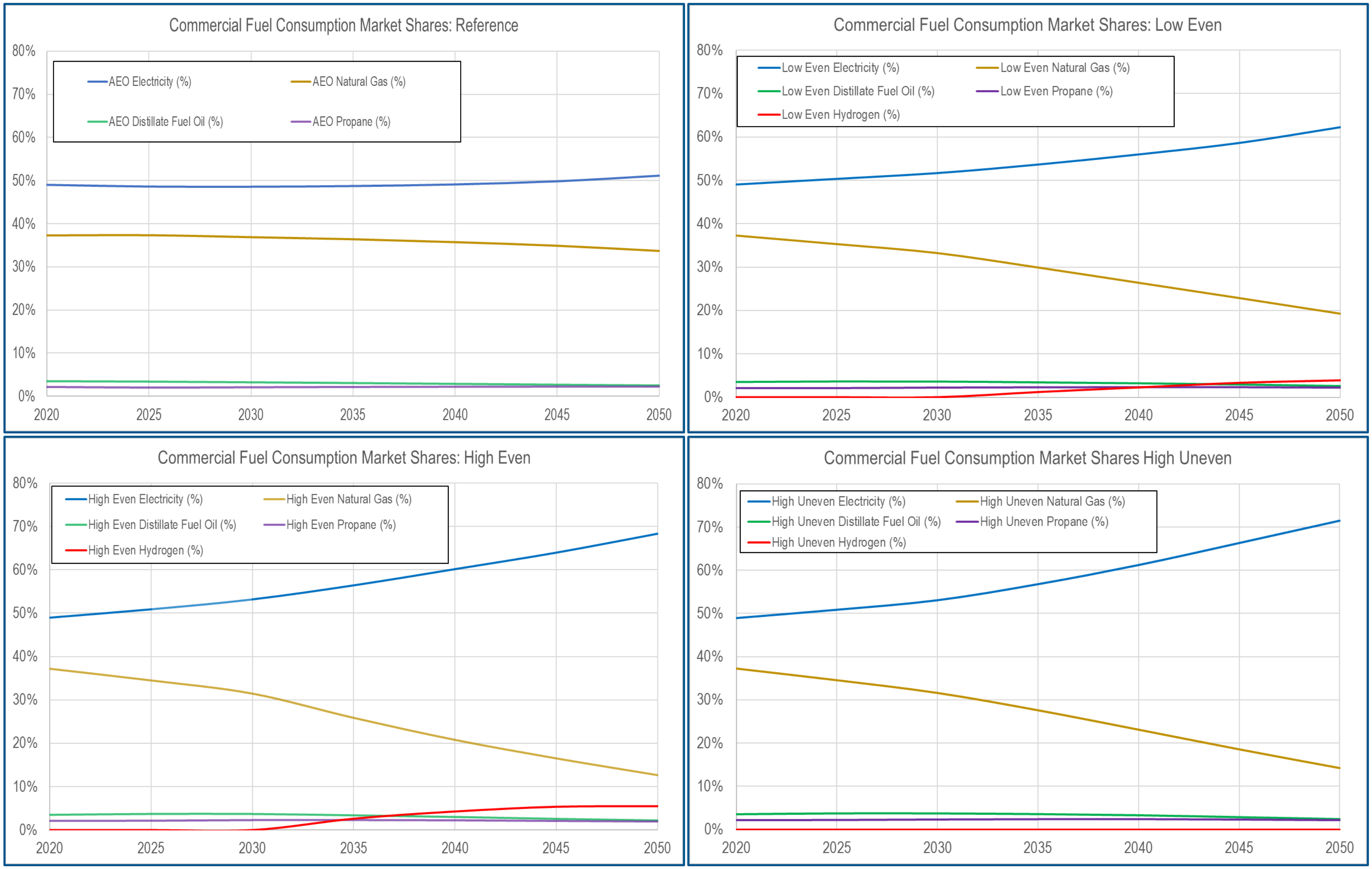
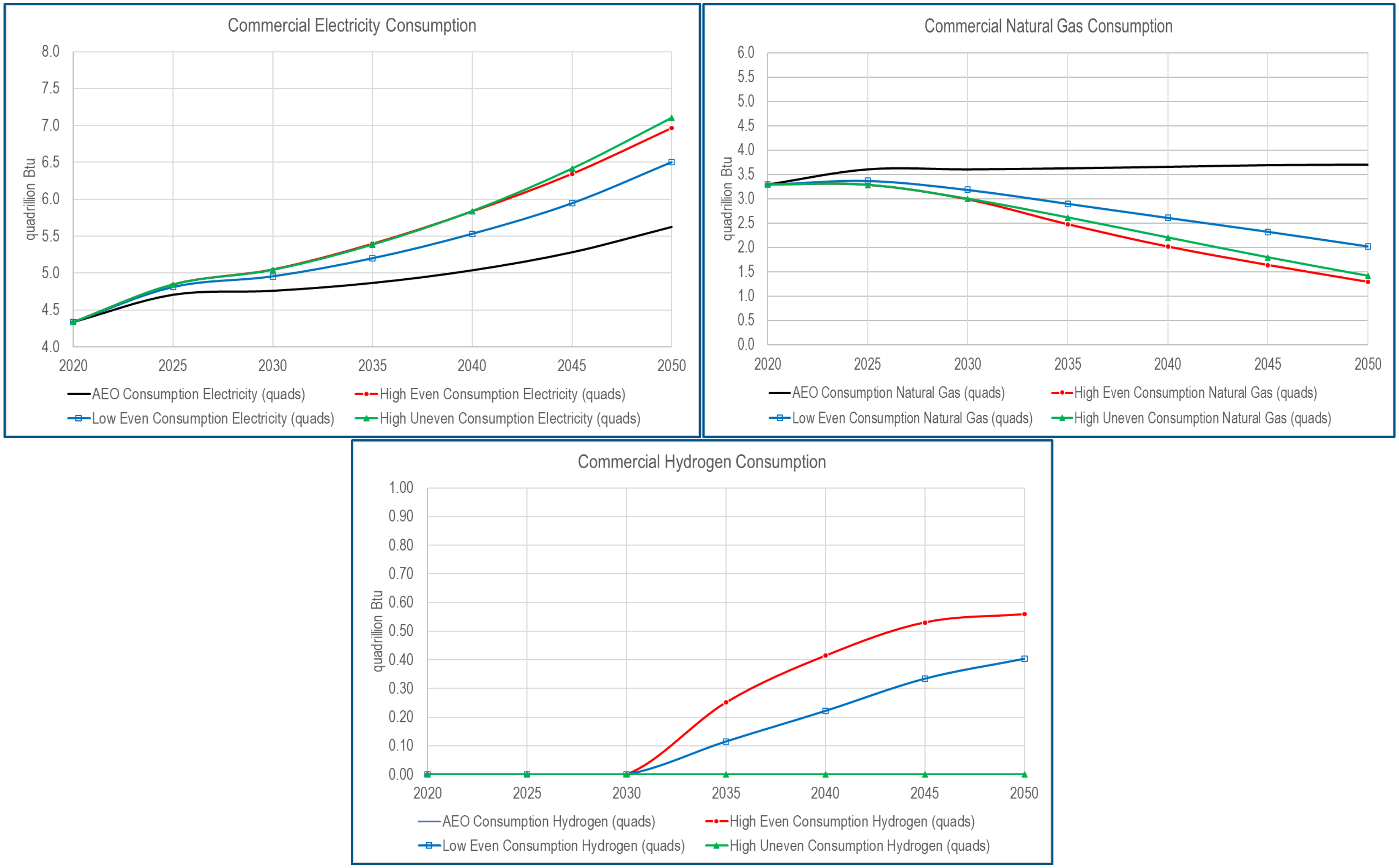


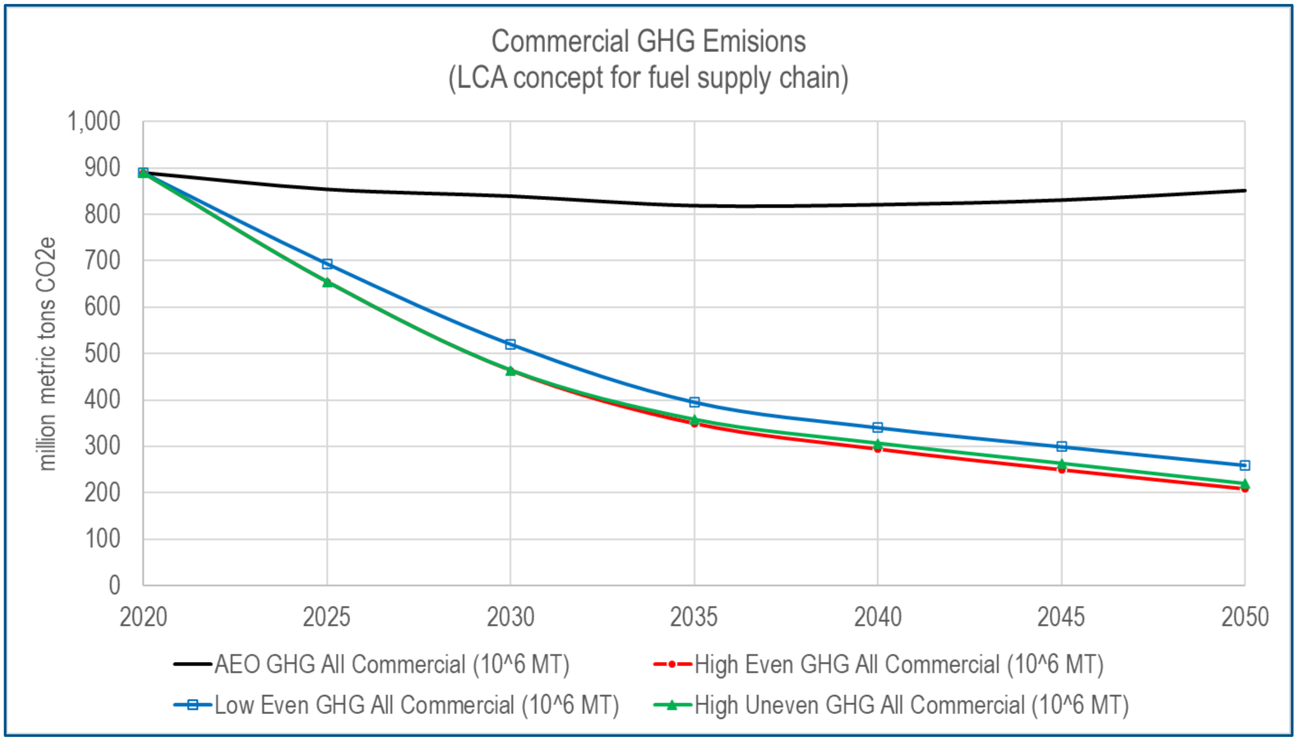
Exhibit 90: Commercial Sector Fuel Use Comparisons Among Cases



7.7.3 GHG Emissions in the Commercial Sector

The commercial sector lifecycle GHG emissions for the Reference Case and the three Alternative Cases are shown in Exhibit 91. The Reference Case GHG emissions decline 4% from 889 million metric tons in 2020 to 851 million metric tons in 2050. All the Alternative Cases have much greater declines. By 2050, the Low Even Case has emissions of 259 million metric tons of CO2 and the High Even Case has emissions of 208 million metric tons of CO2e. Relative to the Reference Case levels these are declines of -71% and -77%. When the composite price for hydrogen is made higher in the High Uneven Case, hydrogen consumption is lowered and there is an increase in commercial GHG emissions. The commercial GHG emissions for the High Uneven Case are 220 million metric tons by 2050, slightly higher than the 208 million metric tons for the High Even Case.

Exhibit 91: Commercial Sector GHG Emissions



7.7.4 Cost of Ownership for the Commercial Sector

The cost of ownership for commercial energy consuming appliances, equipment and fixtures is shown in Exhibit 92 for the Reference and the Alternative Cases. This includes the cost of buying and maintaining the appliances, equipment, and fixtures plus the cost of energy. The total increase in costs over the entire forecast period is 10.2% in the Low Even Case, 13.6% in the High Even Case, and 13.3% in the High Uneven Case.

Exhibit 92: Cost of Ownership for Commercial Sector

Cost of Ownership ($billion): Commercial				
Year	Reference	Low Even	High Even	High Uneven
2020	$353	$353	$353	$353
2025	$386	$404	$412	$412
2030	$397	$433	$445	$445
2035	$411	$458	$475	$473
2040	$424	$481	$500	$497
2045	$442	$505	$524	$522
2050	$462	$525	$543	$543
Cumulative 2021-50	$12,340	$13,604	$14,024	$13,983
% Increase in Cum vs. Ref.		*10.2%*	13.6%	13.3%

Note: Cost of ownership is the annual cost of energy-consuming appliances, equipment, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

7.8 Sector Details: Transportation

In the AEO Reference Case projection for the years 2020 to 2050, the transportation sector accounts for approximately 34.0% of US end-use energy consumption and 35.3% percent of projected GHG emissions. The Alternative Cases examined here suggest that transportation GHG emission could be reduced by 35% to 47% by 2050 with the cost of carbon mitigation going up to between $150 and $250 per metric ton of CO2e. Annual hydrogen consumption in the transportation sector would be the highest of all end-use sectors and might be as high as 5,980 TBtu. Hydrogen consumption would take place primarily in heavy duty vehicles but would be expected to also be used in the light duty vehicle, rail, shipping, and air transport market segments.

7.8.1 Delivered Prices for the Transportation Sector

Exhibit 93 and Exhibit 94 show the delivered fuel prices considered for on-road and off-road transportation energy users in the Reference and Alternative Cases. Like other sectors, the Reference Case fuel prices are those reported by EIA for the AEO 2021 Reference Case. The Alternative cases represent scenarios where the reference price includes an additional cost of carbon mitigation increasing in each future year. The Low Even Case assumes a 2050 cost of carbon mitigation of $150 per metric ton of CO2e and the High Even and High Uneven Cases both assume a 2050 cost of carbon mitigation of $250 per metric ton of CO2e.

The compressed natural gas (CNG) and liquefied natural gas (LNG) prices used include additional costs related to the transportation of those fuels to local retail stations. For delivered CNG, ICF also included the cost of compression. For LNG, ICF applied a liquefaction cost to the industrial natural gas price, as well as a cost of truck delivery to the refueling station from the industrial customer. ICF also included a retail markup which reflects the cost at the pump for on-road vehicles, or at the fueling location for each off-road option.

For electric vehicles, light duty vehicles can be charged at home using smaller, less efficient plugs, while heavy duty vehicles are typically charged with more efficient chargers and when not in service. This study utilized assumptions on these factors to determine an average price used for all fuel costs as discussed and shown in the methodology section.

Hydrogen-powered vehicle costs represented volumes delivered as a liquid before regasification at the pump. Therefore, the price used in fuel cost calculations includes the composite wholesale hydrogen price, a cost to pipeline the gaseous hydrogen from the production location to the city gate, the liquefaction fee, the transportation of liquid hydrogen to the refueling station via truck delivery, onsite regasification at the pump, and a retail markup.

Exhibit 93: On Road Transportation Sector Delivered Fuel Prices

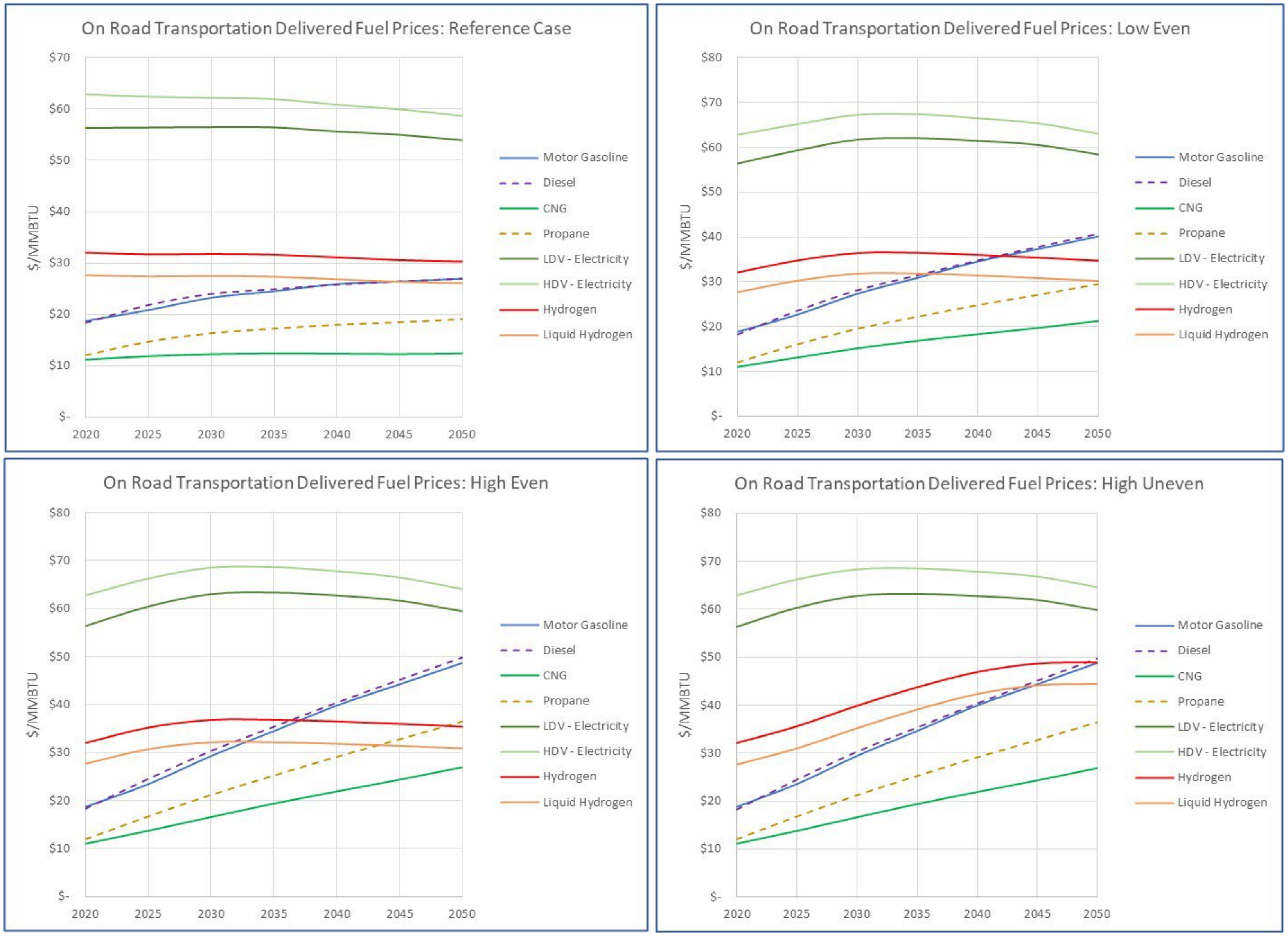
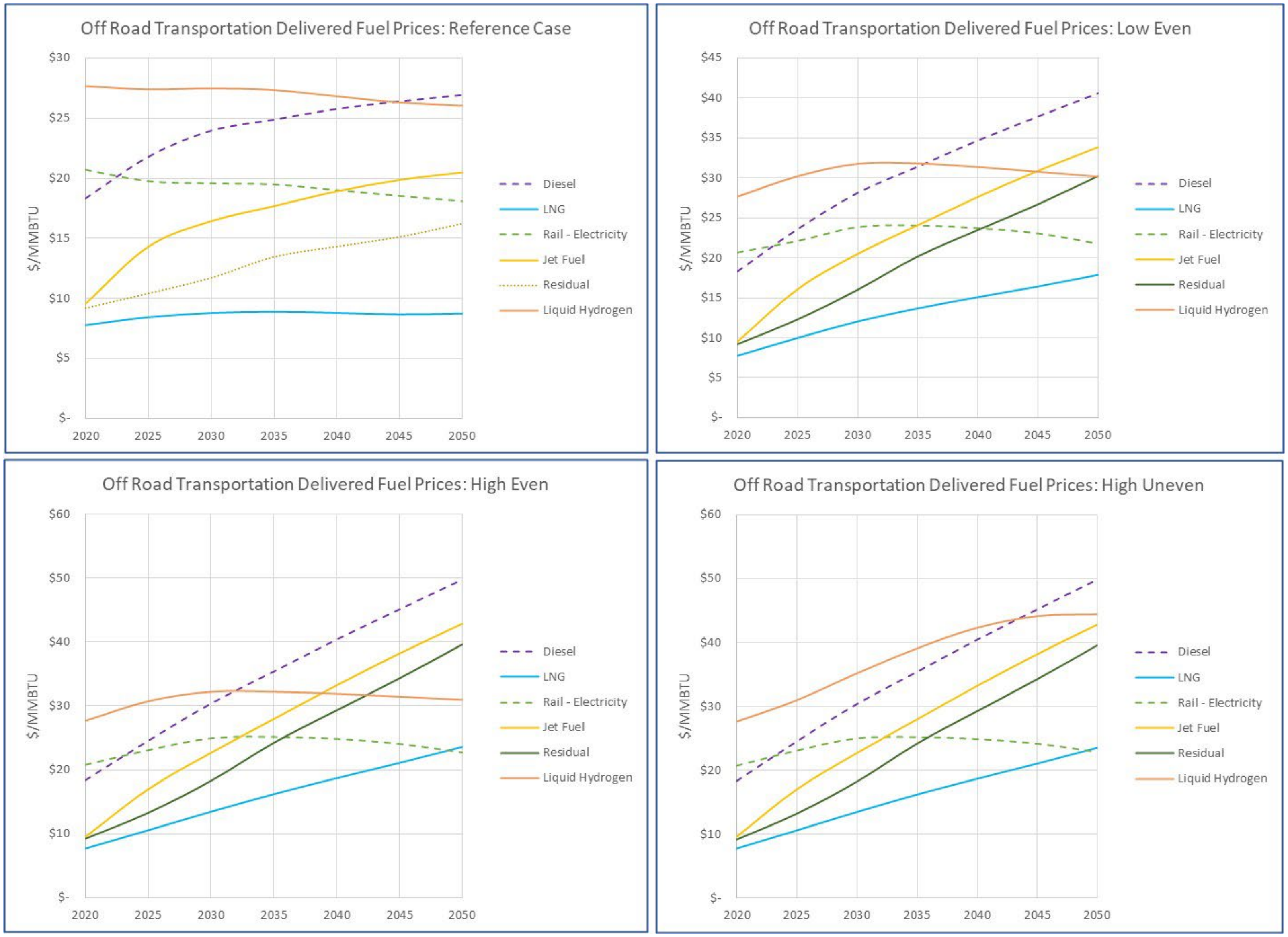


Exhibit 94: Off Road Transportation Delivered Fuel Prices



7.8.2 Fuel Mix Results for the Transportation Sector

The projected fuel mix in the transportation sector is shown on a percentage basis in Exhibit 95. The Reference Case shares show mostly gasoline consumption, with jet fuel usage expected to increase slightly over the 2020 to 2050 forecast period. The Low Even, High Even, and High Uneven Cases all show substantial declines in the use of gasoline in favor primarily for hydrogen fuels. The High Even Case exhibits the most drastic changes as the higher mitigation costs influence the adoption of cleaner emitting fuels.

The High Uneven Case has the same cost of carbon mitigation as the High Even Case, except that blue hydrogen is assumed to have a $12/MMBtu differential in incentives compared to green hydrogen. This increases the composite wholesale hydrogen cost, resulting in less hydrogen adoption in all end-use sectors. In this case, the combination of increased CNG, LNG, and electricity adoption make up the difference.

Exhibit 95: Transportation Sector Fuel Mix

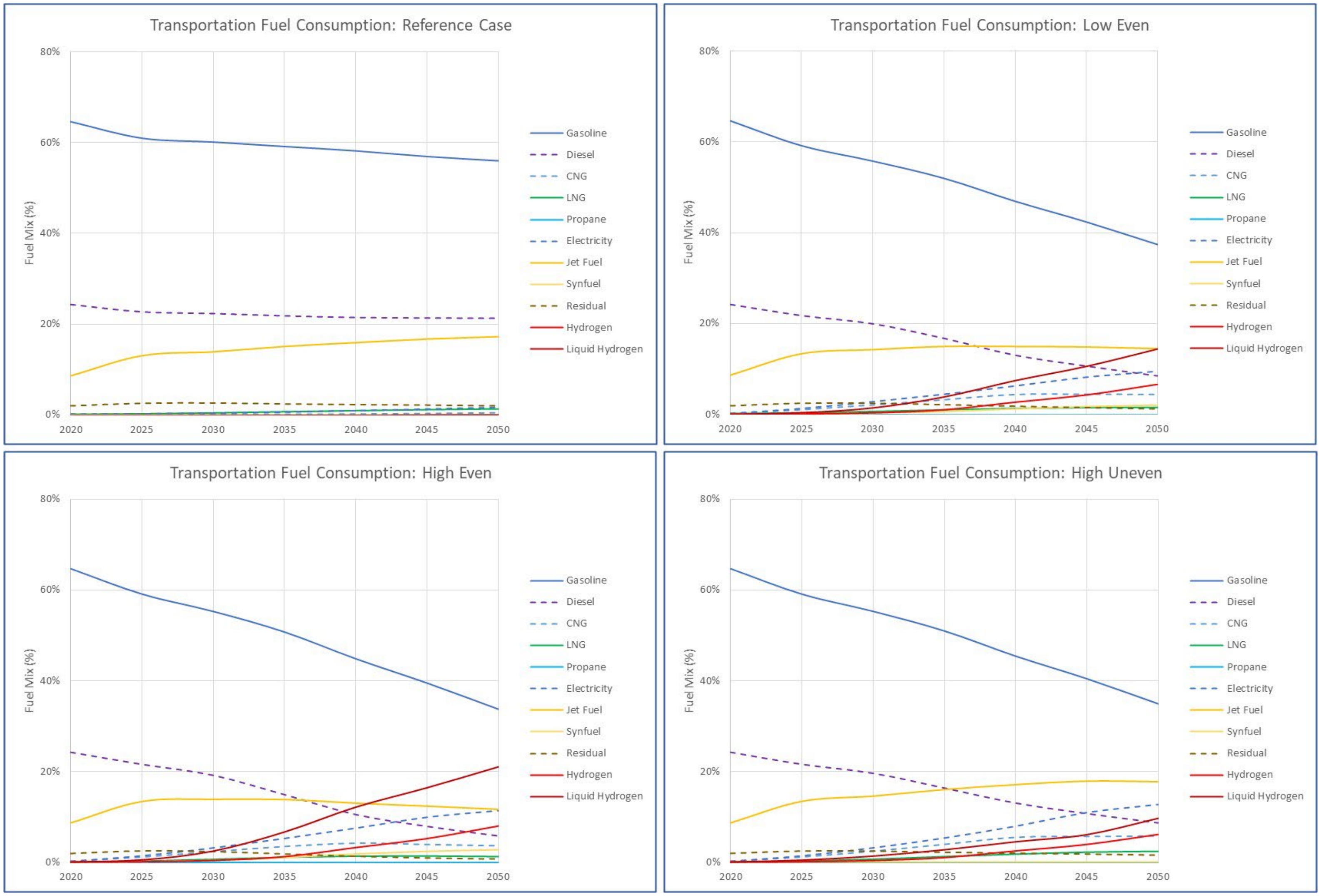
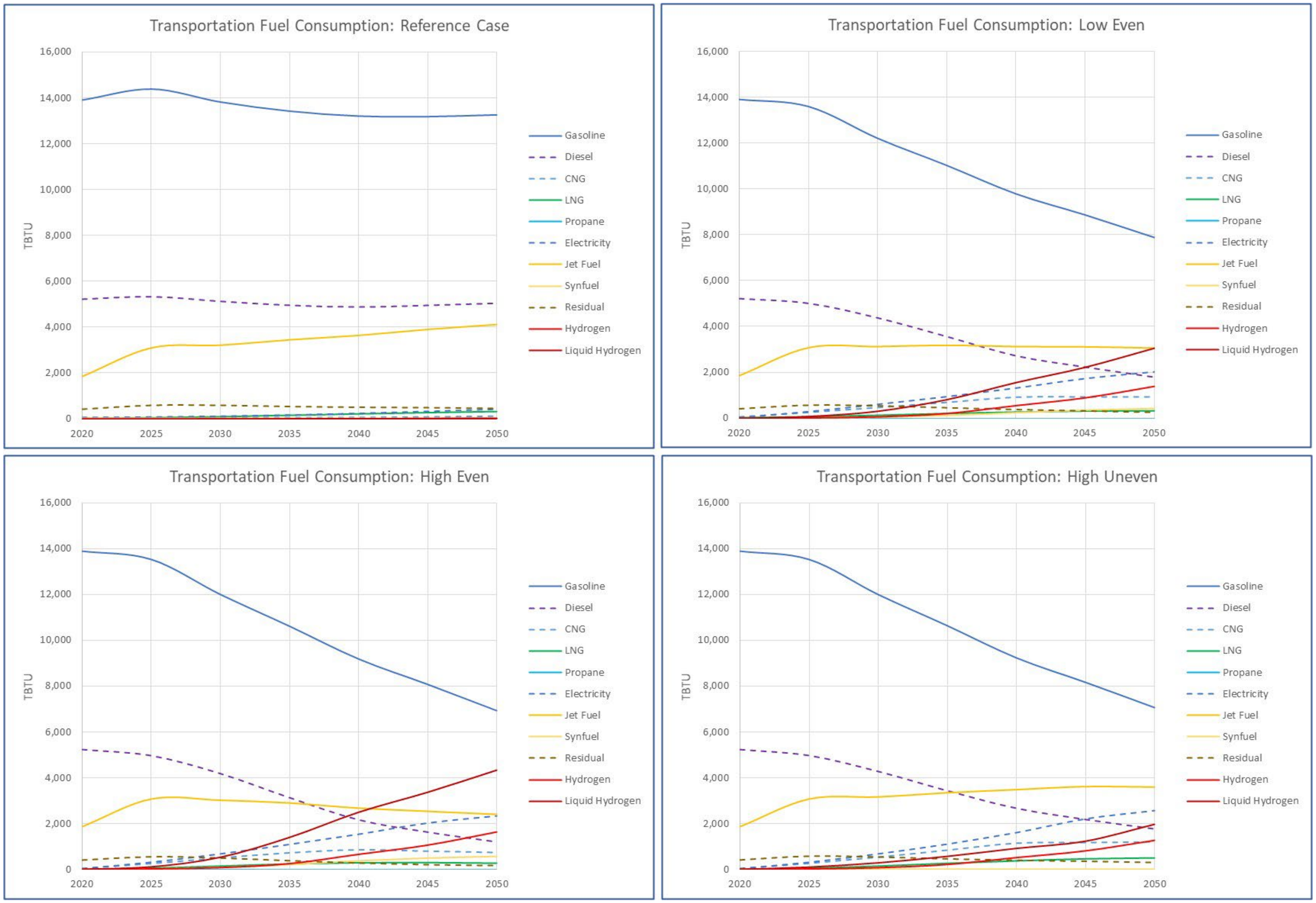


Exhibit 96: Transportation Sector Fuel Consumption



The following exhibits display the expected market share of each technology or fuel type across each transportation market considered in this study. In the Alternative cases, significant hydrogen adoption is expected in the medium and heavy duty on road vehicle markets, including over a 60% shift by 2050 in the High Even case for HDVs. The waterborne transportation market also shows promise for cost efficient hydrogen application in certain scenarios, including a 54% share by 2050 in the High Even case.

Exhibit 97: Light Duty Automobiles Final Market Shares by Technology Type

Market	Year	Scenario	Petroleum Products	CNG	BEV	PHEV	HEV	FCEV	Other	Total
Light duty vehicle, automobile	2030	Reference Case	93.3%	0.0%	1.4%	0.7%	4.5%	0.0%	0.0%	100.0%
Light duty vehicle, automobile	2040	Reference Case	87.7%	0.0%	3.9%	1.4%	7.0%	0.0%	0.0%	100.0%
Light duty vehicle, automobile	2050	Reference Case	81.3%	0.0%	7.7%	1.6%	9.3%	0.0%	0.0%	100.0%
Light duty vehicle, automobile	2030	Low Even	86.2%	0.3%	8.4%	0.9%	3.9%	0.3%	0.0%	100.0%
Light duty vehicle, automobile	2040	Low Even	73.9%	0.6%	17.2%	1.3%	4.6%	2.3%	0.0%	100.0%
Light duty vehicle, automobile	2050	Low Even	62.0%	0.6%	26.8%	1.4%	4.3%	4.8%	0.0%	100.0%
Light duty vehicle, automobile	2030	High Even	85.4%	0.3%	9.0%	1.0%	4.0%	0.3%	0.0%	100.0%
Light duty vehicle, automobile	2040	High Even	71.3%	0.6%	19.4%	1.4%	4.7%	2.5%	0.0%	100.0%
Light duty vehicle, automobile	2050	High Even	57.3%	0.7%	30.8%	1.5%	4.4%	5.4%	0.0%	100.0%
Light duty vehicle, automobile	2030	High Uneven	85.4%	0.3%	9.0%	1.0%	4.0%	0.3%	0.0%	100.0%
Light duty vehicle, automobile	2040	High Uneven	71.5%	0.6%	19.5%	1.4%	4.7%	2.2%	0.0%	100.0%
Light duty vehicle, automobile	2050	High Uneven	57.9%	0.7%	31.1%	1.5%	4.4%	4.4%	0.0%	100.0%

Notes: CNG=compressed natural gas, BEV=battery electric vehicle, PHEV=plug in hybrid electric vehicle, HEV=hybrid electric vehicle, FCEV fuel cell electric vehicle using hydrogen

Exhibit 98: Light Duty Trucks Final Market Shares by Technology Type

Market	Year	Scenario	Petroleum Products	CNG	BEV	PHEV	HEV	FCEV	Other	Total
Light duty vehicle, truck	2030	Reference Case	95.9%	0.0%	1.0%	0.8%	2.2%	0.0%	0.0%	100.0%
Light duty vehicle, truck	2040	Reference Case	91.9%	0.0%	3.0%	1.5%	3.5%	0.0%	0.0%	100.0%
Light duty vehicle, truck	2050	Reference Case	87.4%	0.0%	5.9%	1.8%	4.8%	0.0%	0.0%	100.0%
Light duty vehicle, truck	2030	Low Even	82.2%	0.3%	13.7%	1.0%	2.3%	0.6%	0.0%	100.0%
Light duty vehicle, truck	2040	Low Even	64.7%	0.5%	26.9%	1.4%	2.7%	3.7%	0.0%	100.0%
Light duty vehicle, truck	2050	Low Even	46.8%	0.5%	38.6%	1.4%	2.5%	10.2%	0.0%	100.0%
Light duty vehicle, truck	2030	High Even	80.4%	0.3%	15.3%	1.0%	2.3%	0.6%	0.0%	100.0%
Light duty vehicle, truck	2040	High Even	59.7%	0.5%	31.4%	1.5%	2.8%	4.2%	0.0%	100.0%
Light duty vehicle, truck	2050	High Even	39.5%	0.5%	44.6%	1.5%	2.4%	11.5%	0.0%	100.0%
Light duty vehicle, truck	2030	High Uneven	80.4%	0.3%	15.3%	1.0%	2.3%	0.6%	0.0%	100.0%
Light duty vehicle, truck	2040	High Uneven	60.0%	0.5%	31.6%	1.5%	2.8%	3.5%	0.0%	100.0%
Light duty vehicle, truck	2050	High Uneven	40.3%	0.5%	45.8%	1.5%	2.5%	9.4%	0.0%	100.0%

Notes: CNG=compressed natural gas, BEV=battery electric vehicle, PHEV=plug in hybrid electric vehicle, HEV=hybrid electric vehicle, FCEV fuel cell electric vehicle using hydrogen

Exhibit 99: Medium Duty Vehicle Final Market Shares by Technology Type

Market	Year	Scenario	Petroleum Products	CNG	BEV	PHEV	HEV	FCEV	Other	Total
Medium duty vehicle	2030	Reference Case	99.3%	0.2%	0.1%	0.2%	0.0%	0.1%	0.1%	100.0%
Medium duty vehicle	2040	Reference Case	99.0%	0.2%	0.1%	0.3%	0.0%	0.2%	0.1%	100.0%
Medium duty vehicle	2050	Reference Case	98.6%	0.3%	0.2%	0.4%	0.0%	0.3%	0.2%	100.0%
Medium duty vehicle	2030	Low Even	84.9%	9.2%	0.5%	1.4%	0.5%	3.5%	0.1%	100.0%
Medium duty vehicle	2040	Low Even	32.6%	41.2%	0.4%	0.4%	0.1%	25.2%	0.1%	100.0%
Medium duty vehicle	2050	Low Even	20.0%	36.8%	0.7%	0.5%	0.2%	41.6%	0.0%	100.0%
Medium duty vehicle	2030	High Even	82.3%	10.3%	0.6%	1.7%	0.7%	4.3%	0.1%	100.0%
Medium duty vehicle	2040	High Even	25.9%	39.6%	0.7%	0.4%	0.1%	33.2%	0.1%	100.0%
Medium duty vehicle	2050	High Even	13.3%	30.7%	1.1%	0.5%	0.2%	54.3%	0.0%	100.0%
Medium duty vehicle	2030	High Uneven	82.7%	10.4%	0.6%	1.7%	0.7%	3.8%	0.1%	100.0%
Medium duty vehicle	2040	High Uneven	29.4%	46.0%	0.9%	0.6%	0.2%	22.9%	0.1%	100.0%
Medium duty vehicle	2050	High Uneven	17.2%	42.1%	1.5%	0.8%	0.3%	38.0%	0.0%	100.0%

Notes: CNG=compressed natural gas, BEV=battery electric vehicle, PHEV=plug in hybrid electric vehicle, HEV=hybrid electric vehicle, FCEV fuel cell electric vehicle using hydrogen

Exhibit 100: Heavy Duty Vehicle Final Market Shares by Technology Type

Market	Year	Scenario	Petroleum Products	CNG	BEV	PHEV	HEV	FCEV	Other	Total
Heavy duty vehicle	2030	Reference Case	98.9%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Heavy duty vehicle	2040	Reference Case	98.4%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Heavy duty vehicle	2050	Reference Case	96.7%	3.1%	0.0%	0.1%	0.0%	0.0%	0.0%	100.0%
Heavy duty vehicle	2030	Low Even	81.0%	8.6%	1.0%	0.9%	1.3%	7.1%	0.0%	100.0%
Heavy duty vehicle	2040	Low Even	52.4%	11.4%	4.4%	0.9%	1.1%	29.7%	0.0%	100.0%
Heavy duty vehicle	2050	Low Even	31.1%	9.6%	7.1%	0.8%	1.0%	50.4%	0.0%	100.0%
Heavy duty vehicle	2030	High Even	76.7%	9.8%	1.4%	1.0%	1.5%	9.6%	0.0%	100.0%
Heavy duty vehicle	2040	High Even	41.1%	10.7%	6.3%	0.8%	1.0%	40.2%	0.0%	100.0%
Heavy duty vehicle	2050	High Even	20.3%	7.2%	9.2%	0.5%	0.6%	62.2%	0.0%	100.0%
Heavy duty vehicle	2030	High Uneven	78.6%	10.3%	1.5%	1.1%	1.6%	6.9%	0.0%	100.0%
Heavy duty vehicle	2040	High Uneven	51.3%	15.9%	9.3%	1.3%	1.7%	20.5%	0.0%	100.0%
Heavy duty vehicle	2050	High Uneven	30.3%	14.3%	17.5%	1.3%	1.5%	35.1%	0.0%	100.0%

Notes: CNG=compressed natural gas, BEV=battery electric vehicle, PHEV=plug in hybrid electric vehicle, HEV=hybrid electric vehicle, FCEV fuel cell electric vehicle using hydrogen

Exhibit 101: Aircraft Final Market Shares by Fuel Type

Market	Year	Scenario	Jet Fuel	LH2	Synfuel	Total
All Passenger Planes	2030	Reference Case	100%	0%	0%	100%
All Passenger Planes	2040	Reference Case	100%	0%	0%	100%
All Passenger Planes	2050	Reference Case	100%	0%	0%	100%
All Passenger Planes	2030	Low Even	97%	1%	2%	100%
All Passenger Planes	2040	Low Even	86%	7%	7%	100%
All Passenger Planes	2050	Low Even	75%	15%	10%	100%
All Passenger Planes	2030	High Even	94%	4%	3%	100%
All Passenger Planes	2040	High Even	73%	16%	10%	100%
All Passenger Planes	2050	High Even	58%	28%	14%	100%
All Passenger Planes	2030	High Uneven	99%	1%	0%	100%
All Passenger Planes	2040	High Uneven	96%	4%	0%	100%
All Passenger Planes	2050	High Uneven	88%	12%	0%	100%

Notes: LH2=liquid hydrogen

Exhibit 102: Freight Railcar Final Market Shares by Fuel Type

Market	Year	Scenario	Diesel	LH2	LNG	Electricity	Total
Rail - Freight	2030	Reference Case	91%	0%	9%	0%	100%
Rail - Freight	2040	Reference Case	72%	0%	28%	0%	100%
Rail - Freight	2050	Reference Case	57%	0%	43%	0%	100%
Rail - Freight	2030	Low Even	85%	1%	13%	1%	100%
Rail - Freight	2040	Low Even	56%	6%	34%	3%	100%
Rail - Freight	2050	Low Even	36%	14%	44%	6%	100%
Rail - Freight	2030	High Even	81%	2%	15%	2%	100%
Rail - Freight	2040	High Even	46%	13%	35%	7%	100%
Rail - Freight	2050	High Even	26%	28%	36%	11%	100%
Rail - Freight	2030	High Uneven	82%	1%	15%	2%	100%
Rail - Freight	2040	High Uneven	50%	2%	39%	8%	100%
Rail - Freight	2050	High Uneven	31%	6%	48%	15%	100%

Notes: LH2=liquid hydrogen, LNG=liquefied natural gas

Exhibit 103: Regional Passenger Rail Final Market Shares by Fuel Type

Market	Year	Scenario	Diesel	LH2	LNG	Electricity	Total
Rail - Regional	2030	Reference Case	24%	0%	0%	76%	100%
Rail - Regional	2040	Reference Case	24%	0%	0%	76%	100%
Rail - Regional	2050	Reference Case	24%	0%	0%	76%	100%
Rail - Regional	2030	Low Even	20%	0%	0%	80%	100%
Rail - Regional	2040	Low Even	17%	0%	0%	83%	100%
Rail - Regional	2050	Low Even	15%	0%	0%	85%	100%
Rail - Regional	2030	High Even	18%	0%	0%	82%	100%
Rail - Regional	2040	High Even	14%	0%	0%	86%	100%
Rail - Regional	2050	High Even	13%	0%	0%	87%	100%
Rail - Regional	2030	High Uneven	18%	0%	0%	82%	100%
Rail - Regional	2040	High Uneven	14%	0%	0%	86%	100%
Rail - Regional	2050	High Uneven	13%	0%	0%	87%	100%

Notes: LH2=liquid hydrogen, LNG=liquefied natural gas

Exhibit 104: Railcar Yard Switcher Final Market Shares by Fuel Type

Market	Year	Scenario	Diesel	LH2	LNG	Electricity	Total
Rail - Switcher	2030	Reference Case	91%	0%	9%	0%	100%
Rail - Switcher	2040	Reference Case	72%	0%	28%	0%	100%
Rail - Switcher	2050	Reference Case	57%	0%	43%	0%	100%
Rail - Switcher	2030	Low Even	87%	1%	10%	2%	100%
Rail - Switcher	2040	Low Even	61%	4%	30%	5%	100%
Rail - Switcher	2050	Low Even	38%	8%	46%	8%	100%
Rail - Switcher	2030	High Even	84%	2%	11%	3%	100%
Rail - Switcher	2040	High Even	52%	8%	31%	9%	100%
Rail - Switcher	2050	High Even	24%	15%	46%	15%	100%
Rail - Switcher	2030	High Uneven	85%	1%	11%	3%	100%
Rail - Switcher	2040	High Uneven	56%	2%	32%	10%	100%
Rail - Switcher	2050	High Uneven	29%	4%	48%	18%	100%

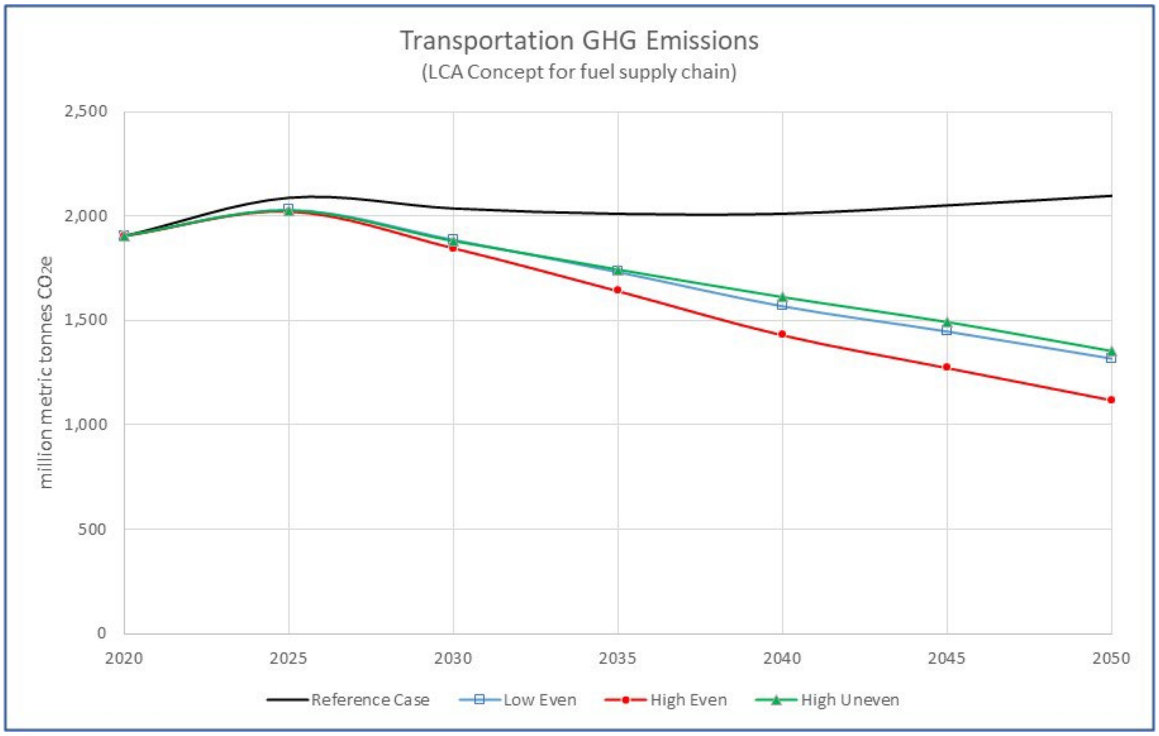
Exhibit 105: Panamax Containership Final Market Shares by Fuel Type

Market	Year	Scenario	LSMGO	LH2	LNG	Residual	Total
Panamax Containership	2030	Reference Case	36%	0%	4%	59%	100%
Panamax Containership	2040	Reference Case	39%	0%	8%	53%	100%
Panamax Containership	2050	Reference Case	40%	0%	12%	49%	100%
Panamax Containership	2030	Low Even	37%	1%	7%	55%	100%
Panamax Containership	2040	Low Even	34%	13%	13%	40%	100%
Panamax Containership	2050	Low Even	26%	32%	14%	27%	100%
Panamax Containership	2030	High Even	36%	4%	8%	51%	100%
Panamax Containership	2040	High Even	28%	30%	13%	29%	100%
Panamax Containership	2050	High Even	18%	54%	11%	17%	100%
Panamax Containership	2030	High Uneven	38%	0%	8%	54%	100%
Panamax Containership	2040	High Uneven	38%	0%	20%	42%	100%
Panamax Containership	2050	High Uneven	32%	5%	29%	33%	100%

7.8.3 GHG Emissions in the Transportation Sector

The transportation sector lifecycle GHG emissions for the Reference Case and the three Alternative Cases are shown in Exhibit 106. The Reference Case GHG emissions increase slowly at a rate of 0.3% per year, going from 1,906 million metric tons of CO2e in 2020 to 2,096 in 2050. The Alternative Cases all show negative rates of annual change: the Low Even Case is at -1.2%, the High Even is at -1.8% and the High Uneven is at -1.1% annual change. By 2050, the Low Even Case has emissions of 1,318 million metric tons of CO2e and the High Even Case has emissions of 1,120 million metric tons of CO2e. Relative to the Reference Case levels these are declines of -37% and -47% in the year 2050. When the economics for hydrogen are made worse in the High Uneven Case transportation GHG emissions decline less reaching 1,355 million metric tons in 2050, 35% less than the Reference level.

Exhibit 106: Transportation Sector GHG Emissions



7.8.4 Cost of Ownership for the Transportation Sector

The cost of ownership for the transportation sector is shown in Exhibit 107 for the Reference and the Alternative Cases. This includes the cost of buying and maintaining the vehicles, airplane, ships, and locomotives, etc. plus the cost of energy. The total increase in costs relative to the Reference Case over the entire forecast period is 6.2% in the Low Even Case, 8.6% in the High Even Case, and 8.7% in the High Uneven Case.

Exhibit 107: Cost of Ownership for Transportation Sector

Cost of Ownership ($billion): Transportation				
Year	**Reference**	**Low Even**	**High Even**	**High Uneven**
2020	$2,412	$2,412	$2,412	$2,412
2025	$2,852	$2,934	$2,957	$2,956
2030	$3,061	$3,216	$3,269	$3,265
2035	$3,225	$3,446	$3,534	$3,529
2040	$3,369	$3,640	$3,746	$3,749
2045	$3,507	$3,809	$3,926	$3,943
2050	$3,646	$3,959	$4,076	$4,115
Cumulative 2021-50	$95,214	$101,156	$103,381	$103,528
% Increase in Cum vs. Ref.		6.2%	*8.6%*	*8.7%*

Note: Cost of ownership is the annual cost of vehicles, ships, locomotives, airplanes, etc. including expenditures for capital, operating and maintenance, energy consumed and the internalized cost of carbon mitigation.

8. Conclusions and Caveats

This chapter summarizes the main conclusions of this study and offers caveats to how those conclusions may be viewed.

8.1 Conclusions

This study was conducted to determine what roles hydrogen, in general, and blue hydrogen, specifically, might play in a low-carbon future for the US and what infrastructure would be needed to allow those roles to be fulfilled. The analysis started with the 2021 AEO Reference Case as the business-as-usual benchmark in which hydrogen continued to be used as a chemical in various industrial processes but had only a minor role in fuel and power markets. Three Alternative Cases were created in which a willingness to pay for carbon mitigation was introduced to represent policies to increase the use of low-carbon technologies/fuels including hydrogen. The willingness to pay for carbon mitigation was assumed to increase annually up to either $150 per metric ton of CO2e or $250/metric ton of CO2e in 2050.

The GHG mitigation policies were assumed to allow energy providers and energy consumers to make investment and purchase decisions based on their "lifecycle costs" or "lifetime cost of ownership" which include capital, operating and maintenance costs, fuel/energy expenditures, the time value of money, and the internalized willingness to pay for carbon mitigation. The modeling did not include the imposition of any GHG targets, performance standards, fuel mandates beyond the existing state and federal policies already included in the AEO Reference Case. Two of the Alternative Cases (Low Even and High Even) assumed "economic competition with uniform incentives" in which all technologies/fuels would receive incentives or pay penalties based on the same $/metric ton of CO2e valuation for carbon mitigation. The third case (High Uneven) assumed blue hydrogen would face a $12/MMBtu policy-related differential in incentives compared to green hydrogen.

The main analytic results of this exercise can be summarized by these points:

Hydrogen Can Have a Large Role in Low-Carbon Energy Markets

US demand for hydrogen by end-users and power plants could reach 9.9 to 12.9 quadrillion Btu by 2050 under scenarios of "economic competition with uniform incentives." Hydrogen consumption would occur in all end-use sectors (residential, transportation, industrial and transportation) and in the power sector. These levels of hydrogen use could represent 12% to 15% of total US energy end-use consumption (83.7 quads) as forecasted in the 2021 EIA Annual Energy Outlook.

Hydrogen Made from Natural Gas May Be the Largest Initial Source of New Hydrogen Supply in the US if Sources Can Compete on an Even Basis

The results of this analysis suggest that under "economic competition with uniform incentives"." blue hydrogen made from natural gas with CCUS could be considerably less expensive than green hydrogen from electrolyzers for the next two or three decades. This is the case even when electrolyzers are assumed to use dedicated solar/wind renewable electricity and there is an assumption of substantial continued technology improvements that reduce the cost of renewable electricity and the cost of conversion of electricity to hydrogen in electrolyzers. Given these economics, blue hydrogen can be expected to make up over 90% of the US market to supply end-users from dedicated, continuous hydrogen production facilities in the Low Even and High Even Cases over the forecast period to 2050.

Hydrogen Made from Renewable Electricity May Also Play a Significant Role

Large amounts of solar and wind generation will be needed to meet national climate goals. This is expected to lead to “excess electricity” when electricity load plus charging for electricity storage is less than generation from non-dispatchable/inflexible generation. Assuming that most of this excess electricity is not curtailed but is used to make hydrogen in electrolyzers, the resulting hydrogen could make up about 7% to 9% of projected hydrogen demand in the US from 2025 to 2050. An additional 2% of hydrogen supply might come from solar/wind generation that is “dedicated” to making hydrogen on a continuous basis.

Policies Providing Uniform Incentives among Sources of Hydrogen May Help Ensure Hydrogen’s Benefits are Realized

The importance of providing uniform incentives to all hydrogen sources to help realize the benefits of hydrogen as a carbon mitigation resource was investigated in this study by modifying the $250/MT CO2e case to assume that blue hydrogen would bear a $12/MMBtu differential in incentives relative to green hydrogen. Relative to the case with uniform incentives, this High Uneven Case has smaller hydrogen end-use markets (3.7 quads versus 12.9 quads by 2050). This smaller market is a result of potentially higher wholesale hydrogen prices as blue hydrogen is more expensive and the market must rely on higher cost green hydrogen. The High Uneven Case also results in 5.5 billion fewer metric tons of GHG emission reductions through 2050 (equivalent to 18.5 months of the average of all GHG emissions). Both the High Even and High Uneven Case have a willingness to pay for carbon mitigation that rises to $250/MT in 2050 but the High Even Case displays better economic efficiency measured as incremental dollars per metric ton of CO2e reductions. The advantage in economic efficiency for the Even Case was 12% averaged over the entire forecast period and 17% in the year 2050 alone.

Requirements for Hydrogen Infrastructure May be Large

The realization of hydrogen’s potential to contribute to GHG mitigation goals will require investments into several kinds of infrastructure including blue hydrogen manufacturing, electrolyzers to convert excess and dedicated solar and wind electricity, hydrogen pipelines, hydrogen storage, local hydrogen distribution systems and hydrogen conversion, transport and dispensing for transportation market. For the Low Even Case, investments in blue hydrogen manufacturing facilities constitute the largest category, coming to $209 billion or 22% of the $950 billion total requirement through the year 2050. The next largest components are conversion of hydrogen (that is, cryogenic liquefaction, compression to very high pressures or conversion to a derived fuel) for transportation markets and end-users not connected to hydrogen pipelines or local hydrogen distribution systems. The High Even Case has greater demand for hydrogen compared to the Low Even Case (12.9 quads versus 9.9 quads in 2050) and also has a higher requirement for capital expenditures ($1.27 trillion versus $0.95 trillion). The percent allocation of expenditures among categories is similar with blue hydrogen manufacturing again being the largest category with about 22% of the total.

8.2 Caveats

Any analysis of long-term energy markets should be understood to contain a high degree of uncertanity stemming from the potential future interactions of many unpredicatable economic, technical, geopolitical factors. This may be particularly true for projections of the potential roles of hydrogen in US energy sector given these considerations:

- **Nascent technologies:** Many of the modeled technologies that use or compete with hydrogen in end-use markets are nascent with uncertain current and near-term cost and performance characteristics.
- **Unpredictable pace of future technology advances:** Long-term advances for electric and hydrogen technologies are not known with any certainty but are expected by many energy analysts (and in this study) to be large. These advances may determine the cost of the low-carbon transitioning and the mix of technologies and fuels that will be employed. For example, advances in battery and electric motor technologies and new design for high-temperature industrial processes may erode hydrogen's advantages in the "niche" markets where hydrogen is now expected to fare well. On the other hand, new ways of storing hydrogen might greatly improve its economics in transportation markets.
- **Unknown future energy market environment:** The future energy market environment and energy prices could be much different than envisaged in the 2021 AEO. Furthermore, climate policies themselves might change the amounts of each primary energy source consumed, causing the prices received by energy producers (before the application of the willingness to pay for carbon mitigation) to drop. In particular, the prices received by producers of coal, petroleum products and natural gas could be lower, making the prices to consumers somewhat lower than assumed in this study.
- **Regional and submarket effects might be important:** Although end-use markets have been modeled here in considerable detail, regional variations and differences among different classes of consumers within a sector have not been considered explicitly.
- **Consumer attitudes and choices are hard to anticipate:** Consumer behavior in terms of how technologies/fuels are viewed, which are purchased, and how they are used may deviate from the simple cost-minimization model employed in this report.
- **Investors risk assessments and decision making are also hard to anticipate:** There also are uncertainties related to the investment behavior of energy producers and suppliers of energy-consuming appliances, vehicles, and equipment. Will they see the GHG mitigation policies as permanent and make the needed investments in R&D and product commercialization in a timely manner?
- **More hurdles may emerge for large-scale geologic storage of CO2 and all energy-related land-uses:** The large-scale adoption of geologic storage forecasted here for the power, industrial, direct air capture, and blue hydrogen sectors may be difficult to achieve in certain areas due to popular opposition, regulatory delays, and other factors. This may also be true of solar, wind, and other technologies that sometimes engender land-use, environmental impact, public nuisance, and other conflicts.
- **Uncertain and varied market interventions:** The form of market interventions that may be adopted to achieve carbon mitigation goals might well deviate from the "economic

competition with uniform incentives" model assumed here and might differ among states and regions.

- **There may a potential for further energy conservation:** This study preserved the AEO's level of "energy-related services" (e.g., vehicle miles traveled, airline passenger miles, gallons of domestic hot water consumed per household) and did not consider conservation beyond that already in the AEO Reference Case. Energy conservation might exceed levels projected in the AEO due to specific policy measures that could be adopted as part of climate policies or (depending on how incentives versus disincentives are applied) could be induced by changes in the cost of ownership of energy-using appliances, equipment, vehicles, etc.
- **International obligations and interactions:** This study was focused on the US and did not incorporate international considerations such as the potential market for export of US hydrogen, trade issues (e.g., application of compensating tariffs on high-carbon-content imports to prevent their import from countries with weak climate policies) or negotiated climate obligations.

9. Acronyms Related to Hydrogen

This Appendix explains acronyms related to hydrogen used in this report and elsewhere.

Acronym	Meaning
AEO	Annual Energy Outlook from the Energy Information Administration
AGA	American Gas Association
AGF	American Gas Foundation
ANL	Argonne National Laboratory'
ASU	air separation unit
ATR	autothermal reforming
BBB	Build Back Better
Btu	British Thermal Unit
Capex	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, use, and storage
CGH2	compressed gaseous hydrogen
CH2	compressed hydrogen
CHP	combined heat and power - also called cogeneration
CNG	compressed natural gas
CO	carbon monoxide
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
DAC	direct air capture
DOE	U.S. Department of Energy
DRI	direct reduction iron
EERE	Energy Efficiency and Renewable Energy within DOE
EIA	Energy Information Administration within DOE
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Administration
FC	fuel cell
FCV	fuel cell vehicle
FOM	fixed operating and maintenance costs
FT	Fischer-Tropsch synthesis process
GDP	gross domestic product
GGE	gallon gasoline equivalent
GHG	greenhouse gas
GREET	GREET - Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GVWR	gross vehicle weight rating
GW	gigawatt
GWh	gigawatt-hour
H2	hydrogen

Acronym	Meaning
HB	Haber-Bosch process to make ammonia
HDV	heavy-duty vehicle
HEV	hybrid electric vehicle
HHV	higher heating value
HP	horsepower
ICE	internal combustion engine
IEA	International Information Agency
kg	kilogram
kg/d	kilograms per day
kg/h	kilograms per hour
kWh	kilowatt-hour
LDV	light-duty vehicle
LH2	liquefied hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LPG	liquefied petroleum gas (largely propane and butane)
MCFC	molten carbonate fuel cell
MMCFD	million cubic feet per day
Mpa	Megapascal (35 Mpa =5,000 psig =350 bar)
MSW	municipal solid waste
MWh	megawatt-hour
NATCARB	DOE's program to characterize the US geologic storage capacity
NETL	DOE's National Energy Technology Laboratory
NGL	natural gas liquids
NGV	natural gas vehicle
NH3	ammonia
Nm3/h	normal cubic meters per hour
NREL	National Renewable Energy Laboratory
NTP	normal temperature and pressure
OCS	Outer Continental Shelf
Opex	operating and maintenance expenditures
PAFC	phosphoric acid fuel cell
PEM	polymer electrolyte membrane
PEMFC	polymer electrolyte membrane fuel cell
PGM	platinum group materials
PM	passenger miles
PSA	pressure swing adsorption
psi	pounds per square inch
psig	pounds per square inch gauge pressure

Acronym	Meaning
quads	quadrillion British thermal units
RFG	reformulated gasoline
RNG	renewable natural gas
SCF	standard cubic feet
SMR	steam methane reforming
SNG	synthetic natural gas
SOFC	solid oxide fuel cell
SUV	sport utility vehicle
TBtu	trillion British thermal units
TWh	terawatt-hour
VMT	vehicle miles traveled
VOM	variable operating and maintenance costs
WRRF	water resource recovery facilities