Comments of the Public Staff

on

2020 Biennial Integrated Resource Plans of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina

and

2020 REPS Compliance Plans of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina

Docket No. E-100, Sub 165

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EXECUTIVE SUMMARY

The Public Staff has investigated the 2020 Integrated Resource Plans (IRP) filed by Duke Energy Carolinas, LLC (DEC),[1] Duke Energy Progress, LLC (DEP), (together, Duke), and Dominion Energy North Carolina (Dominion) (collectively, the Utilities). Overall, the Public Staff believes that the IRPs comply with Commission Rule R8-60 and provide sufficient information for planning purposes. Each IRP attempts to find a least-cost future electric generation system, taking into account recent legislation, load growth, unit retirements, and technological and economic characteristics of new and existing generation. The Utilities' 2020 IRPs, depending on which capacity expansion plan is utilized for future system planning, include additional capacity and energy from natural gas, wind, and solar resources, as well as significant increases in energy storage to provide firm capacity to customers. The Utilities' plans for these new resources represent a continuation of the trend towards greater amounts of renewable generation in relation to previous IRPs, and certain of the identified expansion plans have the potential to increase costs for customers relative to other plans, particularly if the carbon tax revenue is not returned to ratepayers. The shift away from coal has already started to occur and will continue, as Duke and Dominion seek to respond to new and emerging statutory and regulatory requirements, as well as investor expectations, by providing an energy supply that increasingly relies on renewable energy. While there are similarities in their IRP processes and inputs, Duke and Dominion diverge on the timing and rationale for the changes to capacity and energy supply in their

[1] A list of abbreviations is included as Exhibit A.

IRPs, as more fully explained in these comments. Given the long-term scope of impacts and uncertainties inherent in the IRPs of each of the Utilities, the Public Staff's comments highlight general concerns with the IRP process and inputs, and make recommendations regarding the capacity expansion plans based upon a robust analysis of the inputs, the assumptions, and ratepayer risk exposure.

DEC AND DEP IRPS

In October 2018, Governor Roy Cooper issued Executive Order 80, Commitment to Address Climate Change and Transition to a Clean Energy Economy[2] (EO80), which required, in part, that North Carolina greenhouse gas emissions be reduced 40% below 2005 levels by 2025. In addition, as noted in Chapter 16 of its IRPs, Duke announced in 2019 a corporate goal to reduce its carbon dioxide (CO_2) emissions by at least 50 percent from 2005 levels by 2030, and to achieve net-zero by 2050.

Duke has already reduced greenhouse gas emissions by approximately 41% from 2005 levels,[3] putting it on track to achieve compliance with current goals. All of Duke's identified future expansion plans continue the trend of reducing CO_2, with some Portfolios achieving as much as 70% CO_2 reduction by 2030.

EO80 also required the North Carolina Department of Environmental Quality (DEQ) to develop a Clean Energy Plan (CEP) by October 1, 2019. The

[2] https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition.
[3] DEP IRP at 9.

CEP,[4] as developed, calls on Duke to reduce CO_2 emissions at substantially greater levels than Duke's stated corporate goals. It includes a goal to reduce electric sector emissions 70% below 2005 levels by 2030, and attain carbon neutrality by 2050. The CEP also prioritizes the development of carbon reduction policies for accelerated retirement of uneconomic coal plants and other policy options. It is important to note that the CEP is a policy document that provides guidance on paths to achieve significant emissions reductions and currently does not have implementing regulation from the DEQ. None of Duke's plans meet the carbon neutrality goal by 2050.

Due to load growth and unit retirements, all of Duke's proposed portfolios result in increased electric rates. The aggressive 70% CEP targets were modeled in Portfolio E (which relies on small modular nuclear reactors (SMR)) and Portfolio D (which relies on significant buildouts of wind power), both of which would increase rates significantly compared to the base cases, as shown in the following table:

[4] https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16.

Table 1: Average Residential Rate Impacts[5]

	DEC		DEP	
	Annual Average Increase	Average Monthly Residential Increase by 2035	Annual Average Increase	Average Monthly Residential Increase by 2035
Portfolio A: Base Case without Carbon Policy	1.3%	$23	1.2%	$21
Portfolio B: Base Case with Carbon Policy	1.5%	$25	1.5%	$27
Portfolio C: Earliest Practicable Coal Retirement	1.4%	$25	1.4%	$24
Portfolio D: 70% CO2 – High Wind	2.5%	$47	2.1%	$39
Portfolio E: 70% CO2 – High SMR	2.5%	$45	1.9%	$36
Portfolio F: No New Gas Generation	2.4%	$45	2.9%	$58

The table above represents projected rate increases resulting from new capacity to satisfy growing demand, as well as capacity expansion plans that are subject to carbon pricing or carbon-free generation that is “forced in” to the model in order to achieve a certain emission reduction target. The IRP is a comparative analysis, and the cost increases represented above do not include costs common to all portfolios, such as Duke’s proposed Grid Improvement Plan (GIP), coal ash remediation and beneficiation, or other regulatory requirements. In addition, this analysis does not consider the possible cost of inaction; that is, what costs will North Carolina ratepayers be required to pay under Portfolio A, with its existing fleet of fossil resources and planned investments in new natural gas generation, should aggressive carbon policy become reality. Should natural gas assets be

[5] Source: DEC and DEP IRPs, Tables A-17.

forced to retire early due to carbon legislation that was not anticipated at the time the assets were built, ratepayers could be required to pay for service from replacement resources while still paying for the replaced assets.[6]

The Public Staff recommends that the Commission accept for planning purposes both of Duke's base case Portfolios A and B, presented in Chapter 12 of its IRPs. For reasons discussed in more detail later in these comments, the Public Staff notes that there is little short-term difference between the two portfolios, and that there are risks to ratepayers should Duke commit to either Portfolio before the uncertainty surrounding CO_2 policies is resolved. Both Portfolios A and B result in carbon reduction of between 56% and 59% below 2005 levels by 2030 while (1) constructing new natural gas generation to meet reliability standards and load growth, (2) using the most economic retirement dates for existing coal-fired units, and (3) adding large quantities of additional solar, solar plus storage, and standalone storage. The Public Staff believes that both base case Portfolios provide reasonable short-term action plans, while maintaining flexibility to respond to an uncertain regulatory environment. To the extent that Duke must make planning decisions in the near term that require it to follow either Portfolio A or B, the Public Staff expects Duke to make reasonable decisions that minimize both cost and risk to ratepayers.

[6] This concept is often referred to as "stranded assets". The Energy Transition Institute recently published a report analyzing this issue, entitled "Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan," https://energytransitions.org/carbon-stranding.

DOMINION IRP

Dominion's operations in North Carolina are very different from those of Duke. Dominion's North Carolina territory has a small amount of generation and only approximately 5% of Dominion's total electric load. The remaining load, and most of the generation, is located in Virginia.[7] In addition, Dominion is part of the PJM Regional Transmission Organization (RTO).

In April 2020, the Virginia Clean Economy Act (VCEA) became law in Virginia, and among other things, requires Dominion to produce 100 percent of its electricity from renewable sources by 2045. In July 2020, Virginia joined the Regional Greenhouse Gas Initiative (RGGI), which is a market-based program implemented by several Northeast and Mid-Atlantic states to reduce greenhouse gas emissions. RGGI is a state-implemented program, not a utility-implemented program, and requires its member states to cap CO_2 emissions and buy allowances for any CO_2 that is emitted. Dominion modeled the effects of RGGI in all plans but Plan A. The effect of RGGI on future Dominion operations is uncertain, and the future establishment of mandatory federal CO_2 compliance could influence the RGGI market.

Similar to Duke, Dominion has committed to achieve net zero CO_2 and methane emissions by 2050. However, unlike in North Carolina, the VCEA and

[7] Dominion's Mt. Storm Power Station is 1,621 MW of coal-fired generation located in West Virginia, and is interconnected to Dominion's transmission system that serves both Virginia and North Carolina customers.

Virginia's membership in RGGI is a clear mandate for CO_2 reduction and renewable energy. For its IRP, Dominion developed a Plan A, which is a least-cost scenario not compliant with the VCEA. Dominion's Plan B[8] includes significant development of solar, wind, and energy storage resources, and is compliant with the VCEA renewable energy requirements within the study period (2021 to 2045).[9] The Public Staff agrees with Dominion that Portfolios B through D represent similar pathways over the next 15 years, and recommends that the Commission accept Dominion's Plan B as reasonable for planning purposes over the near term.

Dominion also projects each plan's impact on future customer bills. Table 2 below compares Dominion's least cost Plan A with Plan B. Unlike Duke, these future cost projections include the impact of certain programs common to all plans, such as approved investments in its Grid Transformation Plan.

Table 2: Dominion Residential Bill Projection[10]

Portfolio	Annual Average Increase	Average Monthly Residential Increase by 2035
Plan A	0.8%	$11.70
Plan B	2.9%	$45.92

[8] As revised in Dominion's May 15, 2020 supplemental filing.

[9] Plan B still maintains some fossil generation beyond 2045 to address identified "system reliability, stability, and energy independence issues." Dominion also notes that in future IRPs, the carbon-emitting resources included in Plan B could be replaced by new technologies, such as small modular reactors (SMRs), carbon capture and sequestration, or could be fueled by hydrogen or renewable natural gas. Dominion IRP at 6.

[10] Dominion IRP, Figure 2.5.1. Based on 1,000 kWh per month assumption.

AREAS OF CONCERN

The Public Staff highlights several concerns for the Commission's consideration. Specifically, these concerns relate to the carbon reduction goals within the IRPs and Duke's natural gas price forecasts.

CARBON REDUCTION GOALS

The Public Staff has some concerns about the large quantity of solar, wind, and battery resources that Duke has included in its carbon policy Portfolios without any regulatory or legislative mandate. For example, over the next 30 years, Duke's Portfolio B will cost ratepayers approximately $2.7 billion,[11] or 3.5%, more than Portfolio A, and the remaining illustrative Portfolios are even more expensive. Duke's corporate goal "to reduce CO2 emissions from power generation by at least 50 percent from 2005 levels by 2030, and to achieve net-zero by 2050" described in Chapter 16 of its IRPs is driving some of this expected cost increase, although Duke's expectation of future federal carbon legislation,[12] and the carbon price included in the modeling, are also significant drivers of these costs.

Duke has acknowledged its expectation of future carbon legislation later in Chapter 16: "Carbon policy alone, however, is insufficient to address all the challenges associated with the dramatic transition of the grid and generation fleet to reach net-zero carbon, particularly for winter peaking, energy intensive Southeastern utilities. Federal policies are also critical to support and accelerate

[11] In net present value terms, excluding the cost of a carbon tax. DEC and DEP IRPs at 16.
[12] DEP IRP at 152.

research, development, demonstration, and deployment of advanced technologies needed to meet this important goal."[13] The Public Staff addresses the projected cost of these policies later in these comments, while also discussing the risk to ratepayers should federal carbon legislation be enacted without sufficient preparation by Duke.

The Public Staff also has concerns that Duke's anticipated buildout of natural gas in Portfolios A and B could result in the forced early retirement of natural gas assets if carbon legislation is enacted in the future. If this occurred, a situation similar to the early retirement of coal assets proposed in this IRP would arise with natural gas assets. Duke did perform a sensitivity analysis in its IRP, shortening the life of natural gas assets to 25 years from 35 years, with the model predicting only minor changes in capacity expansion plans. While Duke Energy Corporation has stated that reducing the book life of natural gas assets "can still make economic sense,"[14] the Public Staff believes that in such circumstances ratepayers could be required to pay for service from replacement resources while still paying for the replaced assets.[15]

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[13] DEC and DEP IRPs at 142.

[14] "Duke Mulls New Gas Plants That Would Retire Early on Climate Goal", Bloomberg News, February 11, 2021. https://www.bloomberg.com/news/articles/2021-02-11/duke-wants-to-build-gas-plants-but-close-them-early-for-climate.

[15] If the decision is economic, this outcome might be fair and reasonable for the ratepayers.

DEC's and DEP's Price Forecasts for Natural Gas

The Public Staff has concerns with the natural gas price forecasts utilized by DEC and DEP in the IRP. The Public Staff believes that in comparison to the historical **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** pricing to calculate such fuel costs may be somewhat premature.

The Public Staff recognizes that in the 2018 IRP proceeding, Duke was relying on the Atlantic Coast Pipeline (ACP) to transport the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** gas into North Carolina. With the cancellation of the ACP, Duke has relied upon as-yet unavailable natural gas capacity to meet its future and existing natural gas demand. On average, Duke is projecting that its **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

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[16] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[17] Similar assumptions were incorporated in Duke's 2018 IRPs.

[18] Existing CC plants that receive **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** gas: Richmond, W.S. Lee, Sutton, Buck, H.S. Lee, and Dan River.

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**.

[19] Transco Zone 5 consists of North Carolina, South Carolina, and Virginia.

PUBLIC STAFF RECOMMENDATIONS

The Public Staff makes the following recommendations to the Commission based upon its review of the IRPs filed by DEC, DEP, and Dominion:

1. The Commission should accept Duke's Portfolios A and B, and Dominion's Plan B as reasonable for planning purposes.
2. In future IRPs, Duke should present a portfolio that sets a carbon limit and allows the model to economically select the necessary resources to meet that limit, as opposed to iteratively forcing resources into the model to meet a predetermined carbon goal.
3. Dominion should file a resource plan that neither includes forced resources, nor excludes certain resources.
4. The Utilities should use economically optimal endogenous plant retirement dates in future IRPs with the Encompass model, as opposed to exogenously specified retirement dates.
5. Should the Commission approve accelerated coal unit retirements, Duke should analyze the transmission impacts and file a more detailed plan with refined cost estimates, including timelines of required activities to aid in the transition and system production increments or decrements with the proposed replacement generation source
6. Due to the increasing reliance upon energy storage in the Utilities' IRPs to replace coal generation and satisfy reserve margins, the Commission should initiate a rule making proceeding to evaluate whether, and under what circumstances, an electric supplier should be required to receive

Commission approval prior to construction of a battery energy storage facility.

7. In future IRPs, the Utilities should continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding of reserve margin needs, as well as overall system operations.

8. Duke should consider implementing stochastic optimization in its capacity expansion model.

9. In future IRPs, for each capacity expansion plan presented, the Utilities should: a) provide the amount of existing firm transmission import capacity; b) list the additional incremental transmission import capacity needed to support the plan; c) provide a high-level cost estimate associated with these increases; and d) include those transmission costs in their PVRR analysis.

10. The Utilities should attempt to include network upgrade cost estimates within the capacity expansion model in the same manner as transmission interconnection costs.

11. Duke should continue to include in future IRPs a discussion and evaluation of potential subsequent license renewals (SLRs) for each of its existing nuclear units, including an anticipated schedule for SLR application submission and review, and an evaluation of the risks and

required costs for upgrades. Further, the Utilities should continue to reflect any such relicensing plans in future IRPs.

12. The Utilities should file a cost analysis to demonstrate that continued operation of each individual nuclear unit/plant is in the best economic interest for ratepayers. They should file this cost analysis in their next biennial IRPs (2022) and again in 2024.

13. DEC and DEP should continue to evaluate the methods and assumptions in their 2020 Resource Adequacy Studies, and continue to work with the Public Staff and other stakeholders when performing future Resource Adequacy Studies.

14. The Utilities should continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and employ appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events.

15. Dominion should continue to examine the growth of winter peaks, as DEP is doing. In addition, Dominion should weather-normalize its winter and summer peaks with the expectation that this effort will lead to a better understanding of the growth of the winter peaks.

16. The Utilities should continue to review their options for addressing the winter peak as well as better quantifying the response of customers to low temperatures.

17. The Utilities' demand side management (DSM) resources forecast should represent the reasonably expected load reductions that are available at the time the Utilities call upon the resource as capacity.
18. The Utilities should maintain use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability.
19. The Utilities should identify any changes in energy efficiency (EE)-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold required by the Commission.
20. Future market potential studies should consider a more comprehensive list of measures that can contribute and provide a more accurate picture of the achievable market potential for Duke's DSM and EE programs, as described in the Market Potential Study section of these comments.
21. For the 2021 IRP update, Duke should re-evaluate its prediction that additional interstate pipeline capacity will be available. If Duke continues to believe that adequate capacity will be available, Duke should provide the Commission and stakeholders with a detailed narrative that identifies a specific timeline for completion, as well as identification of major challenges associated with potential new interstate pipelines, which require FERC approval.
22. In order to assess the portfolio risk of Duke's natural gas pricing assumptions, Duke should consider developing an IRP portfolio that is

similar to its base case but includes natural gas import restrictions or less reliance on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

23. DEC and DEP should continue to evaluate the residential rate impacts of each portfolio evaluated against a no CO_2 scenario and present this information in a manner similar to that used by Dominion.

24. The Commission should approve the Utilities' 2020 REPS Compliance Plans.

INTRODUCTION

Pursuant to N.C. Gen. Stat. § 62-2(a)(3a), the Commission is vested with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies and declares the policy of North Carolina:

> "To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills."

N.C. Gen. Stat. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis is required to include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC).

N.C. Gen. Stat. § 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction of a generating facility. In addition, N.C. Gen. Stat. § 62-110.1 requires the Commission to submit annually to the Governor and appropriate committees of the General Assembly: (1) a report of the Commission's analysis and plan; (2) the progress in carrying out such plan; and (3) the Commission's program for the ensuing year in connection with such plan.

N.C. Gen. Stat. § 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan. Commission Rule R8-60 provides the Commission's specific requirements for the IRPs.

Over the last decade or more, IRPs have taken on greater significance due to the influence these plans have on directing and guiding public policies associated with energy consumption and the economy. Federal, state, and executive initiatives, including the implementation of PURPA, Senate Bill 3, the VCEA, South Carolina Act 62, House Bill 589, EO80, and the interests of the shareholders of the IOUs have all impacted the direction, scope, and determination of the least cost plan. Consideration of the early retirement of fossil generation and replacement of that generation with renewable generation to reduce carbon emissions have taken a prominent role in the IRP, in part due to Commission direction and changing market economics.[20] Promotion and further development of energy efficiency and demand response are necessary investments to mitigate the cost of CO_2 emission reduction. Uncertainty over the future of regulatory and statutory climate policies persists, at both the state and federal levels. Energy storage and electric vehicles are expected to begin altering traditional load shapes in the near future as they become more widely adopted.

What constitutes a "least cost plan" has become clouded as a result of satisfying the initiatives of policies that are not yet required by law. For example, the CEP and EO 80, as well as corporate commitments, are influencing the method for modeling the least cost plan. As presented in Duke's short-term action plans, the costs for an energy system that complies with the CEP and corporate commitments will come from accelerated retirement of fossil-fueled generation and the replacement of that generation with renewable resources. However, failing to account for future carbon regulation and increasing amounts of low- or no-carbon energy could leave North Carolina ratepayers economically worse off over the long term if a carbon policy is implemented after building new carbon emitting generation resources. The Public Staff also notes that there is value in the deferral of capital investments, and ratepayers may benefit from Duke waiting to make

[20] *See* Order Accepting Filing Of 2019 Update Reports And Accepting 2019 REPS Compliance Plans, *2019 Integrated Resource Plan Update Reports and Related 2019 REPS Compliance Plans*, No. E-100, Sub 157, at 8 (N.C.U.C. Apr. 6, 2020) (2019 IRP Order).

certain large capital investments if unanticipated technological changes occur in the market.

The Public Staff believes that policy assumptions regarding long-term planning – particularly those pertaining to potential carbon regulation – involve significant uncertainty, and failing to properly account for this uncertainty can produce sub-optimal plans or create future risk of higher rates for ratepayers. The Public Staff recognizes that the policy of North Carolina is to “promote adequate, reliable and economical utility service to all of the citizens and residents of the State,” and that this policy requires an accounting for and consideration of the risks of both correctly and incorrectly predicting future regulatory requirements.

2020 PROCEDURAL HISTORY

On May 1, 2020, Dominion filed its 2020 IRP and REPS Compliance Plan. On May 15, 2020, Dominion filed Supplemental Information and Errata Pages. On September 1, 2020, DEP and DEC filed their respective IRPs and REPS Compliance Plans. Pursuant to Commission Rule R8-60(m), DEP and DEC held their stakeholder meeting on September 18, 2020. On November 6, 2020, DEP and DEC filed corrections to their respective IRPs. On December 29, 2020, the Public Staff filed a motion requesting an extension of time to file comments on the Companies’ IRPs.

In addition to the Public Staff, the following parties have intervened in Docket No. E-100, Sub 165: the North Carolina Sustainable Energy Association (NCSEA), Vote Solar, the North Carolina Clean Energy Business Alliance

(NCCEBA), NC WARN Inc., and the Center for Biological Diversity, the Carolina Industrial Group for Fair Utility Rates I and II (collectively, CIGFUR), the Attorney General, the Carolina Utility Customers Association (CUCA), Apple Inc., Facebook, Inc., and Google, Inc. (collectively, Tech Customers), Broad River Energy, LLC, the City of Asheville and Buncombe County, the City of Charlotte, the Southern Alliance for Clean Energy, Sierra Club, the Natural Resources Defense Council, and Electricities of North Carolina, Inc.

EVOLUTION OF THE IRP

Over the past fifteen years, the IRP process has changed significantly. Instead of determining the type of large, centralized, thermal generation unit to build, the IRP now must incorporate consideration of distributed energy resources (DER), intermittent generation such as wind and solar, the complexities of modeling energy storage systems, and legislation that influences the types of generation that can be built. There are significant and novel challenges associated with modeling these various factors. Increasingly, the IRP process is incorporating more granular detail, as well as elements of both the transmission and distribution systems, such as non-wires alternatives (NWA). All of these factors have contributed to the IRP becoming an increasingly complex planning document and a docket that is intertwined with many other proceedings, such as Certificate of Public Convenience and Necessity (CPCN) applications, the determination of avoided capacity and energy, the North Carolina Interconnection Procedures (NCIP), and Demand Side Management (DSM) and Energy Efficiency (EE) programs.

Utilities in North Carolina have responded to this increased complexity, in part, by holding more stakeholder discussions and working groups centered around various aspects of the IRP, such as resource adequacy studies, carbon reduction modeling pathways, coal retirement analysis, load forecasts, and energy storage. The Public Staff anticipates that this trend of increasing complexity will continue, and new tools will be required to manage these challenges going forward.

DUKE'S INTEGRATED SYSTEM AND OPERATIONS PLANNING

Since the introduction of its Integrated System and Operations Planning (ISOP) process in the 2018 IRP, Duke has begun moving towards a more integrated modeling approach envisioned by this process. The high-level goals of ISOP include the introduction of more granular load forecasting, referred to as "Morecast"; Advanced Distribution Planning (ADP), which includes 8760 distribution planning; improved methods for evaluating NWA and non-traditional solutions (NTS); coordination between generation, transmission, and distribution planning; and improved evaluation of emerging technologies. Duke provided updates to stakeholders on its ISOP process during two informational webinars held on January 30, 2020, and March 3, 2020, and solicited feedback from stakeholders during two stakeholder engagement workshops, held on December 10, 2019 and August 21, 2020.

On January 21, 2020, Duke filed a joint report in Docket No. E-100, Sub 157, summarizing the first ISOP workshop held on December 10, 2019. This workshop focused on the drivers, objectives, and estimated timeline and milestones for ISOP, while also soliciting feedback and responding to questions from stakeholders. Panelists provided customer and advocate perspectives as well as environmental and developer perspectives.

On November 9, 2020, Duke filed a joint report in Docket No. E-100, Sub 157, summarizing the second ISOP stakeholder forum held on August 21, 2020. This forum included business use case presentations from developers and customers who detailed how ISOP could improve the IRP and help satisfy goals for additional renewable energy, battery storage, and maintaining low electricity rates. Duke also presented a study on winter peak-shaving, due to the increased emphasis around planning for winter peaks in the Carolinas.

Duke has described the ISOP effort as an "important and necessary evolution in electric utility planning processes," given the changing nature of the grid and nascent technologies such as EVs and DER. The transition towards a more integrated planning process will take years. Duke has identified several milestones for major elements of ISOP, and further expanded its timeline in the November 9, 2020 report on the second ISOP stakeholder forum, as seen below.

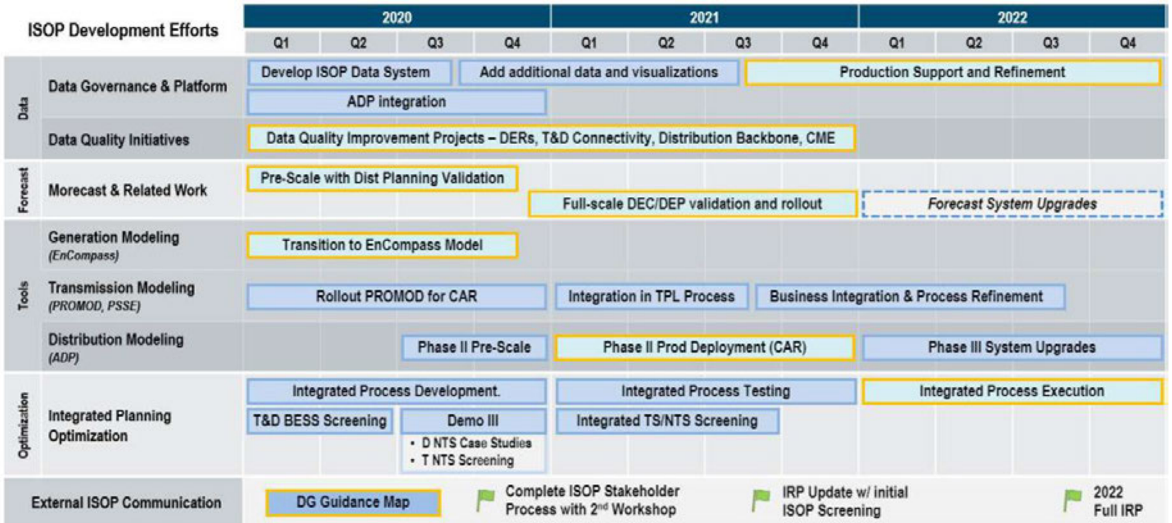

Figure 1: ISOP Timeline from Joint Report on Second ISOP Stakeholder Forum

Duke states in its IRPs that it has also been working with the North Carolina Electric Membership Corporation (NCEMC) to exchange ideas related to ISOP, including improving coordination between distribution and transmission operations. In addition, based in part on expiring technical support for previous capacity expansion models, as well as on ISOP stakeholder input, Duke is moving forward with its transition to the EnCompass suite of resource planning models, from Anchor Power Solutions.[21] The EnCompass model provides additional abilities that can aid in the ISOP process, including the modeling of climate goals, detailed ancillary service modeling, improved optimization of energy storage resources, endogenous retirement of generation assets,[22] and improved dispatch of dual-fuel resources that can burn coal and natural gas, such as the Marshall

[21] Prior Duke IRPs utilized System Optimizer and Prosym, which are ABB products.

[22] Endogenous retirement allows the model to select, based on system operations, the economically optimal retirement date. This is in contrast to the current model capabilities, which requires asset retirement dates to be entered as exogenous inputs to the model.

and Belews Creek plants. Duke teams are also studying the effects of perfect foresight[23] on model behavior and the benefits of sub-hourly modeling, which may in the future improve the IRP's ability to integrate high levels of renewable energy.

ISOP is a component of Duke's Grid Improvement Plan (GIP) proposed in its 2019 general rate cases,[24] and Duke has budgeted approximately $8.7 million in system costs for ISOP for DEC and DEP combined over the 2020 – 2022 implementation timeframe. ISOP was the highest ranked GIP program by the Public Staff, due to its potential to transform the grid, the necessity for its rapid deployment, and its integration with and support of other grid modernization programs.[25] Over the next few IRP cycles, the Public Staff expects to see significant changes to the input data for the IRP models and the methods by which Duke evaluates non-traditional solutions.

DOMINION'S INTEGRATED DISTRIBUTION PLANNING

Dominion recognizes in its IRP the limitations of existing distribution planning methodologies and processes.[26] In September 2019, Dominion filed with the Virginia State Corporation Commission (SCC) a white paper providing a detailed overview of its Integrated Distribution Planning (IDP) process.[27] The

[23] Perfect foresight refers to the concept that the models used in the IRP have certainty as to all future variables, and thus can make optimal decisions. In practice, system planners and operators do not have perfect foresight, and must make decisions based on incomplete and imperfect information.
[24] *See* testimony of Jay Oliver, Docket Nos. E-2, Sub 1219, and E-7, Sub 1214.
[25] *See* Exhibit 4 of the Testimony of David Williamson and Tommy Williamson, Jr., Docket Nos. E-2, Sub 1219, and E-7, Sub 1214.
[26] Dominion IRP, Section 8.1.
[27] Dominion IRP, Appendix 8A.

ultimate objective of the IDP process is to "develop a prudent distribution investments roadmap based on load growth, reliability needs, DER growth, new technology adoptions, and other changes on the distribution system over the planning horizon."[28] Dominion identified areas in which it has made progress, including improving employee training, technologies, processes, and tools used to plan the distribution system. The IDP process is reliant upon the investments proposed as part of the Grid Transformation Plan, as well as the technologies available to Dominion. Some aspects of Dominion's IDP share characteristics with Duke's ISOP, including enhanced feeder-level forecasting, a standardized screening process to consider NWAs, and integration of operational organization structures as needed. Dominion also plans to perform a hosting capacity analysis as part of the IDP effort.

LEGISLATIVE AND EXECUTIVE ACTION INFLUENCING 2020 IRPS

Since the most recent IRP update, there have been significant energy policy actions that influence the 2020 IRPs, as summarized below.

EXECUTIVE ORDER 80 AND THE DEQ CLEAN ENERGY PLAN

On October 29, 2018, Governor Cooper signed Executive Order 80, Commitment to Address Climate Change and Transition to a Clean Energy Economy (EO80). The Order stated that the State will strive to reduce statewide greenhouse gas emissions (GHGs) to 40% below 2005 levels by 2025. The Order required the DEQ to develop a CEP "that fosters and encourages the utilization of

[28] *Id.*

clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modern and resilient electric grid."

After an extensive 10-month stakeholder process, including participation from over 160 stakeholder groups, DEQ released the CEP as directed by EO80 in October 2019. The three primary CEP Goals presented in the report are as follows: (1) reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050; (2) foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes; and (3) accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.[29]

With regard to the recommendation to decarbonize the electric power sector, the CEP states that the Utilities Commission can "[r]equire integrated resource plans and distribution system plans to use portfolios and action plans that incorporate a cost of carbon into the portfolio or plan that is selected for use by the utility."[30]

[29] Clean Energy Plan at 12.
[30] Clean Energy Plan at 13, 55, Recommendation A-2.

For Duke, two resource portfolios meet the 70% CO_2 reduction by 2030 goal, although both would require supportive state policies in North Carolina and South Carolina.[31] With regard to those portfolios, Duke states:

> The 70% CO_2 Reduction High Wind case would require supportive policies for expeditious onshore and offshore wind development and associated, necessary transmission build by 2030. The 70% CO_2 Reduction High SMR case was included to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. The No New Gas case includes dependence on all factors listed, as well as a much greater dependence on siting, permitting, interconnection and supply chain for battery storage. For the 70% reduction and No New Gas cases, the unprecedented levels of storage that are required to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage.[32]

Further, Duke states that the resource portfolios that meet the 70% reduction goal "reflect an accelerated utilization of technologies that are yet to be commercially demonstrated at scale in the United States and may be challenging to bring into service by the 2030 timeframe.[33]

While the CEP is a guide to achieving a 70% carbon emissions reduction, it acknowledges that components of the Plan require policy changes at the legislature to update the State's energy regulatory framework.

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[31] DEC IRP at 6.
[32] DEC IRP at 15.
[33] DEC IRP at 21-22.

In order to explore recommendations of the CEP, the DEQ initiated the North Carolina Energy Regulatory Process (NERP) to develop a regulatory reform scheme, with the Rocky Mountain Institute and the Regulatory Assistance Project serving as facilitators for numerous stakeholder meetings that took place from February to December 2020. The Public Staff was a stakeholder and participated in the NERP. The final report was released on December 22, 2020.[34] The report included several recommendations for legislative and regulatory action, including: adoption of a performance-based regulatory framework; enabling securitization for retirement of fossil assets; studying options to increase competition in the electricity system; and, implementing competitive procurement of resources by investor-owned utilities.

VIRGINIA CLEAN ECONOMY ACT

The VCEA was signed into law on April 11, 2020 and became effective July 1, 2020. The VCEA is major comprehensive energy legislation that mandates a renewable energy portfolio standard (RPS) reaching 100% of total electricity sold to retail customers in VA by 2045. Beginning in 2025, to meet the RPS requirement, at least 75% of all the RECs used to comply with the RPS program must come from resources located in the Commonwealth of Virginia or physically located in the PJM interconnection region.[35]

Further, the VCEA declares the construction or purchase of 16,100 megawatts (MW) of solar and onshore wind, 5,200 MW of offshore wind, and 2,700

[34] https://deq.nc.gov/cep-nerp.
[35] *See* VA § 56-585.5 (C).

MW of energy storage resources located in the Commonwealth to be in the public interest. The VCEA also sets the target of reaching 5% energy efficiency savings (based on 2019 jurisdictional electricity sales) by 2025.

The VCEA also mandates the retirement of all carbon emitting generating resources located in the Commonwealth by 2045, unless the Virginia SCC finds that a given retirement would threaten the reliability and security of electric service.[36] The VCEA also directs Virginia's participation in a carbon trading program through 2050.

Alternative Plan A of Dominion's IRP does not achieve compliance with the VCEA and is for cost comparison purposes only. Alternative Plans B through D comply with the VCEA, although Alternative Plan B and B19 do not retire all carbon-emitting resources by 2045.[37] Dominion states that meeting the VCEA targets for procuring solar in Plans B through D will present challenges going forward, specifically in land acquisition, permitting, and supply chain for both equipment suppliers and construction contractors.[38] Dominion also states that Plans C and D will severely challenge the ability of the transmission system to meet customers' reliability expectations.[39]

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[36] Dominion IRP at 10.
[37] Dominion IRP at 5.
[38] Dominion IRP at 101-02.
[39] Dominion IRP at 124.

VIRGINIA AND THE REGIONAL GREENHOUSE GAS INITIATIVE

The Clean Energy and Community Flood Preparedness Act was also enacted in 2020 and became effective July 1, 2020. This Act authorizes Virginia to join the Regional Greenhouse Gas Initiative (RGGI). The Commonwealth joined RGGI in July 2020 and became eligible to participate in RGGI auctions beginning on January 1, 2021.

RGGI is a market-based program implemented by several Northeast and Mid-Atlantic states to reduce greenhouse gas emissions from electric generating plants. RGGI is a state-implemented program, not a utility-implemented program, and requires its member states to cap CO_2 emissions and buy allowances for any CO_2 that is emitted by electric generating plants within the state's borders.

As an electric generator in Virginia, Dominion must pay an allowance for each ton of CO_2 it emits. Dominion does not have to pay for RGGI allowances for CO_2 emitted from its electric generating plants in North Carolina (Rosemary) and West Virginia (Mt. Storm).

RGGI returns a large portion of auction proceeds back to its member states. The Virginia law requires that 50% of the revenue be used for low-income energy efficiency programs, 45% for assisting localities and residents affected by flooding and sea-level rise, and 5% for administration and planning. Dominion estimates that it will have to buy 19 million allowances in 2021 at a cost of $7.00 each for a total cost of $133 million.

UTILITY NET ZERO POLICIES

DEC/DEP

On September 17, 2019, Duke's parent company, Duke Energy Corporation, announced new enterprise-wide goals of reducing carbon emissions from its electric generation fleet by 50% from 2005 levels by 2030, and achieving "net-zero" carbon emissions by 2050.[40]

In its IRPs, Duke states that all six of the resource portfolios outlined therein keep it on a trajectory to meet its near term enterprise carbon reduction goal of at least 50% by 2030, and long term goal of net-zero by 2050.[41] Chapter 16 of Duke's IRPs discuss the elements needed to accelerate CO_2 reductions and sustain its trajectory toward net zero, which is beyond the 15-year trajectory of the IRP. Duke notes that without the development of new, low- or zero-emitting load following technologies, it cannot meet its corporate goal of net-zero by 2050.[42]

Dominion

On February 11, 2020, Dominion Energy announced expansion of its GHG emissions reduction goals, by establishing a commitment to achieve net zero CO_2 and methane emissions by 2050. In its IRP, Dominion states that the net zero CO_2 and methane emissions commitment parallels the commitment made in the

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[40] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.
[41] DEC IRP at 8.
[42] DEP IRP at 140.

VCEA.[43] In North Carolina, Dominion states that its goals are consistent with the DEQ CEP.

COMPLIANCE WITH COMMISSION ORDERS AND RULE R8-60

Commission Rule R8-60 parts (c) through (i) describe the requirements of the Utilities' IRPs.[44] The Public Staff has reviewed the IRPs filed by Duke and Dominion, as well as recent Commission orders regarding IRPs. Duke and Dominion have met all filing requirements of Commission Rule R8-60.

ECONOMIC DEVELOPMENT

In its Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the Commission ordered North Carolina utilities to review the combined results of existing economic development rates within the approved IRP process and file the results in their short-term action plans. The Public Staff has reviewed the results submitted by DEC, DEP, and Dominion, as well as conducted additional discovery.

DUKE

DEC offers two Commission-approved economic development rates, Rider EC Economic Development and Rider ER Economic Redevelopment. Rider EC is available to new non-residential load associated with initial permanent service to new establishments or the expansion of existing establishments. Rider ER is available to a new non-residential customer operating in an existing establishment,

[43] Dominion IRP at 20. The VCEA establishes a mandatory renewable portfolio standard of 100% clean energy from Dominion's fleet by 2045.
[44] On November 13, 2019, the Commission deleted R8-60(i)(10) and R8-60.1 regarding smart grid impacts and smart grid technology plans.

served or previously served by DEC, that has been unoccupied or dormant for at least six months.

As of November 30, 2020, DEC had 31 customers receiving service on Rider EC, 19 in North Carolina representing 151.1 MW of load, and 12 in South Carolina representing 131.2 MW of load. DEC had one customer on Rider ER located in North Carolina with 41 MW of load. DEC had no pending applications as of November 30, 2020, for Rider EC or Rider ER.

DEC stated that it had no pending economic development initiatives under consideration other than the comprehensive rate design study proposed as part of its general rate case in Docket No. E-7, Sub 1214.

DEP offers two Commission-approved economic development rates, Rider ED Economic Development and Rider ERD Economic Redevelopment. Rider ED is available to new non-residential load associated with initial permanent service to new establishments or the expansion of existing establishments. Rider ERD is available to a new non-residential customer operating in an existing establishment, served or previously served by DEP, that has been unoccupied or dormant for at least 60 days.

As of November 30, 2020, DEP had 11 customers receiving service on Rider ED, 9 in North Carolina representing 18 MW of load, and two in South Carolina representing 8.0 MW of load. DEP had no customers on Rider ERD. DEP had four pending applications as of November 30, 2020, for Rider ED, representing approximately 13 MW of load, and none for Rider ERD.

DEP stated that it had no pending economic development initiatives under consideration other than the comprehensive rate design study proposed as part of its general rate case in Docket No. E-2, Sub 1219.

The Public Staff supports the comprehensive rate design study proposed by Duke in its general rate cases and the IRP, which may include a review of economic development rates.

DOMINION

Dominion offers one Commission-approved economic development rate, Rider EDR Economic Development. Rider EDR is available to new non-residential load associated with initial permanent service to new establishments or the expansion of existing establishments.

As of November 30, 2020, Dominion had 11 customers receiving service on Rider EDR, all in Virginia representing 247 MW of load. Since the inception of the rate, Dominion has had one customer in North Carolina on Rider EDR, but it ceased participation in 2019. Dominion stated that there was one pending customer for Rider EDR in Virginia, representing 3 MW of load.

Dominion stated that its other economic development initiatives provided to potential new load include providing rate comparisons, site selection assistance, and working with third parties on lead generation. It has no other initiatives under consideration at this time.

PEAK LOAD FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2021–2035) of DEC, DEP, and Dominion, both before DSM and EE and after DSM and EE. The compound annual growth rates (CAGRs) for the utilities' summer peak demand forecasts, winter peak demand forecasts, and annual energy sales forecasts are all within the range of 0.5% to 1.1%, as shown in Table 3. All of the utilities used industry accepted econometric and end-use analytical models to forecast peak demand and energy sales. There is a degree of uncertainty associated with any forecasting methodology that attempts to quantify whether the historical relationships of customers' electricity consumption with weather and other economic variables (per capita income, end use appliances, adoption of electric heat pumps and air conditioning), during peak periods and usage throughout the month, will continue in the future.

The dominant seasonal peak has historically occurred during summer afternoons between the hours ending 3:00 p.m. and 5:00 p.m. However, from 2015 through 2019, DEP's and Dominion's annual peaks have all occurred at the hour ending 8:00 a.m. during either January or February. In 2020, DEP's and Dominion's summer peaks were greater than their January 2020 and February 2020 winter peaks. Meanwhile, during this same time period, DEC has realized a more balanced mixture of its annual peaks occurring during winter in some years and summer in others.

__DEC__

DEC's forecasted summer peak loads, after incorporating load reductions associated with EE programs, reflect a CAGR of 0.8% over the forecast years of 2021 through 2035. This predicted growth rate is lower than both the 1.0% CAGR forecast in its 2018 IRP, and the 1.1% CAGR forecast in its 2016 IRP. DEC's forecast of its new EE programs is expected to reduce its summer and winter loads by approximately 1.9%, while DSM, if activated, is expected to reduce summer peak loads by approximately 6.0%, and reduce winter peak loads by 2.8%. Over the next 15 years, DEC's summer peak loads are expected to increase, on average each year by approximately 148 MW, as compared to a predicted annual load growth of 200 MW in the 2018 IRP, and 232 MW in the 2016 IRP. As discussed further in these comments, DEC projects to be a summer peaking system for the foreseeable future; however, its emphasis with respect to system planning[45] focuses on its ability to meet winter loads, largely due to the concentration of loss of load risk in the winter months.[46] DEC's forecasted winter peak loads reflect a CAGR of 0.6%.

DEC forecasts its energy sales, including the effects of its EE programs, to grow at a CAGR of 0.5%, as compared to its 0.9% growth forecast in its 2018 IRP,

[45] The average summer peak is predicted to be, on average, approximately 550 MW greater than the winter peak.

[46] *See* Duke's Resource Adequacy Study, which discusses this in more detail.

and 1.0% growth forecast in its 2016 IRP. The significant decrease in predicted growth rate of energy sales is representative of the increasing use of energy efficiency across its service area. DEC expects its EE programs to reduce its energy sales by approximately 1.4% in 2019, or 604 gigawatt-hours (GWh) versus what they would have been without the EE programs. DEC projects this impact on energy sales from its EE programs to increase to 1.6% by 2030, and then decline to 1.0% (1,013 GWH) by 2035. These reductions in energy sales are significantly less than reflected in the 2018 IRP, which forecasted 4,455 GWh of reduction in 2033. This topic is addressed in more detail in the DSM and EE section.

In addition, DEC projects its load factor to be approximately 58% over the next 15 years, comparable to the 58% load factor projected in its 2018 IRP, and 59% load factor projected in its 2016 IRP. A declining load factor (which can be calculated by taking a utility's energy sales and dividing it by the utility's peak load, annualized for 8,760 hours) generally indicates a utility's greater need for peaking plants, relative to baseload units. A high load factor indicates lower peaks compared to energy sales, while a low load factor indicates high peaks compared to energy sales. A high load factor, with higher loads compared to peak, puts less strain on the utility. The utility industry generally prefers higher load factors, because they result in a greater number of kWh relative to fixed production plant costs, thus lowering average rates.

DEP

DEP considers its winter peak loads, after incorporating load reductions associated with EE programs, which have a forecasted CAGR of 0.8%, to be its annual peaks.[47] This projected growth rate is similar to the forecasted 0.7% CAGR in its 2018 IRP, but significantly less than the 1.2% CAGR in its 2016 IRP. DEP's forecast of its new EE programs is expected to reduce its winter loads by approximately 1.4%, and reduce its summer loads by 1.6%. DSM, if activated, is expected to reduce winter peak loads by approximately 3.3%, and the summer peak loads by 7.6%. DEP's winter peak loads are expected to increase on average by 121 MW annually over the next 15 years. On average, for the next 15 years, winter peaks are projected to be approximately 1,391 MW greater annually than the forecasted summer peaks for the corresponding planning year.

DEP forecasts its energy sales, including reductions associated with its EE programs, to grow at a CAGR of 0.8%, as compared to its growth rate of the 0.5% in its 2018 IRP, and 0.9% in its 2016 IRP. DEP projects its EE programs to reduce energy sales by approximately 0.6% in 2021, or 352 GWh, and by 2.1% in 2035, or 1,479 GWh, versus what they would have been without the EE programs. These reductions in energy sales are significantly less than those reflected in DEP's 2018 IRP, which forecasted 2,345 GWh of reduction in 2033. This topic is addressed in more detail in the DSM and EE programs section.

[47] The average summer peak is predicted to be on average approximately 604 MW smaller than its winter peak and is predicted to grow at a CAGR of 0.8%.

In addition, DEP projects its load factor to be approximately 51% over the next 15 years, comparable to the average 51% load factor projected in its 2018 IRP, but lower than the 55% load factor projected in its 2016 IRP.

DOMINION

Dominion's 15-year load and energy sales forecast is based on PJM's Peak Load Forecast Report,[48] which includes a separate forecast for the Dominion load serving entity (LSE). PJM's forecast projects Dominion to be a winter peaking system over the forecast period. PJM's winter peak load forecast for the Dominion LSE, which it projects to be its annual peak,[49] after incorporating load reductions associated with EE programs, has a CAGR of 1.1%. This projected growth rate is lower than the 1.5% CAGR forecast in Dominion's 2018 IRP, and the 1.3% CAGR forecast in Dominion's 2016 IRP. Dominion expects its EE programs to reduce its summer and winter peak loads on average by approximately 2.9% annually, while DSM, if activated, is expected to reduce the annual summer peak load by approximately 0.4%, and the annual winter peak load by approximately 0.5%. On average, the winter peaks are projected to increase on average by 205 MW each year.

Dominion's energy sales are forecast to grow at a CAGR of 1.1%, an increase from the 0.7% projected in its 2018 IRP, but less than the 1.5% projected in its 2016 IRP. Dominion expects the energy savings from its EE programs to

[48] 2020 PJM Load Forecast Report, January, 2020, www.PJM.com.

[49] The winter peak loads are predicted to be approximately 582 MW higher than its summer peak loads.

reduce its annual energy sales by an average of 1.1% per year, which is slightly less than the expected 1.8% reduction in energy sales projected in its 2018 IRP.

Dominion projects its load factor to be approximately 62% over the next 15 years, which is higher than both the 59% load factor projected in its 2018 IRP, and the 56% load factor projected in its 2016 IRP.

SUMMARY OF GROWTH RATES

Table 3 below summarizes the growth rates for the system peak and energy sales forecasts as stated in the Electric Utilities' IRP filings, as discussed in detail above.

Table 3: Electric Utilities 2021-2035 Growth Rates (After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEC	0.8%	0.6%	0.5%	148
DEP	0.8%	0.8%	0.8%	121
Dominion	0.9%	1.1%	1.1%	205

HISTORICAL ACCURACY OF LOAD FORECASTS

The Public Staff's review of utility forecasting accuracy is focused on a comparison of the Utilities' actual annual peak demands with the previously forecasted peak demands. In assessing the reasonableness of the forecasts, the Public Staff first examined the one-year prediction accuracy vis-à-vis the Utilities' 2019 IRP Update. The Public Staff then analyzed accuracy over a five-year period by comparing actual peak demands and energy sales with the Utilities' annual peak demand and energy sales forecasts from their 2014 IRPs. This analysis includes both the Utilities' actual loads and weather-normalized loads. A review of past forecast errors can identify trends in the Utilities' historical forecasts, and then assist in assessing the reasonableness of the Utilities' 2020 forecasts. Finally, the Public Staff reviewed the forecasts of other regional utilities in the SERC Reliability Corporation, including its VACAR subregion.

DEC

The Public Staff's review of DEC's actual and weather-adjusted one-year peak load shows that DEC's 2019 IRP Update forecast over-predicted the realized peak by 7.1%; however, on a weather-normalized basis, the actual peak was 4.1% less than predicted. Nevertheless, the historical accuracy of DEC's IRP forecasts is best reviewed across a recent six-year period (2015-2020). As such, the Public Staff compared the forecasts from the 2014 IRP to this period. The Public Staff's accuracy analysis yielded a mean absolute error (MAE)[50] of 7.6%, as shown in Table 4. Of the six forecasted peaks reviewed comprising the MAE, one actual peak load was higher than forecast (2015), and five were lower than forecast. The average error of the six forecasts was 1,221 MW. While not shown in the table below, the MAE fell to 2.7% when the forecasts were compared with peaks that were adjusted for abnormal weather.

[50] Mean Absolute Error, or MAE is the absolute average percent difference between the actual peak load and the forecasted peak load.

Table 4: Accuracy Analysis of DEC's 2014 IRP

Date	Actual	2014 IRP Forecast	Difference	% Difference	Absolute % Difference
20-Feb-15	18,931	18,533	(398)	(2.1%)	2.1%
27-Jul-16	18,037	18,869	832	4.6%	4.6%
17-Aug-17	17,539	19,177	1,638	9.3%	9.3%
5-Jan-18	19,077	19,495	418	2.2%	2.2%
16-July-19	17,736	19,853	2,117	11.9%	11.9%
20-July-20	17,405	20,123	2,718	15.6%	15.6%
		Average	1,221		7.6%

Source: 2014 DEC IRP, Docket No. E-100, Sub 141, and Response to Public Staff Data Request No. 2-3, Docket No. E-100, Sub 165.

The Public Staff performed a similar review of the energy sales forecast from DEC's 2014 IRP to actual energy sales, and found that the forecasts had a 13% MAE.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2020 peak and energy forecasts are reasonable, but DEC continues to overestimate its energy sales relative to the forecasted sales in its 2014, 2016, and 2018 IRPs. In prior discussions with the Public Staff, DEC has maintained that its retail energy sales forecast (i.e., excluding wholesale class sales) is reasonably accurate when adjusted for abnormal weather. DEC's peak demand forecast has a greater influence on its capacity expansion plans; as such, the Public Staff places more weight on them than on energy forecasts. In that regard, the Public Staff acknowledges that the MAE, based on weather normalized peak loads versus the 2014 forecast, declined to 2.7%. Thus, the Public Staff finds DEC's peak load and energy sales forecasts to be reasonable for planning purposes.

DEP

A review of DEP's actual and weather-adjusted one-year peak load shows that DEP's 2019 IRP Update forecast overestimated the actual 2020 annual peak load by 12.8%. The actual peak was 12,966 MW, while the one-year ahead forecast was 14,624 MW. The forecast error dropped to 11.4% when the peak load was weather-normalized. As noted earlier, the Public Staff believes that forecasts are better reviewed across a five-year period. DEP's forecast errors from 2015-2020 indicate a MAE of 8.4%, as shown in Table 5.

Table 5: Accuracy Analysis of DEP's 2014 IRP

Date	Actual	2014 IRP Forecast	Difference	% Difference	Absolute % Difference
20-Feb-15	16,080	13,074	(3,006)	-18.7%	18.7%
19-Jan-16	13,357	13,247	(110)	-0.8%	0.8%
9-Jan-17	14,583	13,417	(1,166)	-8.0%	8.0%
7-Jan-18	15,897	13,603	(2,294)	-14.4%	14.4%
22-Jan-19	13,715	13,796	81	0.6%	0.6%
20-Jul-20	12,966	13,974	1,008	7.8%	7.8%
		Average	(915)		8.4%

Source: 2014 DEP IRP, Docket No. E-100, Sub 141, and Response to Public Staff Data Request No. 2-3, Docket No. E-100, Sub 165.

The analysis is comprised of six forecasted peak loads. Four of the predicted loads are lower than the actual loads, with an average over forecast error for the entire review period of 915 MW. While not shown above, the MAE fell to 5.2% when the forecasts were compared with the annual peaks that were adjusted for abnormal weather. The Public Staff made a similar review of DEP's 2014 energy sales forecast, which showed an 8.1% MAE. The error analysis shows that DEP significantly over-forecasted its annual energy sales in every year.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEP's 2020 peak and energy forecasts are reasonable. However, the excessive forecast errors associated with DEP's winter peaks using actual and weather normalized peak loads indicate that review and revision of DEP's statistical and econometric forecasting practices may be warranted. This concern is, in part, based on the 5.2% average forecast error that incorporates historical peaks that are weather normalized. Furthermore, the Public Staff supports DEP's recent efforts to research its customers' end-use of electricity for electric heating needs. This research should improve forecasts and assist in developing cost-effective DSM and EE programs that will better address winter peak demands.

DOMINION

A review of Dominion's one-year peak load forecast shows that Dominion's 2019 IRP Update underestimated the actual 2020 annual peak load by -0.3%. The actual peak was 16,356 MW, while the highest peak load prediction was 16,299 MW. As noted earlier, the Public Staff believes that forecasts are better reviewed across a five-year period. Dominion's forecast errors from 2015-2020 indicate a MAE of 9.2%, as shown below in Table 6. The analysis is comprised of six predictions from Dominion's 2014 IRP, with an average error of 1,373 MW.

Table 6: Accuracy Analysis of Dominion's 2014 IRP

Date	Actual	2014 IRP Forecast	Difference	% Difference	Absolute % Difference
20-Feb-15	18,688	18,148	(540)	(2.9%)	2.9%
25-Jul-16	16,914	18,734	1,820	10.8%	10.8%
9-Jan-17	16,618	19,065	2,447	14.7%	14.7%
7-Jan-18	17,792	18,291	499	2.8%	2.8%
22-Jan-19	16,842	18,507	1,665	9.9%	9.9%
20-Jul-20	16,356	18,702	2,346	14.3%	14.3%
		Average	1,373		9.2%

Source: 2014 Dominion IRP, Docket No. E-100, Sub 141, and Response to Public Staff Data Requests Nos. 1-7, 1-8, and 13-1, Docket No. E-100, Sub 165.

The Public Staff made a similar review of Dominion's 2014 energy sales forecast, which generated a 5.0% MAE. The error analysis shows that Dominion over-forecasted its annual energy sales in every year.

This analysis is based on 2014 Company-derived peak load and energy forecasts. However on March 7, 2019, Dominion submitted a corrected and revised 2018 IRP Compliance Filing,[51] which contained PJM-based peak load and energy forecasts, replacing the Company-derived forecasts. The Public Staff performed a similar forecast review, as shown in Table 7 below. The analysis is comprised of three predictions from Dominion's 2018 IRP Compliance Filing, and show an average error of -347 MW.

[51] 2018 Dominion Integrated Resource Plan – Virginia Corrections and Revisions Compliance Filing, Docket No. E-100, Sub 157, March 7, 2019.

Table 7: Accuracy Analysis of Dominion's 2018 IRP Compliance Filing

Date	Actual	2018 IRP Forecast	Difference	% Difference	Absolute % Difference
7-Jan-18	17,792	16,513	(1,279)	-7.2%	7.2%
22-Jan-19	16,842	16,696	(146)	-0.9%	0.9%
20-Jul-20	16,356	16,739	383	2.3%	2.3%
		Average	(347)		3.5%

Source: Dominion Compliance Filing, Docket No. E-100, Sub 157, March 7, 2019, at 14.

The Public Staff made a similar review of the PJM-based 2018 energy sales forecast, which showed a 0.7% MAE, which reflects an improved level of accuracy.

The Public Staff concludes from its review that Dominion's revised peak load and energy sales forecasts are reasonable for planning purposes. As stated above, the 2014 forecast was developed entirely by Dominion, as opposed to the 2020 forecast, which was initially developed by PJM and later adjusted by Dominion as ordered[52] by the Virginia State Corporation Commission (VSCC). The Public Staff's analyses indicate that the PJM-based peak demand and energy forecasts based on the 2018 IRP Compliance Filing appear to be more accurate than the Dominion-only forecast, and thus the Public Staff supports the continued use of PJM-based forecasts. The observed growth in winter peaks may represent an increased saturation of electric space heating, as compared to other heating sources (such as gas, oil, or propane). The Public Staff notes that this growing dominance of morning winter peaks observed in Dominion's service territory is a concern. As such, the Public Staff recommends that the Company continue to monitor this development. In addition, the Public Staff recommends that in the

[52] Order, *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq*, No. PUR-2018-00065, at 6-8 (V.S.C.C. Dec. 7, 2018).

future, Dominion weather-normalize its winter and summer peaks, with the expectation that this effort will lead to a better understanding of the cause(s) of the growth of the winter peaks.

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

OVERVIEW

The Public Staff's review of the DSM/EE forecasts and programs indicated that DEC and DEP complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. The Companies included information about their respective DSM and EE portfolios that is similar to the information reported in the 2019 IRP updates. DEC and DEP appropriately addressed the changes in their respective forecasts of DSM and EE resources and the peak demand and energy savings from those programs. DEC's projected EE savings 16.7% lower than the 2018 IRP. DEP's projections were 8.2% lower. The reasons for those changes are more fully explained below. Dominion's forecasted EE savings are substantially greater than their 2018 due to the statutory requirements of the VCEA. Dominion is also impacted by the same trends in EE as Duke, however, the significance of the VCEA and how it is driving Dominion's EE potential cannot be underestimated.

As the Public Staff has noted in each IOU's DSM/EE rider proceeding in the last few years, as well as in previous IRP comments, several factors continue to weigh on the Utilities' ability to develop and implement cost-effective EE programs. The DSM/EE rider proceedings have also seen other intervening parties raise concerns about the way cost-effectiveness is determined and whether non-energy benefits should be included in the cost-effectiveness analysis when approving new programs and for program continuation purposes.

Other institutional and regulatory barriers make it difficult for IOUs to develop EE programs related to the building envelope for fear of creating adverse conditions for other utility sectors, like natural gas. Greater efficiency could be achieved through comprehensive EE programs that encompass all utility sectors, specifically electricity and natural gas efficiencies.

Toward the end of 2019, and as noted in recent DSM/EE Rider proceedings, new federal lighting standards were withdrawn. These changes were expected to take effect January 2020 and may influence the baseline of future lighting measures.[53] Duke has already taken necessary strides to acknowledge this transition as it has begun limiting the use of standard LED bulbs to certain programs and utilizing specialty LED bulbs across most of its portfolio of EE programs.

In addition, recent decreases in the Utilities' avoided costs have decreased the value of avoided energy and capacity benefits generated from DSM/EE programs, making it more difficult to design and implement new cost-effective programs, as well as to maintain the cost-effectiveness of existing programs. Other technologies such as space heating/cooling and building envelope measures will continue to face similar headwinds.

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[53] The Public Staff anticipates that these standards originally slated to take effect January 2020, will reemerge soon once the Biden Administration completes its review of the federal lighting standards.

The Public Staff believes the greater emphasis on EE nationwide is focusing the development of EE programs and initiatives originating outside of utility-sponsored programs. These EE savings are being incorporated into the load forecasts used by each Utility to develop its IRP. While difficult to measure, load forecasts are being influenced by many factors related to EE such as: the "roll-off" of utility EE savings[54], more efficient appliance and lighting standards, more efficient heating and cooling equipment, more stringent efficiency standards in building and energy codes, large commercial and industrial customers adopting EE on their own, and consumer preference for efficiency. The impacts of EE embedded in the load forecasts will continue to challenge the Utilities to design and implement cost-effective EE programs that result in additional EE savings. The Public Staff believes that EE has contributed to the lower sales growth rates identified in the Utilities' IRPs, and that the impacts of EE on load forecasts are likely to continue in the near future.

Energy and capacity savings derived from initiatives other than utility sponsored programs will continue to grow as more data is made available to customers. DEC has recently completed the majority of its vast Advanced Metering Infrastructure (AMI) deployment, with DEP planning to have the majority of its service territory completed over the next year. IOUs are currently building the systems necessary for customers to be able to analyze their own data in near real-time.[55] In addition to technology advancements, IOU's and intervenors, including

[54] Duke defines "roll-off" EE savings as savings from measures that have reached the end of their measure lives. Such savings are removed from the Duke's EE savings forecast.
[55] Nearly real-time for the purpose of a customer analysis is meant to reflect 15, 30, and 60 minute intervals.

the Public Staff, have been working to amend certain Commission Rules that will apply to this new technology. The Data Access rules modifications, which are still pending before the Commission in Docket No. E-100, Sub 161, are seeking to remove some regulatory hurdles involving how data is shared between a utility, its retail customers, and third parties who desire access to customer usage data.

This advancement in data acquisition and application provides a far better opportunity for customers to make their homes or workplaces operate more efficiently, as opposed to the previous method where customers would see their total monthly usage 30 to 45 days after the energy was consumed. Quicker access to usage data in real time also provides customers with insight about the operation of electrical equipment. For example, the Public Staff is aware of customers using this usage information to learn of well pump and HVAC equipment that was failing and make repairs before longer-term increased usage occurred. This more contemporaneous access to usage data allows customers to take steps sooner to address high energy usage situations.

The desire for access to usage data and the availability of near real time access to that data is becoming popular, not only in North Carolina, but across the country, as other utilities are beginning to modernize and digitize their normal business operations to provide customers with a new way of interacting with their utility. Customer awareness and expectations of utility operations are increasing as customers express a stronger desire for information and the ability to use that information as they see fit. It should be expected that more natural efficiencies in utility operation will be coming in the future through other aspects of utility service, such as the installation and configuration of modern distribution and transmission equipment to allow for new power flow capabilities, more comprehensive rate designs, and further distribution of customer analytics for the customer's use. This natural growth will have the potential to provide customers with benefits through modernization of typical utility functions. These natural efficiencies, if determined to be prudent and reasonable, should be considered part of a utility's natural growth in the electricity sector and not part of a Company's DSM/EE portfolio, where they have the potential for financial incentives for an initiative that other utilities are adopting with or without incentives, as the need for better data grows.

Dominion has not initiated a mass AMI deployment similar to those of DEC and DEP.[56] The Public Staff anticipates that if Dominion received approval from the Virginia SCC for deployment of AMI, then, as discussed above, other natural efficiency initiatives could follow as Dominion starts to address the expectations of its customer.

DEP's EnergyWise program offers a limited DSM program for controlling water heaters and strip heat on heat pumps in its western service area. While DEC's IRP indicates that it does not offer any residential DSM program that can be used during winter peaking events, it has recently been granted approval of a new winter-focused residential DSM program.[57] Similar to DEC, DEP was also

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[56] Dominion Energy Virginia has requested permission to deploy AMI meters in its Virginia territory on two different occasions and has been denied due to its lack of cost-effectiveness both times.

[57] Order Approving Program Modifications, *Application by Duke Energy Carolinas, LLC, for Approval of Modifications to Residential Power Manager Load Control Rider*, No. E-7, Sub 1032 (N.C.U.C. Oct. 13, 2020).

recently granted approval of a new winter-focused residential DSM program that was not included into the forecast of this IRP.[58] A Winter DSM program study is discussed in more detail later in these comments.

The Public Staff's review also noted the portfolio level energy savings in this IRP, when compared to the Utilities' 2019 Updates, continue to indicate a decrease in the amount of energy savings from their respective portfolios. The Utilities illustrated how EE-related savings are produced through their respective portfolios of EE programs over the measure lives of each program. At the end of each measure's life, the Utilities assume that a customer will replace EE measures with other measures that are as or more efficient than the measures being replaced. Those savings will continue in the form of reductions to the load forecast. This process is explained by the Utilities and designated as historical savings ("roll-off" savings). New measures would be separately identified and incorporated into the load forecast tables as new savings.

MARKET POTENTIAL STUDY

DEC and DEP both provided an updated Market Potential Study (MPS or Study) as Attachment Five to their respective IRP filings. The study spans the 2020-2044 timeframe and is an update to the previous MPS study that was performed by both utilities in 2016. The results of this Study have been incorporated into the DSM/EE forecast projections included in both DEC's and DEP's IRPs.

[58] Order Approving Program Modifications, *Application by Duke Energy Progress, LLC, for Approval of Modifications to Residential Service Load Control Rider* , No. E-2, Sub 927 (N.C.U.C. Oct. 13, 2020).

The Public Staff contracted the services of GDS Associates, Inc. (GDS) to assist with the review of this MPS. GDS has actively been a part of the Public Staff's review of the Evaluation, Measurement, and Verification processes of DEC, DEP, and Dominion over the last several years, as well as assisting the Public Staff in previous MPS reviews. The review of the MPS involved a combination of generating discovery requests, reviewing the responses, and having meetings with pertinent parties to discuss the MPS. Based upon the GDS investigation, the Public Staff has the following comments.

The MPS includes four specific components of market potential: (1) defining the list of measures to be included in the Study; (2) determining the Technical Potential for each measure; (3) determining the Economic Potential; and (4) determining the Achievable Program Potential.

Measure List Determination

The Study defined the measures that would be included by conducting a screening process. Measures that were not cost effective for Duke were not included in the ultimate results of the Economic and Program potential. Additionally, the Study also excluded measures that were determined to be difficult to offer as cost-effective program measures. These exclusions were due to concerns regarding Net-to-Gross factors and market transformation. Examples of these measures include a number of Energy Star appliances and devices such as desktop computers, blue-ray players, and set-top receivers for televisions.

It was noted by GDS during the review that the Measure list appeared to have instances where more measures could have been included in the Study if a more comprehensive approach had taken place. For example, the Study seems to leave out measures such as heat pump water heaters, which can provide long term savings to customers; but were omitted from the Study's final results because the program is not cost-effective. Instead of allowing individual cost effective measure variations that could produce additional savings to be included in the Study, a holistic program approach was utilized. Nevertheless, for purposes of this MPS, the list of measures included in this Study appear to be reasonable.

Technical Potential

Technical Potential is defined as the estimate of savings potential when all technically feasible EE measures are fully installed. Technical Potential can be considered the maximum reduction attainable with available technology and current market conditions.

This section is designed to provide an overview of the Technical Potential by sector for both DEC and DEP, and is represented in Tables 5-1 and 5-2 of the MPS, respectively. For DEC and DEP, the technical potential by 2044 was determined to be more than 15,000 GWh for DEC and 10,000 GWh for DEP, which represents 32% and 34%, respectively, of the 2044 forecasted sales.

Based on a review of other recent potential studies across the country, the savings represented in Tables 5-1 and 5-2 appear to be reasonable.

Economic Potential

Economic Potential compares the expected costs and benefits of energy and demand savings provided by EE and DSM measures and applies the total resource cost (TRC) test to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1.00.

This section is designed to provide an overview of the Economic Potential by sector for both DEC and DEP, and is represented in Tables 6-2 and 6-3 of the MPS, respectively. For DEC and DEP, the technical potential by 2044 was determined to be 5,992 GWh for DEC and 3,414 GWh for DEP, which represents 13% and 11%, respectively, of the 2044 forecasted sales.

Based on a review of other recent potential studies across the country, the savings represented in Tables 6-2 and 6-3 appear to be lower than other studies, with an average Economic Potential of 25% of forecasted sales. The lower than average economic potential is likely due to the lack of a comprehensive measure list, as previously discussed.

Achievable Program Potential

Achievable Program Potential is the subset of economic potential describing EE and DSM measure adoption by customers participating in utility-sponsored programs operating within the subject market or jurisdiction. The Achievable Program Potential estimates the share of customers that may choose to participate in utility-sponsored programs.

This section is designed to provide an overview of the Achievable Program Potential by sector for both DEC and DEP, and is represented in Tables 7-6 and 7-8 of the MPS, respectively. For DEC and DEP, the Achievable Program potential by 2044 was determined to be more than 623,693 MWh for DEC and 351,859

MWh for DEP, which represents 1.31% and 1.28%, respectively, of the 2044 forecasted sales.

The savings represented in Tables 7-6 and 7-8 appear to be lower than average, with a review of other potential studies across the country having an average percentage of achievable potential of 10.9% of forecasted sales.

A major challenge in the review process for this MPS compared to other potential studies was the absence of a stand-alone Achievable Potential scenario. This Study translated the Economic Potential immediately into a "Program Potential" that is not typically identified in market potential studies. It was noted by DEC and DEP that all of the cost effective offerings that passed the initial Measure List screening are already part of DEC's and DEP's current EE portfolios. In other words, this equates Achievable Potential with Program Potential and suggests that much of the potential going forward is already present in the current EE portfolios. However, Program Potential inputs, which are representative of performance, budget, and planning constraints, are based on historical data. These constraints are not the same as those observed in typical achievable potential calculations, since those calculations rely on market research to gauge customer awareness and a customer's willingness to adopt EE measures in the future. DEC and DEP's use of historical program participation data in their Achievable Potential is a primary reason for the lower than average results when compared to other studies.

Conclusions

The results of DEC and DEP's MPS provide an insight into the DSM/EE potential in North Carolina and will provide planning data to inform future program development. However, the Public Staff would recommend that future market potential studies consider a more comprehensive list of measures that can contribute and provide a more accurate picture of North Carolina's Achievable Potential.

The Public Staff believes that the results of this Study should be considered acceptable and reasonable for purposes of inclusion into DEC's and DEP's IRP filings.

WINTER DSM

In addition to the Market Potential Study discussed above, Duke engaged with Tierra Resource Consultants to look at winter peak and potential solutions for both its North and South Carolina service territories. Duke, in conjunction with its consultant, provided in discovery three reports that were produced in late December 2020 to reflect their findings.

The analysis of Duke's Winter DSM study was broken down into three reports:

A Winter Peak Analysis and Solution Set report that looks at various aspects of peak and outlines some potential behind-the-meter solutions. This first report defined the pertinent data related to winter DSM for this region along with market characteristics and information from the market potential study and load forecast.

A Winter Peak Demand Reduction Potential Assessment report that assesses the impact of select rate designs in combination with the behind-the-meter solutions. This second report introduced the modeling methodology utilized to identify and characterize new rate structures and mechanical solutions. The winter peak DSM potential assessed the ability of behavioral measures, equipment controls and industrial and commercial curtailment to reduce Duke's overall system peak in each system.

A Winter Peak Targeted Reduction Plan report that further details the programs that might be used to implement these solutions. The final report defined the customer centric winter peak solutions that can be used to address peak load issues starting in the 2020/2021 winter peak season. Additionally, it provided a roadmap for solutions that can be added to the portfolio in the intermediate term, such as advanced rates that effectively aggregate and optimize the impact of grid interactive distributed energy resource (DER) assets. This report presented a strategic framework and plan for developing a focused solution set of customer programs that drive targeted EE/DR/Flex DER load shape savings impacts to solve near term and longer-term winter peak challenges.

Since these reports were completed and provided to the Public Staff in late December of 2020, the Public Staff's initial comments based upon its preliminary review of the primary eleven findings are below.

The Public Staff notes that these reports incorporate traditional DSM/EE measures, non-traditional measures, and rate schedule and tariff-based DSM opportunities to provide increased winter peak reduction opportunities.[59]

[59] These efforts are a culmination of the Companies' means of tackling the winter peak. While some traditional DSM/EE measures are handled and reviewed through the Companies' DSM/EE rider proceedings, others like the non-traditional DSM/EE measures and the rate schedules and tariff-based DSM opportunities are handled during general rate cases.

The Public Staff believes that Duke has already started tackling the “low hanging fruit” for residential winter DSM potential through its winter-focused smart thermostat programs that were recently approved by this Commission in Docket Nos. E-2, Sub 927, and E-7, Sub 1032.

The Utilities recover the costs of DSM/EE on an annual basis pursuant to North Carolina General Statute. Because this report covers a variety of modes to deal with the winter peak, the differences between traditional and non-traditional measures and rate schedules should be noted in dealing with future opportunities.

DUKE DSM AND EE

DEC's and DEP's portfolios of EE programs are not materially different from those in their 2018 IRPs and 2019 IRP updates. DEC and DEP continue to align the structure, incentives, and participant qualifications of their respective DSM and EE programs. Both utilities have received Commission approval to offer the same new programs, and modify existing programs to make them more consistent or address performance issues.

The Public Staff notes that as observed in the last few DSM/EE rider proceedings, Duke’s portfolios continue to shift the source of EE savings away from lighting measures and toward behavioral programs like the “My Home Energy Report.” Additionally, winter focused measures such as the recently approved smart thermostat – winter focused DSM are beginning to be offered. It is also worth noting that neither DEC nor DEP used any of its DSM resources during the summer or winter peaks in 2020. Table 8 and Table 9 below summarize the system peaks and DSM activation at peak for DEC and DEP, respectively.

[BEGIN CONFIDENTIAL]

Table 8: DEC DSM Peak Activation Information

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 9: DEP DSM Peak Activation Information

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

DOMINION DSM AND EE

Dominion's portfolio of EE programs has continued to develop since the 2019 IRP update. Dominion's portfolio relies heavily on the DSM and EE portfolio associated with its Virginia jurisdictional operations and the decisions made by the Virginia SCC regarding that portfolio. Dominion has worked with the Public Staff to evaluate whether any of the programs that are cancelled in Virginia can continue to be offered on a North Carolina-only basis. When a program can be offered cost-effectively even in the short term, Dominion has requested approval from the Commission.

Recent legislation, such as the VCEA, has had a major influence on Dominion's DSM and EE portfolio in Virginia, which redounds to the North Carolina service territory. While this recent legislation is an expansion of the GTSA, VCEA provides further guidance on future EE and the general direction that Dominion pursues with DSM and EE deployment.

In Dominion's most recent filing with the Virginia SCC for new DSM and EE programs, it proposed a portfolio of 11 new programs with a spending projection of approximately $262 million over the next five years. Dominion's 2020 IRP includes impacts from all 11 programs; however, not all 11 are available options in its North Carolina service territory. Dominion has stated in its program approval filing with the Virginia SCC that it intends to apply this spending toward the $870 million target identified in the GTSA.

The Commission has recently approved six of the 11 Virginia-approved DSM and EE programs. The remaining five programs not filed in North Carolina either did not meet cost effectiveness requirements or were part of a Virginia-focused program created as a result of legislation.

The Public Staff further notes that Dominion has initiated an EE stakeholder process as required by the GTSA. Meetings have been held and are likely to continue for the foreseeable future, with the intent on bringing interested parties together, including the Public Staff, to discuss how EE can be implemented in Virginia.

In regard to DSM activations during its 15 highest peak loads from July 2019 through August 2020, Dominion activated its Residential AC Cycling program nine times and its Distributed Generation program 13 times over the 15 highest peak demands.Table 10 below summarizes Dominion's DSM activation at peak.

Table 10: Dominion DSM Peak Activation Information

	2019 Summer Peak Demand	2020 Winter Peak Demand	2020 Summer Peak Demand
Date and Hour Ending	7/20/19 6pm	1/21/20 8am	7/20/20 5pm
MW Load	16,599	14,661	16,356
MWs Reduced by DSM	0	0	64
Operating Reserve (%)	16%	31%	19%
Dom Zone LMP $ per MWH	$54.27	$34.27	$78.00

RESERVE MARGINS AND RESOURCE ADEQUACY

A reserve margin is generally defined as:

Reserve Margin = (Resources – Demand) / Demand

The "margin" is necessary to ensure that adequate capacity is available to meet the system's needs at peak load, while allowing for scheduled and unscheduled maintenance, higher than expected load growth, operational limitations based on environmental constraints, variance in load due to extreme weather, transmission availability, and disruptions in power supply resulting from noncompliance with purchased power agreements. Once a reserve margin target has been established, utilities build enough capacity to meet the forecasted peak demand plus the reserve margin.

There are different methods used to estimate reserve margins. One of the more common methodologies is a Loss of Load Expectation (LOLE) analysis, where the utility's system is modeled in a particular year or range of years. The model inputs include load forecasts, expected load forecast error (LFE), expected weather, generator outages, neighbor assistance, and output from intermittent energy sources, among other inputs. The model then simulates system operations – often thousands of times – to determine when, and how often, a firm load shed event will occur.

The reserve margin can be adjusted by adding or removing peaking resources, such as combustion turbines (CTs), until the overall probability of a firm load shed event (referred to as the LOLE) is 0.1 events per year, a common industry standard. While not as common, the 0.1 LOLE standard can also be expressed as 2.4 hours per year, assuming the LOLE model can also calculate Loss of Load Hours (LOLH). Both LOLE and LOLH standards are sometimes referred to as a physical reliability reserve margin, as the LOLE standard of 0.1 events per year is chosen arbitrarily and is not based on evaluating trade-offs between the cost of adding new generation and the cost of a firm load shed event.

Some utilities and organizations[60] have also studied the use of an economic optimal reserve margin (EORM), which typically will use the same or similar modeling techniques as the LOLE method. However, instead of setting a target LOLE and adjusting the reserve margin to meet it, the study assigns a cost of adding new incremental peaking capacity, and also assigns additional system costs to high demand days, such as scarcity pricing for energy imports and, should there be insufficient capacity to meet load, assigns a cost of unserved energy (referred to as the value of lost load (VOLL)). The model will then find the optimal point at which the marginal cost of adding new capacity to increase the reserve margin is equal to the marginal cost of emergency power imports and unserved energy. This EORM thus represents the reserve margin at which ratepayers pay the least costs to maintain system reliability, with the understanding that a component of those costs might include increased firm load shed events.

In its final order on the 2018 IRPs, the Commission expressed an interest in learning more about both the LOLH physical reliability standard and the economic optimal reserve margins.[61] On November 4, 2019, DEC, DEP, and the Public Staff filed responses to Appendix A of the 2018 IRP Order, providing further

[60] For example, in its 2019 IRP, Southern Company produced "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System," which utilized the same Astrapé SERVM model to estimate economically optimal and risk adjusted reserve margins.

In 2018, ERCOT produced a study, by and through the Brattle Group and Astrapé, to estimate economically optimal reserve margins.

[61] Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, *2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans,* Docket No. E-100, Sub 157, at 87-89; Appendix A, (N.C.U.C. Aug. 27, 2019). (2018 IRP Order)

justification for the 17% reserve margin proposed by Duke and providing additional context into the use of LOLH and EORM. In its responses, Duke stated that it agrees that utilities "generally enforce a reliability standard without evaluating its economic implications," and that it believes "that the reserve margin determined by the 1 day in 10-year standard was reasonable when studied under an economic framework."[62] Based on the 90th percentile EORM,[63] Duke found that "there was benefit to having reserve margins slightly higher than the 17% winter target that met the 1 day in 10 year standard." [64] With regard to using an LOLH standard of 2.4 hours per year, Duke stated that it was much less stringent than the 0.1 LOLE standard, as one event typically lasts 3-4 hours.[65] While the Public Staff generally agrees with these statements, the choice of what percentile to use to establish the EORM is a matter of judgment and policy. In addition, there is additional uncertainty when calculating the EORM, because the modeler must input a VOLL as well as a scarcity price curve for energy imports during periods of high demand, parameters that are highly subjective.[66]

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[62] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions (Duke Response), No. E-100, Sub 157, at 14, November 4, 2019.

[63] As discussed later in these comments, the 90th percentile EORM is a "risk-adjusted EORM", as opposed to a "risk-neutral EORM". The latter is the EORM when planning for the "median" scenario where weather and other factors are at the expected value. The 90th percentile EORM assumes that some low-probability, high-impact events (such as an extremely cold weather year) will occur.

[64] Duke Response at 14.

[65] *Id.*

[66] In DEP's and DEC's Grid Improvement Plan (GIP), proposed in their 2019 rate cases, there was significant debate over the cost-per-outage figures used to justify reliability improvements. VOLL is similar to the cost per outage, except it is expressed as dollars per MWh.

In the 2020 IRPs, as in the 2018 IRPs, the Utilities all rely upon reserve margins established through an LOLE study. Dominion relies upon PJM's annual reserve requirement study,[67] and Duke relies upon Astrapé to perform modeling specific to the Duke territories. Based on these studies, Dominion's target reserve margin is 15.1% in 2021, 14.9% in 2022, and 14.8% through 2035. DEC and DEP both utilized a target reserve margin of 17% in all planning years.

<u>DUKE ENERGY'S RESOURCE ADEQUACY STUDY</u>

Duke's 2020 IRPs discuss the reserve margin targets established for planning purposes, which are based upon the 2020 resource adequacy studies performed by Astrapé (Resource Adequacy Study).[68] Both Companies used a 17% reserve margin for planning purposes. This study was an update to the 2016 resource adequacy study presented during the 2016 IRP in Docket No. E-100, Sub 147. In the 2018 IRP proceeding, the Public Staff commented on Duke's recommended 17% reserve margin, stating that:

> The Public Staff agrees with the Companies that there are several modeling and market assistance assumptions that need to be revisited in the next resource adequacy study. At this time, with the information currently presented, the Public Staff continues to recommend a 16% reserve margin, but will work with the Companies to reach consensus within the constructs of the next resource adequacy study.[69]

During the interim period, Duke reached out to interested stakeholders and began a series of stakeholder meetings to discuss the inputs, methodology, and

[67] Dominion bases its 2020 reserve margin targets on the 2019 PJM Reserve Requirement Study.
[68] DEC and DEP IRPs, Attachment III.
[69] Comments of the Public Staff, No. E-100, Sub 157, at 46-47, March 7, 2019.

underlying assumptions for the 2020 Resource Adequacy Report. Participants in the stakeholder meetings included the Public Staff, the South Carolina Office of Regulatory Staff, and the North Carolina Attorney General's Office.

The Resource Adequacy Study utilized proprietary software, SERVM, which is a reliability-based probabilistic[70] model that simulates the operation of DEC's and DEP's electrical systems over the course of a single year (in this case, 2024). Based upon existing and planned generation, load forecast error, stochastic weather forecasts, renewable output, and expected generator outages, the model predicts the loss of load probability (LOLP) on an hourly basis, allowing Duke to understand when firm load shed events are most likely. The LOLP translates into a seasonal LOLE, which is affected by the model's reserve margin. Astrapé adjusted the reserve margin by adding or subtracting peaking generation resources until the model predicted a LOLE of 0.1 events/year, which is equal to one event per 10 years, a standard common in the industry. The reserve margin that resulted in a LOLE of 0.1 events/year was 16.0% for DEC, 19.25% for DEP, and an average of 16.75% for the combined companies.[71] Astrapé recommended that both companies use a 17% reserve margin for planning purposes, which is unchanged from the 2016 resource adequacy study.

[70] A probabilistic, or stochastic, model is one that incorporates uncertainty. This is in contrast to a deterministic model, in which inputs with high levels of uncertainty (such as load or solar generator output) are treated as if they are known and invariable throughout the model run.

[71] The combined model run simulated DEC and DEP as a single entity, able to share capacity to meet shortfalls. In all cases but for the island sensitivities, DEC and DEP were able to rely upon external market assistance.

As in 2016, Duke also included an analysis of the EORM for the DEC and DEP territories. As summarized in the Resource Adequacy Study, the risk-neutral EORM represents the reserve margin that is economically optimal in an "expected" scenario – in other words, the scenario representing the 50th percentile of all scenarios. However, events rarely play out as expected, and a particularly cold year or particularly frequent generator outages can result in extremely high costs to meet demand. In the long run, ratepayers may end up benefiting more from a slightly higher reserve margin by paying up front for additional generating capacity, but potentially saving far more should an unseasonably cold winter occur. To determine the risk-adjusted EORM, Astrapé arbitrarily chose the 90th percentile of all scenarios as the planning scenario, and then calculated the associated EORM that minimizes total system costs.[72]

As a result of stakeholder input, a wide range of sensitivity analyses were developed and performed by Astrapé to test the impact of various assumptions, and minor changes to load forecast error distribution were implemented in the base case to increase the probability of over-forecasting load. These sensitivities were modeled and results generated for both the LOLE reserve margin and the risk-neutral and risk-adjusted EORM. Sensitivity analyses were provided for the following inputs:

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[72] Other utilities have utilized various risk-adjustment factors. In 2019, TVA utilized a 90th percentile risk-adjusted EORM (https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan) and in 2019 Southern Company utilized an 80th percentile risk-adjusted EORM (https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=0c1c663d-88b0-4572-85b7-0f9a0f162125).

- Island sensitivity (no neighbor assistance)
- Cold weather outages
- Load forecast error distribution
- Solar penetration
- Costs of CT; costs of imports; cost of unserved energy (EUE)
- Winter demand response equal to summer demand response
- Retire all coal
- Impact of climate change on load shapes and peak load
- Combined sensitivity (DEC and DEP as single utility)
- Combined sensitivity with a 1,500 MW import limit

The results of the sensitivity analyses are shown in Table 11 below, and the individual scenarios are explained in more detail within the Resource Adequacy Study. These results help demonstrate the impact on the reserve margin of individual changes to specific parameters. Table 11 below summarizes the change from the base case reserve margin resulting from each scenario, highlighting these impacts.

Table 11: Resource Adequacy Study Results and Sensitivity Analysis

Scenario	DEC			DEP		
	LOLE	EORM		LOLE	EORM	
		Risk Neutral	90th %		Risk Neutral	90th %
Base Case	**16.00%**	**15.00%**	**16.75%**	**19.25%**	**10.25%**	**17.50%**
Island	22.50%			25.50%		
No Cold Weather Outages	14.75%	14.75%	16.75%	18.50%	9.50%	16.25%
Cold Weather Outages based on 2014 - 2019	17.25%	15.0%	17.00	20.50%	10.50%	17.75%
Remove LFE	16.25%	15.0%	16.0%	20.0%	10.50%	17.50%
Originally Proposed Normal Distribution	17.0%	16.0%	18.0%	20.25%	11.25%	17.50%
Low Solar	16.0%	16.0%	18.25%	19.25%	11.75%	17.50%
High Solar	15.75%	14.0%	14.50%	19.0%	9.50%	16.75%
CT costs 40$/kW-yr	16.0%	16.0%	17.25%	19.25%	12.50%	18.75%
CT costs 60$/kW-yr	16.0%	13.75%	16.0%	19.25%	6.00%	15.25%
EUE $5,000 /MWh	16.0%	14.50%	16.25%	19.25%	7.00%	13.75%
EUE $25,000/MWh	16.0%	15.25%	16.75%	19.25%	11.75%	19.25%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%	20.0%	12.50%	18.50%
Retire all Coal	15.25%	17.0%	20.25%	19.50%	11.25%	17.50%
Climate Change	15.75%	14.25%	16.75%	18.50%	9.75%	16.25%
Combined Target	16.75%	17.0%	17.75%			
Combined Target 1,500 MW Import Limit	18.0%	17.25%	18.25%			
Combined Target - Remove LFE	17.25%	17.00%	18.25%			

As the figure below demonstrates, the island sensitivity has the greatest impact on the reserve margin – treating DEC and DEP as wholly isolated utilities requires a significantly higher reserve margin than when they can rely on their neighbors. Under the LOLE reserve margin, the Public Staff notes that each individual change has a relatively minor impact – for example, even if all cold weather outages are removed, DEC and DEP would see a decrease of 1.25% and 0.75% in their required reserve margins, respectively. However, as the Public Staff noted in the Joint Report of the Public Staff, DEC, and DEP in the 2017 IRP proceeding (Reserve Margin Joint Report),[73] the cumulative effect of several of these sensitivities can result in a significant change to the reserve margin.[74]

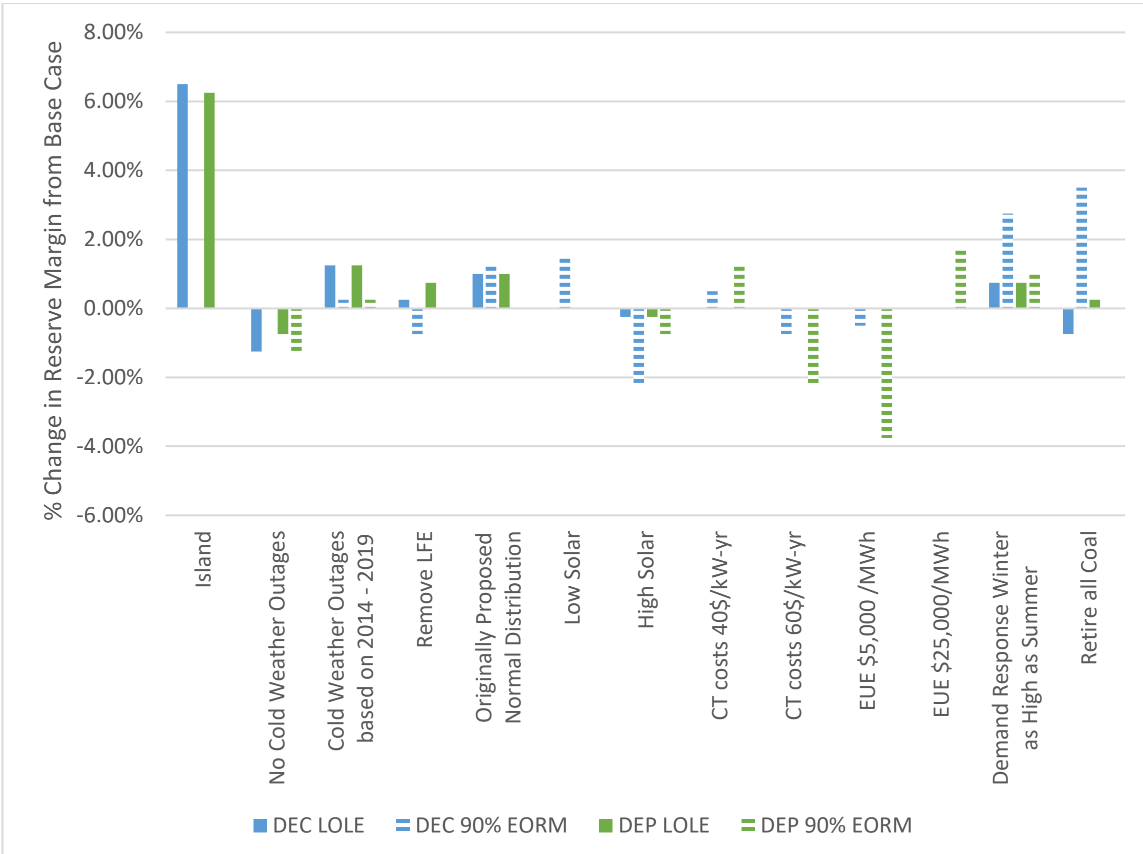

Figure 2: Impact Of Sensitivity Analyses on the Reserve Margins

In the Resource Adequacy Study, several of the Public Staff's concerns regarding the 2016 report were addressed, either in the base case or sensitivities. For example, Astrapé utilized a four-year LFE and, in response to stakeholder

[73] Joint Report of the Public Staff, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, No. E-100, Sub 157, April 2, 2018 (Joint Report).
[74] Joint Report at 9.

inputs, assigned a higher probability to over-forecasting.[75] In the base case, Astrapé also utilized outage data (including cold weather outages) from the 2016-2019 period, which reflects some of the winterization efforts made since 2014 and is an improvement over the 2010-2014 outage data used in the 2016 report.[76] Generally, the Public Staff believes the assumptions in the Resource Adequacy Study are adequate for planning purposes; however, the Public Staff notes that the effect of extremely low temperatures on load is still not well understood and recommends that Duke continue to utilize AMI data to improve this predicted relationship.

The Public Staff notes the efforts made by Duke to include the perspective of other stakeholders in updating its Resource Adequacy Study. The sensitivities are a useful way to look at the most impactful variables that influence required the reserve margin. The Public Staff also believes that there are potential operational benefits associated with treating the DEC and DEP systems as a combined system for the purposes of sharing reserves and firm capacity, notwithstanding the legal barriers that exist to such operation.

CAPACITY VALUES

In estimating the amount of existing generation and reserves necessary to meet load and account for uncertainty, the full capacity of traditional thermal

[75] In the Joint Report, the Public Staff recommended the use of two-year LFE data which placed a higher probability on over-forecasting than under-forecasting.

[76] In the Joint Report, the Public Staff recommended using the 2010-2014 outage data but removing the extreme cold weather outages. The use of 2016-2019 outage data largely alleviates the Public Staff's concerns.

resources are counted towards the necessary generation capacity – in other words, a 1,224 MW natural gas CC plant will provide 1,224 MW of capacity to meet the winter planning reserve margin requirements. This represents a capacity value[77] of 100%. However, intermittent and energy-limited resources such as wind, solar, and battery storage are not able to provide 100% of their capacity during peak demand periods or reliability events. This de-rate of nameplate capacity for intermittent resources reflects that utilities are not able to rely on the full capacity of intermittent resources. For example, the typical winter morning peak load in North Carolina is from 7am – 8am, when solar resources are generating only about 3% of their nameplate capacity.[78] In the 2018 IRP, the Public Staff discussed how Duke used a new Estimated Load Carrying Capability (ELCC) study for solar resources to arrive at a solar winter capacity value of approximately 1%.[79]

While the Public Staff still believes there is a mismatch between the typical capacity planning process (which plans for the peak load hour) and the ELCC study determination (which plans for the hour with highest loss of load risk), it is undeniable that utilities are increasingly relying on ELCC studies to determine the capacity value of intermittent resources.

Duke also filed a Storage ELCC Study[80] with the 2020 IRP. The Storage ELCC Study calculated the appropriate capacity value of standalone energy

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[77] The capacity value is different than the capacity factor of a resource. The former represents the percentage of a resource's nameplate capacity available during peak demand or reliability events. The latter is the ratio of actual energy produced to maximum energy that could be produced.

[78] *See* Initial Comments of the Public Staff, No. E-100, Sub 157, at 88, March 7, 2019.

[79] The winter capacity value for solar is instrumental in capacity planning, as Duke builds generation to meet winter load and reserve margin requirements.

[80] DEC and DEP IRPs, Attachment IV.

storage and solar plus storage resources, using the same model and assumptions as the Resource Adequacy Study and the 2018 Solar Capacity Value study. The model includes limits on energy storage charge and discharge, as well as imperfect foresight, which leads to suboptimal dispatch that more realistically models real-world charge and discharge behavior. The capacity value of storage and solar plus storage resources are determined by first calibrating the system to achieve 0.1 LOLE. Then, the storage or solar plus storage resource is added in blocks, which improves (decreases) the LOLE. Then, a "perfectly negative resource"[81] is added until the LOLE returns to 0.1. The capacity value is the ratio of the amount of storage or solar plus storage added to the amount of the perfectly negative resource added to return to 0.1 LOLE.

In the Storage ELCC Study, Duke modeled 2-hour, 4-hour, and 6-hour standalone storage in three different dispatch modes: (1) Preserve Reliability Mode, with full utility control with capacity reserved for loss of load events; (2) Economic Arbitrage mode, with full utility control, performing economic arbitrage but available for reliability events; and (3) Fixed Dispatch Mode, with no utility control and dispatch based on a fixed rate schedule. For standalone storage, Duke recommends the use of Economic Arbitrage capacity values in its IRP, based on the assumption that most energy storage will be in the form of utility assets. While capacity values are highest for Preserve Reliability Mode, Duke believes that this is largely academic, as batteries will typically not serve only a reliability function.

[81] The Storage ELCC Study adds a resource that produces a negative amount of energy in each hour. It has the effect of increasing load in every hour and is likely simpler to model.

For solar plus storage resources controlled by the utility, Duke recommends the Economic Arbitrage mode. For solar plus storage resources owned and operated by third parties selling their output to Duke, Duke recommends the Fixed Dispatch mode.

Generally, in Economic Arbitrage Mode, the capacity value of standalone storage depends upon several factors: (1) the amount of battery capacity (MW) on the system; (2) the duration (hours) of the battery; and (3) the amount of solar capacity on the system. The study found that generally, a longer duration battery and more solar capacity on the system results in higher storage capacity values. This is intuitive – a longer duration battery can meet a broader peak, and more solar on the system results in more "excess" energy that can be stored to meet that peak. On the other hand, more battery capacity on the system results in lower storage capacity values as the system becomes saturated with storage. In its capacity expansion models, energy storage is assigned a 95% capacity value for DEP and 90% for DEC.

The Public Staff finds the Storage ELCC Study reasonable for planning purposes and the result an improvement over the storage capacity values estimated in the 2018 IRP. The lack of perfect foresight and the choice of Economic Arbitrage with utility control is reasonable for standalone storage assets that will, under current regulatory structures, be expected to be utility assets. At this time, there is no available tariff for independent power producers to sell capacity and other services from a standalone energy storage system. The Public Staff also agrees that the Fixed Dispatch mode is appropriate for PURPA solar plus storage resources at this time. However, the Storage ELCC Study did find that the capacity value of third-party owned solar plus storage resources declined over time as the system characteristics changed, while the fixed rate schedule did not. Future Storage ELCC Study updates should consider the fact that PURPA facilities larger than 5 MW will have their rates and rate schedules renewed every five years, which should mitigate this reduced capacity value effect.

RESERVE MARGINS

The minimum reserve margins from the Astrapé and PJM studies are applied to the peak system load, and in some cases the actual reserve margin is significantly higher than the target reserve margin, due to the timing and discrete sizes of future resource additions, load growth, and unit retirements. For the planning period of 2021 to 2035, the range of reserve margins reported by the Utilities continues to be similar to those seen in previous IRPs. Planned reserves are presented below in Table 12. Under Plan B, Dominion expects that its reserve margin will fall to 11.8% in 2022, largely due to the retirement of Chesterfield 5 and 6 and Yorktown 3. The high reserve margins in the summer for DEP and Dominion do not necessarily indicate overbuilding, but rather the fact that both utilities have higher winter peaks than summer, and solar resources contribute less to winter peaks than summer. The use of peak system load for system planning is not new, but is relevant in the context of the capacity value of solar and storage resources.

Table 12: Reserve Margins

Electric Utility	Target Reserve	Minimum Reserve over Planning Horizon	Maximum Reserve over Planning Horizon
DEP[82]	17%	16.6%	32.3% (summer, 2027)
DEC[83]	17%	17.1%	25.3% (winter, 2021)
Dominion[84]	~15%	11.8% (summer 2023)	40.4% (summer 2035)

The Public Staff also tracks the actual operating reserves on the peak day each week for each Utility.[85] Figure 3 below shows this data for 2019. In 2019, DEP's average operating reserve was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; DEC's average operating reserve was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; and Dominion's average estimated operating reserve was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[86] Note that the minimum reserve margin as reported weekly for all three Utilities falls in the shoulder seasons of spring and fall, and is driven largely by planned unit outages and higher than expected load during the week.

DEC and DEP provide a historical list of minimum operating reserves in their IRP.[87] These operating reserves may vary from those reported weekly in the reserve situation reports.

[82] Portfolio B.
[83] Portfolio B.
[84] Plan B.
[85] Only DEC and DEP provide actual operating reserves in the weekly Reserve Situation Report. The Public Staff estimates the actual operating reserves for Dominion.
[86] Dominion's operating reserves occasionally fall below 0% throughout the year. In these situations, Dominion relies on imports from PJM to meet peak load.
[87] *See* DEC and DEP IRPs, Table 9-A.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 3: Actual Operating Reserves on Peak Day (2019)

[END CONFIDENTIAL]

<u>EXISTING SYSTEM RESOURCES</u>

<u>GENERATION AND TRANSMISSION</u>

The Utilities currently meet electric demand through open-market purchases of energy and capacity, long-term PPAs, and from a diverse portfolio of generation assets. Below are graphs of the current generation mix for each utility, including utility-owned assets as well as non-utility generation (NUG) and wholesale purchases:

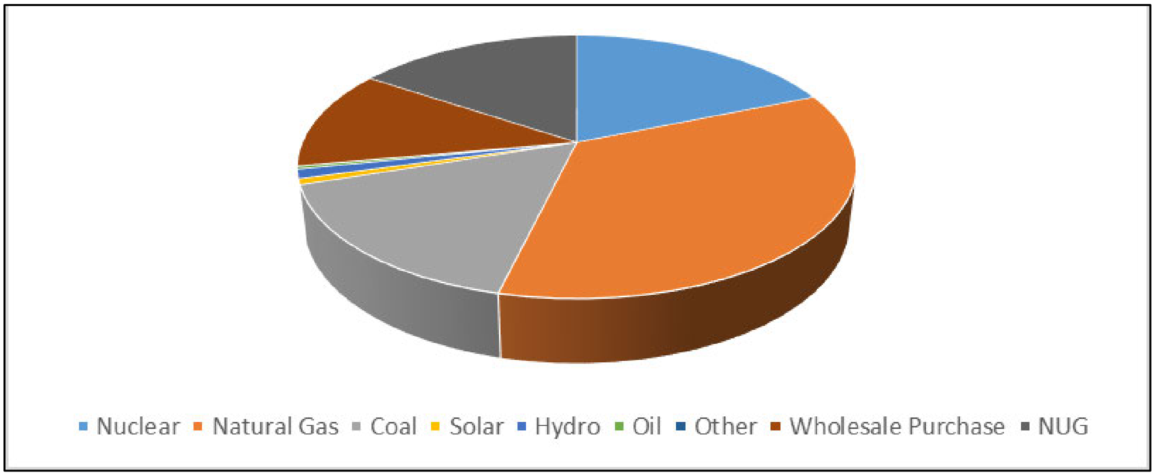

Figure 4: DEP Existing Generation Resource Mix (MW)

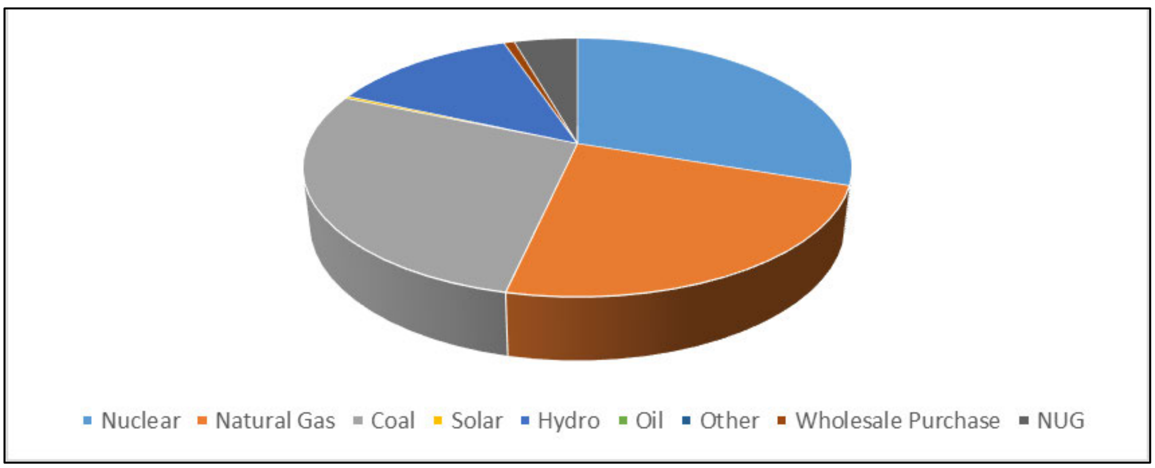

Figure 5: DEC Existing Generation Resource Mix (MW)

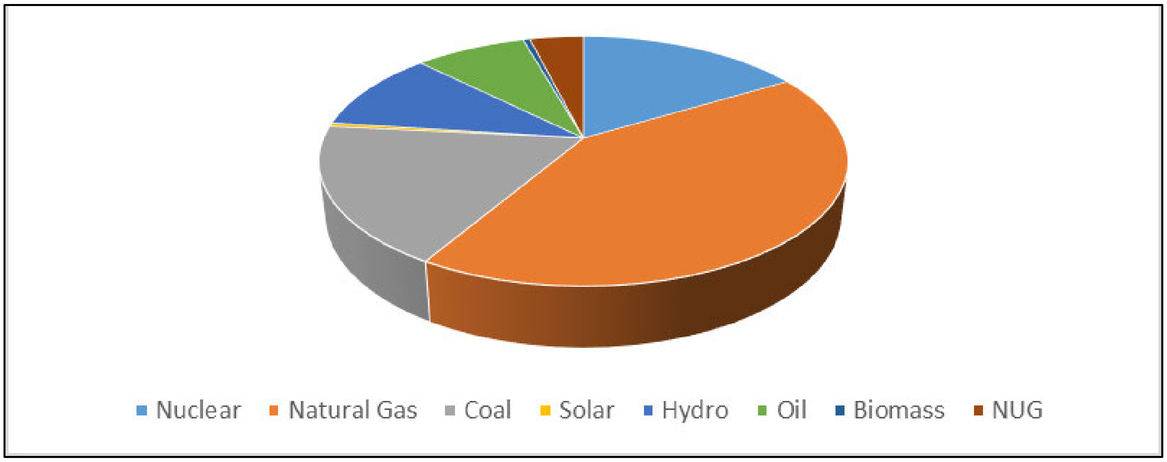

Figure 6: Dominion Existing Generation Resource Mix (MW)

FIRST CAPACITY NEED

In its 2018 IRP comments on DEC and DEP's IRPs, the Public Staff recommended that the Utilities include a statement of need defining the first year of capacity need for purposes of calculating avoided capacity payments.[88] The Public Staff recommended that this statement of need include the following information in order to ensure that the avoided capacity payment calculations accurately reflect system need:

1. The year in which the utility would fall below its planning reserve margin without commitment(s) to procure additional resources.
2. Whether QF contracts expiring within the avoided cost term are renewed or replaced in kind, or excluded.
3. Whether utility uprates are solely installed for additional capacity and if they could be considered avoidable.

[88] Initial Comments of the Public Staff, No. E-100, Sub 157, at 89-92, March 7, 2019.

4. Whether new EE measures are included in the determination of capacity need.
5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.
6. The year in which the utility's first avoidable capacity need becomes unavoidable.
7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Commission did not issue any specific directives related to the statement of capacity need in the 2018 IRP Order; however, the Utilities voluntarily provided these statements with some of the requested information.

DEC and DEP followed similar methodologies to define their respective first year of capacity need. Both Duke utilities use Portfolio B – Base Case with Carbon Policy as the basis for identifying the first year of capacity need. Duke then splits its future resources into three categories:

1. Designated resources – includes projects that are in service and have been granted a CPCN or Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN), unit uprates, firm market purchases for the duration of the contract, and DSM/EE programs. This

also includes existing wholesale contracts for the remaining duration of their PPA.

2. Undesignated resources – PPAs that have not been executed and projected resources in the planning portfolio that do not yet have a CPCN or CECPCN. Existing wholesale contracts are assumed to be replaced with undesignated resources at the end of their current PPA.
3. Mandated Resources – capacity that is required by legislation. In this IRP, this only refers to solar capacity required by legislation such as HB 589 and SC Act 236.

When determining the first year of capacity need for avoided cost purposes, only the designated and mandated resources identified above are included – the first year that undesignated resources are required to meet load is also the first year of capacity need. Notably, by replacing designated expiring wholesale contracts (including PURPA QF contracts) with undesignated resources, Duke recognizes that these QFs do provide needed capacity to the Duke system that can help defer future resource additions. The Public Staff believes that Duke has addressed each of our recommendations in the 2018 IRP related to the first year of capacity need.

The Public Staff would like to raise an additional issue for the Commission's consideration regarding the calculation of the first year of need related to the load reduction DEC expects from its Integrated Volt-Var Control (IVVC) program. IVVC is a part of DEC's GIP, and is included in DEC's Load, Capacity, and Reserves

Tables, providing approximately 174 MW of peak shaving capabilities by 2026.[89] However, in calculating the first year of need, DEC removed IVVC, essentially treating it as an undesignated resource. If IVVC had been treated as a designated resource, DEC's first year of capacity need for the purposes of calculating avoided capacity rates would be 2028.

Unlike utility-owned generation projects with a CPCN, or PURPA projects with an executed Interconnection Agreement, the Company has not committed to a timeline for the implementation of IVVC, nor included it as a designated load reduction resource to be used in calculating the first year of need. DEC argues that because the Commission has not yet issued an order in its general rate case regarding DEC's deferral accounting request,[90] DEC is uncertain as to the timing and level of deployment of the IVVC project over the three year GIP timeline. The Public Staff acknowledges that DEC takes the position that the pace of IVVC rollout might be significantly impacted or delayed if the deferral request is denied.[91] Due to this uncertainty, and the streamlined proceedings in Docket No. E-100, Sub 167, at this time, the Public Staff accepts the exclusion of IVVC from the calculation of the first year of need. The Public Staff's acceptance of this exclusion for purposes of this proceeding should not be taken as an admission on the Public Staff's part

[89] DEC IRP at 100.

[90] Docket No. E-7, Sub 1214.

[91] For illustrative purposes, DEC estimated that total GIP expenditures would be reduced by 80% over the three-year GIP period if deferral was denied. *See* the Joint Testimony of Jay W. Oliver and Jane L. McManeus in Compliance with Commission Order Requesting GIP Information, Docket No. E-7, Sub 1214, at 14, August 5, 2020.

that any potential delay in the implementation of IVVC, because of Commission denial of deferral accounting treatment, be considered prudent and reasonable.

As stated in the IRP, DEC will need 75 MW of undesignated resources in 2026,[92] and DEP will need 107 MW of undesignated resources in 2024.[93] These are the years of first need that are used in DEC's and DEP's initial statements and exhibits in the current Avoided Cost proceeding, Docket No. E-100, Sub 167.

On September 1, 2020, Dominion filed its Statement of Capacity Need as addendum 4 to its 2020 IRP. This document stated that Dominion's first undesignated capacity need is in 2023 in accordance with Figure 2.1.1 of Dominion's IRP. This capacity need is determined inclusive of DSM and EE measures. Generators under construction are considered to be included in the existing resources. In addition, Dominion assumes that existing NUG contracts expire at the end of their contractual term, removing that capacity from the determination of first capacity need.[94] Dominion does not have any unit uprates planned over the IRP planning horizon. Dominion has identified a system-wide capacity gap of 1,643 MW in 2023.

IRP PORTFOLIOS

Both Dominion and Duke present several portfolios or alternative plans in their IRPs. These plans are intended to demonstrate the impact of various policies

[92] DEC's first capacity need in the 2019 IRP was also in 2026.
[93] DEP's first capacity need in the 2019 IRP was in 2020. This has been shifted back due to the executed contracts procured through an RFP solicitation in the fall of 2018.
[94] Dominion IRP at 82.

and carbon reduction goals – for example, Duke's Portfolio A is the least-cost plan that complies with existing law; Portfolio B is the same, except it includes a federal CO_2 tax. Dominion provides a Plan A which is a true "least cost" plan, not complaint with the VCEA, but presented for comparison purposes; Plan B and B19, least-cost portfolios complaint with the VCEA, except for the requirement to retire all carbon-emitting generation by 2045.[95] The other plans put forth by the Utilities, as well as the planning assumptions that drive them, are discussed in more detail below.

PLANNING ASSUMPTIONS

Certain variables in the resource planning process significantly affect determination of the least-cost resource scenarios. Four of these variables significantly affect the PVRR for the alternative resource scenarios, and, ultimately, the potential costs that customers will pay:

- Projected price for natural gas.
- Capital cost and operating characteristics of new generation.
- Assumptions regarding Subsequent License Renewables for existing nuclear plants.
- Planned unit retirements in the planning horizon.

[95] Plan B19 is the same as Plan B, but solar resources have a capacity factor of 19% compared to 25%. In its Final Order, *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, No. PUR-2018-00065, at 11-12, (VA.S.C.C. Jun. 27, 2019), the Virginia SCC ordered Dominion to use "the actual capacity performance of Dominion's Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and 25%." As discussed earlier, the VCEA mandates the retirement of all carbon emitting generating resources located in the Commonwealth by 2045, unless the Virginia SCC finds that a given retirement would threaten the reliability and security of electric service (Dominion IRP at 10.)

Natural Gas Prices

DEC and DEP relied upon ten years of forward natural gas prices from 2021 through 2030 as the support for their natural gas price forecast. Starting in 2031 and through 2034 their price forecast was derived by the blending of forward natural gas prices with a fundamental forecast from IHS Markit, Inc. and for 2035 and beyond, the Company relied solely on its Fundamental Forecast. The Company's use of ten years of forward prices follows its forecasting practice applied in the 2016 and 2018 IRPs.[96]

While the Public Staff appreciates the difficulty in forecasting long-range prices of natural gas, as well as other fuels, it has concerns with the natural gas price forecasts utilized by DEC and DEP in the 2020 IRP. In the 2018 IRPs, Duke had planned that the ACP would supply these plants with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Duke continues to maintain this gas supply source for all new CCs and several existing CCs in the 2020 IRP. The VCEA shifted Dominion's future planning compared to previous IRPs, and Dominion no longer plans to add large-scale natural gas fired generators.

The Public Staff is concerned that in comparison to the historical **[BEGIN CONFIDENTIAL]** [redacted]

[96] For purposes of calculating its avoided energy rates in Docket No. E-100, Sub 167, DEC and DEP have incorporated forward natural gas prices for eight years and its fundamental gas price forecast for years nine and ten. This approach is consistent with the Commission's Orders in the most recent Avoided Cost proceedings, Docket No. E-100, Subs 148 and 158.

[redacted] **[END CONFIDENTIAL]** pricing to calculate such fuel costs is somewhat premature.

On average, Duke is projecting that its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In addition, Duke has included transportation cost estimates for the required interstate and intrastate capacity as a component of capital costs for new generation to account for the delivery of the shale gas.

[BEGIN CONFIDENTIAL] [redacted]

[97] Existing CC plants receiving **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** natural gas are Richmond, W.S. Lee, Sutton, Buck, H.S. Lee, and Dan River.

[redacted]

Figure 7: Commodity Cost of Natural Gas

[redacted] **[END CONFIDENTIAL]**

The Public Staff recognizes that in the 2018 IRP proceeding, Duke was relying on the ACP to transport the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** gas into North Carolina. The ACP was a 600-mile, 42-inch natural gas interstate pipeline which would have transported Appalachian gas on a firm transportation basis to Zone 5 region. Duke had contracted for about 48%

of its capacity or roughly about 725,000 DTs per day. In early July 2020, the cancellation of the ACP, which would have transported up to 1.5 Bcf/day capacity into the Southeast market, brought Duke's assumption of having additional increased interstate pipeline capacity by 2026 into question, especially given the political and economic issues surrounding the construction of new natural gas pipelines.

Another interstate pipeline project currently under construction is the 303 mile, 2-Bcf/day Mountain Valley pipeline (MVP) mainline project, which is designed to provide the demand markets of Virginia and North Carolina with firm transportation natural gas supply access to the low-cost Marcellus and Utica shale productions. MVP is now delayed and scheduled to enter service in late 2021.[98] Further, the project still faces legal and regulatory challenges that cast doubt on its projected in-service date. MVP Southgate, an offshoot to MVP, a 24-inch interstate pipe running approximately 75.1 miles from Southern Virginia to central North Carolina and carrying 375,000 DTs per day of shale gas, cannot start construction until the MVP mainline project has all federal permits approved.[99] **[BEGIN CONFIDENTIAL]** [redacted]

[98] https://www.mountainvalleypipeline.info/overview/.
[99] https://roanoke.com/business/extension-of-mountain-valley-pipeline-gets-federal-approval/article_ee99cc67-1287-5669-8eaf-f589dae56484.html.

[redacted] **[END CONFIDENTIAL]** Currently, however, the growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast demand markets.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

Figure 8: Natural Gas Demand

[redacted]

[redacted] [END CONFIDENTIAL]

Therefore, the Public Staff recommends that for its 2021 IRP update, Duke re-evaluate its assumption that additional interstate pipeline capacity will be available. If Duke continues to believe that adequate capacity will be available, Duke should provide the Commission with a detailed narrative that identifies expected actions by various pipeline developers and other parties and expected timelines that are needed for project completion, as well as identification of major challenges associated with potential new interstate pipelines, which require FERC approval. In order to assess the portfolio risk of Duke's natural gas pricing assumptions, it should also consider developing an IRP portfolio that is similar to its base case, but which includes natural gas import restrictions or less reliance on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** point gas.

CAPITAL COST OF NEW GENERATION AND OPERATING PARAMETERS

The Utilities projected capital cost per kW of new generation is a key variable in determining the optimal least cost capacity expansion plan. The capital cost per kW is combined with the projected cost of fuel, unit heat rates, O&M costs, service life, and other inputs in the Utilities busbar screening, which is largely a static analysis. IRP models minimize total costs of meeting future load by finding the least cost mix of new and existing resources, given capital costs for new units and upgrades to existing units, O&M costs, and operating characteristics for all units, along with unit synergies (for example: the daily generation profiles of solar and wind complement each other). Shown below is a table of important capital and operating characteristics for select new generation units for DEC and DEP:

[BEGIN CONFIDENTIAL]

Table 13: Comparison of Key Variables for New Generation – DEC & DEP

[redacted]	[redacted]	[redacted]	[redacted]		[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Shown below is a table of important capital and operating characteristics for select new generation units for Dominion:[100]

[BEGIN CONFIDENTIAL]

Table 14: Comparison of Key Variables for New Generation – Dominion

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

<u>RENEWABLES</u>

In the Utilities' IRPs, solar can either be forced into the capacity expansion model, or it can be economically selected. Solar that is economically selected was

[100] Figures derived from Dominion response to PS DR 2-6.

chosen by the model as the optimal generation source to meet load and energy requirements. The Utilities generally force in solar that represents projects in the interconnection queue and projects with existing PPAs that are expected to be replaced in kind following their PPA expiration. In some proposed plans, such as Duke's Portfolios C through F, additional solar is forced into the model in order to meet carbon reduction goals. The Utilities also force in mandated solar, which generally refers to solar that is required by law to be added to the system. For Duke, House Bill 589 and SC Act 236 mandate procurement of renewables. For Dominion, the primary legislation that deems a certain target MWs of solar procurement in the public interest is the VCEA. Generally, the solar that is forced into the model is forced in at the same price as solar that is economically selected.

The economic selection of solar depends on several input assumptions, including the capital and operating costs, the capacity factor, and the capacity value. The capacity expansion models used by the Utilities must solve for multiple constraints over the time horizon, such as meeting hourly load and meeting peak load and reserve margin requirements, all while minimizing costs. Duke, which is a winter planning utility, utilizes a capacity value of approximately 1% for its solar-only resources;[101] Dominion, which is a summer planning utility, utilizes a capacity value of approximately 45%.[102] 100 MW of solar, therefore, only contributes 1 MW to Duke's reserve margin, while contributing 45 MW to Dominion's. These capacity

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[101] Duke derives this from its Capacity Value of Solar ELCC study from the 2018 IRP.
[102] Dominion derives this from the PJM ELCC studies published to date.

value estimates can have a significant impact on the deployment of solar, as the utility must meet the reserve margin requirements in any given year.

Duke used the following capacity factors in developing its renewable generation options: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The Public Staff has some concerns that these capacity factors are overly optimistic estimates that may not include practical factors that impact the operation of solar sites, such as weather events, panel outages, cloud cover, wildlife, and system losses. As shown in Table 15 below, Duke has consistently overestimated the amount of generation from its solar facilities in its CPCN applications. The Public Staff recommends that Duke provide a more detailed analysis of proposed capacity factors in its next IRP, since limited knowledge of capacity factors exists for solar with tracking and onshore wind in the Carolinas.

[BEGIN CONFIDENTIAL]

Table 15: **Projected and Actual Capacity Values of Duke-owned Solar**

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[103] Not all facilities have been in operation since 2016. For those with partial years, this average only reflects the years in which the facility was operating.

[END CONFIDENTIAL]

For Dominion's Plans A, B19, and D, it used a solar capacity factor of 19%, which is the average capacity factor of its solar tracking facilities in Virginia for the most recent three year period (2017 through 2019). For Plans B and C, it used a solar capacity factor of 25%, which is the expected future output from solar facilities with tracking. The Public Staff believes that a capacity factor of 25% may be achievable for future solar with tracking, but shares similar concerns about Dominion's capacity factor as it has with Duke's. Dominion used a capacity factor of 42% for its planned offshore wind facilities, which was determined by wind speeds at the Norfolk, Virginia, airport adjusted by using data from NREL's Wind Tool Kit for the Virginia Wind Energy Area. The Public Staff questions these capacity factors but recommends that Dominion provide more analysis in its next IRP since limited knowledge of capacity factors exists for solar with tracking, onshore wind, and offshore wind in the Virginia area.

Competitive Procurement of Renewable Energy

One factor driving the "mandated solar" in Duke's IRPs is the Competitive Procurement of Renewable Energy (CPRE) program. Duke presents its joint CPRE Program Update as Attachment II to its IRPs. The update summarizes the results of Tranche 1 and Tranche 2 of the CPRE, which have procured a total of 1,211 MW of solar capacity, as shown in Table 16 below.

Table 16: CPRE Program Update

	Procured MW - DEC	Procured MW - DEP	Procured MW – Total	# Projects with Energy Storage
Tranche 1	435	87	522	2
Tranche 2[104] [1]	614	75	689	0
Total	1,049	162	1,211	2
CPRE Target			2,660	

The total CPRE target was 2,660 MW; however, HB 589 allowed this total target to be modified based upon the amount of uncontrolled solar not subject to economic dispatch or curtailment that is interconnected to Duke's system in excess or in deficit of 3,500 MW.[105] Duke states that it currently has a total of 4,480 MW of Transition MW connected or with a signed PPA or Interconnection Agreement, and anticipates an additional 265 to 865 MW prior to the end of the CPRE program period. Should the additional Transition MW be on the low end of Duke's estimates, a potential CPRE Tranche 3 would only procure 200 MW; the high end would result in an over procurement of approximately 400 MW.

SUBSEQUENT LICENSE RENEWAL (SLR) OF EXISTING NUCLEAR PLANTS

As discussed in past Public Staff IRP comments, a significant issue faced by Duke and Dominion is the pending expiration of operating licenses for nuclear energy resources in the next 20 to 30 years. If SLRs[106] are not obtained, current schedules call for retirement of approximately 5,900 MW in the 2030 to 2034 period

[104] Tranche 2 contracting was completed October 15, 2020, and was not included in the CPRE program update.

[105] N.C.G.S § 62-159.2. If the total Transition MW exceeds 3,500 MW, the CPRE Target is reduced by such excess. Should the total Transition MW fall short of 3,500 MW, the CPRE Target is increased by such deficit.

[106] Nuclear Regulatory Commission, Subsequent License Renewal, Online at: https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html. *Last accessed* February 5, 2019.

and the loss of an additional approximately 8,400 MW in the 2036 to 2046 period, which equates to 100% of the combined nuclear generation of DEC, DEP, and Dominion.

The Public Staff recommends that the Commission continue to direct Duke and Dominion in future IRPs to include a discussion and evaluation of potential SLRs for each of their existing nuclear units, including an anticipated schedule for SLR application submission and review, and an evaluation of the risks and required costs for upgrades. Each utility should also file a cost analysis to demonstrate that continued operation of each individual nuclear unit or plant is in the best economic interest for ratepayers. This “cost analysis” should be filed in the next biannual IRP (2022) and again in 2024. The Commission should require the Utilities to work with the Public Staff to develop the requirements of the “cost analysis” report prior to the 2022 IRP filing. Further, Duke and Dominion should continue to reflect any such relicensing plans in future IRPs.

UNIT RETIREMENTS

The Utilities make several assumptions regarding planned unit retirements in their IRPs, which contribute to future capacity needs. Table 17 below summarizes the total expected retirements through 2035 for each Utility. This capacity is largely made up of aging coal, gas, and oil facilities, and contributes to future capacity need.

Table 17: Retirement Planning Assumptions through 2035

Primary Fuel	DEC Winter Capacity (MW)	DEP Winter Capacity (MW)	Dominion Summer Capacity (MW)
Coal	3,785	3,208	1,453
Natural Gas	173	355	-
Fuel Oil	-	488	1,823
Biomass	-	-	153
Total	**3,958**	**4,051**	**3,429**

COAL RETIREMENTS

In Chapter 11 of its IRPs, Duke developed accelerated retirement dates for many of its coal-fired units. Duke's assumptions used in the IRPs are different from those relied upon in the accelerated coal retirement analyses in its most recent general rate cases, Docket Nos. E-7, Sub 1214, and E-2, Sub 1219.

The accelerated coal retirement analyses used in the rate cases were selected on a macro level, with a Duke-qualified consultant utilizing industry trends in the retirement of coal assets. The methodology used in the rate cases, at least in part, advanced the schedule for coal replacement generation already selected in the 2019 IRP update. In the current IRP, the coal retirement analysis performed by Duke selected retirement dates for coal units in an economic multi-step process. This multi-step process is referred to as the sequential planning approach.

The sequential planning approach individually analyzed each coal station's overall capacity and associated production cost vis-à-vis the retirement dates established in the 2019 IRP, as well as the earliest new gas capacity that could feasibly be built. The new gas capacity that was evaluated (replacement resource) is a peaking CT. The production cost delta value determined the most economic retirement date. After the economic retirement date was determined, replacement capacity in the portfolio was selected using the production cost model (Prosym) and capacity expansion (System Optimizer or SO).

One minor concern identified with the sequential planning approach is that the cost savings used to establish the retirement dates are not necessarily reflective of actual cost savings because a resource other than a CT was not allowed to be selected by this approach. When evaluating the outcome of the study, the assumption is made that an absolute value listed in a given year will be the actual cost savings. The Commission should be aware it is possible that, if allowed, a different resource may have been selected, meaning that the listed cost savings that are utilized in the sequential planning approach would not be accurate.

It is feasible that over the long term, if planning assumptions hold constant, the total cost differentials between a CT and whichever production asset is ultimately built will be negligible, as capacity expansion modeling typically builds discrete quantities of new generation, sometimes resulting in excess capacity. The primary factor used in this analysis to determine the retirement date was the magnitude of ongoing capital and fixed costs of existing coal plants versus the replacement capacity's capital and fixed cost. The methodology used in the rate cases and the methodology used in the current IRP both have their own advantages and disadvantages, understanding that all future analyses are imperfect and utilize assumptions that may or may not manifest.

Duke's retirement analysis is agnostic to how the remaining book value of coal plants is recovered when their retirement dates are accelerated. The Public Staff does not take issue with this approach, as it is reasonable from a modeling perspective and irrelevant to the forward looking aspect of the PVRR upon which IRP decisions are based. However, the Public Staff believes the Commission should generally be aware of the potential impact that accelerated depreciation rates or accelerated amortization may have on customer bills.

For informational purposes, the Public Staff collaborated with Duke's IRP team to show total cost differences and customer bill impacts for Roxboro Units 3 & 4 and Mayo. The figures below show hypothetical annual revenue requirement differences and the timing of customer bill impacts for only capital and operations and maintenance expense.[107] Changes in the method of recovering the remaining book value of coal units does not affect the overall PVRR, but would affect the timing of bill impacts. Each figure represents individual plant retirement along with three potential options for post-retirement recovery of undepreciated plant balances: (1) accelerating deprecation to match the presumed new retirement date (Change Case), (2) without accelerating the retirement of the coal plant and continue to utilize production until the end of its planned life[108] (Base Case), and

[107] The graphs assumed perfect ratemaking. This analysis simplified the overall approach and aligned coal units under evaluation with the selected early retirement date and included new capital costs in the year they were placed in service. It would be too speculative at this time to add in additional layers of complexity and artificially impose discrete years in which Duke would file a rate case and what would be the outcome of that rate case.

[108] Planned life in this example is utilizing the retirement dates listed in the 2019 IRP Update.

(3) retiring the unit per the calculated economic analysis, but continuing the recovery of any undepreciated balance for a time period past the actual retirement date (Early Retire Reg. Asset).[109] The residential bill impact analysis is based on 1,000 kWh of usage per month.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 9: Confidential Roxboro Units 3 and 4 Revenue Requirement

[END CONFIDENTIAL]

[109] The figures below are estimates. Decisions about ratemaking and calculation of more accurate bill impacts should be made as part of a future general rate case.

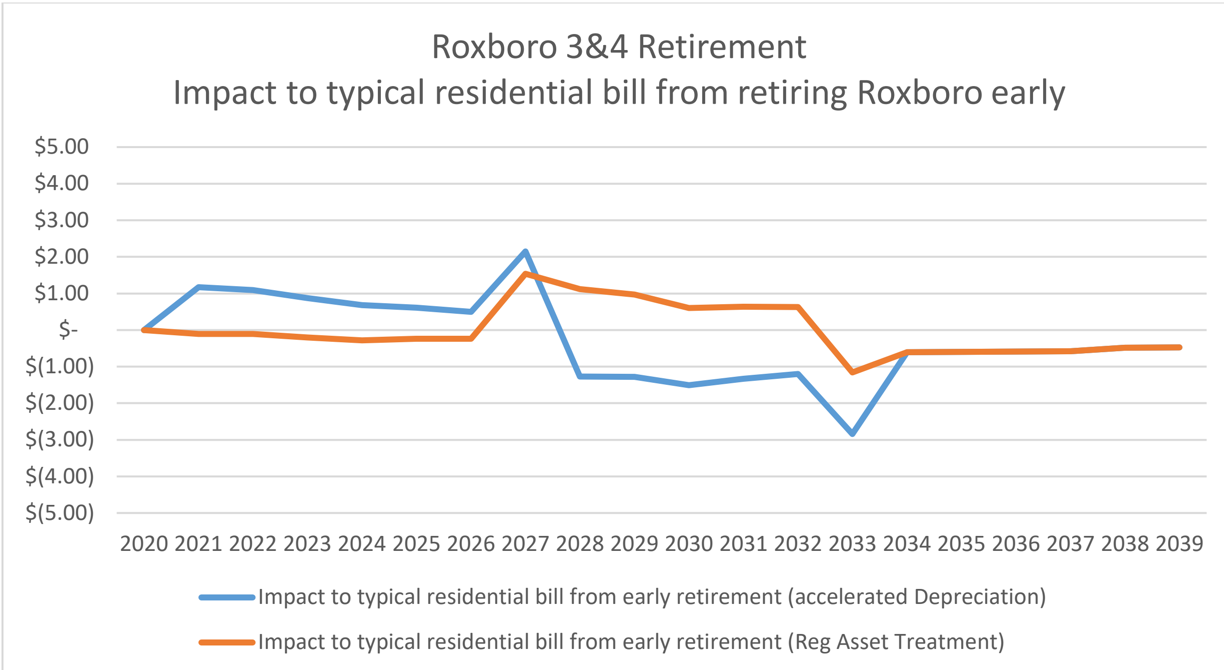

Figure 10: Roxboro Units 3 & 4 Residential Bill Impact

[BEGIN CONFIDENTIAL]

[redacted]

Figure 11: Confidential Mayo Revenue Requirement

[END CONFIDENTIAL]

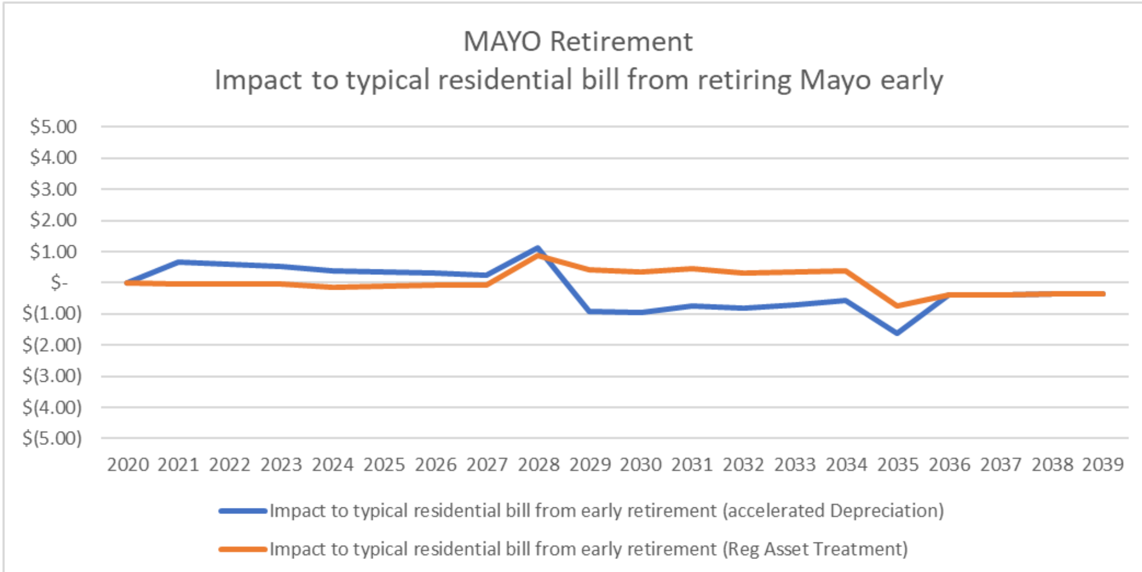

Figure 12: Mayo Residential Bill Impact

The remaining book value of each retired plant is a sunk cost, since the capital cost to build the coal unit has already been spent by Duke, but the ratepayer will likely be paying Duke for the remaining book value after the actual retirement date or even if the unit is not used. Duke is planning other actions not related to coal plant retirements that will also place upward (and potentially downward, albeit unlikely) pressure on rates, such as the proposed GIP, coal ash management and beneficiation, and ongoing utility operations as load grows and shifts geographically. While this analysis does not constitute a basis for rendering a decision in the IRP proceeding, the potential rate impacts of early coal retirements will become an issue in a future rate proceeding and the Public Staff wishes to identify the issue for the Commission sooner rather than later.

In addition, Duke's coal unit retirement analysis in the IRP took into account aspects of potential transmission upgrades. It is the Public Staff's understanding that retirement of the Roxboro and Mayo units will cause the greatest stress on the transmission system, because of the significant amount of capacity in this geographic area, the overall demand, and system interties with other utilities.

The Public Staff believes the model inputs relied upon by Duke are reasonable for planning purposes, but notes that cost savings from the replacement generation may not materialize for numerous reasons including failure of critical equipment, higher than estimated fuel costs, higher than estimated construction costs, and the ultimate selection of replacement resources other than what is modeled. As discussed extensively in the 2019 rate cases and in the current IRPs, the Companies' transmission requirements are dynamic as related to the retirement of coal units. Should the Commission approve accelerated coal unit retirements for economic, earliest practicable date, or other reasons, the Public Staff recommends that Duke analyze the transmission impacts and file a more detailed plan with refined cost estimates, including timelines of required activities and potential synergies with future grid improvement plans, to aid in the transition and system production cost estimates with the proposed replacement generation source.

The Utilities have proposed energy storage as a replacement for some of their coal units, and storage is increasingly impacting the utility reserve margin planning as it is relied upon to provide electricity during peak load hours, similar to a traditional generation resource or pumped hydro storage facility. Battery storage acts as electric load while charging and acts as electric generation while discharging and should be accounted for in the regulatory planning and construction processes. The Commission and the Public Staff must be aware of the replacement capacity needed, alternative solutions, and other aspects of Duke's operations to ensure efficiency, minimize costs, and evaluate reliability, including impacts on individual Duke balancing areas as well as neighboring balancing areas. The Public Staff recommends that the Commission initiate a rule making proceeding that would evaluate whether, and under what circumstances, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility.

The Public Staff believes that to evaluate the accelerated retirement of any generation resource, the Utilities and IRP stakeholders should consider various details, including the dates of retirement, the replacement resources, impact on reliability and resilience, and transmission upgrades. The Public Staff recognizes that the Utilities are responsible for the safe, reliable, and economic planning and operation of their systems while complying with both state and federal mandates. It is important that the issue of the necessity for accelerated coal unit retirements and corresponding replacement by other resources receive regulatory direction sooner rather than later.

The Public Staff attended the A-1 Policy Group[110] meetings, which discussed among other things, the stranded investment risk of building new carbon-emitting natural gas generation assets. Specifically, the Group discussed

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[110] The A-1 Policy Group was formed by the Duke Nicholas Institute and UNC CE3 as a working group focused on the policy pathways presented in the Clean Energy Plan.

the likelihood that replacing coal generation with natural gas may ultimately result in stranded assets if a future carbon price is enacted. This gives rise to an argument that existing coal generation plants should continue to run for a period of time, thus deferring the need for new natural gas plants while carbon policy uncertainty is resolved. This could potentially reduce the risk to ratepayers of stranded natural gas assets while the costs of renewables and storage continue to decline. While the Public Staff makes no recommendation on this point, it is illustrative of the uncertainty that lies ahead. The Public Staff notes that if Duke were to retire its planned natural gas assets early in the future, as contemplated in its IRPs, these same issues will need to be addressed at that time.

Some of this uncertainty could be remedied if Duke were able to model the economic coal retirement dates endogenously in the model; in other words, instead of specifying the retirement date arrived at by a complex external analysis, the model itself could determine when to shut the plant down and replace it with new capacity. The Encompass model, which Duke intends to use going forward, has this very ability. The Public Staff recommends that Duke use economically optimal endogenous plant retirement dates in future IRPs resulting from the Encompass model.

PLANNED GENERATION

DEC'S STAND-ALONE PLANS

DEC's analysis of its resource options is discussed in the quantitative analysis section of its IRP. For the purpose of this section, resource amounts are for the near term (in service 2021-2030), and are only for DEC. There are two types of resources included in the expansion plans: 1) resources that were economically selected by the model to minimize costs, and 2) resources that were added to the portfolio that were not economically selected by the model. Comments on both DEP's Stand-Alone Plans and DEC's and DEP's Joint Planning Scenarios can be found below.

- Portfolio A (Base without Carbon Policy) is a least-cost base case portfolio that does not consider future carbon regulation. It consists of a combination of 914 MW of future CTs, with base case EE and renewable projections. The model did not economically select any renewable resources. After the economic modeling run, DEC added 167 MW of battery storage to the portfolio.
- Portfolio B (Base with Carbon Policy) is a least-cost scenario that considers a future with carbon regulation. A notable difference from Portfolio A is that DEC's first large capacity build is pushed from 2029 to 2030. It consists of 457 MW of future CTs, 450 MW of solar, and 150 MW of solar plus storage; all economically selected. This portfolio includes the same base EE assumptions and 167 MW of battery storage added in by DEC after the economic modeling, similar to Portfolio A.
- Portfolio C (Earliest Practicable Coal Retirements) is not a least-cost scenario, and is largely based on Duke's coal retirement analysis (see "Coal Retirements" section below for full comments). It

accelerates the addition of natural gas capacity additions and consists of a combination of 2,448 MW of future natural gas-fired CCs and 2,285 MW of future CTs. As a result, the Portfolio calls for 2,138 MW of natural gas capacity to be built in 2028, and 2,595 MW of natural gas capacity to be built in 2029. Portfolio C includes the same 450 MW of solar and 150 MW of solar plus storage as Portfolio B, the same base EE assumptions, and 167 MW of battery storage added in by DEC after the economic modeling.

- Portfolio D (70% CO_2 Reduction: High Wind) is not a least-cost scenario, which, along with Portfolio E, plans to achieve a 70% CO_2 reduction, as outlined in EO80 (see "Executive Order 80 and the DEQ Clean Energy Plan" section). The portfolio uses the earliest practical coal retirement days set out in Portfolio C, including high EE and DR projections and renewable projections (1,275 MW of solar and 75 MW of solar plus storage). It accelerates natural gas capacity additions and consists of a combination of 2,448 MW of future natural gas-fired CCs and 1,371 MW of future CTs. While this portfolio focuses on wind, the new offshore wind (1,200 MW) was added into the Portfolio after the economic modeling run, along with the purchase of 90 MW of wind resources in the mid-continental U.S., and 167 MW of battery storage.
- Portfolio E (70% CO_2 Reduction: High SMR) is not a least-cost scenario, which, along with Portfolio D, plans to achieve a 70% CO_2

reduction, as outlined in EO80. While this Portfolio focuses on the development of SMRs, the SMR (684 MW) to be built in 2030 is added into the Portfolio after the economic modeling run. The Portfolio uses the earliest practical coal retirement days set out in Portfolio C, and includes high EE and DR projections. The model selected 1,224 MW of natural gas-fired CCs, and 2,285 MW of future CTs, 1,275 MW of solar, and 75 MW of solar plus storage. The purchase of 300 MW wind resources in the mid-continental U.S., and 167 MW of battery storage, were both added to the Portfolio after the modeling run.

- Portfolio F (No New Gas Generation) is not a least-cost scenario, and focuses on transitioning DEC's generation profile without the deployment of new gas generation. The Portfolio includes the following resources: 1,200 MW of solar and 150 MW of solar plus storage. This Portfolio uses the most economic coal retirement scenario, as in Portfolios A & B, and includes high EE and DR projections.

In total, DEC presented six different portfolios with differing years for its first capacity need, and technology selected to meet the need, as shown in Table 18.

Table 18: DEC First Capacity Build & Technology Selected						
	Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
In-Service Year	2029	2030	2028	2028	2028	2035
Technology	CT	CT	2 CTs & CC	CT & CC	CT & CC	SMR & PS
Capacity (MW)	457	457	2,138	1,681	1,681	2,304
Economically Selected (Y/N)	Yes	Yes	Yes	Yes	Yes	No

It is important to note that in all of DEC's Portfolios, except for Portfolio A, solar is scheduled to be built prior to the technology indicated in Table 18. Solar was not included in Table 18 as the development and construction of solar (and other renewables) can be done in a piecemeal approach, rather than in a 'lumpy' approach, as is the case with traditional generation (fossil and nuclear). The development of traditional generation has a 'lumpiness' to it, as there is very little flexibility in the capacity of facilities. (For example, a utility may only need 100 MW of capacity, and it opts to build a 450 MW CT, expecting to grow into that excess capacity.) Solar, and other renewables, allow utilities to build only what they need to fulfill their capacity needs. As showing in the Summary of Growth Rates section, growth rates are low and continue to decline.

In all of the Portfolios except for Portfolio F, the first capacity need was economically selected by the model, while in Portfolio F, the first capacity need was selected by DEC. In Portfolio F, DEC chose both the technology to build (SMR and a Bad Creek Pumped Hydro facility upgrade), and the year in which those facilities would be constructed (2035).

A comparison of the new capacity planned in each portfolio from 2021-2030 is displayed in Table 19 below.

Table 19: DEC Portfolio Resource Comparison (In Service 2021-2030)

	Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
Stand-Alone Solar (MW)		450	450	1,275	1,275	1,200
Solar Plus Storage (MW)		150	150	75	75	150
Stand-Alone Storage (MW)	167	167	167	167	167	150
CC (MW)			2,448	2,448	1,224	
CT (MW)	914	457	2,285	1,371	2,285	
Offshore Wind (MW)				1,200		
Onshore Wind (MW)						
Midwest Wind (MW)				90		
SMR (MW)					684	
Total (MW)	**1,081**	**1,224**	**5,500**	**6,626**	**5,710**	**1,500**

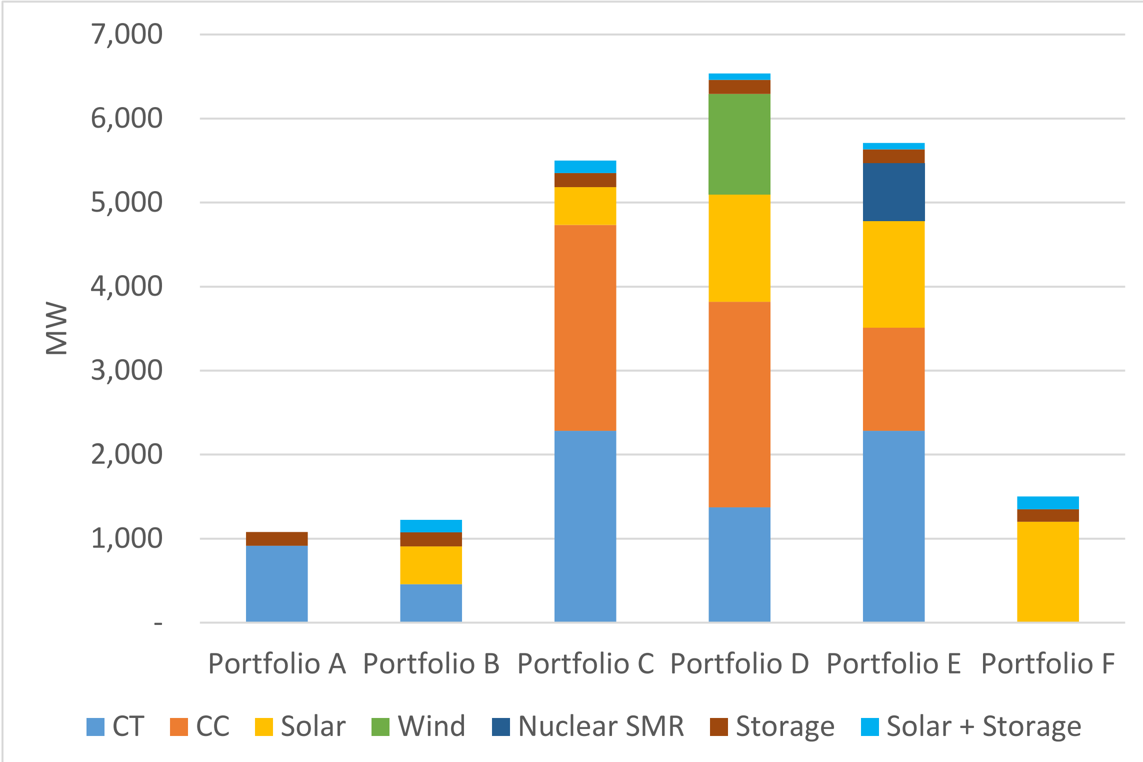
Table 19 shows that the new generation forecasted in Portfolio C, Portfolio D, and Portfolio E greatly outweighs the new generation in Portfolio A, Portfolio B, and Portfolio F. Portfolio C, Portfolio D, and Portfolio E all use the earliest practicable coal retirements, so new natural gas CCs are built, as well as new natural gas CTs. In all of the portfolios, except for Portfolio B and Portfolio F, more natural gas generation is planned in the next ten years than new renewable generation (storage is excluded from the calculation):

- Portfolio A: 100% natural gas, 0% renewables
- Portfolio B: 43% natural gas, 57% renewables
- Portfolio C: 89% natural gas, 11% renewables
- Portfolio D: 60% natural gas, 40% renewables
- Portfolio E: 63% natural gas, 37% renewables
- Portfolio F: 0% natural gas, 100% renewables

The impact of carbon policies, which is discussed later in the Cost of Carbon Policies section, is apparent in the timing of new solar. As seen in Figure 21 of the Cost of Carbon Policies section, Duke's carbon price begins to escalate in 2025. As a result, in Portfolio D and Portfolio E, solar is to be built in 2024; and in Portfolio B, Portfolio C, and Portfolio F, solar is to be built in 2025.

New capacity planned in each portfolio from 2021-2030 is displayed in Figure 13 below.

Figure 13: DEC Cumulative New Builds, In Service 2021-2030



The new generation outlined in Portfolio C, Portfolio D, and Portfolio E exceeds the new generation outlined in Portfolio A, Portfolio B, and Portfolio F, because Portfolio C, Portfolio D, and Portfolio E use the economic coal retirement assumption, while Portfolio A, Portfolio B, and Portfolio F use the earliest practical coal retirement assumption. Duke proposed a large amount of new natural gas generation in the portfolios in which the earliest practical coal retirement assumption is used.

Portfolio A forecasts the lowest amount of new generation, all of which is natural gas generation. No renewables are economically selected in Portfolio A.

79% of Portfolio B's new generation is built from 2035 to the end of the planning horizon in 2050.

Portfolio C is heavily dominated by new natural gas, with 86% of new generation in the next 10 years coming from natural gas. Similar to Portfolio C, Portfolio D is very natural gas generation dominated, except for 1,200 MW of offshore wind that was forced in the portfolio after the model economically selected resources. Once again, Portfolio E is very similar to both Portfolio C and Portfolio D, as it is very natural gas generation dominated, except for 684 MW of SMRs that were forced in the portfolio after the model economically selected resources.

Portfolio F contains only renewable resources and battery storage. In the later years of the Portfolio, DEC forced in significant amounts (6,129 MW) of battery storage, as well as a new Bad Creek pumped hydro storage powerhouse.

The model can select resources for economic reasons, or utilities can force a resource into the capacity expansion model. For each resource type, Table 20 below shows whether the resource was chosen by the model or forced in after the modeling run.

Table 20: DEC: Economic-Selected Resources & Resources Added After Modeling (In Service 2021-2041)							
		Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
Stand-Alone Solar (MW)	Economically Selected		**2,025**	**2,025**	**2,475**	**2,475**	**2,400**
	Forced In[111]	**1,981**	**1,981**	**1,981**	**3,725**	**3,725**	**3,725**
Solar Plus Storage (MW)	Economically Selected		**1,725**	**1,725**	**1,800**	**1,800**	**1,875**
	Forced In[112]	**739**	**739**	**739**	**2,175**	**2,175**	**2,175**
Stand-Alone Storage (MW)	Economically Selected						
	Forced In	**167**	**167**	**167**	**167**	**167**	**6,279**
CC (MW)	Economically Selected	**3,672**	**2,448**	**2,448**	**2,448**	**1,224**	
	Forced In						
CT (MW)	Economically Selected	**6,398**	**6,398**	**6,398**	**3,199**	**4,113**	
	Forced In						
Offshore Wind (MW)	Economically Selected						
	Forced In				**1,200**		
Onshore Wind (MW)	Economically Selected		**300**	**450**	**1,050**	**1,050**	**1,350**
	Forced In						
Midwest Wind (MW)	Economically Selected						
	Forced In				**1,340**	**1,315**	**1,315**
SMR (MW)	Economically Selected						
	Forced In					**684**	**684**
Pumped Storage (MW)	Economically Selected						
	Forced In				**1,620**	**1,620**	**1,620**

One takeaway from Table 20 is that solar and solar plus storage were chosen in all of the portfolios, except Portfolio A. Starting in the 2029-2030 timeframe, depending on the portfolio, solar plus storage is included in the plans.

Onshore wind was also economically selected in all of the portfolios, except for Portfolio A. While offshore wind was forced into Portfolio D, onshore wind was economically selected by the model in 2033 (Portfolio F), 2035 (Portfolio B, Portfolio D, Portfolio E), and 2039 (Portfolio C).

Technologies that were never economically selected by the model include: battery storage, pumped hydro storage, offshore wind, wind resources in the mid-continental U.S, and nuclear SMRs.

DEC forced in pumped hydro storage into Portfolio D, Portfolio E, and Portfolio F. Pumped hydro storage is very expensive, as discussed in the Capital Cost of New Generation and Operating Parameters section below. The Public Staff has concerns regarding pumped hydro storage being forced into portfolios, instead of letting the model economically select resources.

DEP's Stand-Alone Plans

DEP's evaluation of resource options is discussed in the quantitative analysis section of its IRP. For the purpose of this section, resource amounts are for the near term (in service 2021-2030), and are only for DEP. There are two types

[111] In response to a Public Staff data request, Duke indicated that both designated and mandated solar and solar plus storage was added to all portfolios.
[112] *Id.*

of resources included in the expansion plans 1) resources that were economically selected by the model to minimize costs, and 2) resources that were added to the portfolio that were not economically selected by the model. The seven portfolios are described below:

- Portfolio A (Base without Carbon Policy) is a least-cost base case portfolio that does not consider future carbon regulation. It consists of a combination of 1,224 MW of future natural gas fired CCs and 3,199 MW of future CTs, with base case EE and renewable projections. The model did not economically select any renewable resources. After the economic modeling run, DEP added 133 MW of battery storage to the portfolio.
- Portfolio B (Base with Carbon Policy) is a least-cost scenario that considers a future with carbon regulation. Notable differences from Portfolio A: CT capacity was reduced, CC capacity was increased, and 150 MW of solar plus storage was included in the last year of the planning horizon. Portfolio B consists of a combination of 2,448 MW of future natural gas fired CCs and 1,828 MW of future CTs. This portfolio includes the same base EE assumptions and 133 MW of battery storage added in by DEP after the economic modeling, similar to Portfolio A.
- Portfolio C (Earliest Practicable Coal Retirements) is a least-cost scenario and is largely based on Duke's coal retirement analysis. It accelerates the addition of natural gas capacity additions; as a result,

the plan calls for a natural gas CT (457 MW) to be built in 2026. The plan consists of a combination of 1,224 MW of future natural gas fired CCs and 2,285 MW of future CTs. Portfolio C also includes 225 MW of solar plus storage and 450 MW of onshore wind. This portfolio includes the same base EE assumptions as Portfolios A and B, with 1,135 MW of battery storage added in by DEP after the economic modeling, significantly higher than the storage added to Portfolio A and Portfolio B.

- Portfolio D (70% CO_2 Reduction: High Wind), along with Portfolio E, plans to achieve a 70% CO_2 reduction, as outlined EO80. While this portfolio focuses on wind, the new offshore wind (1,200 MW) to be built in 2030 is added into the Portfolio after the economic modeling run, along with the purchase of 60 MW of wind resources in the mid-continental U.S. The plan calls for a combination of 1,224 MW of future natural gas fired CCs and 914 MW of future CTs. This portfolio also includes 300 MW of onshore wind and 75 MW of solar plus storage, both of which were economically selected by the model. The portfolio uses the earliest practical coal retirement days set out in Portfolio C, including high EE and DR projections. After the economic modeling run, DEP added in 1,135 MW of battery storage, the same amount as Portfolio C.
- Portfolio E (70% CO_2 Reduction: High SMR), along with Portfolio D, plans to achieve a 70% CO2 reduction, as outlined EO80. While this

portfolio focuses on the development of SMRs, the SMR (684 MW) to be built in 2030 is forced into the portfolio after the economic modeling run. 1,135 MW of battery storage was also added to the portfolio after the modeling run. The portfolio uses the earliest practical coal retirement days set out in Portfolio C, and includes high EE and DR projections. The model economically selected 1,224 MW of natural gas fired CCs, 914 MW of future CTs, and 300 MW of onshore wind. Also included is 75 MW of solar plus storage.

- Portfolio F (No New Gas Generation) focuses on transitioning DEP's generation profile without the deployment of new gas generation. The portfolio includes the inclusion of the following resources: 225 MW of solar plus storage, and 300 MW of onshore wind. After the modeling run 2,400 MW of offshore wind, and 3,212 MW of battery storage were forced into the portfolio. This portfolio uses the most economic coal retirement scenario, as in Portfolios A & B, and includes high EE and DR projections.

In total, DEP presented six different portfolios with differing years for DEP first capacity need, and technology selected to meet the need, as shown in Table 21.

Table 21: DEP First Capacity Build & Technology Selected						
	Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
In-Service Year	2026	2026	2026	2028	2028	2029
Technology	CT	CT	CT	2 CTs & CC	2 CTs & CC	Wind
Capacity (MW)	457	457	457	2,138	2,138	1,200
Economically Selected (Y/N)	Yes	Yes	Yes	Yes	Yes	No

Portfolio A, Portfolio B, and Portfolio C have the same first capacity build technology and date (457 MW CT in 2026), while Portfolio D and Portfolio E have the same first capacity build in 2028 (two 457 MW CTs, and a 1,224 MW CC.) Portfolio F has forced in 2,474 MW of battery storage prior to the forced in offshore wind in 2029 (150 MW of onshore wind was economically selected in 2029).

In all of the portfolios except for Portfolio F, the first capacity need was economically selected by the model, while in Portfolio F, the first capacity need was selected by DEP. In Portfolio F, DEP choose both the technology to build (offshore wind), and the year in which the facility would be constructed (2029).

A comparison of the new capacity planned in each portfolio from 2021-2030 is displayed in Table 22 below.

Table 22: DEP Portfolio Resource Comparison (In Service 2021-2030)						
	Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
Stand-Alone Solar (MW)						
Solar Plus Storage (MW)		150	225	75	75	225
Stand-Alone Storage (MW)	133	133	1,135	1,135	1,135	3,212
CC (MW)	1,224	2,448	1,224	1,224	1,224	
CT (MW)	3,199	1,828	2,285	914	914	
Offshore Wind (MW)				1,200		2,400
Onshore Wind (MW)			450	300	300	300
Midwest Wind (MW)				60		
SMR (MW)					684	
Total (MW)	4,556	4,559	5,319	4,908	4,332	6,137

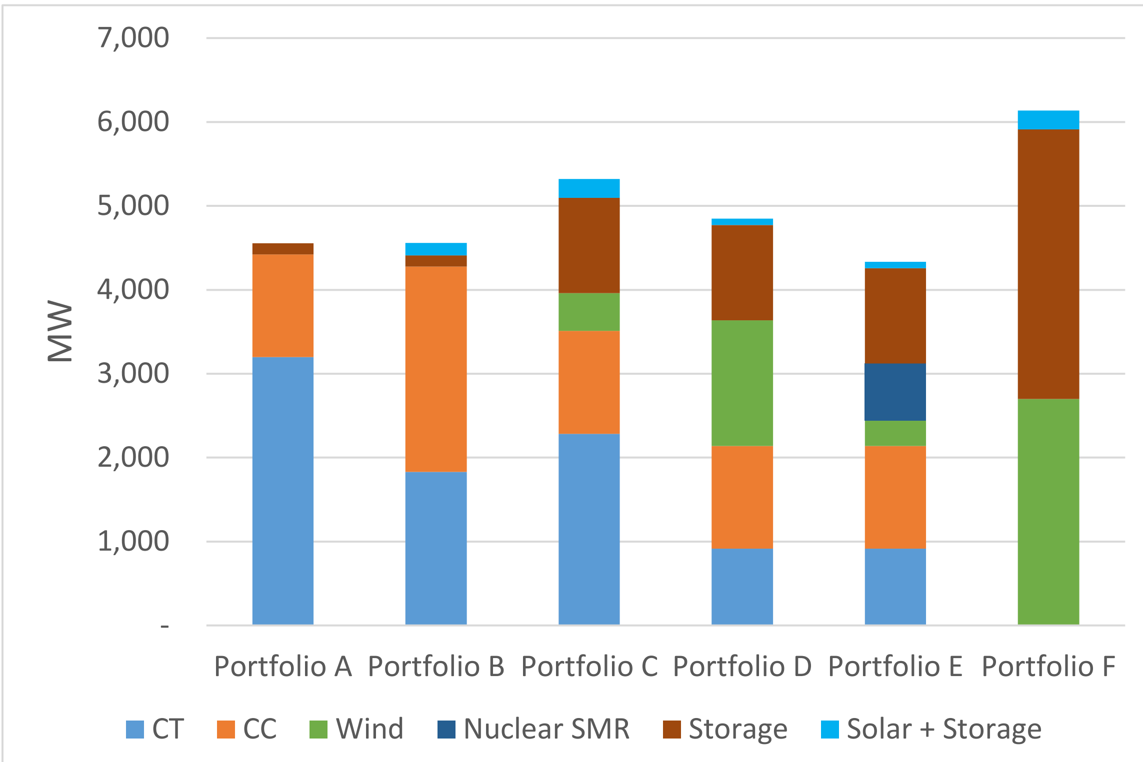
Unlike DEC's portfolios, all of DEP's portfolios have similar amounts of new generation in the next ten years. In all of the portfolios except for Portfolio F, more natural gas generation is planned in the next ten years than new renewable generation (storage is excluded from the calculation):

- Portfolio A: 100% natural gas, 0% renewables
- Portfolio B: 97% natural gas, 3% renewables
- Portfolio C: 84% natural gas, 16% renewables
- Portfolio D: 58% natural gas, 42% renewables
- Portfolio E: 67% natural gas, 33% renewables

- Portfolio F: 0% natural gas, 100% renewables

New capacity planned in each Portfolio from 2021-2030 is displayed in Figure 14 below.

Figure 14: DEP Cumulative New Builds, In Service 2021-2030



All portfolios, except for portfolio F, rely heavily on natural gas generation, and none of the portfolios include economically selected solar, as opposed to the portfolios of DEC and Dominion. Portfolio A consists of all natural gas generation and a small amount of forced in storage.

In Portfolio B, natural gas once again dominates, while solar plus storage is included for the first time.

Portfolio C is dominated by new natural gas generation, with 84% of new generation in the next 10 years coming from natural gas. Similar to Portfolio C, Portfolio D is dominated by new natural gas generation, except for 1,200 MW of offshore wind that was forced in the portfolio after the model economically selected resources. Once again, Portfolio E is very similar to both Portfolio C and Portfolio D, as it is natural gas generation dominated, except for 684 MW of SMRs that were forced in the portfolio after the model economically selected resources.

Portfolio F contains only renewable resources and battery storage. DEC forces in massive amounts (2,400 MW) of offshore wind in 2029-2030. In the later years of the Portfolio, DEC forces in massive amounts (6,129 MW) of battery storage as well as pumped hydro storage.

The model can select resources for economic reasons, or utilities can force a resource into the capacity expansion model. For each resource type, Table 23 shows whether the resource was chosen by the model, or forced in after modeling run.

Table 23: DEP: Economic-Selected Resources & Resources Added After Modeling (In Service 2021-2041)							
		Portfolio A (Base Case Without Carbon Policy)	**Portfolio B** (Base Case With Carbon Policy)	**Portfolio C** (Earliest Practicable Coal Retirements)	**Portfolio D** (70% CO_2 Reduction: High Wind)	**Portfolio E** (70% CO_2 Reduction: High SMR)	**Portfolio F** (No New Gas Generation)
Stand-Alone Solar (MW)	Economically Selected						
	Forced In[113]	**1,662**	**1,662**	**1,662**	**1,337**	**1,337**	**1,337**
Solar Plus Storage (MW)	Economically Selected		**2,550**	**2,625**	**2,400**	**2,400**	**2,550**
	Forced In[114]	**339**	**339**	**339**	**3,224**	**3,224**	**3,224**
Stand-Alone Storage (MW)	Economically Selected	**481**	**1,019**				
	Forced In	**133**	**133**	**1,135**	**1,135**	**1,135**	**6,303**
CC (MW)	Economically Selected	**1,224**	**2,448**	**1,224**	**1,224**	**1,224**	
	Forced In						
CT (MW)	Economically Selected	**6,398**	**3,656**	**4,570**	**2,285**	**2,285**	
	Forced In						
Offshore Wind (MW)	Economically Selected						
	Forced In				**1,200**		**2,400**
Onshore Wind (MW)	Economically Selected		**1,350**	**2,100**	**1,950**	**1,950**	**1,950**
	Forced In						
Midwest Wind (MW)	Economically Selected						
	Forced In				**880**	**865**	**865**
SMR (MW)	Economically Selected						
	Forced In					**684**	

One takeaway from Table 23 is that solar plus storage was included in all of the portfolios, except Portfolio A. Starting in the 2029-2030 timeframe, solar plus storage is included in all of the portfolios except Portfolio A.

Onshore wind was also economically selected in all of the portfolios, except for Portfolio A. While offshore wind was forced into Portfolio D and Portfolio F, onshore wind was economically selected by the model in 2029 (Portfolio C, Portfolio D, Portfolio E, Portfolio F), and 2033 (Portfolio B).

Battery storage was only economically chosen in two portfolios (Portfolio A and Portfolio B). Battery storage was forced in to all of the portfolios.

Technologies that were never economically selected by the model include: offshore wind, wind resources in the mid-continental U.S, nuclear SMRs, and battery storage (except for the two cases mentioned above).

COMMENTS ON DEC'S AND DEP'S STAND ALONE PLANS

The Public Staff has concerns with Duke's presentation of portfolios with little or no renewables (DEC Portfolio A and DEP Portfolio A) to meet its long-term carbon-reduction goals. Duke's IRPs state: "All portfolios keep Duke Energy on a trajectory to meet its near term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050."[115] The Public Staff also has concerns with the disconnect between the net-zero goal set by Duke Energy Corporation (parent company), and the natural gas generation dominated expansion plans set out by DEC and DEP (operating companies).

[113] In response to a Public Staff data request, Duke indicated that both designated and mandated solar and solar plus storage was added to all portfolios.
[114] *Id.*
[115] DEC and DEP IRPs at 6.

This section only discusses new generation build, while the pace of coal retirements must be taken into account when evaluating portfolios. See the "Coal Retirements" section for a discussion of DEC's and DEP's coal retirement analysis.

Economically Selected vs. Forced In

The Public Staff has concerns with forcing generation technologies into all of Duke's portfolios. In addition to forcing in resources (battery storage, pumped hydro storage, offshore wind, wind resources in the midcontinental U.S, and nuclear SMRs), Duke chose to shift other resources, originally economically selected by the model, to earlier years in order to accommodate forced in resources.[116] The Public Staff has concerns with the adjustments Duke made to Portfolio C, Portfolio D, Portfolio E, and Portfolio F, after the model produced an optimal solution given the constraints of the portfolio. Instead of forcing technologies (including the capacity of the facility, and the year of development) into the plan, the Public Staff believes that Duke should have set a carbon goal and let the model produce the optimal capacity expansion plan to meet that goal.

DEC's and DEP's Joint Planning Case

DEC and DEP included in their IRPs a Joint Planning Scenario that examines the potential for them to share capacity, as compared to the JDA, which allows only non-firm energy transactions. A shared capacity arrangement between DEC and DEP would require approvals from the FERC, as well as the North Carolina and South Carolina utility regulatory commissions. Over the 2021 to 2030

[116] *See* Duke response to PS DR 7-1.

planning horizon, the Joint Planning Scenario indicates a reduction of one 457 MW CT (2027), and a reduction of one 457 MW CT (2030), as compared to the separate base case plans. A review of the reserve margins for the Combined Base Case and the Joint Planning Case, showed that they averaged 18.2% and 18.3%, respectively.

DOMINION'S EXPANSION PLANS

For the purpose of this section, resource amounts are for the near term (2021-2030). The four alternative plans presented by Dominion in its 2020 IRP are described below:

- Plan A (Least-Cost) is a base case plan that has no future constraints (legislation, regulations, emission restrictions). It consists of a combination of 1,940 MW of future natural gas generation and 4,320 MW of future solar PPA (power purchase agreement).
- Plan B (Base) takes into account current legislation and is the least-cost plan that represents the current state of Virginia and North Carolina law. The plan forecasts less natural gas generation than Plan A, such that only 970 MW of future natural gas fired generation would be added. The plan calls for 6,060 MW of Company-built solar, 3,360 MWs of solar PPA, and 1,100 MW of solar DER (distributed energy resources). The plan also includes 2,556 MW of offshore wind (OSW). The plan includes 1,414 MW of battery storage and 300 MW of pumped storage. (Plan B19 is the same as Plan B, but solar resources have a capacity factor

of 19% compared to 25%.[117] In the near-term, the generation profile of Plan B19 is the same as Plan D.)

- Plan C (2045 Retirements) calls for the retirement of all carbon-emitting generation in 2045; as a result, the plan has the same generation and storage profiles as Plan B. (This analysis only looks at the next ten years.)
- Plan D (Decreased Solar Capacity Factor) is the same as Plan C, but reduces the capacity factor of solar from 25% to 19%; as such, this plan calls for building more solar resources than the rest of the plans. The plan calls for 7,140 MW of Company-built solar, 3,720 MWs of solar PPA, and 1,100 MW of solar DER (distributed energy resources). The plan also includes the same amount of offshore wind, battery storage, and pumped storage as Plan B and Plan C.

A comparison of the new capacity planned in each portfolio from 2021-2030 is displayed in Table 24 below.

[117] Final Order, *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, No. PUR-2018-00065, at 11-12, (VA.S.C.C. Jun. 27, 2019), ordered Dominion to use "…the actual capacity performance of Dominion's Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and 25%."

Table 24: Dominion Portfolio Resource Comparison (2021-2030)				
	Plan A (Least-Cost)	**Plan B** (Base)	**Plan C** (2045 Retirements)	**Plan D/B19** (Decreased Solar Capacity Factor)
Company-Built Solar (MW)		6,060	6,060	7,140
Solar PPA (MW)	4,320	3,360	3,360	3,720
Solar DER (MW)		1,100	1,100	1,100
OSW (MW)		2,556	2,556	2,556
Battery Storage (MW)		1,414	1,414	1,414
Pumped Storage (MW)		300	300	300
Natural Gas (MW)	1,940	970	970	970
Total (MW)	6,260	15,760	15,760	17,200

Table 24 shows that the new generation forecasted in Plan B, Plan C, and Plan D greatly outweigh the new generation in Plan A. For the next ten years, Plan B and Plan C are identical, while Plan D forecasts an increased quantity of Company-Built solar and solar PPA.

New capacity planned in each Portfolio from 2021-2030 is displayed in Figure 15 below.

Figure 15: Dominion Cumulative New Builds, 2021-2030

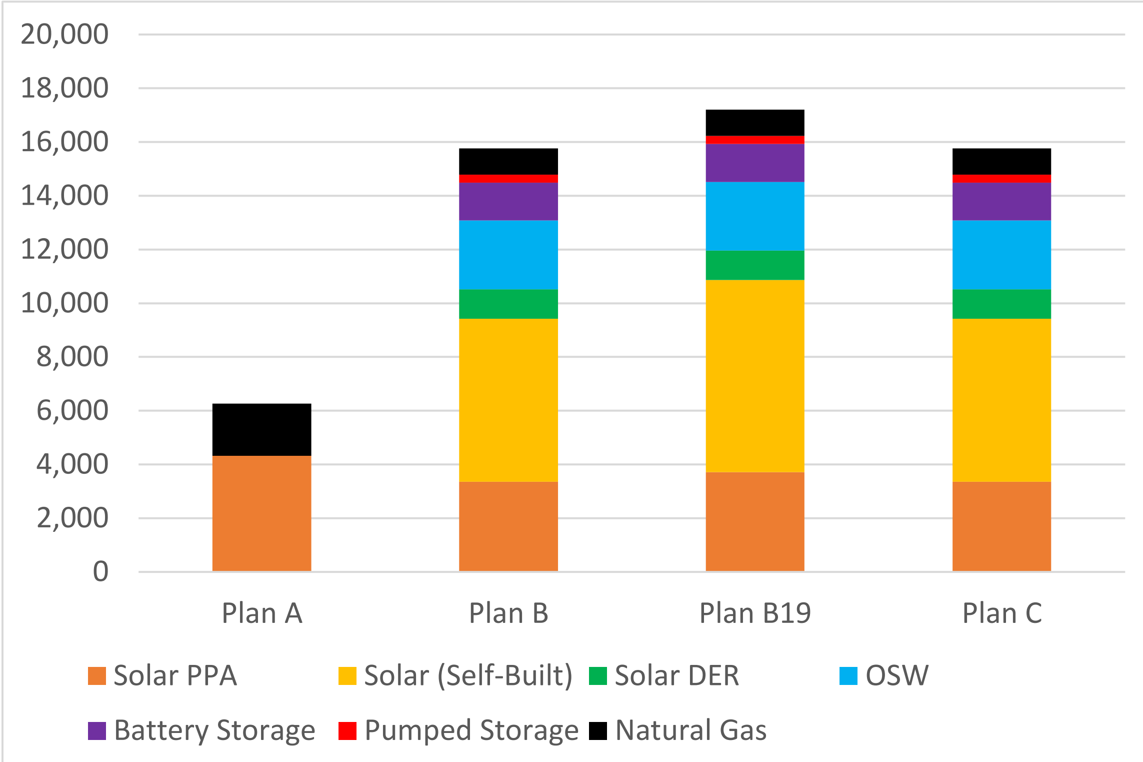


Figure 15 shows that Plan A relies on Dominion's existing generation profile and new natural gas generation for the next ten years. Plan B, Plan C, and Plan D requires large investment in renewable resources to meet the requirements of VA law.

<u>Comments on Dominion's Expansion Plans</u>

On February 1, 2020, the Virginia SCC issued its Final Order on Dominion's Integrated Resource Plan.[118] Pursuant to Virginia state law, the SCC must

[118] Final Order, *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, No. PUR-2020-00035 (VA.S.C.C. Feb. 1, 2020), available at https://scc.virginia.gov/docketsearch/DOCS/4r%24t01!.PDF.

determine whether Dominion's IRP is reasonable and in the public interest. As the VCEA became effective July 2020, the SCC recognized that Dominion "did not have an extended opportunity to conform its 2020 IRP to address all the interrelated aspects of the recent legislation."[119] The SCC found, however, that it could not conclude that Dominion's 2020 IRP is reasonable and in the public interest.[120] The Commission noted that the participants to the Virginia proceeding raised significant issues. With regard to the modeling, the Commission noted that the participants criticized the alternative plans because: (1) the VCEA Plans substantially overbuild for purposes of meeting peak load and energy requirements; (2) Dominion forced all resource additions and retirements to be selected by the model rather than allowing the model to select optimal eligible resources on a least cost basis; (3) the VCEA Plans are substantially similar and do not model multiple compliance paths; and (4) the Plans produce RECs in excess of the requirements of the RPS program.[121] The SCC stated that in its Final Order that the Company should work to refine its modeling process so that it may fully model the VCEA in future IRPs and updates. [122]

Additionally, several parties to the Dominion Virginia IRP proceeding were critical of the Company for failing to include a true least cost VCEA compliant plan. In the Final Order, the SCC noted that Staff to the SCC argued that Dominion's

[119] *Id.* at 5.
[120] *Id.*
[121] *Id.* at 7.
[122] *Id.* at 8.

expensive second tranche of wind was not mandated under the statute.[123] To address this and other issues, in that proceeding, Dominion proposed in future filings to "include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan."[124]

The Public Staff has concerns over the forcing in of resource additions into all of Dominion's portfolios. The Public Staff agrees with the VA SCC, and recommends that Dominion file a resource plan which does not include forced resources, nor excludes certain resources.

<u>TRANSMISSION</u>

Pursuant to the *2014 IRP Order*, the Utilities included a copy of their most recent FERC Form No. 715 (Annual Transmission Planning and Evaluation Report), which presents detailed information concerning their transmission line intertie capabilities, transmission line loading constraints, planned new construction and upgrades, and The North American Electric Reliability

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[123] *Id*. at 13. *See* Prefiled Staff Testimony of David Dalton, PUR-2020-00035, September 29, 2020, available at, https://scc.virginia.gov/docketsearch/DOCS/4p8%2501!.PDF, at 36-37:

> The costs for the first tranche of 2,556 MW of offshore wind are presumed to be reasonably and prudently incurred by the VCEA, subject to certain metrics. The second tranche of 2,556 MW ofoffshore wind, however, does not have the same presumption. As such, Staffs opinion is that it would have been appropriate for the Company to develop at least one plan that substitutes additional solar resources in place of the 2,556 MW second tranche of planned offshore wind resources in an amount as may be necessary to either satisfy capacity requirements to-serve peak load or to meet the mandatory RPS requirements.

[124] *Id.* at 14.

Corporation (NERC) compliance within their respective control areas for the planning period. The Utilities are in compliance with the Commission's filing requirements.

Transmission planning and investment is taking on greater significance than seen in previous IRPs for a variety of reasons: the Utilities have evaluated and proposed accelerated retirement of some fossil fuel generation, either in response to regulatory requirements or investor expectations and customer advocacy, to develop new energy storage assets to firm intermittent generation, to provide greater energy importation capabilities as alternatives to traditional generation capacity development, and to continue interconnection and operation of utility- and non-utility-owned renewable energy resources. Each of these elements are also part of a larger initiative to modernize the grid and continue to enhance the flexibility of more dynamic power flows. As the costs of these elements mature in the future, they may require new modeling and analysis methodologies that have not been part of previous IRPs.

Duke estimates required transmission interconnection and network upgrade costs separately.[125] First, transmission interconnection costs are included in the capital costs of new generation units within the System Optimizer model when selecting generation units. The table below illustrates the transmission interconnection costs that are included in the capital costs for selected generation units.

[125] Interconnection costs are those costs required to physically interconnect the generation facility to the transmission system. Network upgrade costs are those costs required to upgrade other portions of the system to accommodate power flow from the new generator.

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Table 25: Comparison of transmission costs for key technologies

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Duke then estimated network upgrade costs for solar, solar plus storage, stand-alone storage, onshore wind, natural gas, and SMRs based upon historical network upgrade costs for similar projects interconnected to Duke's system. This average transmission adder for new capacity was included in the PVRR analysis and separately reported in the IRP, but was not a factor in System Optimizer decisions. The following figures show projected annual nominal new transmission network upgrade investment for DEP and DEC, by expansion portfolio, through 2050.[126]

[126] Source: Docket No. E-100, Sub 165, Duke PSDR 3-6.

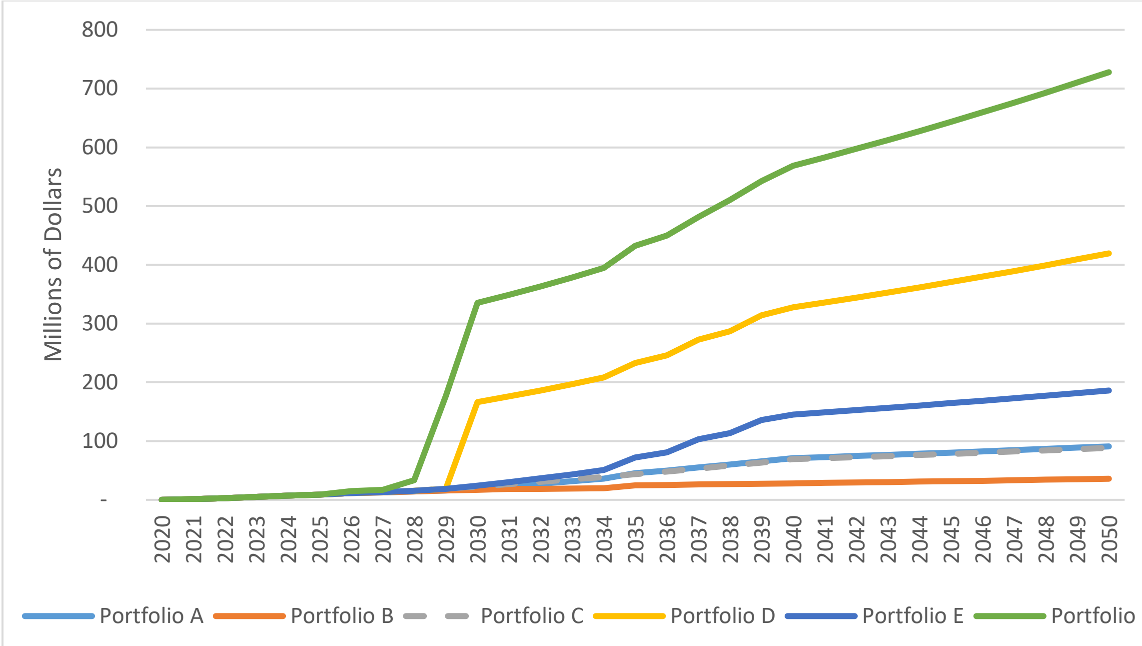

Figure 16: DEP New Transmission Network Upgrade Capital Costs

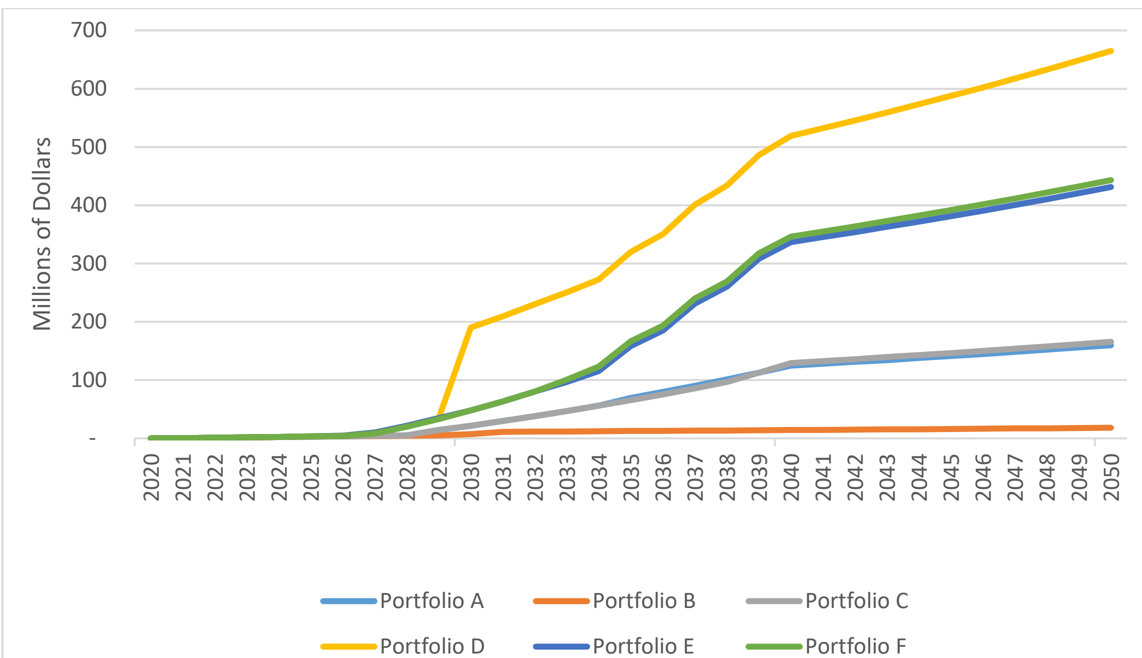

Figure 17: DEC New Transmission Network Upgrade Capital Costs

For both DEP and DEC, there is no significant difference in transmission upgrade costs among the portfolios in the short term (2020 through 2028).

However, beginning in 2029, new transmission upgrade costs relative to new generation cost are higher in the more carbon restrictive portfolios, as shown in the following graphs.[127] This increase is generally indicative of transmission network upgrade costs associated with renewable resources, which see significant growth in later planning years in most portfolios.

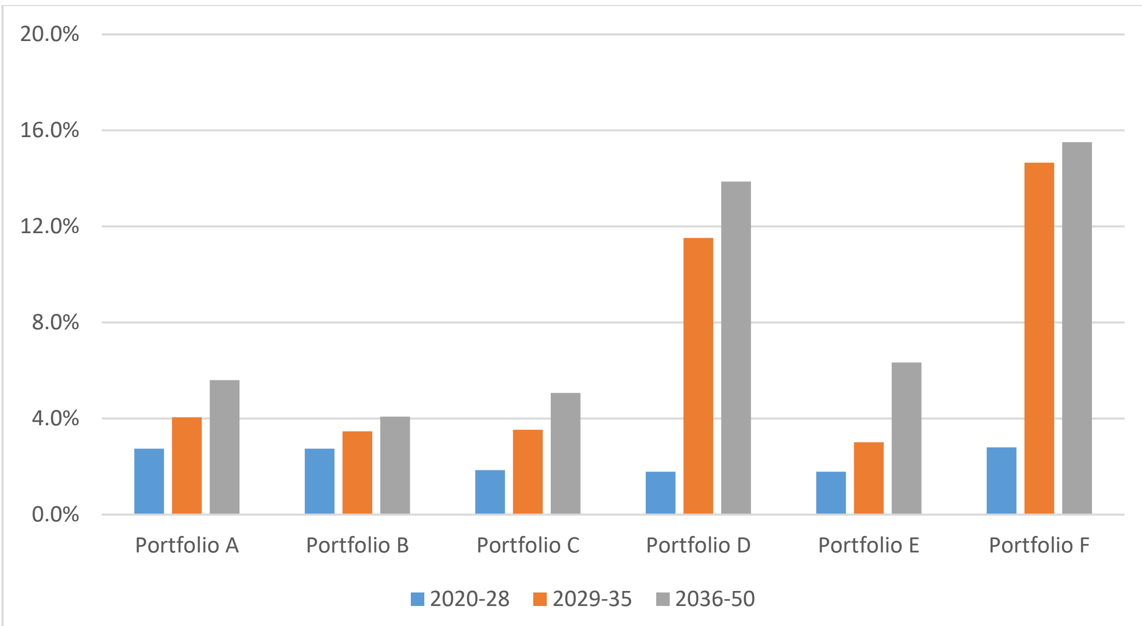

Figure 18: DEP New Transmission Costs as Percent of New Generation Capacity Costs

[127] Source: Docket No. E-100, Sub 165, Duke PSDR 3-6 (Confidential).

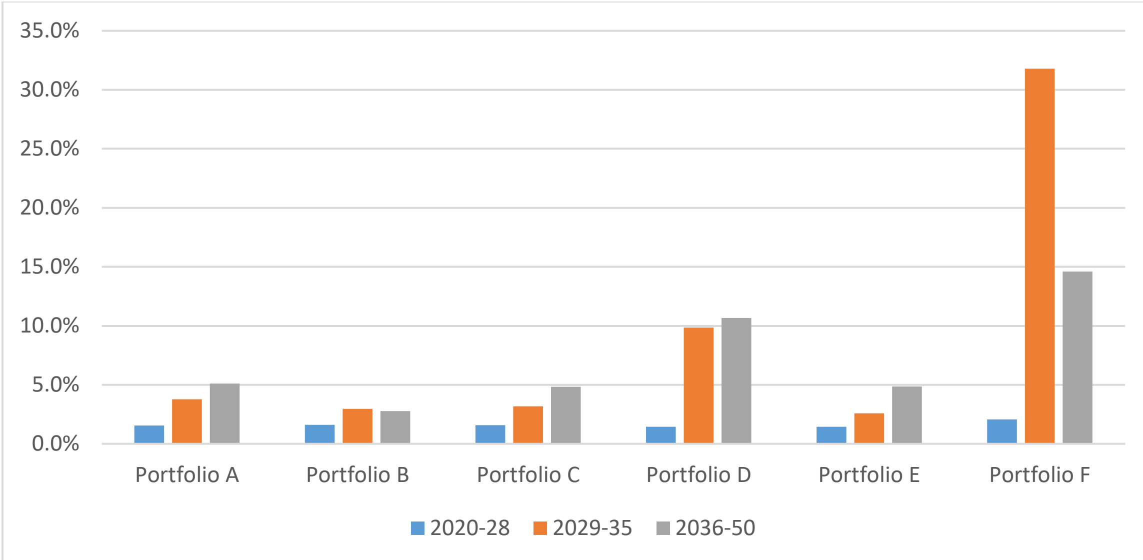

Figure 19: DEC New Transmission Costs as Percent of New Generation Capacity Costs

Figure 18 and Figure 19 show that for both DEP and DEC, new transmission as a percent of new generation in 2036-50 exceeds the 2020-28 period. This holds true for the 2029-2035 period with the exception of DEC Portfolios A and F (Base No CO_2 and No New Gas Generation). This is likely related to the significant investments in wind capacity in 2028 and beyond as described in the Planned Generation section of these comments.

Dominion Plans A and B include new transmission costs resulting from normal transmission planning of $5.1 billion for the planning period. This cost of $5.1 billion is also included in alternate Plan C and D.

Based on current needs and planning, there is little change in the Utilities' estimated transmission upgrade costs through 2028. This aligns with the cumulative generation additions and retirements during the 2021-2025 period in the STAP. As presented, Duke Portfolios A and B along with Dominion Plan B (together "Recommended Plans") are considered by the Public Staff to be acceptable for planning purposes.

The Utilities have presented several alternate paths in Duke Portfolios C-F and Dominion Plans C and D. Compared to the Recommended Plans, these alternate paths have a higher absolute level of transmission cost uncertainty due to the greater magnitude of total transmission investments.

Typically, after the Utilities identify a new transmission need, development of the new transmission resource is a multi-year process that includes, but is not limited to: planning, siting, permitting, regulatory approval, construction, planned outages, and commissioning. The utilities will refine transmission cost estimates as they identify generation parameters and assign appropriate values to them such as the siting of the generation, generation capacity, generation production profiles, and timing of in-service dates. Many of these inputs for transmission and generation are not yet known with certainty, and modelling limitations require tradeoffs between transmission specificity and model complexity.

For example, the Utilities have projected transmission costs over the next 30 years, well beyond the current transmission planning horizons for the

Utilities.[128] The further out in time a utility estimates transmission costs, the less accurate those estimates are likely to be due to changing market conditions, such as material and labor costs or unforeseen changes in siting and permitting processes and costs. The Utilities have also presented the possible need for increased transmission import capability, but did not base their projection of costs on any formal study, evaluation, or analysis.[129] [130] Dominion projects that for Plans C and D, an additional 5,200 MW of transmission import capacity may be required, at a cost of $8.4 billion.[131] Duke estimated that the cost of increasing transmission import capacity by 5,000 MW would be between $4 and $5 billion, and increasing transmission import capacity by 10,000 MW would be between $8 and $10 billion.[132] Duke does not include the cost of increased transmission import capacity in its PVRR calculations for any portfolio. Notably, in the IRP as filed, Duke does not allow imports from or exports to neighboring balancing authorities to meet capacity or energy requirements. However, the Resource Adequacy Study does

[128] Dominion and Duke standard transmission planning analyses use short-term (1-5 years) and long-term (6-10 years) time horizons. Dominion is part of PJM and participates in its Regional Transmission Expansion Plan (RTEP) that applies a 5-year and 15-year outlook. Duke participates in the North Carolina Transmission Planning Collaborative (NCTPC).

[129] In response to a data request, Duke states that a Class 5 cost estimate is based on the least amount of detail and is typically used for budgetary estimates with an inaccuracy in the high range of +100% to -50%. Duke states that its transmission cost estimates are not yet Class 5 level estimates and are beyond the range of variability. For example, if Duke Portfolio F has a Class 5 transmission estimate at $8.9 billion, then applying this range of variability would give a transmission cost range of $17.8 billion to $4.5 billion.

[130] Dominion used the 2012 Trail transmission project as the basis for development of the estimated costs for the four new inter-regional transmission lines in Plans C and D. It used 2012 costs without adjustments for inflation in arriving at the placeholder cost of $8.4 billion.

[131] *See* Dominion IRP at 31-32. The $8.4 billion is included in the PVRR for Plans C and D. Additionally, (PSDR 7-5) $2.7 billion is estimated to upgrade the existing transmission system to avoid NERC violations.

[132] *See* DEP IRP at 60 and DEC IRP at 58. The 5,000 MW import scenario would require four new 500 kV lines, three new 230 kV lines, two new 500/230 kV substations, four 300 MVAR Static Var Compensators (SVCs), and several other upgrades. The 10,000 MW import scenario would require seven new 500 kV lines, four new 230 kV lines, three new 500/230 kV substations, four 300 MVAR SVCs, and several other upgrades.

allow capacity imports when determining the target reserve margin, summarized in the table below.

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Table 26: Cumulative Import Capability in the Resource Adequacy Study

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

The number of permutations of generation types, geographic locations, timing, and capacity within generation scenarios and between scenarios can be significant, making their study complex. In the capacity expansion models used by the Utilities in their IRPs, transmission specificity is traded for reduced model complexity. It is simply not possible at this time to solve a long-term capacity expansion model with sufficient generator site specificity and the typical power flow analyses to support detailed proposed transmission investments.

Duke stated that neighboring third-party transmission systems (Affected Systems[133]) may need substantial upgrades because of the large amounts of new generation.[134] Affected system costs can be a significant part of specific transmission project planning. These Affected Systems upgrades would be

[133] Docket No. E-100, Sub 170, opened September 16, 2020, to address the affected system study process and cost allocation. DEP has at least 22 affected system studies in process (EMP-111, PSDR 3-1).

[134] DEC IRP at 55, and DEP IRP at 57.

dependent on, but not limited to, capacity resource location, amount of capacity, position in the queue of competing transmission service requests, and third-party success in meeting required in-service dates. The scope and estimated costs of the Affected System upgrades were not included in the IRP.[135]

Transmission costs are a critical aspect of planning new generation, and in some cases may even be a barrier to project development.[136] With this increased focus on transmission, the Public Staff wishes to better evaluate the overall system and determine the reasonableness of cost estimates for required imports into each respective balancing area. The Public Staff is concerned that some transmission costs associated with various portfolios – such as network upgrades and additional import capacity – are not included in the capacity expansion model, thus potentially yielding a suboptimal selection of future resources. While the Public Staff understands the current methodology of how the Utilities are attempting to capture certain costs for transmission upgrades, we believe the Utilities could continue to improve the planning process without becoming too granular and time intensive.

The Public Staff believes that future IRPs can improve how costs for required imports and exports are assigned to each portfolio, which the Utilities acknowledge may be necessary to accommodate some future resource mixes. The Public Staff believes that the generic interconnection costs that are included in the existing capacity expansion model do not fully capture required transmission

[135] *Id.*

[136] For example, the Commission denied the CPCN application in Docket No. EMP-105, Sub 0, in part due to the substantial network upgrades required to interconnect a 75 MW solar facility in southeastern NC.

investments, and the evaluation of larger scale system impacts is critical to ensuring that capacity expansion portfolios presented in the IRP represent optimal solutions. The Public Staff recognizes that it would be too complex to include detailed power flow analyses associated with future capacity expansion plans, and is open to input from the Utilities and intervenors on how to address this concern in future IRPs.

The Public Staff recommends the following information be included in future IRPs to address these concerns. For each capacity expansion plan presented, to the extent not already done, the Utilities should: 1) provide the amount of existing firm transmission import capacity; 2) list the additional incremental transmission import capacity needed to support the plan; 3) provide a high-level cost estimate associated with these increases; and 4) include those transmission costs in their PVRR analysis. In addition, for new capacity additions of all technology types, the Utilities should attempt to include network upgrade cost estimates within the capacity expansion model in the same manner as transmission interconnection costs.

SHORT-TERM ACTION PLANS

The Utilities' Short-Term Action Plans (STAP) includes new generation capacity to be built in the next five years, as well as assets retiring in that time period. Below is a summary of new and retiring generation for each utility. Generation additions shown below are not solely utility-owned resources, they are inclusive of independent power producers and legislative programs such as CPRE.

Table 27: Cumulative Generation Additions and Retirements, 2021-2025

Utility	Coal	CT	CC	Nuclear Uprates	Solar	Storage	Solar with storage (solar nameplate / storage nameplate)	Biomass / hydro
DEC	-1,130	418		57	1,302	104	192 / 45	187
DEP		-514	560	4	962	101	14 / 3	-153
Dominion	-2,866	970			3,018	14		

DEC

The STAP proposed by DEC is unchanged across all alternative portfolios. DEC is expected to take ownership and full control of the new Lincoln County CT in 2025, and the Clemson Combined Heat and Power (CHP) Facility in 2021,[137] and has planned uprates to nuclear facilities and the Bad Creek Pumped Storage Facility.

DEP

The STAP proposed by DEP is unchanged across all alternative portfolios. DEP has recently commissioned the Asheville CC Facility (560MW) to contribute to the 2021 winter peak.

[137] The Clemson CHP Facility came online during calendar year 2020 but was not available for winter peaks until calendar year 2021. This generation plant is grouped in the Cumulative Generation Additions and Retirements 2021-2025 “CT” column.

<u>DOMINION</u>

The STAP proposed by Dominion is the same for Alternative Plans B through D. Yorktown Unit 3, a heavy oil-fired generation plant, is grouped in the "Coal" column for unit retirement.

<u>*NON-UTILITY GENERATION*</u>

Commission Rule R8-60(i)(2)(iii) requires each electric utility to provide in its biennial IRP report a list of all non-utility electric generating facilities (NUGs) in its service areas, including customer-owned and stand-by generating facilities. DEC and DEP each provided a list of NUGs in compliance with this requirement.

DEC reported **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** firm wholesale purchased power contracts with a combined summer capacity of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW. Capacity designations include: base, intermediate, and peaking.

DEC reported **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** wholesale sales contracts with a combined winter capacity of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW in 2020. Product designations include: full requirements, partial requirements, fixed load shape, and backstand.

DEC indicated that it has "a very small amount of contracts" that expire under the current contract terms in the next five years, and that it "will determine the feasibility of obtaining additional purchased power arrangements in the future to economically meet customer demand."[138]

DEP reported **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** firm wholesale purchased power contracts with a combined winter capacity of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW. Capacity designations include: intermediate and peaking.

DEP reported **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** wholesale sales contracts with a combined winter capacity of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW in 2020. Product designations include: full requirements and partial requirements.

DEP stated that approximately 425 MW of wholesale purchased power contracts expire under the current contract terms in the next five years, and that it "plans to engage the marketplace to determine the feasibility of extending existing contracts or replacing them with other purchased power arrangements to economically meet customer demand."[139]

With regard to renewal of wholesale contracts, DEC and DEP indicated that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[140]

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[138] DEC IRP at 122.
[139] DEP 2018 IRP at 123.
[140] DEC and DEP IRPs. Appendix J: Non-Utility Generation and Wholesale.

COSTS

The cost of each capacity expansion plan consists of many components, and can be expressed in several ways. In the sections below, the Public Staff discusses the primary metrics by which the Utilities evaluate their plans, as well as the cost risk associated with carbon legislation uncertainty.

PRESENT VALUE REVENUE REQUIREMENTS

One of the primary metrics that the Utilities use to compare their various capacity expansion plans is the Present Value Revenue Requirement (PVRR) metric. Essentially, this is the total amount collected from customers that compensates the utility for all expenditures associated with each generation portfolio. The capacity expansion model converts the annual future expenditures into one single figure, reflecting the approximate present value of the revenue requirements necessary to fund each plan. The annual future nominal expenditures from the capacity expansion model are also used to estimate future rate impacts, as discussed in the next section.

The PVRR for DEC and DEP through 2050 is shown in Figure 20 below. Duke calculates the annual expenditures in several categories for each portfolio:

- Generation Capital Costs or Carrying Charges that include a return on equity and debt investment, depreciation, taxes, and insurance
- Production costs – Fixed and variable O&M for new generation units and existing generation units that vary across portfolios.

- Fuel demand – fuel costs to meet load. Duke's models separate the fuel costs from other production costs.
- Coal capital and fixed O&M – existing coal unit capital investments and fixed O&M leading up to retirement.
- New transmission – capital and operating costs associated with interconnecting new generation capacity to the transmission system.
- Retire Coal Transmission – added transmission costs for those coal stations that require transmission projects upon retirement.
- Carbon tax – the annual carbon costs, calculated as the price per ton multiplied by the total tons emitted by fossil fuel plants.

In its IRP, Duke presents the PVRR figures without the costs of CO_2 - essentially, Duke anticipates that the carbon tax will be similar to a carbon mass cap or cap and trade with allowance allocations.[141] Comparing the plans below, it can be seen that the carbon price accounts for the bulk of the "cost premium", defined here as the difference between a given portfolio and the least-cost Portfolio A. With the CO_2 tax, Portfolio B is 23% more expensive than Portfolio A, for both DEC and DEP. Without the CO_2 tax, Portfolio B is 5% and 1% more expensive than Portfolio A, for DEC and DEP respectively. This highlights the significant influence that carbon policy design can have on ratepayer bill impacts.[142]

[141] *See* DEP IRP at 153.

[142] While the exclusion of the carbon tax from the PVRR figures Duke presents in its IRP is indicative of a carbon mass cap or cap and trade program, it also would be similar to a carbon tax program where the carbon tax proceeds are refunded to ratepayers via a tax credit.

The data show that Portfolio A has the highest production costs of all portfolios, and the highest fuel costs of all but Portfolio B. However, these cost savings are offset by higher costs for new generation capacity, new transmission, and CO_2 in the other portfolios. This is intuitive – as previously discussed, Portfolios B through F all have a significantly larger buildout of solar, storage, wind, and nuclear SMR capacity, requiring significant transmission investments. As that capacity comes online, there is a significant reduction in fuel and production costs associated.

Table 28 below summarizes the percentage cost premium for each Duke portfolio compared to both Portfolio A and Portfolio B, with and without the cost of CO_2. This analysis is presented for DEC and DEP.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 20: PVRR through 2050 for DEP and DEC Portfolios

[END CONFIDENTIAL]

The cost premium analysis highlights several important insights. First, the CO_2 price is the primary driver of the cost premium for Portfolio B and Portfolio C – excluding the cost of CO_2, for the combined utilities, Portfolio B is 3% more expensive than Portfolio A, and Portfolio C is 5% more expensive than Portfolio A and 2% more expensive than Portfolio B. As discussed previously, the cost premiums are being driven by increased costs for new generation capacity, new transmission, and CO_2; while they are offset by lower production costs and fuel costs. This highlights the risks of implementing Portfolio A compared to other portfolios; if carbon policy is enacted, or if capital costs of new capacity are lower than expected, ratepayers may be stuck paying higher production costs over the long term.

Table 28: Cost Premiums of Duke Portfolios

Portfolio	BA	Total PVRR: PVVR Increase from Portfolio B	Total PVRR: PVVR Increase from Portfolio A	PVRR Excluding CO2: PVVR Increase from Portfolio B	PVRR Excluding CO2: PVVR Increase from Portfolio A
A - Base No CO2	DEP	-19%	n/a	-1%	n/a
	DEC	-19%		-4%	
	Combined	**-19%**		**-3%**	
B - Base CO2	DEP	n/a	23%	n/a	1%
	DEC		23%		5%
	Combined		**23%**		**3%**
C - Earliest Practicable Coal Retirements	DEP	2%	26%	5%	6%
	DEC	0%	23%	0%	5%
	Combined	**1%**	**25%**	**2%**	**5%**
D - 70% w Wind	DEP	14%	40%	25%	26%
	DEC	11%	37%	18%	24%
	Combined	**12%**	**39%**	**21%**	**25%**
E - 70% w SMR	DEP	9%	34%	17%	18%
	DEC	6%	31%	13%	18%
	Combined	**7%**	**32%**	**15%**	**18%**
F - No New Gas Generation	DEP	32%	63%	46%	47%
	DEC	16%	43%	24%	30%
	Combined	**23%**	**52%**	**34%**	**38%**

The Public Staff considers Portfolios C, D, E, and F to be illustrative examples of what an expansion plan with aggressive carbon reduction goals might look like. The primary reason that the Public Staff does not believe these portfolios to be reasonable for planning purposes is that these portfolios were not optimized based on a carbon reduction restraint placed on the model. Instead, Duke forced various resources (wind, SMR, solar, and energy storage) into the model until the target CO_2 reduction goal was met.[143] Portfolios A and B were largely allowed to economically select the optimal resources to meet demand subject to system constraints and, in the case of Portfolio B, a carbon tax.[144] In future IRPs, Duke should construct a portfolio that sets a carbon limit and allows the model to economically select the necessary resources to meet that limit. This would represent a least-cost carbon constrained portfolio, which would be preferable to the illustrative portfolios provided in this IRP.

Dominion presents its PVRR analysis for each of its Plans A, B, B19, C, and D in its IRP.[145] This information, along with cost premiums calculated for each plan relative to Plan A (least cost) and Plan B (least cost compliant with VA law prior to 2045), is presented in Table 29 below. The alternative plans' cost premium to Plan A is significant, and represents Dominion's estimate of the cost of recent VA legislation. As Plan A is not compliant with VA law, it is presented for cost comparison purposes only. Plans C and D are identical to Plans B and B19, respectively, except that all carbon-emitting resources are forced offline by 2045 in order to comply with the VCEA.[146]

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[143] *See* Duke response to PS DR 7-1.

[144] Some solar and storage was forced into both Portfolios A and B, reflecting mandated solar resources and planned battery investments. Notably, no additional solar was economically selected in Portfolio A.

[145] Plan B19 is the same as Plan B, but solar resources have a capacity factor of 19% compared to 25%. Plan C is the same as Plan B, but with all carbon-emitting generation retired by 2045. Plan D is the same as Plan B19, but with all carbon-emitting generation retired by 2045.

[146] *See* VA Code § 56-585.5(B)(3): By December 31, 2045, each Phase I and II Utility shall retire all other electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity. Dominion's IRP notes that exceptions can be made if "the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric service." Dominion IRP at 11.

Table 29: PVRR through 2050 for Dominion

2020 $B	Plan A	Plan B	Plan B19	Plan C	Plan D
Total System Costs	**$ 34.7**	**$ 56.8**	**$ 59.2**	**$ 60.7**	**$ 63.0**
GT Plan	$ 0.2	$ 3.2	$ 3.2	$ 3.2	$ 3.2
Strategic Underground Program	$ 2.2	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Broadband	$ -	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Transmission Underground Pilot	$ -	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Transmission	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1
Transmission Level Import Increase	$ -	$ -	$ -	$ 8.4	$ 8.4
Customer Growth	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0
Subtotal Plan NPV	**$ 44.3**	**$ 69.7**	**$ 72.1**	**$ 82.1**	**$ 84.3**
Less Benefits of GT Plan	$ -	$ (3.5)	$ (3.5)	$ (3.5)	$ (3.5)
Total Plan NPV	**$ 44.3**	**$ 66.2**	**$ 68.6**	**$ 78.6**	**$ 80.8**
Plan Delta vs. Plan A	$ -	$ 21.9	$ 24.3	$ 34.3	$ 36.6
Cost Premium vs Plan A	n/a	50%	55%	78%	83%
Plan Delta vs. Plan B	$ (21.9)	n/a	$ 2.4	$ 12.4	$ 14.7
Cost Premium vs Plan B	-33%	n/a	4%	19%	22%

The Public Staff notes that while the VCEA has a requirement that all carbon-emitting generation be offline by 2045, there is a provision that allows Dominion to petition the Commission to keep certain carbon-emitting plants online if the "requirement would threaten the reliability or security of electric service to customers."[147] The statute requires the Commission to "consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition."

[147] *See* VA Code § 56-585.5(B)(4).

In its IRP, Dominion recommends a path forward that substantially aligns with the first 15 years of Alternative Plans B through D; it also recommends Plan B over the longer term.[148] However, the VA Commission Staff noted that the "Company's Plan D fully models the policy goals of the VCEA including being 100% carbon free by 2045."[149] The Public Staff agrees with Dominion that there are not significant differences between Plans B through D in the next 15 years, like the near-term similarity of Duke's Portfolios A and B. In line with the Public Staff's position regarding the Duke IRPs, the Public Staff recommends that Dominion Plan B be accepted as reasonable for planning purposes at this time. As discussed in the IRP Portfolios section, all the Dominion IRP plans force in significant amounts of resources without letting the model optimally solve for a least-cost plan complaint with the VCEA; as such, the Public Staff does not believe that the Commission should accept the high cost of plans C and D.

RATE IMPACTS

For several IRP cycles, Dominion has included an analysis of residential rate impacts associated with its IRP. Beginning in the 2016 IRP review, the Public Staff commented that these rate analyses provided "insightful and compelling information"[150] to customers and the Commission, and recommended that DEC and DEP include similar rate impact analysis.

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[148] Dominion IRP at 7-8.
[149] *See* Prefiled testimony of Gregory L. Abbot, No. PUR-2020-00035 at 3, September 29, 2020.
[150] Comments of the Public Staff, Docket No. E-100, Sub 147, at 81,February 17, 2017.

In the 2018 IRP proceeding, the Public Staff renewed its recommendation that DEC and DEP include a rates analysis for each portfolio evaluated in future IRPs, particularly for residential customers.[151] The Public Staff's recommendation was also supported by the AGO and other parties in the Sub 157 proceeding. The AGO even recommended that the rate impact analysis also include all other rate classes, and not be limited to the residential class bill analysis. However, the Commission's orders[152] approving the 2018 IRP and 2019 IRP update declined to require DEC and DEP to include the same analysis in their future IRPs.

<u>**DUKE**</u>

The Public Staff reviewed Duke's workpapers associated with the calculations represented in Tables A-17 in each IRP. Those workpapers show that Duke developed a residential revenue requirement for each plan that represents the "incremental" increase associated with the new resources (generation and transmission) that would be needed as the plan matures over the planning horizon. Duke used a baseline year of 2021 and incorporated supporting inputs related to depreciation rates, cost of capital and capital structure, cost allocation factors based on the single summer coincident peak methodology, and various plant and expense escalators to determine the overall system-wide retail revenue requirement and rate impact.[153] The workpapers also indicate that Duke should be able to calculate rate impacts for other customer classes. However, such additional

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[151] Comments of the Public Staff, Docket No. E-100, Sub 157, at 92-93,. March 7, 2019.
[152] *See* 2018 and 2019 IRP Orders.
[153] DEC and DEP used the depreciation studies and return on equity and capital structures approved by the Commission in Docket Nos. E-7, Sub 1146, and E-2, Sub 1142, respectively. The more recent rate cases are still pending, and would likely result in slightly different rate impacts.

calculations are difficult to develop for non-residential classes that have a myriad of loads and load factors (i.e., a simple bill per 1,000 kWh is not informative for non-residential bills).

DOMINION

Dominion's approach to calculating the bill impacts represented in Table 2.5.1 is similar to that of Duke. However, there are a few notable differences. First, Dominion's approach focused only on the residential rate impacts of the Virginia jurisdiction. This included the allocation of revenue requirement among the various Virginia retail customer classes using its average and excess cost of service methodology, as approved in Virginia. Second, Dominion indicated that it established a baseline that predates the VCEA. In other words, the rate impact analysis focused on the impacts associated with the VCEA. Dominion also did not include any costs associated with the Commonwealth of Virginia's participation in RGGI, or costs associated with the new solar generation required by the GTSA.[154] Third, Dominion included the impacts associated with the new emphasis on DSM and EE and the impacts of net-metered customers required by the VCEA. Dominion's calculations incorporated actual data for 2019 and 2020 to the extent it was available, and supporting inputs contemporaneous with its most recent cost of service to determine the overall Virginia-area retail revenue requirement for residential service.

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[154] See VA Code § 56-585.1(A)(6) as amended by the GTSA that describes the requirement for 5,000 MWs of new solar generation.

CONCLUSIONS AND RECOMMENDATIONS

The Public Staff does not take issue with Duke's or Dominion's calculations and the results given in Duke's Tables A-17, and Dominion's Table 2.5.1 for residential bills. It is important to note that such calculations are subject to several assumptions, and should not be interpreted in absolute terms. However, the data in the tables provide a good representation of the differences in the bill impacts of each portfolio. The use of consistent supporting inputs for each portfolio provides a reasonable snapshot and comparison between plans. For example, Duke's Table A-17 reflects the two to three-fold increase noted in the 70% CO_2 reduction plans when compared to the base case plans. Dominion calculated similar increases.

Duke's analysis is the first of its kind in its IRP. Dominion has included its residential bill impact analysis now for several IRP cycles. The Public Staff will continue to work with both Duke and Dominion to understand the sensitivities of the various inputs and ensure that the analyses are capturing all of the incremental changes to revenue requirements resulting from each plan.

COST OF CARBON POLICIES

The Public Staff's recommendation of an appropriate planning capacity expansion plan (Duke's "Portfolio" or Dominion's "Alternative Plan") considers many factors, not least of which is the potential for future carbon legislation at the state or federal level. In the case of Dominion, the least-cost plans that are compliant with Virginia law in the study period, Alternative Plans B and B19, include state-level carbon pricing in the form of RGGI allowance prices. In this case, as

Virginia has in fact become a participant in RGGI, and while there is uncertainty around the future cost of carbon allowances, there is no uncertainty regarding the existence of such costs. The carbon price forecasts used by Dominion and Duke are shown in Figure 21 below. Dominion's forecast is generated by an outside consultant, ICF, and is a combination of forecasted RGGI pricing beginning in 2021 and forecasted federal carbon pricing beginning in 2025. Duke's forecast is set at $5 per ton in 2025, and increases by $5 per ton in each year thereafter. Duke describes its internally generated forecast as being in line with federal legislative proposals it has been tracking, and also notes that the values chosen incentivize Zero Emitting Load Following Resource (ZELFR) technologies, additional renewables, accelerated coal retirements, and battery storage.[155]

[155] DEP IRP at 152.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 21: Carbon prices used by Dominion and Duke in their IRPs.

[END CONFIDENTIAL]

Duke's Portfolio A is the only portfolio presented without a carbon price beginning in 2025. All other portfolios include a carbon price that is assessed on all carbon-emitting resources as described in Figure 21.[156] In considering which expansion plan to recommend for planning purposes, the Public Staff adheres to N.C. Gen. Stat. § 62-2(3a), which provides, in part, that it is the policy of the state "to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable . . . ." It is the Public Staff's position that "least cost" must consider not only the factors

[156] The high CO2 price scenario starts at $5 per ton in 2025 and increases by $7 per ton in each year thereafter.

that are known and present at the time of the IRP, but also potential future changes to the electricity industry, combined with their likelihood of occurrence and potential risk factors of pursuing a plan that does not account for these potential changes. This is consistent also with requirements of Commission Rule R8-60 that requires the utility to analyze the risk associated with the costs of complying with environmental regulation.[157]

The recommendation of a "least cost" plan has to, in part, consider the uncertainty around whether there will be carbon pricing in the future. Consider Figure 22 below, which displays the incremental cost of Duke's Portfolio B compared to Portfolio A under various scenarios.[158] The blue bar represents the incremental cost of Portfolio B, if Duke were to proceed with Portfolio B and no carbon price is ever enacted. The orange bar shows the incremental savings to ratepayers if Duke were to proceed with Portfolio B and the base CO_2 price is enacted in 2025 at the rate and escalation Duke expects. The gray bar shows the incremental savings to ratepayers if Duke were to proceed with Portfolio B and the high CO_2 price is enacted in 2025.

[157] Commission Rule R8-60(g) states "The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors."

[158] The Public Staff is only considering Portfolios A and B. Portfolios C through F are, in the Public Staff's view, more illustrative and responsive to stakeholder concerns. They are significantly more expensive than both Portfolio A and B, and the Public Staff does not recommend that Portfolios C through F be accepted for planning purposes.

This figure shows several items of interest. First, should Duke proceed with Portfolio B and no carbon tax is enacted by 2050, the incremental cost to ratepayers is significant: approximately $2.4 billion in PVRR terms, or an increase of 3% over Portfolio A.[159] On the other hand, should Duke build Portfolio B and a high carbon tax is enacted in 2025, the incremental savings to ratepayers is approximately $1.5 billion, or a savings of 1.4% relative to Portfolio A. The expected ratepayer cost or savings, therefore, is highly dependent upon the likelihood of future carbon legislation. The more one believes future carbon legislation is inevitable, the more weight one should assign to the potential benefits of Portfolio B over Portfolio A.

The Public Staff notes that this analysis does not consider the impact of potentially retiring natural gas plants early in the face of future climate legislation, as explored in a sensitivity analysis in Duke's IRPs. DEC found that reducing the book life of natural gas assets to 25 years from 35 years did not accelerate solar or solar plus storage, but it did accelerate additional onshore wind and change the timing of CC and CT generation at the end of the planning horizon.[160] DEP found that approximately 300 MW of gas generation was replaced with accelerated wind and solar plus storage.[161]

[159] The 2050 PVRR of Portfolio A is approximately $79.8 billion.
[160] DEC IRP at 172.
[161] DEP IRP at 171.

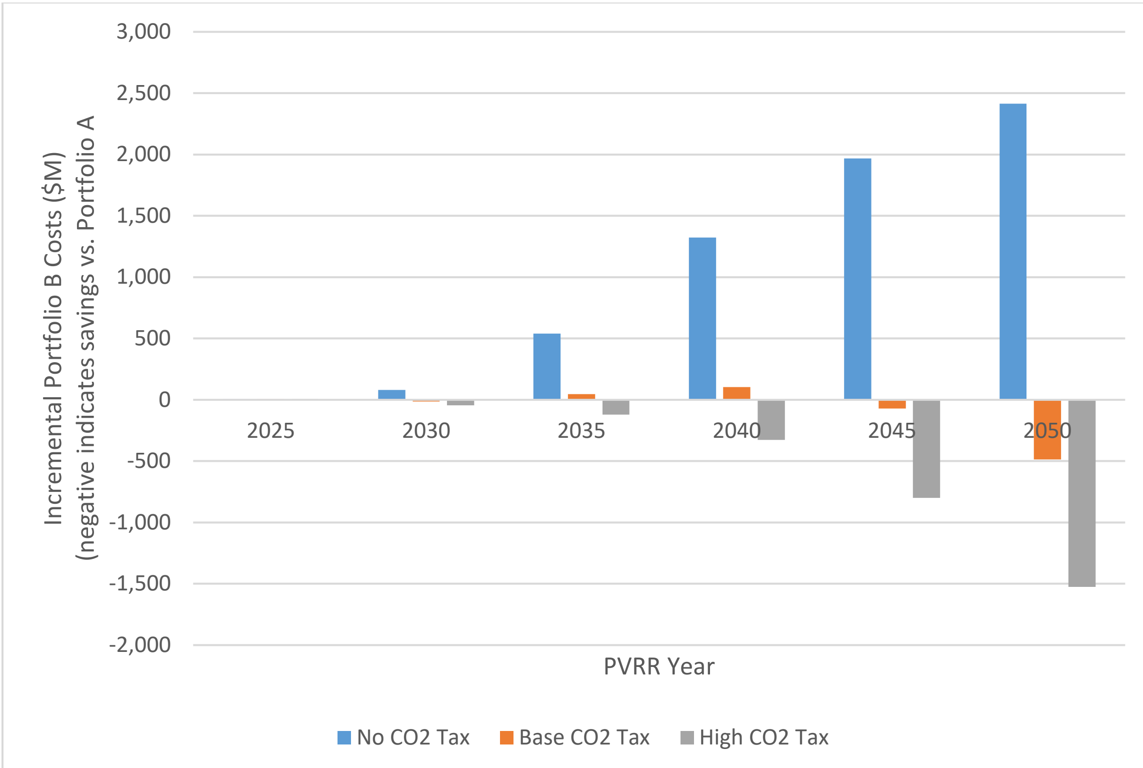

Figure 22: Calculated carbon policy risk. Incremental cost of Portfolio B over Portfolio A, DEC and DEP combined.

However, this analysis is complicated by other factors – namely, that whichever Portfolio (A or B) the Commission accepts for planning purposes in this proceeding is not fixed for the next 30 years. The Utilities file new IRPs every two years with updates in the intervening years; thus, the Utilities have ample opportunities to modify their plan as the uncertainty surrounding carbon legislation is resolved. Portfolios A and B are largely the same through approximately 2030, as shown in Figure 23 below. By 2030, Portfolio B has replaced approximately 600 MW of natural gas with 525 MW of solar and 480 MW of energy storage of various durations. Since Portfolios A and B are largely similar prior to 2030, Duke's short-term action plan does not need to be changed significantly based on the selection of either portfolio.

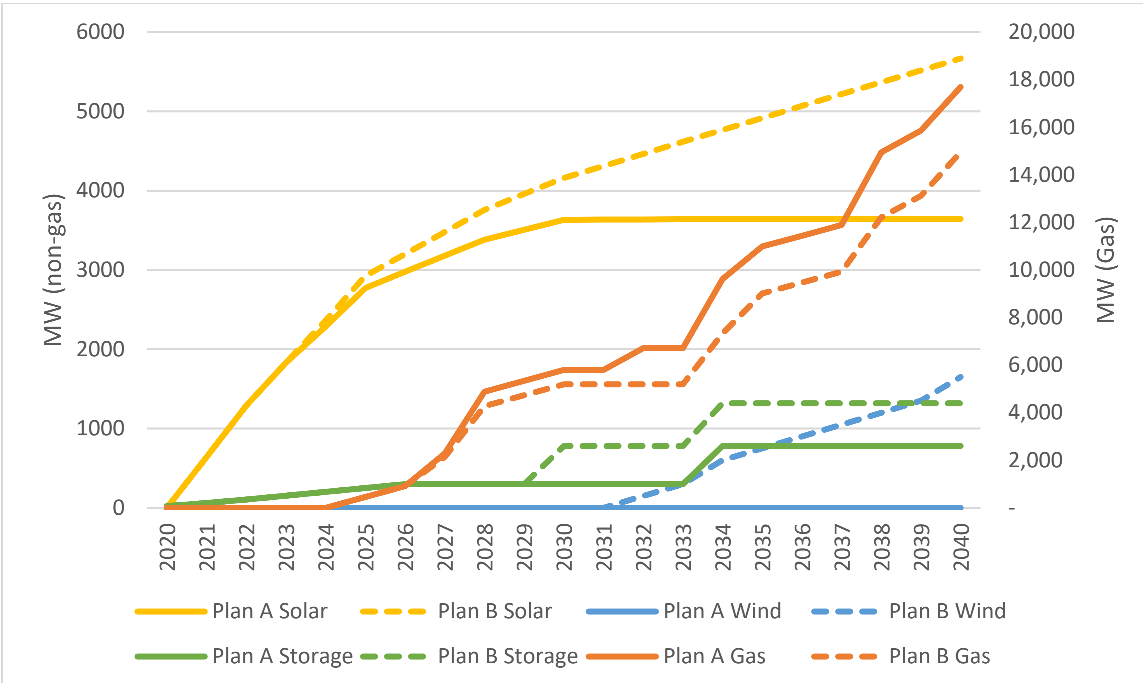

Figure 23: Comparison of new capacity added in Duke's combined Portfolios A and B.

Thus, in recommending to the Commission which Duke portfolio should be accepted for planning purposes, the Public Staff must consider the portfolio estimated costs, the uncertainty of carbon legislation, the incremental costs of the base case Portfolios A and B in various carbon legislation scenarios, and the ability of Duke to adjust course over the next ten years as the uncertainty around carbon legislation is resolved.

Considering the factors presented above, the Public Staff believes that both Portfolios A and B are reasonable for planning purposes, and recommends that the Commission accept both as such. As discussed in our comments, the

Commission's acceptance of either Portfolio A or B would not necessitate significant changes in Duke's short-term action plan over the next five years. In response to a Public Staff data request, Duke stated that only Portfolio C (Earliest Practicable Coal Retirement) and Portfolio F (No New Gas) might require the acceleration of timelines for battery storage and transmission projects; as such, the Public Staff recommends that portfolios other than A and B not be accepted for planning purposes. These portfolios are illustrative of what would be required to meet certain aspirational CO_2 reduction goals, but absent laws or regulations, pursuing these portfolio strategies would impose incremental costs on customers that are not reasonable or prudent at this time.

The Public Staff believes that the current national political climate, potential state action stemming from recommendations made in the CEP, shifts in public opinion regarding climate change and carbon regulation,[162] and commercial and industrial customers' increased support of green energy, all support the expectation that future limits on carbon are more likely than not. The Public Staff finds Duke's CO_2 assumptions in Portfolio B to be reasonable, and therefore assigns significant weight to the carbon cost risk identified above. However, in support of Portfolio A, the Public Staff notes that Duke does not anticipate any significant generation projects prior to September 2022, when it files its next full IRP. At that time, uncertainty around carbon legislation may be resolved, leaving Duke ample time to adjust its short-term action plan to respond to CO_2 regulatory

[162] *See* "Two-Thirds of Americans Think Government Should Do More on Climate", PEW RESEARCH, June 23, 2020, https://www.pewresearch.org/science/2020/06/23/two-thirds-of-americans-think-government-should-do-more-on-climate/.

developments. The Public Staff recommends that Duke continue to include a section in its IRPs discussing potential carbon legislation and regulations.

The Public Staff also emphasizes that the either-or nature of Portfolio A versus B is largely an artifact of how the carbon cost is modeled in System Optimizer. In the model, carbon costs are *deterministic*; that is, they are known for certain in each year. Thus, the two portfolios are optimized based upon that certainty, and it is up to the Commission to determine which "certainty" is more reasonable. In the end, both portfolios are actually sub-optimal, because they ignore the very real uncertainty that exists. What is necessary to determine the optimal portfolio in the face of significant uncertainty is a hedging strategy, which would incorporate carbon policy uncertainty within the model itself. In order to determine the appropriate hedging strategy, Duke should consider implementing stochastic optimization[163] in its capacity expansion model.[164] Stochastic modeling would seek to optimize the expansion plan given uncertainty in carbon pricing year by year, creating a more robust expansion plan that is well situated to provide least-cost electricity regardless of the carbon price outcome.

IMPACT ON AVOIDED COST

As the role of renewable generation grows, the Public Staff notes that the avoided cost proceedings and the IRP become ever more closely linked. While

[163] The Resource Adequacy Study employs stochastic optimization, where uncertainty of load, solar output, and generator outages is kept in the model, and thousands of model runs are executed to determine the optimal solution given the uncertainty of certain variables. These models are significantly more complex and time consuming. At this time, it is unclear if Encompass, the capacity expansion model Duke plans to adopt, permits this level of uncertainty.

[164] Duke discusses models with perfect foresight in Chapter 16 of its IRPs.

Duke's preferred resource expansion plans identified in the IRP and the expansion plans utilized in the determination of avoided energy costs have not always been identical, the inputs and assumptions that underlie the IRPs are largely applied in the determination of the avoided energy costs as well; i.e., both models employ the same generation unit characteristics and projected fuel costs. As such, the dispatching of generation units within the IRP capacity expansion model is comparable to the more detailed and granular dispatch model incorporated in the production simulation model. The most notable difference to date has been the addition of carbon prices in the IRP model.

This issue was first addressed by the Commission in its Order in the 2014 Avoided Cost Proceeding, Docket No. E-100, Sub 140[165] when DEC and DEP were ordered to refile their avoided energy rates exclusive of a generation expansion plan that optimized the inclusion of CO_2 costs. In that proceeding, DEC's and DEP's inclusion of carbon prices resulted in an expansion plan that justified the future construction of a new nuclear unit with its relatively low energy prices, and which contributed to the artificial lowering of Duke's avoided energy costs.

Similarly, in this proceeding, Dominion's Plan B includes an increased presence of renewable generation that emphasizes relatively high capital costs per kW and zero or near zero fuel costs. It is noteworthy that had Dominion modeled

[165] Order Establishing Standard Rates and Contract Term for Qualifying Facilities, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities-2014*, Docket No. E-100, Sub 140, at 24 (N.C.U.C. Dec. 17, 2015).

its avoided energy costs with the resource expansion plan used with Plan A, its avoided energy costs would be approximately 6% higher than modeled with Plan B, which reflects compliance with the Virginia Clean Economy Act (VCEA). Avoided capacity costs are unaffected by the inclusion of renewables because capacity costs are largely based upon the cost (capital & fixed O&M) of a CT. While the Public Staff acknowledges that Dominion's Plan A would not be compliant with the VCEA if implemented, and that the determination of the appropriate capacity expansion plan is properly evaluated within the confines of the IRP process, we believe the Commission should generally be aware of the implications of Dominion's Plan B on avoided energy costs.

REPS COMPLIANCE PLAN REVIEW

N.C. Gen. Stat. § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency (EE) measures. An electric power supplier may comply with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by purchasing renewable energy certificates (RECs).

Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction[166] (or through demand-side management (DSM) measures, in the case of electric

[166] "Electricity demand reduction," as used herein, is defined in N.C.G.S. § 62-133.8(a)(3a).

membership corporations (EMCs) and municipalities). Electric public utilities may use EE measures to meet up to 25% of their overall requirements contained in N.C.G.S. § 62-133.8(b) until calendar year 2021 when this limit increases to 40%. One megawatt-hour (MWh) of savings from DSM, EE, or electricity demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. EMCs and municipalities may use DSM and EE to meet the requirements of N.C.G.S. § 62-133.8(c) without any limit on the maximum amount allowed.

All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of their total requirements, with the exception of Dominion, which may use out-of-state RECs to meet its entire requirement. The total amount of RECs that must be provided by an electric power supplier for 2020 is equal to 10% of its North Carolina retail sales for the preceding year. For the Utilities, the requirement set by N.C.G.S. § 62-133.8(b) increases to 12.5% in 2021 and remains at 12.5% thereafter. For EMCs and Municipalities, the requirement set by N.C.G.S. § 62-133.8(c) remains at 10% in 2021 and thereafter.

Commission Rule R8-67(b) provides the requirements for REPS compliance plans (Plans). The Utilities must file their Plans on or before September 1 of each year as part of their IRPs,[167] and explain how they will meet the requirements of N.C.G.S. § 62-133.8(b), (d), (e), and (f). The Plans must cover the current year and the next two calendar years, or in this case, 2020, 2021, and 2022 (the Planning Period). An electric power supplier may have its REPS compliance

[167] Although municipalities and EMCs do not file IRPs, they are required to file REPS Compliance Plans on or before September 1 of each year.

requirements met by a utility compliance aggregator as defined in Commission Rule R8-67(a)(5).

Below are the Public Staff's individual comments on the Plans filed by DEC, DEP, and Dominion to comply with N.C.G.S. § 62-133.8(b) and (d), the general requirement[168] and the solar energy set-aside. These are followed by consolidated comments on the Utilities' plans to comply with N.C.G.S. § 62-133.8(e) and (f), the swine and poultry waste set-asides.

DEC

DEC serves as the REPS compliance aggregator for Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, and the Town of Highlands (collectively, DEC's Wholesale Customers). DEC has contracted for or procured sufficient resources to meet the general requirement and solar energy set-aside for the Planning Period, both for itself and for DEC's Wholesale Customers.

DEC intends to use EE programs to meet up to 25% of its REPS requirements in 2020, and up to 40% of its REPS requirements in 2021 and 2022.

Hydroelectric facilities and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the REPS requirements of DEC's Wholesale Customers. Hydroelectric facilities of 10 MW or less, together with incremental capacity from the 2012 modifications to its Bridgewater

[168] The overall REPS requirements of N.C.G.S. § 62-133.8(b) and (c), net of the requirements of the three set-asides established by N.C.G.S. § 62-133.8(d), (e) and (f), are frequently referred to as the "general requirement."

hydroelectric plant, will provide RECs for DEC's retail customers. DEC plans to use wind energy, either through REC-only purchases or energy delivered to its system, towards its general requirement. A portion of the general requirement for DEC's retail and wholesale customers will be met through various biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. DEC also expects to use solar resources to satisfy the general requirement, including RECs acquired from its net-metered customers.

DEC plans to evaluate additional projects through the competitive procurement process established in North Carolina HB 589. HB 589 mandates the competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEC may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

To meet the solar energy set-aside, DEC will obtain RECs from its self-owned solar photovoltaic (PV) facilities and from other solar PV and solar thermal facilities. DEC's solar resources include 81 MW of capacity at the Monroe, Mocksville, and Woodleaf solar facilities, and approximately 10 MW_{DC} from the small distributed solar facilities approved in Docket No. E-7, Sub 856.

DEC anticipates that its REPS compliance costs for the Planning Period will increase, but that they will remain below the cost caps contained in N.C.G.S. § 62-133.8(h)(3) and (4).

DEP

DEP has contracted for and banked sufficient resources to meet the general requirement and solar energy set-aside. DEP no longer provides REPS compliance services for other electric power suppliers.

DEP intends to use EE programs to meet up to 25% of its REPS requirements in 2020, and up to 40% of its REPS requirements in 2021 and 2022.

It plans to meet a significant portion of the general requirement using RECs from solar facilities, including RECs acquired from its net-metered customers. A portion of the general requirement will be met through various biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. Hydroelectric facilities will also provide RECs for DEP's retail customers. DEP will continue to evaluate the use of wind energy for future REPS compliance.

DEP plans to evaluate additional projects through the competitive procurement process established in HB 589. HB 589 mandates the competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEP may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

To meet the solar energy set-aside, DEP will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities. DEP owns four solar facilities, totaling 140.7 MW of capacity.

DEP anticipates that its incremental REPS compliance costs will remain below the cost caps set forth in N.C.G.S. § 62-133.8(h)(3) and (4), but it expects them to reach approximately 77% of the cost cap in 2022.

DOMINION

Dominion has contracted for and banked sufficient resources to meet the general requirement and solar energy set-aside through the Planning Period for itself and for the Town of Windsor (Windsor). Dominion plans to use EE, purchased in-state and out-of-state RECs, and company-generated RECs to meet the general requirement for its retail customers. For Windsor, Dominion will use biomass RECs and Windsor's SEPA allocation. Dominion has purchased or plans to purchase solar RECs to meet the solar energy set-aside and has executed contracts with in-state solar facilities to satisfy Windsor's portion of the in-state solar energy set-aside. Dominion's total costs are the same as its incremental costs because, unlike DEC and DEP, Dominion currently plans to purchase only unbundled RECs to meet its REPS requirements, rather than RECs that are bundled with renewable electric energy.

Dominion anticipates that during the Planning Period it will incur minimal annual research costs for the continued operation of the remaining portions of its microgrid project at its Kitty Hawk District Office.

Dominion expects that the REPS compliance costs for the Planning Period for itself and Windsor will be well below the cost caps set forth in N.C.G.S. § 62-133.8(h)(3) and (4).

REPS COMPLIANCE SUMMARY TABLES

The following tables are compiled from data submitted in the DEC, DEP, and Dominion Plans. Table 30 shows the projected annual MWh sales on which the Utilities' REPS obligations are based. It is important to note that the figures shown for each year are the Utilities' MWh sales for the preceding year; for instance, the sales for 2020 are MWh sales for calendar year 2019. The totals are presented in this manner because each supplier's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the supplier is providing REPS compliance reporting and services. Table 31 presents a comparison of the projected annual incremental REPS compliance costs with the Utilities' annual cost caps.

Table 30: MWh Sales for Preceding Year

Compliance Year	DEC	DEP	Dominion	Total
2020	61,263,981	37,938,229	4,328,518	103,530,728
2021	60,617,572	37,869,500	4,520,100	103,007,172
2022	60,700,450	37,711,370	4,537,600	102,949,420

Table 31: Comparison of Incremental Costs to the Cost Cap

		DEC	DEP	Dominion
2020	Incremental Costs	$38,694,000	$44,168,091	$1,001,735
	Cost Cap	$96,103,393	$65,382,724	$5,689,194
	Percent of Cap	40%	68%	18%
2021	Incremental Costs	$43,889,947	$47,329,699	$1,217,736
	Cost Cap	$96,960,516	$66,021,993	$5,563,943
	Percent of Cap	45%	72%	22%
2022	Incremental Costs	$51,853,444	$51,319,147	$1,654,131
	Cost Cap	$97,855,606	$66,629,437	$5,616,197
	Percent of Cap	53%	77%	29%

SWINE WASTE AND POULTRY WASTE SET-ASIDES

The state's electric power suppliers have encountered continuing difficulties in their efforts to comply with the swine and poultry waste requirements. N.C.G.S. § 62-133.8(e) provides that in 2012 at least 0.07% of the electric power sold to customers shall be produced from swine waste, and this percentage increases to 0.14% by 2015, and to 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers shall be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013, and to 900,000 MWh in 2014.

In each year from 2012 through 2017, the electric power suppliers moved the Commission to delay the swine waste requirement until the following year, and the Commission granted each request. For electric public utilities, the delayed requirement was set at 0.02% in 2018, 0.04% in 2019, and 0.07% in 2020. The requirement was further delayed through 2020 for the EMCs and municipalities. The requirement for all electric power suppliers is currently set at 0.07% in 2021 and 0.14% in 2022.

With respect to poultry waste, the electric power suppliers annually requested from 2012 through 2019 that the requirement be delayed and modified. The Commission granted these motions. The requirement was set at 170,000 MWh from 2013 through 2017, 300,000 MWh in 2018, and 500,000 MWh in 2019. The requirement increased to 700,000 MWh in 2020, and increases to 900,000 MWh in 2021 and 2022.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has required the suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, on a semiannual basis in Docket No. E-100, Sub 113A. The Commission has further required the suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in obtaining contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized bi-annual stakeholder meetings beginning in June of 2014. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network, share information, and voice their concerns to the other parties. In 2017, the frequency of the stakeholder meetings was reduced to once per year.

The state's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside, and to an even lesser extent with the swine waste set-aside. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several hog farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous hog farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste through the digestion process, and eliminate impurities from the biogas so that it meets the quality standards of the natural gas pipeline system. This biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a natural gas pipeline used by a gas-fired generating plant that earns the RECs generated. These directed biogas facilities were first built in Midwestern states with extensive hog farming activity. On December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[169]

Four days after the start of construction at the Carbon Cycle facility, in Docket No. G-9, Sub 698, Piedmont Natural Gas Company, Inc., petitioned the

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[169] *See* Order Accepting Registration of New Renewable Energy Facilities*, Application of Duke Energy Carolinas, LLC, for Registration of New Renewable Energy Facilities*, No. E-7, Subs 1086 and 1087 (N.C.U.C. Mar. 11, 2016). In these dockets, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycle Station.

Commission for approval of a new Appendix F to its service regulations, authorizing the company to accept “Alternative Gas” (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont’s proposed appendix and established a three-year pilot program to implement it. The Commission has authorized six firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, Catawba Biogas, LLC, GESS International North Carolina, Inc., and Foothills Renewables, LLC – to participate in the pilot program.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP’s Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations. The Plans for DEC and DEP indicate the ability to meet the swine and poultry requirements in 2020 without further reduction to the requirements. In addition, Dominion’s compliance plan indicates that both Dominion and Windsor have sufficient RECs in NC-RETS to meet the 2020-2022 requirements for swine and poultry waste.

CONCLUSIONS ON REPS COMPLIANCE PLANS

The Public Staff's conclusions regarding the REPS compliance plans of DEC, DEP, and Dominion are as follows:

- Overall, the Utilities are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.

- DEC and DEP should be able to meet their general and solar energy set-aside requirements in the Planning Period, and their poultry and swine waste set-aside requirements in 2020, without exceeding their cost caps. DEC and DEP indicate in their REPS compliance plans that their ability to comply with the swine and poultry waste set-aside requirements in 2021 and 2022 is dependent on the performance of waste-to-energy developers under current contracts.

- Dominion should be able to meet its REPS obligations during the Planning Period without exceeding its cost caps.

- The Commission should approve the 2020 REPS Compliance Plans.

WHEREFORE, the Public Staff prays that the Commission take these comments and recommendations into consideration in reaching its decision in this proceeding.

Respectfully submitted this the 26th day of February, 2021.

PUBLIC STAFF
Christopher J. Ayers
Executive Director

Dianna W. Downey
Chief Counsel

Electronically submitted
s/ Lucy E. Edmondson
Staff Attorney

Electronically submitted
s/ Layla Cummings
Staff Attorney

Electronically submitted
s/ Nadia L. Luhr
Staff Attorney

Electronically submitted
s/ Robert B. Josey, Jr.
Staff Attorney

4326 Mail Service Center
Raleigh, North Carolina 27699-4300
Telephone: (919) 733-6110
lucy.edmondson@psncuc.nc.gov

CERTIFICATE OF SERVICE

I do hereby certify that I have this day served a copy of the foregoing Comments on each of the parties of record in this proceeding or their attorneys of record by electronic delivery.

This the 26th day of February, 2021.

Electronically submitted
s/ Lucy E. Edmondson

430 North Salisbury Street
4326 Mail Service Center
Raleigh, North Carolina 27699-4300
Telephone: (919) 733-6110
Email: lucy.edmondson@psncuc.nc.gov