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National Association of Regulatory Utility Commissioners

Nuclear Energy as a Keystone Clean Energy Resource

The Potential Role of Nuclear Energy to Advance the Decarbonization of the U.S. Electric Grid and Beyond

Prepared by

ENERGY VENTURES ANALYSIS

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I. Executive Summary

Since the first commercial nuclear reactors started operating in December 1957, nuclear energy has been a keystone clean energy source in the U.S. electricity sector. In 2021, nuclear energy accounted for approximately 20 percent of total U.S. electric generation and almost 50 percent of its carbon-free electricity. As of June 2022, 92 nuclear power reactors totaling roughly 97,400 MW operate in 28 states.

Over the decades of operation, nuclear energy has proven to be one of the lowest-cost and most reliable energy resources integrated into the U.S. electric grid. According to the North American Electric Reliability Corporation (NERC), nuclear reactors have the lowest forced outage rates among major fuel and technology types, making them one of the most reliable sources of electricity in the country. Additionally, due to their low cost of fuel, nuclear power plants are also one of the cheapest non-renewable generating resources currently operating in the U.S., providing steady around-the-clock (baseload) electricity to countless customers across the country.

Besides providing carbon-free, reliable power to countless customers across the U.S., nuclear power plants are also a major employer and taxpayer in the regions in which they operate. Jobs at nuclear power plants are often unionized and among the highest paying jobs in the region. Nuclear power plants also bring immense amounts of tax revenues to communities, providing critical funding to local schools, hospitals, and first responders. Lastly, nuclear power plants also require significantly less land than other carbon-free electric generating resources such as wind or solar. New advanced nuclear reactor designs have the potential to further reduce land use requirements and associated safety zones, allowing deployment of such small reactor designs in more and more places.

Lastly, nuclear energy can also help shield the U.S. from the impacts of global events on domestic energy markets and advance the country to true energy independence by (re)investing in the domestic nuclear fuel supply chain. Recent global events such as Russia's invasion of neighboring Ukraine and the corresponding rise in global and domestic prices for energy commodities such as oil, natural gas, and coal, have shown the interdependency of the U.S. energy sector and the global market. Because the U.S. possesses a significant amount of uranium reserves within its border, increasing the use of nuclear power for electricity generation (among other potential uses such as carbon-free hydrogen production or combined heat and power applications, discussed in further detail later in this paper) can significantly reduce exposure to global geopolitical events, while reducing CO_2 emissions in the process.

However, during the ongoing energy transition that started with the Shale Gas Revolution of the late 2000s and continued with significant financial support of renewable energy and the resulting fall in construction and operating costs, nuclear energy has come under immense financial pressure. Since 2012, when natural gas prices fell significantly in response to increased domestic production, electric wholesale power prices, in turn, fell as well, eroding the revenue nuclear power plants earn for electricity. Due primarily to these economic factors, 13 nuclear reactors totaling almost 11,000 MW have retired since 2013, whereas another two nuclear reactors are currently announced to retire within the next three years.

Since the first wave of nuclear retirements was announced in 2016, states have started to recognize the value of the carbon-free electricity nuclear power plants provide and the complementary role these plants can play to the intermittent renewable resources of wind and solar. Currently, 13 states have legally enforceable Clean Energy Standards (CES), which require a large amount of their electricity to come from carbon-free electric generating resources, including nuclear. Furthermore, four states include direct financial support through power purchase agreements or zero-emission credits (ZECs) to nuclear power plants, helping to offset some of the financial distress low wholesale power prices have brought to nuclear power plant owners.

Policies and incentives at the federal level, in tandem with state regulations, can help support existing nuclear reactors and advance new reactor buildout. The Infrastructure Investment and Jobs Act (also known as the Bipartisan Infrastructure Law or BIL), passed in 2021, established a $6 billion Civil Nuclear Credit Program (CNC), to prevent the premature closure of existing U.S. nuclear reactors due to economic stress. The BIL also provided the majority of the federal government's cost share ($2.477 billion) for the demonstration of two advanced reactor technologies through the Advanced Reactor Demonstration Program. Additionally, the August 2022 Inflation Reduction Act (IRA) included a Production Tax Credit (PTC) for electricity produced by existing nuclear plants and a technology-neutral PTC and Investment Tax Credit (ITC) for clean electricity technologies, including nuclear.

Some of the drawbacks of nuclear energy that have limited its deployment in recent decades are high capital costs, construction delays, the significant amount of water needed to cool traditional nuclear reactor designs (boiling water/pressurized water reactors), perceived risk by the public of a possible accident and release of radioactive material, and limited operating flexibility due to current NRC operating license requirements. However, many of the advanced nuclear reactor designs currently in development aim to address some or all of these challenges. Many small modular reactors (SMRs) under development are designed to be plug-and-play and scalable to fit the needs of the owner, significantly reducing the capital costs and construction lead times for these projects. Additionally, locating new nuclear power plants at brownfield sites, e.g., sites of recently retired power plants, can also significantly reduce the capital costs and lead times associated with new projects, as assets like transmission lines and cooling systems may be reused. Many advanced nuclear reactor designs also include passive safety mechanisms that significantly reduce the potential risk of a nuclear accident and make these reactors safe to deploy closer to population and industry centers. Virtually all new reactor designs include enhanced operating flexibility procedures, allowing nuclear power plants to work in tandem and perfectly complement intermittent resources such as wind and solar.

To take advantage of nuclear energy's benefits to a decarbonized economy, several federal, state, and local agencies are collaborating to support the retention of existing deployment of new nuclear power plants. Changing the federal PTC and ITC to be technology-neutral to allow nuclear energy to qualify for these credits can significantly reduce the capital costs of new projects. Updating and streamlining the regulatory approval process by the U.S. Nuclear Regulatory Commission (NRC) beyond the 2018 passed Nuclear Energy Innovation and Modernization Act (NEIMA), without compromising safety, can reduce lead times and costs associated with the deployment of new nuclear energy plants. Adapting existing and future Renewable Portfolio Standards (RPS) to include nuclear energy as a carbon-free resource could bring additional financial support to the industry and provide additional financial and regulatory assurances (safety and operating parameters set by the NRC and financial parameters set by state regulators) to future nuclear energy projects. Additionally, revisiting existing state laws to allow for future nuclear energy deployment would allow for more potential sites to become available. Last but not least, public utility commissions (PUCs) across the country may want to ensure that electric utilities under their jurisdiction adequately explore the inclusion of nuclear energy in all future long-term resource plans and investigate other opportunities to provide future nuclear projects with financial certainty while also minimizing the financial exposure to ratepayers.

In summary, over the last 50 years, nuclear energy has proven to be a reliable and low-cost electricity generating resource. To achieve ambitious decarbonization goals, retaining the existing and expanding the new nuclear energy resource base will be of critical importance. However, some roadblocks hindering a faster and more significant deployment of new nuclear energy resources persist. Reducing or removing these hurdles is the responsibility of many agencies and legislatures on the federal, state, and local levels. Going forward, establishing a more favorable financial and regulatory environment will allow nuclear energy to remain a keystone clean energy resource in a decarbonized U.S. electric grid.

Introduction

Over the last decade, the U.S. electric grid has gone through significant changes and is accelerating towards a carbon-free future. Stricter environmental regulations have forced many coal plants across the country to close; sustained lower natural gas prices in the wake of the Shale Gas Revolution and rapidly falling capital costs for renewable energy sources such as onshore wind and solar have resulted in a dramatic electric generation shift from higher CO_2 emitting coal to lower CO_2 emitting natural gas and zero-emitting renewable energy generation. As a result, U.S. power sector CO_2 emissions have dropped by about one-third from 2005 to 2021. Throughout this period, nuclear energy has been a backbone of this transition.

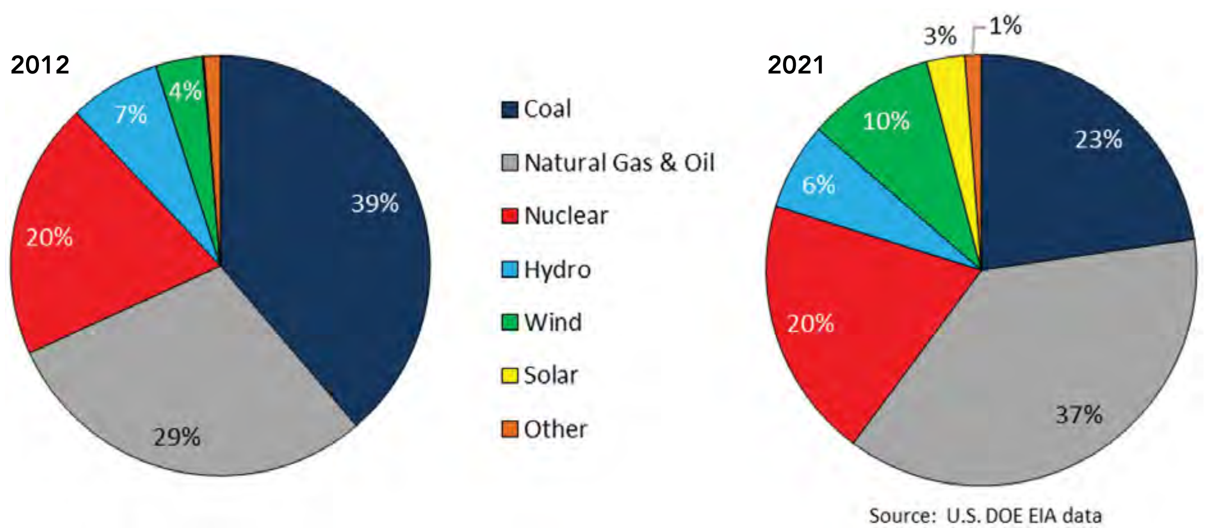
In its most recent report, the Intergovernmental Panel on Climate Change (IPCC)[1] assessed that the world's adaptation to climate change is happening too slowly. Moreover, about 3.5 billion people live in areas highly vulnerable to climate change. Although still achievable, the goal of limiting global temperature rise below 1.5 degrees Celsius from pre-industrial levels requires an accelerated transition away from fossil fuels and toward zero carbon-emitting resources such as wind, solar, geothermal, hydro, and nuclear energy.

Furthermore, recent global events like Russia's invasion of Ukraine have shown that U.S. energy is vulnerable to events abroad. As a result of numerous sanctions imposed by Western countries on Russia, like the ban on Russian oil imports, fossil fuel prices, including oil, natural gas, and coal, have skyrocketed globally. Consequently, fuel and electric power prices in the U.S. have seen a significant increase, highlighting the interdependency of the U.S. fossil fuel and electric power industries with world energy markets and geopolitics. Transitioning away from fossil fuels and embracing zero-carbon resources such as nuclear energy helps combat climate change and move toward energy independence.

To date, at least 13 states have passed legislation or state regulations requiring their electric power sector to be 100% carbon-free before mid-century. In states without Renewable Portfolio Standard (RPS) or Clean Energy Standard (CES) requirements, many utilities have established their own voluntary net-zero carbon targets by no later than 2050, including some of the largest electric utilities in the world, like Southern Company, Duke Energy, and NextEra Energy. To achieve these goals, many utilities are looking to nuclear energy to provide valuable carbon-free electric generation in the future.

As shown in **Exhibit 1**, carbon-free electric generating resources (nuclear, wind, solar, hydro, and other) accounted for 32 percent of the U.S. electric generation mix in 2012. Nuclear energy accounted for 20 percent

Exhibit 1: 2012 & 2021 U.S. Electric Generation Mix by Fuel Type



1 IPCC Sixth Assessment Report, https://www.ipcc.ch/report/ar6/wg2/.

of the total U.S. electric generation mix and almost one-half of electric generation from carbon-free resources. By 2021, zero-carbon resources accounted for 40 percent of the U.S. generation mix, with wind and solar accounting for the most significant increases since 2012. Nuclear energy continues to provide 20 percent of the total U.S. electric generation mix and about half of the electric generation from carbon-free resources. To achieve the ambitious decarbonization goals set by companies and states across the country, retaining and possibly expanding the share of nuclear energy in the U.S. generation mix will be immensely important.

Nuclear energy's unique operating characteristics make it an excellent complement to other renewable energy sources such as wind, solar, hydro, and geothermal. Nuclear energy provides steady, reliable electricity year-round with relatively low variable costs and is much less susceptible to extreme weather impacts when compared to other generation sources. The retention of zero-carbon baseload[2] resources, such as nuclear energy, is especially critical as more fossil fuel-based power plants retire. New and emerging nuclear technologies also focus on more flexibility and easier siting in the future. However, more education on the advantages of nuclear energy and its unique role as a clean energy keystone resource is needed to allow stakeholders such as public utility commissioners, utility executives, and others to make informed decisions. This report, commissioned by the National Association of Regulatory Utility Commissioners (NARUC) with support from the U.S. Department of Energy (DOE) Office of Nuclear Energy, aims to do just that.

In March 2021, NARUC launched the five-year Nuclear Energy Partnership with support from the DOE Office of Nuclear Energy. The purpose of the partnership is to educate state public utility commissions on critical issues related to nuclear energy, discuss issues related to the regulation of the existing and anticipated future nuclear fleet, analyze new developments in advanced nuclear technologies, and facilitate the communication of federal resources and state challenges between DOE and NARUC members. This includes considering nuclear energy as a clean energy resource to meet state policy objectives. Although public utility regulators have varying levels of oversight over the generation of nuclear energy, given the diversity of regulatory environments across states, commissions play integral roles in approving cost recovery, granting Certificates of Public Convenience and Necessity for construction of nuclear units, and overseeing ZEC and CES programs for nuclear generation.

This report covers the following topics:

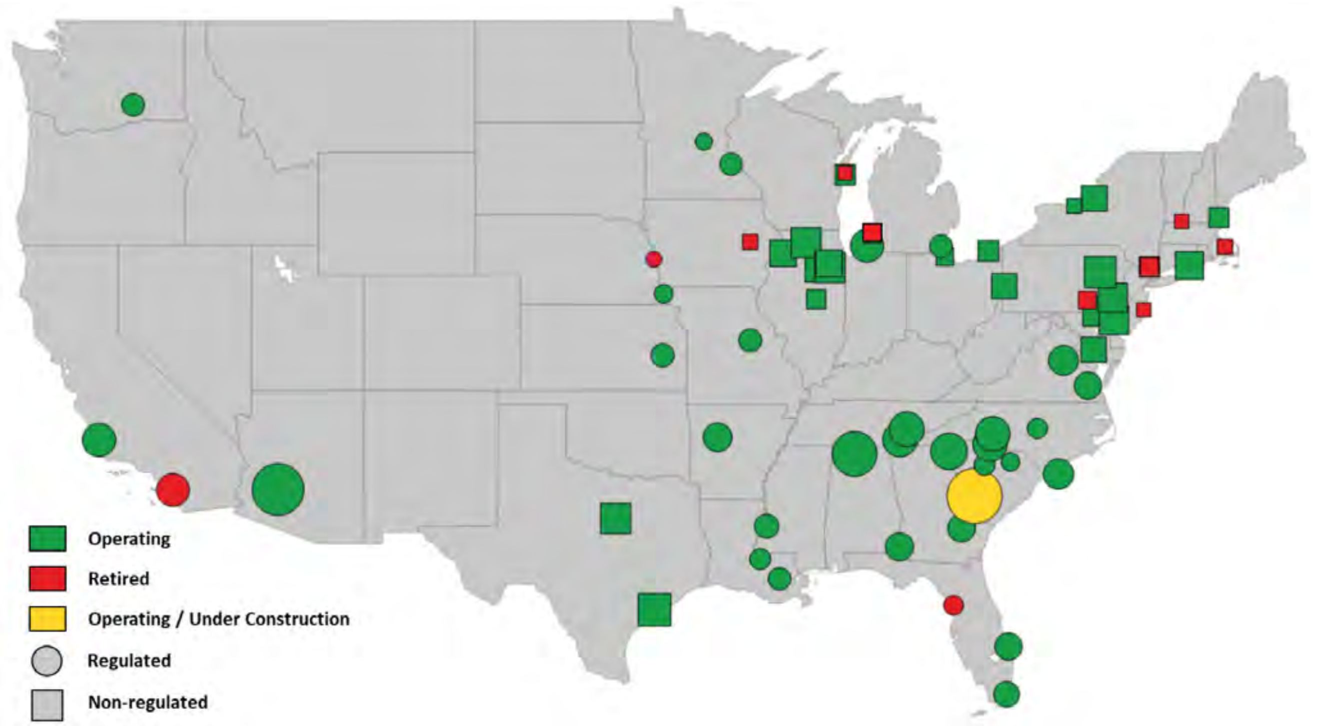
- Overview of the current U.S. nuclear energy fleet and its unique role in the U.S. electric grid
- Current treatment of nuclear energy in current state RPS and CES
- Background on current and emerging nuclear energy technology
- Other possible applications of nuclear energy in a zero-carbon economy
- Current sources of nuclear fuel and management practices of spent nuclear fuel
- Possible states and sites for future nuclear energy plants in the U.S.
- The unique role of PUCs in facilitating the retention and advancement of nuclear energy in their respective states

2 "Baseload" refers to an operating mode where electricity is supplied at a steady rate with limited variability.

III. Overview of the Current U.S. Nuclear Fleet and its Unique Role in the U.S. Electric Grid

Currently, there are 92 commercial nuclear reactors actively operating in the United States, totaling over 97,400 MW of nameplate capacity.[3] **Exhibit 2** shows a map of currently operating nuclear power plants across the country. The nuclear plants in Exhibit 2 are color-coded by operating status, proportionally sized by capacity, and assigned different shapes based on market structure, where "Non-regulated" refers to plant ownership not regulated by PUCs and "Regulated" to plant ownership regulated by PUCs.

Exhibit 2: Map of Nuclear Power Plants Currently Operating, Retired, or Under Construction



As shown in **Exhibit 3**, Constellation Energy, a spin-off from its parent company Exelon focusing on zero-carbon generating resources, is the owner of almost one-quarter of all operating nuclear reactors in the U.S., with Duke Energy, the Tennessee Valley Authority (TVA), Southern Company, and Dominion Energy rounding out the top five. Overall, 22 different majority owners own and operate the roughly 97,400 MW of nuclear generating capacity across the country. The top 10 largest companies account for almost 80 percent of the total capacity.

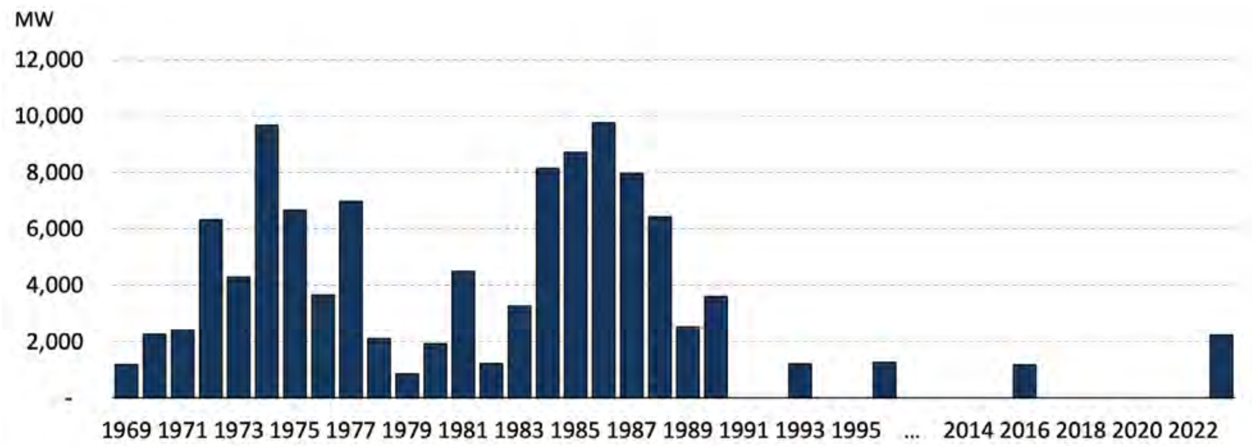
Exhibit 3: Top 10 Owners of Nuclear Capacity

Majority Owner	Regulatory Status	Capacity (MW)
Constellation	Deregulated	22,237
Duke Energy	Regulated	11,240
TVA	Regulated	8,385
Southern Co.	Regulated	5,818
Dominion Energy	Dereg/Reg	5,817
NextEra	Dereg/Reg	5,748
Entergy	Regulated	5,453
APS/SRP/El Paso/SCE/PNM	Regulated	4,209
Energy Harbor	Deregulated	4,084
PSEG	Deregulated	3,510

The vast majority of nuclear power plants were built in the 1970s and 1980s during a time of rapid electricity demand growth and a favorable regulatory environment. **Exhibit 4** shows nuclear generating capacity by online year.

3 Form EIA-860 data https://www.eia.gov/electricity/data/eia860/.

Exhibit 4: Nuclear Generating Capacity by Online Year



Source: EVA's Power Plant Tracking System

Between 1969 and 1990, U.S. electric utilities built more than 104,500 MW of nuclear generating capacity. However, as electricity demand started to slow down and costs for building new nuclear power plants soared substantially, in part as regulatory costs increased following the accident at Three Mile Island in 1979 and the Chernobyl disaster in 1986, the construction of new nuclear reactors came to a virtual standstill. As a result, since 1990, only 3,600 MW of nuclear capacity has come online, with TVA's Watts Bar Unit 2 in 2016 marking the latest addition. Nonetheless, overall U.S. nuclear power capacity in the United States increased by roughly 8,000 MW from 1977 to 2021 from power uprates at existing reactors, which represents the equivalent of 8 new nuclear power plants.[4]

Currently, there are only two nuclear reactors under construction in the United States. Georgia Power, a subsidiary of Southern Company, expects its Vogtle units 3 and 4, totaling more than 2,200 MW of capacity, and located in Eastern Georgia, to come online in Q1 2023 and Q4 2023, respectively, bringing the total generating capacity at the plant to 4,500 MW.[5] Although it is uncertain if the current completion timeline will be met, as significant cost overruns and construction challenges have resulted in years-long delays. In addition, two other nuclear reactors, SCANA Corporation's V.C. Summer units 2 and 3 in South Carolina, have been canceled due to cost overruns, the bankruptcy of the leading owner, and the associated response to the project by state officials and other stakeholders.

Since 2013, almost 11,000 MW of nuclear generating capacity has retired. While the retired nuclear projects at San Onofre in California and Crystal River in Florida retired primarily due to structural issues, the more recent plant closures have cited increased economic pressure due to low energy prices as one of the primary reasons for decisions to close plants before the expiration of operating licenses or not to renew expiring operating licenses. As natural gas prices declined and more renewable energy generation entered the market, wholesale power prices across the country have declined significantly. For example, **Exhibit 5** shows the average total production cost[6] of Constellation's Quad Cities nuclear power plant in Cordova, Illinois, compared to the average wholesale power price at PJM's West Hub,[7] as well as the percentage of the number of hours in a given year where Quad Cities production cost exceeded the local power price.

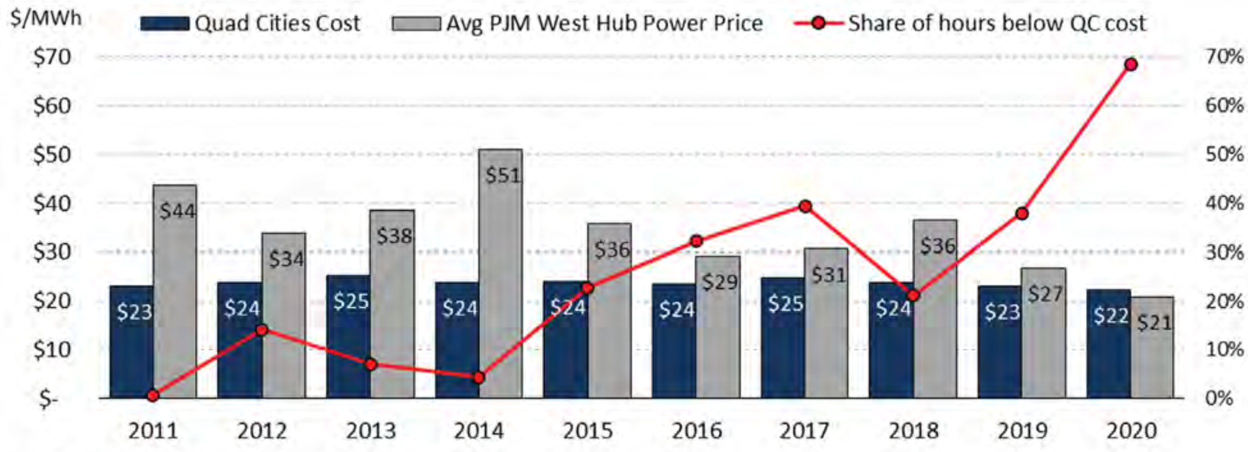
4 Approved Applications For Power Uprates | NRC.gov.

5 Vogtle unit 1 (1,160 MW) came online in May 1987, https://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/approved-applications.html, whereas unit 2 (1,160 MW) came online in May 1989.

6 As reported to the Federal Energy Regulatory Commission (FERC) on Form 1 by Quad Cities' regulated owners.

7 https://www.pjm.com/markets-and-operations/energy.aspx

Exhibit 5: Average Quad Cities Production Cost vs. PJM ATC West Hub Power Price



Source: FERC Form 1 & PJM power price data

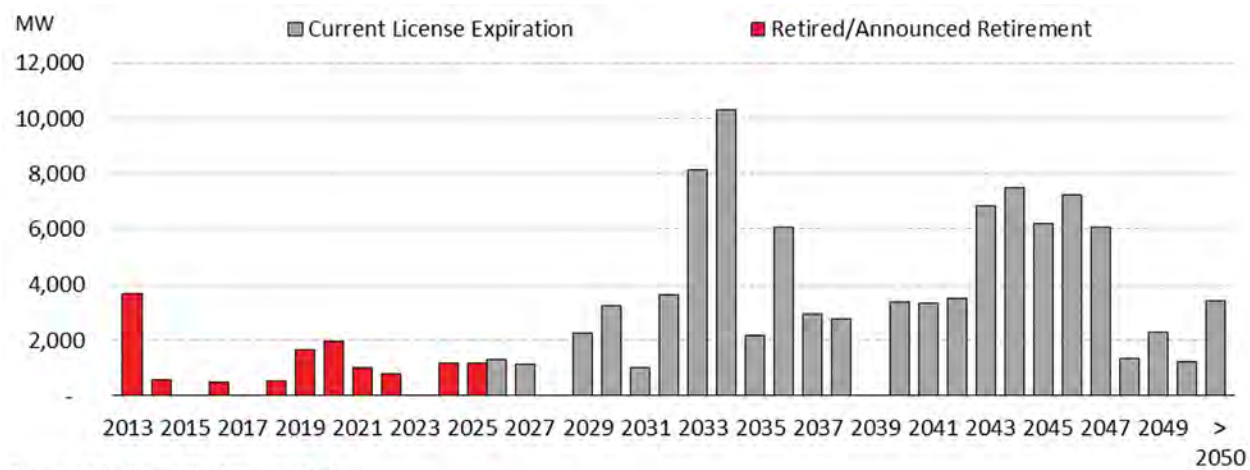
In this example, the share of hours where Quad Cities was uneconomical increased every year since 2014, except for 2018, reaching almost 70 percent in 2020, which also marked the first year when the average PJM West Hub wholesale power price was less than Quad Cities' production cost.

Nuclear power plants in other power markets across the U.S. have faced similar economic pressures. For example, in 2015, Entergy announced the retirement of the Pilgrim nuclear plant in Massachusetts, and Exelon made similar announcements about the Ginna, Fitzpatrick, and Nine Mile Point nuclear plants in New York, citing that the plants are uneconomic to operate under current market conditions. Although the Pilgrim nuclear plant was ultimately retired in June 2019, New York regulators were able to provide financial support to the other three plants via ZECs as part of the state's CES. Since then, other states have followed New York's example with similar subsidies. Most recently, Illinois was able to avoid the pending retirements of its Dresden and Byron nuclear power plants by passing the 2021 Climate and Equitable Jobs Act (CEJA), which provides significant financial subsidies to Illinois' nuclear fleet, including Byron, Dresden, LaSalle and Braidwood nuclear plants. The next section of this report provides more detail on the current state of CES and RPS programs and their treatment of nuclear energy as a qualifying resource.

Since the introduction of CES programs and nuclear energy's inclusion in many of these programs, nuclear retirement announcements have slowed considerably. Currently, only one nuclear plant, PG&E's Diablo Canyon nuclear plant in California in 2024/25, has been announced to retire, after Entergy's Palisades nuclear plant in Michigan retired in May 2022. Entergy cited economic challenges in the MISO power market as the primary reason for retirement, whereas PG&E's Diablo Canyon nuclear plant has faced significant political pressures to close. However, PG&E is now planning to submit an application for funding under the recently enacted Civil Nuclear Credit program, opening the door to possibly retaining the plant past its current retirement date. All other nuclear power plants have received or are in the process of applying for receiving their initial or subsequent license renewals (ILR/SLR).[8] Excluding the plants that are currently applying for their ILR, the next license expiration date is 2029, when the country's oldest nuclear plants are reaching the end of their 20-year ILR (60 years total since the start of operation). **Exhibit 6** shows the capacity of U.S. nuclear power reactors by license expiration year. Additionally, **Appendix 1** includes a full list of all operating, under construction, and retired nuclear power generating units, as well as details on their ownership, location, size, reactor technology, and current operating license information.

8 The initial license renewal (ILR) extends a nuclear reactor's operating license from 40 to 60 years, whereas the subsequent license renewal (SLR) extends the operating license from 60 to 80 years (or an additional 20 years thereafter).

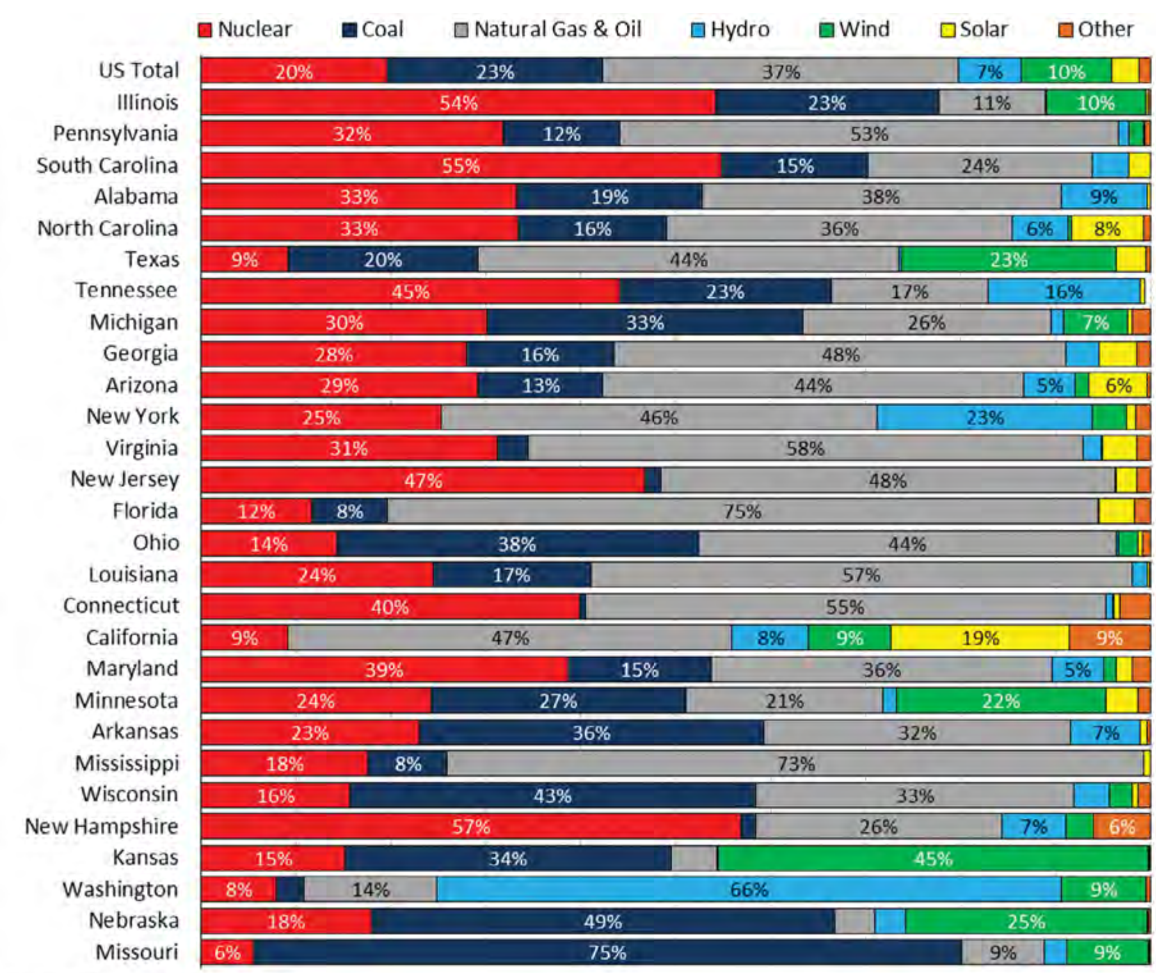
Exhibit 6: Retirement or Current Operating License Expiration



Source: EVA's Power Plant Tracking System

As mentioned in the introduction, nuclear energy accounted for approximately 20 percent of total electricity generation in 2021.[9] However, as shown in **Exhibit 7**, nuclear energy's generation share varies significantly from state to state.

Exhibit 7: 2021 Electric Generation Mix – by State



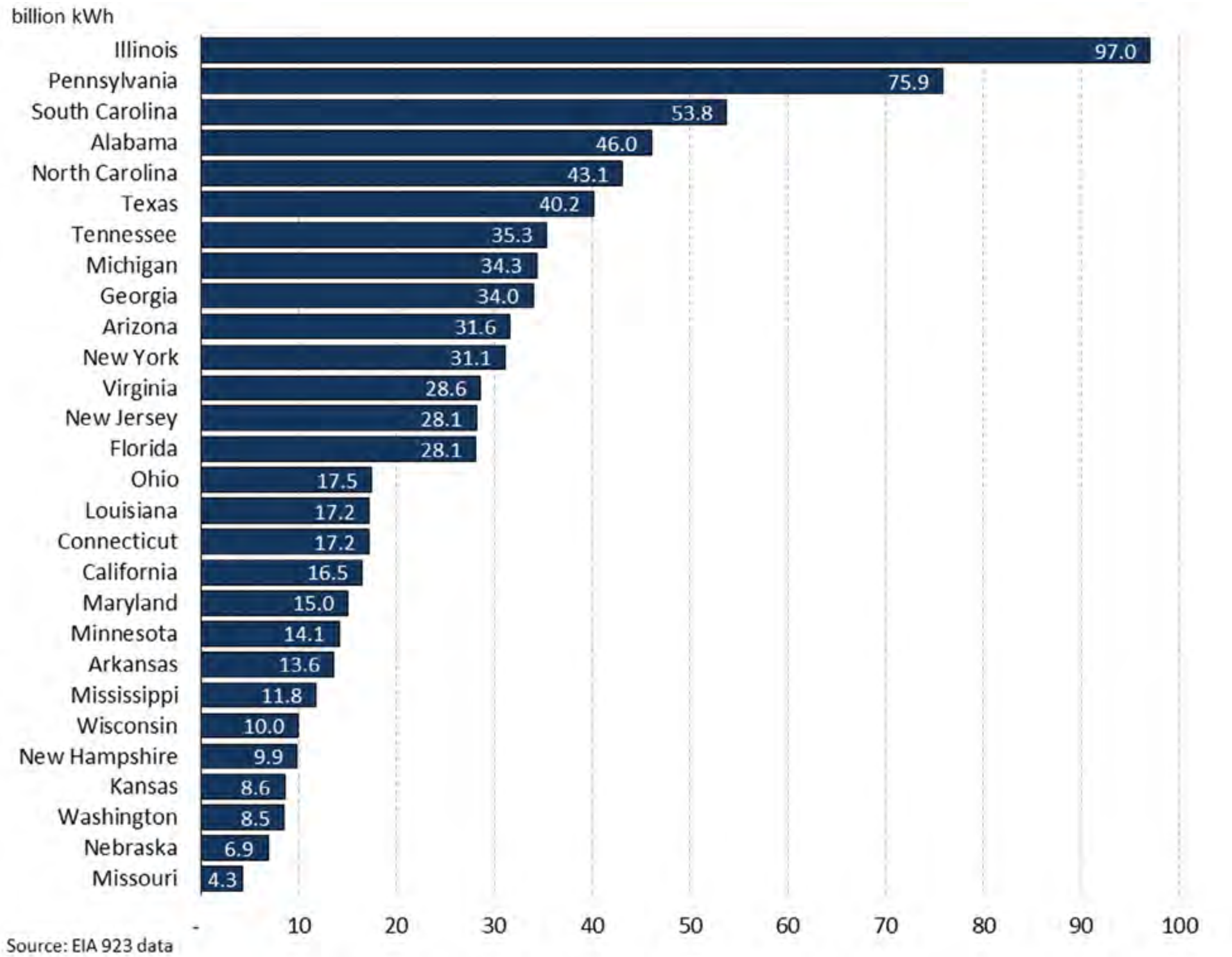
Source: EVA analysis of EIA 923 data

9 Form EIA-923 data.

In 2021, 28 states generated about 778 billion kWh of electricity from nuclear power plants, whereas 22 states and the District of Columbia do not have any in-state nuclear generation. In states with nuclear generation, nuclear's generation share also varies significantly, from 6 percent in Missouri and 8 percent in Washington state to 57 percent in New Hampshire and 55 percent in South Carolina.

As shown in **Exhibit 8**, nuclear generators in Illinois account for more than 12 percent of the total U.S. operating nuclear capacity, generating almost 97 billion kWh in 2021. Overall, Illinois and Pennsylvania, the two states with the largest in-state nuclear generation, accounted for almost one-quarter of the total U.S. nuclear generation in 2021. It is worth noting that all nuclear plants in these two states participate in the PJM power market without guaranteed energy revenues or the ability to recover costs through traditional rate case proceedings. Not coincidentally, both states are also major electricity exporters. In 2021, Pennsylvania's in-state generation exceeded in-state retail sales by 59 percent, whereas in Illinois, the value in 2021 was 24 percent, according to EIA 923 and 861 data.[10]

Exhibit 8: 2021 Nuclear Electric Generation - by State

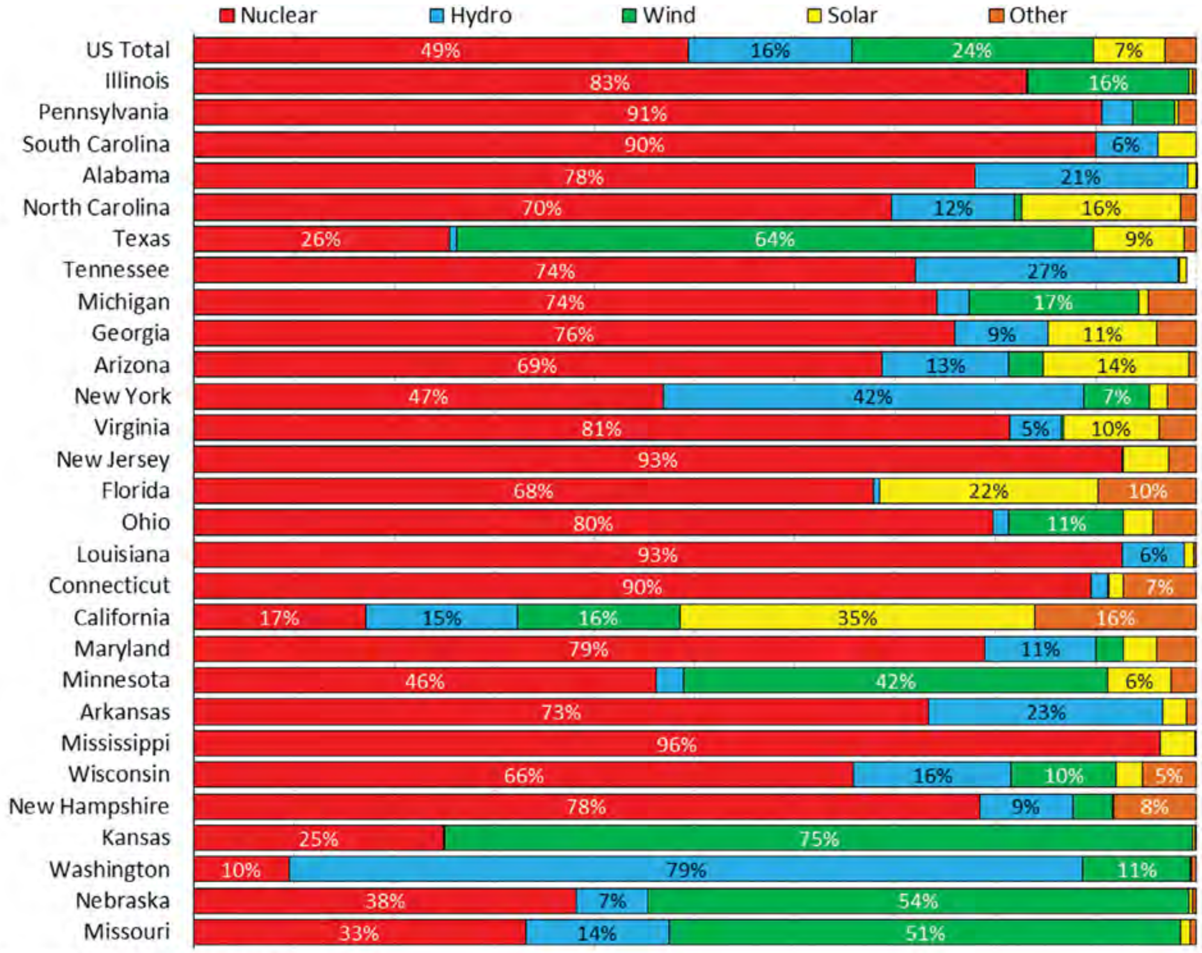


Source: EIA 923 data

More importantly, nuclear energy continues to be the largest carbon-free electric generating resource in the country. In 2021, nuclear accounted for roughly half of the total carbon-free electric generation in the U.S. **Exhibit 9** shows the generation mix of carbon-free resources by state.

10 The percentage includes a 7.5 percent line loss assumption (electricity lost due to the resistance in long-range transmission lines).

Exhibit 9: 2021 Share of Carbon-Free Generation by Fuel Type - by State



Source: EVA analysis of EIA 923 data

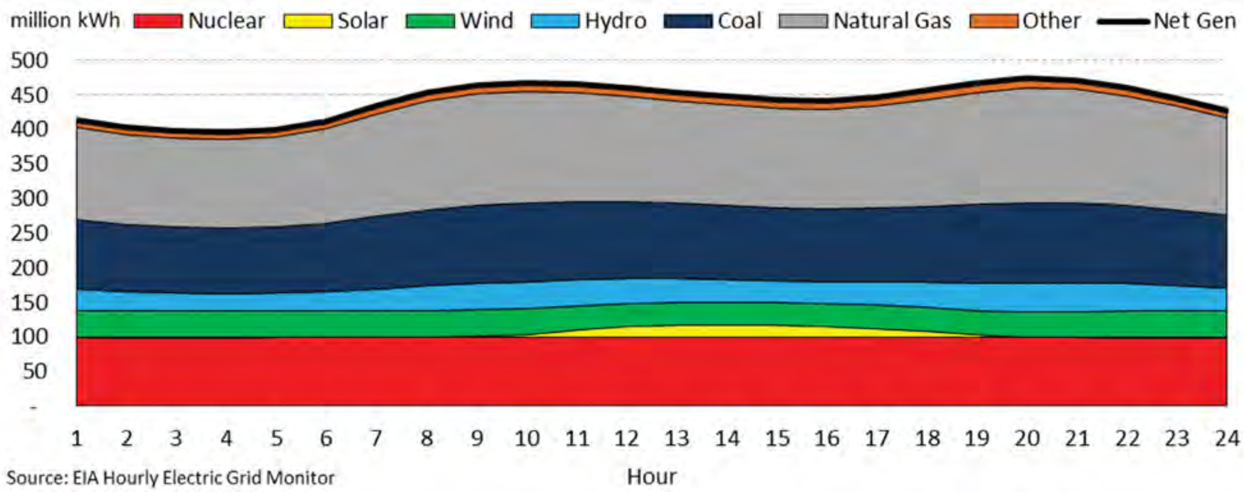
In 20 of 28 states, nuclear energy accounts for at least two-thirds of the state's total carbon-free electricity generation. In Mississippi, nuclear's share of carbon-free generation exceeded 96 percent in 2021. Even in Texas, home to the largest fleet of onshore wind generators, its two nuclear power plants, Vistra's Comanche Peak and NRG's/CPS' South Texas Project, still account for more than one-quarter of the state's total carbon-free electricity.

Nuclear also fulfills a unique role in supplying electricity over the course of a day. **Exhibit 10** shows the average hourly generation profile of the U.S. Lower-48 in January from 2019 to 2021, according to data from EIA's Hourly Electric Grid Monitor.[11] In January, the average U.S. electricity demand curve shows two peaks, one in the morning hours when people heat their homes before heading to work and one in the evening when they return. Despite the variability in electricity demand, nuclear's generation profile remains constant. For reasons described later, nuclear generation operates in baseload mode, where electricity is supplied at a steady rate with limited variability.

Exhibit 11 shows the hourly average generation in the U.S. Lower-48 between 2019 and 2021 for the month of July. Unlike in January, electricity demand in July on average peaks just once in the afternoon and evening hours, when cooling demand is at its peak. However, similarly to January, nuclear's average hourly generation profile shows almost no variability as it operates in baseload. Coal and natural gas-fired resources

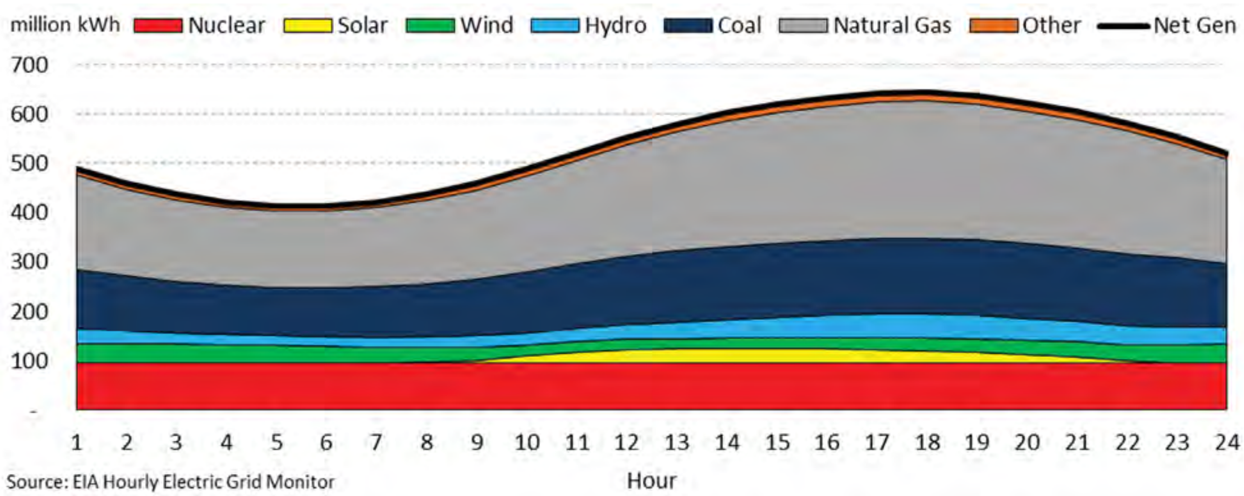
11 https://www.eia.gov/electricity/gridmonitor/.

Exhibit 10: 2019-21 Average January U.S. Hourly Generation - by Fuel Type



currently fill the role of load-following resources, balancing out the intermittency of renewable energy resources as well as variation in overall electricity demand. For example, solar generation in January peaks around 2 pm, whereas electricity demand peaks around 8 pm. Additionally, renewable generation, especially wind, can be highly variable from day to day. On the other hand, nuclear power plants operate at or near-maximum capacity virtually all year and only turn off during refueling and maintenance outages.[12]

Exhibit 11: 2019-21 Average July U.S. Hourly Generation - by Fuel Type



The primary reason for the unique operating characteristics of nuclear power is its comparatively high fixed operating and maintenance costs (FOM) and low fuel costs. **Exhibit 12** shows the 2020 average production expense by fuel and technology, according to analysis by Energy Ventures Analysis (EVA) of Federal Energy Regulatory Commission (FERC) Form 1 data submitted by regulated utilities.[13] According to the FERC Form 1 data, nuclear's total production cost was the lowest when compared with fossil fuel-fired power plants such as natural gas-fired combined-cycle plants or fossil steam generators. However, nuclear's FOM costs account for more than half of its total production expenses. Conversely, FOM only accounts for about 12 percent of the total production expense of the average natural gas combined-cycle power plant. Therefore, as plant output

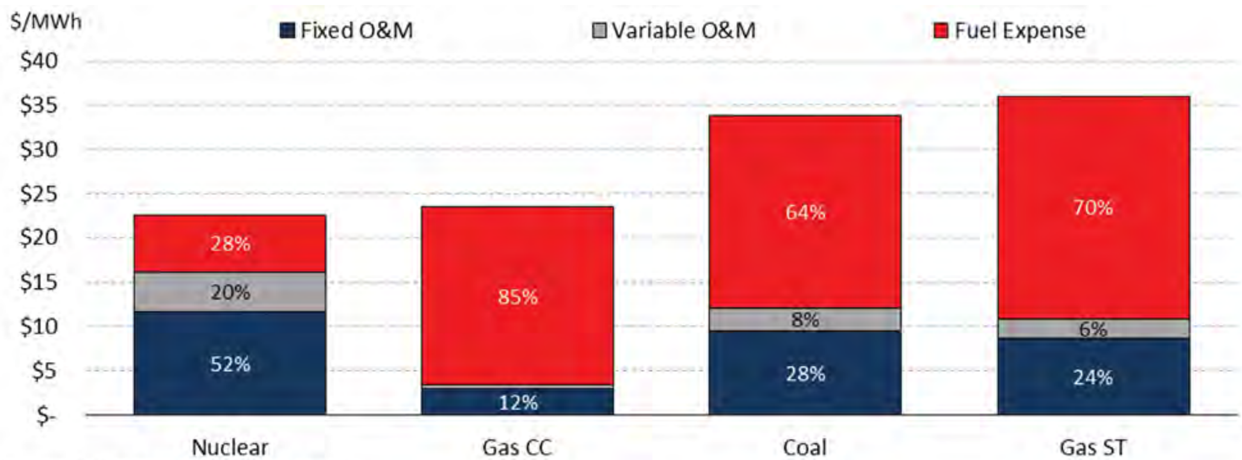
12 Most U.S. nuclear plants follow either an 18 or 24-month refueling schedule. If multiple units are present at the same site, refueling outages are staggered (e.g., unit 1 refuels in the spring, unit 2 refuels in the fall or the following spring). Refueling and maintenance outage typically last between four and five weeks.

13 Only regulated utilities are required to submit the annual Form 1 to FERC. Non-regulated utilities do not submit an annual Form-1.

increases, the cheaper nuclear power becomes relative to these other generation sources, as their fixed costs are spread over more megawatt-hours.

Some nuclear power plants are capable of operating in a load-following capacity similar to coal-fired power plants. In other countries where nuclear generation makes up the majority of electricity generation, such as France, nuclear power plants often cycle between 30 percent and 100 percent of their generating capacity to balance the electric grid. For example, according to the current version of the European Utilities Requirements (EUR), a nuclear power plant must be capable of daily load cycling operation between 50 percent and 100 percent of its rated power, with a rate of change of the electric output of 3-5 percent of rated power per minute. Although generally more complicated and less economical than operating in baseload mode, many existing U.S. nuclear plants could increase their load-following operating capability should the need arise. However, without financial support or significant increase in wholesale power prices, load-following remains cost-prohibitive for many U.S. nuclear plants. Furthermore, new advanced nuclear technologies are prioritizing load-following capabilities and the seamless integration of nuclear plants into a high-renewable penetration electric grid.

Exhibit 12: 2020 Average Production Expense by Fuel/Technology Type



Source: EVA analysis of FERC Form 1 data

Additionally, the total production expense of existing nuclear plants owned by regulated utilities submitting an annual Form 1 to FERC varies greatly. **Exhibit 13** shows the average total production expense of this subset of U.S. nuclear plants between 2011 and 2020. According to the FERC Form 1 data,[14] Dominion Energy's Surry nuclear plant in Virginia realized the lowest average production expense at less than $20 per MWh over the last decade, whereas Xcel Energy's Monticello nuclear power plant in Minnesota averaged almost $43 per MWh over the same period. On average, the production cost of the nuclear power plants included in the analysis was approximately $27.50 per MWh over the last decade. Comparably, the Nuclear Energy Institute (NEI) reported a total fleetwide average production cost of $29.37 per MWh in 2020.[15]

Besides being one of the lowest-cost electric generating resources on average, nuclear power plants are also the most reliable ones. **Exhibit 14** shows the average EFORd[16] percent by fuel and technology type between 2016 and 2020 according to the NERC's Generator Availability Data System (GADS).[17]

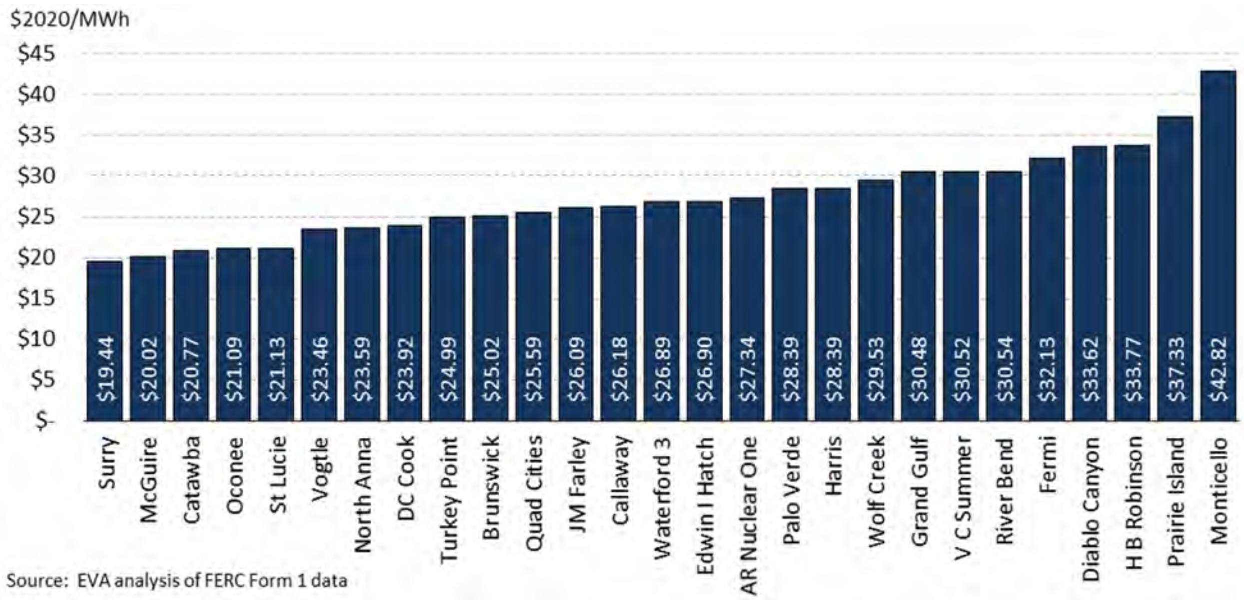
14 https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-1-f-3-q-electric-historical-vfp-data

15 https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context-2021.pdf

16 EFORd stands for Equivalent Forced Outage Rate and refers to the number of hours in a year a generating unit is offline outside of planned outage periods.

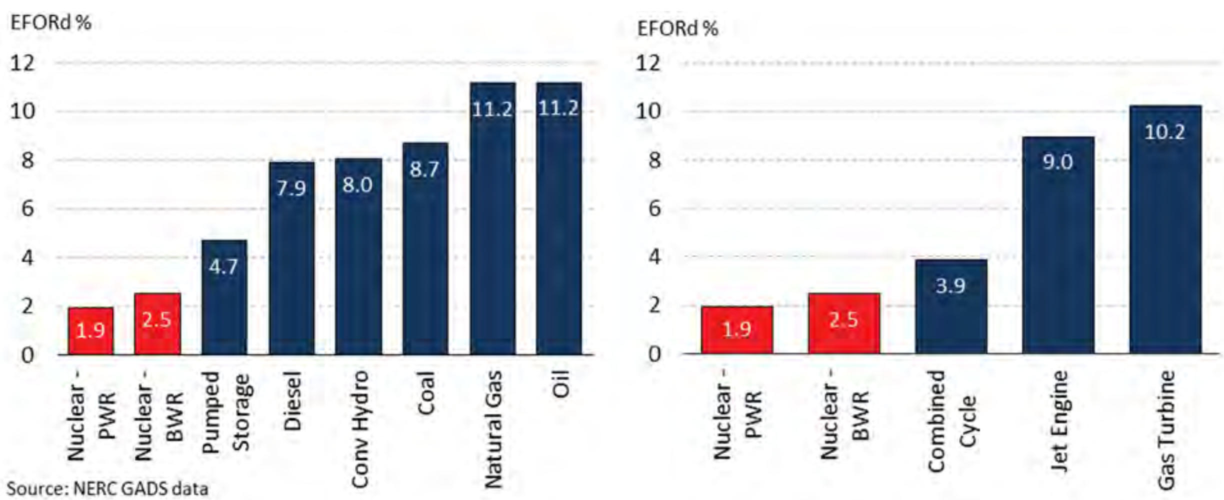
17 https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

Exhibit 13: Average Total Production Expense - 2011 To 2020



Source: EVA analysis of FERC Form 1 data

Exhibit 14: 2016-2020 Average EFORd by Fuel & Technology Type



Source: NERC GADS data

Forced outages can be caused by technical malfunction due to extreme weather conditions. According to NERC's GADS data, the EFORd for nuclear power plants operating a pressurized water reactor (PWR) and a boiler water reactor (BWR) were less than 2 percent and 2.5 percent on average between 2016 and 2020, respectively. By comparison, coal's EFORd over the same period was 8.7 percent, whereas the EFORd of natural gas-fired power plants was more than 11 percent. Therefore, nuclear power plants are among the most reliable dispatchable[18] power plants currently operating in the United States.

The next section explores how nuclear energy is currently accounted for in state CES and RPS programs and other existing federal financial incentives available to nuclear power plants.

18 "Dispatchable" refers to electric generating resources that can be operated "at-will" and are independent on natural resources (e.g., current wind speeds or sun radiation).

IV. Current Treatment of Nuclear Energy in Federal and State Clean Energy Standards

Under the recurring theme of decarbonization, many states, utilities, and corporations are taking big leaps to eliminate or reduce their carbon legacy, calling attention to the diverse terminologies and definitions surrounding terms like "carbon neutrality," "net-zero," or "zero-carbon." The most widely accepted definitions in electricity markets in the U.S., and pertaining to this report, are provided below:

Zero-carbon or carbon-free signifies that no carbon emissions are being produced from the product or service; in other words, there is no need for carbon capture or offsets. Zero-carbon, or carbon-free electricity, refers to the electric generation that does not emit carbon emissions during generation, such as wind, solar, hydro power, geothermal, nuclear power, or hydrogen made from zero-carbon energy.[19]

Net-zero or **carbon-neutral** electricity refers to any form of electricity generation in which the carbon emissions released are balanced out by taking the same amount out of the atmosphere. Emissions are generated but are offset or captured to make overall emissions zero. Biomass-derived energy (wood stock, animal wastes, forestry wastes, paper mill residues, etc.) generally fits the "net-zero" bill. Biomass is a hydrocarbon that produces CO_2 when combusted. However, because the natural process of biomass production (i.e., growing plants) takes CO_2 out of the atmosphere equivalent to the carbon produced by combustion, biomass can be classified as net-zero. Electricity generated from fossil fuels (coal, gas) with carbon capture utilization and storage (CCUS)[20] technology can also be considered net-zero if the system captures 100 percent of emissions.

Low-carbon electricity is derived from technologies that produce substantially lower carbon emissions than conventional fossil-based electric generation. Less-carbon intensive sources such as biomass, fossil fuels with less than 100 percent CCUS, renewable natural gas (RNG),[21] and hydrogen produced from fossil fuels with CCUS are some examples of low-carbon electricity sources. They produce lower quantities of total lifecycle carbon emissions when compared to conventional coal and natural gas power plants.

The House Committee on Energy and Commerce defines clean electricity as that produced by a generator with a carbon intensity of no more than 0.1 metric tons of carbon dioxide equivalent per megawatt-hour (tCO_2e/MWh).[22] In general, this definition of clean electricity includes all renewable energy sources (solar, onshore and offshore wind, hydro power, geothermal), nuclear energy, and fossil fuels coupled with CCUS (assuming a >90 percent CO_2 capture rate).

A. Overview of State Clean Energy Goals

State renewable portfolio standards (RPS) have long been vehicles that drive renewable energy adoption. The RPS landscape has changed dramatically since 1983, when Iowa became the first state to adopt a standard mandating investor-owned utilities (IOUs) to own or contract 105 MW of renewable generation capacity. Since then, such policies have expanded in scale and scope, with several states incorporating additional resources through clean energy standards (CES) or emission reduction goals.

The RPS or CES is a requirement for state electric utilities to source a minimum percentage of their electricity from renewable or clean energy sources by a certain date, and the distinction between the two is based on how states define "renewable" and "clean." For the RPS, other than renewable energy technologies like solar,

19 Zero-carbon hydrogen refers to hydrogen produced via electrolysis using renewable electricity, or hydrogen produced from nuclear energy.

20 CCS with 100 percent capture rate can be classified net-zero, or even carbon-negative if deployed for biomass. However, Fossil + CCUS can be low-carbon if the captured carbon is utilized for processes like enhanced oil recovery (EOR), where direct use of captured CO_2 boosts oil and gas recovery, and in turn produces end-use carbon emissions

21 RNG can be classified as carbon-neutral or even net-negative for certain feedstocks (such as livestock manure) or technologies

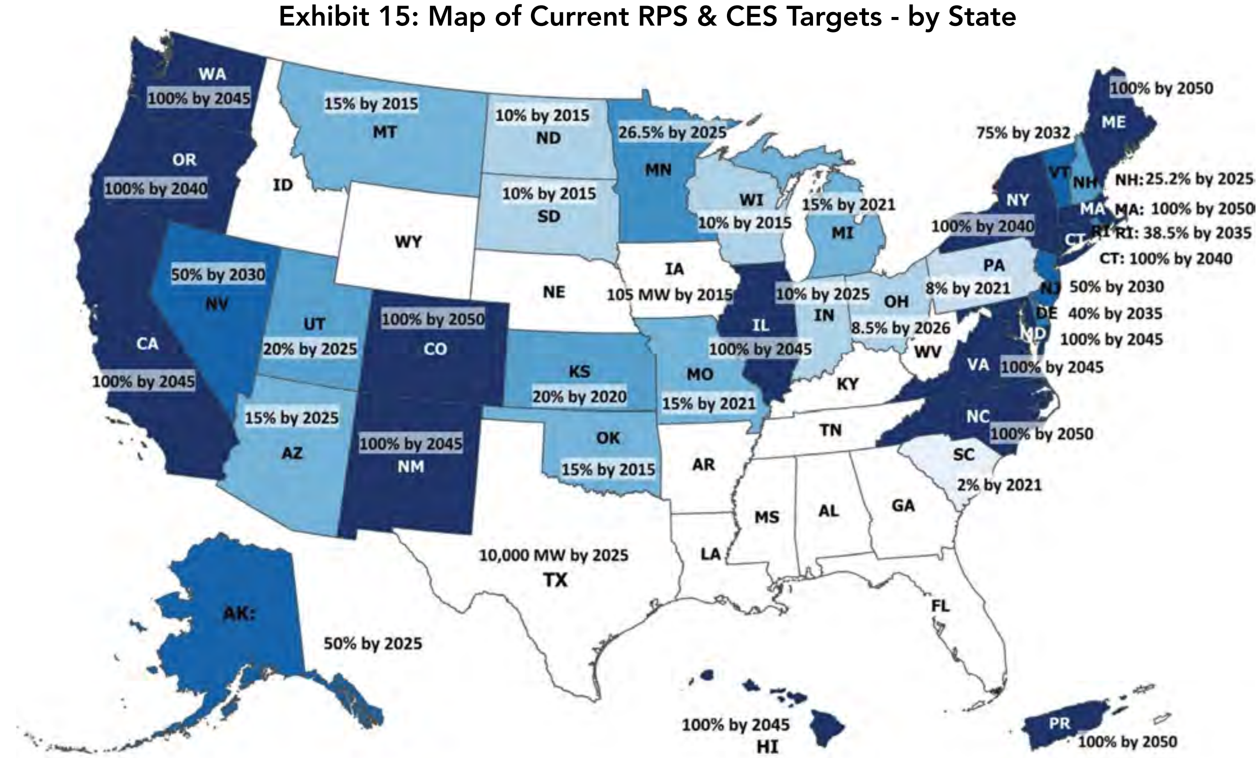
22 https://energycommerce.house.gov/sites/democrats.energycommerce.house.gov/files/documents/Memo_FC%20MU_2021.9.9_0.pdf

onshore/offshore wind, geothermal, tidal energy, and fuel cells, most states do not accept hydroelectric projects greater than 30 MW, CCUS projects, and generation from sources like waste coal – but those requirements are not consistent across states. Some states also include other resources such as landfill gas, municipal solid waste, biomass, biodiesel, anaerobic digestion, and combined heat and power under the RPS umbrella. On the other hand, the CES typically expands the list of accepted energy resources to include nuclear energy and/or natural gas or coal with CCUS. Whereas some states describe CES as technology-inclusive and encourage the development of advanced nuclear reactors, others focus on existing nuclear power plants.[23]

In most cases, CES policy will include RPS as a subset requirement. For example, New York's Climate Leadership and Community Protection Act (CLCPA) established a CES requiring 100 percent carbon-free electricity by 2040. In addition, the Act also increased the state RPS to require 70 percent of electricity from renewable energy sources by 2030.

Currently, 30 states, Washington D.C., and Puerto Rico have binding RPS or CES standards that outline carbon-free or low-carbon mandates, while another three states have voluntary standards. Voluntary standards are non-binding by nature and do not involve a penalty if the target is not met, whereas mandatory standards are legally enforceable with potential financial penalties for non-compliance. California, Colorado, Connecticut, Hawaii, Illinois, Maine, Maryland, Massachusetts, New Mexico, New York, North Carolina, Oregon, Virginia, Washington, Washington D.C., and Puerto Rico have established goals for 100 percent of their retail electricity sales to originate from eligible clean energy resources before mid-century.[24] **Exhibit 15** below maps the renewable portfolio standards or clean energy standards by state, with higher color intensity for states with a higher percentage of renewable or emission reduction requirements. The map does not include state clean energy goals that are not passed by legislation or codified into law, such as those established by executive orders, as they can be changed or repealed by administrative action, and invalidated once the

Exhibit 15: Map of Current RPS & CES Targets - by State



Note: 100% RPS/CES category represents states that have required all retail sales be supplied by renewable or clean resources by that set date. AK, HI, and PR are included, but not shown to scale. The darker the shade of blue, the higher the required RPS or CES percentage.

23 https://nuclearinnovationalliance.org/advanced-reactors-state-policymakers-brief

24 EVA RPS/CES Tracker, https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

governor leaves office. In Louisiana, Michigan, New Jersey, Rhode Island, and Wisconsin, the state's governors passed executive orders calling for 100 percent carbon-free electricity or net-zero GHG emissions by a certain date. Some states that met their RPS targets in the past or allowed them to expire are also included in the map. Iowa and Texas established specific new renewable capacity mandates as RPS, and both states have already surpassed their requirements.

RPS compliance is generally monitored and accounted for by a renewable electricity credit (REC) trading system. A utility that generates more renewable electricity than its RPS requirement can trade or sell RECs to electricity suppliers lacking enough RPS-eligible generation to meet their RPS requirements.

1. Treatment of Nuclear Energy in State Policies

Recognizing the significant reliability and emission reduction benefits of nuclear generation, states have increasingly sought to preserve existing nuclear generating capacity by providing financial and regulatory support. While some states, like New York, New Jersey, and Illinois have specific policies in place, such as ZECs, or Connecticut's clean energy power purchase agreement (PPA), which includes nuclear, to target and support existing nuclear generation, others have pursued different routes. For example, New Mexico, Nevada, Utah, Colorado, and Washington do not incentivize nuclear energy specifically. Still, they include all zero-emitting technologies like nuclear in the CES clean energy language as eligible technologies. Some states, such as Kansas and Nebraska, passed laws allowing tax exemptions or tax incentives for any new nuclear-associated property or investments.[25] As seen in Idaho, Virginia, and Washington, several states established task forces and commissions to explore viable pathways to maintain existing nuclear reactors and support advanced reactors development. In the last few years, some states (Wisconsin, Kentucky, Montana, and West Virgina) also removed moratoriums that prevented the construction of new nuclear reactors.

ZECs are state-created subsidy instruments that reflect the zero-carbon emission attributes of nuclear generation, valued at dollars per megawatt-hour of electricity produced by a qualified nuclear power plant. ZECs are awarded to nuclear plants at risk of closure to provide an additional secured revenue stream and ensure the profitability of the plant into the future. Participating nuclear plants receive ZEC payments from electric utilities, as the state law requires utilities to purchase a specified amount of ZECs at a state-determined price. Ultimately, ratepayers pay for ZEC programs.

New York's Public Service Commission (PSC) created ZECs as part of its CES Order. Tier 1 and Tier 2 of the CES constitute new and existing renewable resources (as part of the RPS), whereas Tier 3 refers to the ZECs. Since its inception in April 2017, the state's utilities must periodically purchase ZECs from the New York State Energy Research and Development Authority (NYSERDA) based on a percentage of their actual load. NYSERDA offers qualifying nuclear facilities a multi-year contract for the purchase of ZECs through March 2029, but the price will be adjusted every two years.[26] The initial ZEC price of $17.48/MWh for 2017–2019 was estimated according to EPA's social cost of carbon (SCC) minus the portion of cost captured by Regional Greenhouse Gas Initiative (RGGI) allowance prices, subject to a price collar if energy and capacity compensation in NY Zone A exceeds $39/MWh.

The PSC evaluated ZEC program eligibility for each facility based on the following criteria: historical contribution to New York's clean energy resource mix, the degree to which the facility's projected revenues are insufficient to preserve its environmental attributes, cost-benefit analysis of the payment compared to other clean energy alternatives, impact on ratepayers, and public interest.[27] The PSC found Fitzpatrick, Ginna, and Nine Mile nuclear facilities to be eligible for the award of ZECs.

25 https://nei.org/resources/reports-briefs/state-legislation-and-regulations

26 https://www.energybusinesslaw.com/2016/09/articles/environmental/ny-creates-new-emissions-credit-for-nuclear-plants/

27 https://digitalworks.union.edu/cgi/viewcontent.cgi?article=1081&context=theses

Exhibit 16: RPS & CES Targets by State by Year & 2020 Status

	State	RPS?	RPS Target	CES?	CES Target	ZEC?	% RPS/CES Achieved in 2020
AZ	Arizona	Y	15% by 2025	N	--	N	5%
CA	California	Y	60% by 2030	Y	100% by 2045	N	35% / 59%
CO	Colorado	Y	30% by 2020	Y	100% by 2050	N	29% / 30%
CT	Connecticut	Y	40% by 2030	Y	100% by 2040	N	26% / 63%
DE	Delaware	Y	40% by 2035	N	--	N	8%
IL	Illinois	Y	50% by 2040	Y	100% by 2045	Y	8% / 69%
IN	Indiana	N	--	Y	10% by 2025	N	8%
IA	Iowa	Y	105 MW by 2015	N	--	N	10,653 MW
KS	Kansas	Y	20% by 2020	N	--	N	20%
ME	Maine	Y	100% by 2050	N	--	N	35%
MD	Maryland	Y	50% by 2030	Y	100% by 2045	N	25% / 32%
MA	Massachusetts	Y	40% by 2030	Y	100% by 2050	N	19% / 24%
MI	Michigan	Y	15% by 2021	N	--	N	13%
MN	Minnesota	Y	26.5% by 2025	N	--	N	24%
MO	Missouri	Y	15% by 2021	N	--	N	7%
MT	Montana	Y	15% by 2015	N	--	N	7%
NV	Nevada	Y	50% by 2030	N	--	N	18%
NH	New Hampshire	Y	25.2% by 2025	N	--	N	12%
NJ	New Jersey	Y	50% by 2030	N	--	Y	21%
NM	New Mexico	Y	80% by 2040	Y	100% by 2045	N	19% / 37%
NY	New York	Y	70% by 2030	Y	100% by 2040	Y	3% / 55%
NC	North Carolina	Y	12.5% by 2021	Y	100% by 2050	N	9% / 46%
ND	North Dakota	Y	10% by 2015	N	--	N	41%
OH	Ohio	Y	8.5% by 2026	N	--	N	4%
OK	Oklahoma	Y	15% by 2015	N	--	N	36%
OR	Oregon	Y	50% by 2040	Y	100% by 2040	N	12% / 68%
PA	Pennsylvania	Y	8% by 2021	Y	18% by 2021	N	16% / 37%
RI	Rhode Island	Y	38.5% by 2035	N	--	N	16%
SC	South Carolina	Y	2% by 2021	N	--	N	3%
SD	South Dakota	Y	10% by 2015	N	--	N	33%
TX	Texas	Y	10,000 MW by 2025	N	--	N	32,340 MW
UT	Utah	Y	20% by 2025	N	--	N	14%
VT	Vermont	Y	75% by 2032	N	--	N	59%
VA	Virginia	Y	100% by 2045	Y	100% by 2045	N	7% / 29%
WA	Washington	Y	15% by 2020	Y	100% by 2045	N	11% / 84%
DC	Washington, DC	Y	100% by 2032	N	--	N	22%
WI	Wisconsin	Y	10% by 2015	N	--	N	13%
AK	Alaska	Y	50% by 2025	N	--	N	31%
HI	Hawaii	Y	100% by 2045	N	--	N	35%
PR	Puerto Rico	Y	100% by 2050	N	--	N	3%

NOTE: % RPS or % CES achieved represents the percent of state retail sales that were procured/derived from eligible renewable or clean energy resources in 2020. There are no compliance tracking reports for CES, % CES are estimated based on CES-eligible generation. The following states do not track RPS compliance, as they are voluntary goals, not mandates: IN, ND, OK, SC, SD, UT.

Illinois' Future Energy Jobs Bill enacted in December 2016 called for the procurement of ZECs from zero-emission facilities and established an annual procurement target of 16 percent of delivered electricity in 2014 for Ameren Illinois and ComEd and 16 percent of actual procured power and energy in 2016-17 by the Illinois Power Agency. The bill's passage allowed Exelon (now Constellation Energy) to reverse its decision to retire the Clinton and Quad Cities nuclear power plants. The first procurement was held in January 2018, and qualified facilities were awarded a 10-year contract to purchase ZECs through May 2027. The initial ZEC price of $16.50/MWh was calculated by incorporating the social cost of carbon and is subject to a market price adjustment.

The qualifying facilities were determined by evaluating the impact of replacement generation on air pollutants (CO_2, SO_2, NO_X, PM) and accounting for an economic stress multiplier (the degree to which a plant is at risk of closure due to economic and market conditions). The Quad Cities and Clinton were the only two power plants that met the criteria established by the Act.

Shortly after, following Constellation Energy's announcement to retire the Byron and Dresden nuclear plants by Q3 and Q4 2021, Illinois lawmakers passed the state's Climate and Equitable Jobs Act (100 percent CES by 2045) to support the two at-risk plants. The bill administered a carbon mitigation credit (CMC) program offering 5-year contracts for CMC credits from June 2022 to Jan. 2028, separate from the ZEC program, which expires in May 2027. CMC is a tradable credit that signifies the carbon emission reduction attributes of 1 MWh of carbon-free energy produced from a qualifying facility (nuclear power plant interconnected to PJM). The first procurement event occurred in Dec 2021, and the winning bids went to Braidwood, Byron, and Dresden facilities for 54.5 million CMCs/year. The credit value varies each month, as the state would subtract indexed energy prices and federal subsidies from the baseline costs for carbon-free energy resources. The baseline cost has a ceiling of $30.3/MWh during the 2022–2023 delivery year, rising to $34.5/MWh during the 2026–2027 delivery year.

In 2017, **Connecticut** lawmakers enacted the Act Concerning Zero Carbon Solicitation and Procurement, authorizing the state's Department of Energy and Environmental Protection (DEEP) to hold competitive procurements for power from nuclear power plants at risk of retirement. The bill offered a lifeline to the state's sole nuclear plant, Millstone, which supplies nearly 40 percent of the state's electricity generation mix. In 2019, DEEP determined Millstone 2 and 3 nuclear units to be at risk of permanent shutdown by June 2023, once the plants' ISO New England (ISO-NE) capacity obligations expire.

As a result, the plant was allowed to participate in the state's renewable solicitation process, along with wind, solar, energy storage, hydro, and other renewable sources. DEEP approved Dominion's bid to sell approximately 50 percent of Millstone's output to Connecticut's two regulated utilities at a price of $49.99/MWh. The PPA is valid for a 10-year period through 2029.

In 2018, **New Jersey** signed into law a bill establishing the ZECs program to support the state's Salem and Hope Creek nuclear-generating stations. The New Jersey Board of Public Utilities (NJBPU) established a ZEC rate of $10 per MWh offered to qualifying facilities in a three-year window. The eligible facilities were determined by using net avoidable costs as the relevant metric. Based on the selection criteria, the power plant would also cease operations within three years in the absence of a material financial change. To be eligible, the plant must be licensed to operate at least until 2030. On April 27, 2021, NJBPU voted to extend the state's ZEC subsidies for Hope Creek and Salem 1 and 2 through May 2025.

In 2019, the **Ohio** legislature enacted House Bill (HB) 6 to provide ratepayer-funded subsidies and keep Energy Harbor's struggling nuclear plants — Perry and Davis-Besse — from shutting down. Both plants were slated to receive an annual payment of $150 million for seven years as subsidies, beginning on January 1, 2021. The bill also indirectly provided subsidies to the Kyger Creek and Clifty Creek coal plants and scaled back the state's renewable and energy efficiency standards. A referendum was introduced to repeal HB 6 in early 2020 but abandoned shortly after. HB 6 bill enactment, its repeal efforts by lawmakers, and its subsequent failure led to an investigation that revealed multiple acts of alleged bribery. Due to the scandal and other bill concerns, the proposed nuclear subsidy was eventually suspended in 2020 and repealed in 2021.

B. Federal Policy Support

Policies and incentives at the federal level, in tandem with state regulations, can help support existing nuclear reactors and advance new reactor buildout. The Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Law) passed in 2021 established a $6 billion Civil Nuclear Credit Program (CNC) to prevent the premature closure of existing U.S. nuclear reactors due to economic circumstances. The CNC is intended to support the continued operation of such reactors due to the fact that they are the nation's largest source of clean power. The CNC will allow qualifying U.S. reactors in competitive markets to apply for certification and bid on credits, provided they can demonstrate that (1) they are at risk of ceasing operations due to economic factors and (2) closure will lead to increases in carbon and air pollutant emissions. The CNC uses federal funds, not tax credits, allocated over a four-year period. Power plant owners and operators of nuclear reactors with publicly announced retirement dates by September 30, 2026, have until July 5, 2022, to apply for the first CNC award cycle.

Although federal tax credits and state renewable portfolio standards have driven substantial growth in wind and solar generation, federal policy support for nuclear energy in the form of tax credits or incentives remains somewhat limited. The current investment tax credits (ITC) awarded to solar, offshore wind, geothermal technologies, waste energy recovery, and fuel cells subsidize their installations, while production tax credits (PTC) boost renewable growth by rewarding electric generation from qualifying resources. On the other hand, these federal tax credit structures for renewables lead to periods of negative power pricing in some markets, which exacerbate the financial strain on traditional baseload nuclear power plants that do not ramp down or shut off at times of low demand and low energy prices.

Last year, several senators introduced the Zero Emission Nuclear Power Production Credit Act of 2021, proposing to make existing merchant nuclear power plant owners/operators eligible for the same $15/MWh tax credits offered to wind operators. The act was included in President Biden's Build Back Better proposed legislation in 2021. However, after the larger package stalled in Congress, the $15/MWh PTC for operating plants was passed as part of the August 2022 Inflation Reduction Act (IRA). The IRA also included a technology-neutral energy tax credit provision, under which zero-emission generation technologies such as advanced nuclear would qualify for either the expanded ITC, at 30 percent of investment, or PTC, at $30/MWh for the first ten years of plant operation. Additional funding for loan guarantees, research and development, and environmental justice was also included in the IRA.

The DOE-sponsored Light Water Reactor Sustainability (LWRS) Program collaborates with other industry organizations to conduct research and develop technologies that improve economics, reliability, and safety of the existing fleet of nuclear power plants, and maintain their long-term operations.

The 2005 Energy Policy Act[28] established the Advanced Nuclear Production Tax Credit (U.S. Code S.45J), a tax credit of $18/MWh of electricity produced by advanced nuclear energy facilities during the first eight years of operation. The credit is limited to the first 6,000 MW of advanced nuclear generating capacity deployed and can be claimed nationwide on a first-come-first-serve basis. The law defines an advanced nuclear facility as any facility for which the reactor design is approved by the U.S. Nuclear Regulatory Commission (NRC) after December 31, 1993. The two Westinghouse AP1000 reactors (Vogtle 3 and 4) being built in Georgia and the NuScale VOYGR planned for construction and operation by 2029 can qualify for the nuclear PTC. The enacted PTC structure aimed to encourage private investments in innovative technologies like advanced nuclear energy, although it is yet to be utilized. The Act also includes a Standby Support mechanism (Section 638) that

28 https://www.govinfo.gov/content/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

provides risk insurance for the first six advanced nuclear reactors to facilitate the construction and operation of new nuclear facilities by covering their financial losses due to regulatory or litigation-related delays.

DOE's Advanced Reactor Demonstration Program (ARDP), launched in 2020, aims to leverage Congress-appropriated funding and establish public-private partnerships to accelerate the development and construction of advanced nuclear reactors in the U.S. through three award pathways:

- **Advanced Reactor Demonstrations:** These are awarded to commercially ready technologies with the goal of testing, licensing, and building fully functional advanced reactors by 2028. Under this program, DOE selected two awardees with the highest technology readiness levels amongst non-light-water reactors in the U.S.: TerraPower's Natrium reactor and X-Energy's Xe-100 gas-cooled reactor, to receive a total of $3.2 billion invested over seven years. The BIL provided the majority of the federal cost-share ($2.477 billion) for these two demonstrations.
- **Risk Reduction for Future Demonstrations:** This pathway supports five additional reactor teams that are further out in technology readiness levels to resolve technical, operational, and regulatory challenges and prepare for future demonstration opportunities (over the next 10–14 years). DOE selected the following five recipients to appropriate nearly $600 million over seven years: Kairos Power's Hermes reduced-scale test reactor, Holtec's SMR-160, Southern Company's molten chloride reactor experiment, BWXT's high-temperature gas-cooled microreactor, and Westinghouse's eVinci microreactor.
- **Advanced Reactor Concepts 2020 (ARC 20):** These awards will support innovative reactor designs with a longer commercialization horizon and prepare them for demonstrations by the mid-2030s. The three selected awardees under this program are the Massachusetts Institute of Technology for a modular integrated gas-cooled high-temperature gas reactor (MIGHTR), General Atomics for a 50 MWe fast modular reactor, and Advanced Reactor Concepts for a 100 MWe seismically isolated advanced sodium-cooled reactor facility.[29] DOE expects to invest a total of $56 million in funds over four years to assist the progression of these reactor designs.

Such federal incentives can help propel the nuclear industry forward by retaining existing nuclear power plants. These incentives will also help bridge the economic feasibility gap to advance new and emerging nuclear technologies by shifting portions of the financial risks of constructing and operating new nuclear plants from electricity ratepayers to taxpayers.

29 https://world-nuclear-news.org/Articles/DOE-selects-advanced-reactor-concepts-for-funding

V. Background on Current and Future Nuclear Energy Technology

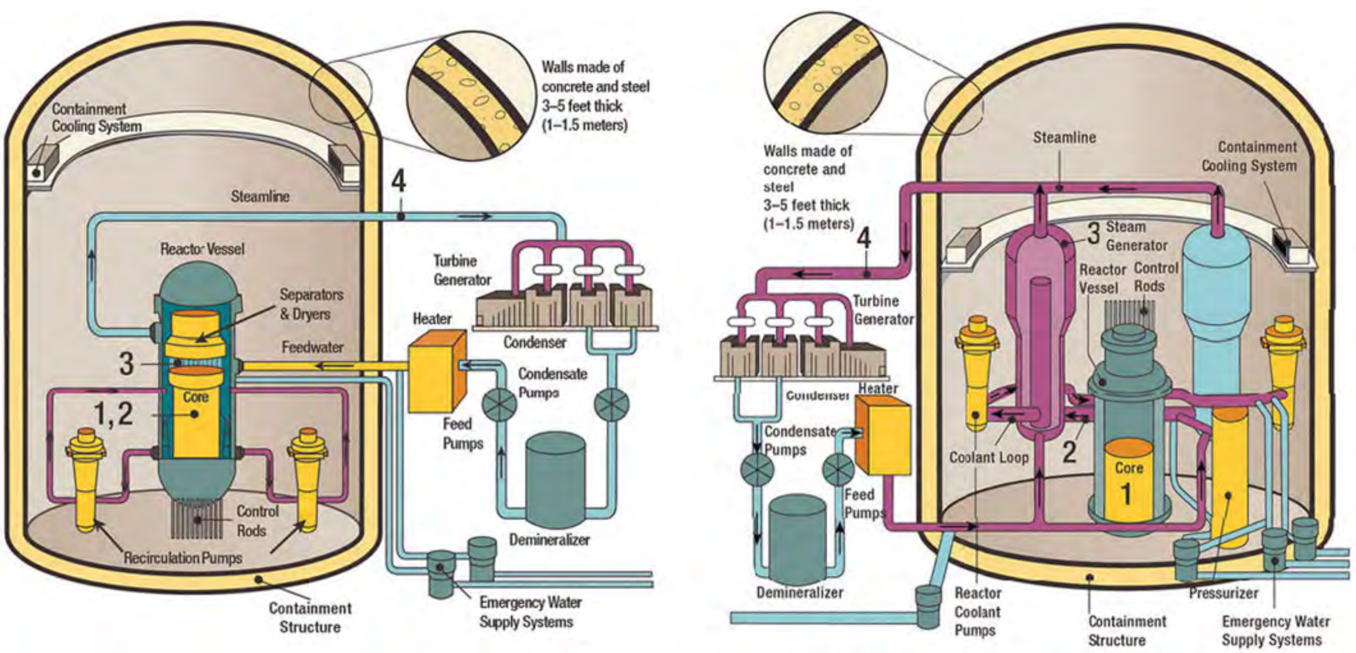
Since the first commercialization of civil nuclear reactors in the 1950s and early 1960s, reactor technology has constantly been evolving and upgrading in terms of performance, costs, and safety. Based on the level of technological advancement, the standard practice is to classify reactors as Generation I, II, III, and IV. Gen I refers to the early prototype or "proof-of-concept" reactors that were developed in the 1950s and 1960s, all of which have now shut down.[30] Most of the currently operating reactors in the U.S. or elsewhere are Gen II or III, which have improved performance and extended design lifetimes. Advanced reactor designs envisioned for the future that incorporate enhanced characteristics such as inherent/passive safety features, modular design, greater fuel utilization, enhanced reliability, improved load-following capabilities, high chemical stability, and the ability to integrate non-electric applications are termed as Gen IV reactors.[31]

A. Current Nuclear Energy Technologies

All existing nuclear power generation in the U.S. relies on light-water reactors, either boiling-water reactors (BWRs) or pressurized-water reactors (PWRs). Of the 92 operating reactors in the country, two-thirds are PWRs, and the rest are BWRs. Many of the conventional light water reactors (LWRs) currently on the market are large, built with 1,000 MW or more generating capacity to capture economies of scale. However, as observed with the Vogtle expansion, cost overruns and delays are driving buyers to shift their focus to smaller and modular designs.

LWRs use ordinary water as both a cooling agent and to maintain the nuclear fission chain reaction, also known as a moderator. The nuclear reaction takes place inside the reactor core, typically consisting of several hundred fuel assemblies in a 1,000+ megawatt reactor. Pencil-thin metal tubes are filled with stacks of uranium oxide pellets and sealed to form fuel rods, and these rods are grouped in bundles to form fuel assemblies. The fuel rods are immersed in water inside the reactor vessel. The heat created by controlled nuclear fission turns the water into steam, which drives the turbine to spin electric generators and produce electricity. The control rods

Exhibit 17: Simplified Overview of BWR (left) and PWR (right) Reactor Technology[32]



30 https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/advanced-nuclear-power-reactors.aspx

31 https://crsreports.congress.gov/product/pdf/R/R45706

32 U.S. Nuclear Regulatory Commission, https://www.nrc.gov/reactors/power.html

absorb neutrons to control the reaction rate and are used to shut down the reactor in the case of emergencies. The presence of steam in the primary loop is the primary distinguishing feature between BWRs and PWRs. **Exhibit 17** provides a schematic overview of a BWR on the left and PWR on the right.

The BWR contains a single internal cooling loop. As a result, the water is at a lower pressure and boils directly inside the core at 285°C. The produced steam-water mixture moves upward through the core, and the water droplets are separated to allow only steam to enter the main turbine. The steam then turns the turbine and generates electricity, after which it is condensed in the condenser and recycled back to the reactor. The disadvantage is that since the same water acts as a moderator, coolant, and steam source for the turbine, the water in circulation is slightly radioactive and has the potential to contaminate the rest of the loop. As a result, appropriate safety measures must be taken in the BWR's turbine building, in comparison to PWRs. BWRs, however, have better fuel utilization characteristics than PWRs.

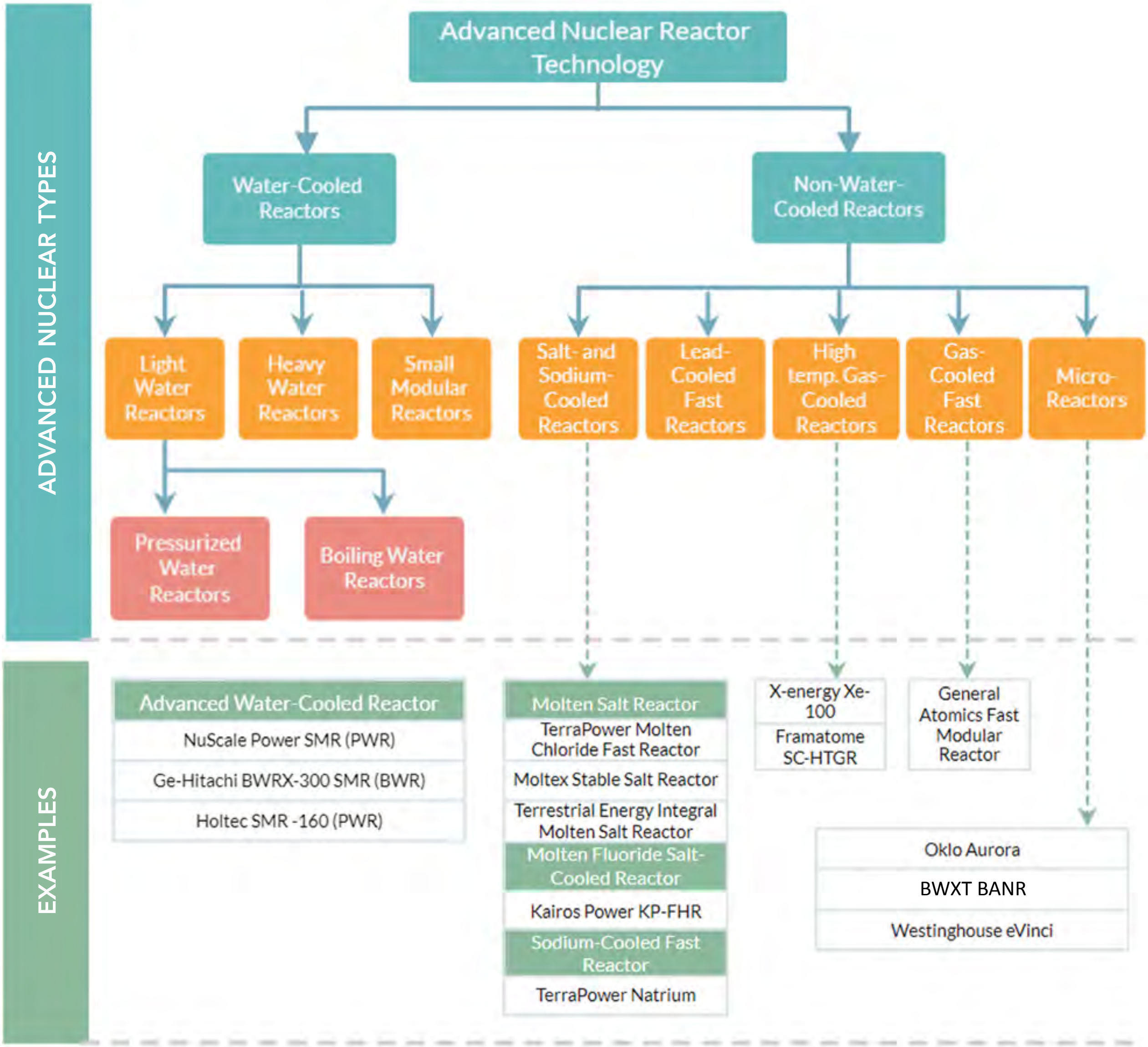
PWRs generate steam indirectly. They contain a) a primary cooling loop that flows through the reactor core at high pressure to prevent boiling and b) a secondary circuit that uses the heat from the primary loop (through heat exchangers) to generate steam at lower pressure. The steam from the secondary loop is directed to the turbine to produce electricity, after which it is condensed into water by the condenser. As a result, the water flowing through the reactor core is isolated from the turbine and cannot pass any radioactive contaminants to the turbine and condenser.

The third type of water-cooled reactor — a pressurized heavy water reactor (PHWR) — is not used in the U.S. but is the main commercial technology in Canada. After PWR and BWR, PHWR is the third most common reactor type under operation internationally and serves as the backbone of the nuclear fleet in Argentina, Romania and India. These reactors use deuterium, or heavy water (D_2O), as coolant and moderator. Heavy water does not occur in nature and must be produced for use in these reactors, which adds a cost not required in LWRs. Despite the expense when compared to light or ordinary water, PHWRs are advantageous as they can run on natural uranium and do not require fuel enrichment as in the other reactor types. Canada's PHWR, referred to as CANDU, also has the added benefit of online refueling, i.e., refueling the reactor core without shutting the reactor down. However, they are not preferred in some countries due to proliferation concerns, in other words, the risk of diverting fissile material to build nuclear weapons.

B. Advanced Nuclear Energy Technologies

Advanced reactor designs use new and existing technologies and materials to make significant improvements over the most recent generation of nuclear reactors in one or more of the following areas: safety, financing, versatility, and waste management. The enhanced features or characteristics incorporated may include inherent safety, simplified or modular designs, better fuel utilization, enhanced efficiency, or cogeneration ability. As depicted in **Exhibit 18**, advanced or Generation IV reactor designs are broadly classified as water-cooled reactors and non-water-cooled reactors. Apart from the technology, advanced reactors can also be classified based on their size as: a) microreactors of capacity ranging 1–20 MW, b) small modular reactors ranging 20–300 MW, or c) full-size reactors ranging 300–1000+MW.

Exhibit 18: Overview of Existing and Currently Under Development Nuclear Reactor Types[33]



1. Advanced Water-Cooled Reactors

Advanced water-cooled reactors function similarly to traditional nuclear reactors in that they generate energy through nuclear fission and use water as the heat transfer medium and moderator. However, these reactors provide improvements through innovative and simplified designs, smaller sizes, or enhanced efficiency. Many advanced water-cooled reactors vary from conventional PWRs or BWRs only in size; they are generally small modular reactors.

Some of the latest advanced nuclear reactor projects are listed below, with a focus on U.S. developments only.

a. Small Modular Reactors

Small modular reactors are intended to be fabricated as ready to "plug and play," thereby lowering capital costs and lead times for construction. SMRs can be assembled in a factory, or major components can be shipped to the plant site and installed on-site using modular construction techniques. SMRs and microreactors

33 CRS Report on Advanced Nuclear Reactors, https://crsreports.congress.gov/product/pdf/R/R45706

only refer to a difference in size as they can fit into the advanced water-cooled reactor category or any other category based on the technology utilized.

NuScale VOYGR SMR: NuScale Power is developing a first-of-a-kind, small, modular, factory-built pressurized water reactor technology that is expected to be safer, more versatile, and cost-effective than conventional nuclear reactors. Each NuScale module will generate up to 77 MWe, and all components for steam generating and heat exchange will be incorporated into a single unit. VOYGR can offer 4-, 6-, or 12-module configurations, providing a gross output of up to 924 MWe.[34]

The reactor sits in a containment vessel surrounded by a vacuum layer and an outer steel wall, which sits in a water-filled pool within a stainless steel-lined concrete building. The reactor relies on the principle of buoyancy-driven natural circulation to circulate water, eliminating the need for cooling pumps. It can be fitted with a dry condenser, potentially eliminating the need for external sources of cooling water and allowing flexible siting. During regular operation, the containment in a vacuum minimizes heat losses, prevents component corrosion, and eliminates the need for reactor vessel insulation. The reactor module boasts inherent safety features that allow it to safely shut down and self-cool in case of a system failure, without the need for operator action, emergency power, or additional water. The NuScale plant has the ability to extensively load-follow to support variable wind and solar generation. The module can ramp up quickly from 20 percent to 100 percent within 96 minutes by manipulating the control rods. The plant can also be integrated for cogeneration applications such as district heating, desalination, hydrogen production, industrial process heat, etc.

In 2020, NuScale's reactor became the first SMR to receive initial design approval from NRC for the 50 MW modules. NuScale is now seeking regulatory approval for its amended design with generating capacity of 77 MW. Utah Associated Municipal Power Systems (UAMPS) has already signed an agreement to deploy the VOYGR reactor at the Idaho National Laboratory, projected to be online by 2029. In October 2020, DOE awarded a $1.4 billion multi-year cost-share award to UAMPS to demonstrate and deploy the NuScale SMR. Xcel Energy and Dairyland Power are among the utilities working with NuScale to explore and evaluate the potential deployment of the VOYGR. In addition, NuScale plans to extend its customer pipeline beyond the U.S. and has 19 Memoranda of Understanding (MOUs) with 11 other countries.

GE-Hitachi BWRX-300: BWRX-300 is a 300 MWe water-cooled natural circulation SMR with passive safety systems. As GE's tenth evolution of its boiling water reactor design, the BWRX-300 aims to be the simplest, innovative, lowest-risk, most cost-effective, and quickest-to-market SMR. All the major reactor components are housed inside the reactor vessel, eliminating the possibility of coolant leakage outside the reactor. Similar to NuScale's design, the natural coolant circulation eliminates the need for pumps and valves present in older BWR models. During a malfunction event, steam condensation and gravity allow the reactor to maintain safety and cool itself for at least seven days without operator action. The BWRX-300 claims to complete construction in 24–36 months and has 60 percent lower capital costs per MW when compared to other water-cooled SMRs. The BWRX-300 was selected by TVA for development at the Clinch River nuclear site in Tennessee and by Ontario Power Generation (OPG) for development at the Darlington nuclear site in Canada.

Holtec SMR-160: The SMR-160 is a single-loop natural circulation PWR design, which includes a passive cooling system with no need for pumps and valves. The reactor is capable of black start and island operations, allowing it to operate independently on a microgrid.[35] The reactor core will be located underground, making it more secure in the case of accidents. The SMR-160 can also be deployed in water-challenged or arid regions by using air instead of water as the condensing medium. It will also provide on-site underground storage of spent nuclear fuel in welded multipurpose canisters. In addition, the reactor can support optional cogeneration equipment for hydrogen production, seawater desalination, and district heating.

34 https://www.nuscalepower.com/technology

35 https://holtecinternational.com/products-and-services/smr/features/

Holtec already fabricates heat exchangers and nuclear waste storage equipment (dry storage casks) for the nuclear industry and is equipped to manufacture the components necessary for the SMR-160. Holtec won $116 million in funding from DOE as part of the Risk Reduction ARDP awards to accelerate its early-stage design, engineering, and licensing activities to deploy the SMR-160. The company is eyeing the site of the old decommissioning Oyster Creek nuclear plant to site its first SMR-160, with 2030 as the online target date.

NuScale's VOYGR, GE-Hitachi's BWRX-300, as well as Holtec's SMR-160 only require conventional LWR fuel, i.e., low enriched uranium (LEU), thereby reducing most of the first-of-a-kind engineering fuel issues and ensuring easy access to a robust international fuel supply chain.

2. Advanced Non-Water-Cooled Reactors

Whereas traditional reactors use water as the heat transfer medium, some emerging reactor technologies use molten salt, liquid metals (sodium, lead), or gases (helium, carbon dioxide), which create opportunities for the reactor to operate at higher temperatures. Based on the use of different fuels or coolants, non-water-cooled reactors can make design choices that can lead to lower capital and operating costs and enable inherent safety features. It also enables more siting opportunities as these reactor designs require less or no access to large bodies of water for cooling.

a. Salt- and Sodium-Cooled Reactors

Sodium-cooled fast reactors (SFR) use fast reactor technology with liquid sodium as the primary coolant. Most of the current nuclear fleet operates in the thermal spectrum, with thermal neutrons which are in thermal equilibrium with the surrounding media. These reactors require a moderator (commonly water or gas) which cools the neutron to a sufficiently low energy to permit the fission chain reaction to occur.[36] A fast reactor relies only on fast neutrons, which have significantly higher energy than thermal neutrons, to sustain the fission reaction. These fast reactors using uranium inherently generate more fissile atoms per fission than slow neutron reactors. The fissile material essentially replenishes as it burns, leading to better fuel utilization. Fast neutrons can also destroy actinides (long-lived radioactive waste) in spent fuel, making the nuclear waste degrade to natural radiation levels much faster than traditional nuclear wastes.

Liquid sodium is a weak neutron moderator, meaning that the neutrons sustaining the chain fission reaction do not slow down in interactions with other nuclei as they do in water-based reactors. Sodium also has a large liquid temperature range, allowing it to operate at higher temperatures but low pressures without expanding, thereby simplifying the design and reactor construction and reducing explosion risks. These designs have reduced corrosion risk for steel reactor parts, offer better fuel utilization, and potentially reduce the radioactive waste produced. One disadvantage is that sodium reacts violently when exposed to air and water, requiring the primary sodium coolant system to be isolated.

Molten salt reactors (MSR) use molten salt (such as fluoride or chloride) as coolant and fuel, thereby permitting lower pressure and high-temperature operations that drive higher thermal efficiencies. In addition, MSRs have a closed fuel cycle, which utilizes low-enriched uranium and allows for online refueling.

TerraPower Natrium: TerraPower and GE Hitachi are collaborating to develop the Natrium technology, a 345 MWe sodium fast nuclear reactor with a molten salt energy storage system that can provide up to 5.5 hours of energy storage at a 500 MWe power output. The heat produced by the reactor can be used to generate electricity instantaneously, contained in thermal storage reserves for later use, or directed to industrial plants for process heat. This allows the reactor to operate at high-capacity factors and capture more energy revenues while simultaneously complementing the variable nature of renewables. Natrium does not require outside energy sources to operate its cooling systems, thereby reducing the system vulnerability in case of emergency

36 https://www.sciencedirect.com/topics/engineering/thermal-reactor

shutdowns. The Natrium uses high-assay, low-enriched uranium (HALEU), or uranium with U-235 enrichments between 5 percent and 20 percent, as fuel to enhance reactor performance.

TerraPower is one of two teams that DOE awarded initial funding through its ARDP to test, license, and build their advanced reactor in the late 2020s. TerraPower and Pacificorp will work together to site a Natrium advanced reactor at the retiring Naughton coal plant site in Wyoming. The company anticipates submitting its construction permit application to NRC in mid-2023.

Terrestrial Energy IMSR: Terrestrial Energy's 195 MW integral molten salt reactor (IMSR) is a graphite-moderated, molten-fluoride salt reactor system that aims to achieve 44 percent thermal efficiency when used for power generation, which equates to 50 percent more electricity generated than conventional LWRs. Terrestrial Energy has completed Phase 1 of the Canadian Nuclear Safety Commission's (CNSC) Vendor Design Review process and expects to finish Phase 2 by mid-2022. In November 2021, the company's U.S. counterpart received a DOE grant of $3 million to work towards licensing and commercialization of the IMSR for U.S. market deployment. The IMSR400, Terrestrial Energy's twin reactor version, was one among three SMRs considered for deployment at Ontario Power Generation's Darlington nuclear site.

TerraPower Molten Chloride Reactor: TerraPower is also working on a fast spectrum molten salt reactor that uses molten chloride as the reactor coolant and fuel. This reactor is fuel-flexible and can run on different levels of enriched uranium. In December 2020, DOE awarded a five-year $170 million cost-sharing award, as part of the ARDP, to Southern Company to further the molten chloride fast reactor experiment in collaboration with TerraPower.

Kairos Power KP-FHR: Kairos Power plans to build the Hermes low-power demonstration reactor, a smaller-scale version of its commercial-scale fluoride salt-cooled high-temperature reactor (KP-FHR), in Oak Ridge, Tennessee, to be operational in 2026. The design involves a pebble-bed reactor that runs on TRISO fuel pebbles with a fluoride salt coolant in a high-temperature, low-pressure system. The Hermes test reactor will only produce heat, not electricity, and lead to the development of the 140-MW commercial-scale KP-FHR. In December 2020, Kairos received the Risk Reduction ARDP funding award from DOE ($303 million) to support the development of the Hermes.

b. High-Temperature Gas-Cooled Reactors

HTGRs are helium- or carbon dioxide- cooled, graphite-moderated thermal reactors that operate at much higher coolant outlet temperatures (700-1,000°C) when compared to existing LWRs (330°C). Graphite absorbs few neutrons and is stable at high temperatures. Instead of water, these reactors use an inert gas like helium as the heat transfer medium. These reactors take advantage of the higher temperatures for increased thermal efficiencies and the provision of process heat for industrial processes.

X-energy Xe-100: Xe-100 is a scalable 80 MW pebble-bed high-temperature gas-cooled reactor that can be integrated into a "four-pack" 320 MW power plant. Xe-100 would use pressurized helium gas to cool its HALEU-based fuel. Instead of the conventional metal fuel rods, the fuel would be packaged in TRISO pebbles (tri-structural isotropic particle fuel), which are graphite spheres infused with ceramic kernels of uranium. In addition to the modular and scalable design, the reactor can integrate into large regional electric grids as a baseload or load-following power source and provide process heat. Other benefits include continuous fueling, on-site fuel storage, reduced construction time, and quick ramping capabilities (from 100 percent to 40 percent power within 20 minutes).

X-Energy was the other recipient of DOE's ARDP awards, which estimated a total of $1.23 billion invested over seven years. The grant was provided to accelerate the development and demonstration of the Xe-100 reactor design and support the construction of a commercial TRISO fuel fabrication facility. As a result, X-Energy, Grant County Public Utility District (GPUD), and Energy Northwest are partnering to evaluate, develop, and site four Xe-100 reactors with a total generating capacity of 320 MW at the Columbia nuclear power station in Richmond, Washington.

c. Gas-cooled Fast Reactors

Gas-cooled fast reactors (GFR) are high-temperature, fast reactors that use helium as the primary coolant. They differ from HTGRs in the spectrum of operation; HTGRs operate in the thermal spectrum, whereas GFRs operate in the fast spectrum. GFRs minimize the production of long-lived radioactive wastes.

General Atomics FMR: EM2 is a 50 MW helium-cooled fast reactor with a core temperature of 850°C. The reactor's higher operating temperature would enhance the net thermal efficiency to 53 percent, compared to 33 percent for conventional LWRs. The reactor will employ a "convert and burn" core design that converts fertile isotopes to fissile and burns them in place for a 30-year core life,[37] eliminating the need to refuel or reposition fuel rods for 30 years. This is significant, in contrast with the 18- to 24-month cycle used to refuel current LWRs. The EM2 aims to produce 1/5th the amount of waste produced by conventional reactors. General Atomics was one of the recipients of DOE's Advanced Reactor Concepts-20 (ARC-20) grant program to develop the conceptual design of the new 50 MW fast, modular reactor and verify fuel, safety, and performance.

d. Lead-cooled Fast Reactors

Lead-cooled fast reactors (LFR) use molten lead or lead-bismuth eutectic alloy as a primary reactor coolant, which offers several advantages, including low-pressure operation and passive cooling in case of accidents. In addition, compared to liquid sodium, molten lead's inert properties add additional safety and economic benefits by solidifying in case of a leak. However, the most challenging problem is the potential to corrode structural steel at higher temperatures.

e. Microreactors

Microreactors are small and compact, comprising about 1 percent of the size of full-sized traditional reactor models, with an electric generating capacity of 1–20 MWs. Microreactors are suitable for use in remote areas that do not have easy access to the electric grid, to displace expensive carbon-intensive fuels such as diesel, or to use for non-electric applications such as hydrogen production and district heating. They are designed to be portable and are compact enough to be potentially transported by truck. Microreactors can operate as part of the grid or independently from the grid as part of a microgrid.

Oklo Aurora: Aurora Powerhouse is a 1.5 MW fast spectrum reactor that intends to operate for 20 years on a single core of HALEU. The first-of-a-kind demonstration microreactor could begin operations in 2025. Aurora was the first advanced non-light water reactor to apply for NRC licensing in June 2020, which was denied without prejudice in January 2022 due to insufficient information on safety and accident response systems. Oklo plans to resubmit a revised application addressing the NRC's questions. In 2021, Oklo received a $2 million cost-sharing award from DOE as part of the Technology Commercialization Fund to help commercialize electrorefining technology for advanced fuel recycling.

BWXT's BANR: BWXT Technologies is working on the development of a transportable prototype microreactor (BANR – BWXT Advanced Nuclear Reactor) that can be used in off-grid and remote areas, with an electric generating capacity of 1–5 MW. The high-temperature gas reactor will use advanced TRISO fuel particles for enhanced fuel utilization. BANR microreactor was selected for one of DOE's Risk Reduction ARDP awards and the Department of Defense's (DoD) second phase of the Project Pele initiative. Project Pele aims to develop and demonstrate a mobile microreactor to provide for resilient and operational power needs.

X-energy Xe-Mobile: Xe-Mobile is a 1-5 MW transportable HTGR microreactor prototype, which aims to operate within three days of delivery and be removed safely within seven days. Xe-Mobile also uses TRISO

37 https://whatisnuclear.com/fast-reactor.html#bigdeal

fuel. X-energy was the other company selected to compete for the Project Pele initiative. After a preliminary design competition and final design review, one of the two companies will be selected for the Project Pele demonstration.

Westinghouse eVinci: Westinghouse is building a 15 MW transportable microreactor that uses TRISO fuel and heat pipe technology to extract passive core heat. The reactor's plug-and-play interface will allow for installation on site within 30 days. The eVinci requires minimal amounts of sodium for use as a coolant and eliminates the need for mechanical pumps, valves, and primary coolant control systems. eVinci has high-speed load-following capabilities and aims to operate for up to 10 years before refueling. Westinghouse was awarded funding from several DOE programs, including the Risk Reduction ARDP award, to help demonstrate and deploy the reactor by 2025.

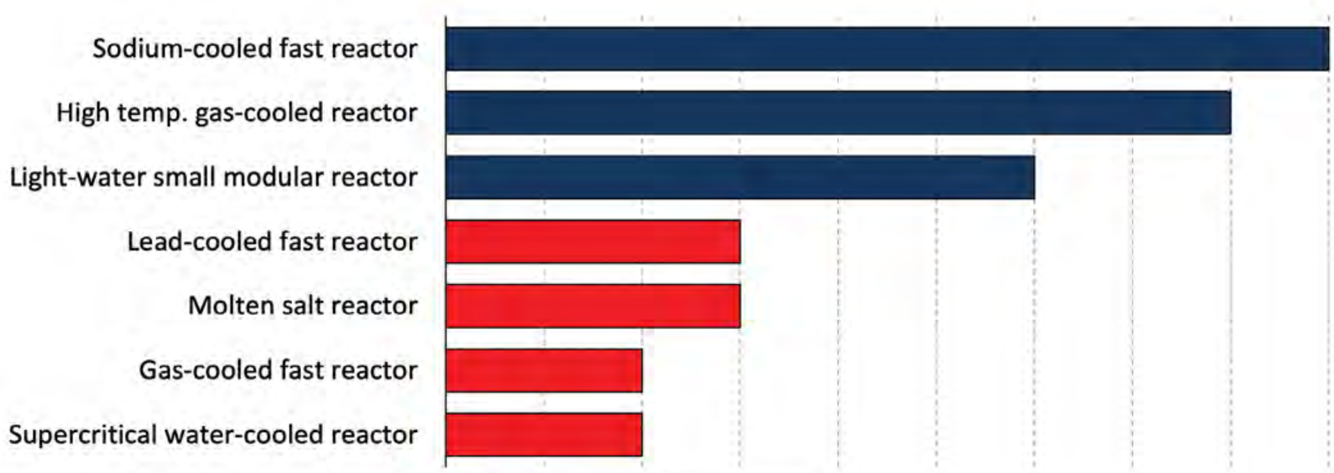
C. Future Deployment and Costs

Every advanced reactor technology type requires continued research and development to identify specific challenges and opportunities for growth. DOE characterizes technology maturity stages using a system of "Technology Readiness Levels" (TRLs), scaling from 1 to 9.[38] The TRL levels for different advanced reactor types are shown in **Exhibit 19**.

Exhibit 19: Advanced Nuclear Technology Readiness Level

Deployment	Actual system proven in operational environment (commercialization)	9
Deployment	System complete and qualified	8
Deployment	Full-scale prototype demonstration in operational environment	7
Development	Pilot-scale prototype demonstrated in relevant environment	6
Development	Technology validated in relevant environment	5
Development	Technology validated in lab	4
Research	Experimental proof of concept	3
Research	Technology concepts formulated	2
Research	Basic principles observed	1

Readiness Level by Type of Reactor



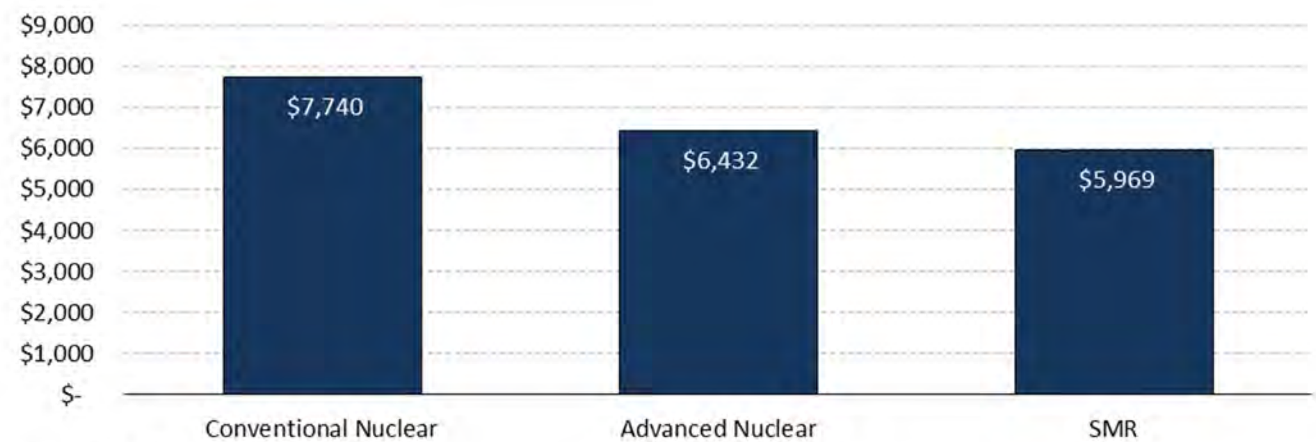
Source: IAEA Power Reactor Information System, Idaho National Laboratory, U.S. DOE

38 Assessment of Technical Maturity of Generation IV Concepts, https://inldigitallibrary.inl.gov/sites/sti/sti/6721146.pdf.

As observed in Exhibit 19 some of these advanced technologies have already been deployed abroad and show global progress (1 HTGR in China, SFRs in Russia, India). However, in the U.S., light-water SMRs are the most mature and have the highest technology readiness levels. NuScale's VOYGR, GE-Hitachi's BWRX-300, and Holtec SMR-160 are in the NRC licensing or pre-licensing stage to enable commercial demonstration and deployment of the reactors by the late 2020s. Among the advanced non-LWRs in the country, SFRs (such as the Natrium) and HTGRs (such as the Xe-100) have the highest technology readiness levels. The proposed advanced reactors' construction and deployment timelines will depend on technology readiness, financing capabilities, and NRC licensing timelines.

Exhibit 20 compares average capital cost assumptions in the latest Integrated Resource Plans (IRPs) filed by several utilities, including Pacificorp, Ameren, Dominion Energy, Entergy, Evergy Metro, etc.[39] As observed, advanced nuclear reactor designs feature reduced capital investments and fewer construction complexities when compared to conventional nuclear reactors, with their cost estimates averaging around $6,400/kW vs. $7,700/kW for traditional nuclear reactors. Advanced reactor developers, on the other hand, are pursuing much more aggressive capital cost targets, as observed with NuScale VOYGR's $3,600/kW estimate[40] and GE Hitachi BWRX-300's $2,250/kW estimate.[41] In addition, the developers contend their models have higher thermal efficiencies than conventional nuclear plants by operating at higher temperatures and using efficient power conversion techniques. Furthermore, compact and simplified designs in SMRs reduce overall capital costs, reduce investor risk, and increase siting flexibility, making them viable carbon-free assets for utilities and electricity customers to consider.

Exhibit 20: 2019-21 Average IRP Capital Cost Estimates for New Nuclear Plants – by Reactor Technology



Source: 2019-2021 Utility IRP Filings

Recognizing the benefits of advanced nuclear energy technologies, several utilities are jumping on the bandwagon to explore the next generation of reactors. **Exhibit 21** lists some advanced reactors under development in the U.S., partnered utilities, and sites selected for demonstration and deployment. In addition, many developers are considering brownfield sites of retired or decommissioned nuclear and coal power plants to take advantage of existing transmission rights, cooling water delivery systems, and the workforce.

39 These costs are average capital cost estimates taken from recent integrated resource plans submitted by regulated utilities and refer to nth of a kind builds where the information was provided.

40 https://www.nuscalepower.com/newsletter/nucleus-spring-2020/featured-topic-cost-competitive

41 https://nuclear.gepower.com/content/dam/gepower-nuclear/global/en_US/documents/product-fact-sheets/GE%20Hitachi%20BWRX-300%20Fact%20sheet.pdf

Exhibit 21: Advanced Reactors Currently Under Development and Their Announced Sites in the U.S.

Reactor Developer	Name	Utility/ Customer	State	Reactor Site	No. of units	Total Cap. (MW)	Tech-nology	Deployment Timeline
X-Energy	Xe-100	Grant PUD, Energy Northwest	WA	Columbia (nuclear)	4	320	HTGR	2027-28
TerraPower	Natrium	Pacificorp	WY	Naughton (coal)	1	345	SFR	2028
NuScale	VOYGR	Utah Associated Municipal Power Systems	ID	Idaho National Lab	6	462	PWR - SMR	2029-30
Holtec	SMR-160		NJ	Oyster Creek (nuclear)	1	160	PWR - SMR	2030
GE Hitachi	BWRX-300	Tennessee Valley Authority	TN	Clinch River (nuclear)	1	300	BWR - SMR	2032
Kairos Power	Hermes	Tennessee Valley Authority	TN	Oak Ridge	1	50	MSR	2026
Westinghouse	Vogtle 3	Southern Co.	GA	Burke County	1	1,117	PWR	Q1 2023
Westinghouse	Vogtle 4	Southern Co.	GA	Burke County	1	1,117	PWR	Q4 2023
Oklo Power	Aurora		ID	Idaho National Lab	1	2	Micro	2025
		U.S. Air Force	AK	Eielson Air Force Base		1-5	Micro	2027
USNC	MMR		IL	Urbana-Champaign	1	15.0	Micro	
TerraPower	MCRE	Southern Co.	ID	Idaho National Lab	1	0.5	MCFR - Micro	

NOTE: The list above does not include projects that have secured financing, but are yet to announce the development site.

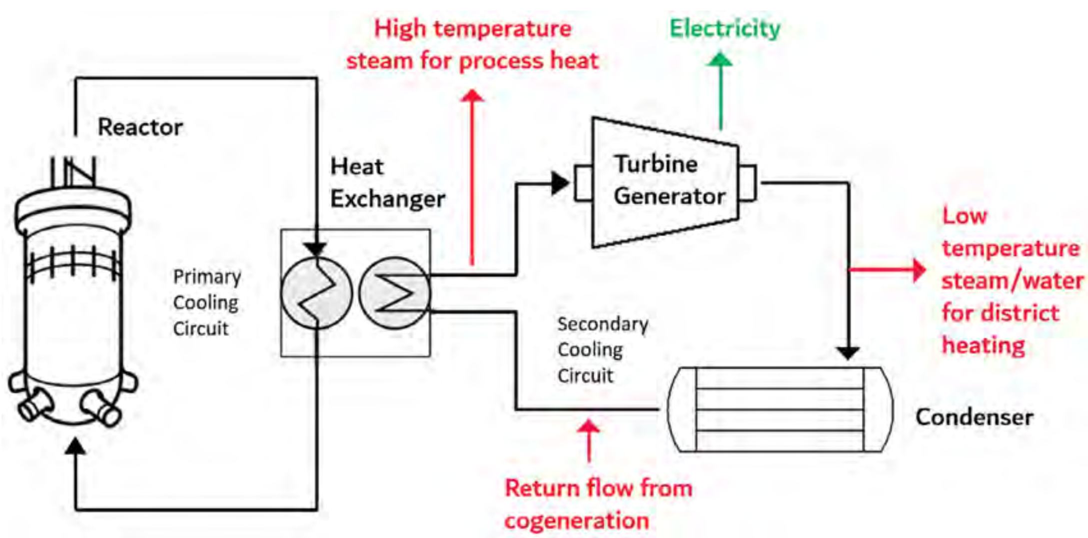
VI. Integrated Nuclear Energy Systems and their Potential Relevance to Meet Net-Zero Carbon Goals

As several countries across the globe venture into economy-wide decarbonization, nuclear energy as a high-energy-density and emission-free fuel source can significantly contribute to achieving these emission reduction goals. However, with low-cost renewables and natural gas depressing wholesale U.S. power prices under the competitive power market structure, today's baseload nuclear generators face immense economic pressures as they sometimes operate at a financial loss during times of low or even negative power prices. To maximize generator profitability, maintain grid reliability, and provide new value creation opportunities, nuclear energy can be coupled with other non-grid applications (e.g., hydrogen production, chemical production, desalination, industrial heating) through integrated energy systems. Increasing the grid flexibility of nuclear generation to better achieve synergies with and complement variable renewable technologies will enhance nuclear energy's value proposition in a net-zero energy world. During low demand periods and at times of negative power prices, the excess energy and heat generated from the nuclear reactor can be diverted to thermal storage or used for hydrogen production.

A. Nuclear Cogeneration: Combined Heat and Power

Nuclear cogeneration describes the process where the heat generated by a nuclear reactor is used to feed electricity into the grid and to meet heating demands in hard-to-abate or difficult-to-electrify industries. Cogeneration or combined heat and power (CHP) applications optimize energy flows and reduce energy losses, improving energy efficiencies. Advantages to the environment are multifold: less heat waste is vented out into the atmosphere, less water is required to cool the reactor, less radioactive waste is produced per energy unit, and the use of nuclear heat in industrial sectors will undoubtedly reduce the need for fossil fuel combustion.[42]

Exhibit 22: Schematic of a Nuclear Cogeneration Power Plant[43]



Based on the point of extraction, high-temperature heat or low-temperature waste heat can be used for a range of cogeneration options. In addition to generating electricity, higher temperature heat (~300–900°C) or steam extracted before the turbine generator can be used for industrial process heating, hydrogen and synthetic fuels production, direct air capture, or thermal energy storage. Some industrial prospects to use the cogenerated high-temperature process heat include oil and tar sand extraction, coal liquefaction and

42 IAEA Guidance on Nuclear Energy Cogeneration, http://www-pub.iaea.org/MTCD/Publications/PDF/P1862_web.pdf.

43 https://royalsociety.org/-/media/policy/projects/nuclear-cogeneration/2020-10-7-nuclear-cogeneration-policy-briefing.pdf

gasification, steelmaking, and aluminum production. Lower temperature waste heat (100–250°C) accessed from the steam turbine exhaust or lower temperature reactors can be used for district heating, seawater desalination, and pulp and paper manufacturing. The only safety concern to account for is the potential radioactivity transfer to the heat application system. This can be resolved by physically isolating the primary loop of the reactor from the heat transfer line.

The overall energy efficiency of a CHP system is defined by the percentage of fuel converted to both grid-supplied electricity and useful thermal energy. Nuclear cogeneration enhances the overall system efficiencies to 65–90 percent, up from the current 33 percent in existing conventional nuclear reactors and 50 percent in advanced nuclear reactors. Co-locating the nuclear power plant with the industrial process site can improve overall economics through waste heat recovery, facility sharing, and reduced transmission costs. LWRs and SMRs can be utilized for low-temperature cogeneration applications such as seawater desalination and district heating. The high working temperatures of liquid-metal fast reactors, molten salt reactors, high-temperature gas reactors, gas-cooled fast reactors, and very-high-temperature reactors make them suitable for industrial process heating.

The concept of nuclear cogeneration is by no means novel.[44] More than 40 district heating nuclear reactors are located in Eastern Europe, where winters are long and cold. China's Haiyang nuclear power station has two Westinghouse AP1000 reactors that produce electricity, cogenerate to cover district heating for the entire city, and replace 12 coal-fired boilers. Japan, Kazakhstan, Pakistan, and the U.S. have desalination capabilities at some reactors to combat water shortages. In addition, about 10 nuclear reactors located in Canada, Germany, India, and Switzerland are used for industrial process heat applications. Nuclear cogeneration's technical and economic viability has already been demonstrated in these situations. Potential issues to tackle for nuclear cogeneration include the need for the industrial process owner to exercise some form of control or ownership of the reactor, licensing ability, public acceptance of reactor sites near population or industrial centers for applications like district heating, and identifying cost-effective methods to transport the heat. In January 2022, U.S. NRC published draft final rules revising its emergency planning requirements for SMRs to allow for smaller emergency evacuation zones – which could enable some of these alternative uses for nuclear energy.

B. Hydrogen Production

Today, hydrogen is mainly used in oil refining, ammonia production, methanol production, and steel making. With hydrogen's high energy content per unit weight and versatility, it is increasingly being viewed as a key component of future energy systems — be it as fuel cell vehicles in the transport sector, fuel for power generation, the industrial-scale replacement for carbon-rich coke in steel manufacturing, or as a clean heat source in metal, glass, and cement manufacturing industries. Hydrogen provides a possible solution to decarbonize industrial processes, for which electrification may not be an option as they require significantly higher temperature heat for some conversions.

Currently, in the U.S., 95 percent of hydrogen production is by steam methane reforming of natural gas and 4 percent by partial oxidation of natural gas via coal gasification, both of which produce significant CO_2 emissions.[45] Only 1 percent of U.S. hydrogen production is by the electrolysis of water. With the economy evolving toward decarbonization and the spotlight shifting to hydrogen, clean commercial-scale hydrogen production methods need to be developed. Clean hydrogen generated from nuclear energy can be one such viable option.

As energy markets continue to incorporate more intermittent wind and solar resources and coal plants continue to retire, the fraction of reliable baseload energy will fall, increasing the need for load-following technologies.

44 IAEA Guidance on Nuclear Energy Cogeneration, http://www-pub.iaea.org/MTCD/Publications/PDF/P1862_web.pdf.

45 NARUC Coal-to-Hydrogen Report, https://pubs.naruc.org/pub/63211779-1866-DAAC-99FB-C7D38972AEB8.

As existing nuclear power plants are more economically viable when operating at full capacity rather than by load-following, cogenerating hydrogen production with excess nuclear energy will enable these plants to achieve a higher rate of operational flexibility and financial viability by creating another value-added product. In theory, nuclear plants could better accommodate seasonal fluctuations in electricity demand and increase their operational revenues by using the generated hydrogen as an energy storage proxy. When electricity prices are low, the nuclear reactor can convert heat or electricity into hydrogen. The produced hydrogen can be stored for later use and converted back to energy during high electricity prices or sold as an energy resource for the transportation or industrial sectors.

There are four technically viable pathways for hydrogen production using nuclear energy:[46, 47]

- Cold electrolysis of water using nuclear electricity (viable at times of low electricity demand)
- Low-temperature (<200°C) or high-temperature (~550–900°C) steam electrolysis using nuclear heat and nuclear electricity (cogeneration)
  - Higher thermal efficiency and lower production cost than conventional water electrolysis
- Thermochemical production using nuclear heat and nuclear electricity (cogeneration)
- Steam methane reforming using nuclear heat
  - Using a nuclear heat source instead of combusting natural gas to facilitate the reaction would reduce natural gas consumption by ~30 percent and eliminate flue gas CO_2 emissions

Exhibit 23 details the candidate hydrogen production technologies for nuclear energy integration, including maximum temperature, pressure, efficiencies, inputs, outputs, and production costs.[48] Different nuclear reactor types are suitable for each hydrogen production pathway, and these are categorized by the process heat temperature levels that they offer. Currently, the predominant reactors in the U.S., LWRs, have outlet temperatures around 300°C and are suitable for water electrolysis or low-temperature steam electrolysis. Advanced nuclear reactors such as GCRs, HTGRs, LFRs, and MSRs are more promising for high-temperature electrolysis and thermochemical production methods.

Exhibit 23: Candidate Technologies for Hydrogen Production Using Nuclear Energy

	Electrolysis			Thermochemical	
	Alkaline electrolysis	PEM electrolysis	Solid oxide electrolysis	Steam methane reforming	Thermochemical S-I
Technology readiness	9	6-8	5	9	4
Temperature (°C)	60	60	800	870	910
Pressure (atm)	1	1	1.57	4.1	3.85
Efficiency (HHV, %)	30	27	36	79	25
Electricity input (MJ)	180	200	146	1.4	75
Heat input (MJ)	26	26	30	0	375
Water input (kg)	11.5	11.5	83	10.3	9
Natural gas input (kg)	0	0	0	2.9	0
CO_2 out (kg)	0	0	0	5-11	0
Production cost ($2019/kg)	$5.92	$3.56 - 5.46	$2.24 - 3.73	$1.54 - 2.30	$2.18 - 5.65

In 2019, DOE awarded cost-share funding to two LWRs to demonstrate integrated hybrid energy systems that can produce electricity and non-electric products. Exelon received an award to install a 1 MW proton exchange membrane (PEM) electrolyzer in one of its reactor sites and demonstrate dynamic operation. Exelon partnered with Nel Hydrogen to demonstrate on-site hydrogen production, storage, and normal usage at the Nine Mile

46 The Royal Society Report on Nuclear Cogeneration, https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/nuclear-cogeneration/.

47 https://www.world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx

48 Roxanne Pinksy et al., Comparative review of hydrogen production technologies for nuclear hybrid energy systems, Progress in Nuclear Energy, Volume 123 (May 2020)

Point nuclear station in New York state. Exelon's generation spin-off, Constellation Energy, which now owns and operates Nine Mile targets to install the PEM electrolyzer and begin operations in late 2022 or early 2023. The second award was provided to Energy Harbor to demonstrate the technical feasibility and economic viability of hybrid hydrogen production at the Davis-Besse nuclear plant, using low-temperature electrolysis with PEM technology. Collaborating with INL, Xcel Energy, and Arizona Public Service (APS), Energy Harbor expects to start producing zero-carbon hydrogen at the Davis-Besse station by 2023.

Shortly after, in October 2020, DOE announced a $10 million award to Xcel Energy to demonstrate high-temperature steam electrolysis at the Prairie Island nuclear plant and enable flexible operations during times of peak wind generation. In 2021, as part of DOE's H2@Scale clean hydrogen initiative, DOE granted $20 million in funding to APS to produce clean hydrogen from a low-temperature electrolysis system integrated at the Palo Verde nuclear plant. The project aims to draw on six metric tons of the stored hydrogen to generate ~200 MWh of electricity during periods of high electricity demand and low solar irradiation, thereby demonstrating power-to-hydrogen-to-power capabilities. All of the listed pilot projects will help advance DOE's Hydrogen Earthshot goal of lowering the cost of clean hydrogen to $1/kg within a decade.

The Bipartisan Infrastructure Law provides $8 billion for the demonstration of regional clean hydrogen hubs and included a directive requiring at least one of the hydrogen hubs to demonstrate hydrogen production from nuclear energy.

C. Nuclear-Coupled Carbon Capture

In a carbon-constrained world, direct air capture (DAC) technology, which uses chemical reactions to capture CO_2 directly from ambient air (as opposed to from point sources such as a fossil power plant or cement factory), can potentially play a significant role in achieving net-zero energy goals. In April 2022, DOE awarded a total of $5 million to two cost-shared projects to explore the benefits of constructing direct air capture (DAC) technology at two nuclear power plants — Constellation Energy's Byron and Southern Company's Farley nuclear. Both projects aim to leverage the available thermal energy from nuclear plants to separate CO_2 from the atmosphere for off-site geological storage.

VII. Current Sources of Nuclear Fuel and Management of Spent Nuclear Fuel

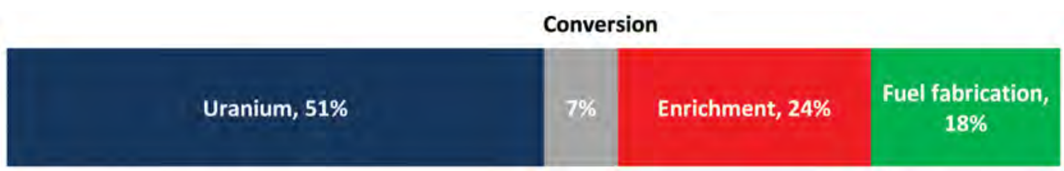
A. Current Sources of Nuclear Fuel

The most common fuel used by nuclear power plants to produce electricity through the nuclear fission reaction is low enriched uranium (LEU), or uranium containing up to 5 percent U-235, a uranium isotope that can split into atoms easily. Uranium goes through the front-end steps of mining, milling, conversion, enrichment, and fabrication to prepare it for use in reactors, whereas the back-end of the fuel cycle tackles safely managing and either disposing or recycling the spent nuclear fuel.

Uranium ore mined through techniques such as open pit, underground, and in-situ recovery is crushed, pulverized, ground to a fine powder, and treated with chemicals in milling facilities to produce uranium concentrate (U_3O_8). In the third step, i.e., conversion, the uranium concentrate is converted to uranium hexafluoride (UF_6). UF_6 is enriched through the process of gaseous diffusion or gas centrifuge to alter the isotopic concentration and increase the prevalence of U-235. Natural uranium mined contains only 0.7 percent U-235. In the final step of fuel fabrication, UF_6 is converted into UO_2 powder that is formed into pellets and fabricated into fuel rods.

As observed in the breakdown of front-end nuclear fuel cycle costs below, uranium extraction contributes to more than 50 percent of the total cost of fuel.

Exhibit 24: Breakdown of Nuclear Fuel Component Costs[49]



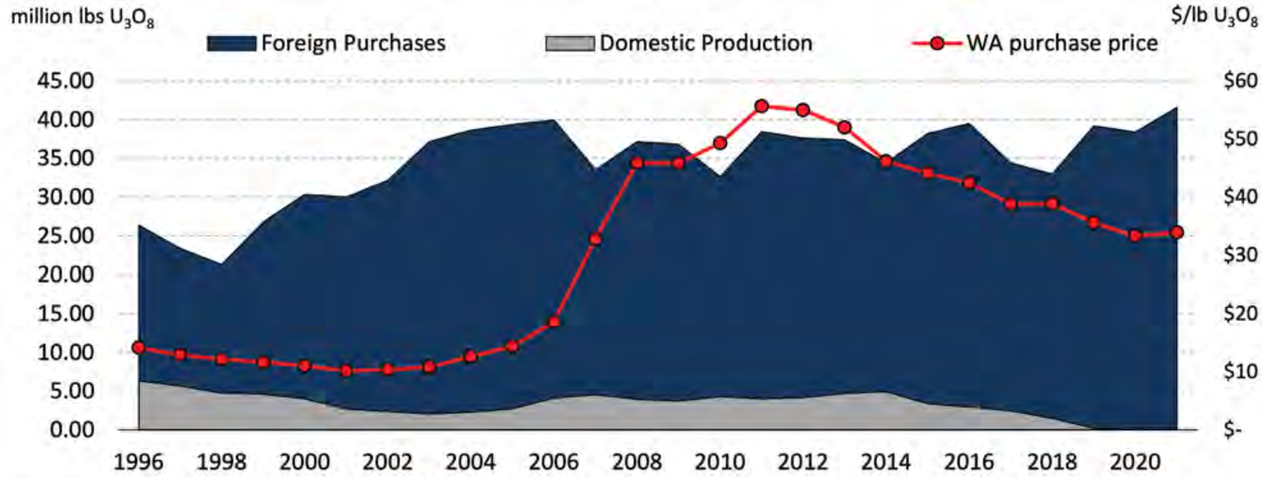
In the early years, federal government subsidies and trade barriers led to a gold rush in American uranium mining, and domestic production peaked in the 1980s. However, after the trade protections were lifted, increased competition from higher-grade and lower-cost ore countries like Canada, Australia, and South Africa, and dumping of subsidized uranium supplies from Russia, Kazakhstan, and Uzbekistan into the market led to a severe decline in U.S. production. In February 1993, the Megatons to Megawatts agreement[50] was executed between Russia and the United States, which required diluting or downblending Russian highly enriched uranium from dismantled ex-Soviet nuclear weapons over the course of 20 years, to produce LEU for use in U.S. nuclear reactors. Although the deal simultaneously addressed American proliferation concerns and energy needs, it provided direct competition to U.S. uranium producers and crowded out the domestic uranium production market. In 1989, U.S. nuclear power plant operators had relied on foreign suppliers for 51 percent of their uranium concentrate (U3O8) needs. This number shot up to 81 percent by 1996 and almost 100 percent in 2019.

After 2010, uranium prices steadily declined. The Fukushima nuclear disaster in 2011 drove the idling/shutdown of many existing nuclear reactors in Japan and other countries, and the cancellation of proposed new reactors, which created a global uranium oversupply and depressed global spot prices. In the U.S. alone, declining domestic demand and premature plant retirements, caused in part by competitive generating sources like natural gas and wind continued to depress uranium prices. Low spot prices and, in some cases, resource depletion forced several mining companies in the U.S. to permanently halt operations.

49 https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx

50 https://www.eia.gov/todayinenergy/detail.php?id=13091

Exhibit 25: U.S. Domestic Uranium Production vs. Imports



Source: EIA Uranium Marketing Report and EVA Analysis

Due to state support and subsidies, State-Owned Enterprises (SOEs) like Kazakhstan's KazAtomProm and Russia's UraniumOne are able to produce uranium regardless of price and market conditions. As a result, uranium production from SOEs flooded the market and artificially depressed global uranium prices, affecting Western miners' ability to cover their operating costs and sustain long-term mining operations.[51] Trends of production cuts will continue until current market rates increase sufficiently to sustain mining operations.

Currently, there are only two mines and one mill operating in the U.S., one operating enrichment plant (Urenco), and four operating fuel fabrication facilities (Framatome, Westinghouse, Global Nuclear Fuel, and BWXT). The nation's only conversion plant (Honeywell's ConverDyn) is idled. ConverDyn is slated to restart in 2023, and until then, the U.S. will rely on foreign conversion plants.

U.S. nuclear power plant operators now rely mostly on imports and inventories to cover their fuel requirements. **Exhibit 27** shows that Canada, Kazakhstan, Russia, Australia, and Uzbekistan were the top five countries of origin for uranium purchases in 2020, accounting for 94 percent of the total purchases, equivalent to roughly 39.4 million pounds of uranium concentrate. Canada and Kazakhstan alone contributed to more than 50 percent of the uranium concentrate purchases. The U.S.' contribution dropped to an insignificant amount. Domestic utilities' inclination to cut costs while ensuring reliable delivery continues to increase the market share of these foreign countries.

On the contrary, the U.S. fuel fabrication industry is still thriving due to restrictive tariffs and strict reporting requirements for imported fuel assemblies. Compared to U.S. producers of uranium concentrate and enriched uranium, fuel fabrication facilities do not face the same market pressures or competition from foreign state-supported facilities.

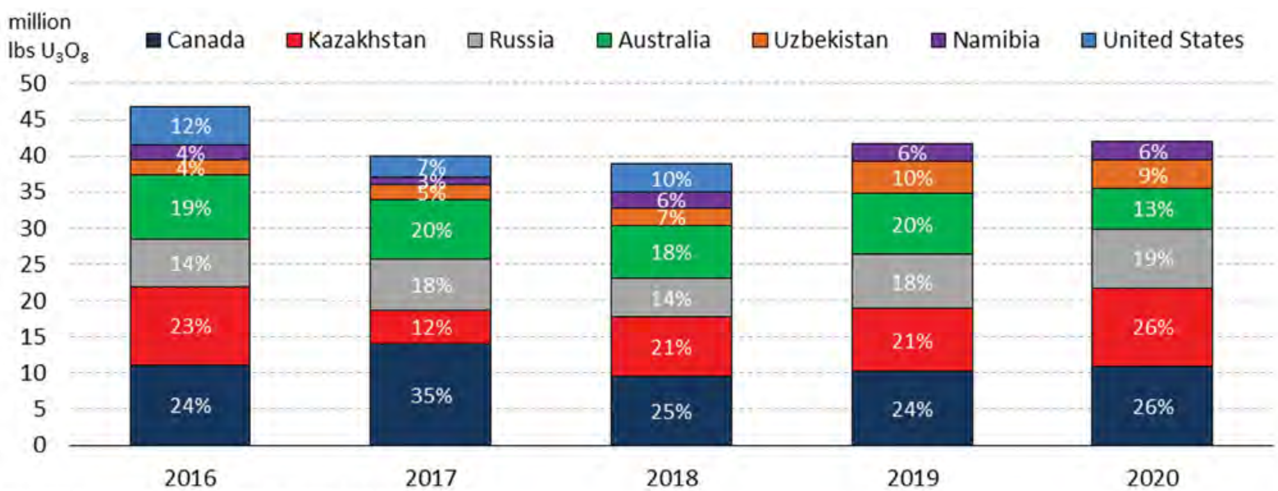
U.S. reliance on imports, especially from SOEs, can raise the risk of fuel shortages and threaten national energy security when events of political disruption, such as Russia's war on Ukraine, lead to import bans or sanctions. In March 2022, the federal government reacted to Russia's assault on Ukraine with a ban on Russian fuel imports including oil, coal, and natural gas, but left uranium out of the mix due to the domestic power sector's dependence. Russia and its allies Kazakhstan and Uzbekistan are responsible for more than 50 percent of the uranium powering U.S. nuclear reactors. Russia dominates the international markets for two essential steps in the nuclear fuel supply chain, i.e., conversion and enrichment, which makes any potential uranium sanctions or embargoes against Russia challenging for the nuclear fuel industry.

51 Report on Effect of Imports of Uranium on the National Security, https://bis.doc.gov/232

Exhibit 26: Commercial Uranium Production Facilities in the U.S.

Facility Type	Name	State	Operating Status
Mining	Lost Creek Project	WY	operating
Mining	Smith Ranch-Highland Operation	WY	operating
Mining	Crow Butte Operation	NE	standby
Mining	Alta Mesa Project	TX	standby
Mining	Hobson ISR Processing Plant	TX	standby
Mining	La Palangana ISR Uranium Project	TX	standby
Mining	Ross CPP	WY	standby
Mining	Nichols Ranch ISR Project	WY	standby
Mining	Kingsville Dome	TX	standby
Mining	Rosita	TX	standby
Mining	Willow Creek Project	WY	standby
Milling	White Mesa	UT	operating
Milling	Shootaring Canyon	UT	standby
Milling	Sweetwater	WY	standby
Milling	Sheep Mountain	WY	undeveloped
Conversion	ConverDyn Metropolis Works	IL	idle-ready
Enrichment	URENCO USA	NM	operating
Enrichment	Oak Ridge	TN	closed
Enrichment	USEC Paducah	KY	closed
Enrichment	USEC American Centrifuge, Piketon	OH	closed
Fabrication	Westinghouse	SC	operating
Fabrication	Global Nuclear Fuel	NC	operating
Fabrication	Framatome	WA	operating
Fabrication	BWX Technologies	VA	operating

Exhibit 27: Uranium Purchases for U.S. Nuclear Reactors by Country of Origin



Source: EIA Uranium Marketing Report and EVA Analysis

Such geopolitical tensions underscore the need to swiftly re-develop and expand the domestic uranium supply chain. Ranked 15th in the world for known and assured uranium reserves, the U.S. has the required resources. In addition, federal government support through policies or subsidies can help ramp up domestic uranium production to reduce reliance on foreign supplies.

Existing nuclear reactors mostly operate on LEU, whereas the next wave of advanced reactors and SMRs currently under development need HALEU. Currently, Russia is the only country that has commercially available HALEU enrichment capabilities. Centrus Energy is deploying a new enrichment technology to build a HALEU production facility in Piketon, Ohio, and has already crossed the NRC licensing milestone for U-235 enrichment of up to 19.75 percent. Urenco, the country's only operating enriched uranium producer, is working on relicensing the existing facility entirely to enable uranium enrichment capabilities of up to 10 percent U-235 by 2024. The company plans to build a co-located, separate enrichment facility for up to 20 percent U-235 enrichment in the presence of strong market signals or long-term takeoff contracts with advanced nuclear reactors. In December 2021, DOE issued a request for information (RFI) to explore and support the availability of HALEU for commercial use in domestic civilian reactors.

B. Management of Spent Nuclear Fuel

The back end of the nuclear fuel cycle includes the steps of interim storage of spent nuclear fuel, final disposal, and reprocessing.

After their use in reactors, fuel assemblies containing the spent nuclear fuel need to be stored safely to allow decay of the radioactivity and heat within. Therefore, they are generally stored in a circulating water-cooled pool at the reactor site to absorb the heat and block radiations from the fission products. Once sufficiently cooled, usually in 5 to 7 years, the spent nuclear fuel can be moved to a dry cask storage system, i.e., large concrete and stainless steel storage containers located at the reactor site or away from the site in a consolidated interim storage facility (CISF). The long-term and permanent disposal solution for spent nuclear fuel is deep geological disposal through mined repositories or deep boreholes. Finland already has one such repository site under construction, slated to start operations in 2024.

The Nuclear Waste Policy Act of 1982 (NWPA) established the Federal responsibility to permanently dispose of spent nuclear fuel and high-level radioactive waste[52] in geological repositories. DOE entered into agreements with utilities and the Federal government collected a fee from electric ratepayers to cover the costs of developing the repository. In 1987, Congress amended the NWPA to direct DOE to continue study of the Yucca Mountain site in Nevada exclusively and authorized DOE to develop a monitored retrievable storage facility subject to limitations associated with continued progress on a repository. However, strong political and legal opposition indefinitely delayed and prevented the Yucca Mountain facility from being built. The fee collection for the Nuclear Waste Fund to support the development of a permanent disposal location was finally suspended in 2014 following lawsuits.

In 2009, the Obama administration deemed the Yucca Mountain site infeasible and established the Blue Ribbon Commission on America's Nuclear Future in the subsequent year to review nuclear waste policy. The panel recommended DOE pursue a consent-based approach to siting spent nuclear fuel and high-level radioactive waste facilities. In 2017, DOE issued a draft consent-based siting process for interim storage and disposal.

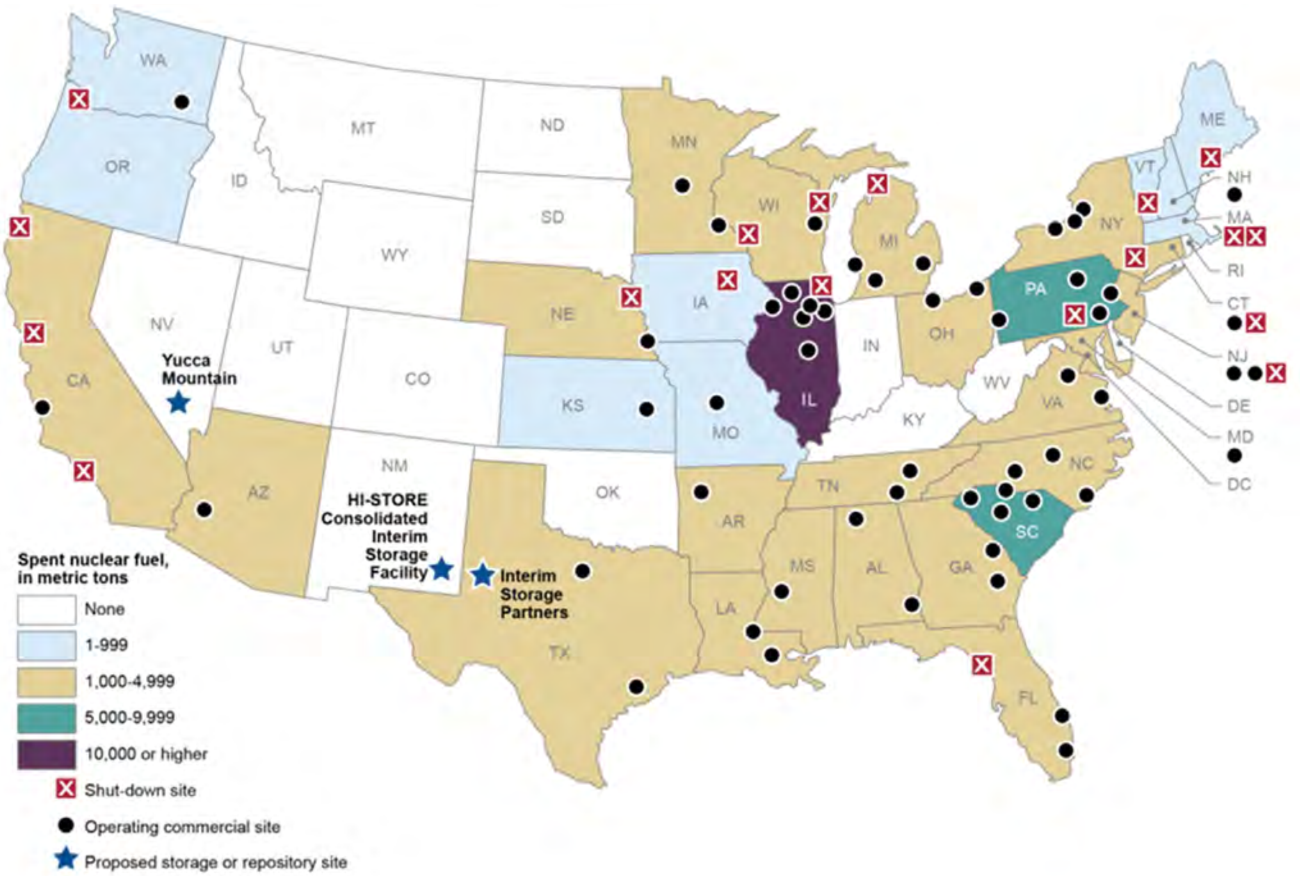
Shortly after, the private industry spearheaded efforts to build CISFs: Holtec International and Interim Storage Partners (ISP) submitted license applications to the NRC to construct and operate CISFs in New Mexico and Texas, respectively. Although NRC issued a license to ISP last year and will soon decide on Holtec, both facilities face strong opposition from New Mexican and Texan state legislators. In November, 2021, DOE once again kickstarted efforts and issued an RFI on using a consent-based siting process to identify Federal interim storage facilities.

52 High-level radioactive waste (HLW) refers to the type of nuclear waste with the highest activity, containing fission products and transuranic elements in the reactor core. Highly radioactive liquid and solid materials also result from the reprocessing of spent nuclear fuel. HLW contain significant quantities of long-lived radionuclides, which necessitate long-term isolation.

Two private companies (Deep Isolation and NuclearSAFE) have begun developing private commercial approaches for deep geological disposal through deep boreholes. The technical basis and legal framework for use of deep boreholes for spent nuclear fuel disposal is yet to be developed.

With the repository efforts stalled and CISFs unfinished, utilities are storing spent nuclear fuel mainly on site at power plants, as the total inventory of stored spent nuclear fuel rises steadily year after year. Many operators have begun moving spent nuclear fuel to on-site dry cask storage to reduce demands on their spent fuel pool storage facilities located on site. At the end of 2019, the total inventory of spent nuclear fuel from 75 commercial reactor sites was 86,000 tons.[53] As observed in **Exhibit 28**, Illinois, Pennsylvania, and South Carolina had the highest volumes of stored spent nuclear fuel.

Exhibit 28: Stored Spent Nuclear Fuel Amounts, through 2019, and Locations, as of June 2021



Reprocessing of spent nuclear fuel to recover fissile and fertile materials (mostly plutonium and small amounts of uranium) for use as recycled fuel is technically feasible. Reprocessing spent nuclear fuel extracts about 30 percent more energy from the original uranium and reduces the volume of high-level waste to be disposed of. Although several countries like Russia, China, and Japan reprocess spent nuclear fuel, it is currently not practiced in the U.S. due to economics and proliferation concerns.[54]

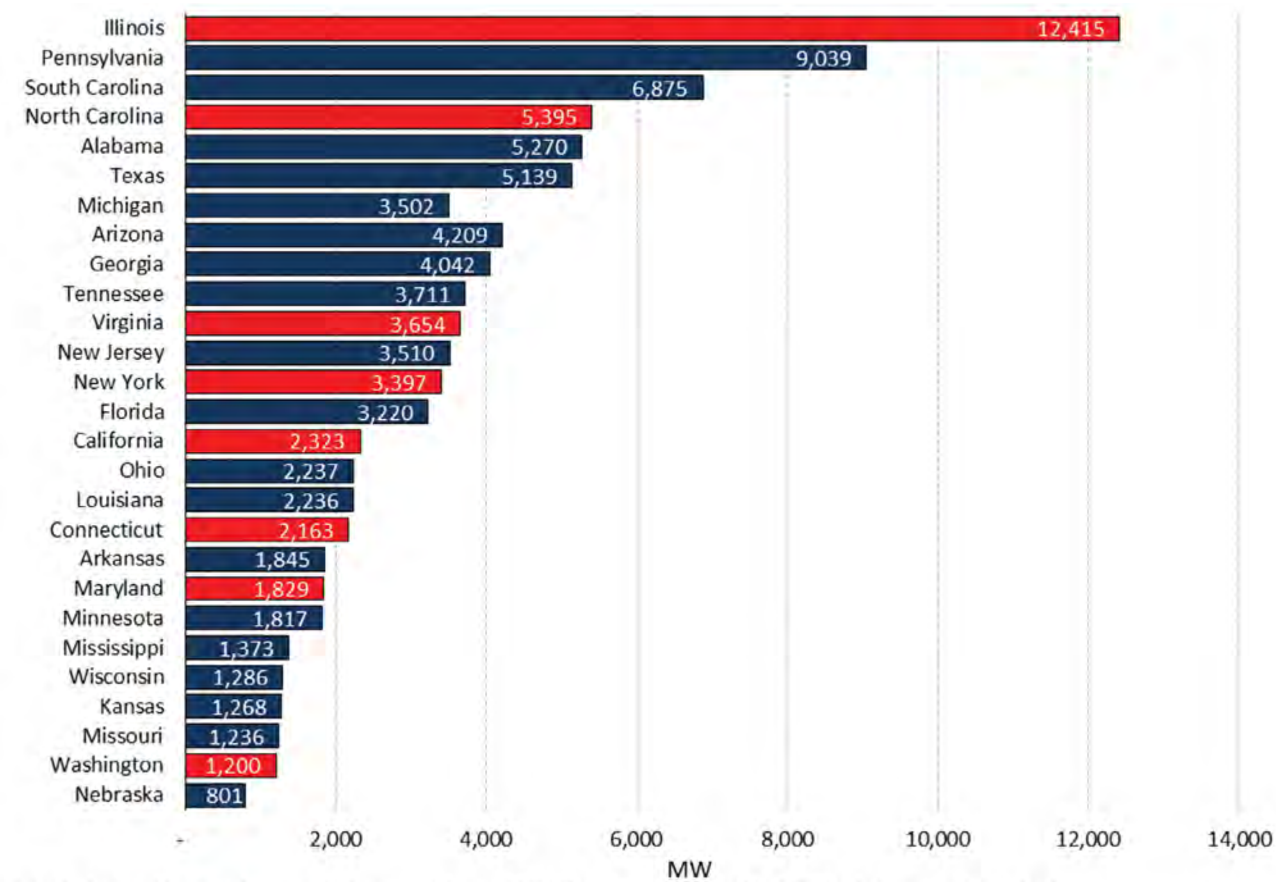
53 USGAO Report on Commercial Spent Nuclear Fuel, https://www.gao.gov/assets/gao-21-603.pdf#page=27

54 https://www.washingtonpost.com/magazine/2022/04/11/america-nuclear-waste-san-onofre/

VIII. States with the Potential to Retain Existing or Develop New Nuclear Energy Projects

As many states in the U.S. continue to advance their own clean energy targets absent any federal consensus, the question of how to meet these ambitious targets arises. Currently, as shown earlier in Exhibit 15, at least 13 states have a 100 percent CES or net-zero carbon goal before the middle of the century, with many other states and localities considering the same. Of the 13 states with 100 percent CES or net-zero carbon goals, eight currently have operating nuclear power plants within their state's footprint that contribute to their zero-carbon generation mix. For example, in Illinois, the state with the largest nuclear fleet in the country, nuclear power plants account for over 80 percent of the state's carbon-free electric generation, as shown previously in Exhibit 9. However, the current operating licenses of all Illinois nuclear plants are set to expire before the state's 2045 goal of 100 percent carbon-free electric generation. **Exhibit 29** shows the nuclear capacity whose operating licenses are currently set to expire before 2050 by state and highlights the states with currently established 100 percent CES or net-zero carbon goals.

Exhibit 29: U.S. Nuclear Capacity with Current License Expirations Before 2050 - by State



Note: Red colored bars mark states which currently have a 100% Clean Energy Standard by 2050 (excludes executive orders)
Source: Nuclear Regulatory Commission data

After the NRC issues its initial 40-year operating license, nuclear power plant operators can apply for incremental 20-year operating extensions; the first one called the initial license renewal (ILR), whereas all subsequent ones are called subsequent license renewals (SLR). All operating nuclear power plants not scheduled for retirement have either received their ILR or applied for their ILR. The first nuclear plants approaching the end of their ILR are also two of the oldest nuclear power plants still in operation. The current operating licenses of Constellation's Nine Mile Point and Ginna power plants, both located in New York state, are set to expire in August and

September 2029. New York is also one of the 13 states with a 100 percent CES or net-zero carbon goal, with its three nuclear plants currently contributing almost half of its zero-carbon emission electric generation.

After addressing the issue of retaining the existing nuclear fleet to meet their CES and net-zero carbon goals, states may consider the various options to add additional zero-carbon resources to their electric generation mix. After long-time opposition to new nuclear projects, many states are revising statutes to enable the siting and construction of new nuclear generation. For example, West Virginia and Indiana recently passed legislation allowing local utilities and public utility commissions to consider new nuclear power projects in their long-term resource plans. In February 2022, West Virginia enacted Senate Bill (SB) 4, which effectively repeals the restrictions on the construction of new nuclear power plants in the state. Currently, there are no operating nuclear power plants in the state of West Virginia. However, SB 4 allows its local utilities to seriously consider new nuclear projects as potential alternatives to reduce their carbon footprint.

In addition, in March 2022, the Indiana General Assembly advanced a bill allowing the state's local utilities to consider SMRs as viable alternatives for zero-carbon power plants in their long-term resource plans. There are currently no operating nuclear plants in the state of Indiana. However, similar to West Virginia, many of Indiana's coal-fired power plants are projected to retire within the next 25 years. As utilities look for ways to replace the retiring coal-fired electric generating capacity, the Indiana and West Virginia state legislatures now enabled these utilities to consider nuclear power plants as replacement generation.

Additionally, the Alaskan legislature is currently considering a bill that aims to streamline the state's approval process for small nuclear reactors. Although the NRC must approve any new reactor, the proposed Alaska House bill would exempt microreactors from some decades-old state requirements. There are currently two advanced nuclear projects under consideration in Alaska: Copper Valley Electric Association's SMR and an SMR on the Eieson Air Force Base.

Whereas states without nuclear power plants, such as Indiana and West Virginia, now allow for the construction of new nuclear power projects, there are still 12 states that currently have some form of restriction on the construction of new nuclear power plants in place. Six of these 12 states have currently operating nuclear plants and two other states (Massachusetts and Vermont) used to have nuclear power plants operating within the state that have since closed. **Exhibit 30** lists the 12 states currently not allowing for new nuclear projects and the conditions under which new nuclear projects could be approved.

Exhibit 30: States with Existing Limitations on New Nuclear Construction

State	Condition	Existing Nuclear Capacity?
California	- Waste Disposal Capability	Yes
Connecticut	- Waste Disposal Capability	Yes
Hawaii	- Legislative Approval	No
Illinois	- Legislative Approval or - Waste Disposal Capability	Yes
Maine	- Voter Approval - Waste Disposal Capability	No
Massachusetts	- Voter Approval - Legislative Approval	Retired
Minnesota	- Outright Ban	Yes
New Jersey	- Waste Disposal Safety	Yes
New York	- Outright ban (in certain counties)	Yes
Oregon	- Voter Approval - Waste Disposal Capability	No
Rhode Island	- Legislative Approval	No
Vermont	- Legislative Approval	Retired

About half of the 12 states listed require some federal decision on the safe long-term storage of spent nuclear fuel and five states require legislative approval. Only one state, Minnesota, outright bans the construction of new nuclear power plants within the state. New York has banned the construction of new nuclear power plants within the counties of Suffolk and Nassau and some portion of the county of Queens, all of which make up Long Island and part of New York City. Most of these 12 states also have already in place or are seriously considering expanding their current goals to a 100 percent CES before the century's midpoint. Allowing local utilities to consider nuclear energy a viable option for zero-carbon emission electric generation resources will be vital to meeting these ambitious decarbonization goals.

A. Non-Electricity Related Benefits of Nuclear Energy

Besides its zero-carbon emission and reliability characteristics, states can also consider nuclear energy's impacts on land use, employment, and local tax revenue over other forms of carbon-free electric generation resources such as wind and solar energy.

By 2050, more than 147,000 MW of currently operating coal-fired power plants will retire, equivalent to approximately 75 percent of the current operating coal fleet. **Exhibit 31** shows the approximate land requirement to replace 1,000 MW of coal capacity with either nuclear, solar, or wind power plants. According to estimates by the National Renewable Energy Laboratory (NREL) and NEI, wind, solar, and nuclear energy require approximately 85.3,[55] 8.0,[56] or 0.8[57] acres per megawatt of installed electric generating capacity in available land. After considering the different utilization rates of the three resources, to replace the energy lost by retiring one 1,000-MW coal plant, a total of approximately 462 acres, or 350 football fields, is required to build a 556-MW nuclear power plant. Conversely, the land use requirement increases 35-fold and 231-fold when replacing the retiring 1,000-MW coal-fired power plant with solar or wind resources, respectively. Hypothetically, if the entire estimated 145,000 MW of retiring coal capacity were to be replaced by just nuclear, solar, or wind resources, the required land size would equal 105 square miles, 3,625 square miles, or 24,143 square miles, respectively. For reference, the size of the entire state of West Virginia is 24,087 square miles.

Exhibit 31: Land Requirement by Technology to Replace 1,000-MW Coal Plant

		Coal	Nuclear	Solar	Wind
Capacity	*MW*	1,000	556	2,000	1,250
Capacity Factor	*%*	50%	90%	25%	40%
Generation	*GWh*	4,380	4,380	4,380	4,380
Land Use	*acre/MW*	n/a	0.8	8.0	85.3
Land Use	***total acres***	**n/a**	**462**	**16,000**	**106,564**

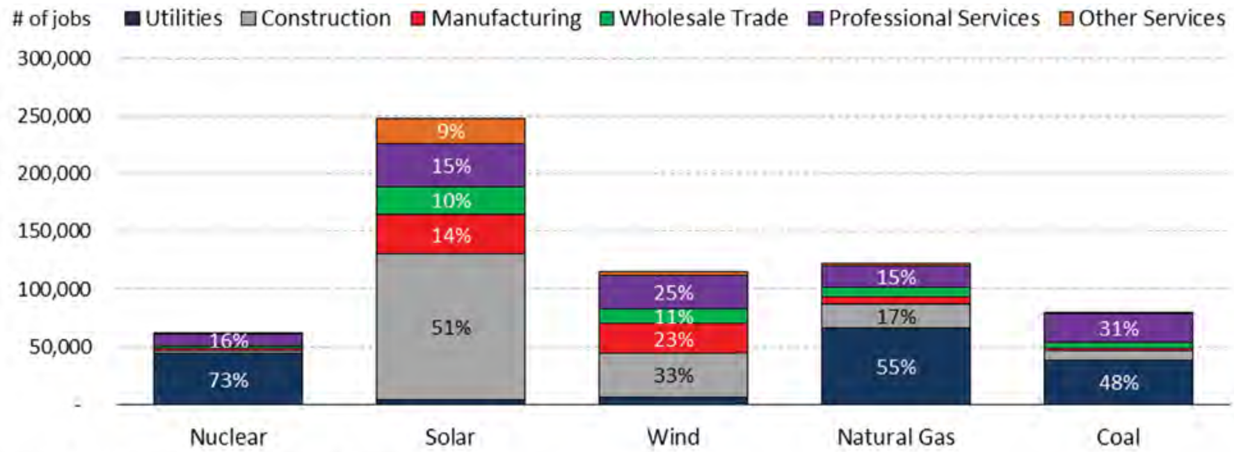
Besides the land requirement, states will also likely consider the impact of various zero-carbon emission resources on local community employment and tax revenues. According to the 2020 U.S. Energy & Employment Report (EER), an annual survey of the U.S. electric power sector workforce, by far the most jobs in the U.S. energy sector are associated with solar energy. **Exhibit 32** shows that almost 250,000 people were employed in the solar energy supply chain, followed by natural gas with 122,000 and wind with 115,000 jobs associated with their respective supply chains. According to the 2020 EER, the nuclear supply chain employed about 61,000 people in 2019.

55 https://www.nrel.gov/docs/fy09osti/45834.pdf

56 https://www.nrel.gov/docs/fy13osti/56290.pdf

57 https://www.nei.org/news/2015/land-needs-for-wind-solar-dwarf-nuclear-plants

Exhibit 32: 2019 U.S. Energy Employment by Fuel Type & Sub-Sector



Source: 2020 U.S. Energy & Employment Report

However, almost all of the jobs associated with the solar energy supply chain are linked to the current massive expansion of solar energy across the country. As of March 2022, almost 373,000 MW of solar energy capacity is currently active in the interconnection queue across the seven major U.S. independent system operators. For reference, the current installed solar capacity is approximately 65,000 MW. As a result, more than half of the almost 250,000 people are employed in the construction sector within the solar supply chain. Conversely, only about 3,700 people are employed in the utility sector within the solar supply chain responsible for operating and maintaining the existing solar farms. Therefore, once the solar projects in a specific community are constructed and operating, only a fraction of the jobs associated with the project remain in the community.

On the other hand, almost three-quarters of the entire workforce associated with the nuclear supply chain is associated with operating and maintaining the existing nuclear fleet. For example, **Exhibit 33** shows the number of employees in the utility subsector in 2019 according to the 2020 U.S. EER[58] by associated generating fuel, the installed capacity in 2019, and the resulting number of employees per 100 MW by fuel. In 2019, almost 45,000 people were employed to operate and maintain the existing nuclear fleet of approximately 99,000 MW, resulting in a ratio of 44.8 employees per 100 MW of installed capacity. On the other hand, solar and wind only employed 11.0 and 6.5 employees per 100 MW of installed capacity in 2019, respectively.

Exhibit 33: 2019 U.S. Utility Sector Employment by Fuel Type & Estimated Utility Employment When Replacing Retiring Coal Capacity

	Employees in Utility Sector	2019 Capacity (MW)	# of Employees per 100 MW	Capacity (MW)	Estimated Capacity Factor	Generation (GWh)	# of Employees
Nuclear	44,366	98,990	44.8	81,764	90%	644,627	36,645
Hydro	17,464	101,666	17.2	210,250	35%	644,627	36,116
Coal	38,158	231,536	16.5	147,175	50%	644,627	24,255
Natural Gas	66,500	447,899	14.8	183,969	40%	644,627	27,314
Solar	3,682	33,397	11.0	294,350	25%	644,627	32,452
Wind	6,360	97,938	6.5	183,969	40%	644,627	11,947

Source: 2020 U.S. EER, EIA 860 data & EVA analysis

Even when adjusting for the lower capacity factor of wind and solar and, therefore, the greater amount of capacity needed to replace the retiring fossil fuel-fired capacity, nuclear energy would still be the largest employer. For example, assuming that one technology would replace the roughly 147,000 GW of retiring

58 https://www.usenergyjobs.org/

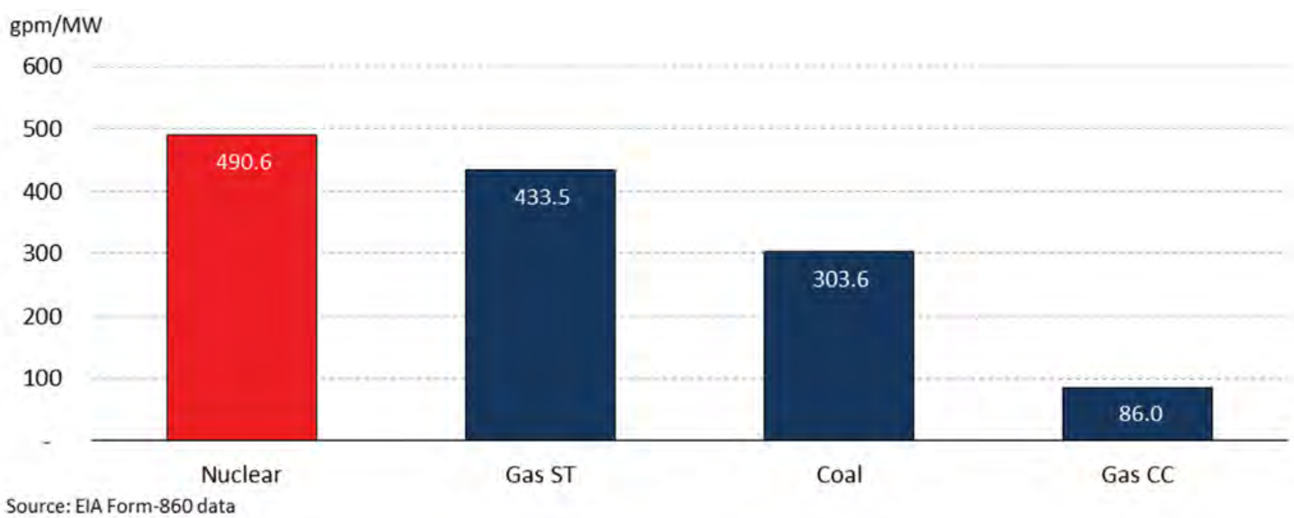
coal capacity, the nuclear power sector would require roughly 36,600 employees to operate and maintain the additional almost 82,000 MW of capacity, compared to 32,400 employees in the solar power sector, and just 12,000 employees in the wind power sector.

It is worth noting that these employment numbers are based on current nuclear energy technologies (PWR and LWR). New reactor designs aim to reduce the staffing requirement to lower the overall cost of a new advanced nuclear project and make it more competitive. Nonetheless, even at reduced staffing levels, nuclear energy provides a significant source of employment in the region it is located.

Besides the significant number of permanent jobs at nuclear power plants, many of which are unionized, nuclear power plants are also some of the largest local, state, and federal taxpayers in their respective communities. According to NEI,[59] the average U.S. nuclear plant pays about $67 million in federal and $16 million in state and local taxes annually. These state and local revenues benefit local schools, roads, and other public programs and infrastructure. Nuclear power plants are the largest single source of funding for local school districts in many communities.[60] Retaining and possibly expanding nuclear energy in the U.S. would increase the amount of electricity generated from carbon-free generating resources and provide significant employment and tax revenue benefits to communities experiencing hardship as coal plants continue to close across the country. At the same time, the reduced land use allows additional land to be used for purposes other than energy generation.

However, one of the many hurdles new nuclear power plants face is the question of where to locate them. Not only do new nuclear plants face strong local opposition due to the perceived risk of a potential nuclear incident similar to Chernobyl, Three Mile Island, or Fukushima, but existing nuclear plants also consume a large amount of water to produce electricity and cool the reactor. **Exhibit 34** shows the average water intake at 100 percent utilization by fuel and technology type according to EIA Form 860 data.[61] The average nuclear plant takes in almost 500 gallons of water per minute per megawatt of electric generating capacity (gpm/MW), almost six times as much as a natural gas-fired combined-cycle power plant. Natural gas steam power plants take in about 433 gpm/MW, whereas coal plants, on average, have a water intake of just over 303 gpm/MW.

Exhibit 34: Average Water Intake @ 100% Utilization - by Fuel/Technology Type



59 https://www.finance.senate.gov/imo/media/doc/Nuclear%20Energy%20Institute.pdf

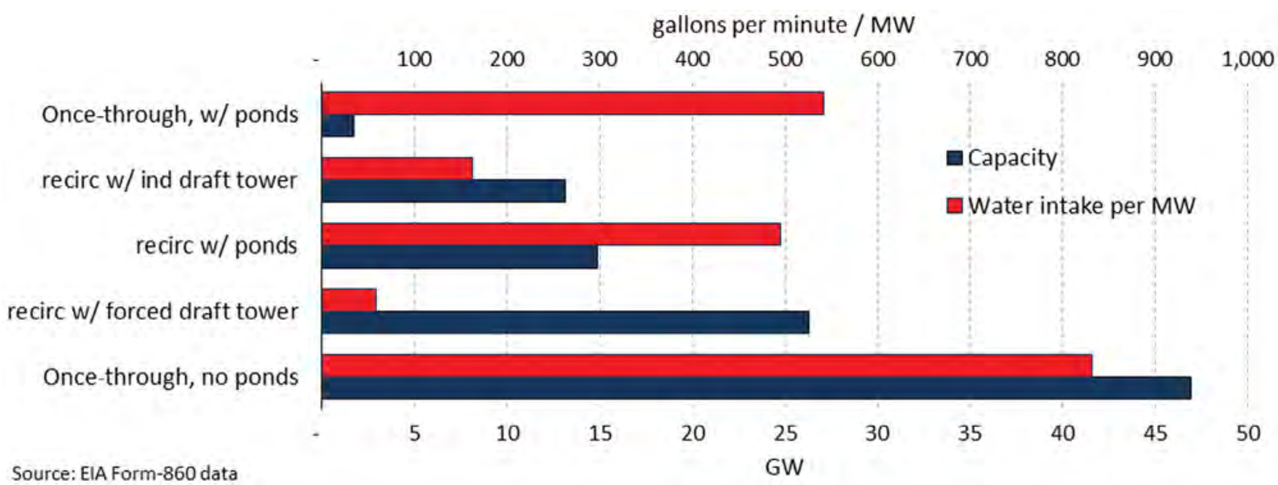
60 https://www.the74million.org/article/it-just-becomes-like-a-ghost-town-as-nuclear-plants-close-in-record-numbers-across-u-s-small-town-school-districts-brace-for-catastrophic-tax-loss/

61 Form EIA-860 data https://www.eia.gov/electricity/data/eia860/

The water intake rate largely depends on the type of plant cooling that is installed at the plant. **Exhibit 35** shows the U.S. nuclear capacity by cooling type and average water intake rates at 100 percent utilization. Almost half of all U.S. nuclear plants operate a once-through cooling system with no additional cooling ponds. These plants are primarily located near large bodies of water (e.g., lakes or tidal waters) and in humid climates. Without any cooling system, these plants' average water intake rate is over 800 gpm/MW.

On the other hand, over a quarter of nuclear plants operate a recirculating cooling system with forced draft cooling towers, which drops their average water intake rate to below 60 gpm/MW. For example, Ameren's Callaway, located along the Missouri River in Missouri, has a water intake rate of just 8.4 gpm/MW, the lowest in the country. In general, better cooling systems result in lower water intake rates and allow nuclear plants to be built in regions with lower cooling water availability. Some nuclear plants, like the Palo Verde nuclear plant, use public wastewater and are integral to the region's wastewater treatment process. However, because all currently operating nuclear plants are either a BWR or PWR design, they all require access to some form of water source.

Exhibit 35: Nuclear Capacity & Water Intake Rates by Cooling Type



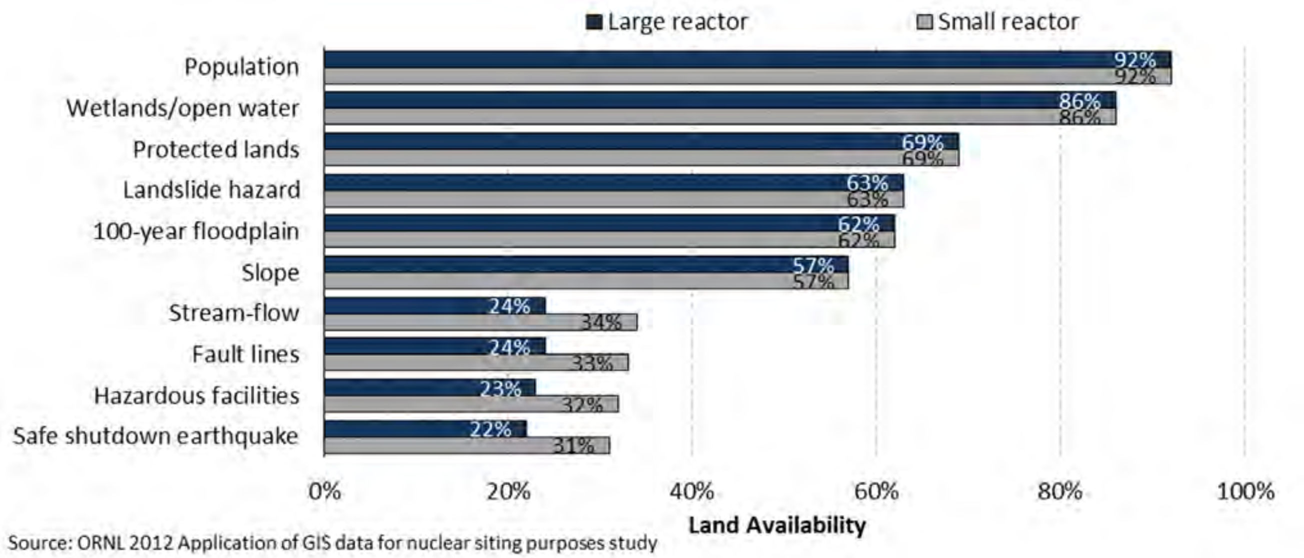
Source: EIA Form-860 data

In 2012, Oak Ridge National Laboratory (ORNL) issued a report in which it presented possible sites for new large and small modular nuclear reactors in the U.S. by applying spatial data modeling and geographical information systems.[62] ORNL used 10 criteria based on existing new nuclear siting requirements (e.g., a 20-mile buffer from population centers with a population density greater than 500 people per square mile, protected lands, wetlands, and open water, among others). **Exhibit 36** shows ORNL's estimated land availability for large (>1,000 MW) and small (~300 MW) new nuclear reactors based on 2010 data and the 10 siting criteria it used.

By far, the most significant drop in land suitable for new nuclear reactors is the requirement of enough cooling water available to support the operation of the large or small water-cooled nuclear reactors. Based on 2010 data for the 10 criteria evaluated, ORNL estimated that the available land could support about 515,000 MW of new large nuclear plants and about 201,000 MW of SMRs. **Appendix 4** shows ORNL's estimated capacity by state. By forecasting likely changes to population and stream-flow, ORNL estimates that the total amount of large and small nuclear reactors that could be supported in 2035 drops to approximately 396,000 MW and 167,000 MW, respectively. However, as described earlier, many new advanced nuclear reactor designs currently in development do not require water to cool the reactor and are, therefore, not bound by the access and availability of water from nearby rivers, lakes, or oceans.

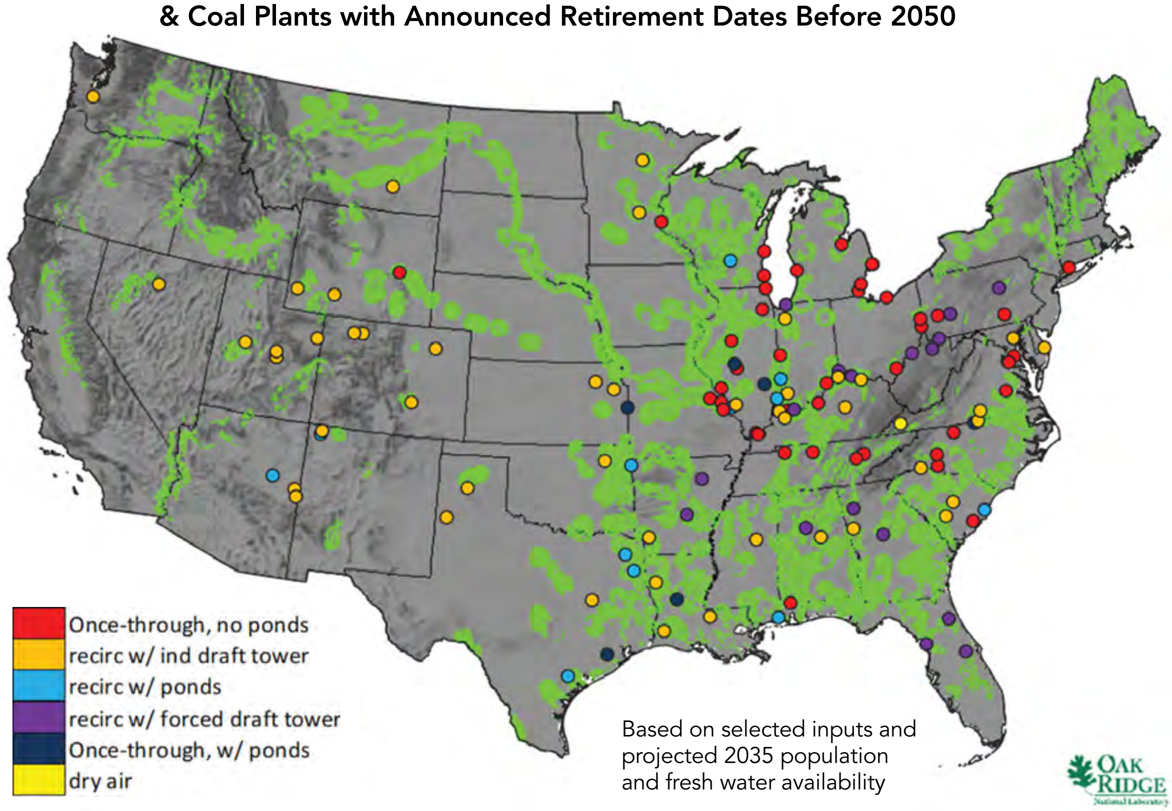
62 https://info.ornl.gov/sites/publications/files/Pub30613.pdf

Exhibit 36: Land Availability by Screening Criteria for Small & Large New Nuclear Reactors



One effective way to reduce the immense capital costs of new nuclear plants is to use existing infrastructure and personnel. Nuclear plants share two large cost items with coal-fired power plants: the switchyard and interconnection and the cooling system for electricity generation. **Exhibit 37** overlays the map of potential sites for small and large nuclear power plants with no siting issues in 2035, according to the 2012 ORNL study, with coal plants greater than 300 MW scheduled for retirement over the next 25 years. The map also shows the cooling systems at each coal-fired power plant site. Under current siting requirements, coal plants located in the green shaded areas from the original ORNL 2035 siting map could potentially be suitable for future nuclear power plants.

Exhibit 37: Map of ORNL 2035 Estimated Available Sites for New Nuclear & Coal Plants with Announced Retirement Dates Before 2050



For example, TerraPower and PacifiCorp recently chose the site of the retiring Naughton coal plant in Lincoln County in southwest Wyoming for their Natrium nuclear project to use the existing workforce and infrastructure. Dave Johnston, also a retiring coal plant in Wyoming, which was one of three other sites also deemed a viable option for the project, was confirmed as a viable site by the map in Exhibit 37 (red dot in Eastern Wyoming). ORNL is now working with the University of Michigan's Fastest Path to Zero Initiative to develop a siting tool to be used in the deployment of advanced nuclear technologies, which will also incorporate social, political, and economic data to connect advanced nuclear companies with communities looking to mitigate climate change by adopting zero-carbon energy systems. Using the existing infrastructure left behind by soon-to-be-retired coal-fired power plants could prove to be an effective way to reduce the cost of new nuclear power plants, retain some of the benefits local communities have received from the previous plant located at the site, and avoid the environmental impact of building new infrastructure on a greenfield site.

One of the reasons why ORNL's assessment of potential sites for small and large nuclear power plants estimated a larger amount of capacity potential for large reactors was the assumption that both SMRs and new large reactors would have to comply with the existing 20-mile buffer zone surrounding nuclear plants. However, in 2019, ORNL put forth some siting policy considerations to enable a larger amount of land suitable for future advanced nuclear reactor development closer to population centers as currently allowed.[63] ORNL found that light-water reactor

> *"operational data have accumulated over time, allowing for safety component and safety system reliability to be predicted more accurately with less uncertainty. In addition, better understanding of LWR fuel failure, coolant chemistry, aerosol behavior, accident progression, and failure timing have enabled better predictions of the timing and magnitude of fission product release from LWRs following severe accidents. Improved understanding of fission product releases following an accident coupled with advanced reactor attributes support the consideration of locating advanced reactors closer to population centers without any increased risk to the public…"*

Additionally, the NRC's most recent requirements would reduce the original 20-mile buffer zone to be reduced to a 10-mile emergency planning zone (EPZ).[64] Allowing SMRs and other new advanced nuclear reactors to be built closer to population centers without increasing the risk to the public would enable advanced nuclear developers to consider sites previously thought off limits and applications other than large-scale electricity production, such as industrial heat or production of carbon-free hydrogen. The next section of the report investigates the possible role of public utility commissions across the country in facilitating the retention and advancement of existing and new nuclear power plants.

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63 https://info.ornl.gov/sites/publications/Files/Pub126974.pdf

64 https://www.nrc.gov/about-nrc/emerg-preparedness/about-emerg-preparedness/planning-zones.html

IX. The Role of Public Utility Commissions in Facilitating the Retention and Advancement of Low-Cost and Reliable Nuclear Energy

Before discussing the potential role public utility commissions can have in facilitating the retention and advancement of low-cost and reliably nuclear energy, an understanding of the existing regulatory framework nuclear energy operates in is helpful to paint a complete picture. All nuclear reactor designs slated for operation in the U.S. need to be approved by the NRC. Additionally, any specific nuclear power plant projects and their specific project designs need to be approved by the NRC as well as all initial and subsequent license renewals. Currently, the role of PUCs across the country is limited to approving the long-term resource plans of regulated utilities presenting the necessity of any new nuclear project, as well as any cost recovery of the construction and ongoing operating and maintenance costs of new and existing nuclear power plants. Approval of a specific nuclear power plant project by the NRC does not mean that the nuclear power plant ends up being built as questions of necessity and cost recovery arise, as shown by the eventual abandonment of SCANA's V.C. Summer nuclear expansion project.

Additionally, the role of state PUCs in facilitating the retention and advancement of nuclear energy depends on whether utility generation within the state is regulated. All of the nuclear plants in operation today were built in regulated environments at the time. However, since the boom of nuclear energy in the 1970s and 1980s, 17 states and the District of Columbia have deregulated their electricity sector and no longer regulate generation. Of the approximately 97,400 MW of nuclear energy capacity in operation today, 55,000 MW are located in regulated states, whereas 42,400 MW are located in deregulated states. Therefore, PUCs have direct jurisdiction over roughly 56 percent of operating nuclear plants.

In deregulated states, the commissions have limited roles with respect to whether existing nuclear plants continue to operate for economic reasons. As discussed in **Section IV**, several state legislatures have provided support to existing plants. For example, the Illinois legislature enacted a bill that provides support for existing nuclear plants that allow them to continue to operate with subsidies. The commission's function in these states is largely relegated to administrative matters to implement these statutes.

This scope of support to existing plants could expand with the passage of the Bipartisan Infrastructure Law, which established the $6 billion CNC Program to support the continued operation of existing U.S. nuclear reactors. The CNC allows qualifying U.S. reactors to apply for certification and competitively bid on credits to help support the plants' continued operation. The program is underway, with DOE currently accepting applications, although the role of PUCs in administering the CNC process and whether state-level subsidies will continue alongside federal CNC support remain unresolved questions.

The role of commissions in deregulated states is also limited regarding new plants. All new plants in these states would be merchant-owned. Therefore, cost recovery and operations are not under the jurisdiction of PUCs. This could possibly change as some states are eliminating restrictions on the use of nuclear power. For the same reasons, a state could decide to carve out nuclear plant ownership in deregulated states, i.e., allow utilities in deregulated states to build new nuclear plants with cost recovery in support of state CES requirements. This would make financing of new nuclear plants easier as cost recovery for these immensely capital-intensive projects would be more certain; however, PUCs would weigh costs and risks to ratepayers as part of a decision to allow cost recovery. Alternatively, PUCs could work with the state legislatures to enact policy mechanisms to ensure financial compensation for new merchant nuclear plants under existing RPS or CES rules, such as ZECs, which could require state PUCs to oversee and administer such programs. However, PUCs need to ensure that the project financed is in actual need of financial support to continue operating and provide carbon-free electricity to minimize the overall financial burden on ratepayers and that any financial support is divided equitably among shareholders and ratepayers. Further, PUCs could work with state legislatures to facilitate changes in current RPS requirements to include nuclear energy as an eligible resource to ensure financial compensation via RECs or ZECs for carbon-free electric generation.

In regulated states, PUCs have a considerable influence on resource decisions. To start with, utilities in regulated states are generally required to file integrated resource plans (IRP) every two to three years, depending on the state. The IRP lays out the resource plan options for the utility, generally over a 20-year period, and provides data on costs and benefits to ratepayers. There is considerable variation by state in IRP requirements. In some states, the state administrative code lays out in great detail what is expected in the IRP. In other states, the process is less rigorous and gives more flexibility to the utility and/or PUC rules and guidance. The terms of the IRP period also vary, with some utilities required to forecast resource requirements for the next 10 years, whereas others are required to forecast the same requirements over the 30 years. Commissions can use the IRP process to ensure that existing and new nuclear power plants are considered adequately as viable resource options to meet decarbonization goals alongside other low- and zero-carbon resources.

Furthermore, utilities in regulated jurisdictions must obtain a Certificate of Public Convenience and Necessity (CPCN) if they decide to build a new nuclear plant. The PUC is the party that must provide its approval. The CPCN filing, which may or may not be reliant on the most recent IRP, must justify the investment as being in the public interest. Ensuring that the assumptions used during the IRP and CPCN proceedings are reasonable and, if appropriate, reflect accurate data for new and emerging advanced nuclear technologies would shield the consumer from unnecessary cost burdens.

As a starting point, commissions could consider directing regulated utilities to undertake the following actions that would provide more complete and accurate information to aid PUCs in decision-making:

- Ensure that regulated utilities properly examine the value of applying for all available ILRs/SLRs for existing nuclear plants to maximize the lifespan of existing nuclear plants.
- Require new nuclear power plants appropriate to each service territory to be given adequate consideration as future resource options.
- Require that the IRP define under what circumstances new nuclear power plants could become a desirable resource (e.g., the value of ZECs needed, CO_2 allowance price level, RPS/CES level).

X. Conclusion and Recommendations for Further Action

Nuclear energy plays a vital role in meeting current and future local, state, and federal decarbonization goals. The current nuclear fleet of approximately 97,400 MW accounts for roughly 20 percent of the total U.S. electric generation and almost 50 percent of generation from zero-carbon resources. Furthermore, the nuclear energy sector is one of the largest steady-state employers on a per MW basis and provides comparatively low-cost, reliable electricity. Retaining the current nuclear fleet will be vital to meet current state decarbonization goals.

Currently, 30 states have established an RPS, which requires utilities within the state to procure a certain percentage of renewable energy based on their electric retail sales. However, only 13 of these states have also established a CES, allowing generation from other zero-carbon resources such as nuclear energy to count toward the requirement. In addition, of these 13 states, only four (New York, Illinois, New Jersey, and Connecticut) provide direct financial support for their in-state nuclear plants through Zero-Emission Credits or other financial subsidies. Expanding existing RPS rules to include nuclear energy as a qualifying resource and establishing financial support under existing CES could enable struggling nuclear plants to continue operation and continue to provide the electric grid with stable, reliable, and low-cost carbon-free electricity.

Six states currently do not allow for the construction of new nuclear power plants, no matter the size, until a federal solution has been found to provide safe long-term storage for spent nuclear fuel. The NRC and the federal government should finalize a decision on the safe long-term storage of spent nuclear fuel at a CISF to enable states like Connecticut, Illinois, or Oregon to consider new nuclear plants as part of their future resource mix. Additionally, enacting proposed federal tax incentives could provide additional financial opportunities for developers and investors to consider building new nuclear plants in the near future.

Furthermore, the current NRC regulations and guidance were developed and optimized for the licensing of conventional light water reactor technology. Updating NRC regulations to be risk-informed, performance-based, and technology inclusive will enable the more effective and efficient licensing of advanced reactor technologies. Working with applicants and the NRC to improve existing processes while simultaneously developing new regulatory frameworks optimized for advanced reactors will enable the streamlining of NRC approval processes while still ensuring safety. Reducing unnecessary regulatory barriers to advanced reactor licensing is one of the keys to helping reduce the prohibitive costs of current conventional and advanced nuclear reactor designs.

Lastly, PUCs should ensure that utilities under their jurisdiction have fully considered the value of retaining their existing nuclear fleet through timely application for SLRs while also appropriately considering new nuclear power plants as viable resource options during their long-term resource planning procedures. PUCs in states with deregulated electricity markets have limited authority over generating resources within the state. However, these PUCs could potentially work with state legislatures and other state regulatory agencies to provide financial incentives for utilities to retain and possibly expand nuclear generation within the state.

XI. Appendix

Appendix 1: List of All U.S. Nuclear Reactors

ID	Plant Name	Majority Owner	State	County	Power Region	Ownership Type	Reactor Type	Capacity (MW)	Online Date	Retire Date	Current License Expiration
8055-1	Arkansas Nuclear One	Entergy	AR	Pope	MISO	Regulated	PWR	903	Dec-74	Dec-74	May-34
8055-2	Arkansas Nuclear One	Entergy	AR	Pope	MISO	Regulated	PWR	943	Mar-80		Jul-38
6040-1	Beaver Valley	Energy Harbor	PA	Beaver	PJM	Merchant	PWR	923	Sep-76		Jan-36
6040-2	Beaver Valley	Energy Harbor	PA	Beaver	PJM	Merchant	PWR	923	Nov-87		May-47
6022-1	Braidwood	Constellation	IL	Will	PJM	Merchant	PWR	1,225	Jul-88		Oct-46
6022-2	Braidwood	Constellation	IL	Will	PJM	Merchant	PWR	1,225	Oct-88		Dec-47
46-1	Browns Ferry	TVA	AL	Limestone	SERC	Regulated	BWR	1,152	Aug-74		Dec-33
46-2	Browns Ferry	TVA	AL	Limestone	SERC	Regulated	BWR	1,152	Mar-75		Jun-34
46-3	Browns Ferry	TVA	AL	Limestone	SERC	Regulated	BWR	1,190	Mar-77		Jul-36
6014-2	Brunswick	Duke Energy	NC	Brunswick	SERC	Regulated	BWR	1,002	Nov-75		Dec-34
6014-1	Brunswick	Duke Energy	NC	Brunswick	SERC	Regulated	BWR	1,002	Mar-77		Sep-36
6023-1	Byron	Constellation	IL	Ogle	PJM	Merchant	PWR	1,225	Sep-85		Oct-44
6023-2	Byron	Constellation	IL	Ogle	PJM	Merchant	PWR	1,225	Aug-87		Nov-46
6153-1	Callaway	Ameren	MO	Callaway	MISO	Regulated	PWR	1,236	Dec-84		Oct-44
6011-1	Calvert Cliffs	Constellation	MD	Calvert	PJM	Merchant	PWR	918	May-75		Jul-34
6011-2	Calvert Cliffs	Constellation	MD	Calvert	PJM	Merchant	PWR	911	Apr-77		Aug-36
6036-1	Catawba	Duke Energy	SC	York	SERC	Regulated	PWR	1,205	Jun-85		Dec-43
6036-2	Catawba	Duke Energy	SC	York	SERC	Regulated	PWR	1,205	Aug-86		Dec-43
204-1	Clinton	Constellation	IL	De Witt	MISO	Merchant	BWR	1,138	Nov-87		Apr-27*
371-2	Columbia	Energy Northwest	WA	Benton	WECC	Regulated	BWR	1,200	Dec-84		Dec-43
6145-1	Comanche Peak	Vistra	TX	Somervell	ERCOT	Merchant	PWR	1,215	Aug-90		Aug-30*
6145-2	Comanche Peak	Vistra	TX	Somervell	ERCOT	Merchant	PWR	1,215	Apr-93		Feb-33*
8036-1	Cooper	NPPD	NE	Nemaha	SPP	Regulated	BWR	801	Mar-74		Jan-34
6149-1	Davis Besse	Energy Harbor	OH	Ottawa	PJM	Merchant	PWR	925	Nov-77		Apr-37
6099-1	Diablo Canyon	PG&E	CA	San Luis Obispo	CAISO	Regulated	PWR	1,159	May-85	Nov-24	Nov-24†
6099-2	Diablo Canyon	PG&E	CA	San Luis Obispo	CAISO	Regulated	PWR	1,164	Mar-86	Aug-25	Aug-25†

Continued

*Submitted LOI †Announced retirement

ID	Plant Name	Majority Owner	State	County	Power Region	Ownership Type	Reactor Type	Capacity (MW)	Online Date	Retire Date	Current License Expiration
6000-1	Donald C Cook	AEP	MI	Berrien	PJM	Regulated	PWR	1,152	Aug-75		Oct-34
6000-2	Donald C Cook	AEP	MI	Berrien	PJM	Regulated	PWR	1,133	Jul-78		Dec-37
869-2	Dresden	Constellation	IL	Grundy	PJM	Merchant	BWR	1,009	Aug-70		Dec-29
869-3	Dresden	Constellation	IL	Grundy	PJM	Merchant	BWR	1,009	Oct-71		Jan-31
6051-1	Edwin I Hatch	Southern Co.	GA	Appling	SERC	Regulated	BWR	857	Dec-75		Aug-34
6051-2	Edwin I Hatch	Southern Co.	GA	Appling	SERC	Regulated	BWR	865	Sep-79		Jun-38
1729-2	Fermi	DTE	MI	Monroe	MISO	Regulated	BWR	1,217	Jan-88		Mar-45
6072-1	Grand Gulf	Entergy	MS	Claiborne	MISO	Regulated	BWR	1,373	Jul-85		Nov-44
3251-2	H B Robinson	Duke Energy	SC	Darlington	SERC	Regulated	PWR	769	Mar-71		Jul-30
6015-1	Harris	Duke Energy	NC	Wake	SERC	Regulated	PWR	951	May-87		Oct-46
6118-1	Hope Creek	PSEG	NJ	Salem	PJM	Merchant	BWR	1,170	Dec-86		Apr-46
6110-1	James A Fitzpatrick	Constellation	NY	Oswego	NYISO	Merchant	BWR	882	Aug-76		Oct-34
6001-1	Joseph M Farley	Southern Co.	AL	Houston	SERC	Regulated	PWR	888	Dec-77		Jun-37
6001-2	Joseph M Farley	Southern Co.	AL	Houston	SERC	Regulated	PWR	888	Jul-81		Mar-41
6026-1	LaSalle	Constellation	IL	La Salle	PJM	Merchant	BWR	1,170	Jan-84		Apr-42
6026-2	LaSalle	Constellation	IL	La Salle	PJM	Merchant	BWR	1,170	Oct-84		Dec-43
6105-1	Limerick	Constellation	PA	Montgomery	PJM	Merchant	BWR	1,139	Feb-86		Oct-44
6105-2	Limerick	Constellation	PA	Montgomery	PJM	Merchant	BWR	1,139	Jan-90		Jun-49
6038-1	McGuire	Duke Energy	NC	Mecklenburg	SERC	Regulated	PWR	1,220	Sep-81		Jun-41
6038-2	McGuire	Duke Energy	NC	Mecklenburg	SERC	Regulated	PWR	1,220	Mar-84		Mar-43
566-2	Millstone	Dominion Energy	CT	New London	ISONE	Merchant	PWR	910	Dec-75		Jul-35
566-3	Millstone	Dominion Energy	CT	New London	ISONE	Merchant	PWR	1,253	Apr-86		Nov-45
1922-1	Monticello	Xcel Energy	MN	Wright	MISO	Regulated	BWR	631	Jun-71		Sep-30
2589-1	Nine Mile Point	Constellation	NY	Oswego	NYISO	Merchant	BWR	642	Dec-69		Aug-29
2589-2	Nine Mile Point	Constellation	NY	Oswego	NYISO	Merchant	BWR	1,259	Jul-87		Oct-46
6168-1	North Anna	Dominion Energy	VA	Louisa	PJM	Regulated	PWR	980	Jun-78		Apr-38
6168-2	North Anna	Dominion Energy	VA	Louisa	PJM	Regulated	PWR	980	Dec-80		Aug-40
3265-1	Oconee	Duke Energy	SC	Oconee	SERC	Regulated	PWR	887	Jul-73		Feb-33

Continued

ID	Plant Name	Majority Owner	State	County	Power Region	Ownership Type	Reactor Type	Capacity (MW)	Online Date	Retire Date	Current License Expiration
3265-2	Oconee	Duke Energy	SC	Oconee	SERC	Regulated	PWR	887	Sep-74		Oct-33
3265-3	Oconee	Duke Energy	SC	Oconee	SERC	Regulated	PWR	893	Dec-74		Jul-34
6008-1	Palo Verde	APS/SRP/El Paso/SCE/ PNM	AZ	Maricopa	CAISO	Regulated	PWR	1,403	Jan-86		Jun-45
6008-2	Palo Verde	APS/SRP/El Paso/SCE/ PNM	AZ	Maricopa	CAISO	Regulated	PWR	1,403	Sep-86		Apr-46
6008-3	Palo Verde	APS/SRP/El Paso/SCE/ PNM	AZ	Maricopa	CAISO	Regulated	PWR	1,403	Jan-88		Nov-47
3166-2	Peach Bottom	Constellation	PA	York	PJM	Merchant	BWR	1,160	Jul-74		Aug-33
3166-3	Peach Bottom	Constellation	PA	York	PJM	Merchant	BWR	1,160	Dec-74		Jul-34
6020-1	Perry	Energy Harbor	OH	Lake	PJM	Merchant	BWR	1,312	Nov-87		Nov-26*
4046-1	Point Beach	NextEra	WI	Manitowoc	MISO	Merchant	PWR	643	Dec-70		Oct-30
4046-2	Point Beach	NextEra	WI	Manitowoc	MISO	Merchant	PWR	643	Oct-72		Mar-33
1925-1	Prairie Island	Xcel Energy	MN	Goodhue	MISO	Regulated	PWR	593	Feb-74		Aug-33
1925-2	Prairie Island	Xcel Energy	MN	Goodhue	MISO	Regulated	PWR	593	Oct-74		Oct-34
880-1	Quad Cities	Constellation	IL	Rock Island	PJM	Merchant	BWR	1,009	Dec-72		Dec-32
880-2	Quad Cities	Constellation	IL	Rock Island	PJM	Merchant	BWR	1,009	Dec-72		Dec-32
6122-1	R E Ginna	Constellation	NY	Wayne	NYISO	Merchant	PWR	614	Jul-70		Sep-29
6462-1	River Bend	Entergy	LA	West Feliciana	MISO	Regulated	BWR	1,036	Jun-86		Aug-45
2410-1	Salem	PSEG	NJ	Salem	PJM	Merchant	PWR	1,170	Jun-77		Aug-36
2410-2	Salem	PSEG	NJ	Salem	PJM	Merchant	PWR	1,170	Oct-81		Apr-40
6115-1	Seabrook	NextEra	NH	Rockingham	ISONE	Merchant	PWR	1,242	Aug-90		Mar-50
6152-1	Sequoyah	TVA	TN	Hamilton	SERC	Regulated	PWR	1,221	Jul-81		Sep-40
6152-2	Sequoyah	TVA	TN	Hamilton	SERC	Regulated	PWR	1,221	Jun-82		Sep-41
6251-1	South Texas Project	NRG/CPS	TX	Matagorda	ERCOT	Merchant	PWR	1,354	Aug-88		Aug-47
6251-2	South Texas Project	NRG/CPS	TX	Matagorda	ERCOT	Merchant	PWR	1,354	Jun-89		Dec-48
6045-1	St Lucie	NextEra	FL	St Lucie	FRCC	Regulated	PWR	850	May-76		Mar-36
6045-2	St Lucie	NextEra	FL	St Lucie	FRCC	Regulated	PWR	850	Jun-83		Apr-43
3806-1	Surry	Dominion Energy	VA	Surry	PJM	Regulated	PWR	848	Dec-72		May-32
3806-2	Surry	Dominion Energy	VA	Surry	PJM	Regulated	PWR	848	May-73		Jan-33
6103-1	Susquehanna	Talen Generation	PA	Luzerne	PJM	Merchant	BWR	1,298	Jun-83		Jul-42

Continued

*Submitted LOI

ID	Plant Name	Majority Owner	State	County	Power Region	Ownership Type	Reactor Type	Capacity (MW)	Online Date	Retire Date	Current License Expiration
6103-2	Susquehanna	Talen Generation	PA	Luzerne	PJM	Merchant	BWR	1,298	Feb-85		Mar-44
621-3	Turkey Point	NextEra	FL	Miami-Dade	FRCC	Regulated	PWR	760	Dec-72		Jul-32
621-4	Turkey Point	NextEra	FL	Miami-Dade	FRCC	Regulated	PWR	760	Sep-73		Apr-33
6127-1	V C Summer	Dominion Energy/ Santee Cooper	SC	Fairfield	SERC	Regulated	PWR	1,030	Jan-84		Aug-42
649-1	Vogtle	Southern Co.	GA	Burke	SERC	Regulated	PWR	1,160	May-87		Jan-47
649-2	Vogtle	Southern Co.	GA	Burke	SERC	Regulated	PWR	1,160	May-89		Feb-49
4270-3	Waterford 3	Entergy	LA	St Charles	MISO	Regulated	PWR	1,200	Sep-85		Oct-44
7722-1	Watts Bar	TVA	TN	Rhea	SERC	Regulated	PWR	1,270	May-96		Nov-35
7722-2	Watts Bar	TVA	TN	Rhea	SERC	Regulated	PWR	1,180	Oct-16		Oct-55
210-1	Wolf Creek	Great Plains Energy/ Westar Energy	KS	Coffey	SPP	Regulated	PWR	1,268	Sep-85		Mar-45
649-3	Vogtle	Southern Co.	GA	Burke	SERC	Regulated	PWR	1,117	Feb-23		Sep-62*
649-4	Vogtle	Southern Co.	GA	Burke	SERC	Regulated	PWR	1,117	Nov-23		Jun-63*
628-3	Crystal River	Duke Energy	FL	Citrus	FRCC	Regulated	PWR	890	Mar-77	Feb-13	Feb-13†
8024-1	Kewaunee	Dominion Energy	WI	Kewaunee	MISO	Merchant	PWR	560	Jun-74	Apr-13	Apr-13†
360-3	San Onofre	Edison	CA	San Diego	CAISO	Regulated	PWR	1,127	Apr-84	Jun-13	Jun-13†
360-2	San Onofre	Edison	CA	San Diego	CAISO	Regulated	PWR	1,127	Aug-83	Jun-13	Jun-13†
3751-1	Vermont Yankee	Entergy	VT	Windham	ISONE	Merchant	BWR	563	Nov-72	Dec-14	Dec-14†
2289-1	Fort Calhoun	OPPD	NE	Washington	SPP	Regulated	PWR	502	Sep-73	Nov-16	Nov-16†
2388-1	Oyster Creek	Constellation	NJ	Ocean	PJM	Merchant	BWR	550	Dec-69	Sep-18	Sep-18†
1590-1	Pilgrim	Entergy	MA	Plymouth	ISONE	Merchant	BWR	670	Dec-72	Jun-19	Jun-19†
8011-1	Three Mile Island	Constellation	PA	Dauphin	PJM	Merchant	PWR	976	Aug-74	Sep-19	Sep-19†
2497-2	Indian Point 2	Entergy	NY	Westchester	NYISO	Merchant	PWR	1,299	Aug-73	Apr-20	Apr-20†
1060-1	Duane Arnold	NextEra	IA	Linn	MISO	Merchant	BWR	680	Feb-75	Aug-20	Aug-20†
8907-3	Indian Point 3	Entergy	NY	West Chester	NYISO	Merchant	PWR	1,012	Aug-76	Apr-21	Apr-21†
1715-1	Palisades	Entergy	MI	Van Buren	MISO	Merchant	PWR	812	Mar-72	May-22	May-22†

*Assumed op. date †Retired

Appendix 2: List of Advanced Nuclear Reactor Designs

Company	Reactor Name	Type	Power Rating (MW)	Fuel Enrichment	Fuel Form	Coolant
GE-Hitachi	BWRX-300	BWR (SMR)	300	LEU	Ceramic UO_2 Pellets	Light water
Holtec International	SMR-160	PWR (SMR)	160	LEU	Ceramic UO_2 Pellets	Light water
NuScale Power	NuScale VOYGR	PWR (SMR)	77 (each)	LEU	Ceramic UO2 Pellets	Light water
TerraPower/GE-Hitachi	Natrium	SFR	345	HALEU	Metallic U-Zr	Sodium
TerraPower	Traveling Wave Reactor (TWR)	SFR	600	LEU	Metal	Sodium
Advanced Reactor Concepts	Advanced Reactor Concept (ARC-100)	SFR	100	HALEU	Metal	Sodium
Kairos Power	Fluoride Salt-Cooled High Temp. Reactor (KP-FHR)	MSR	140	HALEU	TRISO	Molten Salt
TerraPower/ Southern Co.	Molten Chloride Fast Reactor (MCFR)	MSR	780	HALEU	U-Molten Chloride	Molten Salt
Terrestial Energy	Integral Molten Salt Reactor (IMSR)	MSR	195	LEU	U-Molten Fluoride	Molten Salt
Elysium Industries	Molten Chloride Salt Fast Reactor (MCSFR)	MSR	50-1000	LEU, SNF	Molten Salt	Molten Salt
Flibe Energy	Liquid Fluoride Thorium Reactor (LFTR)	MSR	20-50	Thorium	Molten Salt	Molten Salt
X-Energy	Xe-100	GCR	80	HALEU	TRISO	Helium
Framatome - US	Steam Cycle High Temp. Gas-cooled Reactor (SC-HTGR)	GCR	272	HALEU	TRISO	Helium
General Atomics	Fast Modular Reactor	GFR	50	HALEU	TRISO	Helium
General Atomics	Energy Multiplier Module (EM2)	GFR	265	HALEU	Carbide	Helium
Westinghouse	Demonstration Lead-cooled Fast Reactor (DLFR)	LFR	450	LEU	Oxide (Nitride)	Lead
Hydromine	Amphora-Shaped Lead-cooled Fast Reactor (LFR-AS-200)	LFR	200		Oxide	Lead
CBCG	Columbia Basin Consulting Group (CBCG)	LFR	~100		Oxide (initially)	Lead-bismuth eutectic
US Ultra Safe Nuclear	Micro Modular Reactor (MMR)	Micro	5	HALEU	TRISO	Helium
Westinghouse	eVinci Micro Reactor	Micro	0.2-25	HALEU	TRISO	Heat Pipe
HolosGen, LLC	Holos Reactor	Micro	3-13	HALEU	TRISO	Helium or CO_2
Oklo	Aurora	Micro	1.5	HALEU	Metallic U-Zr	Heat Pipe
BWXT Technologies	BWXT Advanced Nuclear Reactor (BANR)	Micro	50	HALEU	TRISO	Helium
X-Energy	Xe-Mobile	Micro	1	HALEU	TRISO	Helium

Acronyms for Reactor Type

- BWR Boiling water reactor
- PWR Pressurized water reactor
- SMR Small modular reactor
- SFR Sodium-cooled fast reactor
- MSR Molten-salt reactor
- GCR Gas-cooled reactor
- GFR Gas-cooled fast reactor
- HTGR High-temperature gas-cooled reactor
- LFR Lead-cooled fast reactor
- LEU Low-enriched uranium
- HALEU High-assay low-enriched uranium

Appendix 3: Nuclear Cost Assumptions in Latest Utility IRPs

IRP Year	Company	Technology	Capital Cost ($/kW)	Fixed O&M ($/MWh)	Variable O&M ($/MWh)	LCOE ($/MWh)
2021	Evergy Metro	Advanced Nuclear	$6,709	$14	$2	$114
2021	Evergy Metro	SMR	$6,939	$11	$3	$114
2021	Entergy	Conventional Nuclear	$7,648	$15	$2	$96
2021	Entergy	SMR	$7,036	$15	$1	$92
2021	Pacificorp	SMR	$5,538	$8	$7	$-
2021	Avista	SMR	$4,664	$-	$-	$96
2021	Omaha Public Power District	Advanced Nuclear	$-	$-	$-	$96
2021	Idaho Power	SMR	$4,394	$15	$2	$103
2021	AEP Indiana Michigan	SMR	$6,751	$11	$3	$-
2020	Ameren	Conventional Nuclear	$7,611	$14	$2	$153
2020	Memphis Light, Gas, and Water	SMR	$7,186	$20	$16	$131
2020	Dominion Energy	SMR	$5,622	$75	$12	$87
2020	Dominion Energy	Advanced Nuclear	$9,598	$120	$12	$132
2020	Arizona PSC	SMR	$5,753	$-	$-	$-
2020	Arizona PSC	Conventional Nuclear	$6,670	$-	$-	$-
2019	TVA	SMR	$5,812	$-	$-	$-
2019	TVA	Advanced Nuclear	$8,703	$-	$-	$-
2019	TVA	Conventional Nuclear	$6,474	$-	$-	$-
2019	Tucson	Conventional Nuclear	$8,118	$9	$6	$-
2019	Pacificorp	Advanced Nuclear	$7,149	$12	$12	$-
2019	Kentucky Power	Conventional Nuclear	$8,829	$20	$4	$181
2019	Appalachian Power	Conventional Nuclear	$8,829	$-	$-	$185

All costs are in 2021$

Appendix 4: ORNL 2010 Potential Capacity for Small & Large New Nuclear Reactors by State

State	Large Reactor Est. Capacity	SMR - Est. Capacity	State	Large Reactor Est. Capacity	SMR - Est. Capacity
Alabama	22,400	5,600	Nebraska	12,800	3,150
Arizona	14,400	3,500	Nevada	3,200	1,750
Arkansas	17,600	4,900	New Hampshire	3,200	700
California	14,400	5,600	New Jersey	1,600	700
Colorado	6,400	4,200	New Mexico	1,600	1,750
Connecticut	-	700	New York	8,000	6,300
Delaware	-	-	North Carolina	11,200	4,550
District of Columbia	-	-	North Dakota	12,800	3,150
Florida	8,000	4,550	Ohio	6,400	2,800
Georgia	16,000	7,000	Oklahoma	14,400	4,550
Idaho	30,400	9,450	Oregon	12,800	5,600
Illinois	16,000	4,200	Pennsylvania	9,600	3,500
Indiana	12,800	5,250	Rhode Island	-	-
Iowa	6,400	3,850	South Carolina	6,400	2,450
Kansas	1,600	1,050	South Dakota	11,200	2,100
Kentucky	12,800	4,200	Tennessee	14,400	5,600
Louisiana	16,000	5,250	Texas	14,400	10,500
Maine	12,800	5,600	Utah	12,800	4,550
Maryland	1,600	700	Vermont	3,200	1,750
Massachusetts	1,600	350	Virginia	4,800	4,550
Michigan	1,600	4,900	Washington	25,600	5,950
Minnesota	14,400	5,950	West Virginia	3,200	1,400
Mississippi	9,600	4,900	Wisconsin	11,200	5,950
Missouri	11,200	4,550	Wyoming	8,000	5,950
Montana	54,400	15,400	**Lower-48 Total**	**515,200**	**200,900**

Source: ORNL Potential Siting Options Study - 2012

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