INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Friday, September 16, 2022
TIME: 9:00 a.m. – 12:16 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 13

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

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BEFORE: Chair Charlotte A. Mitchell, Presiding

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Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

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IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME: 13

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Modeling and Near-Term Actions Panel Exhibit 1: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Carolinas Carbon Plan – Supplemental Portfolio Analysis

Docket No. E-100, Sub 179
August 19, 2022

I. Background

On July 15, 2022, the Public Staff - North Carolina Utilities Commission ("Public Staff") submitted comments on the Companies' proposed Carbon Plan. While supportive of many aspects of the Carbon Plan, as filed, the Public Staff recommended Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies" or "Duke Energy") perform supplemental modeling incorporating certain recommended alternative inputs and adjustments, as presented in Appendix B to their Comments ("Supplemental Portfolio analysis"), and to submit the supplemental modeling by August 19, 2022, ahead of the evidentiary hearing on the Carbon Plan before the North Carolina Utilities Commission (the "Commission"). The Public Staff stated that the purpose of the supplemental modeling was to validate the Companies' proposed short-term execution plan submitted with the Carbon Plan. To the extent the supplemental modeling supported these near-term actions, the Public Staff would recommend approval of those actions within the near-term action plan.[1]

The Companies subsequently met with the Public Staff over a number of meetings to work through details of the recommended Supplemental Portfolio analysis. Through these collaborative discussions, the Companies and the Public Staff evolved and/or limited certain Public Staff recommendations for adjusting the modeling and modeling inputs utilized in the Carbon Plan, which after being reviewed in greater detail, seemed to not influence the results of the Plan. Concurrently, the Companies continued to review the numerous comments from other intervenors with respect to modeling recommendations. The Companies carefully weighed the potential impact to modeling along with the time and resources needed to integrate any additional modeling recommendations on the accelerated schedule of this proceeding. The Companies were able to integrate several modeling recommendations which were consistent across intervenors' comments, perform additional limited sensitivities and address additional recommendations proposed by intervenors in this analysis. This alignment was documented in the Companies' July 28, 2022 update letter to the Commission.[2]

The supplemental analysis contained herein provides background on key topics, modeling assumption changes, and portfolio results of the Supplemental Portfolio analysis.

II. Scope

The supplemental modeling consisted of the development of two additional portfolios, each with two fuel supply assumption scenarios. As recommended by Public Staff, the "primary" natural gas supply assumption for the supplemental analysis is Public Staff's "no Appalachian gas"

[1] Public Staff Comments at 20.
[2] *See* Development of Supplemental Modeling Portfolios.

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Aug 19 2022

assumption, whereas the "limited Appalachian gas" assumption is considered the "alternate" fuel supply scenario. Therefore, for this Supplemental Portfolio analysis, supplemental portfolio 5 ("SP5") represents a no Appalachian gas supply scenario and targets a 2032 interim 70% compliance year, while supplemental portfolio 5 with Alternate Fuel ("$SP5_A$") represents a fuel supply scenario which envisions limited access to Appalachian gas, consistent with the Companies' base fuel supply cases used to develop the Carbon Plan portfolios. Similarly, Supplemental Portfolio 6 ("SP6") targets a 2034 interim 70% compliance year, and like $SP5_A$, Supplemental Portfolio 6 with Alternate Fuel ("$SP6_A$") represents the fuel supply scenario with limited access to Appalachian gas and a 2034 as the compliance year.

The Supplemental Portfolios underwent the same economic evaluations as the filed Carbon Plan portfolios, including the evaluation of capacity expansion selection of peaking resources and reliability modeling within the EnCompass model and in Strategic Energy Valuation and Risk Model ("SEVRM") to evaluate a portfolio's loss of load expectation (LOLE) against the benchmark threshold. Finally, all portfolios underwent CO_2 reduction analysis, present value of revenue requirements (PVRR), and customer bill impact analysis.

Additionally, responsive to intervenor recommendations, the Companies conducted a limited set of sensitivities. The first is a "Low EE" sensitivity, which the Public Staff describes as "a better estimation of the impacts to future load" due to the net effects of potential lower achievement in utility-sponsored energy efficiency ("UEE" or "EE") overall. The second is a "High Solar Interconnection" sensitivity. This sensitivity was proposed by Clean Power Suppliers Association ("CPSA") and was generally supported by multiple intervenors, including the NC Attorney General's Office ("AGO"), with respect to assessing the impact of relieving binding solar selection constraints in the Carbon Plan modeling.

III. Recommendations Integrated into Supplemental Portfolio Analysis

A. Base Supplemental Portfolio Analysis Assumptions

The development of the Supplemental Portfolio consisted of economic selection of resources, including offshore wind and nuclear SMR, for achieving the interim emissions reduction target in 2032 and 2034. The table below summarizes the base cases changes integrated in the Supplemental Portfolio analysis compared to the Carbon Plan portfolio assumptions.

Table SPA-1: Base Case Modeling and Assumption Changes in Supplemental Portfolio Analysis

Supplemental Portfolio Parameter	Carbon Plan Portfolios 1 – 4 Assumption	Supplemental Portfolios 5 – 6 Assumption
First SMR Availability	End of Year ("EOY") 2032	Mid-year 2032
Belews Creek Retirement	Retired EOY 2035	Retired EOY 2037

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Aug 19 2022

Supplemental Portfolio Parameter	Carbon Plan Portfolios 1 – 4 Assumption	Supplemental Portfolios 5 – 6 Assumption
SPS Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch
Available SPS Battery Configurations	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio • 4-hr, 50% battery to solar ratio
Cumulative Battery Limits	4-hr battery capped at 1,500 MW in DEC and 1,800 MW in DEP; 6- hr battery at 32,00 MW in DEC and 2,000 MW in DEP	4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations
Inclusion of Hydrogen Fuel	Yes	No
2050 Emission Reduction Target	100% (Absolute Zero)	95% (Net-Zero)
Limited Appalachian Fuel Supply Case	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ultra-Low Sulfur Diesel ("ULSD") backup	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD backup
No Appalachian Fuel Supply Case	Existing CC fleet fueled Transco Zone 4, no incremental FT for new CCs, new CC configured with ULSD backup	Existing CC fleet fueled Transco Zone 4, FT for two new CCs with Transco Zone 4, new CC do not require ULSD backup
Back-up Fuel Supply	CTs operate on ULSD for entire month of January	CTs operate on ULSD for two weeks in January
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.
DEC/DEP Energy Transfer Hurdle Rate	No energy hurdle rate imposed on DEC/DEP transfers	Energy hurdle rate imposed on DEC/DEP transfers included for resource selection

Additional details on each of the parameter change are described in more detail in the following sub-sections.

1. <u>2032 Mid-year SMR</u>

In the Supplemental Portfolio Analysis, the Companies integrated feedback from intervenors on allowing the accelerated integration of the SMR in the modeling. As described in Appendix L of the Carbon Plan, the Companies believe implementation of the first nuclear SMR unit is feasible

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for June 2032. Because the capacity expansion model is set up to retire and bring on new resources on at the end of the year to ensure the following winter peak capacity needs are met, the originally SMR was first available at the end of 2032. However, due to the material impact a half of a year of a nuclear SMR can have on supplying carbon-free energy, the Companies decided to allow the first SMR to be brought online in June of 2032 in this one instance. All other future additional selection of nuclear units continues to follow the end of year addition assumption.

2. Belews Creek Retirement

The Companies, in the Carbon Plan modeling, originally identified the optimal retirement of the 2,220 MW Belews Creek Coal Station to be retired at the end of the year 2035. The Companies recognize as the industry continues to move forward, coal fuel security and regulatory risk grows. For this reason, the Companies limited the latest retirement of Belews Creek to end of the year 2035, two years ahead of its depreciable life. The Public Staff also recognizes this fact of increased fuel security risk in the industry but concern that the latest available retirement date of Belews Creek in 2035 used in the Carbon Plan coincides with an arbitrary internal Duke Energy target to cease coal generation by 2035.

While the Public Staff recommended in their comments to eliminate coal operation at Belews Creek in 2035, consistent with the Companies' goal, but to allow the station to continue to operate on natural gas through its depreciable life. The units are currently able to generate up to 50% of their rated capacity on natural gas. The Public Staff's recommendation to allow the units to cease coal operations and operate exclusively on natural gas, however, did not originally consider the need for a firm fuel supply for this capacity. Ceasing coal operations at the site means the unit would rely solely on natural gas for firm capacity of the units. While the units are capable of operating up to 50% of rate capacity on natural gas, the Companies do not have enough interstate transportation to supply these units with firm fuel, leaving their capacity subject to potentially constrained supply at Transco Zone 5 delivered. Other natural gas units of the Companies' that do not have firm fuel supply are equipped with backup fuel supply to ensure the capacity of resource if natural gas supply were to be constrained at Transco Zone 5 delivered. For the Companies' existing CCs and CTs, this backup fuel is ultra-low sulfur diesel (ULSD). For the dual fuel optionality (DFO) coal units, such as Marshall and Belews Creek, this backup fuel is coal. The first supply of coal sitting in the coal yards at these sites provides assurance that their capacity can be counted from a fuel supply perspective, in case the units had to operate without access to natural gas supply.

In summary, removing the coal operations at Belews Creek would not result in 50% of firm capacity contribution, but constitute an energy only resource, with ability to generate year around, but whose capacity could not be counted as firm and would therefore need to be replaced regardless. For this reason, the Companies compromised for the purposes of the Supplemental Portfolio analysis, to allow for this analysis that Belews Creek could continue to run through 2037, consistent with its depreciable lives, operating on both coal and natural gas to ensure firm capacity of the resources, while extending the timeline for additional resources to be brought onto the system. The Companies continue to caveat this risk, that fuel security remains an issue and an orderly exit from coal may require 2035 or earlier retirement of Belews Creek.

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3. SPS Battery Dispatch Optimization and Available SPS Battery Configurations

In response to multiple intervenors, to include more detailed and granular operation of solar paired with storage (SPS), the Companies deployed revised storage modeling in the Supplemental Portfolio analysis. The Companies modeling of SPS in the Carbon plan consisted of two SPS configurations. The solar asset included in each SPS configuration had an inverter loading ratio (ILR) of 1.6, while standalone solar had an ILR of 1.4. Also generally referred to as "over paneling" or "DC / AC ratio," ILR represents the ratio of installed DC capacity to the inverter's AC power rating. Therefore a 1.6 ILR on a 75 MW AC inverter limited solar site would have 120 MW DC of Solar capacity at the site. This over paneling of solar sites helps maximize energy output in the shoulder hours when higher cost energy is on the margin, and in the case of solar plus storage, the excess energy that would be "clipped" by the inverter can be captured in batteries and then discharged when the system needs it the most.

The Carbon Plan's modeling of solar plus storage used a fixed generation profile developed by the Companies to optimize the generation profile of the SPS site based on the nine premium-peak, on-peak, and off-peak energy hours defined in the 2020 Sub 167 avoided cost proceedings. The Companies model optimized the dispatch of the hybrid resource based on the DC solar profile, the size of the storage asset and the avoided cost peak periods to maximize value of the SPS system. This has been a reasonable assumption in the past. However, as pointed out by intervenors, with the rapid transformation of the system projected in the Carbon Plan may result in a disconnect between the dispatch of the solar plus storage site and the needs of the system.

For this reason, the Companies have implemented model functionality for the Supplemental Portfolio analysis to allow the Encompass model to optimize the charging and discharging of the resource to best meet system needs. The SPS resource continues to be charged by the paired solar asset exclusively, based on limitations of the model and the storage resource eligibility to qualify for the ITC.

Additionally, the Companies have included in the Supplemental Portfolios, at the recommendation of intervenors, an additional SPS configuration that included a larger battery than those assumed in the Carbon Plan. In addition to the 20 MW / 80 MWh battery (25% battery to solar ratio with 4-hr battery duration) and 40 MW / 80 MWh battery (50% battery to solar ratio with 2-hr battery duration), the Companies have included a 40 MW / 160 MWh battery option paired with solar. To help simplify the modeling, the Companies and the Public Staff agreed to use a single solar transmission cost adder for all solar units. The change from using different solar transmission cost adders based on in service year to using an average used for solar in all years in the Carbon Plan, acknowledges that this cost differential likely had little impact on the selection of solar over time.

While there are nearly infinite combinations and permutations of solar paired with storage, the three SPS configurations included in the Supplemental Portfolios capture a reasonable number of configurations for planning purposes. More precise optimization of combinations is best evaluated in the procurement execution phase of the process.

Finally, in the Carbon Plan modeling, the selection of SPS and standalone batteries did not impact the others effective load carrying capabilities ("ELCC" or "Capacity Value"). In reality, the more

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short-duration storage added to the system, the less each incremental block is able to contribute to meeting system peak as an energy limited resource. With the revised modeling of SPS, the Companies were now able to capture the cumulative impact of short duration storage on the system, both paired with solar and standalone, with respect to its capacity value to the system.

Optimization of storage is computationally intensive in capacity expansion and production cost models. The Companies recognize this as a more accurate depiction of the usage of SPS, but the Companies will continue to evaluate ways to decrease model run time, while also capturing general value of SPS to the system.

4. Cumulative Limits of 4-Storage and 6-hr Storage

The Companies, in an effort to recognize the rapidly declining value of short duration storage, limited the amount of 4-hr and 6-hr storage on the system in the development of the Carbon Plan portfolios. As identified by the Public Staff and other intervenors, short duration storage, despite is declining capacity value at higher penetrations may still be able to provide value to the system with its ability to shift energy from lower cost energy from one period to higher cost energy periods, perhaps being able to overcome the decreased capacity value ascribed. The Companies recognize this possibility, and accordingly have allowed 4-hr and 6-hr battery to be selected across their entire ELCC curves, including down to essentially no capacity value, resulting in energy only resources.

5. Removal of Hydrogen as Fuel

Due to concerns from intervenors on the uncertainty of cost and overall development of a clean hydrogen market and hydrogen production overall, the Supplemental Portfolio analysis removes hydrogen as a fuel. Removing this fuel includes removing the fuel being blended into natural gas supply beginning in 2035 as assumed in the Carbon Plan portfolio. This assumption change removed the cost and CO2 impacts of hydrogen being used to fuel all natural gas units on the system. Additionally, the Companies have also removed the conversion costs associated with converting existing and new natural gas resources built before 2040, to operate exclusively on hydrogen by 2050. These units are now assumed to operate throughout the planning horizon on natural gas exclusively.

Hydrogen as a standalone fuel, stating in 2040 has also been removed for this analysis. These peaking CT resources, in the Carbon Plan modeling, were assumed to be built and operate exclusively on hydrogen fuel. This assumption generally represented a placeholder for future technology such as long duration storage or other zero emitting, load following resources (ZELFRs) options. Peaking CT resources could still be selected by the capacity expansion model in the Supplemental Portfolios in the 2040s but would operate exclusively on natural gas.

As a result of removing hydrogen fuel from the portfolios, and as agreed upon by Public Staff, the Companies modeled net zero (95% reduction) CO2 emissions by 2050, rather than the absolute zero goal used in the Carbon Plan modeling. The Companies utilized the same system mass cap approach used in the Carbon Plan modeling, but once reductions reached 5% or less, the Companies held this level flat through 2050. While not factored into the optimization of the portfolio of resources or simulation of the system, a $210/short ton of CO_2 emitted cost was applied

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Aug 19 2022

to CO_2 emissions in 2050 in the present value of revenue requirements. As part of the Portfolio Verification steps, the Companies verified that the portfolio in fact achieved 5% or less emissions of CO_2 compared to their 2005 baseline, as established in Appendix A of the Carbon Plan.

The Companies believe this to be a bounding assumption. It is highly unlikely that hydrogen will play no role in transformation of the energy system over the next three decades and therefore this extraordinarily conservative assumption is to simply determine if CC and CT resources would still be selected regardless of the degree of development of hydrogen play in the future. This fuel source and its ability to be used for power generation should continue to be viewed as an important factor in long-term reliability of the system and as critical to executing a least-cost plan in achieving the 2050 goal.

6. Natural Gas Supply

As stated above in Section II. Scope, the Companies have run each of the two portfolio development scenarios (compliance with interim reduction target in 2032 and 2034 using the assumptions outlined in the Supplemental Portfolio analysis) in both the Companies primary fuel supply scenario from the Carbon Plan and in the Public Staff's primary fuel supply assumption. The Public Staff's primary fuel supply assumption envisions the Companies securing firm transportation ("FT") service of fuel supply for the remaining existing CC on the Companies' fleet, which do not already have firm natural gas fuel supply, through a Transco expansion project assuming Zone 4 pricing of natural gas. Additionally, the Staff's fuel supply assumption also allows for incremental capacity of FT for approximately 2,400 MW of new CC capacity. The Companies primary fuel supply assumption remains consistent to the Carbon Plan modeling, with the equivalent amount of incremental Appalachian gas supply as assumed in the Public Staff's recommend natural gas fuel supply scenario from Transco Zone 4.

The Companies assumed in the alternate fuel supply scenario in the Carbon Plan that incremental natural gas supply would be limited, and the Companies would not be able procure incremental FT for new CC units. The Companies also assumed that because of the lack of additional incremental supply and overall supply diversity, that CC capacity should be limited to 800 MW and would have to assume operations on ULSD in January due to continued constrained supply at Transco Zone 5 delivered. This is consistent with the treatment of peaking resources in the Carbon Plan modeling, assuring firm capacity through ULSD backup fuel. As a result of slightly relieving this constraint in their recommended gas assumption, the Public Staffs gas supply assumes operation of all CC units exclusively on natural gas throughout the planning horizon.

One final change with respect to fuel supply is the limiting the operation of CT to USLD backup from the entire month of January to only a two-week period in January. During these two weeks, to recognized and acknowledge potential price volatility and supply constraints at Transco Zone 5 delivered, these units operate exclusive on ULSD. However, during the remainder of the month, and throughout the rest of the year, these units operate exclusively on natural gas.

7. Natural Gas Resources

The Supplemental Portfolio analysis retains 35-year book life of assets, while removing associated hydrogen conversion costs from existing and future resources expected to be on the system by

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2050. Because hydrogen conversion is not a consideration in these portfolios, the Companies have adjusted the price and operation from the J-Class peaking CT from one assuming a selective catalytic reducer ("SCR"), to one assuming no SCR. The incremental cost and constraints on operations for these units are more necessary if the CT is expected to need the SCR environmental equipment to lower NOx rates, especially in the case that the CT unit is expected to burn hydrogen in the future. This assumption update represents a cost saving for customers on equipment that is not necessary to the reliable operation of the unit into the future.

Additionally, responsive to multiple intervenors, the Companies have allowed the selection of both F-Class and J-Class CCs and CTs. F-class combustion units generally are smaller and less efficient though more widely deployed today as compared to J-Class units. J-Class combustion units are generally large and more efficient representing advanced turbine technology. The Companies collaboration with Siemens Energy on Lincoln represents a first-of-its-kind deployment of this industry-leading advanced turbine technology. The Supplemental Portfolio analysis allows for the selection among all of these resources, whereas, the Companies only allowed J-Class units in the Company's primary fuel supply scenario, and J-Class CTs and F-Class CCs (for sizing purposes representing a smaller exposure to fuel supply constraints) in the Companies alternative fuel supply scenario.

8. Energy Hurdle Rate

The Public Staff identified in their comments a growing concern over rate disparity between DEP and DEC. According to their comments, this rate disparity is exacerbated in the Carbon Plan modeling failing to adequately represent the true nature and cost of electric utility service. In the Carbon Plan, abundant amounts of renewable resources are integrated into the DEP service territory, with access to offshore wind and higher capacity factor solar and generally lacks existing storage capacity. Due to this modeling result, accompanied with DEC utilizing the Joint Dispatch Agreement ("JDA") to buy over 10% of their annual energy from DEP, DEP is incurring the cost for these resources and based on the analysis of the Public Staff, not being fairly compensated by the JDA for the investment they are making to jointly serve the energy needs of the combined system.[3]

To influence the capacity expansion model to select resources into the service territories in which they are being utilized, the Public Staff has recommended applying an energy hurdle rate to JDA transfers. This hurdle rate would be an additional marginal dispatch cost differential between DEP and DEC that would need to be overcome before transferring energy across the JDA. As a proxy, the Public Staff has recommended using the Open Access Transmission Tariff ("OATT") non-firm transmission service rate. This recommended hurdle rate would not be a real cost incurred by or paid to either of the utilities, but merely a threshold at which the cost disparity would need to reach before the JDA would be used.

The Companies recognize these are not real costs that could or should be applied to either utility as the non-firm transmission service used to execute the JDA has a no "pancaking" provision which would preclude this additional cost for transmission. However, the hurdle cost in modeling

[3] Public Staff Comments at 96-98.

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Aug 19 2022

may influence new resources to rather be selected by DEC rather than selected by DEP and utilize the JDA for serving DEC's load.

B. Supplemental Portfolio Analysis Sensitivity Assumptions

The Supplemental Portfolio analysis includes two sensitivities which are performed from Supplemental Portfolio 5 (no App gas). The parameters for the assumption changes are further described below.

1. Low UEE Load Sensitivity

The Companies used a 1% of available load UEE forecast as a base assumption in the Carbon Plan. This means that UEE grows at a minimum of 1% of annual retail load, net of larger commercial and industrial customers who have opted out of participation in utility sponsored efficiency programs. This methodology yields a higher UEE forecast, particularly in later years, than the standard IRP UEE base case and results in a lower net load forecast. The Companies' base UEE forecasts, such as the UEE forecast used in the Companies' 2020 IRPs, are a blend of near-term program projections transitioning in later years to the achievable potential quantified in a Market Potential Study specific to the Companies service territories. The 1% of available retail load represents an aspirational goal of the Companies through ongoing engagement with the EE Collaborative.

The Public Staff recommended the Carbon Plan's Low UEE forecast be used as a base assumption for the Supplemental Portfolio analysis. After discussion, the Public Staff agreed to use of the Companies' base load forecast, with the use of the 1% of available retail load UEE assumption, as the base load forecast for the Supplemental Portfolio analysis and to conduct a sensitivity for Low EE off the SP5 (no App gas). The Companies have completed this sensitivity and resource selection impacts of this sensitivity are summarized in the results section of this analysis.

2. High Solar Interconnection Sensitivity

The selection of solar in the Carbon Plan portfolios often hit their annual selection limit. Physical constraints exist limiting the Companies' ability to interconnect solar at higher rates than the limits imposed on the Carbon Plan model, as discussed in Carbon Plan Appendix I (Solar). However, to analyze the impacts on achieving the emissions reduction targets if the Companies were able to interconnect more solar capacity each year, the Companies performed a High Solar Interconnection Sensitivity. The High Solar Interconnection sensitivity was performed for informational modeling purposes and the Companies' July 28 update letter explained that the Companies continue to believe that the very aggressive solar volumes proposed by CPSA are not executable in terms of achieving annual solar generator interconnections.

Below is a comparison table of the Companies' base solar selection limits used in P2 through P4 and $P2_A$ through $P4_A$, and the high solar selection limits, increasing risk of creating an un-executable plan, but necessary for achieving the interim emission reduction targets by 2030, used in Portfolio 1 and Portfolio 1_A in the Carbon Plan. Additionally, the solar selection limits used in the Supplemental Portfolio 5-High Solar Interconnection Sensitivity.

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Table SPA-2: Solar Interconnection Limits by Portfolios

	Portfolios 2-4, Supplemental Portfolios 5-6	Portfolio 1	Supplemental Portfolio 5-High Solar Sensitivity
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	750	750	1,500
2028	1,050	1,050	1,500
2029	1,350	1,800	1,800
2030	1,350	1,800	1,800
2031	1,350	1,800	1,800
2032+	1,350	1,800	1,800

The dates used in the table above reflect a beginning of year basis, meaning resources are selected at the end of the previous year, for the full calendar year listed. The increased solar selection limits allow for up to 3 GW of additional solar by 2032 over the base Supplemental Portfolio 5.

The Companies have completed this sensitivity and resource selection impacts of this sensitivity are summarized in the results section of this Supplemental Portfolio analysis.

IV. Additional Post Carbon Plan Filling Modeling Updates

Additionally, the Companies have identified a limited number of input assumptions or modeling updates that were appropriate to incorporate into the Supplemental Portfolio analysis.

A. Update to EnCompass Version 6.1.3

For the modeling of the Carbon Plan, the Companies used the EnCompass capacity expansion and production cost simulation software package from Anchor Power Solutions. This is the first filing in which the Companies have used the EnCompass model to model resource selection and detailed system simulations for resource planning purposes. While the new model offers several enhancements over previous tools that are no longer supported by the vendor, the Companies are still learning the intricacies of the model, especially with respect to sharing modeling inputs and results with intervening parties.

Several issues identified by intervenors in their modeling of the Companies' system have been addressed in version 6.1.3, including a bug in version 6.0.4 that resulted in issues with exporting datasets, resulting in unexpected run failures by the intervenors attempting to recreate the Companies' modeling results.

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B. Declining Capital Cost Modeling for Emerging Resources

As described in the "EnCompass Input Data: Declining Cost Adder Issue and Resolution" briefing to the Commission, the Companies discovered an issue with how the EnCompass model handles certain costs that were being used to reflect the declining cost of emerging technologies. The cost inputs the Companies were utilizing to account for this cost decline was not being recognized or factored into the economic selection decisions of the capacity expansion model. Resources such as offshore wind, solar, and battery technologies are expected to experience price declines over the next decade in the Companies' capital cost forecast for these resources. To account for different near-term and long-term inflation rates (or a short-term deflation rate and long-term inflation rate), the Companies input long-term cost trajectories and then account for near-term deflation using cost adders. The issue identified resulted in the underestimation of the costs of these resources in the selection of resources in the capacity expansion model.

As a resolution, the Companies worked with Anchor Power Solutions and was able to identify an alternative input parameter to use to correctly capture these costs and factor the near-term cost decline into the selection of the resources. The Companies performed preliminary diagnostic runs to show that the selection of resources would not be materially impacted with this change. This change resulted in minor shifts between solar and standalone battery and solar paired with battery, but overall, the materiality of the Final Carbon Plan portfolios was not affected.

Knowing that intervenors would be using this data to conduct their own modeling and, in an attempt, to avoid for intervenors the same modeling issue the Companies encountered, the Companies included this fix in the modeling files made available to intervenors. Upon filing their alternative modeling input parameters, the Companies uploaded to the data site modeling files that included the fix needed to account for this resolution. Additionally, for the Supplemental Portfolio analysis, the Companies have implemented this resolution to capture these near-term cost declines on selectable resources.

C. Transmission Cost Adder

After filing the Carbon Plan, it was discovered that the fixed charge rate used to develop transmission cost adders factored into the cost of new resources, was understated. The Companies have corrected the fixed charge rate for transmission assets, which more accurately reflects the cost of an asset over its projected life. The original misrepresentation of the annual real levelized costs impacted all new resources equivalently, so while the costs were lower, they are lower for all generation resources.

D. New Nuclear Maintenance Rates

With continued use of the EnCompass model and engagement with Anchor Power Solutions, after filing the Carbon Plan, the Companies identified a modeling bug dealing with new nuclear units' maintenance rates. The Companies input maintenance rates for nuclear with discrete number of days on maintenance. This modeling bug resulted in a reduced ability for new nuclear to reliably serve load needs by taking all of the new nuclear offline at the same time. This was particularly impactful at the end of the planning horizon with the retirement of the majority of the Companies' existing natural gas fleet. The revised input change, changing from a discrete number of

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maintenance days to a maintenance rate, allowed nuclear units to capture dispersed maintenance outages more closely reflecting real-world maintenance activities. This update overall reduced the need for the Companies to add additional resources late in the period to meet the energy needs of the system.

E. Solar paired with Storage Fixed O&M

In reviewing the solar paired with storage (SPS) inputs to integrate an additional configuration for the Supplemental Portfolio analysis, as detailed in Section III. A. 3., the Companies discovered that fixed operations and maintenance (FOM) rates for SPS sites had been improperly reflected in the model. This correction resulted in a lower FOM rate for all SPS resources.

F. Degradation of New Solar Output

Solar resources are expected to lose output over time due to degradation of solar panels. This degradation results in the loss of about 0.5% energy output annually. To capture this degradation, the Companies have corrected the output profile for solar paired with storage to account for this degradation.

Reviewing the additions of solar in the Carbon Plan, by 2050, the average life of a unit on the Companies' system is approximately 15 years old. To correct for the degradation factor, the Companies have simulated what this degradation would look like over this average 15-year time frame for a solar unit. The Companies then averaged the annual output over that 15-year time frame to come up with a solar generation profile that approximates this degradation.

This was applied to both new standalone solar and new solar paired with storage for the Supplemental Portfolio analysis. This correction allows both new and existing solar to more accurately factor degradation into the energy they provide to the system.

V. Portfolio Development

A. Preliminary Capacity Expansion and Portfolio Verification

The Companies developed the 2032 and 2034 Compliance year portfolios, SP5 and SP6, with the same approach to the Carbon Plan portfolios. The Companies ran a preliminary capacity run for each portfolio, where the initial selection of resources was selected by the EnCompass model. The Companies then conducted the Portfolio Verification process including the Battery-CT Optimization, Overall Portfolio Reliability and 2050 CO2 Reduction Verification, and the Portfolio LOLE and Resource Adequacy Validation modeling; crucial steps to ensuring low cost and reliable portfolios. Overall, the portfolios required only minor resource adjustments. Due to, in part, the revised input change to new nuclear units' maintenance rates, no Portfolio Reliability and CO2 Reduction Requirement Resources were required to meet the energy and CO2 reduction needs of the system for 2050. Additionally, the portfolios each passed the 2030 and 2035 LOLE validation steps, requiring no additional peaking CT resources in these timeframes to maintain the reliability standard of the system. Finally, due to the revised SPS modeling technique, the Companies Battery-CT economic evaluation including verifying the SPS selection compared to

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Aug 19 2022

standalone solar and CTs. Below are the results of the economic replacements in this step for Supplemental Portfolios 5 and 6.

Table SPA-3: Battery-CT Optimization Results through 2050 [Nameplate MW]

	Supplemental Portfolio 5 (No App gas)	Supplemental Portfolio 6 (no App gas)	Supplemental Portfolio 5 (with Limited App gas)	Supplemental Portfolio 6 (with Limited App gas)
Standalone 4-hr Battery Capacity Removed	0	0	0	0
SPS (4-hr, 50% battery to solar ratio) Capacity Removed	1,350	675	1,350	1,350
SPS (4-hr, 25% battery to solar ratio) Capacity Removed	0	0	0	0
Standalone Solar Capacity Added	1,350	675	1,350	1,350
CT Capacity Added	704	352	704	704

Of note, Supplemental Portfolio 6 (No App Gas), resulted in the selection of very few standalone batteries and SPS-50% battery-to-solar ratio, 4-hr batteries in DEP in the near term. The Companies therefore replaced the remaining SPS-25% battery-to-solar ratio, 4-hr batteries with CTs and conducted the economic evaluation. These batteries were found to not be economic to replace. When this portfolio was further evaluated for portfolio reliability, the LOLE benchmark in 2035 was only barely met, achieving a 0.248 event-days per year LOLE against the 0.253 event-days per year LOLE threshold. The other portfolios, which all included more economic battery CT replacements, resulted in lower LOLEs. This points to evidence, that some of these peaking resources may be necessary from a reliability perspective to ensure resource adequacy and reliability are maintained or improved, in accordance with HB 951.

B. Final Supplement Portfolios 5 and 6

The annual resource additions and coal retirements for DEC and DEP for each final Supplemental Portfolio are presented below in Table SPA-4 through Table SPA-11. Consistent with data presented in Appendix E, resource changes are effective as of the start of the year listed. The one exception is for the new, 2032 mid-year, SMR which is selected in all portfolios. This resource is selected mid-year 2032 and available for system capacity and generation for the second half of the

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year. Resource changes are included through 2038 consistent with the retirement of the last coal unit at the end of the year 2037. DEC Cliffside 6's capacity is reflected in the coal retirements column, as its coal capacity is retired in 2036, though the unit continues to operate on natural gas exclusively thereafter. Capacities in these tables below reflect nameplate capacity of resources including the forecasted solar and storage resources.

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Table SPA-4: Supplemental Portfolio 5 (no App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	34	300	0	0	160	0	0	0	0	0
2028	0	34	450	0	0	240	0	0	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	525	0	0	140	1,216	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	140	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	525	0	0	140	0	0	0	0	0
2036	-849	0	525	0	0	280	0	0	0	0	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	450	300	0	240	0	0	0	500	0

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Table SPA-5: Supplemental Portfolio 5 (No App Gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	110	375	0	28	200	0	0	0	0	0
2028	0	635	0	0	800	0	0	352	0	0	0
2029	-1,766	35	825	300	0	220	0	462	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	35	825	300	150	440	0	0	0	0	0
2032	0	0	825	300	950	420	0	0	0	0	0
2033	0	0	825	0	0	220	0	0	0	0	0
2034	-1,409	0	450	0	0	240	0	0	0	285	0
2035	0	0	825	0	0	220	0	0	0	0	0
2036	0	0	825	0	0	420	0	0	0	285	0
2037	0	0	825	0	0	220	0	0	0	0	0
2038	0	0	825	0	0	440	0	0	0	0	0

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Table SPA-6: Supplemental Portfolio 6 (no App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	259	75	0	0	20	0	0	0	0	0
2028	0	34	450	0	0	120	0	0	0	0	0
2029	-760	34	0	0	0	0	0	0	0	0	0
2030	0	34	0	150	0	0	1,216	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	150	0	0	80	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	525	0	0	280	0	0	0	0	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	525	300	200	280	0	0	0	500	0

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Table SPA-7: Supplemental Portfolio 6 (no App Gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	28	120	0	0	0	0	0
2028	0	110	525	0	0	140	0	0	0	0	0
2029	-1,766	35	450	300	0	120	1,216	0	0	0	0
2030	0	35	825	150	0	220	0	0	0	0	0
2031	0	35	825	300	0	220	0	0	0	0	0
2032	0	0	825	300	0	320	0	0	0	0	0
2033	0	0	675	150	0	200	0	0	0	0	0
2034	-1,409	0	675	0	550	360	0	0	0	0	0
2035	0	0	225	0	0	60	0	0	0	285	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	50	440	0	0	0	0	0
2038	0	0	525	0	0	280	0	352	0	0	0

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Table SPA-8: Supplemental Portfolio 5 (with Limited App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	34	300	0	0	160	0	0	0	0	0
2028	0	34	450	0	0	240	0	352	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	525	0	0	140	0	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	280	0	0	0	0	1,680
2034	0	0	525	0	0	140	0	0	0	0	0
2035	0	0	525	0	0	160	0	0	0	285	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	375	0	0	200	0	0	0	285	0
2038	-2,220	0	300	300	0	160	0	0	0	0	0

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Table SPA-9: Supplemental Portfolio 5 (with Limited App gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	110	375	0	28	200	0	0	0	0	0
2028	0	635	0	0	500	0	0	352	0	0	0
2029	-1,766	35	825	300	0	220	1,216	0	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	35	825	300	350	440	0	0	0	0	0
2032	0	0	825	300	600	440	0	0	0	0	0
2033	0	0	825	0	0	220	0	0	0	0	0
2034	-1,409	0	300	0	0	80	0	0	0	0	0
2035	0	0	825	0	0	220	0	0	0	0	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	0	440	0	0	0	0	0
2038	0	0	825	0	0	440	0	0	0	500	0

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Table SPA-10: Supplemental Portfolio 6 (with Limited App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	484	0	0	0	0	0	0	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	375	0	0	100	0	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	280	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	285	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	525	300	250	280	0	0	0	500	0

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Table SPA-11: Supplemental Portfolio 6 (with Limited App gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	28	120	0	0	0	0	0
2028	0	35	600	0	0	160	0	0	0	0	0
2029	-1,766	35	0	300	0	0	1,216	462	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	710	150	300	0	60	0	352	0	0	0
2032	0	0	825	300	0	440	0	0	0	0	0
2033	0	0	600	0	0	160	0	0	0	0	0
2034	-1,409	0	675	0	100	260	0	0	0	0	0
2035	0	0	825	0	150	400	0	0	0	0	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	0	440	0	0	0	0	0
2038	0	0	750	0	0	400	0	352	0	0	0

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Presented below in Table SPA-12 through Table SPA-14 is a summary of the final resource additions of each portfolio for the year the interim target is achieved, 2035, and 2050. For summary purposes, the solar capacity associated with solar and solar plus storage is grouped together. Similarly, all battery capacity (standalone battery and battery paired with solar) and, for the 2050 summary data, all new nuclear (SMR and Advanced Nuclear with Integrated Storage) additions are grouped together. Of note, the solar and battery capacities noted below represent incremental additions on top of the existing solar on the system at the start of the Carbon Plan. These additions include both forecasted solar and batteries over these time frames and the Carbon Plan economically selected solar (both standalone and pair with storage) and battery (both standalone and paired with solar). Additionally, capacity changes have been rounded for summary purposes and may not sum to data in the previous data presented in this section.

Table SPA-12: Final Resource Additions by Portfolio [MW] for year interim target is achieved

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5 (2032)	-3,500	8,600	1,200	4,500	2,400	1,200	0	300	0
SP6 (2034)	-6,300	9,200	1,400	3,000	2,400	400	0	300	1,700
$SP5_A$ (2032)	-3,500	8,600	1,200	4,100	2,400	1,100	0	300	0
$SP6_A$ (2034)	-6,300	9,400	1,200	2,500	2,400	1,200	0	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table SPA-13: Final Resource Additions by Portfolio [MW] for 2035

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5	-6,300	11,800	1,200	5,500	2,400	1,200	0	600	1,700
SP6	-6,300	10,000	1,400	3,400	2,400	400	0	600	1,700
$SP5_A$	-6,300	12,100	1,200	5,200	2,400	1,100	0	600	1,700
$SP6_A$	-6,300	10,300	1,200	3,000	2,400	1,200	0	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

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Table SPA-14: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
SP5	-9,300	22,800	1,800	13,900	2,400	8,800	1,600	9,000	1,700
SP6	-9,300	21,700	1,800	12,700	2,400	8,200	2,400	9,000	1,700
$SP5_A$	-9,300	22,900	1,800	13,700	2,400	8,700	1,600	9,000	1,700
$SP6_A$	-9,300	22,600	1,800	14,100	2,400	8,800	1,600	9,000	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

VI. Portfolio Analysis

A. General Findings

Overall, the selection of resources in the Supplemental Portfolios supports the near-term execution plan presented by the Companies in the Carbon Plan. Each portfolio continues to add significant levels of solar by the compliance year, ranging from 8.6 GW in the 2032 emissions reduction achievement year scenarios up to 9.4 GW in the 2034 emissions reduction achievement year scenarios. The significant solar additions are further supported by the selection of substantial quantities of storage, both standalone and paired with solar. Additionally, the inclusion of onshore wind continues to be supported by the Supplemental Portfolio analysis, selecting at least 1.2 GW in all portfolios for achievement of the emissions reduction targets. To further support these variable energy and energy limited resources, and help replace retiring existing coal and gas, both CCs and CTs are economically included in each of the portfolios. The capacity expansion model, in both fuel supply scenarios and compliance year targets scenarios, identified the two eligible CCs to be economic and compatible with the net zero 2050 target. The CTs were identified both in the capacity expansion step and in the economic evaluation of batteries and CTs step for inclusion in the portfolios.

While no offshore wind is selected for compliance with the interim emissions reduction target, the resource is selected in all portfolios in the Supplemental Portfolio analysis, re-emphasizing the benefits of resource diversity in achieving the 2050 goal. Furthermore, the first SMR is selected in all portfolios as soon as it is available, in mid-year 2032 for the Supplemental Portfolio analysis. By the end of 2036, the first four SMR units continue to be selected, on pace with the availability of the resources through that time frame. Pumped storage continues to provide significant capacity and energy arbitrage benefits to the system when implemented.

The resource selections in the Supplemental Portfolio analysis were certainly impacted by the assumption and modeling changes integrated into the analysis. However, these differences mainly manifest as shifts between standalone solar and battery and solar paired with battery. Without the assumption of hydrogen but allowing the system to plan to a 95% reduction in 2050, assuming the rest is met with offsets, allowed for the economic selection of CCs and CTs, which over time are used increasing less, primarily for system flexibility and back-standing renewables. Finally,

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Aug 19 2022

improvements to the modeling, such as upgrading to EnCompass Version 6.1.3 and resolving new nuclear maintenance rate issues, allowed for less adjustments in these Supplemental Portfolios.

B. CO2 Emissions Reductions

Below, Table SPA-15 shows the CO2 reduction percentage with respect to meeting the HB 951 CO2 emissions reductions targets and for the combined DEC and DEP systems relative to the 2005 baseline.

Table SPA-15: Annual HB 951 CO2 Emissions Reduction in 2030, the Portfolios Interim Target Year, 2035 and 2050 [Percent reduction relative to 2005]

	2030	Portfolio Targeted Compliance Year	2035	2050
SP5	65%	71%	77%	95%
SP6	63%	71%	74%	95%
$SP5_A$	65%	70%	77%	95%
$SP6_A$	63%	72%	74%	95%

Each of the Portfolios achieves the interim emissions reductions goals by the targeted compliance year. Additionally, each portfolio achieves 95% emissions reductions by 2050, consistent with net-zero goal using up to 5% carbon offsets. As expected, the 2032 compliance portfolios have slightly more aggressive emission reductions by 2030 and 2035, and throughout the planning horizon resulting in overall lower cumulative CO2 emissions through 2050. Because the overall resources do not vary much across each of these portfolios, the timing of resources, based on the targeted interim emissions reduction year, accounts for the majority of the differences in emissions over the planning horizon.

C. Present Value of Revenue Requirement

Shown below in Tables SPA-16 and SPA-17 are the cumulative present value of revenue requirements of each of the Supplemental Portfolios. Annual revenue requirements are discounted to present value at DEC's and DEP's Company specific discount rate. A combined DEC and DEP PVRR is also shown.

Table SPA-16: Present Value of Revenue Requirements through 2050 [2022, $B] – Supplemental Portfolio Analysis (no App gas)

	DEC	DEP	DEC + DEP
SP5	$57.3	$44.4	$101.7
SP6	$56.1	$42.2	$98.4

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Table SPA-17: Present Value of Revenue Requirements through 2050 [2022, $B] - Supplemental Portfolio Analysis (with limited App gas)

	DEC	DEP	DEC + DEP
SP5	$55.6	$42.2	$97.8
SP6	$54.8	$39.9	$94.7

The PVRRs calculated above are consistent with how the system costs were developed for the Carbon Plan. Table SPA-16 shows the PVRRs for Supplemental Portfolios 5 and 6, which are developed in and dispatched in the Public Staff's recommended no Appalachian Gas assumption. Table SPA-17 shows the PVRRs for Supplemental Portfolios 5_A and 6_A, which are developed in and dispatched in the Companies' primary fuel supply scenario which assumes limited access to Appalachian Gas. Each of these portfolios include the assumed cost of carbon offsets as described in Section III. A. 5. for CO2 emissions in 2050 to comply with HB951 carbon neutrality goal.

Due to the variety of assumption and modeling changes in the Supplemental Portfolio analysis, these costs should not be used as direct comparisons to compare the Carbon Plan Portfolios presented in the Carbon Plan. However, it is appropriate to continue to compare SP5 to SP6 and $SP5_A$ to $SP6_A$. These cost differentials represent the cost trade off, in addition to increased executability, for allowing additional time and resources to contribute to the interim emissions reduction target achievement.

D. Customer Bill Impacts

1. <u>Supplemental Portfolio Analysis – "No App Gas" Fuel Supply Scenario</u>

Below, Table SPA-18 through Table SPA-21 show the projected changes to a typical residential customer's bill for the "no App gas" Supplemental Portfolios through 2030 and 2035. Additionally, the projected average annual percentage change from 2023 through 2030 and through 2035 is also shown representing how much a customer's bill would increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the CO2 reductions of the system and development of the PVRRs.

Table SPA-18: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	$17	$33
SP6	$12	$31

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Table SPA-19: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	2.1%	2.2%
SP6	1.5%	2.1%

Table SPA-20: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	$20	$42
SP6	$18	$33

Table SPA-21: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	2.4%	2.9%
SP6	2.1%	2.4%

2. <u>Supplemental Portfolio Analysis – "with Limited App Gas" Fuel Supply Scenario</u>

Below, Table SPA-22 through Table SPA-25 show the projected changes to a typical residential customer's bill for the "with limited Agg gas" Supplemental Portfolios through 2030 and 2035. Additionally, the projected average annual percentage change from 2023 through 2030 and through 2035 is also shown representing how much a customer's bill would increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the CO2 reductions of the system and development of the PVRRs.

Table SPA-22: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	$6	$30
$SP6_A$	$4	$26

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Table SPA-23: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	0.8%	2.0%
$SP6_A$	0.6%	1.8%

Table SPA-24: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	$24	$37
$SP6_A$	$19	$32

Table SPA-25: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	2.7%	2.6%
$SP6_A$	2.2%	2.2%

VII. Sensitivity Analyses

A. Low EE

The capacity expansion model's net resource changes in 2035 and 2050 from the Supplemental Portfolio 5 (no App gas) are presented below in Table SPA-26 for the Low EE sensitivity.

Table SPA-26: Low EE Load Sensitivity - Resource Changes from Supplemental Portfolio 5 (without App Gas) [MW]

	Coal	Solar	Onshore Wind	Battery	CC	CT	Offshore Wind	New Nuclear	PS
2035	0	+700	+200	+300	0	0	0	0	0
2050	0	+900	0	+200	0	-100	0	0	0

The low EE forecast results in a high load sensitivity requiring incrementally more resources to meet the energy and CO2 emissions reductions targets. Notably, by 2035 the sensitivity selects 700 MW more of solar, 200 MW more of onshore wind, and 300 MW more of battery, picking both more standalone battery and battery paired with solar to offset the higher load. By 2050 the Low EE sensitivity selects 900 MW of additional solar, 200 MW of additional battery, while

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slightly offsetting the need for small amount of CT capacity. Overall, the low EE sensitivity has little impact on peak winter load, which typically drives resource selection. The majority of the peak load impact in this sensitivity is realized in the summer when the system already has adequate reserves due to the significant amount of solar already on the system. These factors result in slightly more solar resources selected to offset incremental energy needs, while having little impact on peak load resource requirements above what is already selected in Supplemental Portfolio 5 (no App Gas).

B. High Solar Limit

The capacity expansion model's net resource changes in 2035 and 2050 from the Supplemental Portfolio 5 (no App gas) are presented below in Table SPA-27 for the High Solar Interconnection sensitivity.

Table SPA-27: High Solar Interconnection Sensitivity - Resource Changes from Supplemental Portfolio 5 (without App Gas) [MW]

	Coal	Solar	Onshore Wind	Battery	CC	CT	Offshore Wind	New Nuclear	PS
2035	0	+700	0	-700	0	-500	0	0	0
2050	0	+300	0	-100	0	-100	0	0	0

Allowing for higher solar selection limits overall increases the deployment of solar energy by 700 MW by 2035 and by just 300 MW by 2050. The capacity expansion model selects up to the raised limit in five of the first six year solar is eligible for selection ahead of the targeted compliance year. The system selects up to the 1,500 MW limit in both 2026 and 2027, while selecting 1,800 MW in every year leading up to compliance, with the exception of 2028 which coincides with the selection of the two natural gas combined cycles in that year.

The additional solar in the near-term allows the system to avoid building incremental batteries and CTs in DEP to maintain near-term reserve margin requirements. Instead, the portfolio selects more solar in both jurisdiction and selects a CC in DEP, rather than selecting two CC units in DEC in Supplemental Portfolio 5 (no App gas), to fill the remaining capacity needs created by the retirement of three of the Company's coal units in that time frame.

Overall, the additional solar limits had no impact on the net selection of onshore wind or new nuclear. The same amount of each resource was selected across the system by both 2035 and 2050. By 2050 there is little impact to overall resource selection with the 300 incremental MW of solar offsetting the need for a small number of batteries and CTs.

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Figure 3: Carbon Plan Analytical Process Flow Chart

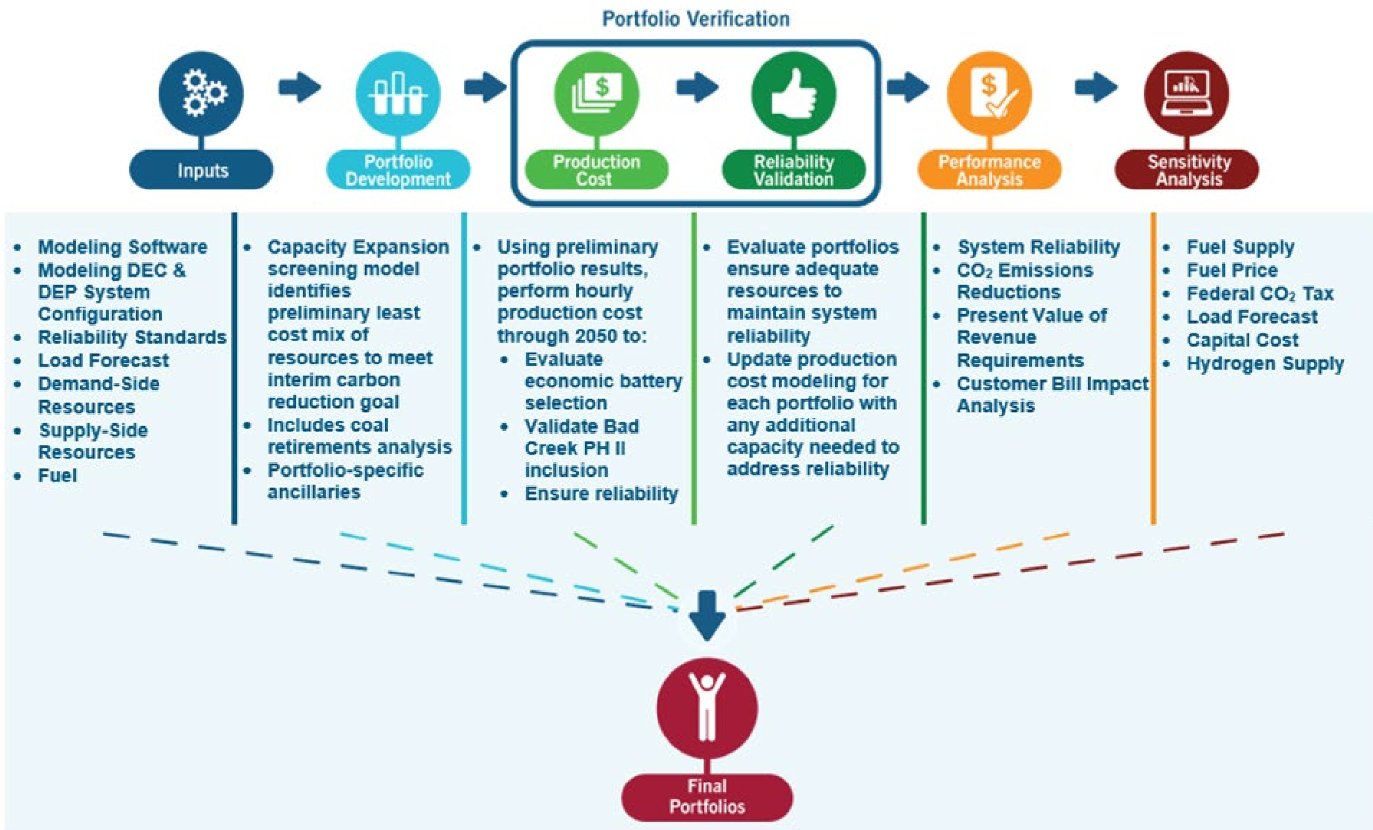

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Figure 4: Portfolio Snapshot to Achieve 70% Interim Target (2030-2034)

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td>2030</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales
IVVC growing to 96% (DEC) and 97% (DEP) circuits
Winter DR & CPP</td><td rowspan="2">(-4.9 GW)</td><td>5.4 GW</td><td>2.1 GW</td><td>0.6 GW</td><td>0.8 GW</td><td></td><td></td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>2032</td><td>P2</td><td>70% 2032 OSW</td><td>5.6 GW</td><td>1.7 GW</td><td rowspan="3">1.2 GW</td><td>1.6 GW</td><td></td><td></td></tr>
<tr><td>2034</td><td>P3</td><td>70% 2034 SMR</td><td rowspan="2">(-6.2 GW)</td><td>7.7 GW</td><td>2.2 GW</td><td></td><td rowspan="2">0.3 GW</td><td rowspan="2">1.7 GW</td></tr>
<tr><td>2034</td><td>P4</td><td>70% 2034 OSW + SMR</td><td>6.8 GW</td><td>1.8 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of the target year of 70% reduction.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

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Figure 5: Portfolio Snapshot in 2035

PORTFOLIOS (Resources by 2035)		Grid Edge	Coal Retirements	New Solar	Battery	Onshore Wind	Offshore Wind	New Nuclear	New Pumped Storage	New CC	New CT
P1	70% by 2030	EE 1% of eligible retail sales	(-6.2 GW)	11.9 GW	4.2 GW	1.2 GW	0.8 GW	0.6 GW	1.7 GW	2.4 GW	1.1 GW
P2	70% 2032 OSW	IVVC growing to 96% (DEC) and 97% (DEP) circuits		8.6 GW	2.3 GW		1.6 GW				
P3	70% 2034 SMR				2.4 GW						
P4	70% 2034 OSW + SMR	Winter DR & CPP		7.6 GW	2.0 GW		0.8 GW				0.8 GW

Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of 2035.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

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NCSEA and SACE, et al.
Docket No. E-100 Sub 179
Carbon Plan – 2022
Joint Data Request No. 4
Item No. 4-22
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Regarding the Companies' answer to question (b) in NCSEA-SACE DR 2-24, please:

a. Provide all files that were used to determine the "retirement securitization value" for each coal plant retiring according to the Carbon Plan. These files include, but should not be limited to, spreadsheets, databases, programming code, depreciation studies, etc. In the spreadsheets that the Companies will provide, please leave the formulas intact and all data references included.
b. Clarify how the difference between the two recovery streams mentioned in the Companies' response. standard post-retirement amortization versus securitized recovery, flows through the production cost model, and how or where it is considered in the calculation of PVRR.

Response:

a. Duke Energy objects to this request to the extent it seeks "all files" and all "spreadsheets, databases, programming codes" as overbroad, unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence, and not proportional to the scope and needs of this case. In particular, Duke Energy objects to this request to the extent it seeks access to a confidential and proprietary internally developed financial analytics model which contains data for all Duke Energy regulated jurisdictions, and which cannot be separated to be limited to provide outputs for DEC and DEP. Notwithstanding the foregoing objection, please see the representative information provided in response NCSEA-SACE DR3-39(g).

b. The securitization opportunity value is added to the FOM cost stream provided to Encompass for its consideration in the coal unit economic retirement analysis. To the extent FOM is an avoidable cost with retirement, adding the securitization opportunity value to FOM enables Encompass to consider it. To the extent the securitization opportunity is a declining stream, Encompass has to incrementally choose year after year to continue to operate the unit and incur the securitization opportunity value as a cost (or rather in the inverse, choose to retire and take the securitization opportunity value as a benefit). As the value gets lower with time, it has less and less effect over time on that decision being made by the model.

Responder: Keith B. Pike, Rates & Regulatory Strategy Director

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NCSEA et al. Response to Duke Energy Data Request 2-9

2-9. Referring to the revised inputs listed under "Existing Resources" in Table 3 on page 10 of the Synapse Report, please provide support for why the "Advanced" NREL ATB costs were used for Offshore wind and storage while "Moderate" was used for the other renewable resources.

Response:

Synapse's use of "Advanced" versus "Moderate" technology cases is based on a judgment of the relative maturity of those technologies in the United States today and anticipated achievement of economies of scale and learning curves.

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Aug 19 2022

CPSA
Docket No. E-100, Sub 179
2022 Carbon Plan
CPSA Data Request No. 1
Item No. 1-8
Page 1 of 2

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

With respect to solar interconnection projections, Appendix I (page 8) states that "The projections are based on a range of factors, some of which are unknown at this time or outside of the Companies' control." Please describe in detail the factors that specifically support the proposed solar capacity limits in each year.

RESPONSE:

Appendices I and P provide substantial details regarding the factors that impact the proposed annual solar capacity amounts included in the Carbon Plan modeling. These factors include, but are not limited to:

- Transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources as described in Appendix P.
- Increasingly complex interconnections as solar facilities are located farther from existing infrastructure
- Unknown future solar project size and impacts on interconnections. Generally larger projects should enable more aggregate MWs to be connected on an annual basis, but it is not known at this time what the size of projects will be in the future and whether larger projects will lead to additional transmission expansion projects beyond those contemplated in Appendix P.
- Finite interconnection resources allocated to non-solar resources. Details of potential other non-solar resources can be found throughout the Carbon Plan including Chapter 3 and Appendix E.
- The Companies' historic annual interconnections, which have consistently been among the highest in the United States, is approximately 520 MW/year since 2015. While not the primary determining factor in developing the solar interconnection capability in the Carbon Plan, it is important to note that Carbon Plan allows for over 3x this annual amount in Portfolio A1 and over 2.5 X this annual amount in all other portfolios.

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- The timeline for interconnection is often delayed by the actions of interconnection customers, who may elect to delay interconnection due to business considerations or other factors.
- Land availability and community acceptance. While not described in great detail in the Carbon Plan, 1,350 MW/year of solar will require approximately 10,800 acres/year of land to be developed, and 1,800 MW/year will require approximately 14,400 acres/year. Community acceptance of this level of development is an unknown factor that may impact the amount of solar that can be added annually.
- Energy storage development will be important to ensure energy supply meets demand and delays in storage development can limit the effectiveness of solar deployments needed to meet the goals of the Carbon Plan.

Responder: Matthew Kalemba, Director DET Planning & Forecasting

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NCSEA et al. Response to Duke Energy Data Request 2-18

2-18. Did Synapse analyze or otherwise take into account the risk of potentially under-achieving the EE targets used in the Synapse portfolios that results in accelerated coal retirements?

a. If yes, please explain in detail how this analysis was considered and incorporated into Synapse modeling and Report.
b. If yes, please provide any documents supporting this analysis.
c. Does Synapse agree that under-achieving aggressive EE targets could lead to a less reliable system if unit retirements are planned and executed ahead of achieving the load reductions?

Response:

Yes.

a. Yes. Synapse ran a capacity expansion and production cost modeling sensitivity using lower energy efficiency targets to understand the impact of lower energy efficiency on results. See pages 26-27 of the *Carbon-Free by 2050* report.
b. Inputs and outputs for the *Optimized Low EE – CapEx* and *Optimized Low EE – PC* scenarios were provided in Synapse's share of EnCompass datasets and outputs.
c. Synapse agrees that failure to develop any planned supply- or demand-side resource could have reliability implications if other elements of the resource plan are not adjusted.

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NCSEA et al. Response to Duke Energy Data Request 2-15

2-15. On page 14 of the Synapse Report, in Table 4, the Annual Solar development Limits are raised to 1,200 MW in 2025, to 1,800 MW in 2026-2028, and 2,300 MW in 2023 and onward as revised inputs for the alternate portfolios developed by Synapse. Please provide justification for the increased limits, with respect to the Limits Duke used in its 2030 interim 70% compliance portfolios. Additionally, please clarify that Synapse did not adjust the forecasted solar into the portfolios and that the 1,200 MW able to be selected for 2025 is on top of the nearly 600 MW that are already forecasted to come into service in 2025.

Response:

Synapse based its solar development limit forecast on the reasonable expectation of further improvements to solar deployment in the Carolinas.

Synapse adjusted total solar resource availability in 2025 to 1,200 MW in order for maximum total deployment in that year to be consistent with Duke Energy's indicated short-term maximum solar deployment of 1,800 MW.

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Tech Customers' Response to Duke Energy Data Request 1-7(a)

1-7. Regarding the statement on page 10 of your Comments that "Duke hardcoded several asset selections into its modeling," please:

a. identify and provide a detailed explanation of any constraints or limits that Gabel and/or Strategen used in performing alternative modeling in EnCompass.
b. Explain whether in your modeling experience, imposing constraints or limits on resources in the model is never appropriate or sometimes appropriate based on the circumstances and judgment of the modeler.

Response:

a. The Preferred Portfolio maintains most of the annual and cumulative resource limits imposed by Duke. However, the following adjustments were made.
   i. Wind resources are available one year earlier than in Duke's model, and in 600 MW annual increments.
   ii. There was no change in limits on storage. Although no limit is specified in Appendix E, standalone batteries are subject to an annual limit in the Duke modeling analysis.
   iii. Annual solar limits are relaxed for years 2026-2029.
   iv. No Combined Cycle units were allowed to be selected. This was to reflect the risk of stranded assets, fuel supply, and fuel cost.

b. A modeling analysis requires critical thinking from the modeler(s). As such, resource limits are often used to reflect the operational and execution issues that would not otherwise be captured in a capacity expansion model. However, based on our experience, we find that Duke's setup of the model in this case overly restricted resources in years with significant energy and capacity need, leaving the model minimal flexibility in selecting resources based on their economics.

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Tech Customers' Response to Duke Energy Data Request 1-8

1-8. Regarding the statement on page 5 of the Gabel Report "Our capacity expansion analysis assumes the Companies' coal assets all retire by 2030 per the Carbon Plan Schedule for retirements before 2030, and a latest retirement date of 2030 for the rest", please explain how you determined that accelerating all coal unit retirement dates to 2030 is reasonable and produce any analysis developed to support this statement.

Response:

As referenced in the Gabel report (pg. 54): "Due to time restrictions and the limited information provided by Duke, the analysis did not attempt to study coal retirement decisions on a per unit basis." Coal fixed operating and maintenance costs, incremental capital expenses (including environmental capital expenses), and securitization benefits were not provided with adequate detail for such an analysis. Still, the preferred portfolio shows that earlier retirement of coal units can be achieved while reducing cost, emissions, and risks for ratepayers..

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CPSA Response to Duke Energy Data Request 1-8

1-8. Please provide detailed documentation for the GridSIM model (user manual or equivalent), including detailed explanations of capacity expansion and production cost methodology as well as the manner in which the model ensures system reliability.

Response: GridSIM is a proprietary software model developed by Brattle. As such, there is no user manual or similar documentation. GridSIM optimizes capacity expansion and system dispatch to meet hourly demand, winter capacity requirement, and CO2 limits, while respecting other constraints included in the model, by minimizing the net present value of system costs over the timeframe modeled. The timeframe modeled in this case was 2020 to 2035, with 2020, 2025, 2030, 2032, and 2035 modeled. The system costs of achieving the specified constraints in each modeled year are assigned a weighting based on the number of years between modeled years. The system costs in each year are based on the levelized costs of adding new resources to meet the necessary constraints (e.g., CO2 limits, winter capacity requirement, and hourly demand) and the operating costs of existing and new resources, including fuel costs, variable operations and maintenance (O&M) costs. The operating costs of existing and new resources are based on simulated chronological hourly dispatch of 49 representative days, including 4 representative days within each of the 12 months and the peak demand day. The 4 days within each month are selected by accounting for differences in demand and renewable generation within each month using a clustering algorithm. The operating costs of meeting hourly demand in each representative day are assigned a weighting based on the number of days within the month of which they is representative.

Please see Response 1-7 for an explanation of how the model ensures that the system meets the winter capacity requirement to maintain system reliability.

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Sep 16 2022

Public Staff
Docket No. E-100, Sub 179
2022 Carbon Plan
Public Staff Data Request No. 5
Item No. 5-13

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Given the likely need to build out transmission for new incremental amounts of generation forthcoming in the Carbon Plan, notably solar, has the Company updated the $/kW transmission cost adder in the Carbon Plan to align with the ~$7B upgrade estimate from the hypothetical transmission build out? If so, please provide the update utilized, along with justification. If not, please explain why not.

RESPONSE:

The Company is not updating the $/W transmission cost adder in the Carbon Plan to align with the ~$7B upgrade estimate from the hypothetical transmission build out. There is too much uncertainty (e.g., no approved Carbon Plan; no formal transmission planning studies as a basis for the hypothetical greenfield transmission expansion projects – dashed lines on the slide 56 map) to allow for consideration of the hypothetical transmission build out in the $/W network transmission upgrade cost adder for incremental resources such as solar.

Responder: Sammy Roberts, General Manager - Transmission Planning and Operations Strategy

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Sep 16 2022

Independent Statistics & Analysis
U.S. Energy Information Administration

March 2022

Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022*

The tables presented below are also published in the Electricity Market Module chapter of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2022* (AEO2022) Assumptions document. Table 1 represents our assessment of the cost to develop and install various generating technologies used in the electric power sector. Generating technologies typically found in end-use applications, such as combined heat and power or roof-top solar photovoltaics (PV), will be described elsewhere in the Assumptions document. The costs shown in Table 1, except as noted below, are the costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency to underestimate the full engineering and development costs for new technologies during technology research and development.

All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind and solar PV, in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To reflect this difference, we report a weighted average cost for both wind and solar PV, based on the regional cost factors assumed for these technologies in AEO2022 and the actual regional distribution of the builds that occurred in 2020 (Table 1).

Table 2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and our modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. We represent this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

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Table 1. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2021$/kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2021$/kW)	Variable O&M[f] (2021 $/MWh)	Fixed O&M (2021$/ kW-y)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2025	650	4	$4,074	1.00	$4,074	$4.71	$42.49	8,638
USC with 30% carbon capture and sequestration (CCS)	2025	650	4	$5,045	1.01	$5,096	$7.41	$56.84	9,751
USC with 90% CCS	2025	650	4	$6,495	1.02	$6,625	$11.49	$62.34	12,507
Combined-cycle—single-shaft	2024	418	3	$1,201	1.00	$1,201	$2.67	$14.76	6,431
Combined-cycle—multi-shaft	2024	1,083	3	$1,062	1.00	$1,062	$1.96	$12.77	6,370
Combined-cycle with 90% CCS	2024	377	3	$2,736	1.04	$2,845	$6.11	$28.89	7,124
Internal combustion engine	2023	21	2	$2,018	1.00	$2,018	$5.96	$36.81	8,295
Combustion turbine—aeroderivative[h]	2023	105	2	$1,294	1.00	$1,294	$4.92	$17.06	9,124
Combustion turbine—industrial frame	2023	237	2	$785	1.00	$785	$4.71	$7.33	9,905
Fuel cells	2024	10	3	$6,639	1.09	$7,224	$0.62	$32.23	6,469
Nuclear—light water reactor	2027	2,156	6	$6,695	1.05	$7,030	$2.48	$127.35	10,443
Nuclear—small modular reactor	2028	600	6	$6,861	1.10	$7,547	$3.14	$99.46	10,443
Distributed generation—base	2024	2	3	$1,731	1.00	$1,731	$9.01	$20.27	8,923
Distributed generation—peak	2023	1	2	$2,079	1.00	$2,079	$9.01	$20.27	9,907
Battery storage	2022	50	1	$1,316	1.00	$1,316	$0.00	$25.96	NA
Biomass	2025	50	4	$4,524	1.00	$4,525	$5.06	$131.62	13,500
Geothermal[i, j]	2025	50	4	$3,076	1.00	$3,076	$1.21	$143.22	8,813
Conventional hydropower[j]	2025	100	4	$3,083	1.00	$3,083	$1.46	$43.78	NA
Wind[e]	2024	200	3	$1,718	1.00	$1,718	$0.00	$27.57	NA
Wind offshore[i]	2025	400	4	$4,833	1.25	$6,041	$0.00	$115.16	NA
Solar thermal[i]	2024	115	3	$7,895	1.00	$7,895	$0.00	$89.39	NA
Solar photovoltaic (PV) with tracking[e, i, k]	2023	150	2	$1,327	1.00	$1,327	$0.00	$15.97	NA
Solar PV with storage[i, k]	2023	150	2	$1,748	1.00	$1,748	$0.00	$33.67	NA

Source: We primarily base input costs on a report provided by external consultants: Sargent & Lundy, December 2019. We most recently updated hydropower site costs for non-powered dams for AEO2018 using data from Oak Ridge National Lab

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kW-y=kilowatt-year, kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.

[c] We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[d] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2022.

[e] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2020 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2022 was $1,411 per kilowatt (kW), and for solar PV with tracking, it was $1,323/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

[f] O&M = Operations and maintenance.

[g] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion, and no set British thermal unit conversion factors exist. The module calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.

[h] Combustion turbine aeroderivative units can be built by the module before 2023, if necessary, to meet a region's reserve margin.

[i] Capital costs are shown before investment tax credits are applied.

[j] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.

[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

Table 2. Total overnight capital costs of new electricity generating technologies by region

2021 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	$3,786	$3,897	$4,259	$4,371	$4,422	$3,918	$4,721	NA	$4,614	$4,763	$4,064	$5,120	$4,385
USC with 30% CCS	$4,777	$4,903	$5,294	$5,437	$5,480	$4,935	$5,846	NA	$5,729	$5,883	$5,094	$6,254	$5,477
USC with 90% CCS	$6,252	$6,411	$6,841	$7,072	$7,078	$6,473	$7,495	NA	$7,303	$7,508	$6,601	$7,994	$7,015
CC—single-shaft	$1,085	$1,107	$1,235	$1,246	$1,277	$1,117	$1,441	$1,912	$1,445	$1,443	$1,197	$1,446	$1,377
CC—multi-shaft	$944	$968	$1,098	$1,117	$1,146	$979	$1,259	$1,725	$1,238	$1,266	$1,037	$1,327	$1,170
CC with 90% CCS	$2,668	$2,693	$2,877	$2,884	$2,928	$2,718	$3,021	$3,422	$2,953	$2,996	$2,756	$3,124	$2,871
Internal combustion engine	$1,898	$1,940	$2,073	$2,155	$2,131	$1,966	$2,209	$2,769	$2,125	$2,209	$1,980	$2,408	$2,056
CT—aeroderivative	$1,145	$1,168	$1,354	$1,357	$1,398	$1,193	$1,456	$1,864	$1,405	$1,448	$1,242	$1,591	$1,317
CT—industrial frame	$692	$707	$822	$826	$851	$723	$886	$1,144	$854	$882	$753	$971	$800
Fuel cells	$6,933	$7,041	$7,362	$7,680	$7,534	$7,159	$7,815	$9,201	$7,498	$7,748	$7,138	$8,261	$7,358
Nuclear—light water reactor	$6,636	$6,779	$7,157	$7,807	$7,530	$7,000	$7,964	NA	$7,430	$7,781	$6,878	$8,556	$7,158
Nuclear—small modular reactor	$7,032	$7,197	$7,841	$8,176	$8,173	$7,287	$8,441	NA	$8,040	$8,459	$7,376	$9,438	$7,660
Distributed generation—base	$1,563	$1,595	$1,779	$1,795	$1,840	$1,609	$2,076	$2,754	$2,081	$2,079	$1,724	$2,083	$1,984
Distributed generation—peak	$1,839	$1,877	$2,174	$2,180	$2,246	$1,916	$2,339	$2,994	$2,257	$2,326	$1,995	$2,555	$2,116
Battery storage	$1,316	$1,320	$1,301	$1,364	$1,319	$1,347	$1,357	$1,351	$1,321	$1,325	$1,313	$1,329	$1,325
Biomass	$4,198	$4,313	$4,669	$4,824	$4,835	$4,348	$5,372	$7,292	$5,389	$5,483	$4,611	$5,493	$5,255
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Conventional hydropower	$4,498	$5,495	$2,186	$1,453	$2,959	$4,378	$2,025	NA	$4,144	$4,305	$3,752	NA	$3,808
Wind	$2,757	NA	$1,552	$1,411	$1,690	$1,411	$1,870	NA	$2,281	$1,870	$1,411	$2,055	$1,948
Wind offshore	$5,901	$7,080	$6,984	NA	$7,234	NA	$7,047	$6,079	$7,370	$6,755	$5,524	$7,999	$6,293
Solar thermal	$7,616	$7,731	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	$1,304	$1,279	$1,323	$1,372	$1,357	$1,290	$1,370	$1,612	$1,357	$1,397	$1,320	$1,440	$1,317
Solar PV with storage	$1,692	$1,710	$1,761	$1,817	$1,792	$1,727	$1,828	$2,078	$1,796	$1,832	$1,721	$1,905	$1,781

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	$3,920	$3,979	$4,032	$3,947	$4,193	$3,991	$4,159	NA	NA	$4,406	$4,119	$4,297
USC with 30% CCS	$4,939	$4,985	$5,059	$4,952	$5,226	$4,999	$5,215	NA	NA	$5,480	$5,159	$5,353
USC with 90% CCS	$6,485	$6,542	$6,620	$6,451	$6,778	$6,497	$6,758	NA	NA	$7,090	$6,658	$6,967
CC—single-shaft	$1,103	$1,116	$1,150	$1,115	$1,183	$1,104	$1,085	$1,590	$1,553	$1,264	$1,023	$1,106
CC—multi-shaft	$968	$980	$1,016	$979	$1,051	$971	$934	$1,398	$1,359	$1,096	$880	$987
CC with 90% CCS	$2,684	$2,698	$2,759	$2,688	$2,777	$2,647	$2,448	$3,071	$3,036	$2,833	$2,303	$2,586
Internal combustion engine	$1,977	$1,982	$2,017	$1,962	$2,068	$1,982	$2,001	$2,398	$2,355	$2,133	$1,975	$2,114
CT—aeroderivative	$1,186	$1,196	$1,241	$1,194	$1,279	$1,203	$1,086	$1,529	$1,491	$1,341	$1,051	$1,198
CT— industrial frame	$718	$726	$753	$724	$777	$729	$658	$934	$910	$816	$637	$728
Fuel cells	$7,211	$7,205	$7,304	$7,080	$7,376	$7,143	$7,243	$8,299	$8,203	$7,585	$7,104	$7,567
Nuclear—light water reactor	$7,090	$7,035	$7,263	$6,807	$7,198	$6,805	$7,058	NA	NA	$7,640	$6,837	$7,648
Nuclear—small modular reactor	$7,323	$7,380	$7,547	$7,306	$7,759	$7,368	$7,465	NA	NA	$8,083	$7,386	$8,028
Distributed generation—base	$1,589	$1,608	$1,657	$1,606	$1,705	$1,591	$1,563	$2,290	$2,238	$1,821	$1,474	$1,593
Distributed generation—peak	$1,905	$1,922	$1,994	$1,919	$2,055	$1,932	$1,744	$2,456	$2,394	$2,154	$1,688	$1,924
Battery storage	$1,359	$1,340	$1,357	$1,310	$1,318	$1,302	$1,333	$1,371	$1,373	$1,348	$1,305	$1,357
Biomass	$4,364	$4,397	$4,455	$4,368	$4,641	$4,460	$4,777	$6,119	$5,981	$4,939	$4,732	$4,731
Geothermal	NA	NA	NA	NA	NA	NA	$3,135	$3,109	$2,517	$3,043	NA	$3,076
Conventional hydropower	$2,120	$4,599	$2,377	$4,550	$1,917	$1,802	$3,655	$3,867	$3,723	$3,083	$3,681	$4,023
Wind	$1,683	$1,907	$1,411	$1,411	$1,552	$1,552	$1,411	$3,116	$2,447	$2,057	$1,411	$1,411
Wind offshore	$5,437	NA	NA	NA	NA	NA	NA	$9,112	$9,560	$6,836	NA	NA
Solar thermal	NA	NA	NA	$7,693	$7,991	$7,614	$7,980	$9,400	$9,282	$8,493	$7,668	$8,510
Solar PV with tracking	$1,343	$1,276	$1,318	$1,278	$1,328	$1,287	$1,300	$1,447	$1,440	$1,332	$1,315	$1,327
Solar PV with storage	$1,739	$1,721	$1,742	$1,709	$1,765	$1,727	$1,736	$1,903	$1,898	$1,795	$1,729	$1,791

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Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors, regional cost multipliers, and ambient condition multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic

Electricity Market Module region map

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Tech Customers'
Modeling Panel Direct Cross-Examination
Exhibit 2

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PJM CONE 2026/2027 Report

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TABLE OF CONTENTS

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Sep 16 2022

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Sep 16 2022

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

[6] For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

[7] The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

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TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

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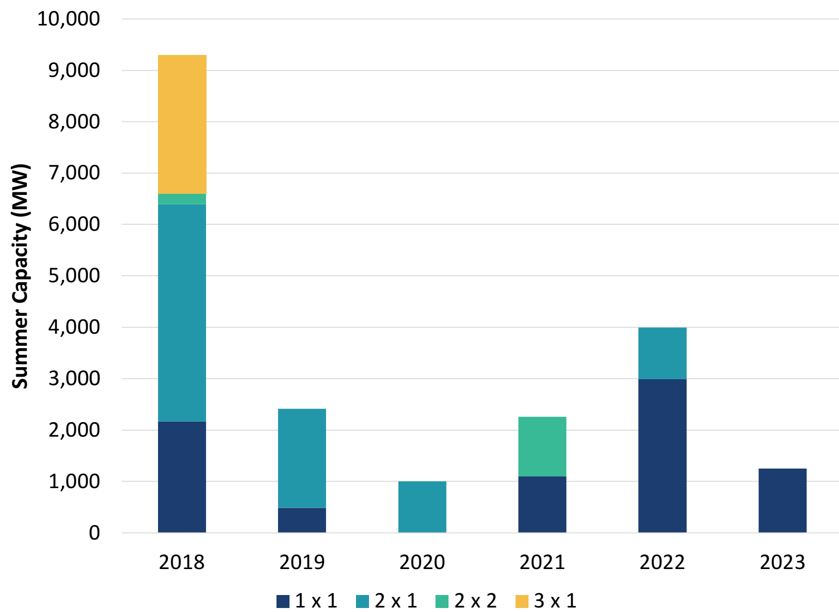
III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

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Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize "wet" cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

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complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

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IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	Turbine Class	PJM		US	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that

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IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

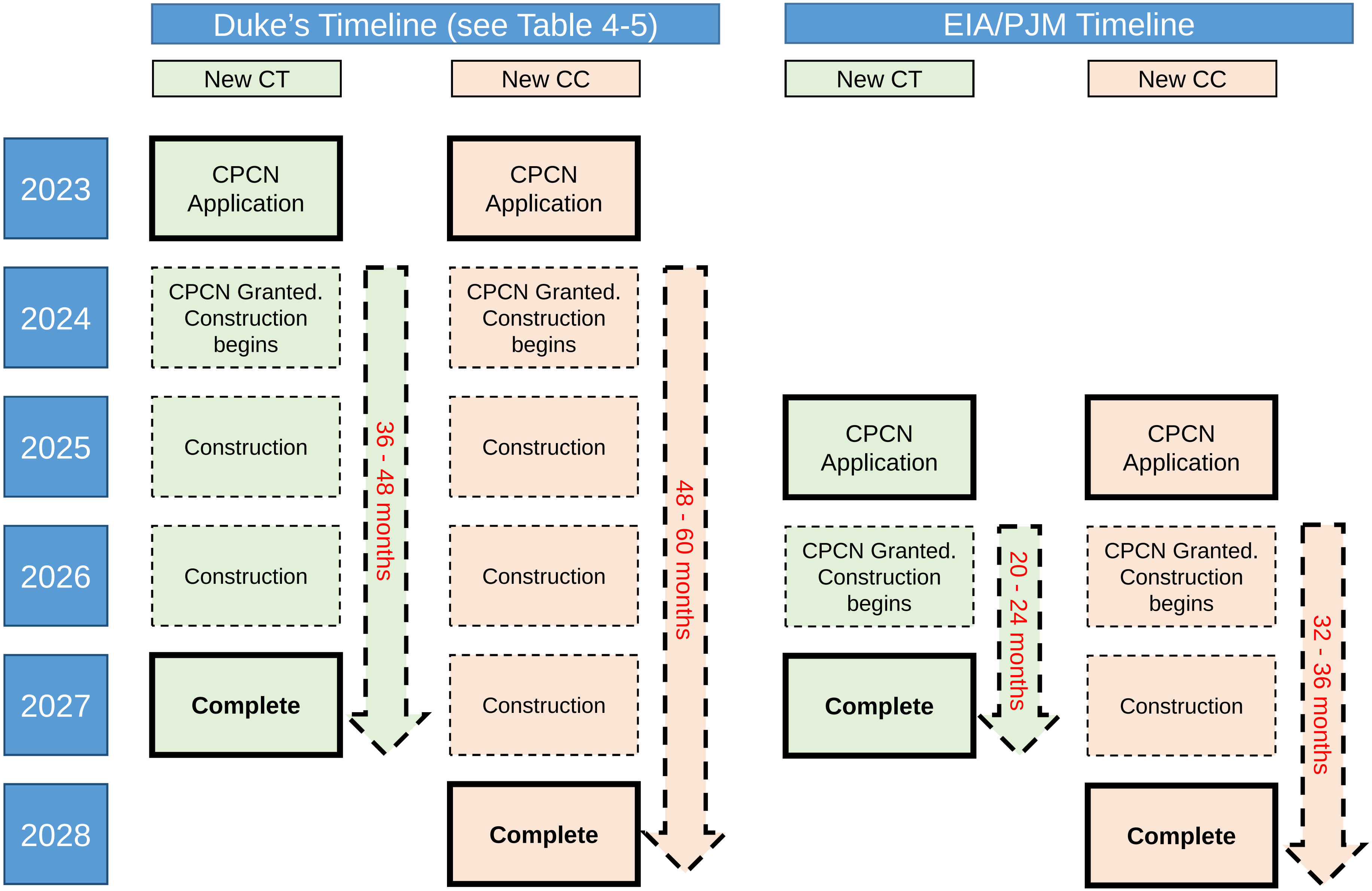
IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

I/A

Tech Customers'
Modeling Panel Direct Cross-Examination
Exhibit 3



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Certificate of Service

I hereby certify that a copy of the foregoing document has been served this day upon all parties of record in this proceeding, or their legal counsel, by electronic mail.

This the 16th day of September, 2022.

BROOKS, PIERCE, MCLENDON,
HUMPHREY & LEONARD, LLP

/s/ Matthew B. Tynan
Matthew B. Tynan