Projected Nuclear Energy Futures Under Deep Decarbonization Policies

Nuclear Technology Research and Development

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Son H. Kim, PNNL
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Abstract

Nuclear energy is a dense and stable source of energy that does not generate carbon emissions during energy production. Heat from nuclear energy can be converted to electricity and hydrogen that can be utilized as carbon-free energy carriers for meeting diverse energy needs of an economy. Thus, nuclear energy has a significant role for addressing global climate change. We explored the contribution of nuclear energy for hydrogen production and electricity generation for the US under the recently implemented Inflation Reduction Act (IRA) and a net-zero carbon dioxide (CO_2) emissions scenario by 2050. The ultimate role of nuclear energy was highly dependent on the nuclear capital cost which is the primary determinant of nuclear electricity and nuclear hydrogen costs. Compared to a reference case without clean energy credits, the IRA induced only marginal gains in relative nuclear competitiveness since the current nuclear capital cost is high, all clean energy technologies benefit from clean energy credits, and the duration of the IRA is short. In this analysis, the IRA resulted in total CO_2 emissions reduction of 32% by 2035 and 37% by 2050, relative to 2005, and was not able to achieve net-zero emissions. The net-zero scenario requires a more aggressive and long-term sustained effort for emissions reduction. In the net-zero scenario of this analysis, nuclear capital cost sensitivity cases show that with aggressive capital cost reductions, the combined nuclear power capacity for electricity and hydrogen production could be an order of magnitude greater than that for the US today. In contrast, if nuclear capital costs remain high, the nuclear energy contribution is limited. The range of nuclear capacities in the net-zero scenario was 197 – 457 GWe in 2050 and 272 - 913 GWe in 2100 for nuclear capital costs of 6600 - 2600 $/kWe, respectively. Hydrogen provides a pathway for emissions reduction where electrification is not possible, and distributed applications of nuclear power plants for hydrogen production are promising. The nuclear capacity for hydrogen production alone was as high as 63 GWe in 2050 and 152 GWe in 2100. Overall, the nuclear capacity for electricity generation was greater than that for hydrogen production due to greater end-use of electricity relative to hydrogen. Nuclear capital cost reductions had clear benefits for improving the competitiveness of nuclear energy for both electricity and hydrogen production and for contributing to CO_2 emissions reduction efforts.

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1. Introduction

Climate change is one of the most pressing and difficult environmental challenges of our time. In response, the United Nations Framework Convention on Climate Change (UNFCC) has as its objective to “stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system” (UNFCCC, 1992). In the recent Paris Agreement, more than 100 countries endorsed limiting global warming to below 2° C above pre-industrial levels and recognized the importance of pursuing 1.5° C above pre-industrial levels (UN, 2015).

Deep decarbonization of the energy system for addressing global climate change entails the removal of greenhouse gas (GHG) emissions from all sectors and energy use activities of the economy that contribute to emissions. Reducing emissions from the electric power sector has been the focus of deep decarbonization efforts due to the large share of GHG emissions from the power sector and the readily available and cost-effective carbon-free technologies, such as renewables and nuclear power. Although the need for emissions removal from all economic activities is recognized, there is no clear and unified path to removing all emissions from all activities due to the diversity of end-use energy services and industrial energy needs. Recently, however, there has been growing interest in the production and use of hydrogen as a strategy for further emissions reduction in addition to the greater adoption of electrification.

Hydrogen (H_2) is an energy carrier that can be produced without carbon emissions from multiple energy sources. Carbon capture and storage (CCS) can be applied to H_2 production methods that utilize fossil or biomass feedstocks for lowering the carbon emissions rate. Electrolysis utilizing multiple electricity sources such as wind, solar, and nuclear can be applied for carbon-free H_2 production. There are keen interests in H_2 supply opportunities and alternative methods for its production. However, the demand for H_2 is currently limited and the infrastructure for the storage, delivery, and use of H_2 is not well established. Technologies for providing energy services with H_2, such as fuel cells and combustion equipment suitable for H_2 fuels, are not yet mature or cost effective. And as there has not been incentives for the substitution of H_2 for current fossil fuel and electricity use or cost advantages to H_2 usage without carbon emission penalties, the long-term demand for H_2 is uncertain. Thus, greater assessment of the future demand and applications for H_2 is needed to understand the scale of the H_2 economy and its potential contribution to GHG emission reduction.

Nuclear power generation in the United States (US) has made significant contributions to the energy system for nearly fifty years and is currently the largest single source of carbon-free electricity generation in the US. The bulk of the currently operating nuclear reactors were constructed from the 1970’s and 1980’s and few new reactors have been added to the existing fleet (EIA, 2022). Due to the lack of nuclear reactor builds in the last thirty years, there has been a loss in the continuity of new nuclear construction and deployment experience (DOE, 2020). Recent efforts to build new reactors have experienced significant construction delays and cost overruns coinciding at a time when climate change concerns have motivated a greater desire for the expanded deployment of nuclear energy.

Concerted efforts to understand and control the cost of new nuclear reactor construction in the US and the emergence of multiple advanced nuclear reactor designs with improved safety and cost potential have encouraged the optimistic outlook for nuclear energy as a tangible solution to energy security and climate change. Nevertheless, uncertainty remains for the realization of future nuclear cost reductions for evolutionary and advanced reactors due to their diverse designs, size, supply chain issues, and limited vendor construction experience. Thus, this analysis investigates alternative nuclear energy cost projections to understand the relationship between nuclear cost and future nuclear energy contributions.

The passage of the Inflation Reduction Act (IRA) sets in motion concrete actions for the reduction of carbon emissions in the US and for addressing global climate change. The IRA provides clean energy credits to a variety of technologies and fuels, and we assess the impact of the IRA on nuclear energy and on total carbon emissions reduction. In addition to the IRA, an economy-wide net-zero emissions scenario by 2050 is investigated to compare the emissions reduction achieved by the IRA to that needed to achieve net-zero. In both scenarios, we assess the role of climate policies on the prospect for improving the competitiveness of nuclear power and quantify the potential range of nuclear power deployments under alternative nuclear capital cost assumptions.

The report begins with introductory remarks and an overview of the Pacific Northwest National Laboratory's (PNNL) Global Change Analysis Model (GCAM) (Calvin et al., 2019). The representation of the expanded hydrogen production and demand sectors in GCAM is described, as well as the assumptions of electric power technology cost and characteristics. This is followed by scenario descriptions for the nuclear capital cost sensitivity cases, alternative IRA implementations, and net-zero emissions by 2050. GCAM modeling results follow with a detailed analysis of H_2 and electricity production and demand, composition of H_2 and electricity generation, nuclear power capacities, and potential for CO_2 emission reductions in the US for the Reference (no policy), IRA, and Net-Zero scenarios. The report is closed with concluding remarks and discussions for future work.

2. Global Change Assessment Model (GCAM)

2.1 GCAM Overview

GCAM is a tool for simulating long-term projections of energy use, agriculture production and land-use change, and greenhouse gas emissions (JGCRI, 2022). It has been utilized extensively for understanding a broad range of global change related issues and for investigating the role of technologies and policies in alternative scenarios of the future in the context of global climate change. GCAM is used in this analysis to investigate the role of nuclear energy in the US for addressing climate change and for reducing carbon emissions.

GCAM simulates a hundred years of future global energy use and runs from 2005 to 2100 in 5-year time steps. The 2005 to 2015 modeling time periods are calibrated to historical datasets and provide consistent transitional context from history to future projections. The current publicly available version of GCAM has 32 global regions with the US as a separate region. Although the full global version is utilized, the focus of the modeling results is on the US in this analysis. It is important to highlight that the 100-year simulation of GCAM provides additional extended information for understanding technology impacts, energy system changes, and climate change mitigation efforts that arise from alternative technology lifetimes, capital stock turnover dynamics, technological change, and long-term nature of the climate change problem.

GCAM's strength is in its ability to track energy resources, transformation of resources to final fuels and energy carriers, and simulation of the demand for energy and energy services from all end-use sectors of the economy, while accounting for GHGs from all emissions activities. GCAM is an economic model with long-term equilibrium behavior in the supply and demand of goods and services. Economic sectors are linked through a market concept and changes in the market prices affect the supply and demand of goods and services. For each period, model solution is reached when supplies and demands for all goods and services in the regional and global economy simultaneously reach equilibrium.

All technologies in GCAM, including electric power and hydrogen production technologies, compete based on their economic costs. Technology costs are separated into resource, fuel or energy costs, and non-fuel costs that include capital and operations & maintenance (O&M) costs. Energy resources including conventional crude oil, unconventional oil, natural gas, coal, and uranium are represented by a supply curve based on graded resources and their cost of extraction. Renewable technologies including hydro, geothermal, wind, and solar are also modeled based on their resource potential and cost of power generation, delivery to grid, backup energy or storage requirements, and systems integration. Numerous technologies for energy transformation from crude or raw fuels to refined fuels and multiple energy carriers are represented, as well as the conversion of solid fuels such as coal and biomass to liquids and gases, and gaseous fuel to liquids.

CO_2 and other emissions from all technologies are calculated with emissions coefficients included for each fossil fuel, crude oil, natural gas, and coal. Biomass use for energy is treated similarly as fossil fuels and contributes to carbon emissions during combustion. However, carbon emissions credits are provided to the agriculture sector in equal amount to the carbon removed from the atmosphere during commercial biomass cultivation. Other than the additional energy inputs for processing and refining of biomass fuels, commercial biomass is treated as a carbon-neutral source of energy on a life-cycle basis. Associated land-use change emissions from biomass production are accounted for separately in the terrestrial system. Nuclear and renewable energy are treated as carbon-free sources of energy.

Recent updates to the hydrogen production and demand representations and expanded detail of the industrial sector, discussed below, provide the capability for assessing the potential of hydrogen as an alternative carbon-free energy carrier for addressing global climate change, in addition to electricity and carbon-neutral fuels.

2.2 GCAM Hydrogen Production and Demand Sector Representation

2.2.1 Hydrogen Production and Distribution

The hydrogen production, delivery, and demand representations in GCAM have been recently updated due to the increasing interest in the wider application of hydrogen as a carbon-free energy carrier. The hydrogen analysis of this report builds on the hydrogen modeling capability developed at PNNL by Kyle et. al. (Kyle P, 2022). This analysis is based on current understanding H_2 technology costs, characteristics, and applications with assumptions for their technical improvements. We continue to improve the representation of the hydrogen energy system with emerging technology applications and new data as it becomes available.

H_2 production is represented by two approaches, central station and forecourt production. Central station production represents large, centralized, dedicated H_2 production facilities that can utilize a variety of fuels, including biomass, fossil, fossil with CCS, nuclear, and renewable energy sources, in the production of hydrogen. Central station facilities are large-scale H_2 production plants with corresponding large-scale power and heat needs and processing plant requirements. Due to their large capacity, central station plants are likely to be located further away from urban areas and demand centers.

Therefore, H_2 produced from central station facilities must be stored and transported to demand locations before it can be utilized. Additional infrastructure, energy, and cost for transport, storage, distribution, compression, and liquefaction of H_2 from central station are needed before it can be utilized at the end-use. Two pathways for H_2 transport are represented, through pipeline in gaseous H_2 form and by trucks as liquified H_2. Costs of the delivery systems are assumed to improve over time.

Forecourt or distributed production of H_2 for on-site applications is also represented. Although no specific capacity range of H_2 production has been defined in this analysis, forecourt H_2 production is assumed to be smaller scale facilities dedicated for specific industrial and end-use applications. Forecourt H_2 production options are limited to electrolysis, steam-methane-reforming (SMR) of natural gas, and small modular and/or micro nuclear reactors with high-temperature-steam-electrolysis. H_2 produced from forecourt plants do not incur the additional cost for transport and delivery that is applied to centration station H_2 production. However, on-site H_2 production may have additional storage and dispensing costs dependent on the end-use application. For the transportation sector and off-road industrial machinery applications of on-site H_2 production, additional costs are required for H_2 storage and higher pressures for dispensing. For other industrial applications, no additional costs or requirements are specified for H_2 produced and utilized on-site.

Ultimately, H_2 for all end-use applications is offered through three competitive options, pipeline delivered, truck delivered, and on-site production. The source of H_2 available via pipelines and trucks originates from central station plants. For dispensing of H_2 for transportation refueling stations, costs for compression and refrigeration are added to the cost of delivered or on-site produced H_2.

The cost and characteristics of all H_2 production technologies in GCAM, except for nuclear H_2, are directly from the NREL Hydrogen Analysis Model (H_2A) (NREL, 2018). The H_2A model provides the data and characteristics for central and distributed H_2 production facilities and by fuel type. The nuclear H_2 production data is from the 2022 INL study by Wendt et. al. (Wendt D, 2022). The cost and characteristics of nuclear H_2 production, which we have expanded upon in this analysis, is discussed below. For detailed information on the cost and characteristics of other H_2 production options, we refer the reader to the H_2A model documentation (NREL, 2018). The results section of this analysis, however, provides the costs of H_2 production for each fuel type.

2.2.2 Nuclear Hydrogen Production

The nuclear H_2 technology represented here is based on the high-temperature-steam-electrolysis (HTSE) method utilizing the nuclear power plant as the source of electricity and high temperature steam as described in the INL study by Wendt et. al., 2022. For the remainder of this report, we refer to this technology as nuclear HTSE.

The base design and cost of the nuclear HTSE is for Nth-of-a-Kind (NOAK) gigawatt-scale light-water reactor (LWR) that is fully dedicated for constant H_2 production. No dispatching of the nuclear power between the HTSE plant and the grid is assumed. The electrolysis process utilizes a solid-oxide-electrolysis-cell (SOEC) stack with steam and electricity from the nuclear power plant to improve the efficiency of H_2 production. The INL report, however, provides additional information on the relationship of the HTSE plant capacity (daily H_2 production rate) to capital costs allowing for extrapolation to smaller scale HTSE plants that are more suitable for distributed H_2 production and application.

Based on the INL study, the levelized cost of H_2 (LCOH) from the nuclear HTSE plant is assessed at 1.86 \$/kgH_2 assuming electricity cost of 30 \$/MWh. The electricity cost alone contributes to more than 60% of LCOH, with thermal energy cost contributing an additional 3% to LCOH. The cost without electricity and thermal energy is 0.66 \$/kgH_2 or 36% of the LCOH. The cost of electricity to power the electrolyzer is the most significant cost of production. According to Wendt et. al., “The strong dependence of LCOH on energy price indicates that energy price is a key variable in determining the economic viability of an LWR-HTSE hydrogen-production plant.”

For this reason and for the consistent treatment of nuclear power plant costs within this analysis, we separated the nuclear HTSE plant cost into two components, the nuclear power plant and HTSE plant. In this analysis, the nuclear HTSE plant was based on investments in new nuclear power plants and not the conversion of currently existing commercial nuclear plants for H_2 production. For new nuclear power plant investments, the nuclear cost assumptions were consistent for both power generation for end-use electricity use and for H_2 production. However, the thermal efficiency for electricity generation was derated by 5% for the nuclear power plant dedicated for H_2 production since high temperature steam is diverted to the HTSE plant. We did not include a cost charge for the steam since it is provided by the dedicated nuclear plant, and the related incremental piping cost from reactor to HTSE plant was assumed to be absorbed as part of the total capital cost of the newly constructed nuclear HTSE plant.

Small-scale nuclear HTSE plants with lower H_2 production capacity for distributed applications are also included in this analysis. The INL study concludes that the hydrogen plant design capacity has little impact on the LCOH. In this analysis, the portion of the LCOH for the HTSE plant was increased by 15% to approximate the scale impact based on the INL study. There are significant commercial interests in the small-scale and distributed applications of nuclear H_2, such as the Ultra Safe Nuclear Corporation’s 15 MW thermal, 5 MW electrical reactor applications for hydrogen hubs at local sites (NEI, 2023).

2.2.3 Hydrogen Demand Sector Representation

Recently, the GCAM industrial sector representation was updated to disaggregate the industrial sector to better project the specific industrial goods produced and better understand their energy and emissions profiles. GCAM industries or categories that are now separately tracked are Refining, Cement, Chemicals, Fertilizer, Agriculture Energy Use, Aluminum, Construction Energy Use, Iron & Steel, and Mining Energy Use. These sectors comprise 70% of global industrial GHG emissions and 56% of global industrial energy consumption. The remaining industrial sectors are aggregated into the Other Industrial Energy Use category in GCAM. Energy consumption by industrial sectors is calibrated using the IEA Energy Balances (IEA, 2020b), and the outputs of industrial sectors are calibrated from multiple industrial association data (PNNL, 2023). For historical years, we follow the IEA Energy Balance convention on fuel categories, and H_2 use by industries where the H_2 is derived from fossil fuels in the industrial process is categorized as fossil fuel consumption (IEA, 2020b).

For all future years, separately represented H_2 production sectors and H_2 markets are created in GCAM for new H_2 applications as alternative options to fossil fuels and other energy carriers. Multiple fuels and energy carriers are utilized by the industrial sectors in GCAM. Hydrogen is available for use in Refining, Cement, Chemicals, Fertilizer, Agriculture Energy Use, Construction Energy Use, Mining Energy Use, Iron & Steel, Other Industrial Energy Use sectors, as well as for industrial mobile equipment and the transportation and buildings sectors.

Delivered H_2 from centrally produced H_2 plants are available for use anywhere H_2 use is allowed. H_2 use from forecourt production is available for nearly all industrial sectors and specific transport services. Forecourt H_2 applications were not available for commercial and residential building heating services. Table 1 provides a list of all sectors for which H_2 use is allowed, and check marks for the sectors where central station and forecourt nuclear H_2 use is applicable. The final distribution forms for H_2 in GCAM are Wholesale Delivery, Wholesale Dispensing, Retail Delivery, and Retail Dispensing, which further differentiate H_2 costs to account for delivery, storage, compression, refrigeration, and dispensing costs where applicable. Retail costs are higher than Wholesale costs to account for additional distribution costs to end users. Dispensing of H_2 for transportation and mobile industrial equipment incurs additional costs, beyond the delivered H_2 costs, for dispensing requirements.

Table 1. Central station and forecourt nuclear HTSE H_2 applications and final delivery form (✓= applicable).

Sectors for H_2 Use	**Central Station Nuclear HTSE**	**Forecourt Nuclear HTSE**	**H_2 Distribution Form**
Fertilizer	✓	✓	Wholesale Delivery
Chemical Energy Use	✓	✓	Wholesale Delivery
Iron & Steel	✓	✓	Wholesale Delivery
Other Industrial Energy	✓	✓	Wholesale Delivery
Process Heat Cement	✓	✓	Wholesale Delivery
Refinery	✓	✓	Wholesale Delivery
Other Industrial Energy	✓	✓	Wholesale Delivery
Mining Energy Use	✓	✓	Wholesale Dispensing
Agriculture Energy Use	✓	✓	Wholesale Dispensing
Construction Energy Use	✓	✓	Wholesale Dispensing
Transport (Aviation Intl)	✓	✓	Wholesale Dispensing
Transport (Shipping Intl)	✓	✓	Wholesale Dispensing
Industrial Mobile Equipment	✓	✓	Wholesale Dispensing
Transport (Freight Road)	✓	✓	Retail Dispensing
Transport (Passenger Road)	✓	✓	Retail Dispensing
Commercial Building Heating	✓		Retail Delivery
Residential Building Heating	✓		Retail Delivery

2.2.4 Hydrogen Demands Not Included in Analysis

H_2 demand for peaking and backup electricity generation and grid support is not included in this analysis. Multiple options exist for peaking and backup electricity needs, such as traditional load-following with dispatchable generators, batteries, heat storage, pump-hydro, as well as H_2 storage. A separate study is warranted to assess the contribution of H_2 for power grid support with an analytical capability that can include all energy storage options which was not possible in this analysis. Applications of nuclear power generation with heat storage, such as the Natrium reactor (TerraPower, 2023), may be a more economical approach for meeting daily peak electricity load demands.

H_2 demand for petroleum refineries were not included. Refined petroleum fuel production with H_2 derived from external sources is difficult to justify based on cost and as an emission reduction strategy since fuels derived from fossil sources remain a carbon emitting energy source. Under carbon mitigation efforts, the demand for all fossil fuels decline. Synthetic fuel production using biomass and alternative sources of H_2, however, is included in this analysis. There are multiple competitive options for biomass conversion to liquid fuels, such as ethanol and biodiesel production, however. Liquid fuels derived from biomass are considered carbon neutral.

The nuclear H_2 production was limited to new nuclear facilities. The application of the legacy nuclear fleet for H_2 production is not specifically investigated in this analysis. We assume that the legacy nuclear fleet continues to generate power as a source of grid electricity. However, H_2 production via electrolysis using grid electricity that occurs in this analysis does include the contribution of electricity produced by the legacy nuclear fleet.

2.3 GCAM Electric Power Technology Assumptions

Integrated-assessment models, such as GCAM, operate at highly aggregated spatial and temporal resolutions to capture the global and regional long-term behavior of energy use. The electricity supply sector for each region is represented as a single balancing authority and electricity trade within a region is not modeled. All power supply technologies including carbon emitting and non-emitting technology options are included. Demands for electricity from all end-use sectors, buildings, industry, and transport, and all energy services are represented to provide a comprehensive assessment of the total electricity demand over time. Changing prices of fuels and energy carriers, and carbon penalties applied to supply and demand activities affect the choice of electric technology and the demand for electricity.

Since the temporal resolution of GCAM is at the annual scale, diurnal and season behaviors of electricity generation and use are not explicitly represented. Electric generating units are not dispatched on an hourly or time-slice basis. Instead, annual shares of electric power technology choices are determined by a statistical approach. Electric power technology competition utilizes the discrete choice method for the technology choice and power market share by technology (McFadden, 1974). A logistic model using levelized cost of electricity (LCOE) and historically calibrated model parameters is implemented. The LCOE provides a distilled and aggregated measure of technology costs that is readily calculated. Historical calibration of model parameters captures unobserved factors, such as diurnal, seasonal, intra-regional heterogeneity, and other impacts, that are not measured by the LCOE alone. Strategies for determining the LCOE of renewable energy technologies and addressing intermittency issues are discussed below.

GCAM version 6.0 utilized for this analysis includes recent updates to the electricity cost data based on the National Renewable Energy Laboratory's Annual Technology Baseline for 2019 (NREL ATB) (NREL, 2019). Historical and projected overnight capital costs for electric power technologies are provided up to 2050 in the NREL ATB. Since GCAM needs cost assumptions to 2100, technology cost assumptions beyond 2050 were determined by technology maturity and technical improvement potential as described by Muratori et al. (Muratori et al., 2017). Table 2 documents the power technology cost, capacity factor, and lifetime assumptions used in this analysis.

Table 2. Electric power plant capital cost, capacity factor and lifetime assumptions in GCAM (NREL 2019 ATB costs adjusted to 2020 USD).

Technology	Capital Cost 2015 [$/kW]	Capital Cost 2050 [$/kW]	Capital Cost 2100 [$/kW]	Capacity factor	Lifetime [years]
Coal (steam plant)	3870	3554	3359	0.85	60
Coal CCS (steam plant)	5922	5395	4904	0.8	60
Coal (IGCC)	4152	3497	3230	0.8	60
Coal CCS (IGCC)	6852	5235	4568	0.8	60
Natural Gas (simple cycle)	938	831	808	0.8	45
Natural Gas (CC)	1098	831	812	0.85	45
Natural Gas CCS (CC)	2292	1857	1678	0.8	45
Oil (simple cycle)	938	831	808	0.8	45
Oil (CC)	1098	831	812	0.85	45
Oil CCS (CC)	2730	2154	1922	0.8	45
Biomass (steam plant)	4061	3588	3294	0.85	45
Biomass CCS (steam plant)	7820	6036	4934	0.8	45
Biomass (IGCC)	6093	4797	3992	0.8	45
Biomass CCS (IGCC)	8987	6528	5006	0.8	45
Nuclear	6501	5342	4259	0.9	60
Wind (on-shore)	1720	1091	972	0.37	30
Wind (on-shore + battery)	6410	2829	2170		30
PV (large-scale)	2543	831	789	0.2	30
PV (large-scale + battery)	7229	2620	2051		30
PV (rooftop)	4129	1232	1155	0.17	30
CSP (+ thermal storage)	8656	3634	3214	0.5	30
Geothermal	5090	3775	3413	0.9	30

Due to the intermittent nature of renewable energy technologies, the use of LCOE based strictly on nameplate costs and characteristics cannot be directly utilized as a consistent or comparable metric for power technology choice (Joskow, 2011). Thus, the LCOE of intermittent energy technologies is treated specially in GCAM to account for the added cost of variable renewable energy integration. In addition to representing wind and solar resource supply curves that account for the spatial distribution of graded wind and solar resources and distance to load centers, intermittent energy technologies in GCAM incur additional cost for integration as a function of renewable share of total electricity generation. This feature of GCAM ensures that the treatment of intermittent technologies properly reflects the complexity and increased cost of renewable energy penetration for capturing realistic levels of renewable energy use under climate mitigation scenarios.

Multiple factors contribute to the added cost of renewable energy integration. Ueckerdt et al. summarizes these costs into three main drivers, balancing cost, grid cost, and profile cost, which contribute to the total systems integration cost of renewable energy (Ueckerdt et al., 2015). Balancing cost arises from need for highly responsive backup energy systems that stabilizes the electricity grid from rapid changes in the output of renewable energy. Grid cost arises from additional transmission lines required for transferring remote sources of renewable energy to load centers, and efforts required for the optimal distribution of power within the grid. Profile cost arises from the mismatch of renewable energy supply with the load demand profiles.

At low levels of renewable energy penetration, the profile cost may be negligible since most or all the renewable energy can be readily absorbed (Hirth, Ueckerdt, & Edenhofer, 2015). Balancing and grid costs remain however and may constitute the bulk of the systems integration costs at low levels. At high levels of renewable energy penetration, the profile cost dominates due to the overall mismatch of renewable supply with demand. Profile cost includes idling, more frequent cycling, and less than optimal operation of dispatchable generation, and the reduced utilization of renewable energy from overproduction or curtailment. At high renewable penetration rates, estimates of 50% additional integration cost are projected based on more detailed dispatch models with greater spatial and temporal resolutions (Hirth et al., 2015). The systems integration cost of renewable energy is modeled in GCAM as a function of renewable energy penetration with the profile cost as the main obstacle to high levels of renewable energy use (JGCRI, 2022).

Wind and solar energy technologies with dedicated energy storage are also included as options for power generation. However, renewable technologies with dedicated energy storage are not treated as variable generation and do not incur any additional integration costs. The total combined costs of renewables with dedicated storage are shown in Table 2.

For a more accurate representation of the US nuclear energy system, further disaggregation of nuclear power representation has been included in this analysis. Each existing nuclear reactor in the US is discretely represented as shown in Figure 1, including Georgia's Vogtle Units 3 and 4 that will come online in 2023 or 2024 (NRC, 2020). The discrete representation of each existing reactor more accurately represents the longevity of nuclear plants, as well as the more accurate profile of the nuclear retirement schedule. All operating reactors are assumed to have a total lifetime of 80 years (DOE, 2008; NRC, 2021) in this analysis, except for California's Diablo Canyon Units 1 and 2 that are assumed to retire by 2025. This implies that the bulk of the electricity generation from existing reactors will occur until 2050 and decline thereafter to 2070 when most existing reactors will have retired. Three reactors, Watts Bar-2, Vogtle-3, and Vogtle-4 are assumed to provide energy throughout the remainder of the 21st century. New nuclear power deployments, beyond Vogtle-3, and Vogtle-4, are not assumed to be available until the 2030 modeling period.

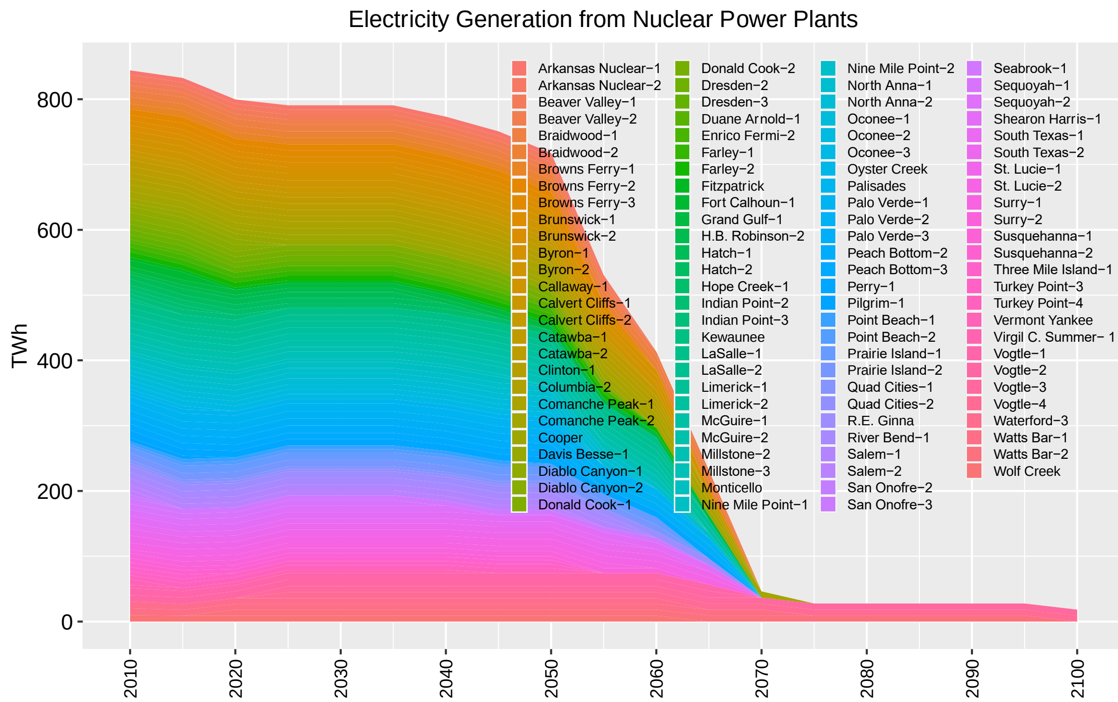


Figure 1. Electricity generation from existing nuclear power reactors in the US assuming 80-year lifetimes, except for Diablo Canyon 1&2, and including Watts Bar-2, Vogtle-3, and Vogtle-4 reactors.

3. Nuclear Capital Cost Sensitivity, IRA, and Net-Zero 2050 Scenarios

3.1.1 Nuclear Capital Cost Sensitivity Cases with and without Net-Zero 2050 Goal

Multiple GCAM scenarios are generated to explore the interactions of nuclear power capital costs and the net-zero emissions goal for assessing the potential role of nuclear energy in the US energy system. Five nuclear capital cost sensitivity cases span the potential range of future nuclear capital costs under a reference scenario and an economy-wide net-zero emissions goal by 2050. All cost sensitivity cases, and carbon mitigation scenarios are summarized in Table 3. A Reference scenario without climate policy is generated to serve as a basis for comparison. Currently existing renewables portfolio standards (RPS), federal production tax credits (PTC), investment tax credits (ITC), and other clean energy credits are not included in the Reference scenario to prevent overlap with IRA and net-zero emission scenarios. The recently enacted IRA policy with variants of the IRA clean energy credit provisions is investigated separately and compared to the net-zero scenario below.

Nuclear overnight capital costs of 2600, 3600, 4600, 5600, and 6600 $/kW by 2050 are explored for the US. The nuclear capital cost not only affects electric power generation but also the production of hydrogen using nuclear energy since the bulk of the H_2 cost is the cost of electricity. The capital cost is based on the Idaho National Laboratory (INL) Nuclear Cost Basis Report and span the range of cost distribution for an LWR (INL, 2022). The cost range also captures the recent cost estimates of nuclear reactors deployed around the world (IEA, 2020a). Capital cost increments of 1000 $/kW were selected to assess the gradated response to cost improvements and to allow for the relative comparison to alternative levels of carbon mitigation efforts. Nuclear capital cost sensitivities were applied to the US only.

The nuclear capital cost for all other regions utilized the nuclear cost assumption shown in Table 2. Although changes in the US nuclear capital costs are likely to affect nuclear capital costs in other regions, cost assumptions for other regions were not changed across the nuclear sensitivity cases to isolate the impact for the US.

Table 3. GCAM scenario list and names for nuclear capital cost sensitivity cases in the Reference and Net-Zero 2050 scenarios.

Nuclear Capital Cost (2020 $/kW)	Reference w/H_2 (No Climate Policy)	Net-Zero 2050 w/H_2
2600	Nuc26_H_2_Ref	Nuc26_H_2_Nz50
3600	Nuc36_H_2_Ref	Nuc36_H_2_Nz50
4600	Nuc46_H_2_Ref	Nuc46_H_2_Nz50
5600	Nuc56_H_2_Ref	Nuc56_H_2_Nz50
6600	Nuc66_H_2_Ref	Nuc66_H_2_Nz50

The capital cost assumptions are phased-in gradually and assumed to be achieved by 2050 as shown in Figure 2. The nuclear capital cost of 6200 $/kW was assumed for 2025. From there, the cost was linearly decreased to the targeted cost goal by 2050 for each of the cost cases except for the 6600 $/kW case. The 6600 $/kW case was assumed fixed from 2025 to 2050. Beyond 2050, nuclear capital costs were assumed to improve modestly at 0.1% per year for the 2600 to 5600 $/kW cases, while the 6600 $/kW remained fixed.

Nuclear reactor fixed O&M costs of 66, 73, 81, 88, and 95 \$/kW and variable O&M costs of 1, 1.5, 2, 2.5, and 3 \$/MWh were associated with the capital costs of 2600, 3600, 4600, 5600, and 6600 \$/kW, respectively (INL, 2022).

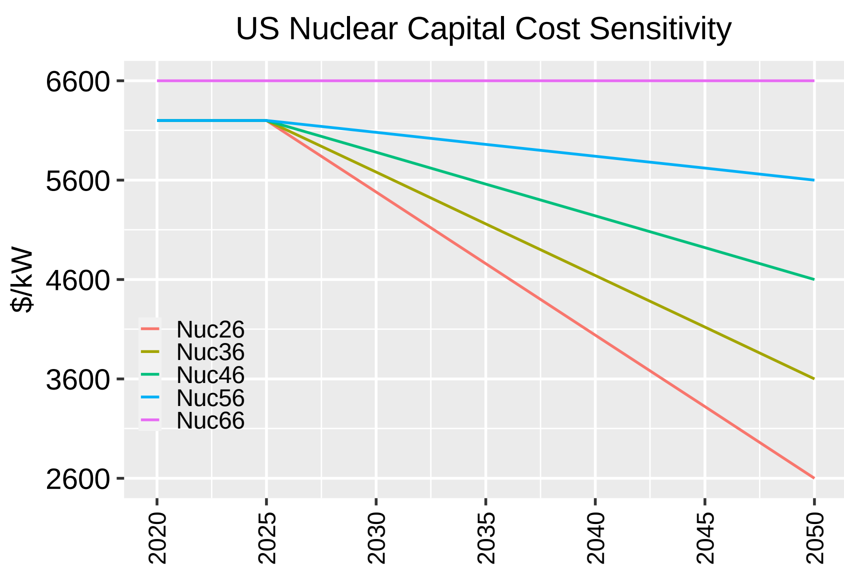


Figure 2. Nuclear power reactor overnight capital cost cases for the US at 2600, 3600, 4600, 5600, and 6600 \$/kW by 2050 (2020 USD).

To address global climate change, the US established a long-term target of reducing economy-wide GHG emissions to net-zero by 2050 (US Excutive Office, 2021). The net-zero emission goal is a stringent response for addressing climate change since all GHG emissions are eliminated or offset with negative emissions technology.

In this analysis, the net-zero scenario constrains the total economy-wide CO_2 emissions from 2025 to a linearly decreasing pathway to net-zero CO_2 emissions by 2050 as shown in Figure 3. We did not include other GHGs as part of the emissions constraint in this analysis. The annual CO_2 emissions constraint drives the energy technology response behavior, and the model determines, through an iterative solution method, the level of carbon taxes that is necessary for meeting the annual emissions constraint. The resulting carbon taxes by period are modeling results and are not input assumptions to the net-zero scenario.

It is also important to highlight that the net-zero emission constraint is imposed on the whole economy in a technology neutral way and not selectively for electricity or H_2 production or any other sectors and technologies. The consequence of this broad and all-inclusive constraint is that emissions from transport, industrial and buildings sectors also play a significant role in determining the level of carbon tax necessary for achieving net-zero emissions. Utilizing a single carbon tax rate per period applied to all emissions activity is a simpler method for implementation in model simulations. Carbon pricing represents an economically optimal approach for meeting emission mitigation goals and forms a basis for comparison to other policy approaches (Jenkins, 2014).

The net-zero CO_2 emissions by 2050 scenario in this analysis is consistent with efforts to limit the Earth's mean surface temperature change to 1.5° C (IPCC, 2018). The cumulative allowable CO_2 emissions for the US implied by net-zero goal by 2050 in this analysis is 79 gigatons of CO_2 ($GtCO_2$) from 2020 to 2100. We note that other GHGs need to be taken into account as well to meet global temperature change goals.

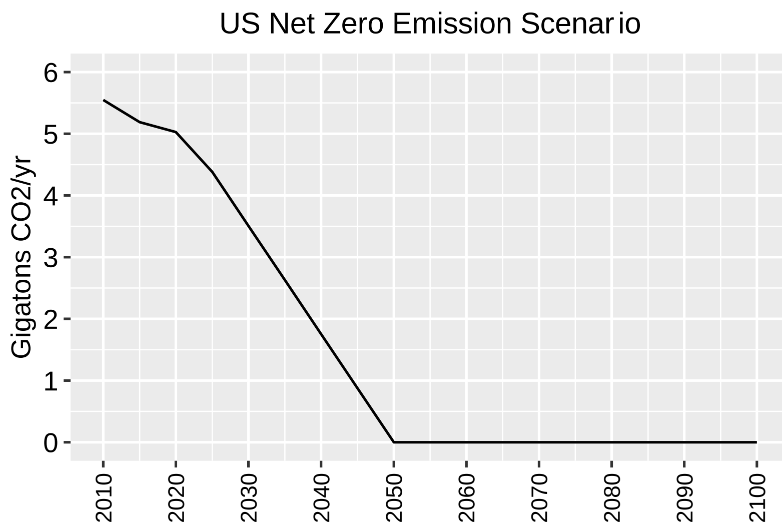


Figure 3. US economy-wide net-zero CO_2 emissions constraint from 2020 to 2100.

3.1.2 IRA Implementation and Scenario Assumptions

In addition to the Reference and Net-Zero 2050 scenarios, we investigate the impact of the IRA policy that has been recently enacted (The White House, 2023). There are multiple clean energy credits targeting multiple energy carriers and technologies. For this analysis, we implemented clean energy credits for electricity generation, hydrogen production, carbon capture storage and utilization, transportation vehicles, and biofuels production. These categories constitute the most important provisions of the IRA directed at reducing US GHG emissions.

Due to the many levels and diverse coverage of the IRA provisions, we utilized the summary report on the IRA by the Idaho National Laboratory, along with other IRA documentation, to develop alternative scenarios of IRA provision and implementation levels (Bipartisan Policy Center, 2023; Guita, 2023; The White House, 2023). Due to the progressively greater and additive credit levels available for meeting labor, domestic manufacturing, and energy community qualifications, as well as income limits on other credits as specified in the IRA, we created two alternative IRA cases for analysis, IRA-Mid and IRA-High. These two cases investigate intermediate and full levels of the credits available for clean energy production and use since we do not yet know the outcome of the IRA implementations. The policy duration of the IRA cases spans from 2025 to 2035 modeling periods to closely approximate IRA time specifications.

Because GCAM provides US energy simulations to 2100, we created two additional IRA scenarios extending the Mid and High cases to 2050 to further explore the impact of continued IRA credits on clean energy technologies. We have labeled them, IRA-Mid-Ext and IRA-High-Ext. Table 4 provides a summary of all the IRA scenarios implemented in GCAM. There is no guidance on the continuation of the clean energy credits beyond that as stated in the IRA. Nevertheless, the full GCAM simulations to 2100 is provided to motivate the need for long-term efforts necessary for achieving net-zero emissions.

The IRA-Mid case is the Base rate with labor requirement met and applies the 30% investment tax credit (ITC 30%) and the production tax credit of 27.5 \$/MWh (PTC 27.5 \$/MWh) to clean electricity technologies for the period of 2025 to 2035. We have applied the PTC to wind and solar PV electricity generation technologies, which benefits low capital cost technologies, and the ITC to all other clean electric technologies as recommended in the recent assessments of the IRA (Guita, 2023; Steinberg, 2023). The IRA-High case increases the credit levels for having met domestic manufacturing and energy community requirements and applies 50% ITC and 33 \$/MWh PTC to clean electric technologies from 2025 to 2035. Again, the PTC is applied to wind and solar PV, while the ITC is applied to all other clean electric technologies.

Carbon capture storage and utilization credits are also available but not stackable with the ITC or PTC. We chose to apply the carbon capture and storage credit of 85 \$/tCO_2 for all biomass and fossil CCS technologies that capture and store carbon rather than the ITC or the PTC. The carbon storge credit of 85 \$/tCO_2 remains fixed for both IRA-Mid and IRA-High cases as indicated in Table 4. The captured carbon from CCS technologies is stored in subsurface geological formations in the GCAM representation and the utilization of captured carbon for synthetic fuel production and other carbonaceous products were not investigated in this analysis.

Clean hydrogen credits are dependent on the carbon emission intensity of hydrogen production and can range from 0.6 to 3 \$/kgH_2. The highest level of the credit is for carbon-free production of H_2. Nuclear, wind, and solar H_2 production received 3 \$/kgH_2 credit, while the biomass H_2 production received 0.6 \$/kgH_2. Fossil CCS H_2 production received the more beneficial carbon storage credit of 85 \$/tCO_2 instead of the clean hydrogen credit. The credit levels for hydrogen production remained the same in both the IRA-Mid and IRA-High cases, see Table 4.

Clean vehicle credits are available for battery electric vehicles (BEV) and hydrogen fuel cell vehicles (FCEV) for passenger and commercial segments. As described in Table 4, for the IRA-Mid case we provided 3,750 dollar per passenger light-duty clean vehicles and 40,000 dollar per commercial heavy-duty clean vehicles. For the IRA-High case we provided the full 7,500 dollar per passenger light-duty clean vehicles and the same 40,000 dollar per commercial heavy-duty clean vehicles. We also included the clean fuels credit for biomass derived liquid fuels, but the credit was applied only for 2025 as specified by the IRA.

A more detailed breakdown of the nuclear capital cost adjustments from the ITC is displayed in Figure 4. Although IRA cost adjustments for nuclear in 2025 is provided below, we emphasize that new nuclear power technologies were not available for deployment until the 2030 modeling period. The two levels of the ITC adjustments to nuclear capital costs in the IRA-Mid and IRA-High cases, as well as the extended cases, are shown in Figure 4. The Base case nuclear capital cost assumptions before IRA adjustments are from NREL ATB 2019 and are 6130, 5960, and 5790 \$/kWe for 2025, 2030, and 2035, respectively (NREL, 2019). For the IRA-Mid case (ITC 30%), the net nuclear capital costs were adjusted down to 4420, 4290, and 4170 \$/kWe for 2025, 2030, and 2035, respectively. In the IRA-High case (ITC 50%), the net nuclear capital cost assumptions were adjusted further down to 3280, 3190, and 3100 \$/kWe for 2025, 2030, and 2035, respectively. After 2035, nuclear capital costs return to Base case values for the IRA-Mid and IRA-High cases. The extension cases of IRA continue the adjustments to nuclear capital costs until 2050 as shown in Figure 4. Thereafter, nuclear capital costs of the extended cases return to Base case values.

We note that prior to the enactment of the IRA, new nuclear power investments were disadvantaged relative wind, solar, and CCS power technologies due to the ITC, PTC, and CCS tax credits that were available for those technologies but were not applicable to nuclear power. The IRA extends and increases the credits available for wind, solar, and CCS, and now includes credits for nuclear energy as well in favor of the technology-neutral clean electricity credit (The White House, 2023).

Of the many aspects of the IRA, loan and credit programs not directly related to climate and energy were not investigated in this analysis due to the limitation of our modeling capability and limited potential impact of those provisions to energy sector carbon emissions reduction.

Table 4. Summary of IRA scenarios implemented in GCAM.

IRA Cases	Duration (Model Periods)	Clean Electricity Credit	Clean Hydrogen Credit	Clean Vehicle Credit	Clean Fuels Credit	Carbon Management Credit
Base	No IRA Credits					
IRA-Mid (Meets labor requirement)	2025-2035	ITC 30% and PTC 27.5 \$/MWh	0.60 - 3.00 \$/kg H_2	3,750 \$/veh (LDV) and 40,000 \$/veh (HDV)	1 - 1.75 \$/gal. (2025 only)	85 \$/tCO_2
IRA-High (Meets labor, domestic content, and energy community requirements)	2025-2035	ITC 50% and PTC 33 \$/MWh	0.60 - 3.00 \$/kg H_2	7,500 \$/veh (LDV) and 40,000 \$/veh (HDV)	1 - 1.75 \$/gal. (2025 only)	85 \$/tCO_2
IRA-Mid-Ext (Meets labor requirement)	2025-2050 (extended)	ITC 30% and PTC 27.5 \$/MWh	0.60 - 3.00 \$/kg H_2	3,750 \$/veh (LDV) and 40,000 \$/veh (HDV)	1 - 1.75 \$/gal. (2025 only)	85 \$/tCO_2
IRA-High-Ext (Meets labor, domestic content, and energy community requirements)	2025-2050 (extended)	ITC 50% and PTC 33 \$/MWh	0.60 - 3.00 \$/kg H_2	7,500 \$/veh (LDV) and 40,000 \$/veh (HDV)	1 - 1.75 \$/gal. (2025 only)	85 \$/tCO_2

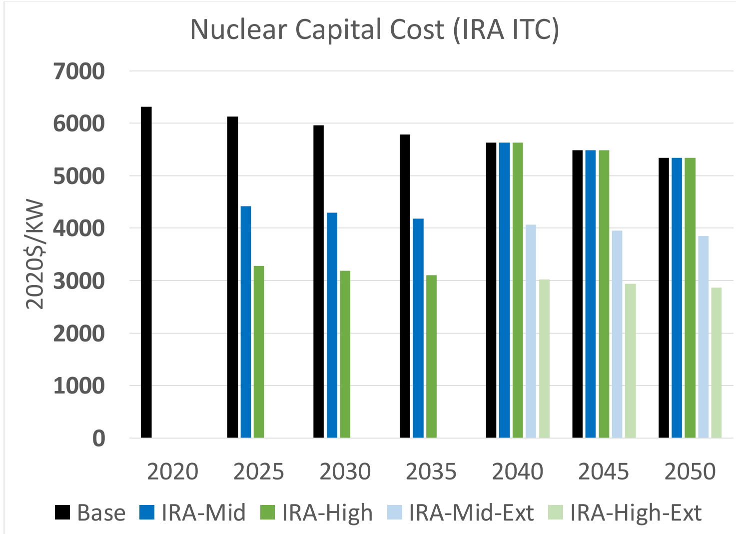


Figure 4. Nuclear reactor capital costs for Base case and adjusted costs for alternative IRA cases.

4. GCAM Results

4.1 Nuclear Cost Sensitivity Cases in the Reference Scenario

4.1.1 Final Energy and Hydrogen Demand in the Reference Scenario

Final energy demand for all end-use energy services in the US are dominated by three energy carriers, natural gas, refined liquids, and electricity in the Reference scenario. These three energy carriers comprise over 90% of the total final energy consumption for the 21st century as displayed in Figure 5. The remaining end-use energy carriers are biomass, coal, and hydrogen.

At the end-use, nearly all the natural gas is utilized by industries and buildings, with an approximate split of 60% to 40% proportion in favor of industrial use. Buildings heating services are responsible for the vast majority natural gas use in buildings. Electricity is also predominately utilized by the buildings sector, nearly 70% initially of all electricity, but falls in the future due to the greater penetration of electric vehicles in transport that occurs in the Reference scenario. Refined liquids are consumed mostly for transport, which is responsible for nearly 80% of refined liquid fuel consumption. Transport share of refined fuel falls as electricity for transport increases.

The consumption of biomass, coal, and hydrogen combined represents a minor share of total final energy at approximately 5% share of the total in the Reference scenario. Hydrogen utilization increases slightly over time to approximately 3% share of total final energy in the long-term. Without any incentives to increase the competitiveness of hydrogen for end-use applications, hydrogen demand is likely to remain low in the Reference scenario. There are no carbon emissions penalties in the Reference scenario to increase the value of hydrogen as a carbon-free fuel.

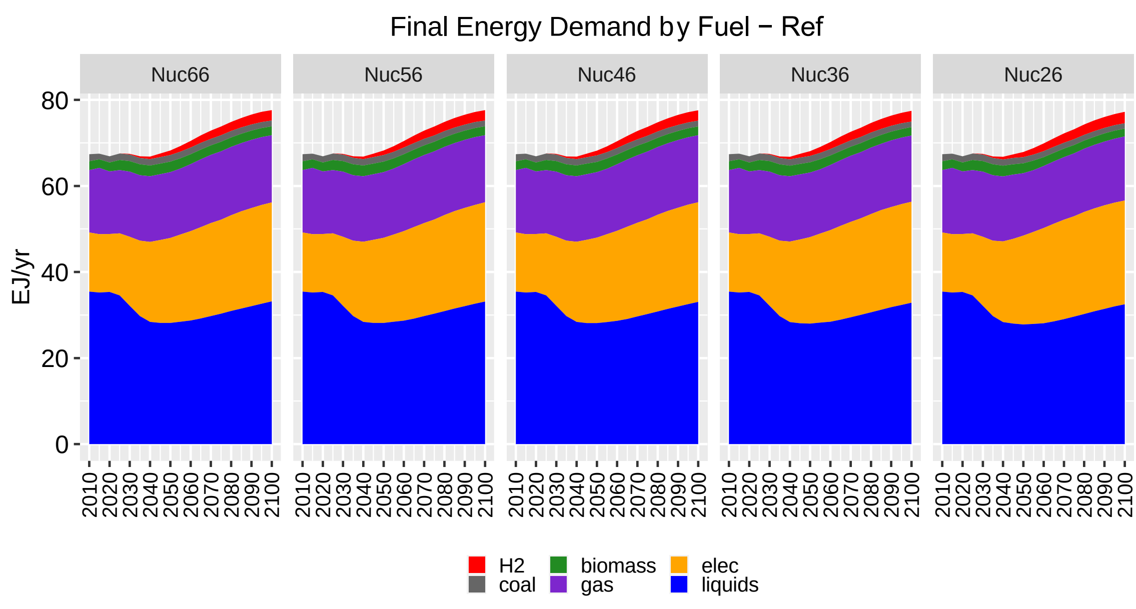


Figure 5. US final energy demand by fuel in the Reference scenario (EJ/yr).

Nevertheless, the annual hydrogen demand in the Reference scenario grows to approximately 10 million tons by 2050 and 20 million tons by 2100 as hydrogen applications begin to emerge, such as fuel cell vehicles for transport and other hydrogen technologies. Figure 6 shows the total H_2 demand from all end-use sectors for the nuclear cost sensitivity cases. The variations in the hydrogen demand are due to the nuclear cost sensitivity cases, with an increase of approximately 10% greater hydrogen demand with falling nuclear H_2 costs.

H_2 demand is driven primarily by transportation, comprising nearly 70% of total H_2 consumption, followed by industries at 25%, and buildings at 5% as shown in Figure 7. The introduction of H_2 fuel cell vehicles for alternative transport modes allows the growth in hydrogen demand to rise with the greater demand for transport services in general. Hydrogen demand from industries and buildings remain relatively small as the H_2 fuel is not a competitive substitute for natural gas, liquid fuels, and electricity in the Reference scenario.

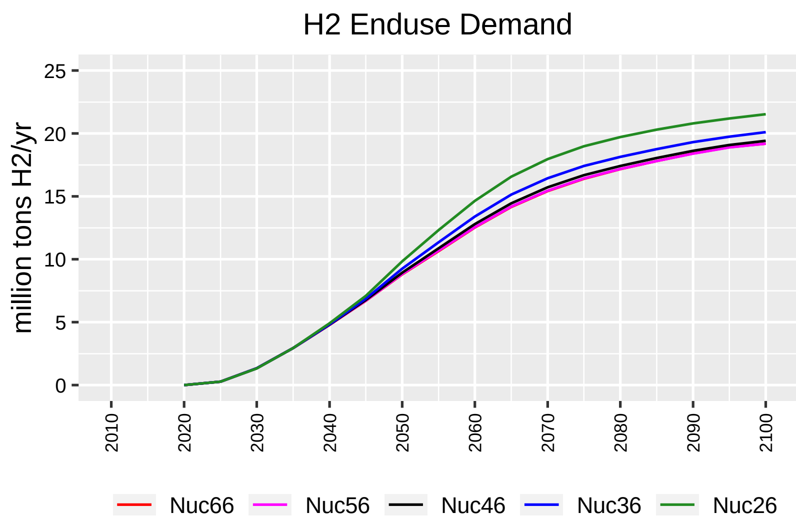


Figure 6. H_2 demand in the US for the Reference scenario (million metric tons of H_2/yr).

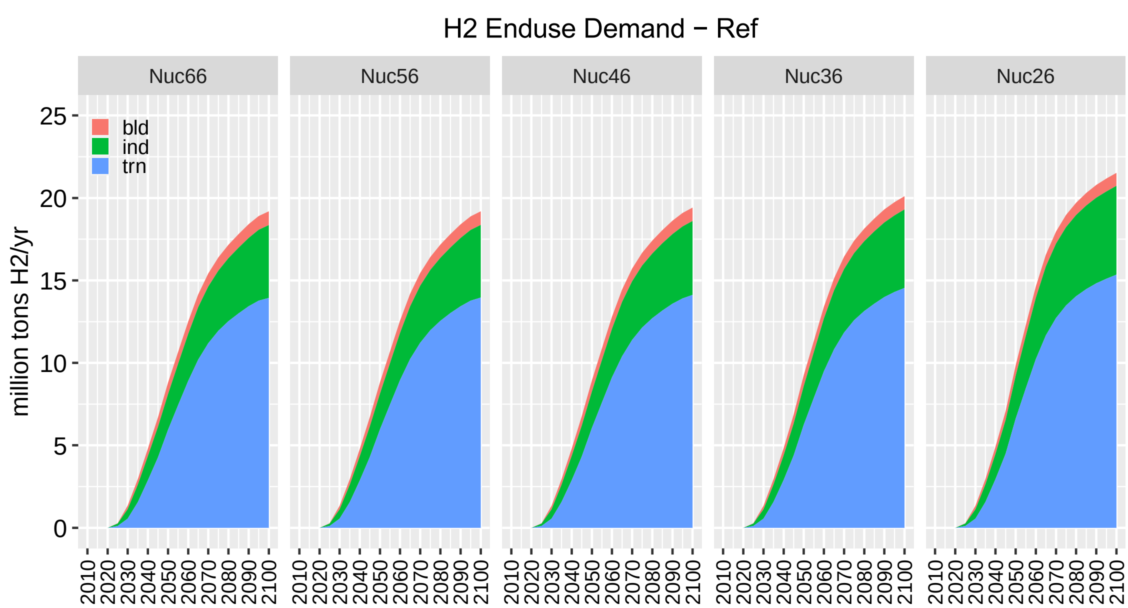


Figure 7. H_2 demand by end-use sectors in the Reference scenario (million metric tons of H_2/yr).

4.1.2 Hydrogen Production in the Reference Scenario

The production of hydrogen is split between central station and forecourt plants in the Reference scenario and nuclear sensitivity cases investigated. For the most part, central station production is the preferred source of H_2 production except for the case with low-cost forecourt nuclear H_2 production. Figure 8 shows the H_2 production amounts by the two approaches for the nuclear cost sensitivity cases. By 2100, 11 – 13 million tons of H_2 in total is produced from central station plants depending on the nuclear cost case, while 8 – 11 million tons of H_2 is produced in total by forecourt plants. Central station and forecourt approaches compete for H_2 market share with forecourt production increasing at the expense of central station production, which declines as distributed onsite applications of nuclear H_2 plants become more competitive. The added burden of H_2 delivery cost from central stations to demand centers benefits forecourt plants as H_2 production costs decline.

In central station H_2 production, SMR from natural gas is the dominant source of H_2 as it is the lowest cost method for H_2 production. H_2 from natural gas comprises 70% to 80% of central station production across all scenarios as shown in Figure 9. Although other fuels and renewable energy also contribute to central station H_2 production to some degree, their production costs are higher and little H_2 is produced from sources other than natural gas. Figure 10 shows the cost of central station H_2 by fuel type. We note that line colors in all figures of H_2 prices and costs do not have any specific meaning regarding fuel type or CO_2 emissions intensity. Natural gas H_2 prices are approximately \$1.5/kgH_2. H_2 from wind and biomass are approximately double the cost of H_2 from natural gas at \$3/kgH_2. Competitiveness of central station nuclear H_2 production are highly dependent on the capital cost of the nuclear power plant. The nuclear H_2 costs are greater than \$5/kgH_2 in Nuc66 and below \$3/kgH_2 in Nuc26 cases as shown in Figure 11. Improvements to the nuclear H_2 cost increases its H_2 market share of central station production from 3% in Nuc66 case to 15% in Nuc26 case by 2100.

The number of technology options available for forecourt production of H_2 is limited due to the requirements for smaller scale, compact footprint, and proximity to demand centers for on-site H_2 production. In this analysis, the choices for forecourt production are limited to grid electrolysis, natural gas SMR, and nuclear HTSE. The distributed applications of small modular and micro nuclear reactors for H_2 production are economically competitive with smaller-scale H_2 production from natural gas and electrolysis. H_2 from natural gas dominates forecourt production initially and when nuclear H_2 costs are high, comprising greater than 80% share initially, as shown in Figure 9.

However, the progressive reduction of the nuclear capital cost from 6600 \$/kW to 2600 \$/kW has a significant impact on the improving competitiveness of forecourt nuclear H_2 production and increasing its share of the H_2 market. Forecourt nuclear H_2 production costs, also shown in Figure 11, follow the same pattern as central station nuclear H_2 costs but have slightly higher costs due to the assumed smaller scale of H_2 production capacity. With lower nuclear capital costs, nuclear displaces natural gas for forecourt H_2 production. In the Nuc26 case, nuclear share grows to 80% and natural gas declines to 18% of total forecourt H_2 production by 2100. Nuclear H_2 shares also increase relative to H_2 from forecourt natural gas SMR due to higher cost for delivered natural gas and smaller capacity of H_2 production.

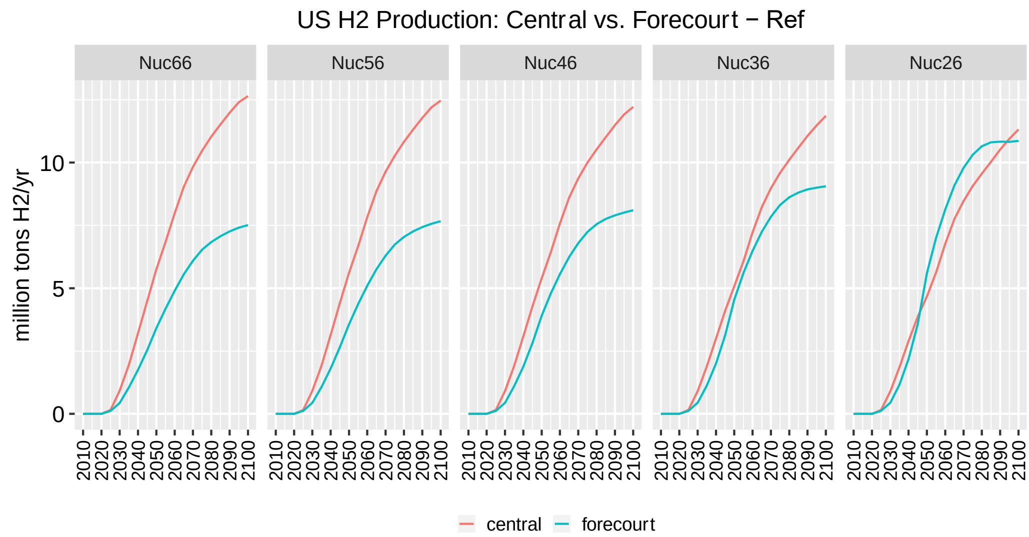


Figure 8. H_2 production from central station and forecourt plants in the Reference scenario (million metric tons of H_2/yr).

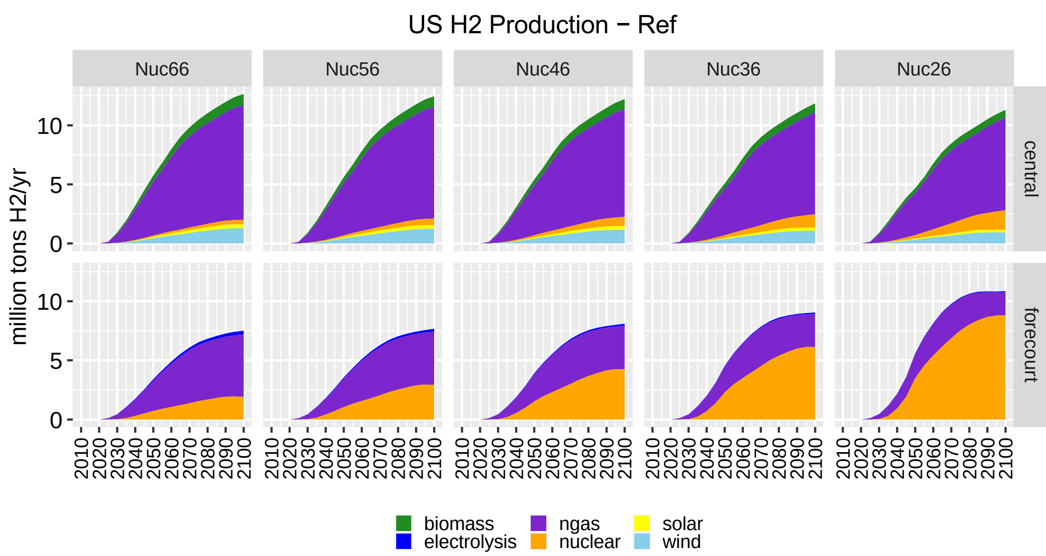


Figure 9. H_2 production by fuel type from central station and forecourt plants in the Reference scenario (million metric tons of H_2/yr).

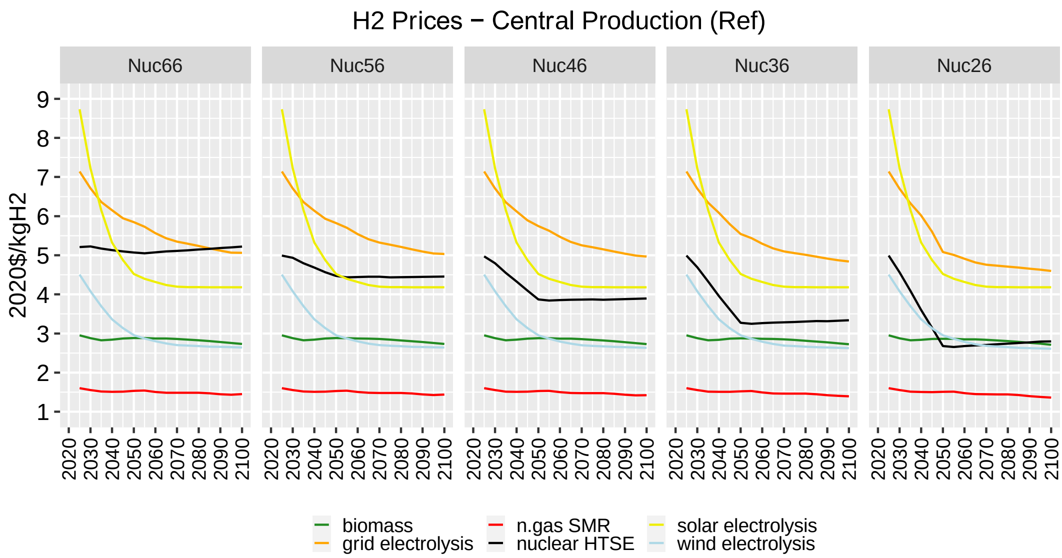


Figure 10. Central station H_2 production cost by fuel type in the Reference scenario (2020 $/kgH_2$).

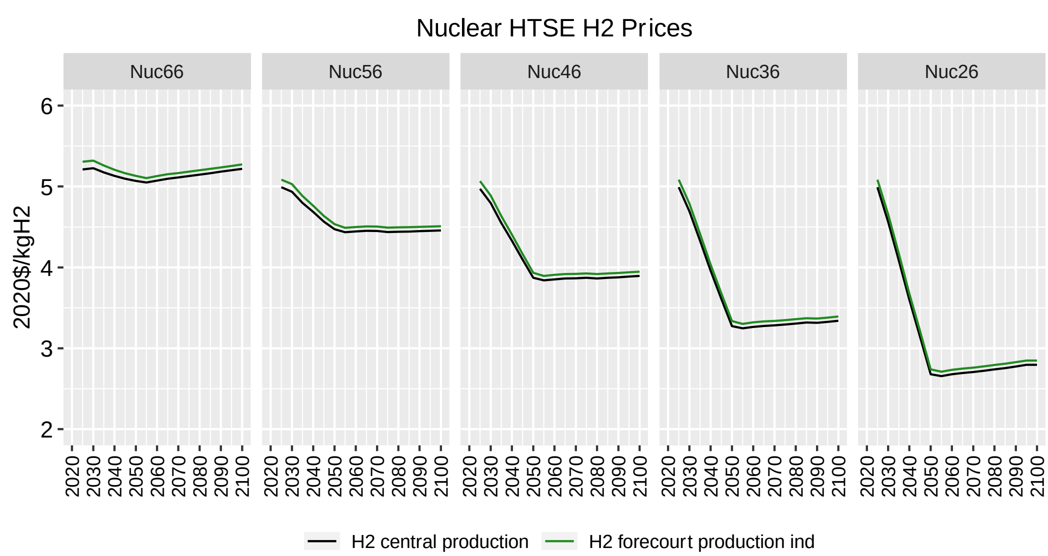


Figure 11. Nuclear HTSE H_2 production cost for central station and forecourt production in the Reference scenario (2020 $/kgH_2$).

Reductions to the nuclear capital cost also affect the relative economic competition between forecourt H_2 production and delivered H_2 originating from central station plants. Lower nuclear capital cost improves forecourt H_2 costs relative to delivered H_2 costs, which results in greater forecourt H_2 production at the expense of central station H_2 production. Figures 12 and 13 show H_2 prices by alternative production and delivery options at two end-use applications, wholesale dispensing and industrial on-site production where nuclear forecourt H_2 facilities are available options.

When nuclear capital costs are high, such as in Nuc66 case, the lowest cost H_2 for wholesale dispensing application comes from natural gas SMR, followed by delivered H_2 from central station. The price of H_2 from natural gas SMR and pipeline delivered H_2 are comparable at between 5 and 6 $/kgH_2$ as indicated in Figure 12. The price of truck delivered H_2 is just slightly greater at 5.5 to 6.5 \$/kgH_2. Nuclear H_2 prices fall within the above range when nuclear power plant capital costs are 3600 \$/kW or less, as in the Nuc36 and Nuc26 cases. The Nuc26 case, however, has the lowest wholesale dispensing cost falling below 5 \$/kgH_2 after 2050, which coincides with when the target nuclear capital cost reductions are achieved. H_2 from grid-based electrolysis is the most expensive forecourt production option at a cost of 8 to 11 \$/kgH_2.

Relative H_2 cost comparisons for on-site industrial production and delivery options are similar to wholesale dispensing options but without the addition of compression and storage costs. For industrial applications of H_2, the least cost H_2 option is again dependent on the nuclear power plant cost (see Fig. 13). When the nuclear capital cost is high, delivered H_2 from centrally produced H_2 is the cheapest option, while lower nuclear capital costs enable nuclear H_2 to become a competitive option for industrial applications. Grid-based electrolysis remains the most expensive option for industrial H_2 applications.

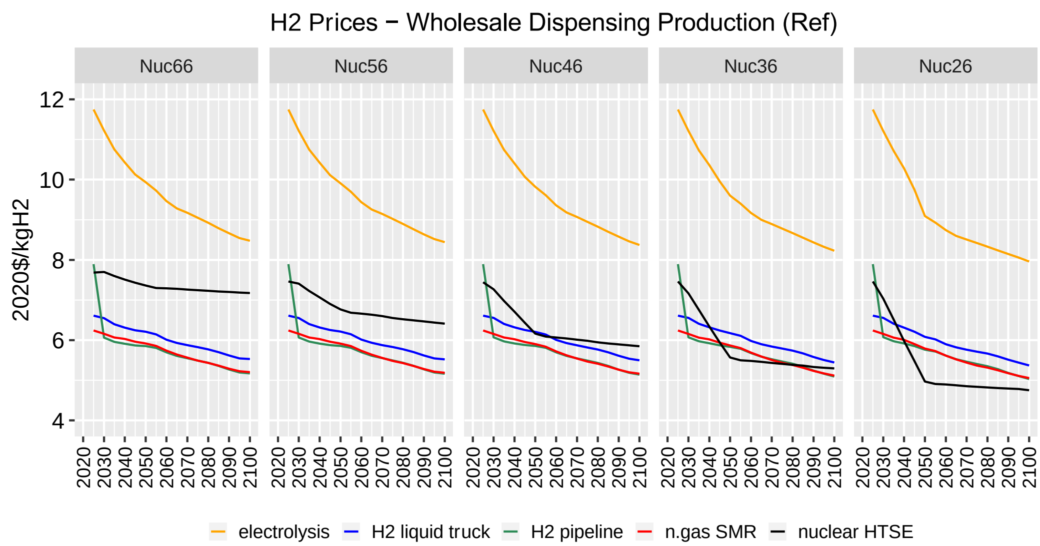


Figure 12. Wholesale dispensing H_2 costs (includes compression and storage costs) in the Reference scenario (2020 \$/kgH_2).

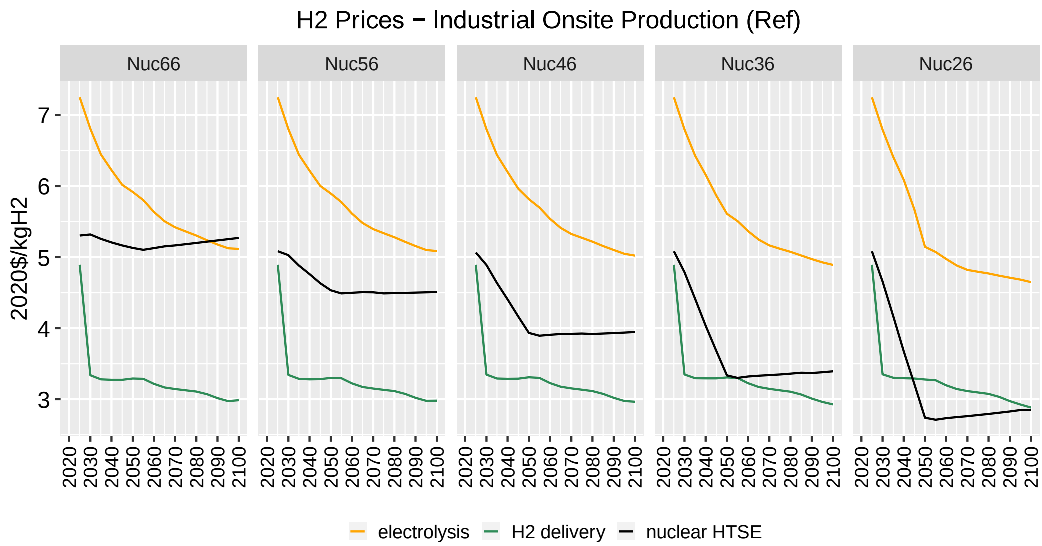


Figure 13. On-site H_2 costs for industrial applications in the Reference scenario (2020 $/kg$H_2$).

4.1.3 Nuclear Power Capacity for H_2 Production and Electricity Generation in the Reference Scenario

The nuclear energy contribution to total H_2 production for both central station and forecourt approaches is highly dependent on the future capital cost of nuclear power plants. When nuclear power plant costs are high, H_2 from natural gas is the main source of all H_2 production as displayed in Figure 14. However, when nuclear plant cost falls, as in Nuc26 case, H_2 from nuclear energy can source half of all H_2 production after 2050, taking significant market share from natural gas sourced H_2. Nuclear shares of total H_2 production are shown in Figure 15 for all nuclear cost cases.

Annual H_2 production from nuclear reaches 1 to 4 million tons of H_2 by 2050 and 2 to 10 million tons of H_2 by 2100 in the Nuc66 and Nuc26 cases, respectively. This translates to nuclear power capacities of 4 to 18 GWe in 2050 and 11 to 49 GWe by 2100 for H_2 production in the Nuc66 and Nuc26 cases as shown in right panel of Figure 15. The impact of the nuclear capital cost reductions on H_2 market share are not linear. Progressively greater reductions to the nuclear capital cost results in greater nuclear share of the H_2 supply market.

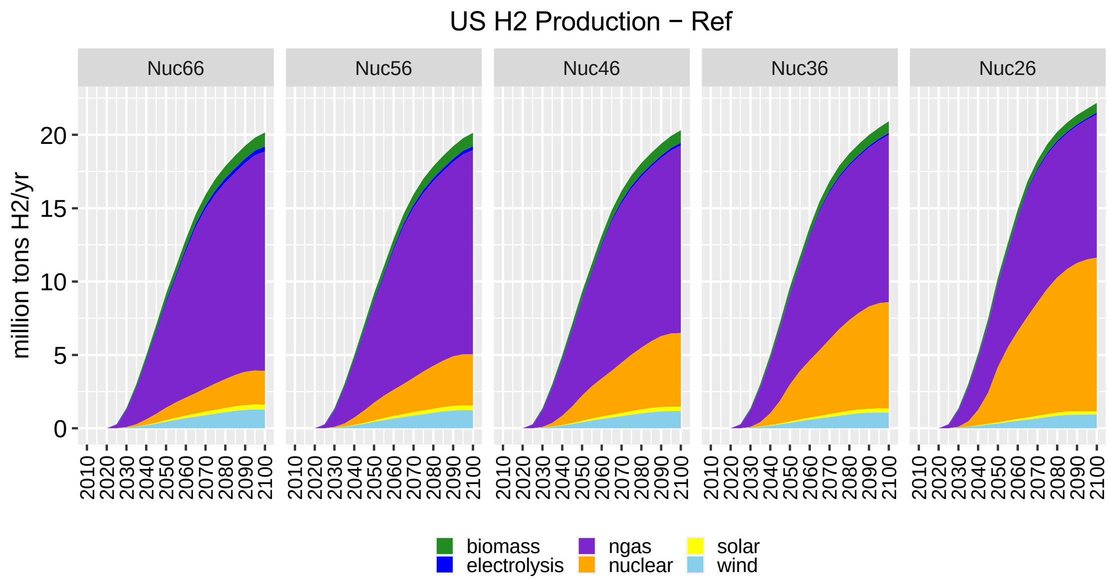


Figure 14. H_2 production by type in the Reference scenario with alternative nuclear reactor capital cost cases (million tons of H_2/yr).

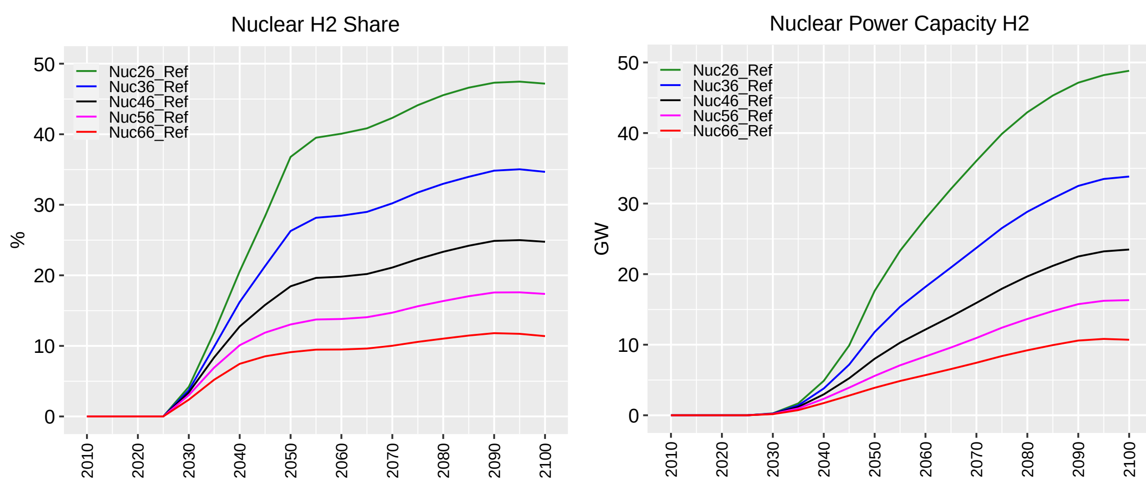


Figure 15. Nuclear share of total H_2 production and corresponding nuclear power capacity in the Reference scenario for alternative nuclear capital cost cases.

Along with the increasing demand for H_2, tremendous growth in the US electricity system is projected for the end of the 21st century. US electricity demand in the Reference scenario grows from 4100 TWh in 2020 to approximately 6100 TWh by 2050, a 50% increase from 2020. By 2100, it reaches 7200 TWh, a 75% increase from 2020. Growth in the demand for electricity is driven by population and economic growth and the increased electrification of end-use energy services over time. Figure 16 shows the composition of electricity and total electricity demand for all nuclear sensitivity cases in the Reference scenario.

Wind and solar energy technologies have growing contributions to electricity generation due to their technological and cost improvements. By 2050, the solar electricity share is around 10% and wind electricity share is around 12%, representing a combined share of 22%. Hydropower and biomass generated power play a limited role in the US electricity system in the Reference scenario.

Without measures to mitigate climate change in the Reference scenario, fossil power generation continues to be a major source of electricity for the US. Natural gas and coal maintain the largest fractions of power generation by 2050, representing about 25% share each. Power generation from oil remains small. Thus, the combined fossil power generation in the Reference scenario comprise about 50% of total power generation by 2050.

The continued strength of fossil power generation in the Reference scenario is, however, contingent on the competitiveness of nuclear power and nuclear cost improvements achieved by 2050. Beyond midcentury, reductions in the nuclear costs have a significant impact on the expanded role of nuclear energy leading to the reduced contributions from renewable and fossil power generation.

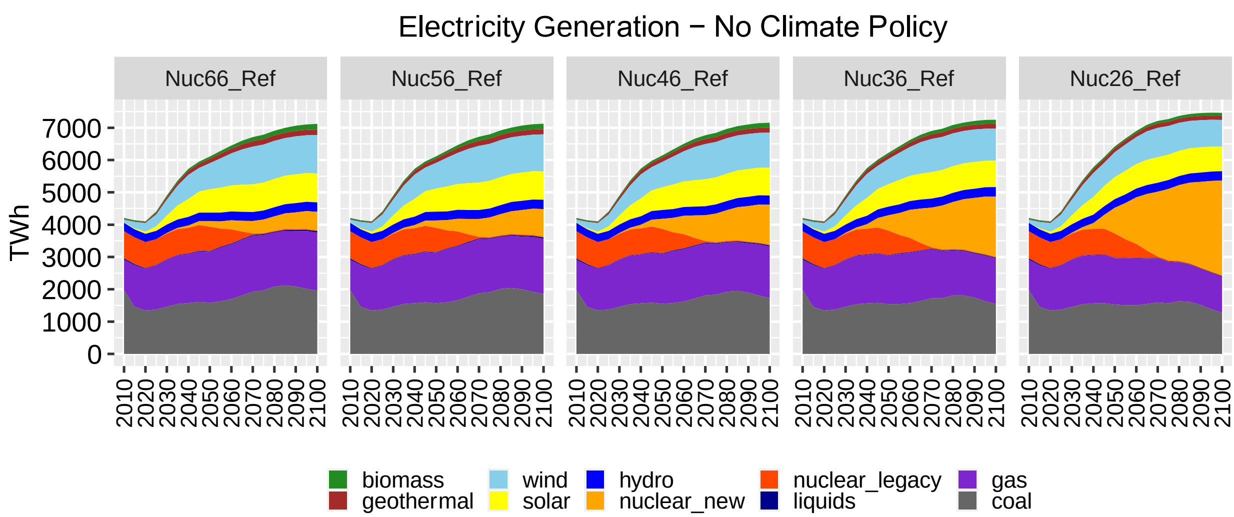


Figure 16. Electricity generation by fuel type in Reference scenario for alternative nuclear capital cost cases (TWh).

In the near-term, nuclear power contribution declines as few additional reactors are deployed due to their high capital costs. The impact of the nuclear capital cost improvements of this analysis is not observed until after 2035. The nuclear power capacity remains flat until 2035 and the nuclear share of electricity generation declines to 15% in 2035 as the few limited new nuclear deployments are not able to keep up with the increasing demand for electricity in the near-term, as shown in Figure 17.

Reductions in the nuclear capital cost have a significant impact on nuclear deployment by midcentury and beyond. By 2050, the total nuclear capacities are 117, 125, 137, 156, and 197 GW for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. The significant expansion of nuclear capacity is due to nuclear cost reductions alone and without the benefit of any carbon penalties in the Reference scenario. At 2600 $/kW, the levelized cost of electricity (LCOE) for nuclear is one of the lowest of all competing technologies and is competitive with natural gas, solar, and wind power in this analysis. The nuclear share in 2050 spans from 15% to 20% in the Nuc66 and Nuc26 reference cases, respectively. Only the lowest cost assumption of the Nuc26 case can ramp up nuclear expansion to maintain current levels of nuclear share for the next several decades, however.

By 2100, the nuclear capacities are 76, 111, 160, 240, and 375 GW for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively, as shown in Figure 17. The future cost assumptions of nuclear power dictate nuclear energy's competitiveness and long-term contribution to the US energy system.

As nuclear capital costs decline, nuclear energy shares increase predominantly at the expense of decreasing fossil power shares. Nuclear electricity becomes more competitive relative to fossil generated electricity than to renewable energy. By 2100, the combined fossil share consisting of natural gas, coal, and oil falls from 53% to 32% in the Nuc66 to Nuc26 cases, respectively, while the combine wind and solar share falls from 29% to 21%. Variable renewable energy remains competitive at lower levels of penetration which does not incur higher grid integration costs.

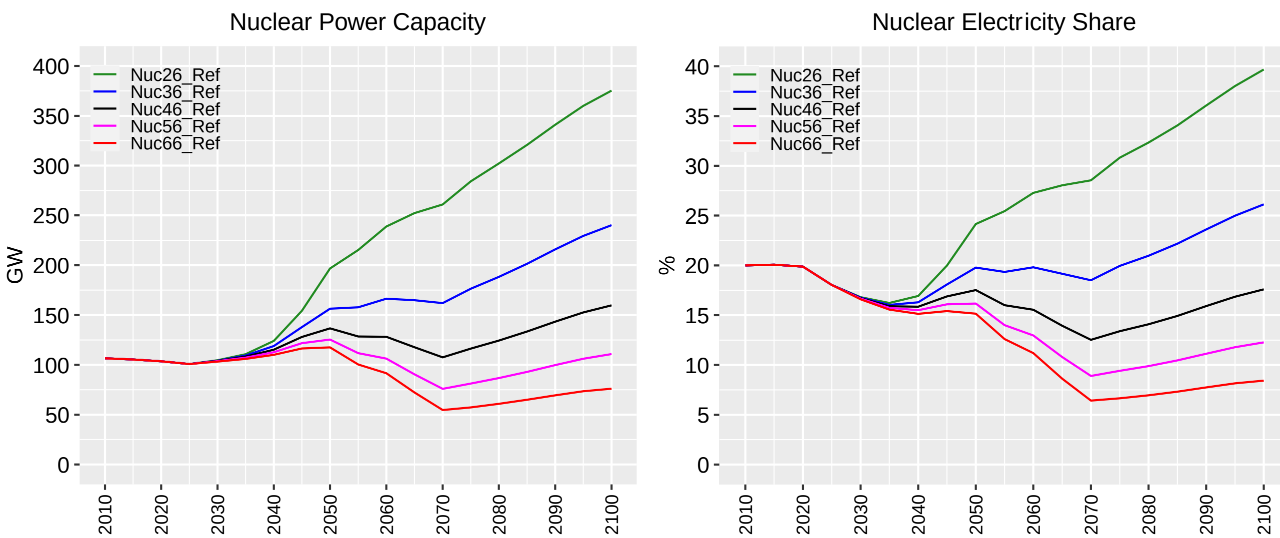


Figure 17. Nuclear power capacity and share of electricity generation in Reference scenario for alternative nuclear capital cost cases.

Although the emergence of the hydrogen market enables greater contribution of nuclear energy for the US energy system, the contribution of nuclear energy beyond electric power generation is limited due to the limited demand for H_2 in the Reference scenario. Unless the carbon-free nature of H_2 as fuel is incentivized, there is no significant economic justification for the substitution of existing fuels and electricity for H_2.

The combined total capacity of nuclear power deployed for electricity and H_2 production are displayed in Table 5 and Figure 18. Of the total capacity, nuclear power capacity for H_2 production is 3% to 8% in 2050 and 12% - 13% in 2100 depending on nuclear cost case. The nuclear energy contribution for H_2 adds to the total nuclear capacity but is not a major share of the total capacity. Nuclear power capacities range from 121 to 214 GWe in 2050 and 87 to 424 GWe in 2100 with the bulk of the nuclear capacity for dedicated to electricity generation.

Table 5. Nuclear power capacity for electricity and H_2 production in 2050 and 2100 for the Reference scenario (GWe).

Nuclear Capacity for Electricity and H_2 Total (GWe)						
	2050			2100		
Case	Electricity	H_2	Total	Electricity	H_2	Total
Nuc66	117	4	121	76	11	87
Nuc56	125	6	131	111	16	127
Nuc46	137	8	145	160	23	183
Nuc36	156	12	168	240	34	274
Nuc26	197	18	214	375	49	424

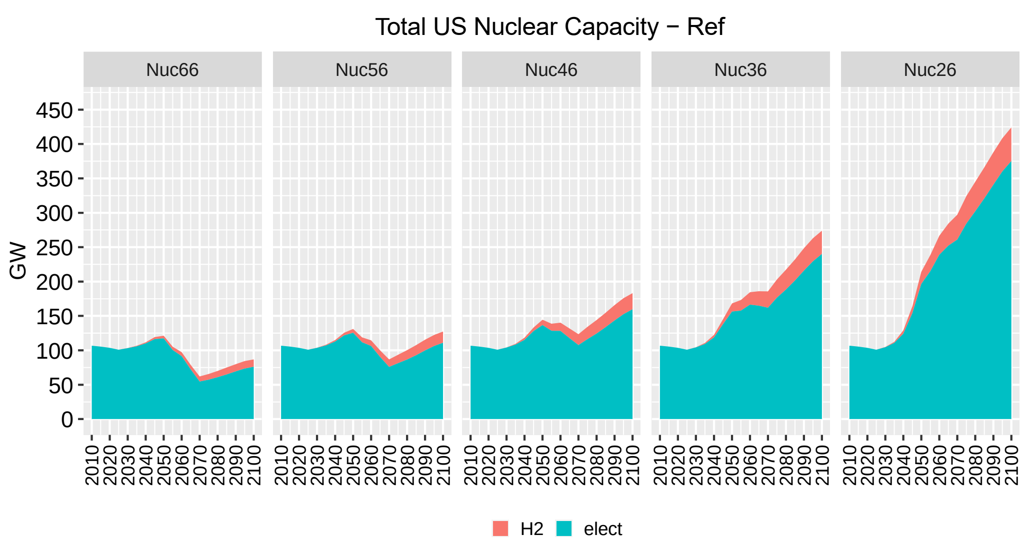


Figure 18. Nuclear power capacity for electricity and H_2 production in Reference scenario for alternative nuclear capital cost cases (GWe).

4.1.4 CO_2 Emissions Impact in the Reference Scenario from Nuclear Cost Sensitivity Cases

Increased nuclear electricity and H_2 contributions across the nuclear cost sensitivity cases play a significant role for US CO_2 emissions. The substitution of fossil electricity and H_2 production for nuclear results in large carbon emissions differences starting from midcentury to the end of the 21st century as shown in Figures 19 and 20. Electricity emissions in the US may have stabilized due to the increased utilization of natural gas and renewable energy in exchange for coal power. Moreover, depending on the competitiveness of nuclear power, electricity CO_2 emission may see further declines in the future. Thus, electricity CO_2 emissions in this analysis have a range of 1.3 to 2 $GtCO_2$/yr by 2100 dependent on the nuclear cost case. The difference in annual electricity emissions between the two nuclear extremes, Nuc66 and Nuc26, is 0.7 $GtCO_2$/year by 2100, or as much as 36% of the electricity emissions of the Nuc66 case. The percentage reductions in CO_2 emissions with increasing nuclear energy penetration in each case is displayed in Figure 19, right panel. Greater penetration of nuclear power, along with growing contributions from renewable energy, ensures that power sector CO_2 emissions are declining from present levels.

CO_2 emissions from H_2 production are at least an order of magnitude lower than that from electricity generation since H_2 demand is relatively small. In addition, H_2 production is based predominantly on natural gas, with low carbon content, and nuclear energy. Figure 20 left panel shows that the CO_2 emissions from H_2 production grow to a range of 0.09 to 0.14 $GtCO_2$/yr by 2100. Reducing the nuclear capital cost has a similar response to power sector CO_2 emissions reduction but for H_2 production. Figure 20 right panel indicates similar percentage reductions of emissions in H_2 production as that for electricity generation. For H_2 production, the Nuc26 case has emissions reduction of 33% relative to the Nuc66 case by 2100.

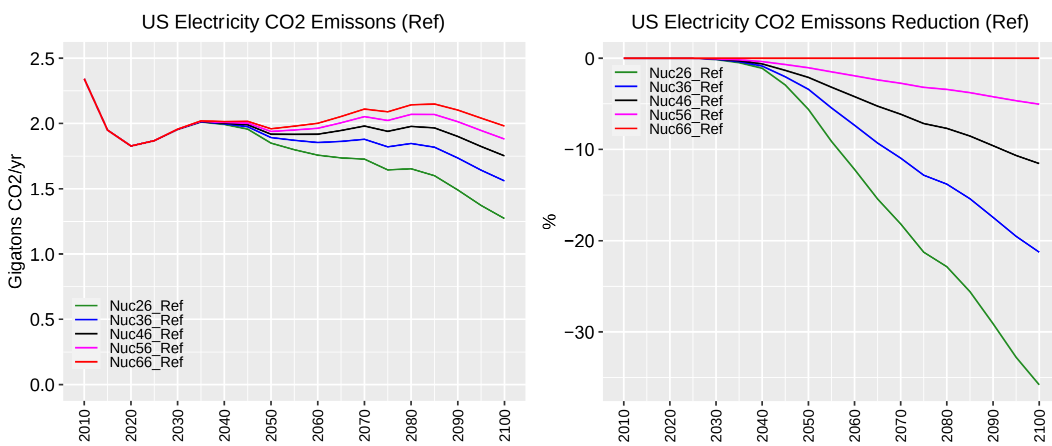


Figure 19. US electricity sector CO_2 emissions and impact of nuclear power capital cost reductions in the Reference scenario.

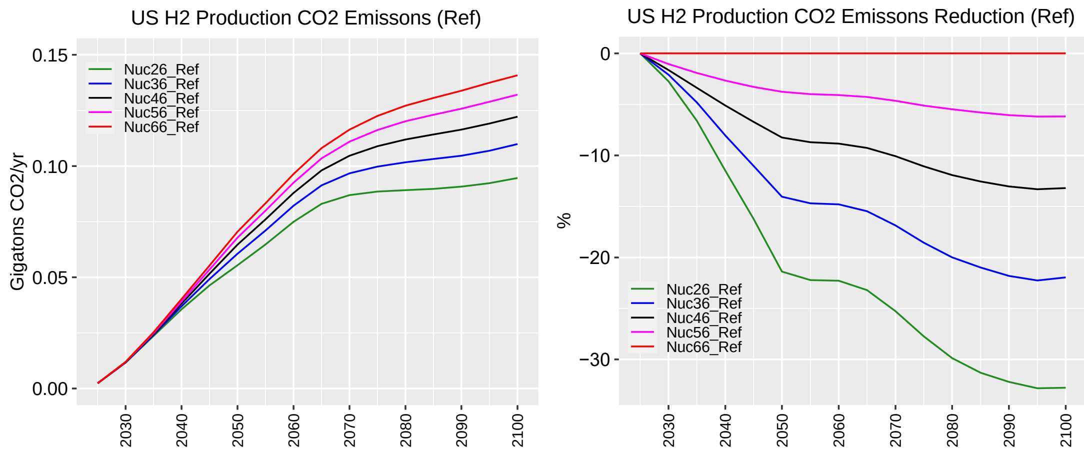


Figure 20. US CO_2 emissions from H_2 production and impact of nuclear power capital cost reductions in the Reference scenario.

Electricity CO_2 emissions are a major a contributor to total US carbon emission throughout the 21st century in the Reference scenario. With current high levels of electricity use and increased electrification of the end-use sectors, such as through the ongoing electrification of the transport and buildings sectors, electricity carbon emissions are the dominant long-term source of US emissions in the Reference scenario. Moreover, increased utilization of H_2 as an alternative energy carrier can further contribute to CO_2 emissions since H_2 production is primarily reliant on natural gas. However, H_2 use in the Reference scenario is low and emissions contribution from H_2 production remains small.

Total US CO_2 emissions across the nuclear cases are shown in Figure 21. Electricity CO_2 emissions are about 40% of the total emissions in 2050 and range from 35% to 41% of total by 2100 dependent on the nuclear case. CO_2 emissions from H_2 production are only around 1% of total emissions throughout all modeling periods. The impact of the nuclear cost improvements is the reduction of total US CO_2 emissions of 4% in 2050 and 16% in 2100 between the two nuclear cost extremes, Nuc66 and Nuc26, as shown in Figure 21, right panel.

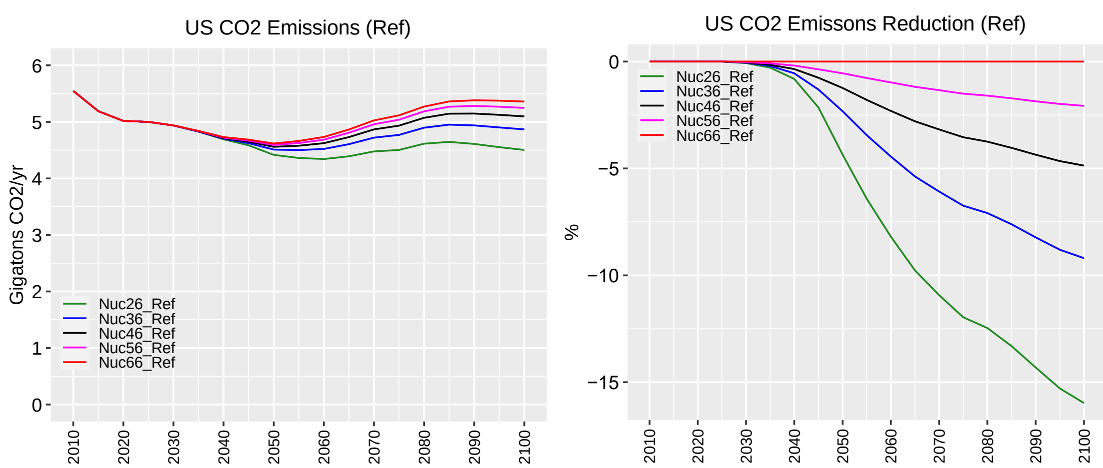


Figure 21. Total US CO_2 emissions and the emissions impact of nuclear sensitivity cases in the Reference scenario.

Absolute differences in total economy-wide CO_2 emissions are somewhat greater than the combined emission differences from electricity generation and H_2 production indicating the indirect feedback of lower electricity and H_2 prices from nuclear cost assumptions. Lower electricity and H_2 prices due to cheaper nuclear technologies encourage greater utilization of electricity and H_2 relative to fossil fuels at the end-use. At the same time, increasing nuclear market share results in decreasing carbon emissions per unit electricity and H_2. The combined impact is the total economy-wide emissions difference of 0.86 $GtCO_2$/year between the Nuc66 and Nuc26 cases by 2100, as compared to the combined electricity and H_2 emissions difference of 0.76 $GtCO_2$/year.

Efforts to reduce the capital cost of nuclear power not only increases nuclear electricity and H_2 competitiveness but is an effective strategy for carbon emissions reduction. More competitive nuclear power primarily substitutes for fossil-based energy carriers and increases the utilization of nuclear energy throughout economy. Thus, strategies for improving the nuclear capital costs and nuclear market share support climate mitigation goals.

4.2 IRA and BIL Policy Impacts

The IRA and BIL policy impacts are presented here, in between the Reference and Net-Zero scenario discussions, because they are interim policies to meet long-term US GHG emissions reduction goals. The IRA moves US emissions toward net-zero from present conditions but does not have the specific goal of achieving net-zero emissions. Results of the IRA and BIL policy impact and changes to alternative energy carriers, end-use sector energy demands, and CO_2 emissions are presented below. This section begins with a discussion of electricity generation and use impacts followed by the results on hydrogen production and use, then transportation, nuclear energy, and CO_2 emissions. The last topic in this section is on the impact of the BIL policy for the continued operation of the existing nuclear reactor fleet which is modeled separately and implemented by exogenous assumptions of alternative nuclear plant lifetimes.

4.2.1 IRA Electricity Generation Impact

Clean energy credits for electricity generation technologies have a dramatic impact on the production and demand for electricity. IRA credits reduce the cost of electricity by as much as 25% to 32% relative to the Base case without the policy as shown on the left panel of Figure 22. The IRA-Mid case has electricity price reductions of 27% in 2025, 25% in 2030, and 22% in 2035. The IRA-High case has greater electricity price reductions at 32% in 2025, 29% in 2030, and 26% in 2035.

Reductions in the electricity price induce an increase in electricity demand from all end-use sectors in both IRA cases. The IRA-Mid case has electricity demand increases of 9% in 2025, 12% in 2030, and 14% in 2035, while the IRA-High case has electricity demand increases of 11% in 2025, 16% in 2030, and 19% in 2035. We caution that changes in the 5-year time step modeling result for 2020 to 2025 may overstate the realistic changes that can occur within the actual two years remaining until 2025.

Although the policy is terminated after 2035 in the IRA-Mid and IRA-High cases, electricity demand continues to be higher than the Base case for a few decades after the policy is terminated. Low electricity prices during the policy implementation periods induce substitution to electricity-based energy services which locks in higher electricity demands until stock turnover returns demand back to Base case levels. The consequence of higher electricity demand without IRA credits after 2035 is that electricity prices rise above the Base case levels as shown in the left panel of Figure 22. IRA-Mid case has price increases of

5% from 2040 to 2050, while IRA-High case has price increase of 6% for the same time periods. Electricity prices do not return to Base case levels until 2060.

The extended IRA cases, IRA-Mid-Ext and IRA-High-Ext, prolong the impact of low electricity prices which results in extending higher electricity demands to 2050 and thereafter. Electricity demands are as much as 16% greater in IRA-Mid-Ext and 21% greater in IRA-High-Ext from 2040 to 2050 relative to the Base case.

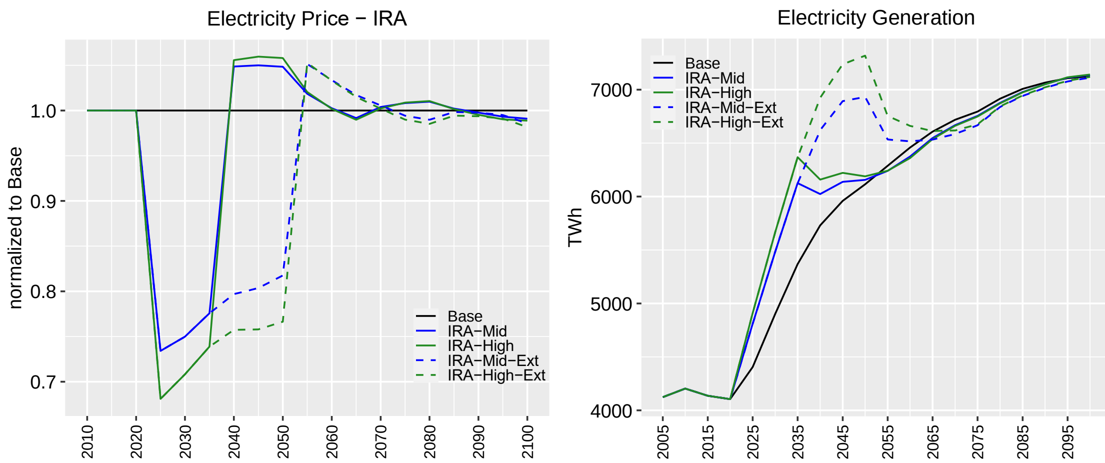


Figure 22. Impact of IRA scenarios on electricity prices (left panel) and electricity demands (right panel).

Overall perspectives on the total generation of electricity by fuel types and specific changes to the carbon-free or low-carbon power technologies from the IRA implementations are shown in Figure 23. Greater penetration of wind, solar, nuclear, coal CCS, and natural gas CCS power generation technologies occurs, while coal and natural gas power generation without CCS declines. The expansion of clean power technologies is also affected by the increase in total electricity demand as discussed above. Due to the temporary nature and coverage limited to clean technologies, the IRA policy suppresses but does not eliminate the use of fossil fuels for power generation. When the IRA policy implementation is removed, fossil power generation without CCS continues to grow after the middle of the century.

The IRA impact on specific clean power technologies is shown in Figure 24. The IRA has the greatest benefit to wind power as measured by changes in electricity generation (TWh), followed by coal CCS, solar, natural gas CCS, and nuclear. Wind power becomes the lowest cost generator of electricity from the IRA credit. Wind becomes cheaper than natural gas power and has greater relative electricity cost reductions than solar power. Electricity generated by wind more than doubles, gaining an additional 1,000 TWh in 2035 from the IRA relative to the Base case. Solar electricity generation grows by about 300 TWh in 2035.

Carbon storage credit of \$85/tCO_2 for fossil CCS technologies benefits both natural gas CCS and coal CCS technology options. The carbon storage credit transforms an uncompetitive power generation option of the CCS technologies to a competition one. The benefit to coal CCS technology, however, is much greater than natural gas CCS since the credit is applied per ton of CO_2 stored. Coal with higher carbon content than natural gas leads to greater amount of carbon captured per unit of energy produced when paired with the CCS technology. Coal CCS power generation produces 300 TWh of electricity by 2035 with the IRA, as shown in Figure 24, whereas natural gas CCS produces about 70 TWh of electricity. There are little differences to CCS power outputs in the IRA-Mid and IRA-High cases since the carbon storage credit did not change. In the Base case, there was no electricity generation from fossil CCS technologies.

As shown in Table 2, the capital cost of the fossil CCS power plant is the primary obstacle to their deployment. Once they are deployed, after having overcome the high capital cost hurdle with IRA credits, CCS plants continue to operate well after the IRA carbon storage credits are removed. The cost of the geologic storage component is relatively low due to the availability of large carbon storage resources in the US (DOE FE, 2013). The geologic carbon storage cost was about 8 $/tCO_2$ throughout the 21st century for the carbon storage levels in the IRA-Mid and IRA-High cases (Schmelz, 2020). Whether CCS technologies can persist without some minimum level of carbon credits remains uncertain, however.

The IRA benefit to nuclear power generation is limited due to three factors, the high current capital cost of nuclear power plants, the credits applied to all clean power technologies, and the duration of the IRA policy period. New nuclear power plants were not available for deployment until after 2025 in this analysis and thus, the IRA benefit to new nuclear power was only applicable for the 2030 and 2035 modeling periods. Because nuclear power is not able to deploy immediately, the near-term benefit of the IRA is not realized. Moreover, although the ITC of the IRA has a significant impact on nuclear capital cost reductions, nuclear power fails to gain a significant cost advantage relative to other clean power technologies that are also benefiting from the IRA credits in equal or greater magnitudes. New nuclear power generation, however, does increase by an additional 30 to 65 TWh in 2035 in the IRA-Mid and IRA-High cases, respectively.

Extending the IRA policies to 2050 has greater impact on nuclear power growth due to the longer duration of clean energy credits for nuclear and the underlying decline in nuclear capital costs assumed to fall from 6130 $/kW in 2025 to 5340 $/kW by 2050 prior to IRA credit adjustments. Figure 24 shows a nuclear power generation increase of 250 TWh in the IRA-High-Ext case which persists for the duration of the 21st century. Improving the baseline capital cost of nuclear power prior to applying the IRA credits can enhance the impact of the IRA on nuclear power deployment as shown by the extended IRA cases. The IRA impact with nuclear capital cost sensitivity cases, however, was not investigated.

Long lifetimes of electric power technologies affect the composition of the electric power sector beyond the duration of the IRA policy period. Clean power investments that occur from 2025 to 2035 will have an impact for a minimum of 30 years (wind and solar lifetimes) to 80 years (nuclear lifetime) far exceeding the approximately 10-year duration of the IRA. Gas and coal CCS power plants have assumed lifetimes of 45 and 60 years, respectively. Figure 24 clearly shows the lifetime dynamics of each technology from the IRA. Nuclear with its long lifetime has an impact on power generation for the duration of the 21st century, whereas the benefit of wind and solar investments with shorter lifetimes primarily affects electricity generation in the first half of the 21st century.

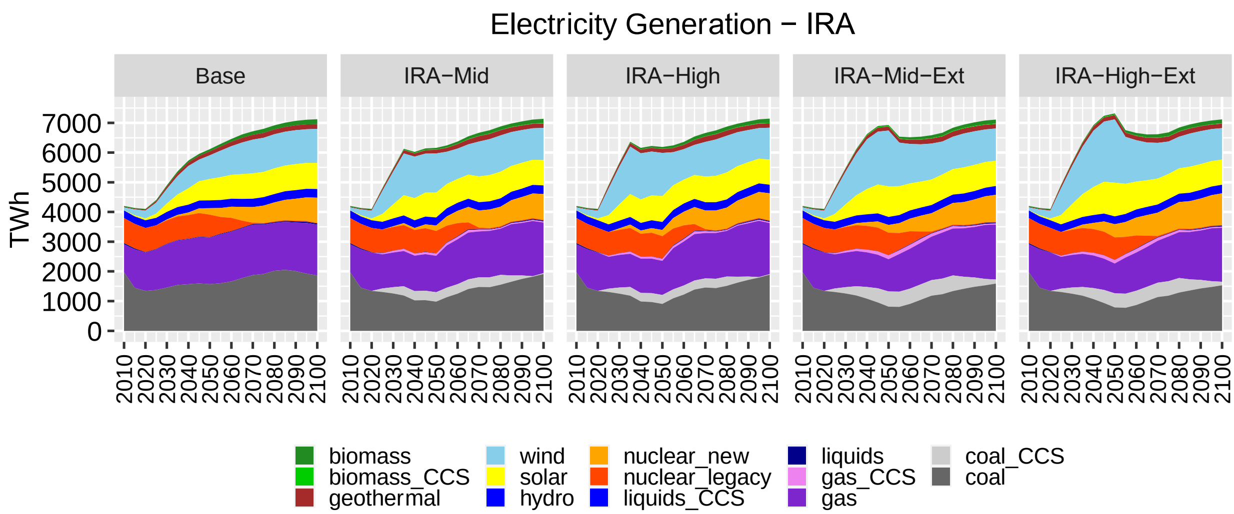


Figure 23. Electricity generation by fuel for alternative IRA scenarios (TWh).

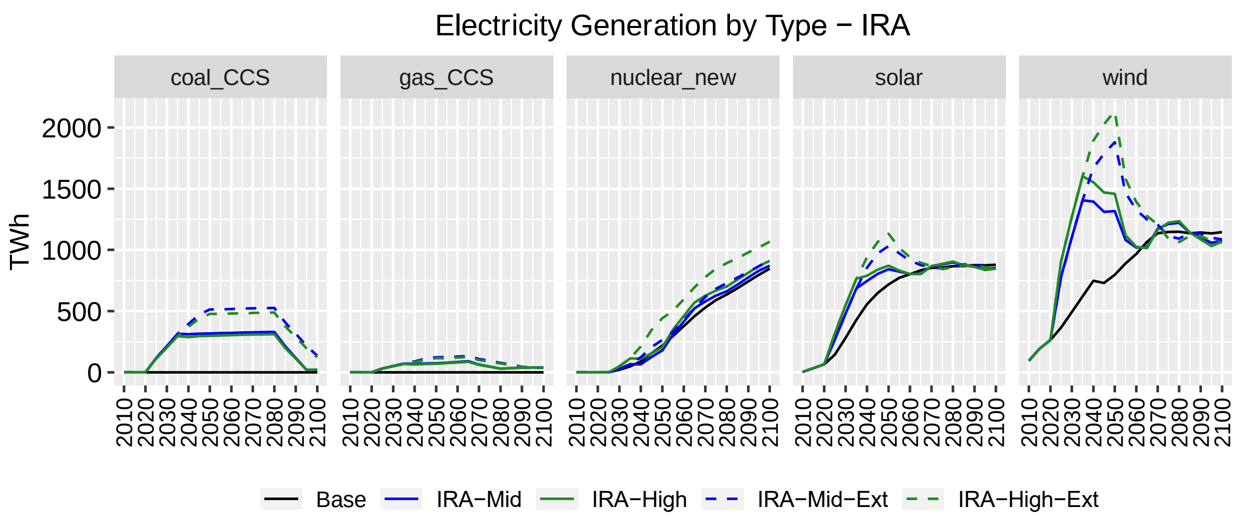


Figure 24. Comparison of electricity generation impact of IRA scenarios for clean power technologies (TWh).

4.2.2 IRA Hydrogen Production Impact

H_2 prices are also significantly affected by the IRA credits for clean hydrogen production. The credits are graduated based on the carbon emissions rate with full credits to carbon-free hydrogen production. For H_2 production from fossil CCS, the carbon storage credit of 85 $/tCO$_2$ was applied rather than the clean H_2 credit. H_2 production from coal CCS, natural gas CCS, wind, and nuclear benefits the most from the IRA credits. Coal CCS H_2 production had the lowest cost of H_2, followed by H_2 from wind, natural gas CCS, and nuclear. There are no differences in the IRA-Mid and IRA-High cases for H_2 production and use since clean hydrogen credits remain the same in both cases.

H_2 prices produced from a central station dropped from 2 $/kgH$_2$ in the Base case to less than 1 $/kgH$_2$ in the IRA scenario for 2025 to 2035, driven mainly by low coal CCS H_2 cost, as shown on the left panel of

Figure 25. Similar large price reductions occur for H_2 prices at industrial and wholesale dispensing facilities as shown in the middle and right panels of Figure 25. Industrial onsite H_2 prices drop from 3.5 $/kg$H_2$ to 2 $/kg$H_2$, while wholesale dispensing H_2 prices fall from above 6 $/kg$H_2$ to below 5 $/kg$H_2$. IRA credit for forecourt nuclear H_2 production of 3 $/kg$H_2$ plays a large role in onsite industrial and wholesale dispensing price reductions.

The extended IRA scenarios continue to create low H_2 prices to 2050. Central station H_2 production prices fell to 0.20 $/kg$H_2$ by 2050 driven lower by wind electrolysis cost improvements. Central station H_2 prices rise sharply back to 2 $/kg$H_2$ after 2050 once the credits are removed. H_2 prices at the end-use are higher than above central station costs, however, due to additional delivery, storage, and compression costs. Industrial and wholesale dispensing H_2 prices at 1.3 and 4 $/kg$H_2$ by 2050, respectively, are also further improved in the extended IRA cases driven by the H_2 credit and nuclear capital cost reductions over time.

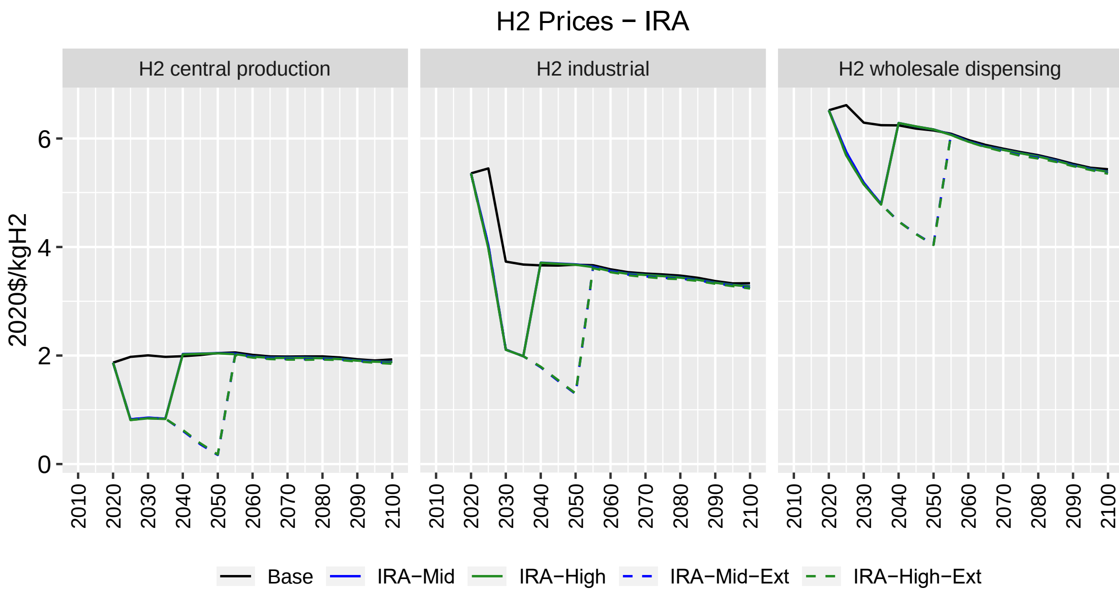


Figure 25. Impact of IRA scenarios on hydrogen prices (2020 $/kg$H_2$).

H_2 demands from all end-uses increase in response to lower H_2 prices from the IRA. In relative terms, H_2 demand increases by as much as 46% in 2030, or by as much as 2.3 million tons of H_2 by 2035 in both the IRA-Mid and IRA-High cases. H_2 demands return to Base case levels by 2040 once the IRA credits are removed.

Significantly lower H_2 prices resulting from the extended IRA cases to 2050 has a more dramatic impact on the total H_2 demand, which has increased by 70% relative to the Base case. In absolute terms, an additional 21 million tons of H_2 is demanded by 2050. The buildings sector and the competitive use of H_2 for heating services is responsible for the sharp rise in H_2 demand as shown in the right panel of Figure 26. H_2 use for the buildings heating is assumed to be a direct replacement for pipeline natural gas as a fuel for heating, where the substitution of natural gas for H_2 is more sensitive to H_2 price reductions. Approximately 20% of the heating service in 2050 is provided by H_2 before falling back down to less than 1% of the heating service in 2055 once the IRA credits are removed. An increase in H_2 demand from transport and industries also contribute to an increase in total H_2 use but the competitiveness of H_2 end-use applications for these sectors is not as strong.

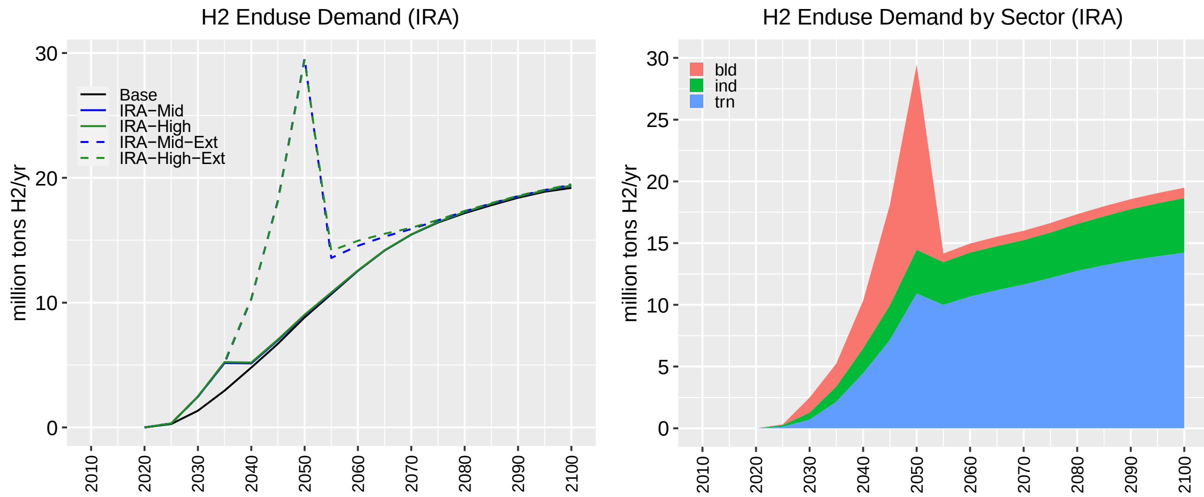


Figure 26. Impact of IRA scenarios on total hydrogen demand (left panel) and end-use hydrogen demand for IRA-High-Ext case (right panel) (million tons of H_2/yr).

4.2.3 IRA Transportation Impact

IRA credits for clean vehicles increase the adoption of BEV and FCEV, which do not have tailpipe emissions, while reducing the use of petroleum fuels and internal combustion engine vehicles (ICE). The credit for passenger light-duty vehicle (LDV) has a greater impact on the adoption of clean vehicles than the credits for freight road transport as displayed in Figures 27 and 28.

In passenger LDV transport, the ongoing adoption of BEV is further enhanced by the IRA vehicle credit. In the IRA-Mid case, as much as 40%, and in the IRA-High cases, as much as 80% increase in BEV passenger service is realized from the vehicle credits by 2030 (see left panel of Figure 27). FCEV use also increases by similar percentages but the increase in terms of passenger service is small due to the current low rate of FCEV adoption (see middle panel of Figure 27). The vehicle credits alter the relative competitiveness of all clean vehicle options and to the detriment of ICE vehicles. Passenger service from ICE drops by10% in IRA-Mid and 20% in IRA-High cases by 2035 (see right panel of Figure 27).

Increases in BEV and FCEV passenger service more than compensate for the reductions in passenger service from ICE vehicles. The overall demand for LDV passenger service increases by 2% to 5% in the near-term as the IRA vehicle credits reduce the cost of passenger transport service in general. The impact of the clean vehicle credit is felt for an additional 15 years after the credit is removed in 2035 due to vehicle stock lifetimes. LDV passenger vehicle composition and service demands return to Base case levels once clean vehicle credits are removed and after stock turnover by 2050.

The IRA extension cases, IRA-Mid-Ext and IRA-High-Ext, push the pattern of BEV and FCEV adoption and ICE reduction further out in time to 2050 with residual changes in passenger service continuing to 2070. BEV passenger service increases by 30% to 60% until 2050 with notable changes to actual passenger service provided in passenger-kilometer. The percentage changes to FCEV are high but small in terms of actual passenger service. Reductions to ICE vehicles are greater at 20% to 30% lower service in 2050.

Relatively small impact to freight road transport is observed from the IRA credits for clean commercial vehicles as shown in Figure 28. IRA credits for commercial vehicles are not sufficiently high enough to significantly alter the composition of commercial vehicles and the adoption of BEV and FCEV trucks and commercial vehicles.

Many vehicle manufacturers have announced the phase-out of ICE vehicle production and support for BEVs. The IRA clean vehicle credits further encourage the adoption BEVs which could spur the phase-out of ICEs. Nevertheless, the phase-out of ICE vehicles was not assumed in this analysis due to the uncertainty of future clean vehicle transitions once the IRA policy comes to an end. Thus, passenger and freight road transport continue to be dominated by petroleum fuels and ICE vehicles in the long-term in these scenarios.

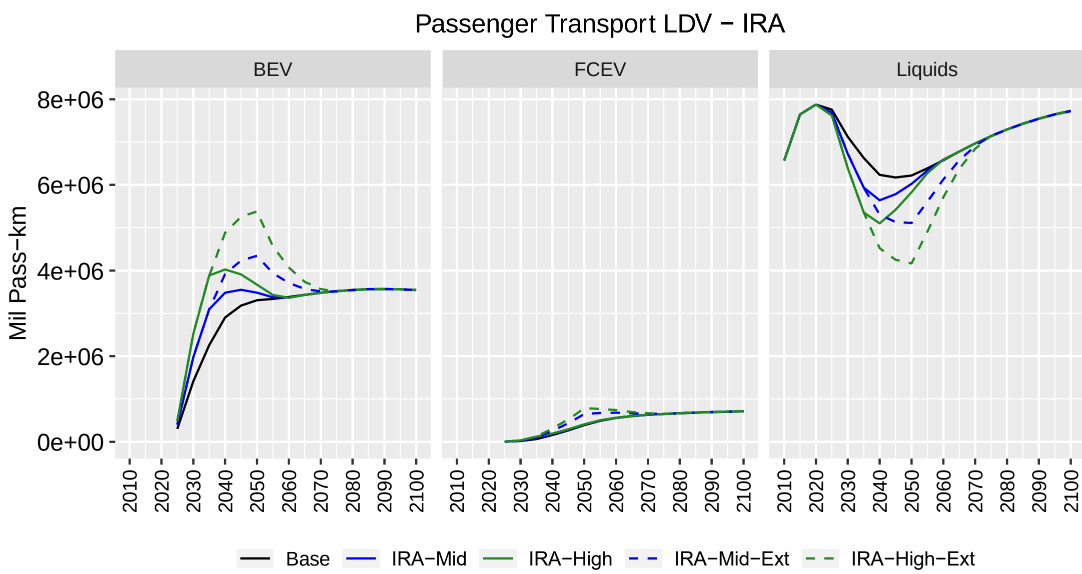


Figure 27. Impact of IRA scenarios on passenger transport service by vehicle type (million pass-km).

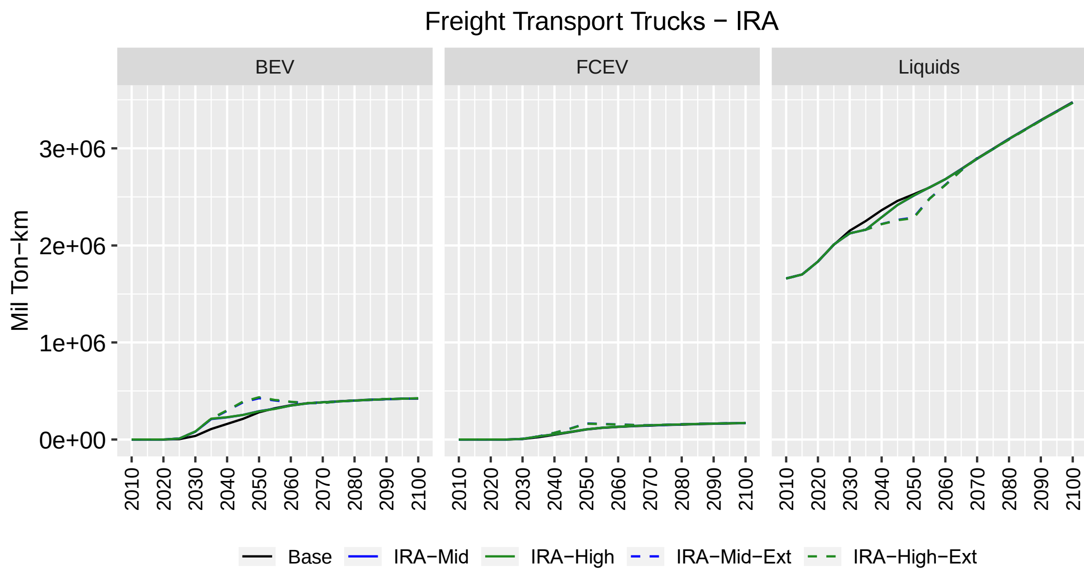


Figure 28. Impact of IRA scenarios on freight road transport service by vehicle type (million ton-km).

4.2.4 IRA Impact on Nuclear Power Capacity

The benefit of the IRA to nuclear energy for electricity generation and hydrogen production is relatively small in the IRA-Mid and IRA-High cases. The extended IRA cases, however, had a greater impact on increasing the utilization of nuclear energy. Plots of the nuclear capacities for H_2 production, electricity generation, and total capacity for all IRA cases are shown in Figure 29. Nuclear capacity for H_2 production increased by 5 GWe in 2035 relative to the Base case. Nuclear power plants for H_2 production are assumed have a lifetime of 60 years, versus 80 years for electricity generation. Due to the longevity of nuclear power plants, the nuclear capacity increase for H_2 production persisted until 2095, long after the end of the IRA.

For electricity generation, the increase in nuclear power capacity depends more heavily on the specific IRA case. Nuclear power capacity increases to 109 GWe in IRA-Mid case and 115 GWe in IRA-High case by 2035 as displayed by the middle panel of Figure 29. The Base case nuclear capacity in 2035 is 107 GWe. Although the investment tax credits, 30% and 50% ITC, are significant for nuclear power, the relative improvements to nuclear power competitiveness are less meaningful since all other low-carbon technologies are also benefiting from the credit and current nuclear capital costs are high. In the long-term, nuclear reactor lifetime of 80 years assumed for power generation ensures that the 2 to 8 GWe increase in additional nuclear capacities persist for the duration of the 21st century.

The abrupt removal of the IRA credits after 2035 causes some dislocations to the electric power system during mid-century. Due to prior higher investments in power generation induced by the IRA, excess power capacity exists for 2040 and no new power investments of any kind occurs until 2045. In the IRA-Mid case specifically, the nuclear electricity generated from 2040 to 2050 is actually less than in the Base case due to the prior period shift towards greater wind and solar investments from the IRA. The IRA-High case, however, has greater nuclear power capacities relative to Base case throughout all periods.

The IRA-High-Ext case has a noticeably greater impact on the expansion of the nuclear power capacity for both H_2 production and electricity generation as the underlying nuclear capital cost has improved prior to the IRA adjustments (see Figure 4). Thus, the impact of the IRA credit is greater on reducing nuclear costs if the IRA is extended. By 2050, the nuclear capacity is 26 GWe for H_2 production and 152 GWe for electricity generation in the IRA-High-Ext case, relative to 5 GWe for H_2 and 124 GWe for electricity in the Base case.

The total nuclear power capacity for H_2 and electricity production is greater in all IRA cases than the Base case as shown on the right panel of Figure 29. Nevertheless, unless the duration of the IRA credits is extended for a longer period, the gain in total nuclear capacities is generally small. In the Mid and High extended cases, the total nuclear capacities are 25 to 49 GWe greater throughout the 21st century than the Base case. Their persistence is due to the longevity of nuclear power plants. The greatest total nuclear capacity is in 2050 at 178 GWe for the IRA-High-Ext case, as compared to 129 GWe for the Base case in 2050. The sharp drop in total nuclear capacity from 2050 to 2070 reflects the retirement of the legacy nuclear fleet with assumed lifetimes of 80 years.

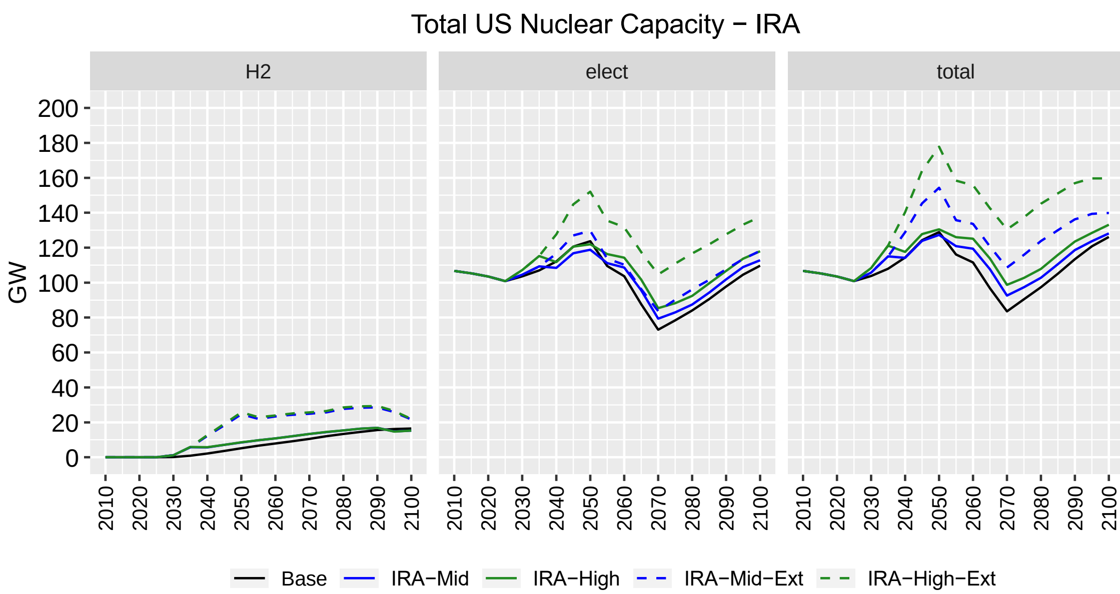


Figure 29. The impact of IRA scenario on total nuclear power capacities for H_2 and electricity production (GWe).

4.2.5 IRA Impact on CO_2 Emissions

The increased penetration of all clean energy production and demand technologies from the IRA results in CO_2 emission reductions as shown in Figure 30. The IRA-Mid and IRA-High cases have CO_2 emissions reductions of 30 - 32% in 2035 and 36 - 37% in 2050, respectively, relative to historical 2005 emissions. The actual emissions were about 4.1 $GtCO_2$/year in 2035 and about 3.7 $GtCO_2$/yr in 2050 for both cases. The difference in emissions between the two IRA cases is small as only marginal differences to fossil energy use are realized between the two. The range of emission reduction in this analysis is consistent with other studies of IRA impact on CO_2 emissions reduction. The Rhodium Group and DOE report CO_2 emissions reduction of 31 – 44% relative to 2005 emissions (Bistline et al., 2023; DOE, 2022; King, 2022).

Electricity sector emissions are the main contributor to emissions reduction comprising more than 50% of the total reduction for the duration of the IRA policy, but the buildings, industries, and transport sectors also contribute to emission reduction from substitution to electricity and hydrogen from fossil fuels. Industries, transport, and buildings contribute approximately 20%, 15%, and 8%, respectively, to the remaining CO_2 emissions reduction in 2035. The duration and clean energy credits of the IRA to 2035 are not sufficient to achieve economy-wide net-zero emissions. However, the impact of the IRA on emissions reduction has a long shadow due to investments in long-lived capital stocks, such as nuclear and coal CCS, and total emissions remain below Base case levels until the end of the century.

The extension of the IRA to 2050 continues the downward trajectory in CO_2 emissions beyond 2035. By 2050, emissions reduction of 46% and 48% is achieved for the extended Mid and High cases relative to 2005. The CO_2 emissions rate in 2050 is approximately 3 $GtCO_2$/yr in both cases. Once the IRA credits are removed after 2050, CO_2 emissions begin to rise again as fossil energy production and use technologies regain their competitive edge. CO_2 emissions reach 4.8 $GtCO_2$/yr by 2100 for the extended IRA cases, which is still below the Base case emissions of 5.2 $GtCO_2$/yr for 2100. The goal of achieving net-zero emissions is difficult without persistent long-term disincentives for the utilization of fossil fuels.

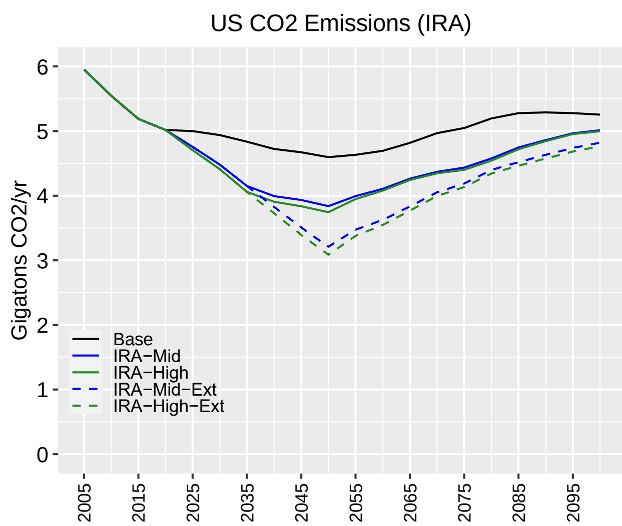


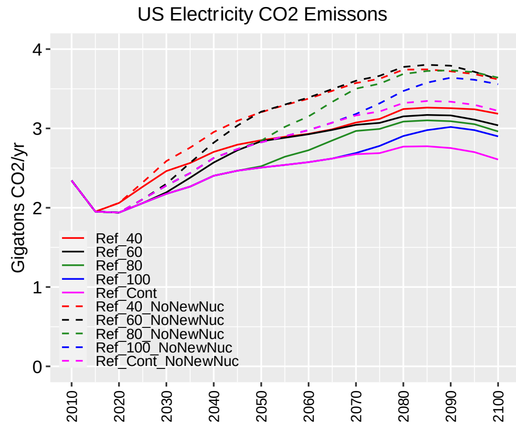
Figure 30. The impact of IRA scenarios on total US CO_2 emissions (Gigatons CO_2/yr).

4.2.6 BIL Impact on Existing Nuclear Power Plants

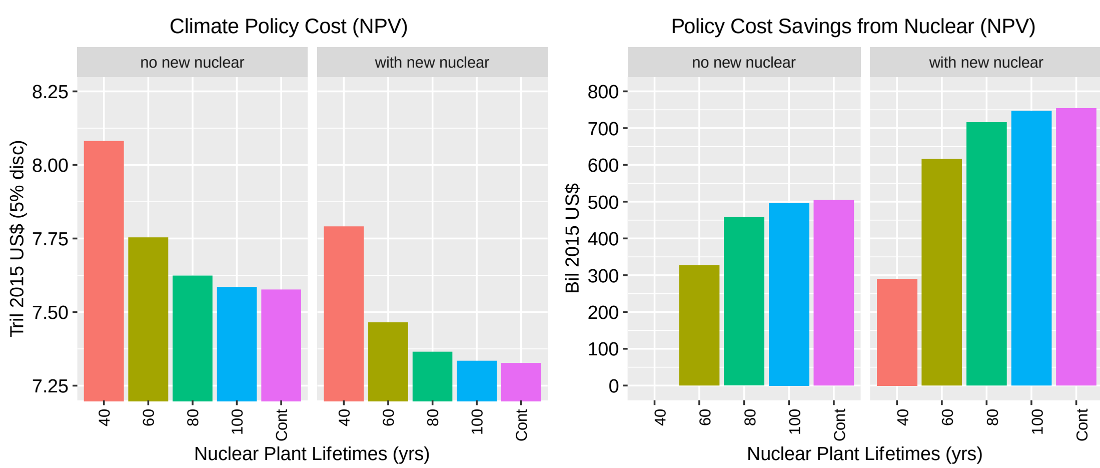
A detailed and complete investigation of the BIL impact was not within the scope of this analysis. The Civilian Nuclear Credit Program within the BIL has a funding level of 6 billion dollars for the prevention of premature retirements of existing commercial nuclear reactors due to economic factors. We are not able to specifically assess the economic operating condition of every US nuclear power plant in this analysis. Instead, a broad and representative impact of alternative lifetimes of the existing nuclear fleet is explored to assess the impact of premature retirements.

We pull from our 2021 work by Kim et. al. on the carbon value of nuclear power plant lifetime extension to assess the potential benefit of the Civilian Nuclear Credit Program on ensuring the continued operation of the existing nuclear fleet (Kim, Taiwo, & Dixon, 2022). Comparison of existing nuclear power plant lifetime assumptions of 60 and 80 years in Figure 31 shows that extending nuclear lifetimes result in significant differences in the avoided CO_2 emissions from the electric power sector. The emissions difference from a lifetime extension of 20 years was approximately 0.4 $GtCO_2$/yr in 2050 or greater than 10% reduction in the total power sector emissions.

Preventing premature retirements of existing commercial nuclear reactors has tangible economic benefits for reducing the cost of CO_2 emissions mitigation. Figure 32 shows that lifetime extensions of the nuclear fleet have significant implications for the cost of meeting long-term climate change goals which is denominated in trillions of dollars in net present value (NPV) (Figure 32 left panel). The extension of the nuclear lifetime from 60 to 80 years alone is valued at 130 billion dollars in emissions mitigation cost savings (right panel). The potential savings from avoiding premature nuclear retirements is well worth the funding level of the Civilian Nuclear Credit Program.



Figures 31. US electricity sector CO_2 emissions for alternative nuclear lifetimes assumptions (Gigatons CO_2/yr).



Figures 32. US climate mitigation costs and savings (NPV) from nuclear lifetime extensions and new nuclear deployments in a 2° C climate scenario.

4.3 Net-Zero 2050 Scenario with Nuclear Cost Sensitivity Cases

The IRA scenarios in this analysis move US carbon emissions below the Reference scenario emissions and towards a sharply declining path, but the emission reduction achieve by the IRA is well short of the desired net-zero emissions goal. We present the results of the Net-Zero 2050 scenario below which investigates the levels of policy incentives and energy system changes necessary for achieving net-zero emissions by 2050 and for maintaining net-zero for the remaining duration of the 21st century.

4.3.1 Carbon Tax Levels for Achieving the Net-Zero 2050 Goal

Model results of the net-zero policy show that carbon tax levels of approximately 300 $/t$CO_2$ is required to achieve net-zero CO_2 emissions by 2050 as displayed in Figure 33. In the net-zero scenario, carbon taxes begin at 107 $/t$CO_2$ in 2025 and reach 291 to 304 $/t$CO_2$ by 2050 dependent on the nuclear cost case. The lowest nuclear cost results in the lowest peak carbon tax. Carbon taxes fall for a couple of decades after reaching the peak in 2050 as the economy has fully decarbonized and fewer carbon-free or negative emissions technologies are needed to maintain net-zero emissions. As the economy and energy demand continue to grow, carbon taxes rise again in the second half of the century. However, the carbon tax never approaches the peak levels of 2050 due to technological change and steady improvements in the cost of all carbon-free technologies over time.

The primary determinant of the carbon tax rates is driven by the emissions mitigation potential from outside of the electricity sector and in the buildings, industry, and transport sectors. The alternative nuclear capital cost sensitivity cases had only a small influence on the peak tax levels needed to achieve net-zero emission as multiple clean energy technologies are available for deployment in power generation and H_2 production.

The full cumulative NPV cost to the US of achieving net-zero emissions is typically denominated in trillions of dollars as shown in Figure 32 left panel above. Such high sums are an indication of the scale of the climate change problem and the difficulty of achieving the net-zero emissions goal.

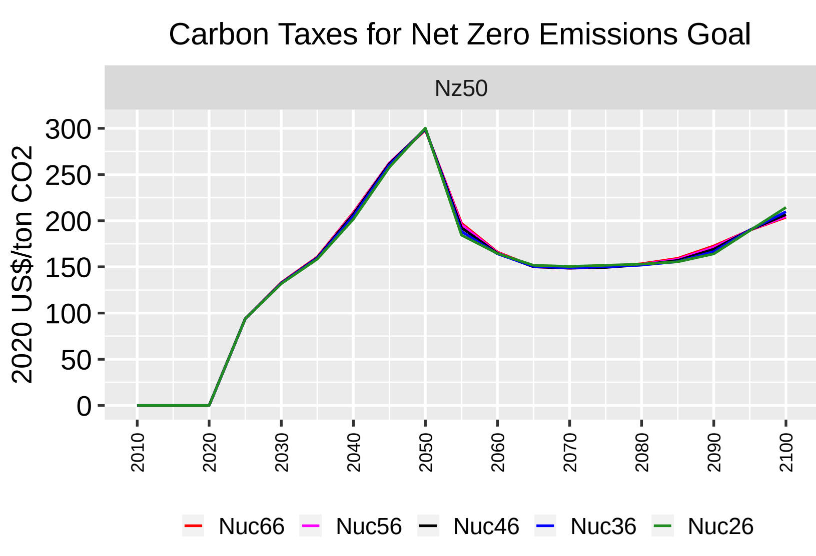


Figure 33. Carbon taxes required to meet net-zero emissions goal by 2050 (2020 $/ton CO_2).

4.3.2 Final Energy and Hydrogen Demand in the Net-Zero 2050 Scenario

In the Net-Zero scenario, carbon penalties on fossil fuels lead to higher end-use energy prices and the reduction of total final energy demand as compared to the Reference scenario. By 2100, total final energy demand drops from 78 EJ/yr of the Reference scenario to 64 EJ/yr, a reduction of approximately 20%.

The composition of final energy consumption shifts to greater utilization of electricity and hydrogen as displayed in Figure 34 for meeting the net-zero goal. Electricity and H_2 use increases as they do not contribute to direct CO_2 emissions and their upstream production becomes decarbonized. Refined liquids and natural gas consumption falls significantly.

H_2 use grows to about 6% share of final energy in 2050 and 13% share by 2100. Electricity becomes the dominant final energy carrier at 46% share in 2050 and 55% share by 2100. Liquids and gas use falls to 18% and 13% shares, respectively, by 2100. Approximately 30% of the liquids are composed of biomass derived carbon-neutral fuels.

Although all end-uses, transport, buildings, and industries, substitute from refined liquids and natural gas towards greater use of electricity and H_2, the transport sector undergoes the greatest fuel switching. The transport sector's near exclusive reliance on refined liquids transforms to 60% electricity, 30% H_2, and 10% liquids use by 2100 in the Net-Zero scenario. Changes to the building and industry fuel composition are less dramatic but both increase the share of electricity and H_2. For buildings, final energy shares of electricity and H_2 shares are 75% and 11%, respectively, in 2100, while for industries, electricity and H_2 shares are 33% and 4%, respectively.

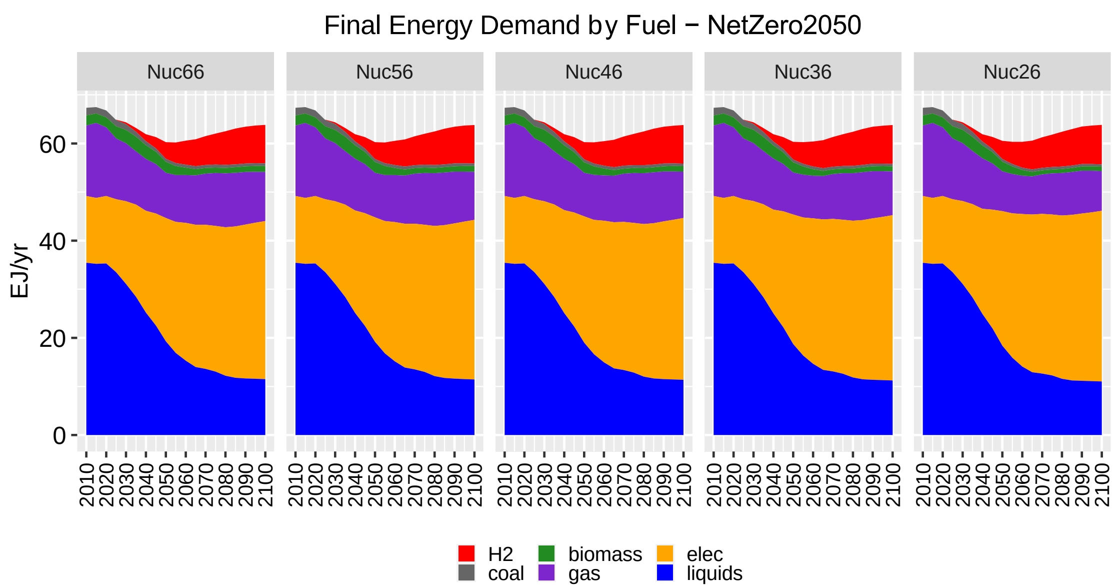


Figure 34. US final energy demand by fuel in the Net-Zero 2050 Scenario (EJ/yr).

The total H_2 demand increases to approximately 30 million tons in 2050 and 65 million tons by 2100 in the Net-Zero 2050 scenerio. Comparisons of H_2 production for the Net-Zero and Reference scenarios are shown in Figure 35. The H_2 demand increases more than three-fold in the Net-Zero scenario relative to the Reference scenario from end-use fuel substitution.

H_2 demand is driven strongly by transportation, followed by buildings and industries as shown in Figure 36. Transportation sector comprises 46% and 66% of total H_2 demand in 2050 and 2100, respectively. The buildings sector has greater penetration of H_2 use for heating services in the Net-Zero scenario as the carbon penalty increases the cost of natural gas use. Buildings H_2 demand comprises 44% and 25% of total H_2 demand in 2050 and 2100, respectively. The industrial demand for H_2 is 10% and 9% of the total H_2 demand in 2050 and 2100, respectively. Some variations in the H_2 shares result from alternative nuclear cost assumptions but these differences are not significant.

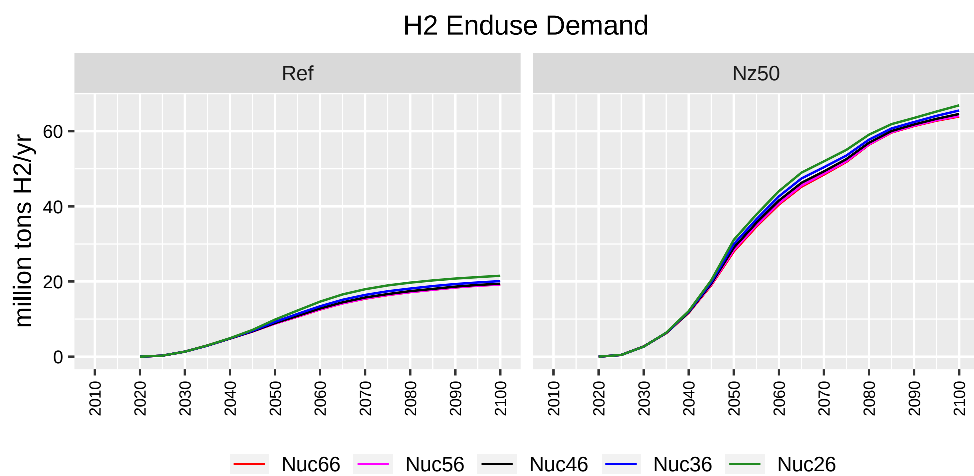


Figure 35. H_2 demand in the Reference and Net-Zero 2050 scenario (million metric tons of H_2/yr).

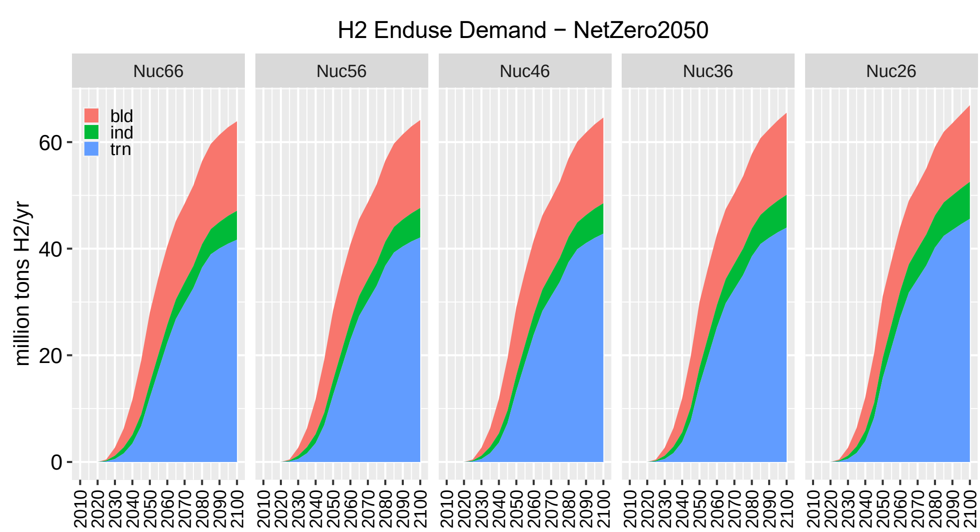


Figure 36. H_2 demand by end-use sectors in the Net-Zero 2050 scenario (million tons of H_2/yr).

4.3.3 Hydrogen Production in the Net-Zero 2050 Scenario

H_2 production from central station and forecourt plants contribute to meet the total H_2 demand in the Net-Zero scenario. Centration station H_2 provides the bulk of H_2 in the Net-Zero scenario as displayed in Figure 37. However, as nuclear H_2 costs fall due to reductions in the nuclear capital cost, forecourt H_2 production increases with a corresponding decrease in central station H_2 production. Total central station H_2 production drops from 50 million tons in Nuc66 to 40 million tons in Nuc26 by 2100. On the other hand, total forecourt H_2 production rises from 17 to 28 million tons in Nuc66 to Nuc26, respectively, by 2100. As shown above, the combined total production of H_2 do not vary significantly across the nuclear cost sensitivity cases.

Multiple technologies for H_2 production are available without CO_2 emissions or at least with lower emission rates. H_2 production from coal and natural gas with CCS, wind, solar, nuclear, biomass, and grid electrolysis are available for central station plants. H_2 production from nuclear and electrolysis are the only carbon-free options available for forecourt plants. The contributions of H_2 production by technology and fuel type for central station and forecourt production for the Net-Zero scenario are shown in Figure 38. The dominant source of centration station H_2 production is from natural gas CCS and coal CCS. Their combined shares of central station production are 78% in Nuc66 and 69% in Nuc26 by 2100. Wind, solar, and nuclear play a smaller role for central station H_2 production. In 2100, wind and solar shares are 13% and 4% in Nuc66 and 10% and 3% in Nuc26, respectively. The nuclear share of central station H_2 increases from 4% in Nuc66 to 17% in Nuc26 by 2100.

Nuclear plants play a much stronger role for forecourt H_2 production, and it is the dominant distributed source of H_2 production in the Net-Zero scenario. In Figure 38, forecourt nuclear H_2 has a 53% share in Nuc66 and a 92% share in Nuc26 by 2100. As nuclear capital costs decline, forecourt nuclear H_2 production gains market share from other forecourt production sources, as well as from delivered H_2 from central station sources.

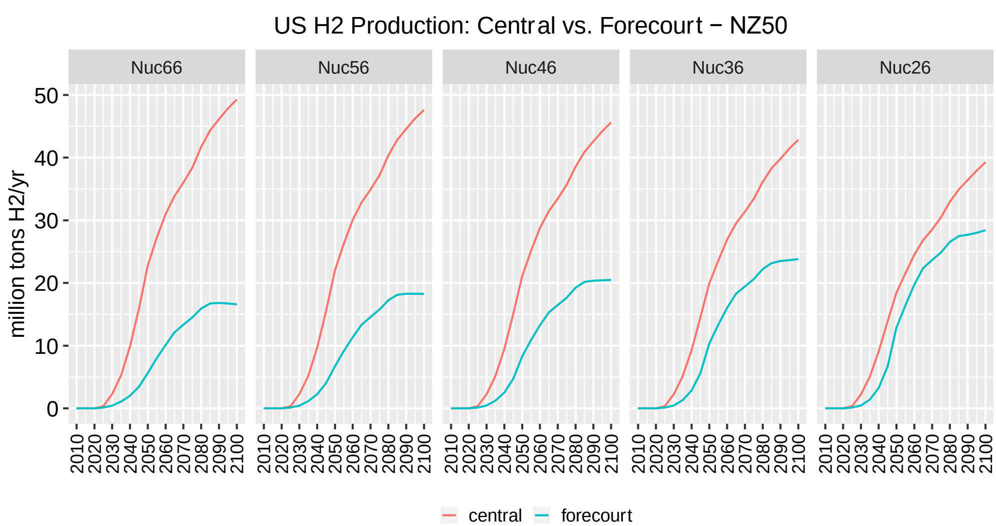


Figure 37. H_2 production from central station and forecourt plants in the Net-Zero 2050 scenario (million metric tons of H_2/yr).

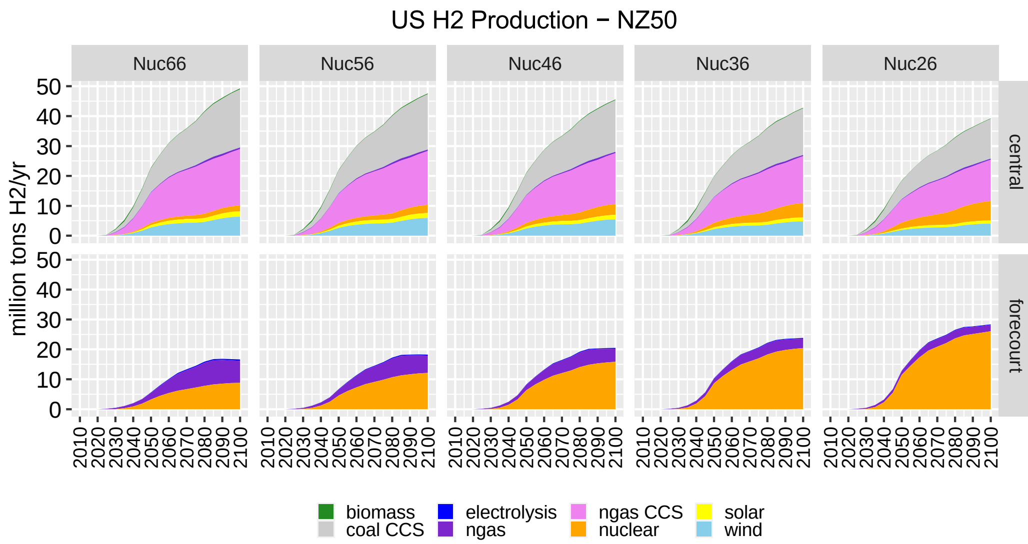


Figure 38. H_2 production by fuel type for central station and forecourt facilities in the Net-Zero 2050 scenario (million metric tons of H_2/yr).

H_2 production costs are greater in the Net-Zero scenario than the Reference scenario due to the carbon penalty and the substitution to carbon-free and low-carbon H_2 prodution methods. As shown in Figure 39, central station H_2 costs are approximately 20% to 30% greater in the Net-Zero scenario than Reference. Industrial on-site H_2 costs are 10% to 20% greater and wholesale H_2 dispensing costs are 4% to 18% greater in Net-Zero than Reference.

Central station H_2 costs range from 2.2 to 2.7 \$/kgH_2 throughout the century and does not vary much across the nuclear cost cases due to the availability of multiple low-carbon H_2 production options in the Net-Zero scenario. Industrial onsite H_2 production costs range from 3.2 to 4.5 \$/kgH_2 and varies more significantly with the forecourt nuclear H_2 cost. Wholesale dispensing H_2 costs range from 5.5 to 7.3 \$/kgH_2 and also varies with the nuclear H_2 cost.

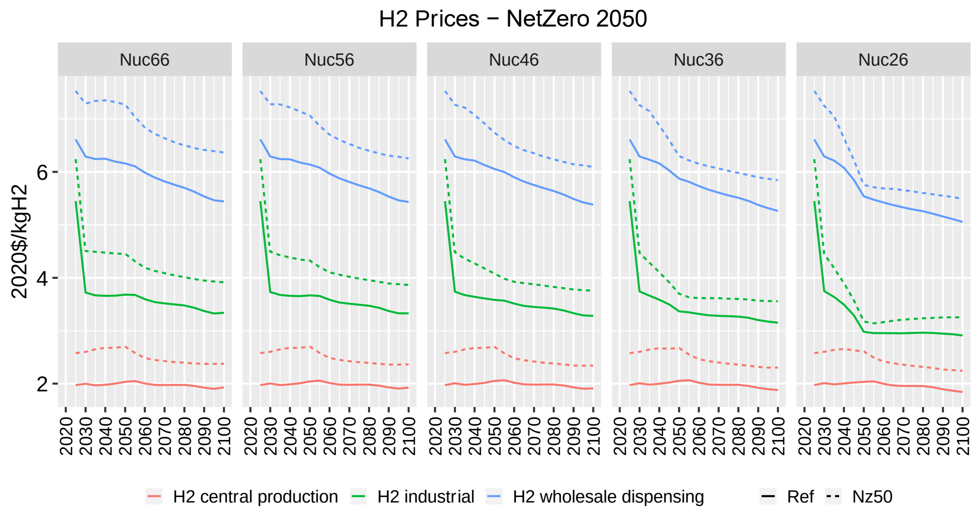


Figure 39. H_2 prices by end-use applications in the Net-Zero 2050 scenario (2020 $/kgH_2$).

Multiple carbon-free and low-carbon production methods contribute to central station H_2 production. H_2 from natural gas SMR with CCS and coal with CCS have the lowest H_2 costs as compared to all other technologies, even after accounting for the additional CCS equipment and carbon penalties. Comparison of H_2 cost by all central station production methods is displayed in Figure 40. Gas SMR CCS and coal CCS H_2 costs are approximately 2 $/kgH_2$ or less throughout the century. H_2 cost from wind electrolysis comes next at approxitmately 3 $/kgH_2$ or less. H_2 cost from natural gas SMR without CCS follows the trajectory of the carbon tax, rising and falling with the carbon tax rate. After 2050 when the carbon tax rate falls, H_2 cost from SMR without CCS is similar to the wind H_2 cost at 3 $/kgH_2$.

As previously shown, the H_2 cost from nuclear HTSE has a broad range, approximately 3 to 5 $/kgH_2$, that is dependent on the nuclear reactor capital cost. H_2 costs from nuclear HTSE are not affected by the carbon tax in the Net-Zero scenario but is slightly higher than in the Reference scenario due to higher nuclear fuel prices. The nuclear H_2 cost impact of higher uranium prices from the regional and global increase in nuclear energy use is shown in Figure 41. Higher uranium prices add about 0.25 $/kgH_2$ to all of the nuclear sensitivity cases by 2100. Nuclear H_2 costs are comparble with wind and gas SMR H_2 at 3 $/kgH_2$ in the Nuc26 case with the lowest nuclear capital cost.

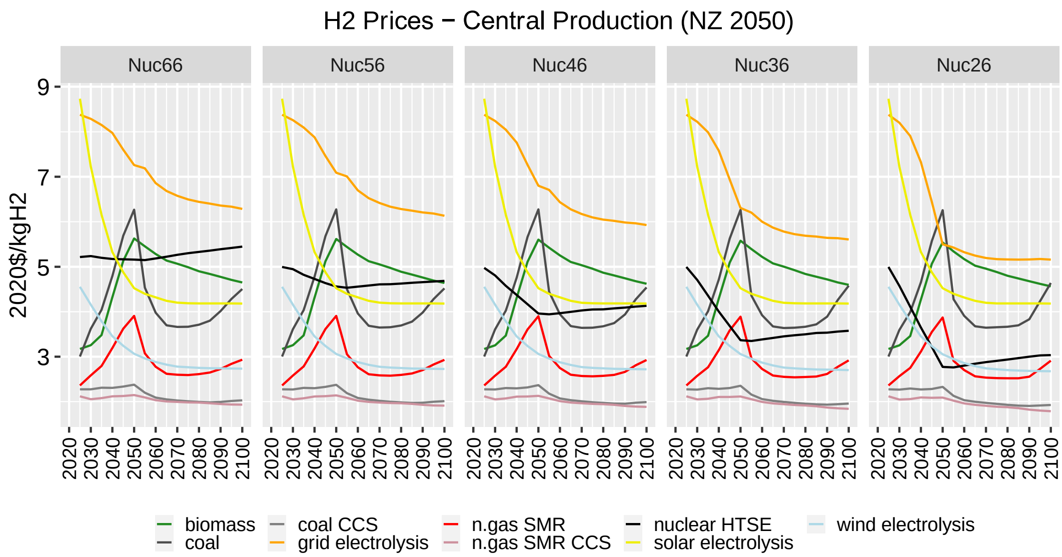


Figure 40. Central station H_2 production cost by fuel type in the Net-Zero 2050 scenario (2020 $/kgH_2$).

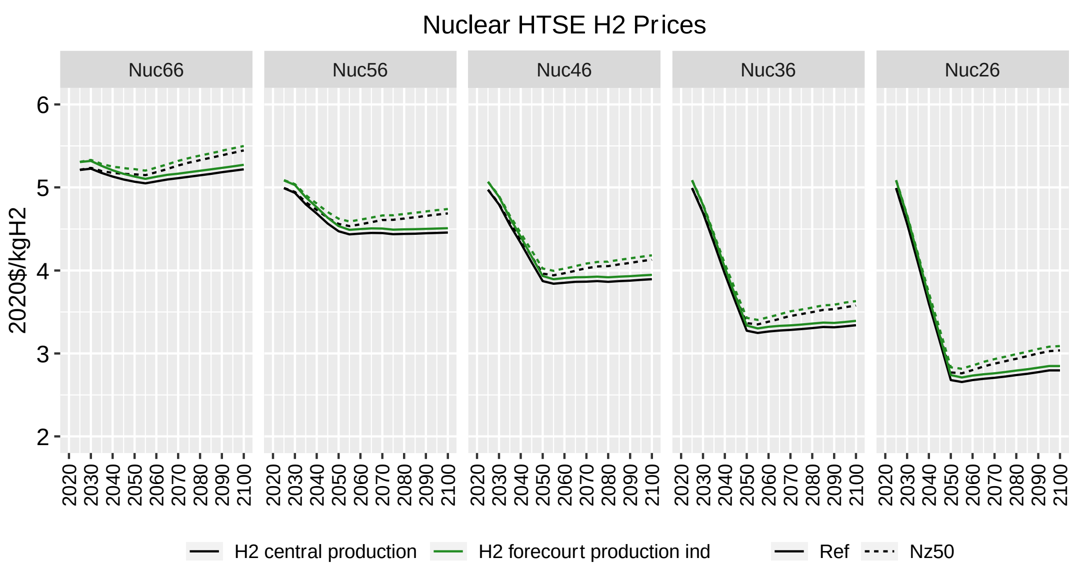


Figure 41. Nuclear HTSE H2 production cost for central station and forecourt production in the Net-Zero 2050 scenario (2020 $/kgH2).

Ultimately, the H_2 price at the end-use is what matters for its use. The relative competitiveness of nuclear H_2 improves for forecourt production and relative to centrally produced H_2 with added delivery costs. H_2 costs by alternative production and delivery methods for wholesale dispensing and industrial applications in the Net-Zero scenario are shown in Figures 42 and 43.

Pipeline delivery of H_2 adds approximately 3 $/kgH_2$ and truck delivery of H_2 adds 4 to 5 $/kgH_2$ to the cost of centrally produced H_2. For wholesale H_2 dispensing, an additional 2 $/kgH_2$ is added for compression and storage. As shown in Figure 42, pipeline and truck delivered H_2 have the lowest cost when nuclear capital costs are high. However, when nuclear captial costs fall to 4600 \$/kWe or below, forecourt produced nuclear H_2 becomes the lowest cost H_2 source for wholesale dispensing. In Nuc26, the nuclear H_2 cost for wholesale dispensing is as low as 5 \$/kgH_2 with compression and storage costs included and is the cheapest source of H_2.

The competitiveness of nuclear H_2 for industrial applications are similar to that for wholesale dispensing. Delived H_2 cost for industries falls from 4 \$/kgH_2 in the near-term to 3.5 \$/kgH_2 by 2100. Nuclear H_2 costs fall to 3.5 \$/kgH_2 or less when the reactor capital cost is 3600 \$/kWe or below. At 2600 \$/kWe, nuclear H_2 has the lowest cost for industrial applications (see Figure 43).

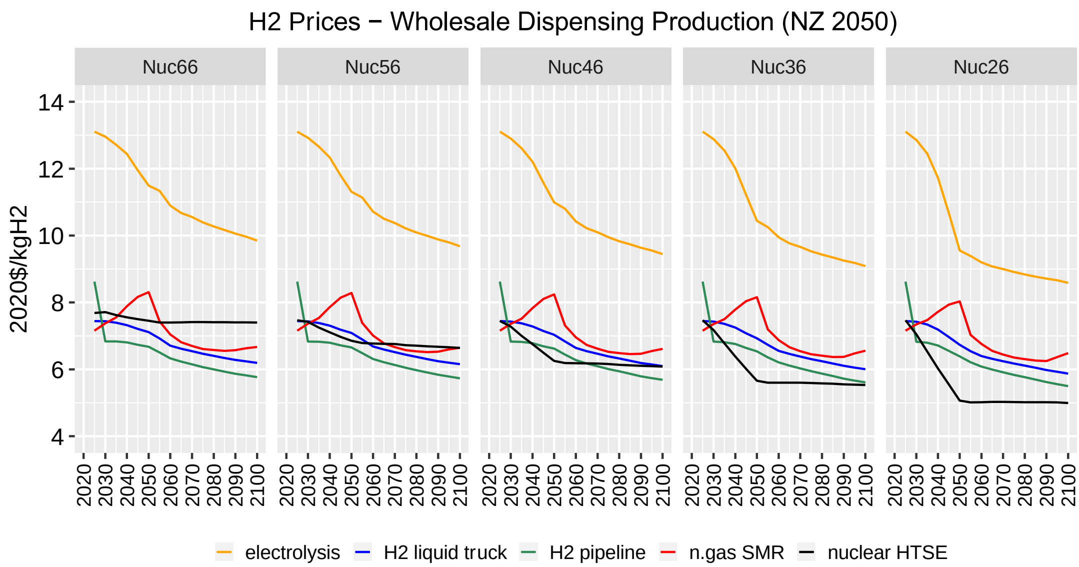


Figure 42. Wholesale dispensing H_2 costs (includes compression and storage costs) in the Net-Zero 2050 scenario (2020 \$/kgH_2).

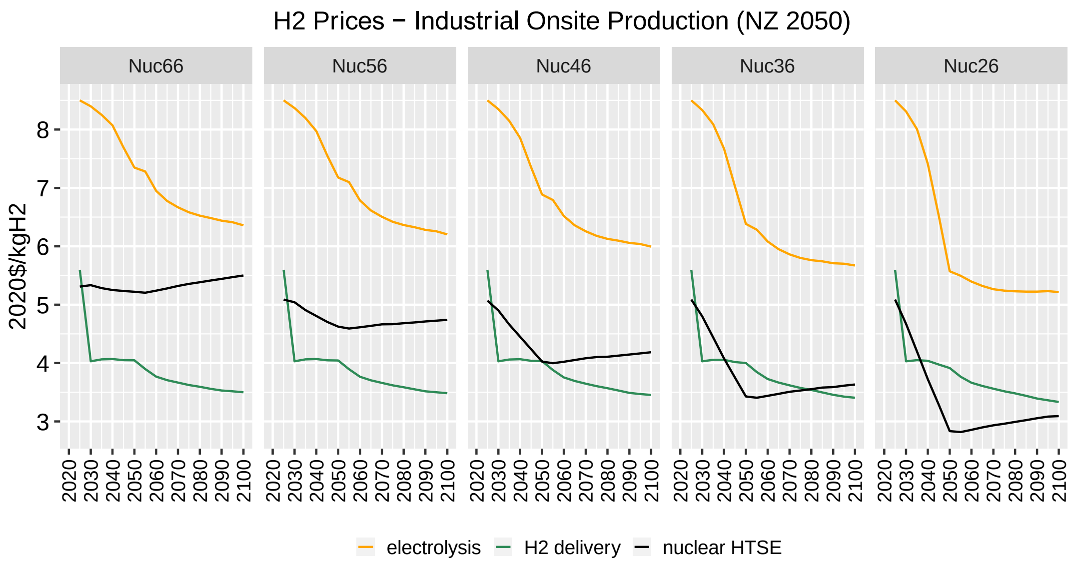


Figure 43. On-site H_2 costs for industrial applications in the Net-Zero 2050 scenario (2020 $/kg$H_2$).

4.3.4 Nuclear Power Capacity for H_2 Production and Electricity Generation in the Net-Zero 2050 Scenario

Multiple carbon-free and low-carbon technologies contribute to the total production of H_2 for all end-use applications. Figure 44 shows that fossil CCS, wind and solar, and nuclear all contribute to the production of H_2. The total production of H_2 from all nuclear facilities, central and distributed, are 4 to 14 million tons in 2050 and 11 to 33 million tons in 2100 and is highly dependent on the nuclear capital cost.

Of the total, nuclear H_2 from combined central and distributed production comprise appoximately 15% to 50% share dependent on nuclear capital cost. The nuclear H_2 shares of the total is displayed in Figure 45. The nuclear H_2 production and shares in the Net-Zero scenario translate to nuclear power capacities in the range of 19 to 63 GWe in 2050 and 50 to 152 GWe in 2100 for the Nuc66 and Nuc26 cases, repectively, as shown in the right panel of Figure 45.

In the Net-Zero scenario, nearly all of the H_2 production is decarbonized but some level of natural gas SMR without CCS remains competitive, and some residual emissions from CCS operations exist. Small amounts of CO_2 emissions from H_2 production are compensated for by net-negative emissions from the electric power sector and the use of biomass energy with CCS (BECCS). Sectoral emissions are further discussed below.

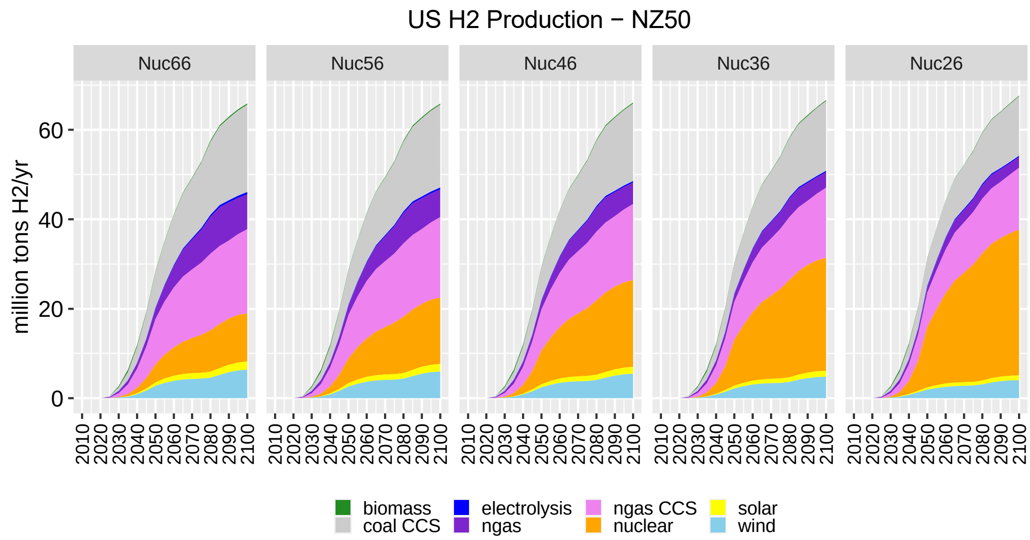


Figure 44. H_2 production by fuel type for alternative nuclear capital costs and Net-Zero 2050 scenario (million tons of H_2/yr).

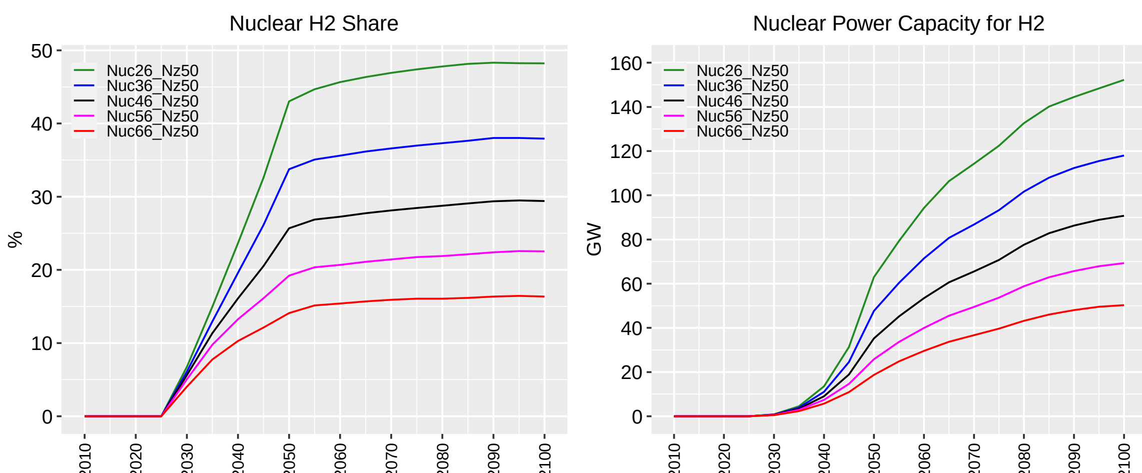


Figure 45. Nuclear share of total H_2 production and corresponding nuclear power capacity for H_2 production in the Net-Zero 2050 scenario for alternative nuclear capital costs cases.

The net-zero emisson goal induces greater electrification of the energy system and a substantial increase in the demand for electricity relative to the Reference scenario without carbon mitigation efforts. Figure 46 shows that the total electricity demand exceeds 10,000 TWh/yr by the end of the century in the Net-Zero 2050 scenario. This represents about a 50% increase in electricity demand relative to the Reference scenario electricity demand of 7,000 TWh/yr by 2100. Moreover, nuclear power plant capital cost assumptions have a noticeable impact on the total demand for electricity by affecting overall electricity prices. It is important to highlight the changes in total electricity demand as they affect the magnitude of the individual technology contributions and implications for carbon-free and low-carbon technology shares.

The magnitude of the carbon taxes in the net-zero scenario induces the complete decabonization of electricity production and all available carbon-free or low-carbon technology options contribute to power generation. The compositions of power generation by fuel type for Net-Zero and Reference scenarios are compared in Figure 47.

By 2050, the share of wind and solar combined is 35 to 40%, fossil CCS (oil, gas and coal) is 14 to 20%, BECCS is 10 to 13%, and nuclear is 17 to 36% in the Net-Zero scenario, where the range in shares is from the Nuc66 and Nuc26 cases, respectively. The composition of electricity generation varies with the nuclear cost, where low cost nuclear raise the nuclear contribution at the expense of all other carbon-free technology options. Consequently, as nuclear shares rise, all other carbon-free technology shares decline.

By 2100, the share of wind and solar combined is 24 to 40%, fossil CCS is 10 to 25%, BECCS is 5 to 10%, and nuclear is 17 to 54% for the two nuclear cost extremes. Nuclear power becomes the cheapest source of firm carbon-free electricity generation as capital costs decline and carbon penalties rise. At capital costs below 4600 $/kWe, nuclear is the most dominant source of electricity generation in the Net-Zero scneario. We note that while BECCS is a smaller share of generation, it provides important net-negative emission allowances that compensate for difficult-to-remove emissions elsewhere (see section 4.3.5).

The specific nuclear power capacities and shares for the alternative nuclear sensitivity cases in the Net-Zero scenario are shown in Figure 48. In 2050, nuclear capacities for electricity are 179, 207, 244, 302, and 394 GW by 2050 for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. The corresponding nuclear electricity shares are 18, 20, 23, 28, and 35% for the same cases. By 2100, nuclear capacities have increased to 222, 305, 409, 557, and 761 GW, with shares of 17, 23, 31, 41, and 54% for the Nuc66, Nuc56, Nuc46, Nuc36 and Nuc26 cases, respectively.

Nuclear cost reductions have a significant and disproportionate impact on the composition of power generation over the long-term. By 2100, the nuclear share of electricity is 54% in the lowest nuclear cost case as compared to about 35% at most in 2050. The longevity of nuclear power technologies has long-term stabilizing benefits for the electricity system. The sustained incremental investments in nuclear power contributes to the accumulation of total power capacity and high nuclear generation shares by the end of 21st century. Other carbon-free technologies with shorter lifetimes may have higher levels of incremental investments, but their more frequent capital stock turnover constrain the growth of their market shares.

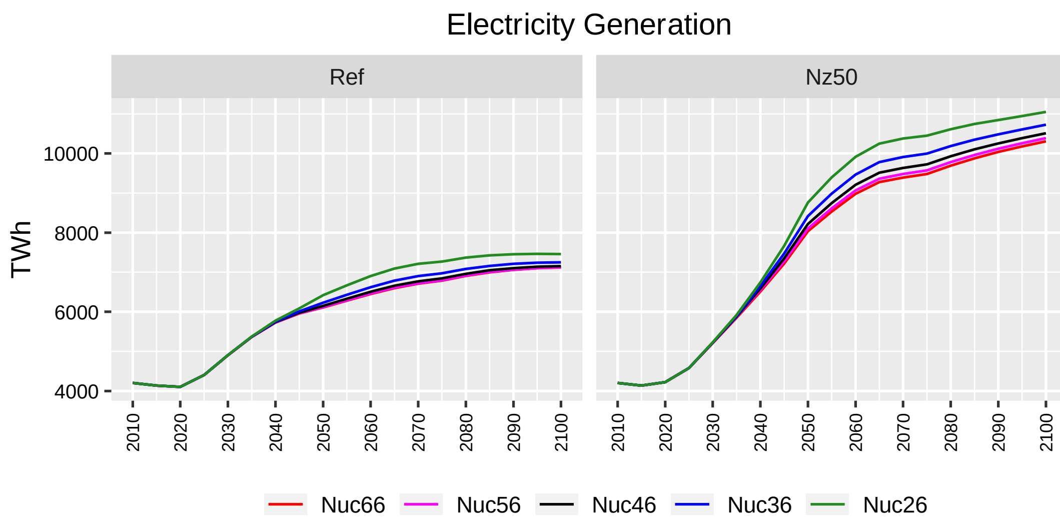


Figure 46. Total US electricity demand in the Reference and Net-Zero 2050 scenarios (TWh/yr).

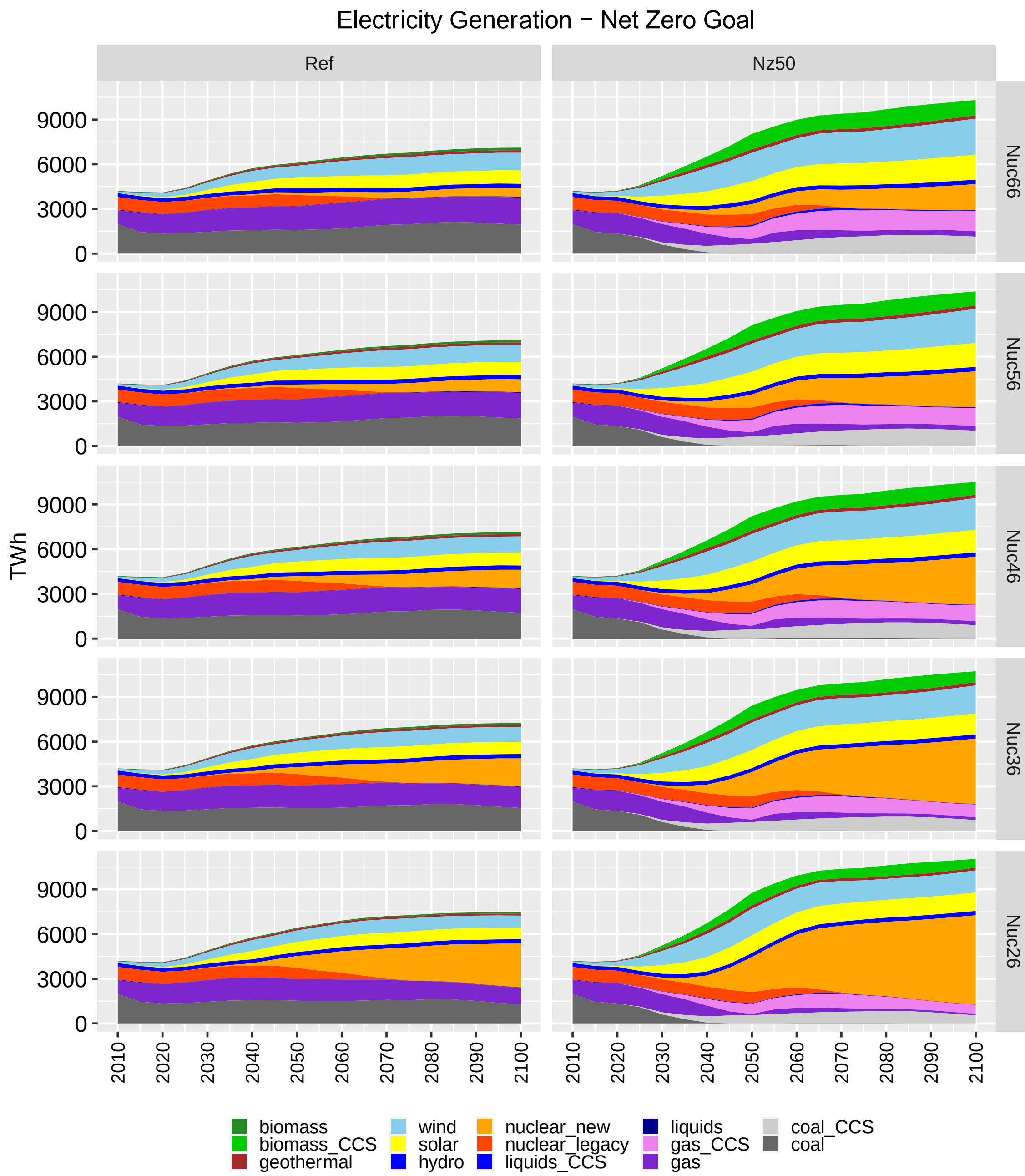


Figure 47. Electricity generation by fuel type for the Reference and Net-Zero 2050 scenario with alternative nuclear capital cost cases (TWh/yr).

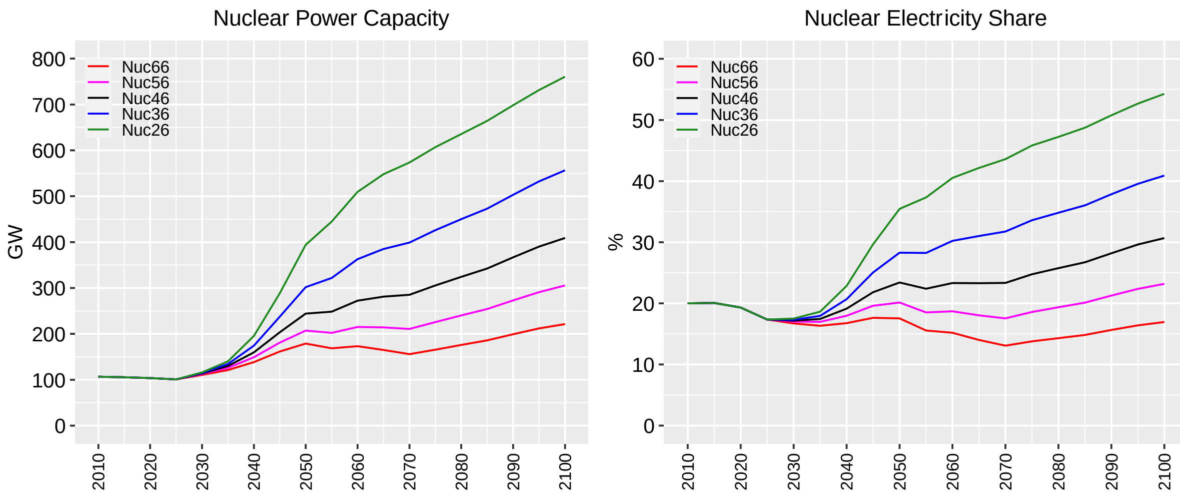


Figure 48. Nuclear power capacity and share of electricity generation in the Net-Zero 2050 scenario.

The combined contribution of nuclear power capacity for H_2 production and electricity generation in the Net-Zero scenario is summarized in Table 6. The total combined nuclear capacity is 197 to 457 GWe in 2050 and 272 to 913 GWe in 2100 for the Nuc66 and Nuc26 cases, respectively. The inclusion of nuclear H_2 production expands the potential market for nuclear energy technologies but the market for H_2 is relatively smaller than the market for electricity. See also Figure 49. Nuclear capacity for H_2 production is less than 20% of the total nuclear capacity for all nuclear cost cases.

Including nuclear H_2 production supplements the total nuclear power capacity as a general observation. However, reducing the nuclear capital cost is equally or more important as exploring potential new markets for the use of nuclear energy. The comparisons of the nuclear capacities in Table 6 reveals that nuclear cost reductions have significant impact on nuclear capacity changes. In 2100, the difference in nuclear capacity for electricity generation alone is 104 GWe between the Nuc56 and Nuc46 cases, whereas the added nuclear capacity for H_2 is 91 GWe. Comparison of the Nuc36 to Nuc26 cases shows a difference of 205 GWe for electric power as compared to 152 GWe of capacity added for H_2 production. However, nuclear capital cost reductions and nuclear H_2 production both combine to increase the total use of nuclear energy and contribute to the goal of net-zero emissions.

Table 6. Nuclear power capacity for electricity and hydrogen production in 2050 and 2100 for the Net-Zero 2050 scenario (GWe).

Total Nuclear Power Capacity (GWe)						
	2050			2100		
Case	Electricity	H_2	Total	Electricity	H_2	Total
Nuc66	179	19	197	222	50	272
Nuc56	207	26	233	305	69	375
Nuc46	244	35	279	409	91	500
Nuc36	302	48	350	556	118	674
Nuc26	394	63	457	761	152	913

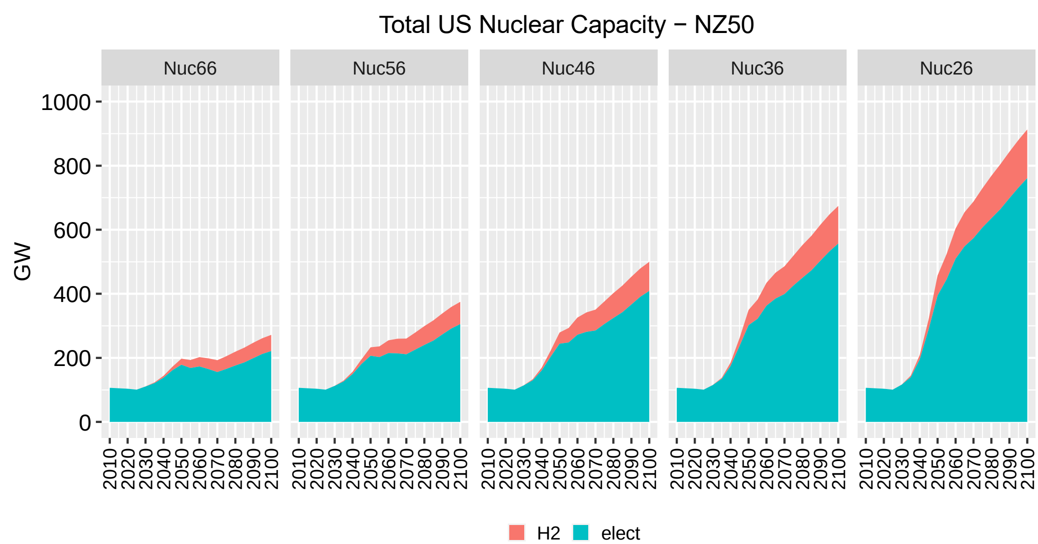


Figure 49. Total nuclear power capacity for electricity and hydrogen production in the Net-Zero 2050 scenario for alternative nuclear capital costs cases (GWe).

4.3.5 CO_2 Emissions by Sector in Net-Zero 2050 Scenario

US CO_2 emissions by sector (building, industry, transport, and electricity) for the net-zero scenario and nuclear cost cases are shown in Figure 50. Economy-wide net-zero emissions are achieved by 2050 according to the policy implementation and imposed emissions constraint. The electricity sector is the first to decarbonize as there are multiple low-cost carbon-free technology options. Other sectors also reduce their emissions but not all carbon emissions from industries and other end-use energy services can be readily and economically eliminated at this time. In this analysis, net-negative emissions from power sector BECCS are more economical for compensating persistent and difficult-to-remove emission sources from buildings, industries, and transport.

Several observations emerge from Figure 50 and the changes in sectoral CO_2 emissions over time in the net-zero scenario. All sectors make steep reductions in emissions in compliance with the rapidly declining emission constraints of the net-zero goal. Total emissions decline linearly until the target years as prescribed by the emission constraints. Upon reaching the 2050 target year, however, emissions from transport, buildings, and industries are not completely removed. Electricity BECCS deployment compensates for the remaining emissions of approximately 0.6 $GtCO_2$/yr and 0.4 $GtCO_2$/yr by 2100 in the Nuc66 and Nuc26 cases, respectively. Hence, greater utilization of nuclear energy also reduces the need for negative emissions in achieving the net-zero emission goal.

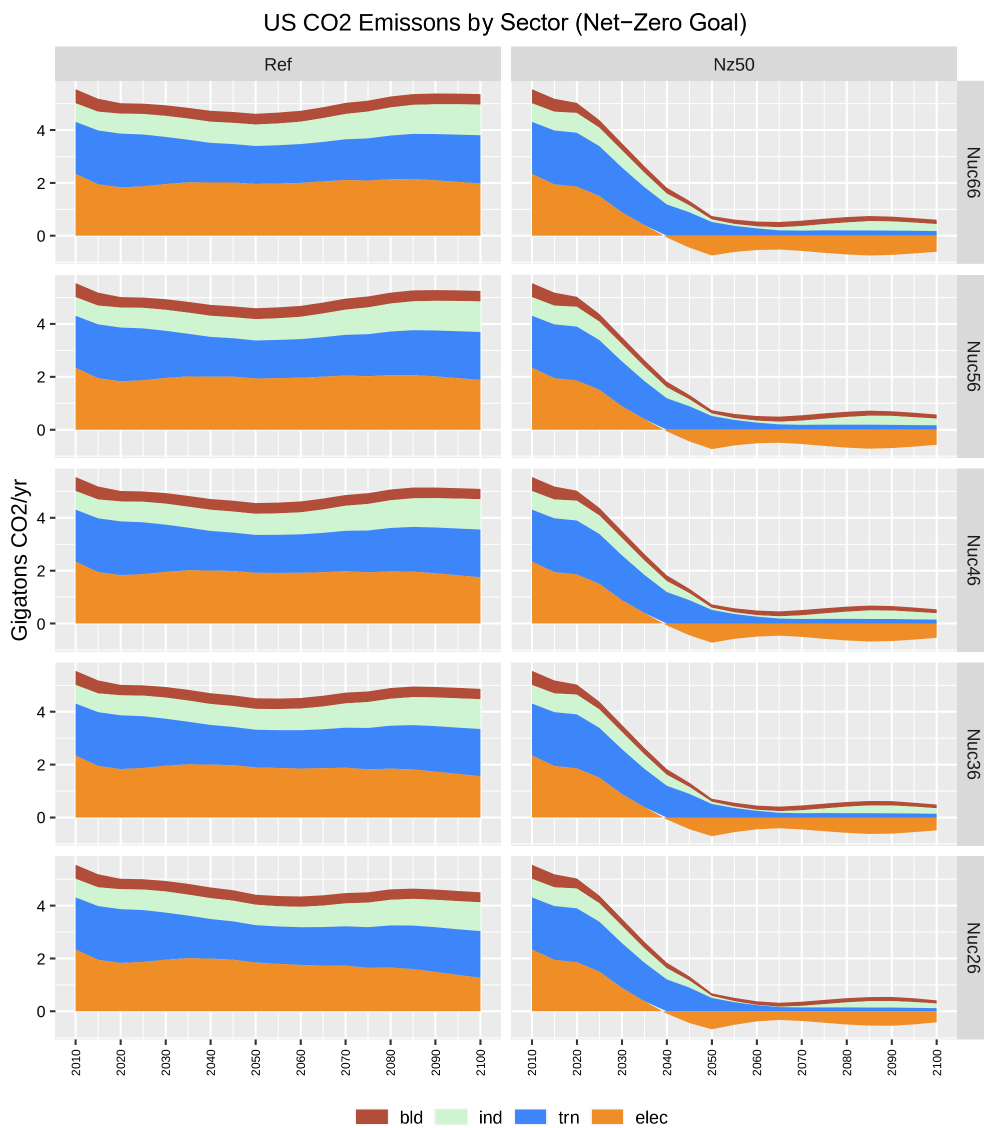


Figure 50. US CO_2 emissions by sector in the Net-Zero 2050 scenario ($GtCO_2$/yr).

5. Conclusions

This analysis explores the future nuclear energy contributions to the US energy system under efforts to mitigate global climate change and US efforts for carbon emissions reduction. We expanded the representation of the hydrogen energy system in the PNNL GCAM model so that nuclear energy applications for H_2 production could be assessed and so that we could quantify the total potential scale and timing of nuclear energy use for both electricity and H_2 production. Nuclear capital costs, competition with other clean energy technologies, and climate policy measures directly affect the degree to which nuclear energy contributes to the broader energy system.

We also assessed the potential of the hydrogen energy system in its contribution to overall carbon emissions reduction. The inclusion of the H_2 energy system in a Reference scenario without any policy efforts for carbon emissions mitigation does not have a significant impact on expanding the use of H_2 as a preferred energy carrier, nor does it have a significant impact on carbon emissions reduction for the US. H_2 does not provide a competitive advantage as an energy carrier relative to existing energy carriers and fossil fuels unless the potential of H_2 as a carbon-free energy carrier is valued.

In the Reference scenario, nuclear power capacity for H_2 production added 3 - 8%, or 4 - 18 GWe, to the total nuclear capacity in 2050 and 12 - 13%, or 11 - 49 GWe, in 2100 in addition to the nuclear capacity for electricity generation. The range is dependent on the nuclear cost case where the nuclear capital cost assumptions were 6600 $/kWe (Nuc66) and 2600 $/kWe (Nuc26) by 2050. The total nuclear capacity for both H_2 and electricity production ranged from 121 - 214 GWe in 2050 and 87 - 424 GWe in 2100 for the Nuc66 and Nuc26 cases, respectively. The majority of the US nuclear H_2 production capacity was for forecourt and on-site applications of H_2 which did not incur additional H_2 delivery costs. The forecourt nuclear capacity is assumed to be based on small modular and micro reactors. Nuclear power capacity for end-use electricity demand remains the dominant market for nuclear energy in the Reference scenario.

Increased nuclear energy penetration from the reduction of nuclear capital costs alone, without carbon policy, resulted in lower carbon emissions. The range of nuclear energy use explored reduced total US CO_2 emissions by 4% in 2050 and 16% in 2100, mostly from the electric power sector. Thus, efforts to reduce the nuclear capital cost can contribute to and support emissions reduction goals.

Multiple interpretations of the IRA were implemented to explore the depth of the IRA provisions and the time duration of the IRA. The IRA clean energy credits for electricity, hydrogen, vehicles, and carbon storage were the focus of the analysis. The IRA-Mid and IRA-High cases, which investigated intermediate and full credit levels, have total US CO_2 emissions reductions of 30% to 32% in 2035 and 36% to 37% in 2050, respectively, relative to historical 2005 emissions. Greater penetration of clean energy technologies for electricity and H_2 production and increased end-use utilization of both electricity and H_2 as energy carriers were responsible for the emissions reduction. The benefit to wind and coal CCS electricity generation were relatively stronger than to nuclear. The IRA moves US emissions towards the net-zero goal but is not able to achieve that goal on its own. The extension of the IRA policy to 2050 in this analysis resulted in nearly 50% reduction in US CO_2 emissions by 2050 relative to 2005 but was still insufficient for achieving net-zero.

The impact of the IRA on nuclear energy use for electricity and H_2 production was modest. An additional 7 – 13 GWe of nuclear power capacity for combined H_2 and electricity production was added by 2035 in the IRA-Mid and IRA-High cases, respectively, as compared to the base capacity of 108 GWe for 2035. The impact to nuclear energy is small due to fact that the current nuclear capital cost is high, all competitive clean energy technologies receive the credit, and the time duration of the IRA is not sufficiently long enough for nuclear technologies to benefit fully. These three factors limit the competitive economic benefit to nuclear energy relative to other clean energy technologies even as substantial ITC are applied to nuclear reactor investments. However, extension of the IRA to 2050 increased the total nuclear capacity, for both H_2 and electricity, by an additional 49 GWe in 2050, relative to the base nuclear capacity of 129 GWe. Nuclear energy benefited from improved economic competitiveness from the underlying assumptions in the reduction of nuclear capital costs over time.

Achieving the net-zero emissions goal for the US will require significantly more stringent limits on carbon emissions activities throughout the economy than that achieved with the IRA. A net-zero emission scenario by 2050 was explored to better understand the scale of energy system changes required for achieving net-zero. In the Net-Zero 2050 scenario of this analysis, carbon penalties were applied to all emissions activities to meet a linearly declining economy-wide CO_2 emissions constraint, where the constraint approaches zero by 2050. This ensures the full participation of all energy producing and use actors in a technology neutral approach.

The carbon penalty for achieving net-zero goals peaked at approximately 300 $/t$CO_2$ in 2050. The carbon penalty falls after 2050 from achieving net-zero and from the accumulation of clean energy capital stock, before rising again towards the end of the century due to stock turnover and increased energy demands. The electricity sector is fully decarbonized by midcentury, while H_2 production has some residual emissions from natural gas use. The primary determinant of the carbon penalty was driven not by the electricity or H_2 sectors but by the difficulty in removing emissions from buildings, industry, and transport sectors. Additionally, alternative nuclear capital cost sensitivities of 6600 to 2600 $/kW had little impact on the carbon penalty levels needed to achieve net-zero emission goals due to the availability of multiple low-cost carbon-free power options. However, nuclear cost differences did have a significant impact on the nuclear energy share and the composition of the energy system.

In the Net-Zero scenario, the demand for H_2 increased three-fold over the Reference scenario. Transport, buildings, and industries all increased H_2 demand but the transport sector had the greatest demand. Nuclear H_2 was more competitive with the carbon penalty and the nuclear capacity for H_2 production increased to 9 - 14%, or 19 - 63 GWe, of total nuclear capacity in 2050 and 17 - 18%, or 50 - 152 GWe, in 2100 for the Nuc66 and Nuc26 cases. The bulk of nuclear H_2 capacity assumes small modular and micro nuclear reactor deployment for the forecourt production of H_2. The nuclear capacity for electricity generation was 179 – 394 GWe in 2050 and 222 – 761 GWe in 2100 for the Nuc66 and Nuc26 cases. The total nuclear capacity was 197 – 457 GWe in 2050 and 272 – 913 GWe in 2100 for the Nuc66 and Nuc26 cases. The expanded nuclear capacity in the net-zero scenario reflects the significant total increase in electricity and H_2 demands, as well as from improvements to nuclear capital costs.

The Net-Zero scenario with alternative nuclear capital cost assumptions and the IRA implementation differ in the way the two approaches affect nuclear energy competition. Carbon penalties in the Net-Zero scenario has the result of separating carbon-free technologies from carbon-emitting, such that all carbon-free technologies are equally valued according to their production costs. Amongst the carbon-free and low-carbon technologies, the nuclear capital cost sensitivity cases isolate the impact of improved competitiveness of nuclear technologies relative to other clean technologies. The IRA, on the other hand, was more difficult to systematically investigate the impact on nuclear energy technologies due the multiple and alternative levels of clean credit provisions on a variety of energy carriers and end-uses, and the emphasis on technology choice rather than emissions reduction. Nevertheless, greater utilization of nuclear energy led to greater carbon emissions reduction under all scenarios investigated. Moreover, nuclear cost sensitivity cases show clearly that reductions in the nuclear capital cost have significant and disproportionate impact on greater nuclear energy use for benefitting long-term US emission reduction goals.

6. Discussion

H_2 storage and use as a strategy for supporting the electricity grid and for generating backup electricity was not investigated in this analysis. There is motivation for utilizing curtailed wind and solar electricity for H_2 production as a potential competitive storage option to batteries since the curtailed electricity is available at very little to no cost. Also, the limits to batteries for long-duration energy storage motivate alternative energy storage options possibly using H_2. Similarly, there is interest in the application of potentially unused nuclear electricity from existing commercial plants that may provide added market value from the production and sale of H_2 from low-cost nuclear electricity. Because there are multiple supply and demand responses for addressing daily and seasonal electricity load issues arising from variable renewable energy penetration, a more detailed, comprehensive, and separate treatment of electricity system energy storage issues is needed and was not within the scope of this analysis.

Small-scale distributed nuclear applications for H_2 production were economically competitive in this analysis, particularly as nuclear capital costs declined and carbon mitigation efforts increased. The distributed and self-contained nature of small-scale nuclear H_2 production is unincumbered by additional costs, safety, and complexity of the H_2 delivery infrastructure that is necessary to move centrally produced H_2 sources to demand locations. Greater clarification of H_2 demand capacity, for example by daily H_2 consumption, from alternative end-use applications is desirable to better match the nuclear reactor type and size with the H_2 production facility to refine the H_2 cost from nuclear energy.

While the scale of H_2 energy system was relatively small in this analysis, it provides a pathway for emissions reduction from those sectors that cannot be readily electrified or utilize carbon-neutral fuels. For this reason, Wolfram et. al. concludes that deploying H_2 can contribute to significant climate mitigation cost savings relative to an energy system without H_2 (Wolfram, 2022). Thus, the contribution of H_2 may be an important complement for achieving the net-zero emission goal and further investigation of the cost impact is recommended.

There is increasing concern that H_2 leaked to the atmosphere has indirect influences on the climate that cannot be ignored. Although H_2 does not directly act like a GHG, additional human contribution of H_2 to the atmosphere competes with the naturally occurring H_2 budgets and its interaction with the Earth and atmospheric systems (Derwent R, 2006). Future analysis of H_2 use in the energy system may require more careful consideration of leakage rates and their potential negative impacts to climate change.

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