Comments of the Public Staff

2018 Biennial Integrated Resource Plans

Docket No. E-100, Sub 157

May 6, 2019

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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. These policies include requiring "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" and assuring 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." 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. Duke Energy Progress, LLC (DEP), Duke Energy Carolinas, LLC (DEC), and Dominion Energy North Carolina (DENC) filed IRPs in this proceeding.

S.L. 2007-397 AND COMMISSION RULES

S.L. 2007-397 (Senate Bill 3) expanded the Commission's review of electric utilities' resource planning. The act amended N.C. Gen. Stat. § 62-2(a) to provide that the policy of North Carolina is "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard" (REPS) that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency (EE), and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 enacted N.C. Gen. Stat. § 62-133.8, which establishes a REPS applicable to each electric power supplier [investor-owned utility (IOU), electric membership corporation (EMC), and municipal electric power supplier] in North Carolina.

Senate Bill 3 further enacted N.C. Gen. Stat. § 62-133.9, which provides in subsection (c) that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." N.C. Gen. Stat. § 62-133.8(a)(2) defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods." N.C. Gen. Stat. § 62-133.8(a)(4) defines an EE measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function" and specifically states that EE measures do not include DSM. The foregoing statutory definitions are used in these comments.

To meet the requirements of N.C. Gen. Stat. § 62-2(3a), N.C. Gen. Stat. § 62-110.1, and portions of Senate Bill 3, the Commission conducts an annual investigation into the electric utilities' integrated resource plans (IRPs) and REPS compliance. For the IRPs, Commission Rule R8-60 requires each electric utility to furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60(i), including forecasts and assessments for at least a 15-year period (planning period). Rule R8-60(h)(2) also requires for years in which a biennial report is not filed, "an annual report shall be filed with the Commission containing an updated 15-year forecast . . . as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable." Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of its IRP report. Commission Rule R8-62(p) requires that the electric utilities incorporate information in their IRPs concerning the construction of transmission lines.

Within 150 days of the filing of each electric utility's biennial report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP reports. The Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing.

CLEAN POWER PLAN

On June 18, 2014, the United States Environmental Protection Agency (EPA) proposed a new rule under Section 111(d) of the Clean Air Act (Clean Power Plan or CPP) to limit carbon dioxide (CO_2) emissions from existing fossil fuel-fired electric generating units by requiring substantial reductions in CO_2 intensity. On August 3, 2015, the EPA finalized the CPP, requiring states to submit to EPA an initial state implementation plan designed to achieve the required CO_2 reductions by September 6, 2016, and a final plan by September 6, 2018.

On March 28, 2017, President Donald Trump signed Executive Order 13783, which called for a review of the CPP, and on October 16, 2017, the EPA issued a notice of proposed rulemaking to repeal the CPP. The Public Staff notes that on October 9, 2018, the U.S. Supreme Court ruled against any challenges to stop EPA's repeal.

Despite the regulatory uncertainty regarding the CPP, DENC indicated that it believes that carbon regulation will occur in the future. The Commonwealth of Virginia has elected to continue the development of its state implementation plan.[1]

[1] In its 2014, 2015, and 2016 IRP proceedings, the Virginia State Corporations Commission (VSCC) directed the Virginia Electric and Power Company (operating as DNCP in North Carolina

However, DENC is concerned that this plan will result in more imports of electricity from high carbon-emitting sources. In Section 6.4, DENC included a least cost plan with no carbon constraints (Plan A), as well as four compliance plans with state and federal carbon constraints (Plans B through E).

REGIONAL GREENHOUSE GAS INITIATIVE

In 2009, several northeastern states formed the Regional Greenhouse Gas Initiative (RGGI) in order to collectively reduce carbon emissions from the electric power industry. The Commonwealth of Virginia has taken steps to reduce carbon emissions and could possibly join RGGI by 2020 or create an intrastate RGGI like program specific to Virginia. At this time, the issue is unresolved legislatively, but DENC has considered the carbon emission reductions necessary for a RGGI-like program in its Plans B, C, and D. In Section 3.1.3.1, of its IRP, DENC presents the most likely scenario for a RGGI program in which Virginia's carbon emissions for 2020 are capped at 33 to 34 million tons with a 3% per year reduction for ten years.

COAL COMBUSTION RESIDUALS

DENC presented its coal combustion residuals (CCR) requirements in Section 3.1.3 of its IRP. On October 19, 2015, the EPA's CCR rule became effective, setting criteria for the disposal of CCR, as well as the design, assessment, and monitoring of CCR surface impoundments. On July 17, 2018,

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and Dominion Virginia Power in Virginia) to consider and include various options for complying with the Clean Power Plan because of its significance to electric utility resource planning. *See* VSCC Case No. PUE-2013-00088, Final Order dated August 27, 2014; VSCC Case No. PUE-2015-00035, Final Order dated December 30, 2015; and VSCC Case No. PUE-2016-00049, Final Order dated December 14, 2016.

EPA finalized changes to the CCR rule (Phase One, Part One rule) that established alternative groundwater protection standards for cobalt, molybdenum, lead, and lithium. The changes also extended the deadline to commence closure of unlined coal ash impoundments that fail to meet groundwater protection standards or the aquifer separation location requirement. EPA finalized changes that apply only to states with approved CCR permit programs, or where EPA is the permitting authority. EPA has stated it will address the other proposed revisions in a subsequent rulemaking.

In 2014, the North Carolina General Assembly enacted the Coal Ash Management Act (CAMA), which it amended in 2015 and 2016.[2] CAMA goes further than EPA's rule and requires the closure of high-risk CCR impoundments by December 31, 2019, and low-risk impoundments by December 31, 2029. DENC is not affected by CAMA because it has never had any coal-fired power plants in North Carolina. However, on March 19, 2019, the Commonwealth of Virginia promulgated Senate Bill 1355, which required that coal ash from the Bremo, Possum Point, Chesapeake, and Chesterfield power plants in Virginia be placed in a lined landfill within 15 years.[3] Cap-in-place is not allowed for the coal ash from these four plants.

VIRGINIA GRID TRANSFORMATION AND SECURITY ACT OF 2018

In July 2018, the Virginia Assembly enacted Senate Bill 966, the "Grid Transformation and Security Act of 2018", or GTSA.[4] The GTSA made substantial

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[2] *See* Session Laws 2014-122, 2015-110, and 2016-95, respectively.
[3] 2019 Va. Acts of Assembly, Ch. 651.
[4] 2018 Virginia Acts of Assembly, Ch. 296 (effective July 1, 2018);

amendments to the regulatory planning and cost recovery in Virginia, as well as provided incentives for utilities to invest in new renewable energy facilities, "grid transformation" projects, and energy conservation measures. In addition, the GTSA changed the IRP filing requirement in Virginia to a triennial review. Moreover, the legislation provides that over 5,000 MW of utility wind and solar projects are found by the legislature to be "in the public interest," and also directed Dominion to propose approximately $870 million in energy conservation programs over the next decade. Finally, the legislation requires the VSCC to authorize certain distribution and transmission undergrounding programs proposed by the utilities.

CURRENT PROCEEDING

On May 1, 2018, DENC filed its 2018 IRP and REPS Compliance Plan. On September 5, 2018, 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 24, 2018. On September 27, 2018, the Commission scheduled a public hearing on the 2018 IRPs and the 2018 REPS compliance plans for February 4, 2019, in Raleigh.[5]

On December 7, 2018, the VSCC DENC's IRP, finding that DENC "did not comply with the Commission's directive to include a least-cost plan in its 2018 IRP." [6] ("VSCC Order"). The VSCC Order directed DENC to utilize PJM's Dominion

[5] The IOUs Smart Grid Technology Plans (SGTPs) are filed in this docket, but their review is conducted separately from the IRPs and is governed by Commission Rule R8-60.1. As such, the procedural history for the 2018 SGTP proceeding is omitted.

[6] DENC's parent company, Virginia Electric and Power Company, files one IRP in both Virginia and North Carolina. The IRP was rejected in Case No. PUR-2018-00065.

Zone Coincident peak load forecast and energy sales forecast that are scaled down to the Dominion load serving entity. Secondly, the VSCC Order required the Company to follow the requirement of the GTSA for a proposed $870 in spending on new energy efficiency programs by 2028. Third, the Company was required to reduce its projected solar capacity factors from 26% as originally modeled to 23%. The VSCC Order directed the Company to consider the possible use of 3x1 combined cycle units in the future expansion plans and to revise its REC price forecasting methods to consider actual market prices. Finally, the VSCC Order required DENC to produce a least cost plan, without the mandates of Virginia legislation, so that the cost of those mandates could be measured.

On January 22, 2019, the Public Staff and DENC filed a joint motion requesting an extension of time to file comments on DENC's 2018 IRP, given that modifications would be necessary to comport with the VSCC Order. The Commission granted this request on January 24, 2019, allowing interested parties 60 days from the date DENC files its revised IRP to file comments.

On March 7, 2019, DENC filed an update to its IRP to comply with the VSCC Order ("Compliance Filing"). The 30-page Compliance Filing included updated cost estimates, created a new alternative plan, and made other changes in an effort to comply with the VSCC Order.

In addition to the Public Staff, the following parties have intervened in Docket No. E-100, Sub 147: NCSEA, EDF, the North Carolina Clean Energy Business Association (NCCEBA), the Carolina Industrial Group for Fair Utility

Rates I, II, and III (collectively, CIFGUR), the Carolina Utility Customers Association, Inc. (CUCA), NC WARN, the Southern Alliance for Clean Energy (SACE), the Sierra Club, and the Natural Resources Defense Council.

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak demand and energy forecasts (2019–2033) of DENC. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.7% to 1.5%. In its original IRP, DENC used accepted econometric and end-use analytical models to forecast its peak and energy needs. With any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future. The Compliance Filing revised its peak demand forecasts, modeling them using the PJM DOM Zone non-coincident peak forecast, which resulted in a significant reduction of peak demand over the forecast horizon.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utility's most recent weather-normalized peak loads to those forecasted in its 2017 IRP update. The Public Staff then analyzed the accuracy of the utility's peak demand and energy sales predictions in its 2012 IRP by comparing them to actual peak demands and energy sales. A review of past forecast errors can identify trends in forecasting and assist in assessing the reasonableness of the utility's current and future forecasts.

DENC's 15-year forecast (2019-2033) in the Compliance Filing is based on PJM's peak load and energy sales forecast, scaled down for the Dominion load serving entity, which predicts that DENC will become a winter peaking system in 2024.[7] The dominance of the winter peak stems from the faster CAGR of 1.5% for the winter peaks as compared to a 0.7% CAGR with its summer peaks. While the IRP's winter peak CAGR is slightly higher than the 1.3% growth rate from the 2016 IRP, the CAGR for the summer peak is significantly lower than the 1.5% CAGR from the 2016 IRP. Even though PJM predicts that the Dom Zone will become a winter peaking system, the fact that PJM is a summer peaking system warrants that the Company procures adequate capacity for the summer peak demand forecast. As such, the Company's IRP is modeled to procure both supply-side and demand side resources with the annual forecast of summer peak demands. On average over the 15-year forecast, the winter peaks are approximately 173 MW greater than the forecasted summer peaks. In the Compliance Filing IRP, DENC's EE programs are predicted to provide approximately 1% to 2% reduction of the summer and winter peaks through 2033 and the activation of DSM programs are expected to reduce the peak demands by approximately 1% of MW load. The average annual growth of its winter peak is predicted to be 267 MW and the annual growth of its summer peak is 124 MW over the next 15 years, as compared to 293 MW annual growth of its summer peaks from the 2016 IRP.

[7] DENC Revised Appendix 2I, provided in response to Public Staff Data Request 8-1 in Docket No. E-100, Sub 157.

DENC projects in the Compliance Filing that its energy sales will grow at an average annual rate of 0.7%, a significant decrease from the 1.5% growth rate from the 2016 IRP, and a decrease from the original IRP forecast of 1.4%. DENC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 2% by 2033, which is greater than the 1% reduction in energy sales previously forecasted in its 2016 IRP.

The Public Staff's review of DENC's actual peak load forecasting accuracy for one year shows that its 2017 IRP over-predicted the Company's 2018 summer peak load by 7% and under-predicted its 2018 winter peak load by 15%. The Public Staff's review of DENC's peak load forecasting accuracy is based on the 2012 IRP forecasts for 2013 - 2018. The review indicates that all of the predicted annual peak demands were greater than the actual peaks which generated a mean forecast error of 6% and an average annual overestimation of 1,040 MW of load. DENC's energy sales from the 2012 IRP generated an 11% error rate. In addition, over the 2013 – 2018 period, four of the previous six annual peaks occurred during the winter season. The following Table provides an overview of DENC's annual peak load forecasts:

Table 1: Accuracy Analysis of DENC's 2012 IRP

Date	Actual	2012 Forecast[8]	Difference	% Difference	Absolute Difference	Absolute%
19-Jul-13	16,366	17,550	1,184	7.2%	1,184	7%
30-Jan-14	16,840	18,077	1,237	7.3%	1,237	7%
20-Feb-15	18,434	18,595	161	0.9%	161	1%
25-Jul-16	16,914	18,062	1,148	6.8%	1,148	7%
9-Jan-17	16,618	18,318	1,700	10.2%	1,700	10%
7-Jan-18	17,792	18,599	807	4.5%	807	5%
		Average	1,040		1,040	6%

Source: DENC's 2012 IRP filed in Docket No. E-100, Sub 137, and Response to Public Staff Data Request No. 1-15 in Docket No. E-100, Sub 157.

CONCLUSIONS ON PEAK LOAD FORECASTS

Based on the review of DENC forecast accuracy and its pattern of predicting its loads being greater than the actual loads, the Public Staff supports the use of the relatively lower PJM peak demand forecast for the DENC, as ordered by the VSCC. Therefore, the Public Staff concludes that DENC's revised peak load and energy sales forecasts are reasonable for planning purposes. However, the Public Staff notes the growing dominance of morning winter peaks, as similarly observed with DEC and especially with DEP. This growth appears to represent a shift in the use of electricity and warrants further examination with respect to the Company's econometric and statistical forecast models.

SUMMARY OF GROWTH RATES

The following summarizes the growth rates for DENC's system peak and energy sales forecast in the IRP Compliance filing.

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[8] DENC's 2012 forecast assumed that the peaks occurred in the summer season; however, several of the actual peaks occurred in the winter season.

Table 2: 2019-2033 Growth Rates (After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DENC	0.7%	1.5%	0.7%	124

SYSTEM PEAKS AND USE OF DSM RESOURCES

DENC

DENC's 2018 annual system peak of 17,792 MW occurred on January 7, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 7 degrees. Also, DENC's summer system peak of 16,528 MW occurred on July 2, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 91 degrees. DENC activated its DSM resources during both the winter and summer seasonal peaks.

In regard to DSM activations during its 15 highest peak loads from July 2017 through August 2018, DENC activated its Residential AC Cycling program nine times and its Distributed Generation program thirteen times over the fifteen highest peak demands.

CONCLUSIONS ON DSM ACTIVATIONS

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. Nevertheless, utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of DENC's DSM activations at the time of the 15 highest hourly peaks for each utility, the Public Staff notes an ongoing concern: the difference in DSM resources available in the winter and the summer due, in part, to the fact that winter season programs are typically not cost effective. DENC activated its distributed generation program during the Company's 2018 winter peak and most of the other near peaks during the winter season; however, the activations only led to a four MW to six MW load reduction. As with DEC and DEP, the Public Staff recommends that each IOU investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands.

GENERATING FACILITIES

EXISTING GENERATION

DENC currently meets electric demand through company owned generation assets, non-utility generators (NUGs), and market purchases from the PJM system. PJM dispatches resources within the DOM Zone from the lowest to highest cost units, while maintaining mandated reliability standards. Table 3 below summarizes the existing capacity resources in DENC's Virginia and North Carolina territories at the time of its original filing. DENC states that it has a balanced portfolio of generating units and the majority of its fossil fuel fleet is equipped with modern emission controls. Any remaining small coal-fired units without sufficient emission controls to comply are considered "at risk units" for purpose of DENC's IRP.

Table 3: Existing Generation Resources in Service by Primary Fuel, in MW (summer)

Fuel Source	DENC
Coal	3,684
Nuclear	3,348
Natural Gas - CC	4,693
Natural Gas – CT	2,415
Light and Heavy Fuel Oil	1,833
Renewables (Solar, Wind, Biomass)	168
Hydro - Conventional	316
Hydro - Pumped Storage	1,808
Total	**18,265**

SUBSEQUENT LICENSE RENEWAL (SLR) OF EXISTING NUCLEAR PLANTS

As discussed in previous Public Staff IRP comments, one of the significant issues faced by the IOUs is the pending expiration of operating licenses for nuclear energy resources in the next 20 to 30 years. If SLRs[9] are not obtained, current schedules call for retirement of approximately 5,900 MW in the 2030 to 2034 period 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 DENC. The following table summarizes the current license expiration dates for the IOUs' nuclear facilities.

[9] Nuclear Regulatory Commission, Subsequent License Renewal, Online at: https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html. *Last accessed* April 24, 2019.

Table 4: Potential Nuclear Retirements

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DENC	838	May 2032
Surry Unit 2	DENC	838	January 2033
Oconee Unit 1	DEC	847	February 2033
Oconee Unit 2	DEC	848	October 2033
Oconee Unit 3	DEC	859	July 2034
Brunswick Unit 2	DEP	932	December 2034
Brunswick Unit 1	DEP	938	September 2036
North Anna Unit 1[10]	DENC	948	April 2038
North Anna Unit 2	DENC	944	August 2040
McGuire Unit 1	DEC	1158	June 2041
McGuire Unit 2	DEC	1158	March 2043
Catawba Unit 1[11]	DEC	1140	December 2043
Catawba Unit 2	DEC	1150	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff notes that since the filing of the Utilities' 2016 IRPs, the Nuclear Regulatory Commission (NRC) has issued initial regulatory guidance documents[12] that may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. Any additional license extension will be evaluated by the utility based on the specific risks and costs associated with each unit. There are currently three SLR applications under review by the NRC: NextEra's Turkey Point Units 3 and 4,

[10] DENC owns 88.40% of the capacity of North Anna Units 1 and 2; Old Dominion Electric Cooperative owns the remaining 11.60%.

[11] DEC owns 19.20% of the capacity of Catawba Units 1 and 2. The other owners are as follows: North Carolina Municipal Power Agency 1 - 37.60%; North Carolina Electric Membership Corporation – 30.68%; and Piedmont Municipal Power Agency – 12.52%.

[12] NUREG-2191 (Generic Aging Lessons Learned for Subsequent License Renewal Report); NUREG-2192 (Standard Review Plan for the Review of Subsequent License Renewal Applications for Nuclear Power Plants)

Exelon Corporation's Peach Bottom Units 2 and 3, and Dominion Energy's Surry Units 1 and 2. Dominion Energy has also filed a letter of intent with the NRC to apply for SLRs for its North Anna Units 1 & 2.[13] DENC estimates that the capital cost of obtaining SLRs for North Anna Units 1 and 2 will be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the costs for Surry Units 1 and 2 will be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** DENC states that the optimization models used to construct its IRP selected the nuclear SLRs based upon these cost estimates.

The Public Staff recommends that the Commission continue to direct DENC in future IRPs to include a discussion and evaluation of potential subsequent license renewals 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 IOUs should continue to reflect any such relicensing plans in future IRPs.

PLANNED GENERATION

DENC

DENC did not choose a single or direct plan/scenario as its preferred plan. It is also noteworthy that since filing its IRP in the summer of 2018 followed by its Compliance Filing, as directed by the VSCC Order, the Company has accelerated retirement of ten older generation plants,[14] mostly coal. While the accelerated

[13] DENC included the Letter of Intent as Exhibit 3Y in its 2016 IRP at A-101, Docket No. E-100, Sub 147.

[14] *See* March https://www.richmond.com/business/local/dominion-to-retire-old-coal-burning-power-units/article_cde22772-f5c2-5fa4-bcdf-2af9314a3176.html.

retirement does not appear to have an immediate effect in the IRP scenarios, portions of the IRP, like the short-term action plans (which is inclusive of plant retirements), do not currently reflect these changes. Listed below are the short-term renewable resource additions for DENC for all plans.

Table 5: DENC Renewable Resources by 2023

Resource	Nameplate MW
VCHEC Biomass	61
Solar NUGs	760
CVOW[15]	12
Solar 1	142
Solar 2	98
Solar 2020	320
Solar 2021	400
Solar 2022	480
Solar 2023	480

All of the Alternative Plans include subsequent license renewals for all four of the Company's nuclear units (Surry Units 1 and 2 and North Anna Units 1 and 2). DENC believes that the subsequent license renewals can be achieved at a reasonable cost, though the NRC has not yet approved formal guidance on subsequent license renewals. In DENC's 2016 IRP, North Anna 3 (nuclear generation) was forced into the model under a Mass-Based Emissions Cap plan. At that time, the Company did not believe 7,000 MW or more of Solar PV was practical and could potentially cause system operation problems. In the 2018 IRP, North Anna 3 is no longer selected and the Company's Alternative Plans reflect an increased renewable portfolio, as mandated by the GTSA. The alternative plans studied in DENC's original IRP specify solar additions ranging from approximately

[15] Coastal Virginia Offshore Wind demonstration project, or "CVOW."

5,000 MW to 7,000 MW over the study period. The Compliance Filing forecasts solar additions ranging from approximately 1,000 MW (in least cost Alternative Plan A) to 6,000 MW.

However, DENC did begin to address the potential for system operation issues, as it calculated a re-dispatch charge associated with higher levels of solar penetration. This re-dispatch charge addresses the higher costs associated with intermittent renewable energy, and DENC intends to recover this charge from QFs with intermittent resources.[16] This re-dispatch charge of $1.78/MWh was added to the dispatch price of solar PV in DENC's model. In addition, the Alternative Plans add a $155/kW fixed charge to the cost of solar PV, to function as an estimated charge for transmission and distribution integration costs. This fixed charge was estimated using a steady state power flow analysis, assuming 7,000 MW of solar PV added to DENC's transmission grid.[17]

The Public Staff recommends that DENC continue to discuss mitigation strategies to address the 2016 IRP comments of high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs. DENC also points out that its integration analysis "did not consider the aggregate effect of the distributed solar PV on to the transmission grid."[18] To the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar PV, such as the

[16] DENC proposes assessing this re-dispatch charge on all intermittent QFs in Docket No. E-100, Sub 158.
[17] *See* DENC IRP, section 5.1.3.1.
[18] *See* DENC IRP at 52.

addition of a supplemental combustion turbine (CT) to address generation volatility or ramp rates, those applicable costs should be assigned to the overall installed cost of solar.

DENC's interconnection queue report filed on February 1, 2019, in Docket No. E-100, Sub 101A, indicated that DENC's interconnection queue contained 109 MW of solar facilities. DENC's report on interconnected renewable energy facilities filed on March 29, 2019, in Docket No. E-100, Sub 113B, indicated that it had 486 MW of state-jurisdictional solar facilities in operation and 396 MW of FERC-jurisdictional solar facilities in operation.

NON-UTILITY GENERATION

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. DENC provided a list of NUGs in compliance with this requirement within Appendix 3B in its original filing.

Table 6 provides a simplified detailed breakdown of DENC NUGs and "behind the meter" (BTM) generation units which are also considered to be a NUG.

Table 6: NUG and BTM Detailed Summary

Classification	VA	NC	Total
NUG-Project Count	1	-	1
NUG-Nameplate (MW)	218	-	218
BTM-Project Count	14	73	87
BTM-Project Count, Solar	1	69	70
BTM-Nameplate (MW)	238	508	746
BTM-Nameplate, Solar (MW)	20	479	499
BTM-Nameplate, Non-Solar (MW)	218	29	247

For the past several years, DENC has included a Figure 3.1.1.3 in its IRP that provides its capacity resource mix by unit type, including NUGs. DENC has also included an Appendix 3B with non-company owned generation that includes NUGs. The Public Staff has become aware of the following: (1) some facilities that are listed as NUGs in Appendix 3B are not included in the NUG capacity in Figure 3.1.1.3, (2) some utility-scale solar facilities are considered as NUG capacity in Figure 3.1.1.3 but others are not, and (3) DENC considers all utility-scale solar facilities to be BTM, but these facilities typically separate the metering of electricity sales from electricity purchases. The Public Staff recommends that in future IRPs, DENC do the following: (1) clarify its definition of a NUG facility and use that definition consistently through the IRP; (2) re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; (3) separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and (4) maintain consistency on references to nameplate rating or equivalent firm capacity rating throughout the document.

RESERVE MARGINS

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. DENC, as a member of PJM, is a summer planning and summer peaking utility, and generally considers summer peak load as the load upon which the reserve margin is based.

In its original filing, DENC used PJM's reserve margin in conjunction with its own load forecast to determine long-term capacity requirements. PJM has recommended using a 15.9% installed reserve margin to satisfy NERC and Reliability First Corporation (RFC) Adequacy Standard BAL-502-RFC-02. This recommendation is based upon an annual reserve requirement study, a probabilistic assessment which calculates a Loss of Load Expectation (LOLE). The study determines the adequate level of capacity to maintain the probability of a loss of load in one day over a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period (often referred to as a 0.1 LOLE standard).

DENC then adjusts this number based on the coincident factor[19] between the DOM Zone coincidental and non-coincidental peak load – this coincident factor is less than one because DENC's peak load has not typically occurred during the same hour as PJM's peak load. DENC calculates its coincident factor to be 96.47%.[20] The reserve margin for DENC is calculated by the below formula:

$$Adjusted\ Planning\ Reserve = [(1 + Full\ Planning\ Reserves) * Coincident\ Factor] - 1$$

This results in a DENC reserve margin target of 11.7%.[21] This calculated figure is the same in both the original IRP and the Compliance Filing, although the load forecast upon which the reserve margin is added is reduced, in order to comply with the VSCC Order in DENC's Compliance Filing. Figure 1 below illustrates the reduction in peak demand caused by using PJM's 2018 DOM Zone non-coincident peak demand forecast and an adjusted planning reserve, as opposed to DENC's internal forecasts. Also shown is generation existing and under construction in DENC's Alternative Plan E, which assumes a federal CO2 program. The original IRP projected a deficit under Alternative Plan E of 5,275 MW; the Compliance Filing projects a deficit of 3,028 MW – a 43% reduction in capacity need by 2033.

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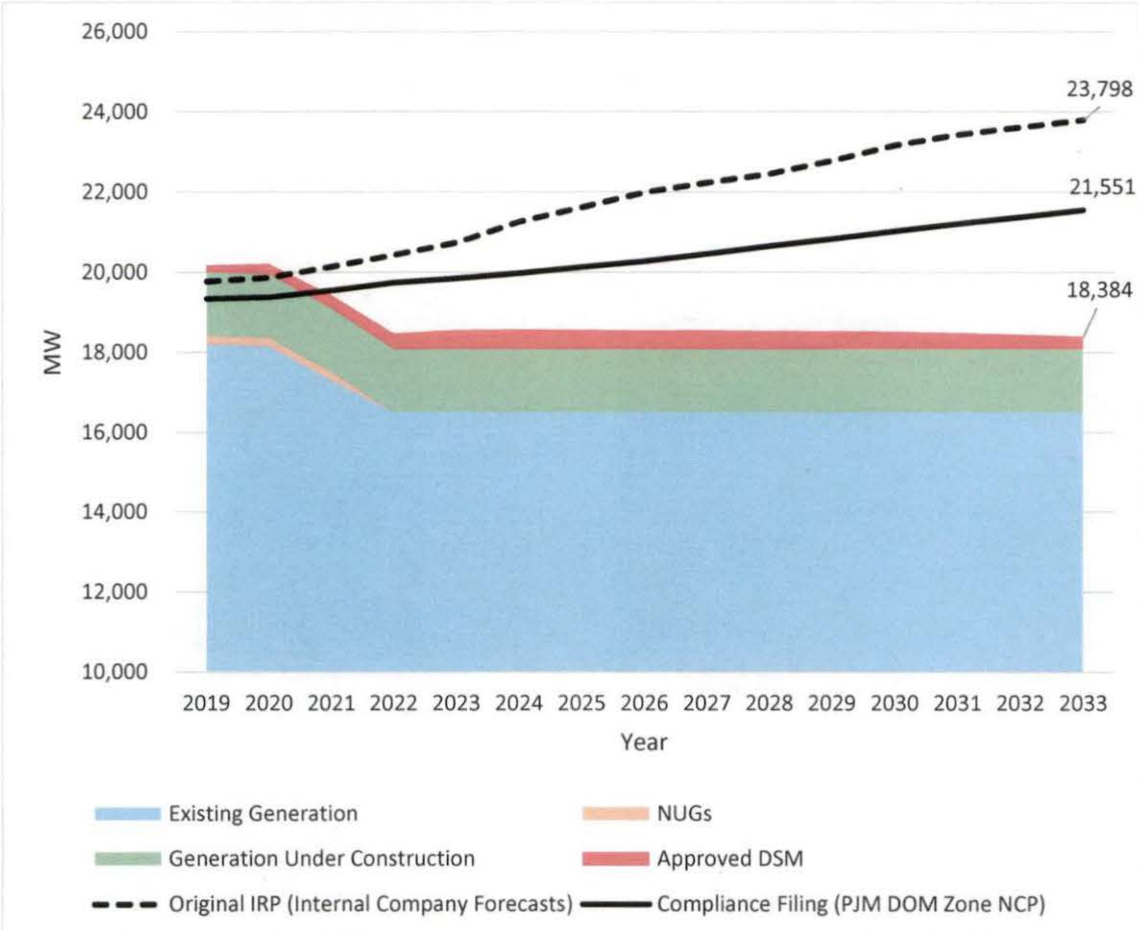
[19] Also referred to as a "diversification factor" in DENC's Compliance Filing.

[20] *See* DENC's IRP at 53.

[21] DENC's 2016 IRP calculated an adjusted reserve margin of 12.46%, based upon a PJM recommended reserve margin of 16.5%.

Figure 1: Total Resource Requirements, Compared to Capacity Under Plan E: Federal CO2 Program



CAPACITY VALUE OF NON-DISPATCHABLE RESOURCES

When calculating the reserve margin, DENC assigns solar and wind resources a percentage of their nameplate capacity towards meeting summer and winter peak demand, based on respective factors like non-dispatchability and intermittency. This percentage, referred to as the "capacity value", reflects that the resources could not be relied upon to provide 100% of its nameplate capacity to meet peak demand. Table 7 below summarizes the capacity values used by DENC in its IRP:

Table 7: Capacity Values of Renewable Resources for DENC[22]

Resource Type	Nameplate Capacity (MW)	Firm Capacity (MW)	Capacity Value
Onshore Wind	1,000	130	13.0%
Offshore Wind	1,000	167	16.7%
Solar PV	1,000	229	22.9%

However, it should be noted that PJM publishes a methodology for calculating capacity values for non-dispatchable resources.[23] PJM recommends using a three-year average of historical wind and solar facility output during the summer peak hours[24] to determine the applicable capacity value for use in reserve margin planning. For facilities less than three years old, PJM publishes "class average capacity factors" for use in the determination of capacity values,[25] as presented in Table 8 below. DENC's proposed capacity values for solar are significantly lower than the PJM class average. DENC should continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research.

Table 8: PJM Class Average Wind & Solar Capacity Values, Effective June 1, 2017

Resource Type	Capacity Value
Onshore Wind – Mountainous Terrain	14.7%
Onshore Wind – Flat Terrain	17.6%
Solar PV – Ground Mount, Fixed	42.0%
Solar PV – Ground Mount, Tracking	60.0%

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22 *See* DENC's IRP at 86.

23 *See* Appendix B of PJM Manual 21: Rules and Procedures for Determination of Generating Capability, revision 12, effective date January 1, 2017. Accessed at: https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/manuals/m21.ashx?la=en

24 Summer peak hours are defined as the period June 1 through August 31, and hours ending 3, 4, 5, and 6 PM local time.

25 *See* PJM Resource Adequacy Planning Resource Reports and Information website, at https://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx

In addition, PJM has proposed new rules for its Manual 21 revision 13 update, which would require wind and solar capacity values be based upon an Effective Load Carrying Capability (ELCC) study.[26] Due to the significant variance between PJM and DENC's capacity values, the potential changes proposed or other changes that be proposed or adopted by PJM, and the legislatively mandated 5,000 MW of solar and offshore wind projects, the Public Staff does not recommend that DENC be directed to refile its 2018 IRP with revised capacity values. However, the Public Staff recommends that in future IRP filings (including updates), the Commission require DENC to (1) provide PJM's capacity value for renewable resources as comparison benchmark, and (2) to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

RESERVE MARGIN ADEQUACY

The calculation of the adjusted reserve margin and the coincidence factor in the Compliance Filing appear reasonable for planning purposes. Based on its review of the annual plans, the Public Staff believes that the reserves listed are reasonable at this time for IRP planning purposes, and recommends that DENC maintain its proposed reserve margins as filed.

To understand the impact of renewable generation on reserve margin adequacy, precise modeling is needed. Analysis of the operational impact of renewable energy injected into the electrical system, which is inherently

[26] A description of the proposed change can be found at https://pjm.com/-/media/committees-groups/committees/pc/20190307/20190307-item-06a-m21-changes.ashx

intermittent in nature, requires sub-hourly modeling with multiple and potentially complex scenarios to more accurately capture system costs. Probabilistic modeling can also help utilities understand the impact of renewable generation. Sub-hourly modeling would necessitate more time and material intensive resources than currently used in DENC's estimate of fixed and variable integration charges for intermittent resources. DENC indicated that it is currently using the sub-hourly features contained in the PLEXOS and AURORA models to better examine and value electricity storage and other fast ramping resources such as aeroderivative turbines, and plans to incorporate the results of these studies in future IRPs.

The Public Staff recommends that DENC, in future IRPs, evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling, more granular system performance data, probabilistic analysis, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

WHOLESALE CONTRACTS FOR PURCHASE AND SALE OF POWER

DENC provided lists of its firm wholesale purchased power contracts and sales contracts. DENC listed three Wholesale Power Sales Contracts with an approximate nameplate capacity of 310 MW; it does not list any obligations for wholesale power purchases.

TRANSMISSION FACILITIES

Pursuant to the *2014 IRP Order*, DENC included a copy of its most recent FERC Form No. 715 (Annual Transmission Planning and Evaluation Report) and discusses detailed information concerning its transmission line inter-tie capabilities, transmission line loading constraints, planned new construction and upgrades, and NERC compliance within its respective control areas for the planning period. DENC appears to be in compliance with the Commission's filing requirements.

TRANSMISSION PLANNING

The FERC issued its Order No. 1000 in 2011 amending the transmission planning requirements of FERC Order No. 890 and requiring each public utility transmission provider to do the following:

(1) participate in a regional transmission planning process that produces a regional transmission plan;

(2) amend its Open Access Transmission Tariff (OATT) to describe procedures for the consideration of transmission needs driven by public policy requirements established by local, state, or federal laws or regulations in the local and regional transmission planning processes;

(3) remove federal rights of first refusal from Commission-jurisdictional tariffs and agreements for certain new transmission facilities;

(4) coordinate with neighboring transmission planning regions; and

(5) participate in an inter-regional cost allocation method for new inter-regional transmission facilities.

DENC is a member of PJM, an RTO registered with NERC as DENC's Planning Coordinator and Transmission Planner. DENC participates in the PJM Regional Transmission Expansion Plan (RTEP) to develop the RTO-wide transmission plan for PJM that includes projects proposed by DENC. The PJM RTEP process uses a 5-year and 15-year planning horizon. DENC, as a member of PJM, continues to satisfactorily address the reliability concerns of both planning horizons.

DSM AND EE

DENC

DENC's portfolio of EE programs has undergone significant changes since the 2017 IRP update. DENC's portfolio relies heavily on the DSM and EE portfolio associated with its Virginia-affiliated company and the decisions made by the VSCC regarding that portfolio. DENC's 2018 IRP reduced the energy savings by 30% over the planning horizon from the savings that were identified in the 2017 IRP update. This is primarily due to the cancellation of several programs in Virginia that were offered on a system-wide basis. DENC has worked with the Public Staff to evaluate whether any of the cancelled programs can continue to be offered on a North Carolina-only basis and when it can be offered cost-effectively even in the short term, DENC has requested approval from the Commission.

The Public Staff also notes that DENC completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period. However, DENC indicated to the Public Staff that it had not incorporated any of the measures identified in the market potential study in its 2018 IRP. Much of the economic potential for residential and non-residential sectors lies in lighting and space heating and cooling measures. There are two notable observations from the report that bear mentioning. First, there are no recommendations on specific measures that would contribute toward the achievable potential going forward for either customer class. Second, the achievable potential excludes the impacts of customers who are eligible to opt-out of utility-sponsored EE portfolios.

The market potential study has limited influence on DENC's EE portfolio. While the study provides guidance on future EE and the general direction the Company pursues with EE deployment, much of what happens with EE is driven by and the GTSA and its implementation by the VSCC. As previously discussed, the GTSA enacted by the Virginia General Assembly in 2018, requires the Company to spend $870 million over the next ten years on EE. This spending could include existing EE programs, but was intended to spur new EE programs. In the Company's most recent filing with the VSCC for new DSM and EE programs, the Company has proposed a portfolio of 11 new programs with a spending projection of approximately $262 million over the next five years. DENC's 2018 IRP does not include impacts from these proposed programs. The Company has stated in its program approval filing with the VSCC that it intends to apply this spending toward the $870 million target identified in the GTSA. Approval by the

VSCC is pending. Once the VSCC rules, DENC will move to offer these programs in North Carolina.

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.

Assessment of Alternative Supply-Side Energy Resources

Commission Rule R8-60(i)(7) requires each utility to file its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. Each utility must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. DENC provided the information as required.

DENC included its assessment of alternative supply-side energy resources in Section 5.1 of its IRP. For 2018, DENC evaluated aero-derivative CTs, batteries, biomass, circulating fluidized bed combustion, coal carbon capture and sequestration, fuel cells, gas-fired combined cycle, gas-fired CTs, integrated-gasification combined cycle, nuclear, pumped storage hydroelectric, reciprocating internal combustion engines, small modular reactors, on-shore wind, off-shore wind, solar photovoltaic, and solar concentrated energy.

EVALUATION OF RESOURCE OPTIONS

Commission Rule R8-60(i)(8) requires each utility to include in its IRP a description and summary of the results and analyses of potential resource options and combinations of options. DENC indicates in its IRP that they use accepted models to identify the mix of resources required to meet the future energy and capacity needs, subject to physical, technological, and regulatory constraints, in an efficient and reliable manner at the least cost. DENC primarily uses the utility modeling and resource optimization tool PLEXOS to develop its IRP from 2019 through 2043.

PLEXOS has capabilities similar to the PROSYM model used by DEC and DEP. It is a mixed integer linear optimization model, which identifies the mix and timing of new resources to satisfy the utility's future load requirements at the least cost. The models are designed to compare various generation portfolios to determine which has the lowest total system costs while maintaining the target reserve margin. The PLEXOS model incorporates forecasts of energy sales and peak load, including an 8760-hour annual load profile, with assumptions regarding the operating characteristics of existing and future generating units (including net MW output, planned outages, forced outage rates, projected fuel prices, heat rates, start costs, emission costs, and variable O&M expenses) to calculate the projected dispatch cost of each generating unit. The models also incorporate the PVRR needed for capital investments in new generating capacity and in upgrades to existing capacity.[27] In order to arrive at a least-cost plan, the models integrate assumptions regarding planned generation uprates and retirements, planned renewable energy generation, DSM/EE programs, environmental regulations, and the capital costs and operating characteristics for proposed traditional generation and alternative resources.

To consider uncertainties in future regulatory and legislative efforts, DENC developed a set of Alternative Plans, which represent plausible future paths for meeting its customers' electric needs. These Alternative Plans estimate the costs of generation planning decisions made under the influence of various state and federal policies, such as a federal CO2 tax and various iterations of a Regional Greenhouse Gas Initiative (RGGI). These plans are presented below.

[27] PLEXOS technically calculates the net present value (NPV) of each portfolio, which is similar to the PVRR.

DENC

DENC's Plans

The originally filed IRP evaluated five Alternative Plans, and the Compliance Filing evaluated six Alternative Plans. These plans have been modified by the directives of the VSCC Order, and the summaries presented below reflect the revised plans presented in the Compliance Filing. Per the VSCC Order, Plan A has been recast as the "Least Cost Plan". As such, it does not force the inclusion of or unreasonably exclude any resource[28] to meet demand, and does not reflect the impact of any new state or federal mandates.[29]

- Plan A: No CO2 Tax. This plan assumes no new regulations or restrictions on CO2 emissions. It does not include the CVOW project, 5,000 MW of new solar, or 30 MW of battery storage mandated by the GTSA. It consists of seven new natural gas-fired CTs totaling 3,200 MW and approximately 1,240 MW (nameplate) of new solar added between 2019 and 2022, with no additional solar in the following years.
- Plan B: Virginia RGGI with unlimited imports; includes the Company's proposed Grid Transformation ("GT") Plan.[30] This also

[28] Specifically, the VSCC Order required DENC to include a 3x1 combined cycle natural gas generator, which was excluded in the original IRP to "prevent future grid stability issues due to the addition of too many large generators in the DOM Zone as well as limited gas availability." *See* DENC IRP, page 103.

[29] The VSCC Order required DENC to remove certain programs included in the GTSA (namely, the CVOW, 5,000 MW of solar, and 30 MW of battery storage pilots). It did not require the removal of any prior legislative or regulatory mandates.

[30] *Petition of Virginia Electric and Power Company, for approval of a plan for electric distribution grid transformation projects pursuant to§ 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2018-00100, Final Order (Jan. 17, 2019).

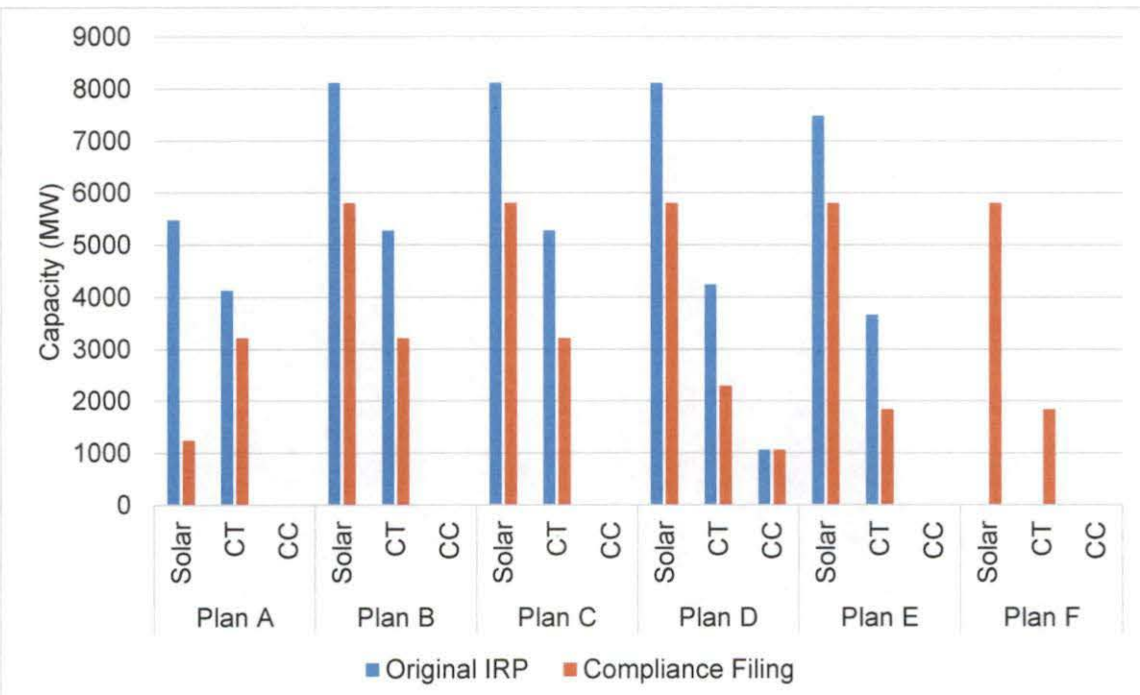
consists of seven natural gas-fired CTs totaling 3,200 MW. However, this plan includes the impact of the GTSA, and has approximately 5,800 MW of solar added between 2019 and 2028.

- Plan C: RGGI with unlimited imports; includes the GT Plan. This plan also consists of seven natural gas-fired CTs totaling 3,200 MW and approximately 5,800 MW of solar added between 2019 and 2028.
- Plan D: RGGI with limited imports; includes the GT Plan. This plan consists of five natural gas-fired CTs totaling 2,290 MW and one new natural gas 2x1 natural gas combined cycle plant of 1,062 MW planned in 2025. The combined cycle plant eliminates the CTs planned in 2025 and 2026 and pushes out the CTs in 2029 and 2031 by one year each. This plan also includes approximately 5,800 MW of solar added between 2019 and 2028.
- Plan E: Federal CO2 program; includes the GT Plan. This plan consists of four natural gas-fired CTs totaling 1,830 MW and approximately 5,800 MW of solar added between 2019 and 2028.
- Plan F: This plan was added with the Compliance Filing in order to demonstrate the impact of Virginia's legislative mandates on total system cost. This plan has no Federal CO2 program and includes the GT Plan and effects of all Virginia legislation, including GTSA. Comparing this plan to Plan A can isolate the impact of Virginia legislative mandates. However, except for total system cost, there

appears to be no appreciable difference among the generation and retirement decisions between plan E and plan F.

The effect of DENC's compliance with the VSCC Order is apparent in the changes in planned generation due to the reduction in forecasted demand. For example, Plan B in the original IRP included thirteen (13) natural gas-fired CTs, totaling 5,275 MW; complying with the VSCC Order reduced the total CT capacity by approximately 65%. Solar capacity in Plan B was similarly reduced by 40%. A summary of the changes between the original IRP and the Compliance Filing, in relation to solar and natural gas additions, are presented below:[31]

Figure 2: Comparison of new generation capacity in the original IRP and Compliance Filing



[31] This chart excludes the Greensville CC plant, which is included in all plans, original IRP and Compliance Filing, and is currently commercially operational.

Given the significant uncertainty surrounding the future of CO2 and greenhouse gas regulation, DENC did not identify a "Preferred Plan" or recommended path forward beyond the short-term action plan (STAP)[32]. The Alternative Plans are offered for consideration, and one of these options may be the eventual path forward once the uncertainty over CO2 regulation is resolved.

The cumulative resource additions anticipated in the STAP are presented in Table 9 below. The STAP is only provided in the original IRP, and is not updated for the Compliance Filing. However, the Compliance Filing presents very little change in Alternative Plans B through E in years 2019 through 2023, and thus the STAP is essentially unchanged between the original IRP and the Compliance Filing. For example, all five Alternative Plans anticipate 2,680 MW of undesignated solar between 2020 and 2023 (including DENC's self-build US-3 Solar 1 and US-3 Solar 2 projects and the 760 MW of solar NUGs in North Carolina and Virginia). The two CTs that are planned in 2022 and 2023 are also in every Alternative Plan, although Alternative Plans B, C, and D in the Compliance Filing no longer have plans for 119 MW aero-derivative CTs in 2023.

[32] DENC also did not identify a "Preferred Plan" in the 2015, 2016, or 2017 IRPs.

Table 9: Short Term Action Plan - Resources added by 2023[33]

Description	Primary Fuel	Nameplate (MW)
Greensville CC	Natural Gas	1,585
Generic CT	Natural Gas	916
CVOW	Wind	12
Surry Unit 1 SLR	Nuclear	838
Surry Unit 2 SLR	Nuclear	838
North Anna Unit 1 SLR	Nuclear	838
North Anna Unit 2 SLR	Nuclear	834
VCHEC	Biomass	61
Solar NUGS (2020)	Solar	760
Solar (2020-2023)	Solar	1,920

COMPREHENSIVE RISK ANALYSIS

DENC also performs a comprehensive risk analysis of each of its portfolios in the original IRP. This approach identifies key sources of "portfolio risk" within each Alternative Plan, including natural gas prices, natural gas basis, coal prices, oil prices, load, hourly solar generation, CO2 emission allowance prices, and new generation capital costs. A stochastic (probabilistic) model, AURORA, is used (with the same data used in PLEXOS), which runs many possible futures in hundreds of iterations. Each iteration creates variations in key drivers of portfolio risk, utilizing Monte-Carlo techniques. These variations represent stochastic realizations of each key driver, and as each key driver is set to a value, production cost runs are simulated using the AURORA multi-area model. These hundreds of model runs are then distilled into an expected levelized cost, a standard deviation, and an "upward" standard deviation to calculate the adverse cost risk to DENC's

[33] This summary table is compiled from information in Chapter 7 of DENC's original IRP. As of the date of this filing, the Greensville CC is operational.

customers (referred to as the "semi-standard deviation"). An advantage of this approach is that it allows for the quantification of high impact risk factors even though they have a low probability of occurrence.

Notably, DENC did not re-run its comprehensive risk analysis for the revised Alternative Plans presented in its Compliance Filing; therefore, Alternative Plan F was not evaluated under the comprehensive risk analysis. The results from the original IRP are presented below; generally, a higher standard deviation means higher risk. The analysis demonstrates that Plan A has the lowest expected cost and the least risk, making it the most attractive plan. However, Plan A may not be the most realistic path forward due to other considerations, such as the likelihood of future regulations on CO2 emissions.

Table 10: Original IRP Alternative Plan Portfolio Risk Assessment Results

Alternative Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan A: No CO2 Tax	$31.84	$5.16	$5.73
Plan B: Virginia RGGI (unlimited imports)	$34.06	$5.83	$6.36
Plan C: RGGI (unlimited imports)	$35.98	$5.83	$6.36
Plan D: RGGI (limited imports)	$36.36	$5.68	$6.17
Plan E: Federal CO2 Program	$34.32	$5.53	$5.91

The Public Staff finds that the approach taken by DENC to analyze the various scenarios with regard to exposure to fuel price volatility scenarios, consideration of rate impacts to customers, and utilizing a probabilistic risk assessment framework provides insightful information to its customers and the Commission. The Public Staff believes that the comprehensive risk analysis provides insight to how each Alternative Plan would be expected to perform under various scenarios, and supports DENC's efforts in this regard.

The Public Staff recommends that DENC continue to provide comprehensive risk analysis of Alternative Plans in future IRPs and IRP updates.

PLAN COSTS AND RATE IMPACT

DENC presents the incremental cost of compliance of each of the Alternative Plans compared to the least cost plan (Alternative Plan A). The results are presented below. Due to the VSCC Order, the incremental compliance costs of the legislation contemplated in the Alternative Plans increases significantly, as Alternative Plan A is stripped of many of the legislative mandates that added costs. The comparison between Plan A and Plan F illustrate the costs of compliance with the GTSA in compliance with the VSCC Order.

Table 11: Incremental NPV of Costs over Plan A[34]

	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO2 Program	Plan F: No CO2 Tax
Original IRP	$1.54	$3.71	$4.04	$3.09	n/a
Compliance Filing	$8.14	$9.65	$10.37	$9.10	$5.81

In its original IRP, DENC also demonstrates the rate impact of each alternative plan over the planning horizon. However, due to the significant changes in investment decisions in the Compliance Filing over the planning

[34] Incremental costs in the Compliance Filing do not include the estimated benefits of the GT Plan.

horizon, these estimates are no longer valid. As such, the Public Staff recommends that DENC submit as a supplemental filing to the Commission the recalculated rate impact analysis of the modified Alternative Plans found in its Compliance Filing.

FURTHER OBSERVATIONS REGARDING ALTERNATIVE RESOURCE PLANS

Solar Integration Cost Assumptions

In Section 5.1.3.1 of its IRP, DENC described the cost of integrating solar photovoltaic facilities. DENC stated that these facilities have caused re-dispatch costs, which are additional costs incurred by the Company. Generator dispatch is typically planned a day ahead for economic dispatch. However, if a weather event, like cloud cover, and the resulting solar output are different than that predicted, generators will have to operate in a less than optimal sequence and the generation fleet will have to be re-dispatched.

DENC used a computer model to determine that the re-dispatch cost caused by solar photovoltaics is $1.78 per MWh and has requested that this cost be charged to solar generators in the current avoided cost proceeding in Docket No. E-100, Sub 158. In its comments filed on March 27, 2019, the Public Staff recommended that this cost should be $0.78 per MWh using what it believes are more realistic inputs to the computer model. See Docket No. E-100, Sub 158, for further details.

DENC also stated that the variable output of solar photovoltaics creates the additional costs of higher spinning reserves and the increased cycling of conventional generators, leading to more wear and tear. DENC plans to present these costs in future IRPs.

The Public Staff agrees that the Utility's cost described by DENC as a re-dispatch charge, or by Duke as a solar integration charge (see Docket No. E-100, Sub 158 for further details), are important concepts as increasing levels of intermittent and non-dependable generation are added into the electrical grid. To the extent possible, the modeling programs used by the Utilities within the IRP process for selection of future projects should evaluate and use appropriate price signals to reasonably demonstrate the costs to ratepayers as new generation units are selected.

ENERGY STORAGE

In Docket No. E-100, Sub 147, the NCUC required utilities to "provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the 'full value' as discussed in the NCSEA comments. If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs."[35] Further, the GTSA requires DENC to submit a proposal to deploy up to 30 MW of batteries.

[35] Docket No. E-100 Sub 147, June 27, 2017 *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* (2016 IRP Order) at 60.

In DENC's IRP, battery storage is discussed in extremely broad terms, and DENC recognizes that energy storage could have value to provide grid stability as more renewables are integrated into the grid. They acknowledge that they can also reduce the intermittency of wind and solar generation. However, DENC states that battery storage technologies were "not considered for further analysis in the Company's busbar curve."[36] There does not appear to be any complete or thorough assessment of battery storage technologies, nor is there a separate discussion justifying their absence from the IRP.

The Public Staff believes that DENC did not comply with the Commission's 2016 IRP Order to provide a more complete and thorough analysis of battery storage technologies. In DEC and DEP's 2018 IRP, battery storage was included as a technology which their models could select; even though battery storage was not selected by the model, placeholders were input to the model and production cost runs reflected the effect of bulk energy shifting. The Energy Information Administration (EIA) estimates that there were approximately 700 MW of installed battery storage projects at the end of 2017, with 40% of that capacity in PJM.[37] It is clear that despite the cost of battery storage, this technology is being utilized by utilities to provide grid services.

In light of the rising deployment and falling costs of battery storage, the deployment scenarios considered in the *Energy Storage Options for North*

[36] DENC IRP at 72.
[37] EIA, *U.S. Battery Storage Market Trends*, May 2018. Accessed at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Carolina study[38], and the NCUC's 2016 IRP Order, the Public Staff recommends that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis of why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs. This analysis should address the estimated installation and operation costs of energy storage compared to more traditional resources. While the cost of battery storage may be prohibitive at this time, modeling storage technology in PLEXOS would provide the utility with information even if the technology is not selected – for example, the reduced cost[39] output of the model would provide insights, such as at what cost energy storage *would* have been selected.

In addition, as DENC has acknowledged that energy storage could reduce the integration costs of intermittent resources[40], DENC needs to address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies. DENC should be required to file this information in future IRPs and IRP updates.

IMPACT OF CERTAIN KEY VARIABLES

Certain key variables in the resource planning process have significant impacts on determining the least-cost resource scenarios. Two of these variables,

[38] This study was mandated by HB 589 (S.L. 2017-192) and was released in December, 2018. It is accessible at: https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf.

[39] Also known as the "shadow price", the reduced cost indicates what cost value the technology would have needed to have in order to be selected by the model.

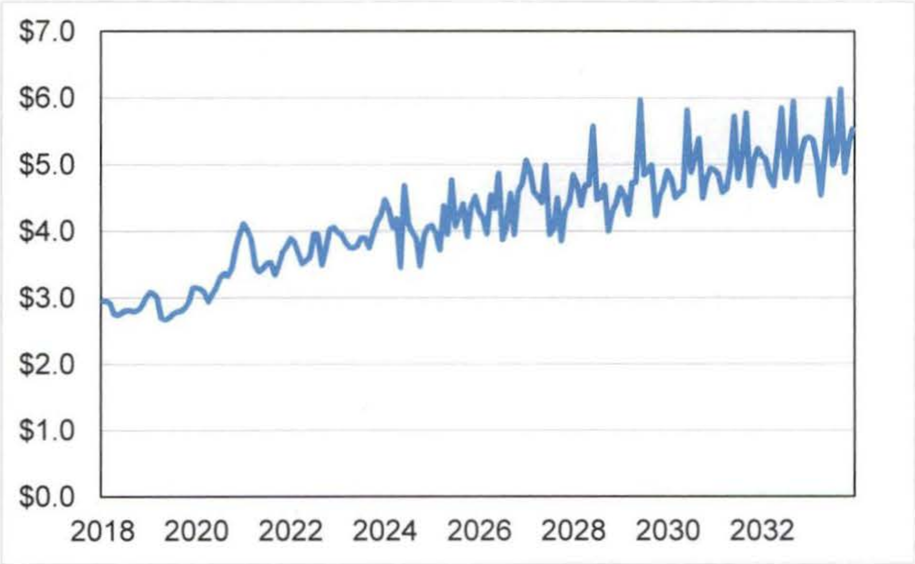
[40] *See* DENC IRP at 89.

in particular - the projected price for natural gas, and the projected cost of new generation – lead to significant changes in PVRR between the alternative resource plans considered, and, ultimately, the potential costs that customers will face. As previously noted, the assumption regarding nuclear relicensing can have a significant impact on future expansion plans.

DENC's Projected Prices for Natural Gas

The Public Staff appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and finds that DENC's reliance on forecasts from ICF International, Inc. (ICF), as reasonable. For the first eighteen months, DNCP relies completely on natural gas prices derived from the forward market for natural gas and then over the next eighteen months of the forecast, the Company gradually blends the monthly prices from the forward market with the monthly prices from ICF long-term price projection. This weighting process allows for a consistent transition of the two forecasts as illustrated in the graph below:

Figure 3: DENC's Henry Hub Natural Gas Price Forecast



The Public Staff finds the overall upward trend in DENC's natural gas price forecast over the next fifteen years as reasonable. The prices are projected to grow slightly over 4% over the next fifteen years and then decreasing the projected growth of prices to a rate in excess of 3% out to 2043. This long-term projected price forecast represents a long-term upward trend in its real or inflation-adjusted prices over the next fifteen years and beyond, which is a rational expectation, given the current low natural gas prices.

Capital Cost of New Generation

The 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 are combined with the projected cost of fuel, unit heat rates, O&M costs, service life, and other inputs in DENC's busbar screening. 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. Shown below are some of the characteristics for several generation units:[41]

[41] Figures derived from DENC response to PS DR 2-6.

[BEGIN CONFIDENTIAL]

[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]

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[END CONFIDENTIAL]

RECOMMENDATIONS REGARDING IRPS

In conclusion, the Public Staff makes the following recommendations:

(1) That the Company's 2020 IRP should rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts. As such, the Company is encouraged to present it internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

(2) That the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures.

(3) That the IOUs maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability.

(4) Utilities should put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.

(5) That the Commission direct the IOUs in future IRPs to include a discussion and evaluation of potential subsequent license renewals for all 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. Further, the Companies should continue to reflect any such relicensing plans in future IRPs.

(6) That DENC maintain its proposed reserve margins as filed.

(7) That in future IRP filings (including updates), DENC should be required to (1) provide PJM's capacity value for renewable resources as comparison benchmark, (2) to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

(8) That in future IRPs, DENC do the following: (1) clarify its definition of a NUG facility and use that definition consistently through the IRP; (2) re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; (3) separately identify facilities that sell energy/capacity directly to DENC from facilities that sell

directly into PJM; and (4) maintain consistency on references to nameplate rating or equivalent firm capacity rating.

(9) That DENC, in future IRPs, evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling, more granular system performance data, probabilistic analysis, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

(10) That DENC submit a supplemental filing with a rate impact analysis based upon the modified Alternative Plans found in its Compliance Filing.

(11) That DENC continue to provide comprehensive risk analysis of Alternative Plans in future IRPs and IRP updates.

(12) That DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis of why battery storage technologies were excluded from the Company's busbar curves.

(13) That DENC, in future IRPs and IRP updates, be required to address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies.

(14) All three IOUs should continue to explain any changes of the savings projections that are more than 10% different than the previous IRP or IRP

update. Additionally, the IOUs should identify any changes in EE-related technologies, regulatory standards, or other trends that would impact future projections of EE savings regardless of the 10% threshold. Those changes and trends should receive more detailed discussion in the IRPs.

(15) That the IOUs continue to pursue all cost effective EE and DSM.

(16) That DENC should continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, anytime the Company is denied approval by the VSCC to implement the program on a system-wide basis.

(17) That DENC include in future IRPs and updates a discussion of its use of data from smart meters to inform its load forecasting, cost of service studies, and rate designs.

Respectfully submitted this the 6th of May, 2019.

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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 6th day of May, 2019.

Electronically submitted
/s/ Tim R. Dodge