NARUC
National Association of Regulatory Utility Commissioners

Nuclear Generation in Long-Term Utility Resource Planning:

A Review of Integrated Resource Plans and Considerations for State Utility Regulators

Kathryn Kline, Sam Stephens, and Kiera Zitelman
NARUC Center for Partnerships and Innovation

November 2023

Acknowledgements

This report was developed under the project: "U.S. Department of Energy (DOE)-NARUC Nuclear Energy Partnership," an initiative of the National Association of Regulatory Utility Commissioners (NARUC) Center for Partnerships and Innovation. This material is based upon work supported by the DOE under Award Number DE-NE0009043.

This report was authored by Kathryn Kline, Sam Stephens, and Kiera Zitelman of the NARUC Center for Partnerships and Innovation. The views and opinions expressed herein are strictly those of the authors and may not necessarily agree with positions of NARUC or those of the U.S. Department of Energy.

NARUC thanks Cheryl Moss Herman and Billy Valderrama with the DOE, Office of Nuclear Energy, and their colleagues for their contributions to this report and their support of the DOE-NARUC Nuclear Energy Partnership. Commissioner Tim Echols of the Georgia Public Service Commission and Commissioner Anthony O'Donnell of the Maryland Public Service Commission have graciously volunteered their time and expertise to this report and other NARUC resources as co-chairs of the Nuclear Energy Partnership. NARUC also wishes to thank the following individuals for their assistance and information in developing this report:

- **Kati Austgen**, Nuclear Energy Institute
- **Hon. Brent Bailey**, Mississippi Public Service Commission
- **Amanda Best**, Maryland Public Service Commission
- **Kelly Bielen**, Nuclear Energy Institute
- **Hon. Ann Bukacek**, Montana Public Service Commission
- **Danielle Sass Byrnett**, National Association of Regulatory Utility Commissioners
- **Hon. Milt Doumit**, Washington Utilities and Transportation Commission
- **Hon. Tim Echols**, Georgia Public Service Commission
- **Kristy Hartman**, Nuclear Energy Institute
- **Jennifer Heaton-Amrhein**, Wisconsin Public Service Commission
- **Hon. Mary-Anna Holden**, New Jersey Board of Public Utilities
- **Rachel Keathley**, U.S. Department of Energy
- **Jeff Kitsembel**, Wisconsin Public Service Commission
- **Paul Kjellander**
- **Kelly Lefler**, U.S. Department of Energy
- **Jeff Merrifield**, Pillsbury Law
- **Elliott Nethercutt**, National Association of Regulatory Utility Commissioners
- **Marcus Nichol**, Nuclear Energy Institute
- **Hon. Katherine Peretick**, Michigan Public Service Commission
- **Hon. Ann Rendahl**, Washington Utilities and Transportation Commission
- **Brett Sproul**, Maryland Public Service Commission
- Michigan Public Service Commission staff

Please direct questions regarding this report to Kiera Zitelman, NARUC, at kzitelman@naruc.org or (202) 898-2200.

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Contents

Executive Summary

Decarbonization goals, customer demands for zero-carbon electricity, and a growing need for clean firm power have renewed interest in nuclear generation—both in retaining the existing, nearly 100-gigawatt nuclear fleet and adding new advanced nuclear capacity. Advanced nuclear reactors share beneficial characteristics with the existing nuclear fleet, including zero-emission power, reliability, and dispatchability. They also offer numerous distinct advantages including improved load-following capability, modularity, a smaller land use footprint, new safety features, and low operating costs. On the other hand, critics point out that advanced reactors are unproven. Advanced nuclear projects are in various stages of research, development, demonstration, and deployment. While these technologies have been operated successfully in the past, the "first-of-a-kind" (FOAK) commercial pilot and demonstration reactors for several new designs projected to come online within the end of the decade do not provide empirical cost and performance data until the units become operational. A further challenge facing advanced reactors is fuel availability: several designs rely on high-assay, low-enriched uranium (HALEU) fuel, for which a commercial supply is currently only available from Russian enrichment facilities. This could change in the next year. Centrus Energy Corp is demonstrating a U.S. Nuclear Regulatory Commission (NRC)-licensed commercial HALEU production facility in Piketon, Ohio, which is on track to begin initial pilot-scale production by the end of 2023.[1] Advanced nuclear technologies have progressed in the past two decades, with one developer reaching the milestone of design certification with the NRC in early 2023 and others in various stages of engagement with the NRC.

At this stage in the technology readiness cycle of advanced reactors, electric utilities are beginning to think seriously about the role of both existing and new nuclear in their generation portfolios. A readily available method of observing the degree to which utilities are considering nuclear is through integrated resource planning processes. An Integrated Resource Plan (IRP) sets out utilities' long-term expectations on how they will procure sufficient generation to meet future demand while satisfying state policies around decarbonization, the use of in-state resources, economic development, and other factors. Public utility commissions (PUCs) have oversight of IRP filings for the investor-owned utilities serving approximately three-quarters of the country, although the acceptance or approval of an IRP does not constitute a final investment decision for particular generation resources. Stakeholders such as large electricity customers, environmental advocates, municipalities, Tribes, labor unions, consumer advocates, and other state agencies can participate in the IRP process by expressing support or opposition to utility proposals, requesting further information from the utility, or advocating for the utility to pursue or consider other options not included in the initial filing.

While there were differences across utilities, NARUC found three overarching trends from a review of 17 utility IRP filings submitted from August 2019 to March 2023, discussed in Section III:

1. The majority of regulated utilities are aware of advanced nuclear technologies. For many IRPs, the time horizon of evaluation is 10 years or less, and for many of the first advanced reactors the schedule for deployment would push their dates for coming online outside of the window of the IRP. In addition, uncertainties around the technological maturity, uncertainty about costs and financial risks, and unfavorable state regulatory or policy landscapes discourage inclusion of advanced nuclear in IRPs. These utilities tend to express a willingness to continue monitoring the development of advanced nuclear technologies for potential inclusion in future IRPs. The most commonly cited advanced nuclear technology was SMRs broadly.
2. Some utilities have explicitly included advanced nuclear in their IRPs, namely PacifiCorp, Idaho Power, DEC, DEP, and TVA. With the exception of DEC and DEP, these organizations all share a geographic

1 Centrus, June 15, 2023, "Centrus Completes Operational Readiness Review for HALEU Production and Receives NRC Authorization to Introduce Uranium into Centrifuge Cascade." https://www.centrusenergy.com/news/centrus-completes-operational-readiness-review-for-haleu-production-and-receives-nrc-authorization-to-introduce-uranium-into-centrifuge-cascade/.

commonality: they have a nuclear-focused national lab located within their service area (Idaho National Laboratory and Oak Ridge National Laboratory) and/or have a major commercial advanced nuclear project underway. Also noted is UAMPS CFPP, a set of six 77 MW NuScale SMRs to be sited on the INL campus, expected online in 2029.[2] TVA and UAMPS, as public power utilities, are not regulated by state utility commissions.

3. Most utilities propose keeping existing nuclear resources online to maintain reliability and progress toward decarbonization goals. This includes keeping ownership stakes in nuclear plants as well as extending the operating life of existing nuclear units and reapplying for 20-year operating licenses from the NRC. Utilities cite employment, economic contributions to local communities, reliability, and clean energy as key benefits of extending the lifetimes of existing nuclear units.

This paper begins with an overview of IRPs and existing and advanced nuclear generation (Sections I and II). Section III reviews inclusions of advanced nuclear in selected recently filed IRPs. Section IV offers questions and considerations for public utility regulators.

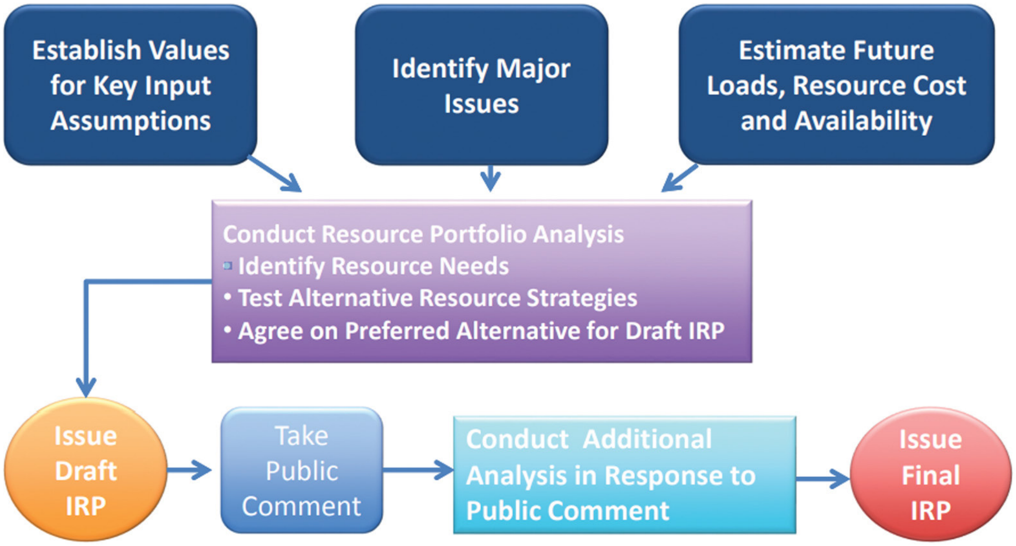
2 Utah Associated Municipal Power Systems, July 21, 2021, "CFPP Updates since October Off-Ramp." https://losalamos.legistar.com/View.ashx?M=F&ID=9618711&GUID=087139CA-D9AE-4A61-B2BB-602CAD1CCFC9.

Introduction

Incorporating energy from existing and new nuclear generation resource technologies into IRP processes has a substantial bearing on both the market for nuclear energy and the ability of utilities to achieve voluntary and statutory goals for zero-carbon electricity generation. Through the IRP process, regulated utilities convey long-term generation investment decisions to state utility regulators. The primary objective of an IRP is generally to enable utilities to "meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas and satisfy all related state and federal laws and regulations."[3]

The transition to cleaner energy sources is an increasingly important factor that utilities are evaluating in IRP processes. Meeting clean energy goals set by state legislatures or governors must be balanced with the regulatory requirements of maintaining safety, reliability, and affordability of electricity infrastructure. The IRP process offers a reflection of the level of utility interest in various generation technologies and reactions by regulators. **Figure 1** shows a generic IRP process. While utility filings and regulatory responses to IRPs are far from final investment decisions and generally do not obligate utilities to spend ratepayer or shareholder money on specified generation resources, these plans create a shared set of expectations for utilities, regulators, and stakeholders about the general direction of long-term resource investments.

Figure 1: Overview of Generic IRP Development Process



Source: Tom Eckman and Natalie Mims, August 8, 2017, Presentation before the *Michigan Public Service Commission Integrated Resource Planning Stakeholder Group Meeting*, slide 8, Lawrence Berkeley National Laboratory.

A significant and growing group of policymakers and stakeholders sees advanced nuclear technology as both a compelling decarbonization solution as well as a chance to maintain or improve grid reliability. The capability of advanced nuclear generation resources to adapt to changes in load can complement the variable nature of renewable energy sources such as wind and solar. As several regions of the United States struggle to meet peak demand, particularly in extreme weather conditions, advanced reactors can play an important role in supporting a clean, flexible, reliable, affordable, and safe energy grid. Investing in dispatchable,[4] zero-carbon

3 James W. Gardner, October 2013, *Integrated Resource Planning: The Basics and Beyond*. National Association of Regulatory Utility Commissioners. https://pubs.naruc.org/pub.cfm?id=537D1370-2354-D714-51E5-7253869CB747.

4 Dispatchable generation can be delivered at will without depending on external factors outside of the generation facility's control. These technologies can be deployed when variable renewable energy sources (such as wind and solar) are not available due to lack of adequate wind or sunshine. This characteristic helps to maintain the stability and reliability of the power grid.

(or low-carbon) resources is critical to achieving the United States's decarbonization goals without sacrificing reliability. Currently, 93 nuclear reactors across 28 states supply nearly 20 percent of U.S. electricity and half of the country's zero-carbon power.[5] The existing fleet operates at a high capacity factor, generating power totaling approximately 93 percent of the units' rated capacity—the highest capacity factor of any energy source.[6]

However, additions to the fleet have been relatively stagnant. Only three new units (Watts Bar Units 1 and 2 in Tennessee, and Plant Vogtle Unit 3) have entered service since 1996.[7] Plant Vogtle in Georgia is home to two existing units completed in the late 1980s; two new AP1000 reactors at Units 3 and 4 have been under construction since 2009. Unit 3 began supplying electricity to the grid in June 2023, and Unit 4 is expected to enter service by early 2024.[8] These new Vogtle units are expected to add 2,200 MW of nuclear capacity to the grid upon their completion. Multiple units have retired as they reach the end of their operating lifetimes or—more frequently—before the end of their operating lifetimes as they face economic pressure from competing natural gas and renewable resources, particularly in competitive wholesale power markets that do not adequately value the attributes of firm clean electricity provided by nuclear energy. Seven nuclear units totaling 5,541 MW have retired since 2017.[9] California's Diablo Canyon Units 1 and 2 had announced plans to retire in the mid-2020s, but DOE selected both units for conditional awards of credits under the Civil Nuclear Credit program, funded by the Bipartisan Infrastructure Law of 2021 (BIL). The plant faces new challenges renewing its operating licenses with the NRC, section V, subsection D, elaborates on these challenges. Michigan's Palisades plant closed in 2022, and ownership transferred from Entergy to Holtec, a decommissioning contractor, in June 2023. Holtec announced that it did not receive a Civil Nuclear Credit award from DOE. In February 2023, Holtec applied for funding from the DOE Loan Programs Office to support a plant restart.[10]

Outside of the existing fleet, a new generation of advanced nuclear reactors is emerging as an increasingly attractive generation choice for utilities. Today's nuclear reactors are water-cooled: either boiling water reactors (BWRs) or pressurized water reactors. Both use water as a moderator to control the speed of neutrons emitted during fission and as a coolant to carry away heat created by fission reactions. The term "advanced reactor" can refer to a number of different technologies, differing by the coolant, power output, and type of fuel:[11]

- **Water-cooled:**
  - Advanced light water SMRs
  - Advanced large light water reactors
- **Non-water-cooled:**
  - Molten salt reactors
  - Sodium-cooled reactors
  - High temperature gas-cooled reactors
  - Gas-cooled fast reactors

---

5 Energy Information Administration, 2023, "Nuclear & Uranium." https://www.eia.gov/nuclear/data.php#nuclear.

6 Energy Information Administration, 2022, "Nuclear Explained: U.S. Nuclear Industry." https://www.eia.gov/energyexplained/nuclear/us-nuclear-industry.php.

7 Energy Information Administration, March 7, 2022, "How Old Are U.S. Nuclear Power Plants, and When Was the Newest One Built?" https://www.eia.gov/tools/faqs/faq.php?id=228&t=21.

8 Marisa Mecke, March 20, 2023, "Plant Vogtle Unit 4 Begins Hot Functional Testing," SavannahNow. https://www.savannahnow.com/story/news/environment/2023/03/20/plant-vogtle-georgia-power-unit-4-conducts-hot-functional-testing/70030972007/.

9 Energy Information Administration, April 8, 2022, "U.S. Nuclear Electricity Generation Continues to Decline as More Reactors Retire." https://www.eia.gov/todayinenergy/detail.php?id=51978. Energy Information Administration's figures do not include the May 2022 Palisades retirement (805 MW); see https://www.world-nuclear.org/reactor/default.aspx/PALISADES.

10 American Nuclear Society, March 3, 2023, "DOE Guidance for Nuclear Credit Program's Second Award Cycle Released." https://www.ans.org/news/article-4793/doe-guidance-for-nuclear-credit-programs-second-award-cycle-released/.

11 Nuclear Innovation Alliance, updated March 2023, *Advanced Nuclear Reactor Technology: A Primer.* https://nuclearinnovationalliance.org/advanced-nuclear-reactor-technology-primer.

- Microreactors: depending on definition, are capable of output between 1 and 50 MW or less using graphite as a moderator and liquid metal, helium, or heat pipes as a coolant.

Specific reactor designs and the role of the NRC in approving them are discussed in Section IV. Multiple developers have submitted applications or begun preapplication engagement activities with the NRC. In January 2023, the NRC approved NuScale Power's SMR design, making the 50–600 MW SMR (a one- to twelve-unit plant) the first to receive NRC approval.[12] Utilities can now reference NuScale's design when applying to the NRC for a combined license to build and operate a reactor.

Advances in renewable generation, energy storage, hydrogen, and fossil generation have also taken place as advanced reactors have developed, presenting utilities with a range of generation resource options to include in IRPs. The NRC's design certification for NuScale, as well as other milestones in advanced reactor development and increasing interest in dispatchable zero-carbon power, make this an ideal time to assess utility interest in advanced nuclear.

12 U.S. Department of Energy, Office of Nuclear Energy, January 20, 2023, "NRC Certifies First U.S. Small Modular Reactor Design." https://www.energy.gov/ne/articles/nrc-certifies-first-us-small-modular-reactor-design.

I. Overview of Integrated Resource Planning Processes

While there is considerable variation from state to state, integrated resource plans are generally a process in which a regulated utility forecasts future needs of the system, and then explores potential options for meeting those needs. IRPs provide opportunities for PUC staff and stakeholder engagement, although the extent of stakeholder engagement varies by state. One of the key objectives cited in the development of early IRP processes was to "rationalize the means of providing energy services to ratepayers."[13] When implemented successfully, the IRP process identifies "the lowest practical costs at which a utility can deliver reliable energy services to its customers" by utilizing analytical tools to evaluate the costs and benefits of demand- and supply-side resources in an unbiased manner.[14]

There are several distinct steps that comprise a typical IRP proceeding. First, the IRP is docketed for review by the commission and stakeholders. This docket will contain all information and testimony related to the specific IRP. Once the IRP is docketed, many states allow for information requests or the use of a discovery process, so that stakeholders can gather information to help in the decision-making process. During an IRP process, commission staff play a key role in reviewing a utility's filing. IRPs provide opportunities for stakeholder involvement and feedback. During the process, the commission will review prior IRPs to ensure that past recommendations were incorporated into the utility's planning process. Some commissions approve a proposed IRP, while others simply acknowledge the IRP's submission.[15]

A. Background

The late 1970s and early 1980s were a tumultuous time for energy regulators. A variety of factors coincided during this period that catalyzed regulators and other stakeholders to develop a greater interest in approaching future integrated resource plans in a more holistic manner. These factors included:

- Higher and more volatile fuel prices,
- The burgeoning environmental movement, coupled with mounting concerns about negative externalities caused by fossil fuels,[16]
- Cost overruns and construction delays for large generation projects,
- A reduction in the forecasted growth rate in the demand for electricity,
- Increased evidence that energy use did not have to grow in correlation with economic growth,[17]
- Expanding interest in energy efficiency and demand-side management activities as a legitimate and valuable part of a utility's resource mix,[18]
- Passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA),[19] and
- Increased interest in public participation and "sunshine" laws on the heels of the Watergate scandal.

Growing awareness around these issues all contributed to the development of new planning processes. During this period, many commissions developed "least-cost plans" which, as the name suggests, worked to identify

13 Krause and Etto, 1988, *Least-Cost Planning: A Handbook for Public Utility Commissioners, Volume 2: The Demand Side: Conceptual and Methodological Issues*, National Association of Regulatory Utility Commissioners.

14 Rachel Wilson and Bruce Biewald, June 2013, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project, p. 4.

15 Ibid., p. 11.

16 Dan York and David Narum, 1996, "The Lessons and Legacy of Integrated Resource Planning," *American Council for an Energy-Efficient Economy 1996 Summer Study on Energy Efficiency in Buildings*, Vol. 7, p. 7.179.

17 Ibid.

18 Douglas Bauer and Joseph Eto, August 1992, "Future Directions: Integrated Resource Planning," *American Council for an Energy-Efficient Economy*, Vol. 8, p. 8.1.

19 Alan Cooke, March 1, 2021, "Integrated Resource Planning in the U.S. Overview," Pacific Northwest National Laboratory, slide 3.

least-cost resources that should be incorporated in future planning efforts. Least-cost plans were a step forward but did not necessarily consider energy efficiency or demand-side management options. In most of these states, least-cost planning evolved into integrated resource planning in the late 1980s with the inclusion of these two considerations.[20] IRPs have continued to evolve in recent years and can now explicitly include distributed energy resources and distributed system investments as part of plans, an effort that NARUC supports through its Comprehensive Electricity Planning Task Force.[21] While many states engage in IRP processes, utilities in restructured states, where generation is not regulated by state commissions, do not necessarily engage in IRPs.[22]

B. Frequency and Time Windows

IRP frequency and forecasting periods vary by state, and not all states have an IRP filing requirement. The term "planning horizon" refers to the forward-looking time period that an IRP will consider. These planning horizons are generally 10-, 15-, or 20-year periods, with 20-year periods as the most commonly used planning horizon. A few states allow utilities to employ different planning horizons. For example, the Colorado PUC allows the utility to determine the most appropriate planning horizon. Alternately, Montana Public Service Commission (PSC) planning horizons vary based on whether the utility is a vertically integrated or restructured utility. Table 1 provides an overview of state IRP horizon requirements for states that use IRP processes. Vertically integrated utilities are required to engage in long-term planning for 20- to 25-year periods, while for restructured utilities, the planning horizon is "the longer of: (1) the longest remaining contract term in a utility's supply resource portfolio; (2) the period of the longest lived electricity supply resource being considered for acquisition; or (3) 10 years."[23] **Table 1** reviews state IRP horizons.

Table 1: State IRP Horizon Requirements

Frequency	States				
10 years	Alaska California	Delaware Florida	Oklahoma South Dakota	West Virginia Wyoming	Maryland*
15 years	Arizona Kentucky	Michigan** Minnesota	North Carolina South Carolina	Virginia	
20 years	Georgia Hawaii Idaho	Indiana Louisiana Mississippi	Missouri Nebraska Nevada	New Mexico North Dakota Oregon	Utah Vermont Washington
Other	Colorado—Utility determined planning horizon*** Montana—Multiple planning periods**** New Hampshire—Not specified*****				

*While Maryland does not have an "IRP" per se, Maryland does produce a 10-year plan annually, and addresses similar issues that are included in an IRP such as transmission planning, load-forecasting, and long-term goals.[24]

20 Ibid., slide 4.

21 For more information, see NARUC Task Force on Comprehensive Electricity Planning: https://www.naruc.org/taskforce/.

22 For more information on IRPs, and specifically long-term planning comparisons, see Lawrence Berkeley National Lab's Resource Planning Portal: https://resourceplanning.lbl.gov/login.php.

23 Rachel Wilson and Paul Peterson, April 28, 2011, "A Brief Survey of State Integrated Resource Planning Rules and Requirements," Synapse Energy. http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf.

24 Public Service Commission of Maryland, November 2022, "Ten-Year Plan (2022–2031) of Electric Companies in Maryland." https://www.psc.state.md.us/wp-content/uploads/2022-2031-Ten-Year-Plan-Final.pdf.

**Michigan's statute includes 5-, 10- and 15-year time horizons (MCL 460.6t (20)).

***Electric resource plans filed in 2021 by the Public Service Company of Colorado and in 2022 by Black Hills Energy planned through 2030.

**** Montana-Dakota Utilities' 2021 and NorthWestern's 2023 IRP filings both used 20-year planning horizons.

*****Eversource used a 10-year planning horizon for a least-cost IRP filed with the New Hampshire Public Utilities Commission in 2020; Liberty Utilities used a 5-year planning horizon for a 2021 filing.

Sources: Rachel Wilson and Bruce Biewald, June 2013, "Best Practices in Electric Utility Integrated Resource Planning," Regulatory Assistance Project, p. 6 and Appendix; Coley Girouard, August 11, 2015, "Understanding IRPs: How Utilities Plan for the Future," Advanced Energy United. https://blog.advancedenergyunited.org/understanding-irps-how-utilities-plan-for-the-future.

After a utility's IRP process is completed, they must update their plans periodically so that the IRP is responsive to changing conditions such as fuel prices, load forecasts, and environmental regulations. Most states require utilities to update their IRPs every two or three years, although some states allow for more or less time between reviews. **Table 2** represents IRP frequency in states that require filings. As discussed in Section II.A, not all states require IRP filings due to differing electricity market structures and regulatory oversight of generation.

Table 2: State IRP Frequency

Frequency	States				
1 year	Florida				
2 years	Arizona California Delaware	Idaho Indiana Minnesota	Montana New Hampshire North Carolina	North Dakota Oregon South Dakota	Utah Virginia
3 years	Alaska Georgia Hawaii	Kentucky Louisiana Mississippi	Missouri Montana Nevada	New Mexico Oklahoma South Carolina	Vermont
4 years	Colorado	Washington			
5 years	Michigan*	Nebraska	West Virginia		
Other	West Virginia—has a 3-year retrospective period Wyoming—frequency not specified				

Sources: Rachel Wilson and Bruce Biewald, June 2013, "Best Practices in Electric Utility Integrated Resource Planning," Regulatory Assistance Project, p. 6 and Appendix; Coley Girouard, August 11, 2015, "Understanding IRPs: How Utilities Plan for the Future," Advanced Energy United. https://blog.advancedenergyunited.org/understanding-irps-how-utilities-plan-for-the-future.

* MCL 460.6t (20-21) says "not later than 5 years after" and Commission may request a utility to file a plan review at any time.

States have established a variety of requirements around which investor-owned utilities (IOUs) must file IRPs. States may require all IOUs in a state, utilities above a certain size, the default power supplier (in retail choice states), or state agencies (instead of utilities in restructured states) to file IRPs.[25]

IRP processes consider both objective analysis and the values and judgements of stakeholders, and provide opportunities for community input and stakeholder engagement during different phases of the process. Third

25 Alan Cooke, April 2019, "Task Force Member States: Introductory Information," National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, slide 4. https://pubs.naruc.org/pub/67D4F994-B9A4-8A67-DF79-86F5FC4688D5.

parties granted legal status in regulatory proceedings are called intervenors.[26] Intervenors in an IRP process may include a diverse set of stakeholders such as: consumer advocates, community groups, advocacy groups, and other governmental organizations that may have a stake in the energy planning process (such as state environmental and energy departments).[27]

C. Commission's Role and Common Elements of IRP

PUCs generally handle oversight of the IRP review process for IOUs. State regulators review a utility's IRP and have the options to approve/reject, accept, acknowledge, modify, or deny the plan presented based on consistency with state statutory requirements.[28] While each state's IRP (including process and time frame) varies based on the state's objectives, there are common elements included in most IRPs. An overview of these elements is reviewed in the following chart.

Figure 2: Common Elements of an IRP

Overview of the Planning Environment

Generally, the IRP process commences by reviewing basic facts about:

- The utility,
- The planning process, and
- Relevant legal mandates or regulatory requirements that must be considered in the planning process.

Load Forecast

Because the goal of an IRP is to develop a plan to meet the long-range needs of customers (see Table 1 for time horizon requirements), this process will always include a forecast of future customer demand for energy. IRPs generally include multiple load forecasts based on different scenarios such as:

- Anticipated regional growth,
- Increases in energy efficiency programs, and
- Increased building electrification.

Resource Options

- The IRP will include information about the electric resources already used in the utility system, and any known or planned future changes in those resources (this can include planned retirement dates for plants).
- The IRP will also explore different new types of energy resources that the utility should consider to meet
- future customer's needs, including details about resources' capability and estimated costs.

26 Jake Duncan, Julia Eagles, David Farnsworth, John Shenot, and Jessica Shipley, October 2021, "Participating in Power: How to Read and Respond to Integrated Resource Plans," Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2021/10/rap_imt_participating_in_power_how_to_read_and_respond_to_integrated_resource_plans_2021_october.pdf.

27 Christopher Greacen, Chuenchom Greacen, David von Hippel, and David Bill, October 2013, "An Introduction to Integrated Resource Planning," International Rivers.

28 Washington's Utilities and Transportation Commission, for example, determines whether IRPs are consistent with state statutory requirements. See RCW 19.280.030, Development of a Resource Plan—Requirements of a Resource Plan—Clean Energy Action Plan, https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030.

Resource Portfolios

- Based on load forecast, the IRP will identify portfolios (consisting of different combinations of existing and new resources) that will meet customer needs through the duration of the established planning period.
- By developing a variety of different portfolios, the utility can assess the costs and environmental impacts of different resource mixes.

Analysis

- The utility simulates how the system would operate every hour of the year for the duration of the planning horizon established, and what this would cost for each resource portfolio identified.
- The resulting analysis for each portfolio can be compared based on variables such as costs, reliability impacts, and environmental outcomes.

Preferred Portfolio

The goal of the IRP process is to choose a preferred portfolio of resources based on stakeholder input and objective analysis that will form the basis of the utility's future procurement efforts. Preferred portfolios must:

- Meet legal and regulatory mandates (e.g., clean energy goals),
- Perform well in modeling for reliability concerns, and
- In general, cost the least in a baseline scenario.

Near-Term Action

- Many PUC rules require utilities to provide information on their intended near-term (i.e., three- to five-year period) actions based on the IRP. These actions might include plans for resource procurement or new program development.

This source was constructed using information from: Jake Duncan, Julia Eagles, David Farnsworth, John Shenot, and Jessica Shipley, October 2021, "Participating in Power: How to Read and Respond to Integrated Resource Plans," Regulatory Assistance Project, pp. 6–8, https://www.raponline.org/wp-content/uploads/2021/10/rap_imt_participating_in_power_how_to_read_and_respond_to_integrated_resource_plans_2021_october.pdf, and Rachel Wilson and Bruce Biewald, June 2013, "Best Practices in Electric Utility Integrated Resource Planning," Regulatory Assistance Project.

In most cases, state IRP rules have requirements that establish planning horizons, the frequency with which plans must be updated, and what types of generating resources should be considered. Some states go further in providing requirements for how states consider IRPs or what types of modeling must be used. Commissions may have explicit authorization to ensure utilities meet environmental or social goals. For example, in 2018, Washington, DC, passed the Clean Energy Omnibus Act, which included a provision directing the PUC to consider "public safety, the economy of the District of Columbia, the conservation of natural resources, and the preservation of environmental quality, including effects of global climate change and the District's public climate commitments."[29]

D. Sources of Data and Types of Models

PUCs with IRP requirements provide a list of attributes each IRP must exhibit. These attributes are specified in a commission's administrative rules or state law. Generally, IRP requirements include a checklist of requirements that utilities must meet, and a near-term plan that describes the steps to be taken between the publication of the current IRP and the next IRP.[30]

29 Code of the District of Columbia, Chapter 8: Public Service Commission; Members; Counsel; Employees. https://code.dccouncil.us/dc/council/code/titles/34/chapters/8/

30 Alan Cooke, March 1, 2021, "Integrated Resource Planning in the U.S. Overview," Pacific Northwest National Laboratory, slide 8.

Some commonly required types of models used in the IRP process may include:

- Range of load forecasts,
- Assessment of commercially available conservation,
- Assessment of commercially available generation resources,
- Assessment of transmission system capacity,
- Comparative evaluation of supply resources (including transmission and distribution) and improvements in conservation, and
- Integration of demand forecasts and resource evaluations.

E. IRPs Over Time

The role of an integrated resource plan has grown and evolved over time due to changes in clean energy policies, stakeholder engagement, and customer demands. In states that experience rapid load growth, it is recognized that the IRP process may only represent a snapshot in time and in many states these filings are not approved as road maps, but instead are merely accepted for filing. In service territories that are experiencing unprecedented requests for service from large load and industrial customers, the IRP process cannot keep up with the increased requests for power/service. In these instances, IRPs can be outdated even before they are officially filed with regulatory commissions. While it is useful to review IRPs from a historical lens to understand the circumstances in which the concept was created, it is important to contextualize IRPs in the current energy landscape and recognize differences that occur over time and from state to state.

II. Overview of Advanced Nuclear Technologies

There are several emerging advanced nuclear technologies that have gained increased traction both in terms of testing and inclusion in IRPs. These new, smaller, and innovative nuclear technologies provide potential for greater flexibility in use cases, faster and less expensive assembly, and improved safety measures. Several of these technologies are being demonstrated across the country with plans to become commercially available in the coming decade.

One such example is being constructed by TerraPower in partnership with GE Hitachi. TerraPower's Natrium reactor uses a sodium fast reactor combined with a molten salt energy storage system that can produce a maximum of 500 MW.[31] The partnership announced in 2021 that it would team up with Rocky Mountain Power, a subsidiary of PacifiCorp, to demonstrate the advanced nuclear technology in Kemmerer, Wyoming. The Wyoming location is near a retiring coal plant and is expected to generate thousands of construction jobs in addition to hundreds of permanent jobs at the plant.[32] This project highlights the potential transition opportunity for coal to clean energy sources such as nuclear that provide coal-dependent communities the opportunity to maintain energy sector jobs and economic benefits provided by power generation. The Kemmerer project will also reuse existing infrastructure, such as transmission and interconnection, which will help to reduce the overall cost of the project. This project is expected to come online by 2030 and could lead to more coal-fired plants being replaced with advanced nuclear projects, a concept that is already gaining momentum.[33]

Another innovative advanced nuclear technology is the Oklo Aurora microreactor. This type of reactor uses metal fuel to produce heat, which is converted into electricity through a heat exchanger.[34] Aurora is unique in that Oklo plans to create a commercially viable microreactor powered by spent nuclear fuel. In 2020, Oklo was selected to gain access to INL's recovered spent nuclear fuel, a key step in achieving the goal of demonstrating the first Oklo Aurora plant.[35] Currently, there are more than 90,000 metric tons of spent nuclear fuel in storage in the United States alone, largely at the sites at which the fuel was used to produce electricity, offering a potentially abundant fuel source. More recently, Oklo has announced sites for two additional power plants in Southern Ohio in partnership with the Southern Ohio Diversification Initiative, which are expected to provide up to 30 MW of clean power and more than 50 MW of clean heat when fully deployed.[36]

Other advanced nuclear projects include NuScale, X-energy, Kairos, Terrestrial, Holtec, and the Marvel microreactor, all of which are also in the process of developing nuclear reactors in partnership with INL.[37] X-energy has also received an award through DOE's Advanced Reactor Demonstration Program (ARDP) to demonstrate a four-unit Xe-100 facility at a Dow manufacturing site on the Texas Gulf Coast.[38] NuScale is unique in that it is developing its reactor at INL to be commercially viable and useable, as reflected in Idaho Power's latest IRP and a power purchase agreement (PPA) between NuScale and UAMPS, a group of public power utilities.

These and other designs all use different materials and technologies. The varying capacities, land use impacts, and costs show the potential for nuclear energy to provide flexible and clean energy in a variety of ways

---

31 TerraPower, "Natrium Reactor and Integrated Energy Storage." https://www.terrapower.com/our-work/natriumpower/.

32 U.S. Department of Energy, Office of Nuclear Energy, November 16, 2021, "Next-Gen Nuclear Plant and Jobs Are Coming to Wyoming." https://www.energy.gov/ne/articles/next-gen-nuclear-plant-and-jobs-are-coming-wyoming.

33 TerraPraxis, 2023, "Decarbonizing the Global Coal Feet by 2050." https://www.terrapraxis.org/projects/repowering-coal.

34 Robert Walton, January 7, 2022, "NRC Denies Oklo Power's Plan to Construct 1.5 MW Advanced Nuclear Reactor in Idaho," Utility Dive. https://www.utilitydive.com/news/nrc-denies-oklo-powers-plan-to-construct-15-mw-advanced-nuclear-reactor-i/616807/.

35 Idaho National Laboratory, February 19, 2020, "INL Selects Oklo Inc. for Opportunity to Demonstrate Reuse of Fuel Material." https://inl.gov/article/inl-selects-oklo-inc-for-opportunity-to-demonstrate-reuse-of-fuel-material/.

36 "Oklo Announces Sites for Two Power Plants in Southern Ohio," May 18, 2023, Business Wire. https://www.businesswire.com/news/home/20230518005314/en.

37 Idaho National Laboratory, 2022, "3 Types of Nuclear Reactors." https://inl.gov/document/3-types-of-nuclear-reactors/.

38 American Nuclear Society, May 15, 2023, "Site for Dow, X-energy SMR Project Selected," Nuclear Newswire. https://www.ans.org/news/article-4991/site-for-dow-xenergy-smr-project-selected/.

for customers with differing needs. Additionally, SMRs and microreactors appeal to energy companies and regulators who value the reduced scale of the financial risk associated with construction compared to traditional nuclear projects.[39] Some components of these builds will be manufactured in a factory, transported, and installed on-site as compared to having raw materials shipped to the construction site to be assembled. This manufacturing process should provide greater efficiency and cost savings. As these technologies (see **Table 3** for a breakdown and comparison) are starting to take shape and approach commercialization, utilities across the country are considering the costs and benefits of adding these reactors to their energy generation fleet.

Table 3: Selected Advanced Nuclear Technologies

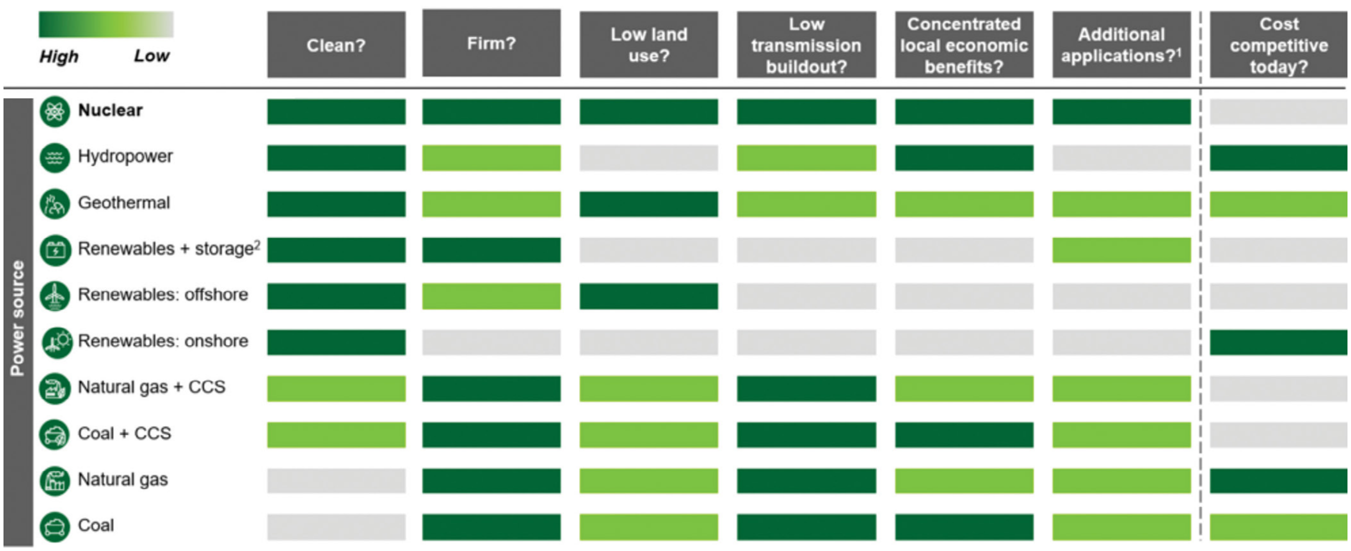
Design	Classification	Nameplate Capacity	Licensing Status
NuScale VOYGR	Light Water	77 megawatts electric (MWe)	The NRC approved the Final Safety Evaluation Report on August 28, 2020. $1.4 billion of DOE funding for UAMPS's demonstration of a 6-module reactor at INL. The NRC approved the 50 MW design certification on January 20, 2023.
GE Hitachi BWRX-300	Light Water	300 MWe	Selected for potential deployment by Ontario Power Generation (OPG) and TVA. Multiple topical reports submitted to/approved by NRC.
X-energy Xe-100	High-Temp Gas (Pebble Bed)	80 MWe	Selected for ARDP ~$1.23 billion of funding by DOE over a 7-year demonstration period to deploy at the Dow site in Seadrift, Texas. Also completed a feasibility study for Xe-100 at a retired coal plant in Maryland. NRC pre-application activities.
Terrestrial Energy IMSR	Molten Salt	195 MWe	Selected for a NRC/Canadian Nuclear Safety Commission pilot project. NRC pre-application activities.
TerraPower Natrium Reactor	Sodium Fast Reactor with Molten Salt Storage System	345 MWe 500 MWe (5.5 hours)—with Molten Salt Storage System	Selected for ARDP ~$1.23 billion of funding by DOE over a 7-year demonstration period to deploy near the former PacifiCorp coal site in Kemmerer, Wyoming. NRC pre-application activities.
Oklo Aurora	Liquid Metal	1.5 MWe	Filed a combined construction and operating license with the NRC on March 11, 2020—denied without prejudice on January 6, 2022. Company stated intent to reapply. NRC pre-application activities.
Kairos Power KP-FHR	Pebble Bed with Molten Salt Coolant	140 MWe	Selected for a $30 million risk reduction award by DOE. Research reactor construction permit application under NRC review.
Westinghouse eVinci	Solid Core Heat Pipe	200 kilowatts electric (kWe) to 5 MWe	Selected for a $30 million risk reduction award by DOE. NRC pre-application activities.

Source: Jeffrey Merrifield (Partner and Global Energy Leader—Pillsbury Law), July 20, 2022, "Presentation at the NARUC Summer Policy Summit on Formative Advanced Nuclear Technologies That Are Driving Rare Bipartisanship in Washington, DC," slide 3. Note: Addendums made by authors to reflect recent developments.

39 One example of this can be found in PacifiCorp's 2021 Integrated Resource Plan, p. 191.

Changes in electricity consumption, load-following capabilities of advanced reactors, and recent cost overruns associated with the construction of large conventional reactors make advanced reactors the likelier choice for new nuclear construction. Like conventional reactors, advanced reactors would apply for a 40-year initial license from the NRC and subsequent 20-year renewals. Zero-carbon power, the ability to provide firm generation, low land use, low transmission buildout, economic benefits, and applications beyond power generation make nuclear a valuable piece of a decarbonizing grid (**Figure 2**). In a feasibility study for the Maryland Energy Administration, X-energy noted the ability of advanced nuclear to support greenhouse gas reduction, decarbonization planning, energy resilience, economic development, and job growth.[40] As shown in **Figure 3**, the long operating lifetimes of nuclear units are a further advantage with wind and solar tending to have 20- to 30-year lifetimes; batteries can operate for 10 years or fewer depending on the frequency of the charge/discharge cycle. New natural gas and coal units may operate for 40 years or longer; however, largely due to utility and customer demands for lower-carbon power and environmental regulations impacting the coal fleet, no new coal plants have been constructed since 2013,[41] and gas plants may retire before the end of their useful economic lifetimes.

Figure 2: Value of Nuclear in a Decarbonized Grid



1. Additional applications include clean hydrogen generation, industrial process heat, desalination of water, district heating, off-grid power, and craft propulsion and power
2. Renewables + storage includes renewables coupled with long duration energy storage or renewables coupled with hydrogen storage

Source: U.S. Department of Energy, March 2023, The Pathway to Advanced Nuclear Commercial Liftoff. https://liftoff.energy.gov/advanced-nuclear/.

As shown in **Figure 3**, one large nuclear plant—or a set of co-located advanced reactors—can enable a similar level of reliability and decarbonization as multiple wind and solar, bulk energy storage, and natural gas resources. Nuclear units—particularly SMRs and microreactors—also take up far less land than wind and solar resources and are competitive with coal and natural gas units from a land use perspective (see **Table 4**). Smaller nuclear reactors can also be paired with renewable generation to provide firm power. Unlike coal or natural gas units, nuclear plants rely on highly concentrated fuel sources as opposed to a steady stream of coal or natural gas delivered by train, truck, or pipeline.

40 X-energy, November 30, 2022, "Feasibility Assessment and Economic Evaluation: Repurposing a Coal Power Plant Site to Deploy an Advanced Small Modular Reactor Power Plant." https://energy.maryland.gov/Reports/MD%20Feasibility%20Assessment%20and%20Economic%20Evaluation%20%28Jan2023%29.pdf.

41 Energy Information Administration, November 7, 2022, "Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Scheduled to Retire by 2029." https://www.eia.gov/todayinenergy/detail.php?id=54559.

Figure 3: Elements of a Deep Decarbonization Portfolio

Source: Jeffrey Merrifield (Partner and Global Energy Leader—Pillsbury Law), July 20, 2022, "Presentation at the NARUC Summer Policy Summit on Formative Advanced Nuclear Technologies That Are Driving Rare Bipartisanship in Washington, DC," slide 3. Note: Minor edits made by NARUC for inclusion in this report.

Table 4: Land Requirements 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

Source: *Nuclear Energy as a Keystone Clean Energy Resource*, August 2022, NARUC and Energy Ventures Analysis, Exhibit 31. https://pubs.naruc.org/pub/5D91CEFD-1866-DAAC-99FB-768958414493.

Cost estimates for advanced reactors are limited at this point. Appalachian Power Company, a subsidiary of American Electric Power (AEP Energy), does provide a rough estimate in their 2022 IRP for the cost of two 300-MW GE Hitachi SMRs. AEP Energy states in the 2022 plan that they determine their cost estimates by "continually track[ing] and monitor[ing] changes in the estimated cost and performance parameters for a wide array of generation technologies."[42] In this model, AEP Energy estimates that 600 MW for a small reactor nuclear power plant would have an installed cost of $7,300 per kilowatt (kW) and a levelized cost of energy (LCOE) estimated to be $129 per megawatt-hour (MWh).[43] Recently, UAMPS agreed to raise the allowable price of the NuScale project to $89 per MWh.[44]

In DOE's "Pathways to Commercial Liftoff: Advanced Nuclear" report, DOE estimates that as of 2023, the overnight capital costs (or the cost required to construct a nuclear plant without the impact of interest accrued during construction) are estimated to range from ~$6,000 to $10,000 per kW for a FOAK advanced nuclear

42 American Electric Power, *Integrated Resource Plan to the Commonwealth of Virginia State Corporation Commission*, p. 59.

43 Ibid.

44 Steve Ernst, January 13, 2023, "NuScale's SMR Costs Jump 53 Percent; UAMPS Members Remain Committed," *California Energy Markets*. https://www.newsdata.com/california_energy_markets/regional_roundup/nuscales-smr-costs-jump-53-percent-uamps-members-remain-committed/article_e1aa55da-937f-11ed-90fc-0ba22de948e3.html.

reactor. DOE estimates that with repeat builds, the nth-of-a-kind (NOAK) overnight cost for an advanced nuclear reactor could be ~$3,600 per kW.[45]

As indicated in Figure 2, nuclear is not cost-competitive today with hydropower, onshore renewables, and natural gas. However, it is worth noting that simply comparing LCOE metrics, which provide a dollar per kW value, paints an incomplete picture of the differences between generation resources. LCOE attempts to reflect all costs of producing electricity over a plant's lifetime; however, LCOE cannot be used to contrast different resources that provide different services, such as capacity and flexibility.[46] LCOE generally overvalues intermittent generating technologies by failing to value electricity produced at peak hours higher than non-peak generation. Although LCOE is a useful metric in certain scenarios, energy economist Paul Joskow recommends that decision-makers consider differences in production profiles, variations in wholesale market prices, and lifecycle costs to more comprehensively assess the costs of generation technologies.[47]

In 2022, the Nuclear Innovation Alliance (NIA) launched an effort with members of the energy modeling community to develop a better understanding of the knowledge gaps that exist between the real and anticipated costs of advanced nuclear, better understand how these costs and capabilities are characterized in energy system modeling efforts, and pinpoint actions that could help the energy modeling community close identified gaps. From this process, NIA highlighted two key takeaways: capital cost was perhaps the most important modeling parameter, and increasing the number and types of advanced nuclear technologies and energy services that nuclear energy technologies provide can improve the projected economics of advanced nuclear in energy system models.[48]

This effort included outreach to both modelers and advanced nuclear reactor developers. From these questionnaires, NIA identified significant gaps in understanding between modelers and advanced reactor developers about the capabilities of advanced nuclear technologies:

- Most energy models included in the survey (8 of 10) simulated nuclear energy technology with limited or no operational flexibility, while most advanced nuclear developers report technologies that feature high degrees of operational flexibility.
- The average estimated "initial year" capital costs of new nuclear facilities in energy system models surveyed was $7,100 per kilowatt electric (kWe) whereas advanced nuclear reactor developers surveyed reported the average FOAK capital cost estimates for reactors with capacities larger than 20 megawatt electric (MWe) was $4,800 per kWe.
- Half of the energy modelers surveyed assumed that advanced nuclear technologies could provide one or more energy services (such as industrial processes and heat, combined heat and power, hydrogen production, water desalination, synthetic fuels production), while all of the advanced nuclear reactor developers surveyed are designing for the supply of one or more additional energy services.[49]

Another significant factor in advanced nuclear cost discussions is the impact of the Inflation Reduction Act (IRA). The IRA opened the door for advanced nuclear to access two types of credits for clean electricity: Production

45 U.S. Department of Energy, Loan Programs Office, March 2023, "Pathways to Commercial Liftoff: Advanced Nuclear," pp. 18–19. https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Advanced-Nuclear-vPUB.pdf.

46 Sam Huntington, July 14, 2020, "From Cost to Value: Going Beyond LCOE in Assessing the Competitiveness of Renewables," *S&P Global*. https://www.spglobal.com/commodityinsights/en/ci/research-analysis/cost-to-value-beyond-lcoe-assessing-competitiveness-renewables.html.

47 Paul L. Joskow, 2011, "Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies," *American Economic Review*, 101(3): 238–241. https://www.aeaweb.org/articles?id=10.1257/aer.101.3.238.

48 J. Greenwald, C. Mokoena, M. Chupka, and M. Luke, January 2023, *Modeling Advanced Nuclear Energy Technologies: Gaps and Opportunities*, Nuclear Innovation Alliance. https://nuclearinnovationalliance.org/modeling-advanced-nuclear-energy-technologies-gaps-and-opportunities.

49 Ibid., pp. 3–4.

Tax Credit (PTC) and Investment Tax Credit (ITC). The IRA amends the definition of a qualified facility to include advanced nuclear facilities. The PTC is set at an initial base rate of 0.3 cents per kilowatt-hour, multiplied by five if certain worker standards are met. The PTC goes into effect for projects placed in service after December 31, 2024, and lasts for 10 years. The ITC ranges from 6 percent for most generators up to 30 percent for units producing less than 1 MWe. The ITC is also available for facilities coming online after December 31, 2024, and phases out at the end of 2023, or once carbon dioxide (CO_2) emissions from electricity production fall 25 percent below 2022 levels. Both the PTC and ITC include a bonus of 10 percentage points for energy facilities located in an energy community.[50] Facilities that qualify for both the PTC and ITC may only take advantage of one credit.

A. Oversight of Generation; Role of FERC

While states provide oversight of utility planning via the IRP process, the Federal Energy Regulatory Commission (FERC) plays a different role in the planning for advanced nuclear. FERC is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. While FERC also reviews proposals to build liquified natural gas terminals and interstate natural gas pipelines and licenses hydropower projects,[51] it also plays a limited role in nuclear planning. Section 215 of the Federal Power Act (FPA) directs the commission to approve the Nuclear Plant Interface Coordination Reliability Standard developed by the North American Electric Reliability Corporation (NERC). Additionally, pursuant to section 215(d)(5) of the FPA, FERC directs NERC to develop modifications to the Reliability Standard to address specific concerns.[52]

NERC was formed as the National Electric Reliability Council in 1968, following the 1965 Northeast blackout. NERC's initial purpose was to assure the reliability of the bulk power system. Beginning with the passage of the Public Utility Regulatory Policies Act of 1978 and continuing with the introduction of competition to multiple sectors of the power market in the 1980s and 1990s, NERC evolved to assure reliability in a competitive market environment. And with the 2003 blackout and subsequent passage of the Energy Policy Act of 2005, NERC became the North American Electric Reliability Corporation, responsible for setting reliability standards for newly established Electric Reliability Organizations.

Source: David Nevius, 2020, "The History of the North American Electric Reliability Corporation." https://www.nerc.com/news/Documents/NERCHistoryBook.pdf.

B. Role of the NRC in Approving Advanced Nuclear Reactor Designs

Historically, the NRC has licensed nuclear power plants under a two-step process described in Title 10 of the Code of Federal Regulations (CFR) under Part 50. Most of the operating plants were licensed using this process. The NRC adopted its current licensing process, known as combined licensing, in 1989 to improve efficiency and add greater predictability to the nuclear licensing process. This combined licensing process is described in 10 CFR Part 52. The NRC's combined license provides a construction permit and an operating license with conditions, instead of requiring a two-step process.[53] Regardless of the licensing framework, the NRC must provide approval before a plant can be built and operated. Once approval is granted, the NRC

50 The IRA defines energy communities as a brownfield site; a metropolitan statistical area or a non-metropolitan statistical area that has (or had at any time after 2009) 0.17 percent or greater direct employment or 25 percent or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas and that has an unemployment rate at or above the national average unemployment rate for the previous year; and a census tract (or directly adjoining census tract) in which a coal mine has closed after 1999 or in which a coal-fired electric generating unit has been retired after 2009.

51 Federal Energy Regulatory Commission, March 30, 2022, "What FERC Does." https://www.ferc.gov/what-ferc-does.

52 Federal Energy Regulatory Commission, October 16, 2008, "Mandatory Reliability Standard for Nuclear Plant Interface Coordination," Docket No. RM08-3-000; Order No. 716. https://www.federalregister.gov/documents/2008/10/27/E8-25139/mandatory-reliability-standard-for-nuclear-plant-interface-coordination.

53 Nuclear Regulatory Commission, Office of Public Affairs, July 2020, "Nuclear Power Plant Licensing Process." https://www.nrc.gov/docs/ML0521/ML052170295.pdf.

maintains oversight of construction and operations throughout the lifetime of the plant to ensure compliance with health, safety, security, and environmental regulations.[54]

With the maturation of advanced nuclear reactors, the NRC has worked to reduce regulatory uncertainty while streamlining advanced reactor design and licensing processes for non-light water reactor technologies.[55] The existing licensing processes (Parts 50 and 52) focus on light-water reactor designs, and novel reactor concepts have experienced difficulty meeting the regulatory requirements established in these licensing processes.[56] One reason for this difficulty is that advanced reactor designs have passive or inherent safety features[57] that traditional licensing processes do not consider. The finalized advanced reactor licensing approach adopts a risk-informed, performance-based review process that reviews realistic scenarios that the developer must consider. This new advanced reactor licensing approach applies to light-water and non-light-water reactor designs under the existing Parts 50 and 52 licensing approval processes.

A combined license application under Part 52 includes information about the inspections, tests, and analyses that an applicant must perform, in addition to acceptance criteria necessary to provide reasonable assurance that the nuclear facility has been constructed and will operate in accordance with the license and applicable regulations. After issuing a combined license, the NRC authorizes operation of the facility once it has confirmed that the applicant has completed the aforementioned inspections, tests, and analyses. The NRC publishes notices of these completed requirements in the *Federal Register*, and the NRC will publish a notice of intended operation of the facility in the *Federal Register* at least 180 days prior to the date established for the initial plant fueling. During this 180-day period, there is a limited opportunity for petitions that demonstrate that the licensee has not met or will not meet the acceptance criteria that were established as part of the license.[58]

In March of 2023, NRC staff shared a draft proposed Part 53 rulemaking package with the NRC commissioners, requesting approval to publish the draft proposed rule in the Federal Register. The proposed rule uses a Risk-Informed, Technology-Inclusive Regulatory Framework for Advanced Nuclear. The draft proposed rules provide a voluntary, performance-based alternative regulatory framework that could be used to license future nuclear plants. The regulatory requirements for Part 53 would incorporate methods of evaluation into the licensing process such as risk-informed and performance-based methods. The draft proposal would accommodate all reactor technologies. The NRC expects to issue the final Part 53 rule by July 2025.[59] In July 2023, a bipartisan group of lawmakers urged the NRC to modify the proposed Part 53 rule to address six issues identified by stakeholders and support the NRC's "capacity to license the large volume of applications necessary to meet

54 Ibid.

55 U.S. Department of Energy, Office of Nuclear Energy, July 9, 2020, "NRC Approves New Approach to Streamline Advanced Reactor Licensing Process." https://www.energy.gov/ne/articles/nrc-approves-new-approach-streamline-advanced-reactor-licensing-process.

56 X-energy and TerraPower plan to undertake the Part 50 process for their demonstration plants.

57 The International Atomic Energy Agency describes passive and inherent safety in a 1991 report, "Safety Related Terms for Advanced Nuclear Plants." The definitions hold true today: "The concepts of active and passive safety describe the manner in which engineered safety systems, structures, or components function and are distinguished from each other by determining whether there exists any reliance on external mechanical and/or electrical power, signals, or forces. The absence of such reliance in passive safety means that the reliance is instead placed on natural laws, properties of materials, and internally stored energy. Some potential causes of failure of active systems, such as lack of human action or power failure, do not exist when passive safety is provided. However, it is important to note that passive devices remain subject to other kinds of failure, such as those resulting from mechanical or structural failure or willful human interference. Therefore, passive safety is not synonymous with inherent safety or absolute reliability… An inherent safety characteristic is a fundamental property of a design concept that results from the basic choices in the materials used or in other aspects of the design which assures that a particular potential hazard cannot become a safety concern in any way" (emphasis original). See https://www-pub.iaea.org/MTCD/publications/PDF/te_626_web.pdf.

58 Nuclear Regulatory Commission, Office of Public Affairs, July 2020, "Nuclear Power Plant Licensing Process." https://www.nrc.gov/docs/ML0521/ML052170295.pdf.

59 Nuclear Regulatory Commission, March 9, 2023, "Part 53 – Risk Informed, Technology-Inclusive Regulatory Framework for Advanced Reactors." https://www.nrc.gov/reactors/new-reactors/advanced/rulemaking-and-guidance/part-53.html.

our energy and national security priorities, provide grid reliability, and achieve our environmental goals."[60] Some stakeholders have expressed opposition to the proposed rule at such a level that they urge the NRC to restart its entire approach to license future reactor designs.[61]

NuScale Case Study: 50-MWe SMR Design Certification and 77-MWe SMR COLA Plan

NuScale Power's 50-MWe SMR design made history in September 2020 when it became the first SMR to receive NRC design approval, and more recently in January 2023 when the NRC issued a final rule certifying the SMR design. NuScale's SMR design was based on a small light water reactor developed at Oregon State University in the early 2000s. When NuScale submitted its Design Certification Application (DCA) in 2017, this submission represented over 2 million labor hours of work by NuScale to develop supporting materials for the DCA.

Next steps: NuScale plans to deliver six 77-MWe SMRs for the CFPP, a subsidiary of UAMPS, to be sited in Idaho. CFPP plans to submit a combined license application (COLA) for the 77-MWe design, the first license application for a multi-module SMR power plant to undergo NRC licensing review. If approved, this COLA will authorize the licensee to construct and operate a nuclear power plant at a specific site.

January 2017—NuScale submits its application to NRC for design certification for the 50-MWe design.

March 2017—NRC accepts NuScale's Design Certification Application for review.

August 2020—NRC staff complete regulatory review by issuing a safety evaluation with no open items.

September 2020—NRC issues standard design approval (customers can move forward with development of VOYGR power plants knowing that the design is NRC-approved).

July 1, 2021—NRC opens public comments on proposed rulemaking for NuScale's SMR standard design certification.

July 29, 2022—NRC directs NRC staff to issue a final rule certifying the NuScale SMR design for use in the United States.

January 20, 2023—NRC issues a final rule in the Federal Register certifying NuScale's SMR design, effective February 21, 2023.

For more information, see https://www.nrc.gov/reactors/new-reactors/smr/licensing-activities/nuscale.html and https://www.nrc.gov/reactors/new-reactors/smr/licensing-activities/pre-application-activities/idaho-national-labs-preapp.html.

Sources: https://www.nrc.gov/reactors/new-reactors/smr/nuscale.html, https://www.nrc.gov/reactors/new-reactors/col.html, https://www.energy.gov/ne/articles/nrc-certifies-first-us-small-modular-reactor-design.

60 Thomas R. Carper, Cathy McMorris Rodgers, et al., July 14, 2023, Letter to Honorable Christpher T. Hanson, Chairman, U.S. Nuclear Regulatory Commission. https://d1dth6e84htgma.cloudfront.net/Chairman_Hanson_Commission_Review_of_Part_53_Rulemaking_Letter_FINAL_79792c48e7.pdf.

61 Breakthrough Institute, September 16, 2022, "Can Part 53 Be the Nuclear Licensing Rule We Need?" https://thebreakthrough.org/blog/can-part-53-be-the-nuclear-licensing-rule-we-need.

Finally, a key part of the NRC review process focuses on Emergency Planning Zones (EPZ) for nuclear plants. The EPZ is the area surrounding the nuclear power plant where special considerations and management practices are pre-planned in case of emergency. These requirements were issued in 1978 and based on the footprint of large reactors being built during this time period. Since the 1970s, the analytical tools for evaluating sizing and plume exposure pathways for EPZs have advanced considerably. Additionally, the types and amounts of radioactive or hazardous materials that could be released following an accident, are much smaller for SMRs, compared to traditional reactor designs, which therefore require a much smaller EPZ. NuScale's VOYGR SMR, which received design approval from the NRC in 2022, is the first SRM using this risk-informed approach to EPZ sizing and resolution in an EPZ limited to the site boundary of the power plant.[62]

62 "US Regulator Approves Methodology for SMR Emergency Planning," October 28, 2022, World Nuclear News. https://world-nuclear-news.org/Articles/US-regulator-approves-methodology-for-SMR-emergenc

III. Advanced Nuclear in Integrated Resource Planning

No recent study has specifically reviewed the incorporation of nuclear generation into IRPs and the role played by nuclear generation in meeting future demand at least cost. With several advanced nuclear technologies progressing toward commercialization, including multiple demonstration plants to be built in the coming decade, NARUC undertook a review of recent IRP filings to extract information about the inclusion of advanced nuclear generation. Based on this review of 17 IRP filings, NARUC identified three overarching conclusions about utilities' inclusion of advanced nuclear:

1. The majority of regulated utilities are aware of advanced nuclear technologies. For many IRPs, the time horizon of evaluation is 10 years or less, and for many of the first advanced reactors the schedule for deployment would push their dates for coming online outside of the window of the IRP. In addition, uncertainties around the technological maturity, uncertainty about costs and financial risks, and unfavorable state regulatory or policy landscapes discourage inclusion of advanced nuclear in IRPs. These utilities tend to express a willingness to continue monitoring the development of advanced nuclear technologies for potential inclusion in future IRPs. The most commonly cited advanced nuclear technology was SMRs broadly. (Section III.A).
2. Some utilities have explicitly included advanced nuclear in their IRPs, namely PacifiCorp, Idaho Power, DEC, DEP, and TVA. With the exception of DEC and DEP, these organizations all share a geographic commonality: they have a nuclear-focused national lab located within their service area (Idaho National Laboratory and Oak Ridge National Laboratory) and/or have a major commercial advanced nuclear project underway. Also noted is UAMPS CFPP, a set of six 77 MW NuScale SMRs to be sited on the INL campus, expected online in 2029.[63] TVA and UAMPS, as public power utilities, are not regulated by state utility commissions. (Section III.B).
3. Most utilities propose keeping existing nuclear resources online to maintain reliability and progress toward decarbonization goals. This includes keeping ownership stakes in nuclear plants as well as extending the operating life of existing nuclear units and reapplying for 20-year operating licenses from the NRC. Utilities cite employment, economic contributions to local communities, reliability, and clean energy as key benefits of extending the lifetimes of existing nuclear units. (Section III.C).

All IRPs reviewed included discussion about the emergence of advanced nuclear, although at varying levels. At a minimum, the majority of IRPs reviewed, filed between 2019 and 2023, cite advanced nuclear as a technology of interest that is continuing to be monitored by the utility. The amount of detail given to advanced nuclear varies widely, but these more basic discussions either mention advanced nuclear broadly or describe what this new generation of nuclear could look like, detailing its benefits and potential output. The utilities that express reservations cite in relying on the technology in energy outlooks are largely similar: uncertainty both as to the timing of commercialization of these technologies will become feasible and what the costs will be. A review of state IRP filings and information on the overarching conclusions identified through NARUC's review process are explored in greater detail in this section.

A. Awareness of Advanced Nuclear Technologies

The following section is a review of selected utilities' IRPs. This review focused on capturing whether utilities were including discussion of advanced nuclear reactors in their long-term planning efforts. This report reviews IRPs filed by regulated utilities in the following states: California, Georgia, Idaho, Michigan, Minnesota, New Mexico, Oregon, South Carolina, Tennessee, Utah, Vermont, Virginia, Washington, and Wyoming. An overview

63 Utah Associated Municipal Power Systems, July 21, 2021, "CFPP Updates since October Off-Ramp." https://losalamos.legistar.com/View.ashx?M=F&ID=9618711&GUID=087139CA-D9AE-4A61-B2BB-602CAD1CCFC9.

of state IRPs reviewed and an IRP inclusion of advanced nuclear is available for reference in Appendix A. These states were chosen for inclusion in this review due to their use of IRPs and the utility's existing ownership of nuclear generation or stated interest in developing new nuclear. These trends are reviewed in greater detail in the following.

In the 17 IRPs reviewed by NARUC, 15 of the regulated utilities included in the review were aware of advanced nuclear technology, and many utilities discussed the potential of these technologies in sections dedicated to forward-looking potential.

In **Georgia Power'**s 2022 IRP, it included "Generation III+ and Generation IV Nuclear technology" in a list of technologies that are being monitored as candidates for expansion of its grid.[64] Although these technologies were not used in a subsequent model of various expansion plans, advanced nuclear was mentioned further in a detail of what Georgia Power looks to continue to research for the future. Here, Georgia Power stated that it hoped to see the domestic nuclear industry modernize to a point where advanced nuclear technologies can be deployed by the 2030s. Georgia Power also mentions their partnership with TerraPower and work on advanced nuclear that will continue with demonstrations of various aspects of TerraPower's molten chloride fast reactor technology. Georgia Power went on to discuss the potential for microreactors to support decarbonization needs in the future, highlighting the potential flexibilities that advanced nuclear could bring.[65] It is worth noting that Georgia Power has acquired 7,000 acres of land in Stewart County, Georgia, near the Alabama line. The Georgia PSC has allowed Georgia Power to spend up to $49 million to evaluate the suitability of the site for future AP1000 or any type of SMRs. Georgia Power's evaluation concluded that the Stewart County site was appropriate for the development of nuclear generation plants if the PSC determines in the future that it is appropriate to take action.[66]

Northern States Power Company, an Xcel Energy subsidiary, briefly mentions advanced nuclear and SMRs in its 2020 IRP, filed in Michigan and Minnesota. In a short section on "Emerging Nuclear Technologies," Xcel acknowledges that various companies are working to navigate the NRC licensing processes with goals of completing pilots by the late 2020s.[67] Xcel further notes benefits of SMRs, such as their flexibility, lower costs, and fewer scheduled outages.[68] The section concludes with the explanation that it remains unclear whether SMRs will be cost-competitive with other sources of energy.[69]

Public Service Company of New Mexico's (PNM) 2020 IRP briefly mentioned SMRs in its "Technology Trends & Innovation" section.[70] As part of the IRP, PNM put out a request for information seeking market intelligence on emerging energy technologies. NuScale was one of twelve companies, and the only nuclear company, to respond.[71] While PNM mentions SMRs, citing advantages such as the flexibility to right-size to customer needs, PNM admits that there is little room for these technologies in New Mexico because they do not meet New Mexico renewable portfolio standard (RPS) requirements, and the state has set stringent RPS goals for the next two decades.[72] Thus, PNM concludes in its IRP that the role of SMRs in the portfolio is limited, but the technology and advancements will continue to be monitored.

64 "Georgia Power 2022 IRP," p. 10–167.

65 Ibid., p. 10–173.

66 Tim Echols, June 16, 2023, Email message to author.

67 Northern States Power Company, "2020–2034 Upper Midwest Resource Plan," Appendix F6, p. 18.

68 Ibid.

69 Ibid.

70 Public Service Company of New Mexico, "2020–2040 Integrated Resource Plan," p. 34.

71 Ibid., p. 35.

72 Ibid., p. 41.

Dominion Energy South Carolina (DESC), a subsidiary of Dominion Energy, filed a 2021 South Carolina IRP Update. This update briefly includes advanced nuclear as an emerging technology that has the "potential to significantly reduce carbon emissions." However, this mention is only for the purpose of stressing that in order for South Carolina and Dominion Energy to meet their respective clean energy goals, supportive legislation and regulations are needed that will spur the testing and development of technologies "such as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture and sequestration."[73] This highlights that utilities would like to incorporate emerging clean energy technologies, but that utilities will likely not be able to increase nuclear utilization without additional regulatory and policy certainty.

Less than a month after its South Carolina filing, another Dominion Energy subsidiary, **Virginia Electric and Power Company (VEP)**, filed an update to an IRP in both North Carolina and Virginia.[74] In this update, advanced nuclear is mentioned in greater detail, although still at a high level. In a section dedicated to "Future Supply-Side Resources," the IRP lists "Advanced Nuclear Technologies" where it considers what the deployment of SMRs could look like.[75] VEP listed nuclear in four of its five alternative plans included in the IRP, listing nuclear as a resource in its 25-year window. Citing many benefits of SMRs, including flexibility created by the smaller size, the ability to right size, and significant investment by the DOE, the company states that it anticipates SMRs could be a viable supply-side resource by the early 2030s and that the progression of the technology will continue to be monitored.[76]

Appalachian Power Company, a subsidiary of AEP Energy, also recently filed its latest IRP in April 2022 detailing its 15-year outlook for 2022–2036 and included a brief discussion of advanced nuclear. While Appalachian Power did not include SMRs in any of the resource portfolios it considered, it did analyze advanced nuclear and even included estimated costs of an SMR. Appalachian Power estimated that two 300-MW GE Hitachi SMRs could be available in 2035 when considering construction and regulatory hurdles, but ultimately "screened out" SMRs, citing the same factor as building new traditional nuclear plants: economic infeasibility.[77] It is of note that the SMR analyzed was the only zero-carbon resource option capable of dispatchable/baseload generation.[78]

Duke Energy Progress (DEP), a Duke Energy subsidiary, included advanced nuclear in its discussions for the future in its 2020 IRP.[79] In a section analyzing zero-emissions load following technology, DEP provided a section on "Advanced Nuclear."[80] Here, DEP details how the company and its staff are actively involved with advanced nuclear technologies and mentions potential for commercialization of these technologies in the 2030s.[81] Later in the IRP, DEP addresses both advanced nuclear reactors and SMRs in its technical screening section. This section looked at various technologies to "eliminate those that have technical limitations, commercial availability issues, or are not feasible."[82] In its SMR technical screening, DEP details federal support for the technology while also mentioning several companies developing SMRs, including NuScale Power, GE Hitachi, and Holtec. The section cited the flexibility of SMRs as a key feature distinguishing them from other resources.[83]

73 Dominion Energy South Carolina, "Integrated Resource Plan 2021 Update."

74 Virginia State Corporation Commission Case No. PUR-2021-00201; North Carolina Utilities Commission Docket No. E-100, Sub 165.

75 Virginia Electric and Power Company, "2021 Update to the 2020 IRP," p. 40.

76 Ibid.

77 American Electric Power, "Integrated Resource Plan to the Commonwealth of Virginia State Corporation Commission," p. 60.

78 Ibid., p. 59, Table 12.

79 DEP's proposed Carbon Plan, and the associated discussion of advanced nuclear, is reviewed in subsection B.

80 Duke Energy Progress, "Integrated Resource Plan 2020 Biennial Report (North Carolina)," p. 141.

81 Ibid.

82 Ibid., p. 309.

83 Ibid., p. 311.

Despite the positive comments on SMRs, DEP does not change its SMR approach substantively from its 2018 IRP, screening the technology out due to a lack of commercial availability.[84]

Despite excluding SMRs, DEP does factor in SMR technologies as a resource in its "System Optimizer" as an "informative item" so the model is able to meet high CO_2 constraints in a sensitivity analysis.[85] Here, DEP uses the assumption that SMRs are in operation by 2030 and notes that while this is unlikely due to the difficulties with this "FOAK technology," the model was used more to stress the importance of advancing such technologies to allow for further reductions in carbon emissions.[86] The "70% CO_2 Reduction: High SMR" portfolio adds 684 MW of SMRs at the beginning of 2030, enabling the portfolio to achieve 70 percent CO_2 emissions reductions by 2030.

Immediately following the SMR subsection in the IRP update is another subsection on "Advanced Nuclear Technology." Here, DEP summarizes the advanced nuclear outlook as one with a number (25) of U.S. companies working on alternatives to traditional light water reactors with a wide variety of differing technologies.[87] DEP cites various examples of its parent company's involvement in these technologies both as part of working groups as well as serving on the industry boards of three different advanced reactor companies.[88] DEP concludes by stating that it will continue to follow the progress of advanced reactor technologies and provide input as information becomes available.

DEP's IRP was published before completion of the Duke Energy Carbon Plan, which was produced in response to a 2021 North Carolina law that codified a requirement that the North Carolina Utilities Commission (NCUC) "take all reasonable steps to achieve a 70 percent reduction" in CO_2 emissions from electric generating facilities. The Duke Energy Carbon Plan is discussed in greater detail to follow. The first combined DEP IRP and Carbon Plan was due to the NCUC by September 1, 2023.[89]

DTE Electric Company, which supplies customers in Michigan with retail electric service, included discussion of advanced nuclear in its November 3, 2022, IRP filing. Specifically, the company states that it had considered advanced nuclear and small modular nuclear reactors when preparing the IRP as potential emerging technologies.[90] In the filing, DTE highlighted that new nuclear technology is available 24/7, and is "considered firm dispatchable and capable of load following," which would work well in coordination with intermittent renewable resources.[91] DTE also noted the potential to produce clean hydrogen from nuclear generation.

Finally, **Indiana Michigan Power** filed its latest IRP in Michigan in 2021 and included nuclear SMRs in its "Supply-Side Resource Options and Costs" discussion along with a variety of other resources.[92] It is noteworthy that the only resources that Indiana Michigan Power included in its performance review of carbon-free plants were nuclear, wind, solar, and lithium-ion batteries.[93] Of these carbon-free sources, nuclear SMRs are the only resource able to provide a consistent baseload heat rate. In the description of SMRs, Indiana Michigan Power conceded that there are currently no SMRs in operation, but that there are several under construction.[94] The

84 Ibid., p. 312.

85 Ibid.

86 Ibid., p. 22.

87 Ibid., p. 312.

88 Ibid.

89 Duke Energy, "Carolinas Resource Plan." https://www.duke-energy.com/our-company/about-us/irp-carolinas.

90 DTE Electric Company, "In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan," Michigan Public Service Commission Case No. U-21193, p. 21.

91 Ibid., p. 22

92 Indiana Michigan Power, "Integrated Resource Plan Report 2022," Volume 1. Michigan Public Service Commission Case No. U-21189, p. 95.

93 Ibid.

94 Ibid., p. 97.

section goes on to detail the numerous benefits of SMRs in comparison with traditional nuclear reactors including enhanced safety, smaller size leading to increased flexibility, and the off-site construction allowing for more consistency in costs and delivery times.[95] Subsequently, in a list of "Available Technologies," NuScale's SMR is listed. Indiana Michigan Power goes on to compare SMRs to various natural gas combined cycle options, looking at a number of metrics including construction time, book life, generation amounts, and costs. Here, nuclear appears to be the most expensive option, although it is the only carbon-free option out of the five baseload options considered. Despite this inclusion and comparisons, advanced nuclear is not included in any of the energy outlook portfolios put together by Indiana Michigan Power. Instead, the utility relies on renewables and energy storage technology, as seen in the "Rapid Technology Advancement" portfolio.[96]

Although some utilities such as Indiana Michigan Power and DEP analyzed the costs of SMRs, and others such as Georgia Power and PNM merely described what the technologies are and the potential benefits, none of these IRPs seriously weighed the utilization of advanced nuclear. While acknowledging the promise of various technologies and even showing how the technology may compare to other advanced energy technologies, none of the utilities reviewed in this section saw the commercialization of advanced nuclear as a mature enough technology to begin planning advanced nuclear integration in their respective fleets at the time that the IRP was prepared.

B. Deliberate Inclusion of Advanced Nuclear

A few utilities do go further and include advanced nuclear in their IRP efforts. Specifically, three utilities factored advanced nuclear into IRPs: PacifiCorp, Idaho Power, and the TVA.[97] All three utilities share a common factor of having advanced nuclear projects already underway in their service area. This might lead to an increased awareness of advanced nuclear technologies in these service areas and eventually among other utilities, such as those detailed in Section III.A awaiting commercially available advanced reactors.

PacifiCorp filed its 2021 IRP with PUCs in California, Idaho, Oregon, Utah, Washington, and Wyoming, with minimal differences between state filings, and filed an update in March 2023.[98] The year 2021 marked the first time the utility included advanced nuclear in its IRP.[99] Unlike utilities in the previous section, PacifiCorp looked to solidify advanced nuclear as a part of its future generation mix, including advanced nuclear in several of the portfolio options that it considered. Advanced nuclear was even a part of PacifiCorp's preferred portfolio.[100] Here, advanced nuclear is included in all of the portfolio options with the exception of one variant preferred portfolio (P02e – No Nuc) that is specifically designed to account for the scenario of advanced nuclear not coming online in time for the IRP's time horizon.[101]

> Colorado, Illinois, Indiana, and Wyoming are a few examples of states that have numerous retired or retiring coal sites with access to transmission lines, skilled workforces, air and water permits, and other attributes that could facilitate a transition to other industrial or power generation activities such as advanced nuclear. DOE released a report in September 2022 identifying 158 retired coal plant sites and 237 operating coal plant sites as potential candidates to host nuclear generation in the future.
>
> Source: https://www.energy.gov/ne/articles/doe-report-finds-hundreds-retiring-coal-plant-sites-could-convert-nuclear.

95 Ibid., pp. 97–98.

96 Indiana Michigan Power, "Integrated Resource Plan Report 2022," Volume 3. Michigan Public Service Commission Case No. U-21189, p. 85.

97 The Tennessee Valley Authority is a public power agency and is not regulated by any state PUCs.

98 PacifiCorp, "2021 Integrated Resource Plan," p. 31.

99 Ibid., p. 12.

100 Ibid., p. 290.

101 Ibid., p. 247, Figure 8.11—Preferred Portfolio Variants.

The nuclear energy that PacifiCorp expects to come online is initially delivered from the Natrium project underway in Kemmerer, Wyoming, via a partnership between TerraPower, GE Hitachi, and Rocky Mountain Power, a PacifiCorp subsidiary.[102] PacifiCorp anticipates the project to come online in 2028, bringing an estimated 500 MW of capacity to the grid near the former Naughton coal plant.[103] The DOE has provided TerraPower with $2 billion in funding via the ARDP, which has also supported the X-energy Xe-100 demonstration project in partnership with Dow Chemical in Texas and NuScale CFPP in Idaho.[104]

PacifiCorp further anticipates in its preferred portfolio that an additional 1,000 MW of advanced nuclear will come online through 2040.[105] This additional advanced nuclear is not as specific in terms of where it will be located or what technology will be used, but PacifiCorp estimates this group of nuclear will be added by 2038, a decade after the advanced nuclear Natrium project is scheduled to begin operation.[106] PacifiCorp describes one of the crucial benefits of advanced nuclear as its potential to be built off-site and transported to its ultimate location, leading to lower construction costs than traditional nuclear facilities.[107] This shows optimism from the utility that advanced nuclear will play a critical role in its transition to cleaner sources of energy.

Since the 2021 filing, PacifiCorp filed an updated IRP in March 2023 reiterating support for advanced nuclear. The plan's preferred portfolio includes 1,500 MW of new nuclear energy, including the previously announced 500 MW Kemmerer project (with a revised delivery date of 2030) and two similarly sized reactors to come online in 2032 and 2033, tentatively sited at the Huntington and Hunter coal plants in central Utah. PacifiCorp noted the signing of an October 2022 agreement with TerraPower to evaluate the feasibility of deploying up to five additional Natrium reactors in PacifiCorp's service territory by 2035.[108]

Advanced nuclear is also included in **Idaho Power's** 2021 IRP. Here the utility anticipates that NuScale's SMR, currently under development at INL, will come online in 2030, bringing 77 MW to the grid. While not explicitly stated that Idaho Power's selected advanced nuclear technology is NuScale's, the estimated completion and generation information is consistent with the NuScale project.[109] Further, Idaho Power noted the benefits of the 77-MW NuScale SMR, including its smaller physical footprint, reduced capital investment, plant size scalability, enhanced flexibility, and baseload generation capabilities.[110] Although Idaho Power does not ultimately include SMRs or advanced nuclear in its preferred portfolio, it does include the NuScale project in a comparison to the preferred portfolio that shifts 100 percent clean energy goals to 2035 from the current goal of 2045.[111]

Unlike PacifiCorp, this was not the first instance that advanced nuclear technologies were analyzed in Idaho Power's IRP. Idaho Power has discussed advanced nuclear in every IRP filed since its 2006 IRP.[112] As has been the case during this time, Idaho Power does not include advanced nuclear in its 2021 preferred portfolio, despite including it in an alternate portfolio that accelerates clean energy goals. However, it notes that the

102 PacifiCorp's 2021 IRP was completed prior to the site selection and uses the assumption that the selected site is Naughton Coal Plant in Fontenelle, Wyoming.

103 PacifiCorp, "2021 Integrated Resource Plan," p. 12, p. 292, Table 1.1–Transmission Projects Included in the 2021 IRP Preferred Portfolio.

104 Government Accountability Office, September 2022, "DOE Should Institutionalize Oversight Plans for Demonstrations of New Reactor Types." https://www.gao.gov/assets/gao-22-105394.pdf.

105 PacifiCorp, "2021 Integrated Resource Plan."

106 Ibid., p. 293, Figure 9.31–2021 IRP Preferred Portfolio (All Resources).

107 Ibid., p. 191.

108 PacifiCorp, "2023 Integrated Resource Plan," p. 204.

109 NuScale, 2023, "Products." https://www.nuscalepower.com/technology/technology-overview.

110 Idaho Power, "2021 IRP: A View from Above." Idaho Public Utilities Commission Case No. IPC-E-09-33, p. 158.

111 Ibid.

112 Ibid., p. 69.

NuScale project received its final NRC safety evaluation in late 2020 and that the utility would continue to monitor the progress of both the project and other SMR developments.[113]

The **Tennessee Valley Authority (TVA)** explored advanced nuclear as part of its energy generation future over the next 20 years in its most recent (2019) IRP. TVA is unique in that it is a federally owned, legally protected public power monopoly with its service region established by Congress in 1933.[114] As a result, TVA has unilateral authority to set its own rates without the regulatory overviews that investor-owned utilities face, as well as other unique powers such as eminent domain.[115] While TVA is not subject to any state IRP requirements, its board is required to "develop long-range plans to guide the Corporation in achieving its goals."[116]

In its 2019 IRP, TVA discusses advanced nuclear, particularly SMRs, in depth. In identifying potential new generation assets, TVA mentions pressurized water reactors, advanced pressurized water reactors, and SMRs under its nuclear category.[117] Despite the mention of the three, TVA only expands upon SMRs as a potential asset that could be added to its energy fleet.[118] Here, TVA cites advantages of SMRs stemming from their smaller size, including increased flexibility in use and installation.[119] SMRs are considered in one of the expansion scenarios in which existing nuclear plants are retired and replaced with advanced nuclear.[120] The advanced nuclear considered in this scenario (6C) includes adding multiple SMRs totaling 1,200 MW. This particular scenario includes the assumption that existing nuclear plants are retired and is geared toward a strategy of promoting resiliency. Key characteristics of the resiliency promotion strategy include flexibility and response to short-term disruptions.[121]

TVA's approach to its IRP recommendation differs from other utilities in that it does not advocate for one total generation makeup for the future. Instead, TVA provides recommendations by source type and gives policy considerations. Included in these recommendations are calls to both extend existing nuclear licenses and "[c]ontinue to evaluate emerging nuclear technologies including [SMRs] as part of technology innovation efforts."[122] TVA notes that the thirty scenarios it considered will guide how the recommended energy mix may change as the energy landscape changes.[123]

In February 2022, TVA announced a new nuclear program, with the board of directors approving spending of up to $200 million to assess and develop advanced nuclear. TVA obtained an early site permit at the Clinch River site in Oak Ridge, Tennessee, and plans to submit a construction permit application to the NRC for a light-water SMR.[124] In March 2023, TVA announced a partnership with Ontario Power Generation (OPG), GE Hitachi, and Synthos Green Energy to deploy the BWRX-300 SMR at the Clinch River site.[125]

113 Ibid., p. 59.

114 16 U.S.C. § 831-831dd.

115 National Archives, updated February 8, 2022, "Tennessee Valley Authority Act (1933)." https://www.archives.gov/milestone-documents/tennessee-valley-authority-act.

116 16 U.S.C. § 831a(g)(1)(B).

117 Tennessee Valley Authority, "2019 Integrated Resource Plan," p. 5-5.

118 Ibid., p. 5-6.

119 Ibid.

120 Ibid., p. 7-3.

121 Ibid., Appendix F, p. F-1.

122 Ibid., p. 9-3.

123 Ibid., p. 9-2.

124 Tennessee Valley Authority, February 10, 2022, "TVA Board Authorizes New Nuclear Program to Explore Innovative Technology." https://www.tva.com/newsroom/press-releases/tva-board-authorizes-new-nuclear-program-to-explore-innovative-technology.

125 Tennessee Valley Authority, March 23, 2023, "Tennessee Valley Authority, Ontario Power Generation, and Synthos Green Energy Invest in Development of GE Hitachi Small Modular Reactor Technology." https://www.tva.com/newsroom/press-releases/tennessee-valley-authority-ontario-power-generation-and-synthos-green-energy-invest-in-development-of-ge-hitachi-small-modular-reactor-technology.

In fall 2021, North Carolina passed House Bill (HB) 951: Energy Solutions for North Carolina, which codified a requirement that NCUC "take all reasonable steps to achieve a 70% reduction" in CO_2 emissions from electric generating facilities.[126] This reduction was based on 2005 levels, with a goal of 70 percent reduction by 2030 and carbon neutrality by 2050. The legislature directed NCUC to consider "power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management and the latest technological breakthroughs to achieve the least cost path… to achieve compliance with the authorized carbon reduction goals."[127] To achieve this goal, the legislation directed NCUC to consider proposals from electric utilities, with stakeholder input, by December 31, 2022.

Although **Duke Energy's proposed Carbon Plan** is a separate process from the NCUC's IRP process, the proposed Carbon Plan includes discussion of advanced nuclear; thus, an overview of Duke Energy's proposed Carbon Plan as it relates to advanced nuclear has been included in this paper. Recognizing the timing of the commission's review of Duke Energy's Carbon Plan, the NCUC delayed filing of Duke Energy's IRPs in 2022 with the intent to eventually sync the Carbon Plan proceedings with the IRP proceedings, which it did in its final Carbon Plan order. The next combined iteration was due to the commission by September 1, 2023.

In the proposed Carbon Plan, Duke Energy identifies advanced nuclear reactor technologies as having "significant potential to perform as zero-emitting load-following resources." This language provides part of the rationale for including advanced nuclear technology in potential portfolios.[128] Duke Energy developed four potential portfolios to meet the Carbon Plan mandate, two of which include the addition of advanced nuclear in the form of 285 MW SMRs installed by 2032 to reach 70 percent carbon reduction.[129] Duke Energy is a Natrium team partner, providing consulting and advisory services to TerraPower as part of TerraPower's Natrium reactor project being built in Kemmerer, Wyoming. Duke Energy states that "[p]artnering with TerraPower and PacifiCorp on [the Kemmerer] project will allow Duke Energy to be involved early in the development of this new technology without taking on the risk of building a first-of-its-kind plant."[130]

In December 2022, NCUC adopted its Carbon Plan after a review of the plans proposed by Duke Energy and other parties to the proceeding. Based on HB 951, the NCUC's decision adopted "reasonable steps, including the approval of a number of near-term actions, towards meeting the carbon dioxide emissions reduction mandates, including… [requiring] Duke to seek to extend the licenses for its existing nuclear fleet, and [authorizing] Duke to incur project development costs associated with new nuclear generation."[131] The commission's order found Duke Energy's request to undertake limited development activities for new nuclear generation was appropriate, adding that NCUC recognized the risks of "breakthrough technologies," and allowed Duke Energy to spend up to $75 million to review potential new nuclear resources to determine the most viable and cost-effective pathways for review in future NCUC proceedings: "The Commission places great weight on Duke's pledge to be a 'second mover' and allow time for reactor technology to develop and complete the NRC licensing phase." NCUC underscored that the risks of new nuclear should not be viewed in isolation from the risks associated with other zero-carbon resources, such as dependence on favorable weather conditions for a major buildout of wind and solar generation.[132]

---

126 HB 951, 2021, North Carolina General Assembly. https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

127 Ibid., section 1 (1).

128 Duke Energy, May 16, 2022, Carolinas Carbon Plan, Docket No. E-100, Sub 179. Nuclear Subsection, p. 5. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=a419f03b-b8ac-4997-a1b1-82b08d8a8c02.

129 Ibid., Portfolios subsection, pp. 10–11. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=050df3ad-7b50-4014-8d56-2146f881cc38.

130 Ibid., Nuclear Subsection, p. 7.

131 North Carolina Utilities Commission, December 30, 2022, "North Carolina Utilities Commission Issues Order on Carbon Plan," Docket No. E-100, Sub 179. https://www.ncuc.gov/documents/carbonfinalpressrelease.pdf.

132 North Carolina Utilities Commission, December 30, 2022, "Order Adopting Initial Carbon Plan and Providing Direction for Future Planning," Docket No. E-100, Sub 179, pp. 93–96. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=7b947adf-b340-4c20-9368-9780dd88107a.

C. Maintaining Existing Nuclear Resources to Ensure Reliability and Provide Clean Energy

In addition to new and emerging nuclear technologies, support for extending the life of existing nuclear reactors is widespread in the IRPs NARUC reviewed. Due to nuclear energy's prominence in many generation mixes (accounting for approximately 19 percent of the national energy supply and half of carbon-free electricity), nearly every utility discusses existing nuclear resources both within and outside of their respective service areas.[133] Support for keeping existing nuclear plants in service appeared to be nearly universal in the IRPs reviewed. Of the 17 IRPs reviewed, all but one recommended extending the licenses of existing plants.

For leased power from nuclear plants, both **Green Mountain Power (GMP)** and **PNM** allowed leases of nuclear power to expire in their respective preferred portfolios, although both retain current ownership stakes in the same portfolios. Starting in 2019 when the NRC granted a second 20-year license renewal to NextEra's Turkey Point Nuclear Plant to operate for a total of 80 years, the NRC has appeared willing to continue this trend by granting second license renewals. Subsequently, the NRC has approved second 20-year extensions to Exelon Corporation's (now Constellation's) Peach Bottom plant and Dominion Energy's Surry station.[134]

Georgia Power is advocating in favor of extending the licenses of its existing nuclear plants. Georgia Power is in a unique position because it is also involved in constructing the first new nuclear units in the United States in decades at Plant Vogtle. Georgia Power is a 45.7 percent owner of the two new nuclear units expected to come online in late 2023 and 2024, respectively, bringing the total number of nuclear reactors owned by the utility to six.[135] Further, Georgia Power states that it is requesting approval to spend $28 million to extend the life of its oldest two nuclear units, Hatch 1 and 2, to 80 years with additional 20-year operating license renewals.[136] In justifying its request, Georgia Power details the benefits of extending the plant licenses in terms of diversifying its energy portfolio and keeping a zero-emission resource online.[137] Georgia Power also cites supporting the local community as one of the reasons for the extension, highlighting the local tax revenue and jobs that the plants produce.[138] Throughout its IRP, Georgia Power advocates for supporting both its existing fleet (with a stated intent of renewing licenses for Hatch 1 and 2) as well as support for its new units at Vogtle.

Further support for extending the life of existing nuclear resources can be found in **Xcel Energy's** 2020 Upper Midwest IRP covering its outlook for 2020 through 2034 for the state of Minnesota. Xcel discusses its existing nuclear fleet in Minnesota at length. This existing fleet includes three units at two plants in Minnesota—Monticello and Prairie Island, which have a combined capacity of 1,740 MW.[139] Xcel states that nuclear accounts for over half of its clean energy resources in its Upper Midwest service region, which includes service to Minnesota and four other states, as well as 30 percent of its total energy generation.[140] Xcel further discusses the critical value that the two nuclear plants hold in terms of reliability and meeting clean energy goals. In advocating for the continued operation of Prairie Island through 2033 and 2034 and extension of Monticello's license to 2040 in its Preferred Portfolio, Xcel states that it would be impossible to account for an early retirement of Monticello without adding carbon intensity to its fleet and losing the reliability benefits of the current plants.[141] In its economic analysis of more than a dozen scenarios, Xcel's models show that

133 Energy Information Administration, March 2, 2023, "What Is U.S. Electricity Generation by Energy Source?" https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

134 Duke Energy Progress, "Integrated Resource Plan 2020 Biennial Report (North Carolina)," p. 78.

135 Georgia Power, "2022 Integrated Resource Plan," Attachment A.

136 Ibid., p. 11–78.

137 Ibid., Attachment D, D-152.

138 Ibid.; Daniel Shea, 2023, "Nuclear Policy in the States: A National Review," *Journal of Critical Infrastructure Policy*, 3(2): 13–27. https://www.jcip1.org/uploads/1/3/6/5/136597491/nuclear_policy_in_the_states_a_national_review.pdf.

139 Northern States Power Company, "2020–2034 Upper Midwest Resource Plan." Minnesota Public Utilities Commission Docket No. E002/RP-19-368, p. 57.

140 Ibid., p. 9; p. 57.

141 Ibid., p. 10.

plans that include retiring the nuclear units in Minnesota would cost well over $1 billion more than any plan that extends the life of its nuclear units.[142] Further, Xcel includes a scenario for operating its nuclear units at least through the end of their current licenses, with the potential for extensions, under a list of four "essential elements" of its future plans, showing that the utility is considering extending all units.[143] Xcel clarifies that it is leaving decisions on whether to extend the license of the two Prairie Island nuclear units to later IRPs.[144] Thus, Xcel is another example of a utility that supports keeping existing nuclear resources online. Xcel goes so far as to suggest that keeping these resources online and extending their life is necessary to meet clean energy goals while also maintaining system reliability.

The **PNM** 2020–2040 IRP continues the trend of keeping existing nuclear resources in its fleet. Although PNM advocates for retaining its ownership in Arizona's Palo Verde Nuclear Generating Station and expresses the necessity of doing so, PNM declared its intent to not renew leases for additional nuclear energy from Palo Verde.[145] Currently, PNM owns 288 MW of capacity at Palo Verde and has two active leases that account for an additional 114 MW from the station.[146] PNM's leases in the Palo Verde plant are set to expire in 2023 and 2024, respectively.[147] Currently, the combined 402 MW of capacity (3,255,777 MWh of annual energy) from Palo Verde makes up a 30 percent share of PNM's generation, with no carbon emissions. PNM's decision not to renew its Palo Verde lease would reduce this amount to approximately 20 percent.[148]

PNM states that this nonrenewal will allow it to reduce customer costs and right-size the percentage of its portfolio that Palo Verde accounts for.[149] Despite its decision to let the lease at Palo Verde expire, PNM indicated support for maintaining significant nuclear resources for the duration of the IRP's outlook. PNM states that it intends to maintain its ownership stake at Palo Verde at least until the respective licenses expire in 2045 and 2047 and that the decision (more than two decades away) to extend or replace this source will be one for future IRPs.[150]

PNM goes on to detail the critical nature of maintaining nuclear energy, classifying its nuclear energy as a firm capacity. Thus, while the lease abandonment reflects a decision to decrease the amount of nuclear from its portfolio, this should not be viewed as opposing nuclear generally. PNM plans to continue to utilize significant nuclear resources and attributes its lease abandonment decision more to investing in other clean energy solutions such as "solar, battery storage, and hydrogen-ready combustion turbines" rather than any opposition to nuclear.[151]

With nuclear accounting for 31.9 percent of GMP's 2020 fuel mix, the existing nuclear resources and what GMP decides to do with them will have a large effect on its future.[152] GMP's nuclear resources include 21.4 MW from its 1.7303 percent ownership of Millstone Unit 3 in Connecticut as well as two PPAs at NextEra's Seabrook nuclear plant in New Hampshire: one for 55 MW of plant-contingency energy and the second for 150 MW of plant-contingency capacity.[153] GMP analyzes the effect that extending its 55-MW PPA at Seabrook past

142 Ibid., p. 112, Figure 5-7.

143 Ibid., p. 24.

144 Ibid., p. 69.

145 PNM, "2020–2040 Integrated Resource Plan," 1.5.3 PVNGS Lease Abandonment, p. 19.

146 Ibid.

147 Ibid.

148 Ibid., p. 19; p. 61, Table 8.

149 Ibid., p. 19.

150 Ibid.

151 Ibid., p. 177.

152 Green Mountain Power, "2021 Integrated Resource Plan," p. 6-1, Table 6-1; 6-2.

153 Ibid., p. 6-12; 6-16.

its 2034 expiration date would have through its look at ten different potential portfolios.[154] Its final portfolio, dubbed the "Carbon-Free Focus," analyzes a portfolio under the assumption that the expiring Seabrook PPA is extended past 2034.[155] GMP notes that this portfolio "shows the most favorable results from the perspective of supply/demand alignment" as well as the most stable in terms of exposure to market price changes.[156]

Existing nuclear resources are discussed at length in South Carolina, North Carolina, and Virginia by both **Duke Energy** as well as **Dominion Energy** and its subsidiaries. In South Carolina, DESC highlighted its recent license renewal for its lone nuclear unit, V.C. Summer Station in Jenkinsville, South Carolina.[157] In 2020, V.C. Summer Station, which is 66.67 percent owned by DESC, represented 21.73 percent of DESC's energy needs with more than 8,000 gigawatt-hours of "non-carbon emitting base-load" energy generated.[158] Further, DESC notes the great reliability of the plant with a 0.73 percent outage rating in 2020 as well as capacities of 652 MW in summer 2020 and 663 MW in winter 2020.[159] Not only has DESC successfully renewed V.C. Summer Station's license through 2042, but it also states that it is looking to extend its license another 20 years through 2062, which would bring the plant's approved usage to 80 years.[160]

Dominion Energy subsidiary, **VEP**, also includes discussion of license extensions in an update to its latest IRP in 2021 that was filed in both North Carolina and Virginia. VEP details its recent 20-year license extension of two nuclear units at Surry Power Station in Surry County, Virginia, granted on May 4, 2021, permitting operation of Unit 1 and Unit 2 to 2052 and 2053, respectively.[161] Further, the utility details its plans to extend the license of Units 1 and 2 of its North Anna Power Station for another 20 years, extending operations to 2058 and 2060, respectively.[162] Currently, the two Surry units have a output capacity of 847.5 MW each, and the two North Anna units have an output capacity of 979.7 MW each.[163] Thus, nuclear currently accounts for roughly 20 percent of VEP's capacity. With these nuclear license extensions for units in both Virginia and South Carolina that also serve North Carolina, Dominion makes it clear that it views its existing fleet as part of its long-term energy generation future.

DEP, located in North Carolina, also filed an update to its 2020 IRP. It is noteworthy to mention that DEP and **DEC's** updates to their respective IRPs are identical, despite the two being separate companies. This paragraph looks at the larger Duke Energy nuclear fleet, which includes four units at three locations under DEP's purview and seven units at three locations under DEC's purview for a total of eleven units across six sites in the Carolinas.[164] This amounts to approximately 3,662 MW of nuclear generation for DEP and approximately 7,280 MW for DEC.[165] In this update, Duke Energy announces its intentions to adhere to the original plans laid out in its 2020 IRP to improve and extend its nuclear fleet. This includes plans to continue the process for 20-year license renewals for all eleven units in its nuclear fleet, extending each to 80 years.[166]

154 Ibid., p. 7-34, Table 7-3.

155 Ibid.

156 Ibid., p. 7-36, Figure 7-18.

157 Dominion Energy South Carolina, "Integrated Resource Plan 2021 Update," p. 7.

158 Ibid., p. 27.

159 Ibid.

160 Ibid.

161 Virginia Electric and Power Company, "2021 Update to the 2020 IRP," p. 11.

162 Ibid.

163 Ibid., Appendix 2B (iv-v).

164 Duke Energy Progress, "2021 Update to 2020 Short-Term Action Plan, NC Reps and CPRE Plan." North Carolina Utilities Commission Docket No. E-100, Sub 165.

165 Duke Energy Progress, "Integrated Resource Plan 2020 Biennial Report (North Carolina)," p. 208; Duke Energy Carolinas, "Integrated Resource Plan 2020 Biennial Report (North Carolina)," p. 214.

166 Duke Energy Progress, "2021 Update to 2020 Short-Term Action Plan, NC Reps and CPRE Plan." North Carolina Utilities Commission Docket No. E-100, Sub 165, p. 11.

Following the filing of its 2020 IRP, DEP initiated the renewal process for the three units at Oconee Nuclear Station located in South Carolina, which are set to expire in 2034 (Units 1 and 2) and 2035 (Unit 3).[167] DEP also stood by its decision to continue with Measurement Uncertainty Recapture enhancements to all three units at Oconee, which will result in an increased capacity of 15 MW per unit.[168] In continuing its support of its nuclear resources, Duke Energy stated in the update to the 2020 IRP that "[n]uclear generation is a necessary resource in the Company's plans to aggressively reduce carbon emissions."[169] The update builds upon the respective IRPs in solidifying Duke Energy and its subsidiaries' reliance and support for continuing and improving existing nuclear resources.

In August 2023, DEP and DEC filed an IRP with the South Carolina PSC presenting a preferred portfolio relying on 2,400 MW of SMRs through 2038, with 600 MW online by 2035.[170] To achieve the 2035 goal, the companies plan to evaluate advanced nuclear reactor technologies and begin developing an Early Site Permit (ESP) for one site in 2023. By 2026, DEP and DEC propose to choose a reactor technology, submit ESPs for two sites, develop construction permits and license applications, contract with a reactor vendor, and order long-lead equipment. The companies note the assumption of continued operations of 11,113 MW of existing nuclear units as well as power uprates at two nuclear plants to increase capacity. The companies cite the similarity of SMRs to existing large light-water reactors, the ability of SMRs to ramp to meet load, and the opportunity to site SMRs at existing or retiring coal power sites (and the availability of incentives through the IRA for coal-to-nuclear projects) as reasons for prioritizing the consideration of SMRs over other advanced reactor technologies. Duke emphasizes that it is "not planning to be a 'first mover' with SMR—but follow close behind other FOAK projects that are planned (e.g., OPG, TVA, and UAMPS), incorporating the lessons learned from those projects, which reduces our risk exposure."

TVA's 2019 IRP continues the trend of support for maintaining existing nuclear resources and incorporating existing nuclear as part of its future energy portfolio. TVA operates seven nuclear reactors across three plants, including Browns Ferry Nuclear Plant (3), Sequoia Nuclear Plant (2), and Watts Bar Nuclear Plant (2).[171] These reactors have a combined generating capacity of approximately 7,700 MW.[172] Like Duke Energy, TVA detailed plans to uprate (the process of increasing the maximum power level at which a commercial nuclear power plant may operate) three units at Browns Ferry, which is expected to add 450 MW of additional capacity.[173], [174] TVA also stated that it planned to seek license renewals to extend the life of its nuclear fleet for all relevant units, with the three Browns Ferry units, set to expire in 2033, 2034, and 2036, respectively, to be the first license renewals sought.[175]

The last IRP NARUC analyzed that discusses existing nuclear resources is **Indiana Michigan Power**. Indiana Michigan Power is the lone IRP analyzed in which a utility that operates an existing nuclear power plant does not explicitly state its intention to apply for a 20-year license renewal. Although other utilities considered portfolios showing the hypothetical scenario that nuclear licenses were not sought, these were widely dismissed as resulting in lower reliability and higher costs and were widely included simply for the sake of covering a variety of scenarios. Indiana Michigan Power currently operates one nuclear plant, Cook Nuclear Plant, that has two

167 Ibid.

168 Ibid., p. 10.

169 Ibid., p. 11.

170 Duke Energy, "2023 Carolinas Resource Plan," Chapter–South Carolina. https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-south-carolina.pdf?rev=780c79d133f5423dbbc7ff2cadb50380.

171 Tennessee Valley Authority, "2019 Integrated Resource Plan," p. 5-3.

172 Ibid.

173 Ibid.

174 Nuclear Regulatory Commission, March 9, 2020, "Power Uprates." https://www.nrc.gov/reactors/operating/licensing/power-uprates.html.

175 Ibid.

units that have licenses set to expire in 2034 and 2037, respectively.[176] Unit 1 has a maximum output capacity of approximately 1,100 MW, and Unit 2 has a maximum output capacity of approximately 1,200 MW.[177] Indiana Michigan Power makes it clear in the IRP that "decisions have not been made" regarding the license extensions of Cook Nuclear Plant and that further analysis on the costs of doing so are yet to be completed.[178]

Only two of the portfolios analyzed by Indiana Michigan Power use the assumption that Cook Units 1 and 2 are relicensed, compared to twelve scenarios in which the plant is retired.[179] While the IRP stated numerous times that extending the life of the Cook Nuclear Plant units does not include capital costs associated with relicensing, thus creating lesser capital costs outcomes than would actually be the case, Indiana Michigan Power does find value in the sustainability, reliability, and resource adequacy reflected by the portfolios.[180] The portfolios extending the operating licenses of Cook Units 1 and 2 also perform better than the preferred portfolio in terms of reducing emissions, with emissions reduced by an approximate additional 10 percent.[181] Ultimately, Indiana Michigan Power essentially assumes that Cook Nuclear Plant is retired in its preferred portfolio, with nuclear capacity decreasing in 2034 and dropping to 0 MW in 2037.[182] This marks the only IRP analyzed that assumes that existing nuclear resources operated by the utility will be offline by the end of the planning horizon.

Several utilities that appear in previous sections are omitted here solely because these utilities do not have existing nuclear resources in their portfolios. This includes both PacifiCorp and Idaho Power, which discussed advanced nuclear at length. It also includes Appalachian Power, which does not have any existing nuclear energy in its portfolio and serves Virginia and West Virginia.

D. Conclusions from Nuclear Relicensing Reviews

The discussions of existing nuclear in these IRPs show a general widespread support for keeping existing nuclear resources online. With a number of utilities extending nuclear licenses to 80 years and several others stating plans to follow suit, this appears to have become the new norm. Existing nuclear plants' unique capabilities to

DOE Civil Nuclear Credit Program

The Bipartisan Infrastructure Law created the Civil Nuclear Credit (CNC) Program—a $6 billion strategic investment to help preserve the existing nuclear fleet and thousands of high-paying jobs associated with the industry. This credit was established in recognition that the current nuclear fleet is vital to achieving the nation's goals of a carbon pollution-free electricity sector by 2035. Under this program, owners or operators of U.S. reactors can apply for certification to bid on credits to support the continued operation of a reactor. Applications must demonstrate that the reactor is projected to close for economic reasons and that the closure will lead to an increase in carbon emissions and air pollutants. Credits of the CNC Program will be allocated to selected reactors over a four-year period, 2022–2026. On November 21, 2022, DOE announced the conditional selection of the Diablo Canyon Power Plant in California to receive the first round of funding from the CNC Program. The DOE released application guidance for the second award cycle of the CNC Program on March 2, 2023; the second round expanded eligibility from nuclear reactors that are at risk of closure to include reactors that ceased operations after November 15, 2021.

Source: https://www.energy.gov/gdo/civil-nuclear-credit-program

176 Indiana Michigan Power, January 2022, "Integrated Resource Planning Report," pp. 2, 31.

177 Ibid., p. 62–63.

178 Ibid., p. 6.

179 Ibid., p. 121, Table 18.

180 Ibid., p. 142.

181 Ibid., p. 152.

182 Ibid., p. 148, Figure 55: Preferred Portfolio Mix.

Analyzing Nuclear Generation in Restructured States: Illinois and Maryland

Not all state utility commissions oversee IRP processes or exercise authority over generation resources. Nevertheless, commissions in these regulatory environments can still take steps to consider the value of existing and potential new nuclear generation. The Illinois Commerce Commission (ICC) provides one example. In 2017, in response to the potential economic closures of multiple nuclear plants in the state, Illinois enacted Public Act 99-0906, which established a zero-emission standard and created zero-emission credits for which nuclear generation facilities would be eligible to receive based on generation.[1] In 2021, Public Act 102-0662 created a procurement process for nuclear plants to receive carbon mitigation credits,[2] preventing the shutdowns of two plants. The ICC, along with other state agencies, prepared or commissioned multiple reports to the state legislature demonstrating the value of the state's existing nuclear fleet in meeting its clean energy goals. These findings were a major factor in enacting both pieces of legislation.

The Maryland Energy Administration (MEA) provides an example of State Energy Office actions in assessing the feasibility of new nuclear generation. Like Illinois, Maryland's PSC does not regulate generation. Resources are owned by competitive power producers and are not subject to cost recovery via rates. In June 2022, the MEA announced a partnership with X-energy and Frostburg State University to conduct a collaborative study to determine the potential to site a SMR in the state, preferably at a fossil fuel site.[3] The report was released in November 2022, finding that replacing a retiring coal plant with an advanced reactor would result in a significant positive economic impact, compared to a loss of up to $122 million of economic output if no replacement was located at the site.[4]

1 Illinois General Assembly, June 1, 2017, "Public Act 099-0906." https://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=099-0906.

2 Illinois General Assembly, September 15, 2021, "Public Act 102-0662." https://ilga.gov/legislation/publicacts/fulltext.asp?Name=102-0662.

3 Maryland Energy Administration, June 14, 2022, "MEA Announces Partnership with X-energy and Frostburg State University." https://news.maryland.gov/mea/2022/06/14/mea-announces-partnership-with-x-energy-and-frostburg-state-university/.

4 X-energy, November 30, 3022, "Feasibility Assessment and Economic Evaluation: Repurposing a Coal Power Plant Site to Deploy an Advanced Small Modular Reactor Power Plant." https://energy.maryland.gov/Reports/MD%20Feasibility%20Assessment%20and%20Economic%20Evaluation%20%28Jan2023%29.pdf.

serve as both clean and reliable energy sources make them a favorable option with many IRPs showing that the absence of these resources would drive both costs and emissions up while decreasing overall grid reliability.

Even Diablo Canyon in California is having its retirement plans reconsidered because it serves as a clean baseload option, supplying 9 percent of California's electricity and serving an important reliability role as extreme weather affects load and power plant operations throughout the state. Diablo Canyon is worth noting, despite not being in any of the reviewed IRPs, because it highlights the recent trend to reconsider the closure of zero-carbon power plants. As California's last nuclear plant, Diablo Canyon's two units were scheduled to be decommissioned in 2024 and 2025, an announcement made in 2016 by owner and operator Pacific Gas and Electric (PG&E).[183] However, facing energy reliability issues, California Governor Gavin Newsom posed the idea of keeping the plant online, a plan that has since gained momentum.[184] PG&E announced its intention to apply for federal funds through the Civil Nuclear Credit (CNC) Program, an initiative created by the Infrastructure

183 Evan Symon, July 6, 2022, "PG&E to Submit Application for Federal Funds to Keep the Diablo Canyon Nuclear Plant Operating Past 2025," California Globe. https://californiaglobe.com/environment/pge-to-submit-application-for-federal-funds-to-keep-the-diablo-canyon-nuclear-plant-operating-past-2025/.

184 Kavya Balaraman, July 29, 2022, "The Clock Is Ticking: PG&E Exploring Possibility of Keeping Diablo Canyon Open to Boost Reliability," Utility Dive. https://www.utilitydive.com/news/pge-exploring-possibility-of-keeping-diablo-canyon-nuclear-open-poppe-ceo/628414/.

Investment and Jobs Act (or BIL) geared toward keeping existing nuclear plants at risk of premature retirement running.[185] In November 2022, DOE selected Diablo Canyon for $1.1 billion in funding to keep the plant online.[186] However, both units are rapidly approaching the expiration of their NRC operating licenses[187] in 2024 and 2025. In January 2023, the NRC announced that it would not consider PG&E's previously filed 2009 license renewal application, which was submitted before PG&E stated its intent to retire both units prior to the end of their current licenses. PG&E now faces an accelerated timeline to submit new license renewal applications to the NRC—which it intends to do by the end of 2023—and for the NRC to complete its review of those applications.[188] In the interim, the NRC has granted an exemption for Diablo Canyon to continue operating while the NRC considers the license renewal applications, and there is an open docket before the California PUC to extend the retirement dates, for which a decision is expected before the end of the year.[189] While Diablo Canyon's future is still up in the air, these events highlight growing federal support for the existing nuclear fleet and emphasize the unique position of these units to prevent losses in reliability as the transition to cleaner energy progresses.

E. Key Takeaways

NARUC's review of IRPs identified that utilities are generally motivated to maintain existing nuclear plants but are more hesitant to incorporate advanced nuclear technology in their long-term planning. Even for utilities that considered advanced nuclear in greater detail, it still does not appear to be advocated or planned for to the degree of other commercially available and technologically mature sources such as renewables and battery storage, despite the projected comparative reliability, land use, and operational benefits of advanced nuclear. PacifiCorp was the only utility identified that planned to include an advanced nuclear plant in its future resource mix. However, interest in advanced nuclear is growing, and PUCs can benefit by proactively increasing their own familiarity with advanced nuclear technologies and their feasibility to support clean, reliable, and affordable electricity for states. X-energy's feasibility report for the Maryland Energy Administration (MEA) offers an example of assessing the suitability of advanced reactors with Maryland's energy policy goals.

While both Idaho Power and TVA weigh advanced nuclear, neither utility includes advanced nuclear technology in its future energy generation plans. Both utilities eventually come to a similar conclusion as other utilities identified in previous sections: advocating for further evaluation and monitoring of SMRs in the future. Of note, TVA's IRP was completed in 2019, and there have since been several developments in the advanced nuclear field, particularly at Oak Ridge National Laboratory, including an announcement by X-energy that it selected Oak Ridge as the site for its first fuel fabrication facility.[190] TVA also announced intent to deliver a plant design, NRC license application, and a project plan for a GE Hitachi BWRX-300 SMR at its Clinch River

185 Irvin Dawid, July 11, 2022, "Funding Allocated to Extend Life of Diablo Canyon Nuclear Power Plant," Planetizen. https://www.planetizen.com/news/2022/07/117668-funding-allocated-extend-life-diablo-canyon-nuclear-power-plant.

186 U.S. Department of Energy, Grid Deployment Office, 2022, "Civil Nuclear Credit First Award Cycle." https://www.energy.gov/gdo/civil-nuclear-credit-first-award-cycle.

187 The NRC issues 40-year initial operating licenses to nuclear units, with the option to renew in 20-year increments. Fifteen reactors have applied for or received license extensions enabling operation for 80 years. DOE and the Electric Power Research Institute partnered on research to demonstrate that most existing nuclear units can safely operate for 80 or even 100 years. See https://www.energy.gov/ne/articles/whats-lifespan-nuclear-reactor-much-longer-you-might-think.

188 Kavya Balaraman, January 30, 2023, "California's Plan to Keep Diablo Canyon Nuclear Plant Online Hits Regulatory Snag," Utility Dive. https://www.utilitydive.com/news/california-plan-diablo-canyon-nuclear-plant-online-regulatory-snag-NRC-PGE/641482/.

189 World Nuclear News, March 3, 2023, "Regulatory Progress for Continued Operation of Diablo Canyon." https://world-nuclear-news.org/Articles/Regulatory-progress-for-continued-operation-of-Dia.

190 Benjamin Pounds, April 5, 2022, "Nuclear Fuel Company Announces Plans for Oak Ridge Plant, 400 Jobs," *Oakridger*. https://www.oakridger.com/story/news/2022/04/05/nuclear-fuel-company-announces-plans-new-oak-ridge-plant-400-jobs/9464577002/.

site in Tennessee, for which TVA holds an early site permit from the NRC.[191] Thus, as advanced nuclear projects continue to progress both at the National Labs and across the country, the discussion about adding these new nuclear generation technologies to the grid are likely to get more serious and detailed.

While there were differences across utilities, NARUC found three overarching conclusions based on this review:

1. The majority of regulated utilities are aware of advanced nuclear technologies. For many IRPs, the time horizon of evaluation is 10 years or less, and for many of the first advanced reactors the schedule for deployment would push their dates for coming online outside of the window of the IRP. In addition, uncertainties around the technological maturity, uncertainty about costs and financial risks, and unfavorable state regulatory or policy landscapes discourage inclusion of advanced nuclear in IRPs. These utilities tend to express a willingness to continue monitoring the development of advanced nuclear technologies for potential inclusion in future IRPs. The most commonly cited advanced nuclear technology was SMRs broadly.

2. Some utilities have explicitly included advanced nuclear in their IRPs, namely PacifiCorp, Idaho Power, DEC, DEP, and TVA. With the exception of DEC and DEP, these organizations all share a geographic commonality: they have a nuclear-focused national lab located within their service area (Idaho National Laboratory and Oak Ridge National Laboratory) and/or have a major commercial advanced nuclear project underway. Also noted is UAMPS CFPP, a set of six 77 MW NuScale SMRs to be sited on the INL campus, expected online in 2029.[192] TVA and UAMPS, as public power utilities, are not regulated by state utility commissions.

3. Most utilities propose keeping existing nuclear resources online to maintain reliability and progress toward decarbonization goals. This includes keeping ownership stakes in nuclear plants as well as extending the operating life of existing nuclear units and reapplying for 20-year operating licenses from the NRC. Utilities cite employment, economic contributions to local communities, reliability, and clean energy as key benefits of extending the lifetimes of existing nuclear units.

F. Public Utility Commission Reactions

In the IRP cases reviewed, state utility commissions expressed hesitancy to strongly support the inclusion of nuclear resources in IRPs, citing concerns about technology maturity and costs. Commission staff from Idaho, Oregon, and Utah filed comments in response to PacifiCorp's IRP, all voicing concerns with PacifiCorp's inclusion of TerraPower's Natrium reactor in the preferred portfolio.

The strongest commission action comes from Oregon PUC (OR PUC) commissioners in Order 22-178, published in May 2022.[193] In this unanimous order, the OR PUC states that the only portion of the IRP pertaining to TerraPower's Natrium reactor that the OR PUC will acknowledge is the portion that calls for "the company to continue to monitor key milestones for development and make regulatory filings as applicable."[194] The reasons given by the commission for declining to acknowledge consideration of Natrium in PacifiCorp's IRP portfolios include significant uncertainty, risk regarding estimation of the final costs of the Natrium project, and uncertainty surrounding the timeline for completion.[195] The OR PUC clarifies that its lack of acknowledgement of the Natrium plant in the IRP portfolios should not be misconstrued as opposition to the Natrium project,

---

191 Tennessee Valley Authority, February 10, 2022, "TVA Board Authorizes New Nuclear Program to Explore Innovative Technology." https://www.tva.com/newsroom/press-releases/tva-board-authorizes-new-nuclear-program-to-explore-innovative-technology.

192 Utah Associated Municipal Power Systems, July 21, 2021, "CFPP Updates since October Off-Ramp." https://losalamos.legistar.com/View.ashx?M=F&ID=9618711&GUID=087139CA-D9AE-4A61-B2BB-602CAD1CCFC9.

193 Public Utility Commission of Oregon, May 23, 2022, "Order No. 22-178," p. 1.

194 Ibid., 9.

195 Ibid.

but that it is merely a recognition that the IRP guidelines requiring "companies to analyze resources using consistent methodologies and to thoroughly air the risks and uncertainties involved" was not met.[196] Ultimately, the OR PUC directed PacifiCorp to reevaluate its portfolio.

Finally, staff of the Idaho PUC filed comments recommending the commission acknowledge PacifiCorp's IRP.[197] In its recommendations, the staff highlighted five areas of "potential concern," with the fourth being the "[s]election of the proposed advanced Natrium nuclear plant" because of uncertainties leading to potential schedule risk and increased costs.[198] Although the staff does acknowledge that the Natrium project would be "highly beneficial," it ultimately recommends that PacifiCorp assess the risks associated with the Natrium project.[199]

Although other commissions acknowledge existing nuclear resources in various actions and comments, these highlighted instances come in the form of staff recommendations to approve IRPs and do not reflect any support, opposition, concerns, or opinions toward nuclear resources. Thus, as more advanced nuclear projects emerge, commissions would be expected to comment and address concerns about these new, relatively unknown technologies.

The landscape of advanced nuclear appears to be changing fast, moving quickly toward the first SMR coming online in the next decade, or sooner. Several SMR companies have initiated NRC applications. Further, utilities are more and more willing to engage in considering advanced nuclear for future deployment, as seen by PacifiCorp's controversial inclusion of the Natrium reactor in its preferred portfolio.

Finally, utilities are continuing to take additional steps to include advanced nuclear in future energy generation portfolios. In July 2022, Entergy Corporation (Entergy) solidified plans to consider adding advanced nuclear to its fleet in the future. Entergy entered into a Memorandum of Agreement with Holtec International, an SMR developer, committing to evaluating Holtec's SMR-160 system for future deployment of one or more units.[200] After research was conducted for this paper, Dominion Energy Virginia and Salt River Project have explicitly included advanced nuclear in their IRPs, joining a growing number of utilities interested in advanced nuclear. Additionally, a 2023 survey, conducted by the Nuclear Energy Institute to obtain a better sense of the impacts that recent federal actions are having on nuclear industry activities, highlights some promising insights. Nearly two-thirds of respondents indicated that recent federal policy developments have resulted in increased interest in new nuclear within their company, and half of the respondents indicated that their company is considering or actively working to include new nuclear in their IRPs.[201] These developments provide examples of the progression of utility consideration of advanced nuclear technologies, and they underline the importance of PUCs preparing for increased industry interest in advanced nuclear.

196 Ibid.

197 Idaho Public Utilities Commission, March 15, 2022, "Case No. PAC.E-21-I9. Comments of the Commission Staff," p. 3.

198 Ibid., pp. 3–4.

199 Ibid., pp. 17–18.

200 Holtec International, July 20, 2022, "A $7.4 Billion Nuclear Build Program Submitted to the Loan Programs Office of the DOE to Bring Forth the First Batch of SMR-160s and a Massive Expansion of Holtec's Domestic Manufacturing Capacity." https://holtecinternational.com/wp-content/uploads/2022/07/HH-37.11.pdf.

201 Nuclear Energy Institute, 2023, "The Future of Nuclear Power: 2023 Baseline Survey," p. ii. https://www.nei.org/CorporateSite/media/filefolder/advantages/The-Future-of-Nuclear-Power-2023-Baseline-Survey.pdf.

IV. Conclusions and Lessons Learned

Regulators can draw useful lessons from these recent IRPs and responses by their peers in certain states. As advanced nuclear technologies continue to evolve, regulators should be prepared to see utilities give more weight to these technologies in the future. Even in states without existing nuclear units, the small land footprint and operating characteristics of advanced nuclear may be able to open new geographic locations as potential nuclear development sites. Several states, including Connecticut, Kentucky, West Virginia, and Wisconsin have partially or fully lifted moratoriums on the construction of nuclear generation, and other state legislatures are considering similar actions, opening the door to even more locations.[202] Sites with existing or retiring conventional nuclear generation or retiring fossil fuels can be attractive sites for advanced nuclear given existing transmission rights, water resources, the existence of a highly skilled workforce, and environmental permits that may be transferable to new ownership as the existing generation ceases to operate.[203]

Additionally, it is worth monitoring states where utilities are effectively unable to include consideration of advanced nuclear energy in IRPs, either due to moratoriums for new nuclear or by lack of clarity for the economic regulation of these technologies. More recently, many states have taken action to address these structural barriers to considering advanced nuclear energy, including repealing moratoriums in states like West Virginia, directing state regulators to establish a framework for advanced nuclear like in Indiana, or commissioning studies to understand state-induced barriers like in Montana.

Regulators can benefit from increased and ongoing awareness of advanced nuclear, given the rapid speed of technological and regulatory developments in this space and differences from oversight of conventional nuclear. In particular, advanced nuclear differs from conventional nuclear among the following characteristics:

- Land footprint and water needs,
- EPZs,
- Load-following capabilities and ability to integrate intermittent renewable generation,[204]
- Frequency and duration of maintenance and fuel reloading outages,
- Fuel supply needs for advanced nuclear, including availability of domestic HALEU fuel, and
- Spent fuel disposal.

Regulators can also benefit from asking critical questions about a utility's IRP (or alternative planning processes), regardless of how much consideration is given to advanced nuclear by utilities, to ensure that utilities are appropriately considering a range of options discussed below.

Policy

- Does the utility require more clean firm power?
- Does the state have net-zero energy goals? When are the interim and final deadlines? What is considered "clean"?
- Is the utility proposing to fully or partially own the new units? What is the business model?
- How will spent fuel be managed?
- How will ratepayers be protected from cost overruns or delays?
- Are the operating lifetimes of existing units being maximized or optimized?

---

202 Nuclear Energy Institute, January 2023, *State Legislation and Regulations Supporting Nuclear Energy*. https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Compendium-January-2023.pdf.

203 Daniel Shea, 2023, "Nuclear Policy in the States: A National Review," *Journal of Critical Infrastructure Policy,* 3(2): 13–27. https://www.jcip1.org/uploads/1/3/6/5/136597491/nuclear_policy_in_the_states_a_national_review.pdf.

204 Richard S. Mroz, 2023, "How Advanced Nuclear Generation Technologies Support Electric Grid Resilience," *Journal of Critical Infrastructure Policy,* 3(2): 29–36. https://www.jcip1.org/uploads/1/3/6/5/136597491/advanced_nuclear_generation_technologies.pdf.

Grid Needs

- Is the industrial load that needs 24/7 power planning to locate in the balancing authority?
- How is load expected to change in the IRP window? What resources are retiring and coming online? If new firm generation is needed, how much? When does peak demand occur?
- For options such as advanced nuclear that may not meet the definition of least-cost, should the commission consider valuing attributes that are currently not priced into generation resources, such as carbon intensity and reliability?

Technology

- What types of advanced nuclear technology are being considered?
- What are the operating characteristics of preferred technologies? What are the expected costs?
- Where is new construction likely to occur? Can utilities repurpose transmission infrastructure, brownfield sites, or other existing assets?
- What type of fuel will be used by advanced nuclear? Where will it come from?

As advanced reactors progress through technology readiness levels and become operational, regulated utilities will have a dataset from which to draw conclusions about costs and benefits of advanced nuclear and how new nuclear compares to other types of generation and storage resources. Although INL assessed technology readiness levels for advanced nuclear fuels and materials in 2014,[205] a more current look at the suite of advanced reactors at varying stages would help utilities and regulators understand what lies ahead in the advanced nuclear market. This capability would be particularly valuable given the varying time windows in IRP processes.

Further, the openness of utilities such as Idaho Power, PacifiCorp, TVA, and UAMPS to document and share lessons learned from early construction or procurement of advanced nuclear generation will aid regulators and other utilities in making informed decisions in the future. Compared to FOAK projects, building identical NOAK projects can be done with substantially less upfront capital investments—but only if lessons from the FOAK project are discussed and incorporated.

The latter half of the current decade will be a critical period in which to observe the progress of advanced nuclear reactors under construction and in the stages of NRC approval. NARUC expects continued awareness and observation by regulated utilities and PUCs alike to understand the role that existing and advanced nuclear can play in supplying customers with reliable, affordable, safe, and clean power.

205 Jon Carmack, January 2014, "Technology Readiness Levels for Advanced Nuclear Fuels and Materials Development," Idaho National Laboratory. https://inldigitallibrary.inl.gov/sites/sti/sti/5935853.pdf.

Appendix A: State IRPs Reviewed

Company	States Operating in	IRP Year	Includes Advanced Nuclear in IRP: Awareness of advanced nuclear	Includes Advanced Nuclear in IRP: Deliberate inclusion of advanced nuclear	Includes Advanced Nuclear in IRP: Maintaining existing nuclear resources
Duke Energy Carolina (DEC)	North Carolina, South Carolina	2022	X	X	X
Appalachian Power Company	Tennessee, Virginia, West Virginia	2022	X		–
Dominion Energy South Carolina (DESC)	South Carolina	2021	X		X
DTE Electric Company	Michigan	2022	X		X
Duke Energy	North Carolina, South Carolina	2023	X	X	X
Duke Energy Progress (DEP)	North Carolina	2020	X	X	X
Entergy Mississippi	Mississippi	2021			X
Georgia Power	Georgia	2022	X		X
Green Mountain Power (GMP)	Vermont	2021			X
Idaho Power	Idaho, Oregon	2021	X	X	–
Indiana Michigan Power	Indiana, Michigan	2021	X		*
Mississippi Power	Mississippi	2021	X		–
Public Service Company of New Mexico (PNM)	New Mexico	2020	X		X
Northern States Power Company (Xcel subsidiary)	Michigan, Minnesota	2020	X		X
PacifiCorp	California, Idaho, Oregon, Utah, Washington, Wyoming	2021	X	X	–
Tennessee Valley Authority (TVA)	Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee, Virginia	2019	X	X	X
Virginia Electric and Power Company (VEP)	North Carolina, Virginia	2022†	X		X

* In 2 out of 12 portfolios, Indiana Michigan Power considers relicensing Cook Units 1 and 2, but Indiana Michigan Power's preferred portfolio assumes Cook Nuclear Plant is retired.

– indicates utility with no existing nuclear resources included in generation portfolio.

† update to 2020 IRP

NARUC
National Association of Regulatory Utility Commissioners

1101 Vermont Ave, NW • Suite 200 • Washington, DC 20005
www.naruc.org • (202) 898-2200