STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
Duke Energy Progress, LLC, and	)	
Duke Energy Carolinas, LLC, 2022	)	COMMENTS OF
Biennial Integrated Resource Plans and	)	CIGFUR II AND III
Carbon Plan	)	

NOW COME the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) and the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) (collectively, CIGFUR), pursuant to the Commission's November 19, 2021 *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines* and November 29, 2021 *Order Granting Extension of Time*, and respectfully submit the following evaluation of and comments on the Carbon Plan proposed by Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC) (collectively, Duke).

As a preliminary matter, CIGFUR notes its objection to one of Duke's positions as relayed in its July 8, 2022 *Update Letter Concerning Carbon Plan Modeling, Intervenor Engagement and Discovery Status*; namely, that "the Companies will not be in a position to respond to further detailed discovery in the short-term." CIGFUR contends it is unreasonable for Duke to unilaterally decide it will not be responding to additional discovery requests in the short-term, particularly considering the relatively compressed time frame intervenors have had to conduct discovery in the first place and the high probability that more data requests to Duke may be prompted following review of other intervenors' comments or alternative Carbon Plan proposals. While CIGFUR made every effort to evaluate Duke's proposed Carbon Plan thoroughly and completely within the time frame allotted, material and substantive questions remain, including but not limited to those contained in a Data Request CIGFUR served on Duke that remains pending as of the time of this filing.

For ease of reference, CIGFUR has organized its comments so that each section header corresponds to the section headers contained in Duke's Verified Petition for Approval of Carbon Plan (Petition), filed in this docket on May 16, 2022.

I. General Information

a. On October 13, 2021, Governor Cooper signed into law House Bill 951 (S.L. 2021-165). In the days preceding enactment of House Bill 951 (HB 951), Governor Cooper and the North Carolina General Assembly (General Assembly or Legislature) signaled through a series of public statements that North Carolina would pursue the least-cost pathway to decarbonize its electric grid while maintaining or improving the reliability of the existing electric grid.[1] Leaders of North Carolina's executive and legislative branches of government were intent on ensuring Duke's ratepayers can continue to "'depend[] on a stable supply of reliable and affordable energy [during the energy transition].'"[2] Indeed, affordability was a primary bipartisan focus: "'I am encouraged that we have been able to reach across

[1] "'This was an opportunity to apply conservative principles to [decarbonizing] the grid. What this bill ensures North Carolinians is yes we'll reduce carbon, but we're going to do it in the least cost and most reliable way possible.'" Senator Paul Newton, Co-Chair of the Joint Legislative Commission on Energy Policy (2021-2022 Session), ABC 11 EYEWITNESS NEWS, "Energy bill compromise poised to fight climate change, but at a cost" (Oct. 6, 2021), *available at* https://abc11.com/house-bill-951-energy-solutions-for-north-carolina-nc-carbon-emissions/11090239/.

[2] *Id.*, *quoting* Senate President Pro Tempore Phil Berger.

the aisle to find a way forward that will update our energy systems while saving people money and doing our part to slow climate change.'"[3]

b. CIGFUR actively participated in the legislative stakeholder process that culminated in the introduction of HB 951 at the General Assembly. CIGFUR lobbied,[4] among other positions, for the Commission to retain discretion as the agency with the subject matter expertise necessary to determine the least-cost, most reliable resource mix for achieving the carbon dioxide (CO_2) emissions reductions goals set forth in HB 951.

c. Maintaining or improving the reliability of North Carolina's electric grid under these circumstances will be a challenging undertaking under the best of circumstances. Unfortunately, many other areas throughout the country are already facing far less than ideal circumstances: increasingly weather-dependent load,

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[3] *Id.*, *quoting* Governor Roy Cooper.

[4] One of CIGFUR's primary concerns regarding the House version of HB 951 (before it was amended in the Senate and subsequently enacted and signed into law) was that the House version of HB 951, had it been enacted into law, would have weakened Commission discretion and authority to make decisions as the agency with the relevant subject matter expertise.

> [HB 951] also includes some surprisingly specific instructions for future plant construction . . .
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> Those last provisions create some of the issues for [CIGFUR and the North Carolina Manufacturers Alliance]. Those directions 'compromise the [Commission's] authority to determine the amount and types of new generation that will serve customers in North Carolina,' [Preston Howard, lobbyist for CIGFUR and NCMA,] says.
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> 'They outright neuter that authority and in some ways eliminate the ability we have and others have to participate with the Commission (sic) as they weigh these decisions,' he says.
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> The NCMA and CIGFUR believe that the Commission (sic) has handled those decisions for years and have the expertise needed to make them. They don't want that stripped away.

John Downey, "NCMA wants utility regulation issues addressed before it endorses Duke Energy-backed reform bill," CHARLOTTE BUSINESS JOURNAL (June 21, 2021), *available at* https://www.bizjournals.com/charlotte/news/2021/06/21/ncma-manufacturing-duke-energy-nc-utility-reform.html.

capacity shortfalls, heat events, drought conditions, wildfires, supply chain issues, cybersecurity threats, and unexpected tripping of solar photovoltaic (PV) resources during grid disturbances are all contributing factors to a summer of elevated or high summer reliability risk for many parts of the country.[5] An adequate supply of dispatchable generation remains critically necessary to ensure reliability despite increasingly weather-dependent load combined with variable energy generation. Much like CO2 emissions reductions will be meticulously tracked and accounted for to ensure the goals set forth in HB 951 are satisfied, CIGFUR recommends that the Commission likewise adopt certain metrics relating to reliability to ensure Duke is also complying with the requirement in HB 951 to maintain or improve the reliability of the existing grid. In so doing, CIGFUR recommends using metrics beyond SAIDI and SAIFI, to include power quality issues that serve as a more accurate measure of reliability as increasingly variable generation is accommodated on the grid. These include things like voltage variations, frequency regulation, and related metrics.

d. Duke acknowledged before the legislative stakeholder process culminating in the introduction of HB 951 at the General Assembly began that achieving a 70% systemwide reduction in CO_2 emissions by 2030 would require supportive state policies in both North Carolina and South Carolina.[6] It should also be noted at the

[5] *See, e.g.*, North American Electric Reliability Corporation (NERC), 2022 Summer Reliability Assessment, May 2022, a true and accurate copy of which is identified and attached hereto as Attachment C.

[6] "In North Carolina, Duke Energy is an active participant in the state's Clean Energy Plan stakeholder process, which is evaluating policy pathways to achieve a 70% reduction in greenhouse gas emissions from 2005 levels by 2030 and carbon neutrality for the electric power sector by 2050. Accordingly, this year's IRP includes two resource portfolios that illustrate potential pathways to achieve 70% CO2 reduction by 2030, **though both scenarios would require supportive state policies in North Carolina and South Carolina**[,]" Duke Energy Progress Integrated Resource Plan 2020 Biennial Report, p. 6 (emphasis added).

outset that unlike the Virginia Clean Economy Act (VCEA),[7] which was enacted in Virginia in April 2020, there is no analogous provision in HB 951 directing certain costs to be recovered solely from North Carolina customers. Similarly, there is no analogous provision in HB 951 that authorizes Duke to recover from its North Carolina customers any compliance costs requested but disallowed from system customers outside North Carolina. To the contrary, HB 951 was specifically predicated on the assumption that Carbon Plan compliance costs would be spread among Duke's North Carolina and South Carolina customers.[8]

e. During the HB 951 legislative process, estimates of ratepayer impacts and costs associated with HB 951 were prepared by Duke and the Public Staff at the request of lawmakers. A true and accurate copy of the estimated bill impacts prepared by

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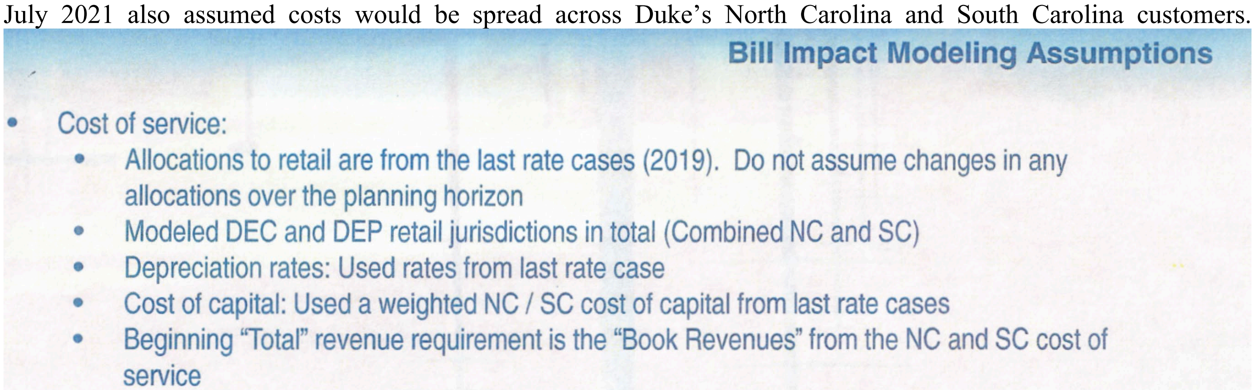
[7] The VCEA, unlike HB 951, declares in pertinent part that if the applicable utility

> serves customers in more than one jurisdiction, such utility shall recover all of the costs of compliance with the RPS Program requirements from its Virginia customers through the applicable cost recovery mechanism, and all associated energy, capacity, and environmental attributes shall be assigned to Virginia to the extent that such costs are requested but not recovered from any system customers outside the Commonwealth.

Va. Code Ann. § 56-585.5(F).

[8] See following excerpt from a handout disseminated by Duke's lobbying team to certain members of the General Assembly and their staff, as well as certain stakeholders, including CIGFUR, in or around early April 2021. Upon information and belief, the HB 951 cost and bill impact analysis prepared by the Public Staff in or about early July 2021 also assumed costs would be spread across Duke's North Carolina and South Carolina customers.



Duke, as well as an initial proposed coal retirement plan with prescribed replacement capacity, is attached hereto and identified as Attachment A.[9] A true and accurate copy of the estimated bill impacts prepared by the Public Staff is attached hereto and identified as Attachment B.[10]

f. Importantly, the Carbon Plan does not supersede, supplant, or otherwise serve as a substitute for the regulatory processes necessary for Duke to obtain a certificate of environmental compatibility and public convenience and necessity (CECPCN) pursuant to G.S. 62-101 before constructing a transmission line, or a certificate of public convenience and necessity (CPCN) pursuant to G.S. 62-110.1 before constructing a new electric generating facility. CPCN proceedings, unlike a broad resource adequacy and planning proceeding like the instant docket, allow for a more narrow, focused evaluation of one specific proposed electric generating facility (or transmission line, if a CECPCN proceeding, as the case may be). The instant proceeding cannot and should not be treated as a multi-project certification of new generation and/or transmission projects.

g. CIGFUR recognizes what a tremendous undertaking it was for Duke to perform Carbon Plan modeling and submit to the Commission an 880-page filing proposed Carbon Plan approximately seven months after Governor Cooper signed HB 951 into law. By comparison, however, the Public Staff and intervenors had just two months to evaluate Duke's proposed Carbon Plan, conduct discovery, develop

[9] The bill impact estimates prepared by Duke were shared in or around early April 2021, before HB 951 was introduced.

[10] The bill impact estimates prepared by the Public Staff were shared in or around early July 2021, after HB 951 was introduced but before it was amended by the Senate and then subsequently enacted and signed into law.

positions and recommendations, and prepare comments or alternative plans for filing with the Commission. Beyond that, Duke's proposed Carbon Plan inundated intervenors with information overload, requiring intervenors to spend countless hours sifting through an overwhelming volume of data in an effort to decipher obscure answers to what often could or should have been straightforward "yes" or "no" questions. With that said, and while CIGFUR diligently endeavored to be as thorough as possible in these comments, it reserves the right to raise issues not explicitly addressed herein at a later date, as allowed and appropriate.

II. Planning Requirements for the Carbon Plan Under HB 951

a. Among other things, HB 951 enacts uncodified provisions directing the Commission to develop a Carbon Plan "to achieve the least cost path consistent with this section" in order to meet the CO_2 emissions reductions goals set forth in HB 951.[11] HB 951 further provides that in developing and implementing the Carbon Plan, the Commission shall "[c]omply with current law and practice with respect to the least cost planning for generation, pursuant to G.S. 62-2(a)(3a), in achieving the authorized carbon reduction goals and determining generation and resource mix for the future."[12] In addition, HB 951 directs the Commission to "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[13]

[11] S.L. 2021-165, Part I, Section 1(1).

[12] *Id.*, at Part I, Section 1(2).

[13] *Id.*, at Part I, Section 1(3).

b. Aside from mandating that the Carbon Plan shall adhere to least-cost generation planning and maintain or improve the reliability of the existing grid, the General Assembly delegated broad discretion to the Commission in developing and implementing the Carbon Plan. More specifically, HB 951 directs the Commission to "take all ***reasonable*** steps" to achieve the CO_2 emissions reductions targets set forth in HB 951.[14]

c. For all of the reasons set forth *infra*, CIGFUR has serious concerns about the short- and long-term economic and affordability impacts associated with Carbon Plan implementation. While HB 951 directs the Commission to "take all reasonable steps"[15] to achieve the CO_2 emissions reductions goals, it does not direct or authorize the Commission to take every possible step, nor does it direct or authorize the Commission to take unreasonable steps. CIGFUR worries that the ability (or lack thereof, as the case may be) of Duke's customers to finance the energy transition by absorbing the kind of rate increases contemplated in the Carbon Plan will be tested and potentially pushed to the absolute limit—or worse, beyond the limit—this decade and beyond. As the Commission well knows, the ability of each of Duke's customer classes to absorb rate increases is not infinite; to the contrary, it is quite finite. That is never truer than in times like the present, when inflation is soaring, and all economic markers are strongly indicating toward an impending recession.[16]

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[14] *Id.*, at Part I, Section 1 (emphasis added).

[15] *Id.*

[16] *See, e.g.*, "American inflation tops forecasts yet again, adding to recession risks," The Economist (July 13, 2022), *available at* https://www.economist.com/finance-and-economics/2022/07/13/american-inflation-tops-forecasts-yet-again-adding-to-recession-risks; Greg Ip, "Beware Wishful Thinking About Inflation and Recession,"

d. Additionally, the General Assembly empowered the Commission with specific discretion "to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction[.]"[17] The General Assembly clarified this specific discretion by providing that the Commission may extend the time frame for compliance with the carbon reduction goals set forth in HB 951 by two years for any reason. Beyond that, the Commission also has the discretion, following receipt and consideration of stakeholder input, to extend the period for compliance indefinitely in either of two scenarios:

(1) if the Commission "authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or"[18]

(2) "in the event necessary to maintain the adequacy and reliability of the existing grid."[19]

The Wall Street Journal (July 13, 2022), *available at* https://www.wsj.com/articles/beware-wishful-thinking-about-inflation-and-recession-11657719575.

[17] S.L. 2021-165, at Part I, Section 1(4).

[18] *Id.*

[19] *Id.*

III. Duke Energy's Proposed Carbon Plan

a. With some modifications and recommendations addressed herein, CIGFUR generally appreciates—at least in the near-term while substantial additional information is gathered, and some uncertainty is resolved— the flexibility afforded by the multi-portfolio approach proposed by Duke for the initial Carbon Plan. That said, CIGFUR believes the Commission, intervenors, and members of the public would benefit from certain additional information and analyses, as well as a few modifications to the proposal, as further discussed herein.

b. CIGFUR has serious concerns that power quality was not explicitly or directly addressed in the Carbon Plan.[20] Duke previously has recognized that "[m]aintaining safe and adequate system operations, reliability of service, and power quality on the grid are at the core of DEC's and DEP's operations as regulated public utilities in North Carolina generally[.]"[21] Indeed, power quality is almost always considered *together* with reliability or, at a minimum, within the umbrella of reliability considerations. Duke has acknowledged in various settings that there are "growing power quality concerns on the distribution system."[22] CIGFUR views power quality as part and parcel of system reliability, inasmuch as power quality events can adversely impact facility operations as significantly, if not more significantly, than a power outage. A voltage sag, for example, occurs "when the voltage drops to less than 90% of the nominal or standard voltage, as specified in R8-17(b)(2) of the

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[20] *See* Duke's Response to CIGFUR's DR 1-2, a true and accurate copy of which is attached hereto as Attachment D.

[21] Duke Energy Carolinas, LLC's Answer and Motion to Dismiss Complaint of Salisbury Solar, LLC and Bear Poplar Solar, LLC, p. 30, Docket No. E-7, Sub 1123 (Dec. 9, 2016).

[22] *See, e.g.*, *id.*, at p. 24.

Commission's rules. A sag is normally a relatively short event, a few cycles, or about a tenth of a second."[23] Power sags affect industrial customers with differing levels of severity, ranging from total plant shutdowns and damage to equipment, to lost revenues and inability to meet customer demand. Because power quality and

[23] Direct Testimony of Michael Ferguson, Manager, Pulp Manufacturing/Recovery and Utilities, on behalf of Blue Ridge Paper Products, Inc. D/B/A Evergreen Packaging, Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Sep. 8, 2011). While the 2011 testimony excerpted below references historical power quality events that occurred before the merger between Duke Energy and Progress Energy, it provides important context underscoring the importance of power quality issues generally and specifically from the perspective of an industrial customer. CIGFUR believes these insights into the potential negative consequences resulting when power quality is compromised are important to bring to the Commission's attention as it implements the Carbon Plan.

> **Q. How do power quality events affect your operations?**
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> A. These power quality events cause lost production throughout the mill. The impact has ranged from the entire mill being shut down to only portions of the mill, such as our #19 paper board machine or the Pine fiberline system. Unlike the nuisance of having to reset your clock when you have a power quality event at home, these events in the mill setting take hours and sometimes days to reestablish normal operations. Each and every one of these events adds cost to our production that we cannot simply pass on to our customers. Since our facilities run 24 hours a day, 365 days a year (less our planned maintenance outages) and our product price is set by a competitive market, these events have a negative impact on our profitability. The direct loss from these events between January 2008 and July 2011 is approximately $2.5 million dollars.
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> **Q. How do voltage sags in electric power service from Progress Energy affect the operation of your facilities at Canton and Waynesville?**
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> A. Voltage sags have the same impact as outages, and possible generate higher overall costs due to shortening the life of electrical and electronic equipment that rely on relatively stable voltage. During a voltage sag, electronic equipment such as programmable logic controllers, variable speed drive and motor starters will shut down or fault. When this happens the production equipment that these devices are associated with immediately shut down. These voltage sags cause lost production throughout the mill . . .
>
> **Q. Is there a significant difference in the adverse impact on your operations at the Canton and Waynesville facilities from a power service outage as opposed to a voltage sag?**
>
> A. Both of these issues have a negative impact on the operation of our Canton and Waynesville facilities. The sudden shutdown of the process equipment that occurs with either of these power quality events can lead to equipment damage and the possibility of injury to personnel. As I stated earlier, both of these type events cause lost production and increased cost of operation.

Id. at p. 4, line 7 through p. 5, line 18.

reliability are fundamentally and inextricably linked to one another, and more importantly because a reliable system does not necessarily equate to a system with good power quality, CIGFUR recommends that the Commission direct Duke to explicitly incorporate power quality metrics in its evaluation of the relative reliability of each of the portfolios and make a supplemental filing showing whether and how consideration of power quality issues may impact the comparative reliability assessment for each portfolio.

c. The bill impact estimates provided by Duke are concerning enough as is, but unfortunately they are, if anything, severely understated. Duke acknowledged at multiple points throughout both its proposed Carbon Plan filing or in discovery, or both, that certain cost-adders were underestimated, not considered, or excluded from its bill impact analysis altogether. CIGFUR provides the following non-exhaustive list of such omissions:

   i. **[BEGIN CONFIDENTIAL]** [redacted][24] **[END CONFIDENTIAL]**

   ii. Transmission cost adders related to the projected $7 billion in proposed upgrades.[25]

   iii. Duke did not include any projected costs associated with the subsequent license renewals (SLRs) for Duke's existing nuclear fleet.[26] This is

[24] *See* Duke's Confidential Response to Public Staff's DR 3-20, a true and accurate confidential copy of which is attached hereto and identified as Confidential Attachment E.

[25] *See* Duke's Response to Public Staff's DR 5-13, a true and accurate copy of which is attached hereto and identified as Attachment F.

[26] *See* Duke's Response to CIGFUR's DR 2-6, a true and accurate copy of which is attached hereto and identified as Attachment G.

particularly concerning given that Dominion Energy (Dominion) recently applied for SLRs for four (4) existing nuclear generation units: its North Anna Unit 1 (838 MW) (nameplate), North Anna Unit 2 (834 MW) (nameplate), Surry Unit 1 (838 MW) (nameplate), and Surry Unit 2 (838 MW) (nameplate), totaling 3,348 MW of generation.[27] Altogether, the relicensing and upgrade costs for these four (4) existing Dominion nuclear generation units at two nuclear stations are expected to cost $3.9 billion.[28] Duke, by comparison, plans to seek SLRs for the ***eleven*** existing nuclear generation units operating at six nuclear stations across the Carolinas, totaling 10,773 MW of generation. That Duke did not even attempt to provide estimates for these costs or include such estimates in the estimated PVRRs for each Carbon Plan portfolio should be cause for serious concern.

iv. Duke did not consider how total cost or bill impact analyses would be affected in the event of the Public Service Commission of South Carolina (PSCSC) either disapproving the Carbon Plan in Duke's next South Carolina Integrated Resource Plan (IRP) proceeding, including but not limited to generation and transmission siting and investments.[29, 30] CIGFUR recommends that the Commission direct Duke to perform this analysis and

[27] *See* Petition of Virginia Electric and Power Company for approval of a rate adjustment clause designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia, ¶¶ 5-6 (Case No. PUR-2021-00229) (Oct. 5, 2021), *available at* https://scc.virginia.gov/docketsearch/DOCS/5qx%4001!.PDF.

[28] *See id.*, at p. 2.

[29] *See* Duke's Response to CIGFUR's DR 1-3, a true and accurate copy of which is attached hereto and identified as Attachment H.

[30] *See* Duke's Response to Public Staff's DR 5-5, a true and accurate copy of which is attached hereto and identified as Attachment I.

submit a supplemental filing to the Commission containing this information.

v. Duke did not analyze or otherwise model how a possible future merger between DEP and DEC[31] could impact resources selected or model outputs as evaluated against the four-pronged framework of cost, reliability, emissions reductions, and executability as used by Duke in its proposed Carbon Plan.

vi. Duke performed no analysis to consider whether reliance on carbon emission offsets, as expressly authorized pursuant to HB 951, could potentially reduce compliance costs.[32]

vii. **[BEGIN CONFIDENTIAL]** [redacted][33] **[END CONFIDENTIAL]**

viii. Duke did not analyze how implementation of new non-residential demand response programs previously requested by CIGFUR on multiple occasions,[34] including during Duke's Comprehensive Rate Design Study[35] and during

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[31] *See* Duke's Response to Public Staff's DR 13-9, a true and accurate copy of which is attached hereto and identified as Attachment J.

[32] *See* Duke's Response to CIGFUR's DR 1-1, a true and accurate copy of which is identified and attached hereto as Attachment K.

[33] Duke's Confidential Response to CIGFUR's DR 1-12, a true and accurate confidential copy of which is identified and attached hereto as Confidential Attachment L.

[34] *See* Duke's Response to CIGFUR's DR 1-26, a true and accurate copy of which is identified and attached hereto as Attachment O.

[35] *See, e.g.*, PowerPoint slide deck presented by Christina D. Cress (counsel for CIGFUR), Nicholas Phillips, Jr. (rate consultant for CIGFUR), and Steve Castracane (on behalf of Messer Americas, a CIGFUR III member) during a meeting of Working Group #4 – Non-Residential Rates as part of Duke's Comprehensive Rate Design Study on October 11, 2021, a true and accurate copy of which is identified and attached hereto as Attachment P.

DEC's most recent DSM/EE (demand-side management/energy efficiency) Annual Rider hearing,[36] could potentially increase the expected non-residential participation in DSM/EE programs, providing benefits to both the system and all classes of ratepayers.

ix. Duke did not consider if retiring other electric generating facilities, aside from its coal fleet, could potentially result in the least-cost pathway to achieving the CO_2 emissions reductions goals set forth in HB 951.[37]

x. Duke performed no analysis or modeling with respect to the potential cost effects related to changing net energy metering rate tariffs.[38]

xi. Importantly, rate impacts attributable to costs recovered through the fuel clause are not factored into the projected rate increases associated with the Carbon Plan.[39]

xii. Despite Duke's assumption of a significantly increased adoption rate of electric vehicles through at least 2035 and related load growth projected as a result, Duke performed no analysis regarding how electric vehicle-to-grid or electric vehicle-to-home managed charging programs could potentially

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[36] *See* Transcript of Hearing Held in Raleigh, North Carolina on June 7, 2022, Docket No. E-7, Sub 1265, pp. 160-165, a true and accurate copy of which is identified and attached hereto as Attachment Q.

[37] *See* Duke's Response to Public Staff's DR 3-25, a true and accurate copy of which is identified and attached hereto as Attachment R.

[38] *See* Duke's Response to CIGFUR's DR 1-29, a true and accurate copy of which is identified and attached hereto as Attachment S.

[39] *See* Duke's Response to CIGFUR's DR 2-15, a true and accurate copy of which is identified and attached hereto as Attachment T.

provide peak load shaving and/or demand response benefits to help offset system and cost impacts.[40]

xiii. Rather than attempt to provide transparency and clarity into an estimate for the anticipated total "all-in" costs ratepayers can expect to be recovered through increased electric rates, Duke steadfastly refuses to include cost estimates for any cost drivers not directly associated with the Carbon Plan,[41] and even then, as referenced *supra*, Duke does not even capture an exhaustive list of directly-related costs associated with the Carbon Plan. This, unfortunately, conceals from the Commission the complete, full picture of the impact this Carbon Plan will have on ratepayers. Without having thorough, complete information about anticipated rate impacts in the coming years resulting from costs both related and unrelated to the Carbon Plan, how can the Commission be in a position to evaluate whether the steps Duke has asked them to approve in implementing an initial Carbon Plan are reasonable, as is required by HB 951?

[40] *See* Duke's Response to Attorney General's Office DR 4-15, a true and accurate copy of which is identified and attached hereto as Attachment M (exclusive of embedded attachments); *see also* Duke's Response to CIGFUR's DR 1-20, a true and accurate copy of which is identified and attached hereto as Exhibit N. That said, it should be noted that numerous electric utilities throughout the United States have marketed the prospect of using the power stored in EV batteries to balance load, but at present no such cost-effective system exists. It is a highly inefficient process to convert AC power to DC power and back, and to step up/down voltage multiple times, thereby producing a significant net increase in emissions. Moreover, this process results in the accelerated degradation of the EV battery and range, further increasing the need and frequency with which batteries must be charged and replaced. All of these factors combined to result in significant related life-cycle emissions attributable to EVs. Moreover, there is no utility in the country in which EV does not *increase* peak demand. California, where there is currently the highest EV penetration in the U.S., has studied this issue extensively and always found an increase in peak demand that is only expected to further increase commensurate with increased EV penetration in the coming years.

[41] *See* Duke's Response to CIGFUR's DR 2-8, a true and accurate copy of which is identified and attached hereto as Attachment U; *see also* Duke's Response to CIGFUR's DR 2-17, a true and accurate copy of which is identified and attached hereto as Attachment V.

d. In addition to the exclusions and omissions set forth above, CIGFUR contends the following aspects of the Carbon Plan rely on assumptions that are incomplete, faulty, or far too speculative to be dependable:

    i. Optimal economic retirement dates for Duke's coal fleet were determined through the methodology described in Appendix E of Duke's proposed Carbon Plan filing. Importantly, Duke explains the cost benefits for ratepayers resulting from securitizing the remaining net book value of its subcritical coal units at the time of each unit's modeled retirement:

> [t]he Companies have previously performed retirement analyses agnostic of remaining net book value of units at the time of modeled retirement. **However, for the Carbon Plan, the Companies have factored into the coal retirement analysis, the benefits associated with securitization of the remaining net book value of subcritical coal at time of modeled retirement**. HB 951 states that early retirement of subcritical coal-fired electric generating facilities to achieve the authorized CO2 reduction targets shall have costs be securitized at fifty percent (50%) of the remaining net book value of the facilities with any remaining non-securitized costs being recovered through rates. The accelerated retirement of these units allows for lower costs to customers associated with the securitized portion of the remaining net book value of the units if retirement is to achieve the authorized emissions reductions targets. To capture this benefit in the coal retirement analysis, the Companies modeled a securitization benefit for subcritical coal units that would have to be forgone if the unit were modeled to continue to be operated each successive year.[42]

Unfortunately, however, Duke notes in a footnote in the same section that

> The coal retirement analysis, and therefore securitization benefit calculations for the retirement analysis, was performed before the Commission issued its Rulemaking to Implement Securitization of Early Retirement of Subcritical Coal-fired Generating Facilities, which could affect the eligibility for securitization in certain circumstances. Therefore, **the modeling may be considered somewhat conservative toward retirement, to the extent that**

[42] Duke's proposed Carbon Plan, Appendix E, pp. 46-47 (emphasis added).

some units retired in certain years in certain cases may not actually be eligible for securitization under the Commission's order.[43]

ii. Duke's analysis only considered fuel type generally when calculating CO_2 emissions and did not consider specific emissions produced by individual electric generating facilities.[44]

iii. With geopolitical events such as the Russia-Ukraine War, combined with rising inflation and both domestic and foreign supply chain problems, exerting extreme market pressure on natural gas prices,[45] CIGFUR has

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[43] *Id.* at 47, FN 6 (emphasis added).

[44] *See* Duke's Response to Public Staff's DR 6-3, a true and accurate copy of which is identified and attached hereto as Attachment W.

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Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	3.45	2.15	1.89	2.03	2.25	2.20	2.19	2.49	2.88	3.07	3.01	2.35
1998	2.09	2.23	2.24	2.43	2.14	2.17	2.17	1.85	2.02	1.91	2.12	1.72
1999	1.85	1.77	1.79	2.15	2.26	2.30	2.31	2.80	2.55	2.73	2.37	2.36
2000	2.42	2.66	2.79	3.04	3.59	4.29	3.99	4.43	5.06	5.02	5.52	8.90
2001	8.17	5.61	5.23	5.19	4.19	3.72	3.11	2.97	2.19	2.46	2.34	2.30
2002	2.32	2.32	3.03	3.43	3.50	3.26	2.99	3.09	3.55	4.13	4.04	4.74
2003	5.43	7.71	5.93	5.26	5.81	5.82	5.03	4.99	4.62	4.63	4.47	6.13
2004	6.14	5.37	5.39	5.71	6.33	6.27	5.93	5.41	5.15	6.35	6.17	6.58
2005	6.15	6.14	6.96	7.16	6.47	7.18	7.63	9.53	11.75	13.42	10.30	13.05
2006	8.69	7.54	6.89	7.16	6.25	6.21	6.17	7.14	4.90	5.85	7.41	6.73
2007	6.55	8.00	7.11	7.60	7.64	7.35	6.22	6.22	6.08	6.74	7.10	7.11
2008	7.99	8.54	9.41	10.18	11.27	12.69	11.09	8.26	7.67	6.74	6.68	5.82
2009	5.24	4.52	3.96	3.50	3.83	3.80	3.38	3.14	2.99	4.01	3.66	5.35
2010	5.83	5.32	4.29	4.03	4.14	4.80	4.63	4.32	3.89	3.43	3.71	4.25
2011	4.49	4.09	3.97	4.24	4.31	4.54	4.42	4.06	3.90	3.57	3.24	3.17
2012	2.67	2.51	2.17	1.95	2.43	2.46	2.95	2.84	2.85	3.32	3.54	3.34
2013	3.33	3.33	3.81	4.17	4.04	3.83	3.62	3.43	3.62	3.68	3.64	4.24
2014	4.71	6.00	4.90	4.66	4.58	4.59	4.05	3.91	3.92	3.78	4.12	3.48
2015	2.99	2.87	2.83	2.61	2.85	2.78	2.84	2.77	2.66	2.34	2.09	1.93
2016	2.28	1.99	1.73	1.92	1.92	2.59	2.82	2.82	2.99	2.98	2.55	3.59
2017	3.30	2.85	2.88	3.10	3.15	2.98	2.98	2.90	2.98	2.88	3.01	2.82
2018	3.87	2.67	2.69	2.80	2.80	2.97	2.83	2.96	3.00	3.28	4.09	4.04
2019	3.11	2.69	2.95	2.65	2.64	2.40	2.37	2.22	2.56	2.33	2.65	2.22
2020	2.02	1.91	1.79	1.74	1.75	1.63	1.77	2.30	1.92	2.39	2.61	2.59
2021	2.71	5.35	2.62	2.66	2.91	3.26	3.84	4.07	5.16	5.51	5.05	3.76
2022	4.38	4.69	4.90	6.60	8.14	7.70						

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 7/7/2022
Next Release Date: 7/13/2022

U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price (Dollars per Million Btu), *available at* https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

some concerns with respect to the question of whether new natural gas plants are economical in the near-term. For example, Duke did not contemplate a price point at which natural gas would be considered uneconomic as a near-term fuel source for implementation of the Carbon Plan.[46] Rather, Duke only performed a "high gas price" analysis on Portfolio P4;[47] but even when looking at the "high gas price" analysis used for Portfolio P4, the prices used in the modeling are still significantly less than current natural gas prices. On the other side of the coin, however, CIGFUR also worries about the reliability impacts in the event Duke is unable to secure an adequate supply of natural gas and pipeline capacity in the event that the construction of the Mountain Valley Pipeline is precluded from being completed and placed into service, thus requiring implementation of one of the alternative proposed portfolios: P1A, P2A, P3A, and P4A. Should one of these alternative proposed portfolios be required to be implemented in this scenario, the projected costs to comply with the reliability requirements set forth in HB 951 could be even significantly higher than one of the non-alternative portfolios.

e. In addition to failing to consider the aforementioned cost-adders, CIGFUR contends Duke also failed to adequately consider several potentially more cost-effective alternative solutions to reducing CO2 emissions, including but not limited to the following:

[46] *See, e.g.*, Duke's Response to CIGFUR's DR 2-10, a true and accurate confidential copy of which is identified and attached hereto as Confidential Attachment X (exclusive of embedded attachment).

[47] *See id.*

i. Retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets instead of building out all new generation to serve as replacement capacity for the capacity lost through the early retirement of Duke's coal fleet;

ii. Evaluating CO2 emissions on a plant-by-plant basis and potentially installing scrubbing technology at Duke's existing coal and/or natural gas plants in lieu of building out all new replacement generation;

iii. Carbon capture and sequestration (CCS) technology, about which Duke reached the conclusory assessment that CCS "is not currently deemed viable for the Carolinas region from both geology and economic perspectives;"[48] and/or

iv. Maximizing pooled power, imported power, and/or power purchased through the Southeast Energy Exchange Market (SEEM). Despite Duke being a founding member of SEEM[49] and touting its cost-saving benefits to ratepayers, SEEM is not mentioned once in Duke's proposed Carbon Plan.

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[48] Duke's Proposed Carbon Plan, Appendix M, at p. 3.

[49] As relayed on SEEM's website:

> SEEM is a unique and thoroughly new approach to enhancing the existing bilateral market. The new SEEM platform will facilitate sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. Participation in SEEM is open to other entities that meet the appropriate requirements.
>
> SEEM is a 21st century solution designed for the incredible pace of change resulting from the electricity sector growing toward an ever-greener future. Southeastern electricity customers will see cost and environmental benefits as a result of the new platform that is set to become operation in the fourth quarter of 2022.
>
> Founding members of SEEM include Associated Electric Cooperative, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Georgia Systems Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, N.C. Municipal Power

f. CIGFUR also has concerns about approval of a Carbon Plan that is so dependent and reliant upon generating technologies that are either unproven[50] in the context of large-scale adoption or facing extreme market pressures, or both.

g. Notably, significant amounts of capacity for each generating technology resource prescribed in each portfolio had to be "forced in" because they were not economically selected by the EnCompass capacity expansion model.[51] Again, all HB 951 requires is that the Commission "take all ***reasonable*** steps"[52] to achieve the CO2 emissions reductions targets. Given that all portfolios proffered by Duke already include uneconomic selections as is, CIGFUR has difficulty imagining that alternative portfolios offered by other intervenors—to the extent they may involve even higher present value revenue requirements (PVRRs) or are on the more aggressive end of the period for compliance—can be considered reasonable, under the circumstances.

IV. Near-Term New Supply-Side Development and Procurement Activities

a. Duke requests approval of the "following supply-side development and procurement activities for the 2022-2024 period: (1) 3,100 MW of solar generation (sic)

Agency No. 1, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company and TVA.

The founding members represent nearly 20 entities in parts of 11 states with more than 160,000 MWs (summer capacity; winter capacity is nearly 180,000 MWs) across two time zones. These companies serve the energy needs of more than 32 million retail customers (roughly more than 50 million people).

Southeast Energy Exchange Market, "Delivering more economic and clean energy to our customers," *available at* https://southeastenergymarket.com/.

[50] For example, currently there are only four (4) SMRs in advanced stages of construction, none of which are located in the United States. Instead, they are located in Argentina, China, and Russia. *See "Small modular reactors"*, International Atomic Energy Agency, *located at* https://www.iaea.org/topics/small-modular-reactors.

[51] Duke's Response to Public Staff's DR 3-11, a true and accurate copy of which is identified and attached hereto as Attachment Y (exclusive of embedded attachment).

[52] S.L. 2021-165, Part I, Section 1 (emphasis added).

(a substantial portion of which is assumed to include paired storage), including 750 MW to be procured through the 2022 Solar Procurement Program; (2) 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar); (3) 600 MW of onshore wind; (4) 800 MW of combustion turbines units ('CTs'); and (5) 1,200 MW of combined cycle units ('CC')."[53] With respect to this request, CIGFUR reiterates and incorporates by reference its comments and recommendations contained in Sections III *supra*.

b. Duke also requests that the Commission "**approve as reasonable and prudent** initial project development activities on three longer-lead time resources—offshore wind, SMRs, and new pumped storage hydro—all of which are **likely** to be needed **either** to achieve the interim 70% CO_2 emissions reductions **or** carbon neutrality over the longer term."[54] Duke acknowledges throughout its Petition and proposed Carbon Plan filing that the resources underpinning this request are replete with uncertainty and as-yet unknown information.[55]

   i. Given the speculative and uncertain nature of whether these development activities are likely to ever become used and useful in the provision of electric service to Duke's ratepayers, combined with the timing of expected in-service

[53] Duke's Petition, at ¶ 18.

[54] *Id.* (emphasis added).

[55] *See, e.g.*, *id.*, at ¶ 20 ("[T]he Commission will have its next comprehensive opportunity in a biennial Carbon Plan proceeding to 'check and adjust' the strategy with the benefit of substantial additional and more refined information"); *see also id.*, at ¶ 21 ("The two-year period following the Commission's decision in this proceeding will offer substantially greater clarity and precision regarding a range of issues that will significantly impact the longer-term trajectory of the Carbon Plan . . . In addition, the Companies will be able to gather and assess a wide range of additional, crucial information as they begin to execute the near-term Carbon Plan steps, including but not limited to, more refined cost estimates and timelines for new-to-the-Carolinas technologies, availability of gas supply from Appalachia, more clarity on supply chain challenges, and more detailed market information gathered from procurement activities, *etc.*").

dates when ratepayers would first see potential benefits associated with such costs, CIGFUR contends this request would violate the matching principle and the principle of intergenerational equity. Ratepayers cannot and should not be expected to pay costs in the 2020s for new generation that may not become used and useful in the provision of electric service to Duke's customers until the 2030s or 2040s, if ever.

ii. Regardless of whether the Commission authorizes these initial project development activities, a pre-determination of reasonableness and prudence would be premature, inappropriate, and inconsistent with applicable statutes and Commission precedent.[56] To the extent Duke's request amounts to such a request for a pre-determination of reasonable and prudence, CIGFUR opposes such request and thinks a reasonableness and prudency analysis should be conducted in a future rate case when Duke eventually seeks cost recovery for costs incurred to undertake any Commission-approved initial project development activities.

iii. Similarly, Duke's request to earn a return on the unamortized balance at its applicable then-authorized, net-of-tax weighted average cost of capital is premature, inappropriate, unreasonable, and inconsistent with Commission precedent.[57]

[56] *See, e.g.*, G.S. 62-110.7(b) ("The Commission shall approve the public utility's decision to incur project development costs if the public utility demonstrates by a preponderance of the evidence that the decision to incur project development costs is reasonable and prudent; **provided, however, the Commission shall not rule on the reasonableness or prudence of specific project development activities or recoverability of specific items of cost**.") (emphasis added).

[57] *See, e.g.*, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Subs 819, 1110, 1146, and 1152, at ¶¶ 45-49 (June 22, 2018) (finding in pertinent part that DEC's actions in developing the Lee Nuclear Project were reasonable and prudent; that DEC's decision to cancel the project

iv. It would be appropriate and consistent with Commission precedent[58] for the Commission to impose limits—by way of cost caps, parameters, and/or guidelines—in the event it approves Duke's request to undertake pre-development activities of offshore wind, SMRs, and new pumped storage hydro. Such limitations are necessary to ensure both that (1) Duke is sufficiently incentivized to manage its project development activities in a cost-efficient, reasonable, and prudent manner; and (2) ratepayers are protected from cost overruns and unconstrained spending, particularly for "longer-lead time resources." After all, a "longer-lead time resource" essentially means a new generation resource that is much more likely to (1) never become used and useful in the provision of electric service to customers; or (2) be placed into service at a time many years after development and/or construction work in progress (CWIP) costs are incurred. It should also be noted that the greater the uncertainty and speculation involved in a potential new generation, the greater the risk that the project will never become used and useful in the provision of electric service to customers.[59] While certain advocates may try to claim this

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was reasonable and prudent; that DEC's project development costs incurred for the Lee Nuclear Project were reasonable—with a few exceptions—and should be amortized over a 12-year period; and that "**[i]t is not appropriate to permit the Company to earn a return on the unamortized balance of these project development costs during the amortization period, as requested. This rate treatment is consistent with Commission precedent and results in rates that are fair to both the Company and its ratepayers for the costs of the cancelled Lee Nuclear Project**") (emphasis added).

[58] *See, e.g.*, *Order Approving Decision to Incur Limited Additional Project Development Costs*, Docket No. E-7, Sub 819, p. 22 (Aug. 5, 2011).

[59] In late 2010, DEC applied for approval from the Commission of its decision to incur project development costs in order to continue development work on the Lee Nuclear Station in Cherokee County, South Carolina. DEC had already incurred nuclear project development costs of approximately $172 million through December 31, 2009 and sought approval of its decision to incur costs of up to $283 million to continue work from January 1, 2010 through December 31, 2013, for a total of $455 million through the end of 2013.

uncertainty and risk is unique to certain electric generating technologies, there are industry examples spanning all resources,[60] except of course those resources still so new and as-yet unproven that there are currently no other examples in the United States from which to glean insights or apply lessons learned.

V. Near-Term Existing Supply-Side Activities

a. CIGFUR notes its concern that Duke seems much more focused on supply-side solutions rather than less costly demand-side ones. Moreover, Duke's proposed supply-side solutions are much more focused on building new generation owned by Duke as opposed to less costly alternatives, such as arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and

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Upon review, the Commission found that there were a number of uncertainties about the Lee project that posed risks about the reasonableness of spending more on its development. Based on those uncertainties, the Commission concluded

> 1. That, in light of Duke's position that it will not proceed with construction absent legislation allowing recovery of CWIP financing costs outside a general rate case, and the fact that no such legislation is now pending before the General Assembly, it is not appropriate to approve Duke's application at this time. Instead, the approval granted by this Order is limited to Duke's decision to incur only those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Station, including Duke's [construction and operating license (COL)] application at the [Nuclear Regulatory Commission (NRC)].
>
> 2. That nuclear project development (sic) costs incurred on or after January 1, 2011, shall be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million.

Order Approving Decision to Incur Limited Additional Project Development Costs, Docket No. E-7, Sub 819, p. 22 (Aug. 5, 2011).

[60] *See, e.g.*, "Plans for largest US solar field north of Vegas scrapped," AP News (July 23, 2021), *available at* https://apnews.com/article/technology-government-and-politics-environment-and-nature-las-vegas-nevada-9bf3640dfefbc6f7f45a97c6810f5ff7; Sarah Vogelsong, "Chickahominy Power cancels plans for natural gas plant in Charles City," Virginia Mercury (March 17, 2022), *available at* https://www.virginiamercury.com/blog-va/chickahominy-power-cancels-plans-for-natural-gas-plant-in-charles-city/; Dan Gearino, "AEP Cancels Nation's Largest Wind Farm: 3 Challenges Wind Catcher Faced," Inside Climate News (July 30, 2018), *available at* *https://insideclimatenews.org/news/30072018/aep-cancels-wind-catcher-largest-wind-farm-oklahoma-oil-gas-opposition-clean-power-plan/;* "Factbox: U.S. nuclear reactors that were canceled after construction began, Reuters (July 31, 2017), *available at* https://www reuters.com/article/toshiba-accounting-westinghouse-reactors/factbox-u-s-nuclear-reactors-that-were-canceled-after-construction-began-idINKBN1AG280.

other methods for providing reliable, efficient, and economical service." Without adequate guardrails, the energy transition does indeed present a ripe opportunity for Duke to gold-plate its generation and transmission plant. CIGFUR suggests, among other recommendations, that to the extent new natural gas assets are determined to be the least-cost, most reliable increment of new generation, power purchase agreements (PPAs) with third parties should be, at a minimum, evaluated as a potentially more cost-effective alternative.

b. CIGFUR recommends that in a future rate case, the Commission require Duke to establish a peak demand charge for all customers and classes of customers. Duke's ratepayers already funded hundreds of millions of dollars' worth of smart meters and such meters are not presently being used in the manner that would most significantly send a market signal to residential (and other) customers to take demand response measures. Alternatively, Duke should, at a minimum be required to study and file with the Commission a report showing how implementing a peak demand charge would help further "shrink the challenge" through these additional demand-side management measures, thereby reducing overall Carbon Plan implementation costs for all ratepayers.

c. In addition, CIGFUR reiterates and incorporates by reference herein the concerns and recommendations relevant to this section contained in Section III and IV *supra*.

d. CIGFUR suggests that the Commission direct Duke to adopt new, innovative demand-side solutions and expand its existing suite of programs. CIGFUR provides specific feedback with respect to its recommendations for Grid Edge and Customer Programs in Section VI, *infra*.

VI. Grid Edge and Customer Programs

a. As previously mentioned, CIGFUR encourages Duke to offer new EE/DSM programs and expand its existing suite of demand response programs consistent with the feedback CIGFUR has previously provided in multiple stakeholder forums. More specifically, CIGFUR encourages Duke to adopt a program mirrored after the Southern California Edison's Time-of-Use Base Interruptible Program (TOU-BIP), a voluntary program which would also include the option to participate in a related Emergency Load Reduction Program (ELRP).[61]

b. As an initial matter, Duke should be required to implement innovative, outside-of-the-box new customer programs to incentivize private sector investment in renewable energy resources. Not only would this be in furtherance of the CO2 emissions reductions goals set forth in HB 951, but it is also critically necessary as a cost mitigation measure to encourage private sector investment as a means of defraying as many costs as possible which will otherwise have to be rate-based. Unsurprisingly, Duke has not volunteered any ideas for incenting private sector investment in renewable energy resources, because it is contrary to their pecuniary interest to do so. For these reasons, CIGFUR submits it is in the public interest, and certainly in the interest of ratepayers and in furtherance of the emissions reductions policy established in HB 951. Along these lines, CIGFUR recommends that the Commission direct Duke to study and, where appropriate, propose for regulatory

[61] *See* PowerPoint slide deck presented by Christina D. Cress (counsel for CIGFUR), Nicholas Phillips, Jr. (rate consultant for CIGFUR), and Steve Castracane (on behalf of Messer Americas, a CIGFUR III member) during a meeting of Working Group #4 – Non-Residential Rates as part of Duke's Comprehensive Rate Design Study (previously identified as Attachment P).

approval new programs that incentivize private sector investment in clean energy resources, including but not necessarily limited to the following program concepts:

i. A bill credit for non-residential customers in exchange for each "clean" or "green" kilowatt-hour generated or dispatched from either behind-the-meter renewable energy resources, renewable co-generation, or grid-side resources generated or dispatched on behalf of the customer; and

ii. Public-private partnerships to facilitate cost savings—for example, if the Commission approves a Carbon Plan that contemplates a future shift away from natural gas and toward green hydrogen, Duke should be required to explore win-win partnerships with the private sector that will lower costs for all ratepayers. One such possible future partnership could potentially be with respect to green ammonia, which can be used as both a liquid fertilizer and a fuel source. While natural gas is still used as the primary fuel source to produce green ammonia, emissions can be further reduced through carbon capture and sequestration (CCS) technology and storage technology.

c. CIGFUR encourages Duke to offer new voluntary non-residential customer renewable programs, including incentives for adoption of behind-the-meter distributed generation and storage resources, as well as front-of-the meter programs including a temporary extension/expansion of the Green Source Advantage Program (GSA Program) as a short-term bridge in the interim while new customer renewable programs are being developed. Based on feedback CIGFUR has received from various non-residential customers of Duke, Duke's existing customers would have a serious interest in subscribing to approximately 250 MW, at a minimum, of additional GSA Program capacity in the event it was made available to them.

d. As an aside, CIGFUR notes that while Duke contends the first step of its proposed Carbon Plan is to "shrink the challenge" through a goal of 1% systemwide adoption of EE/DSM solutions, news broke in early July that Duke is potentially studying whether cryptocurrency mining would be beneficial to its system.[62] This is ironic, of course, considering cryptocurrency mining is notorious for being a massive consumer of energy. Indeed, "Bitcoin, the world's largest cryptocurrency, currently consumes an estimated 150 terawatt-hours of electricity annually – more than the entire country of Argentina, population 45 million."[63]

VII. Transmission System Planning

a. As previously mentioned, CIGFUR believes exclusion of projected transmission system upgrade costs in the estimated amount of $7 billion from the total PVRRs and bill impact analyses related to each Carbon Plan portfolio proposed by Duke contributes to deflating the true total cost and bill impacts. CIGFUR recommends

[62] "According to the lead rates and regulatory strategy analyst at Duke Energy Corporation, the second-largest U.S. energy corporation is currently studying bitcoin mining. Lead analyst Justin Orkney said that a bitcoin demand response (DR) study was being worked on and the energy firm is partnered with bitcoin miners that are enrolled in Duke's DR programs," Bitcoin.com News (July 6, 2022), *available at* https://news.bitcoin.com/analyst-says-duke-energy-corporation-is-studying-bitcoin-mining-applied-to-demand-response/.

[63] Jeremy Hinsdale, "Cryptocurrency's Dirty Secret: Energy Consumption," Columbia Climate School (May 4, 2022), *available at https://news.climate.columbia.edu/2022/05/04/cryptocurrency-energy/.*

that the Commission direct Duke to make a supplemental filing including these costs in total PVRRs and bill impact analyses for each portfolio.

b. In addition, Duke performed no analysis to consider whether siting new electric generation close in proximity to its existing coal plants could reduce the need to build new transmission infrastructure or to upgrade existing transmission infrastructure.[64] CIGFUR recommends that the Commission order Duke to conduct this analysis and make a supplemental filing containing the results of said analysis.

c. Duke did not adequately analyze the total capacity of new solar generation able to be accommodated by its existing transmission infrastructure.[65] CIGFUR recommends that the Commission direct Duke to conduct these analyses and make a supplemental filing containing the results of said analyses.

VIII. <u>Methodologies for Carbon Baseline Calculation and Accounting</u>

a. **[BEGIN CONFIDENTIAL]** [redacted][66]

[END CONFIDENTIAL]

b. Duke should be required to account for carbon leakage associated with the loss of incremental power demand from residential, commercial, and industrial customers leaving the state due to, at least in part, higher electric rates in Duke's service territory. In other words, it is unreasonable to ignore emissions leakage while claiming North

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[64] *See* Duke's Response to Attorney General's Office DR 3-11, a true and accurate copy of which is attached hereto and identified as Attachment Z.

[65] *See* Duke's Response to Public Staff's DR 5-12, a true and accurate copy of which is identified and attached hereto as Attachment AA.

[66] *See* Duke's Confidential Response to Public Staff's DR 6-4, a true and accurate confidential copy of which is attached hereto and identified as Confidential Attachment BB (exclusive of embedded attachment).

Carolina has achieved the CO_2 emissions reductions goals set forth in HB 951 if the result is simply that power demand shifts to other jurisdictions as a result of these policies and the toll they will inevitably take on the North Carolina economy.

c. CIGFUR recommends that the Commission direct Duke to conduct the analysis omitted pursuant to Section VIII.a. *supra* and to make a supplemental filing with the Commission containing the results of such analysis.

d. CIGFUR further requests formal, ongoing analysis of emissions leakage from price-induced demand erosion. Importantly, this analysis should account for fewer ratepayers and load across which to fund the generation and transmission projects proposed by Duke in the Carbon Plan, which will result in *even* higher cost and rate impacts per remaining ratepayer.

e. In addition, Duke should also be performing life-cycle emissions analyses for each of its Carbon Plan portfolios. In other words, Duke should be required to account for the significant amount of emissions associated with mining and processing materials for batteries and other generation, transmission, and distribution technologies from point of origination to each step of the supply chain, through installation and being placed into service and beyond.

IX. Future Proceedings

a. Though HB 951 requires that the Commission develop an initial Carbon Plan by the end of 2022, CIGFUR appreciates that HB 951 also contemplates that this will be an iterative process and, therefore, provided for a mechanism by which the Carbon Plan can be reviewed and adjusted at least "every two years and may be adjusted as necessary in the determination of the Commission and the electric public utilities."[67] Along these same lines, CIGFUR encourages the Commission and other parties to this proceeding to view the initial Carbon Plan through the lens that this is not a river journey wherein there is but one single path followed from the head of the river to its mouth, but instead this is an ocean journey wherein a ship sets sail across the open ocean with a seemingly infinite number of paths for how it can reach its destination.

b. In furtherance of the CO2 emissions reductions goals set forth in HB 951 and for the benefit of all ratepayers, CIGFUR recommends that the Commission direct Duke in its next general rate cases to propose rate designs that will encourage and incentivize increased adoption of behind-the-meter renewable energy resources and storage for non-residential customers, as well as increased participation in front-of-the-meter renewable energy programs.

c. Importantly, the Carbon Plan does not supersede, supplant, or otherwise serve as a substitute for the regulatory processes necessary for Duke to obtain a certificate of environmental compatibility and public convenience and necessity (CECPCN) pursuant to G.S. 62-101 before constructing a transmission line, or a certificate of public convenience and necessity (CPCN) pursuant to G.S. 62-110.1 before constructing a new electric generating facility. CPCN proceedings, unlike a broad resource adequacy and planning proceeding like the instant docket, allow for a more narrow, focused evaluation of one specific proposed electric generating facility (or transmission line, if a CECPCN proceeding, as the case may be). More specifically, G.S. 62-110.1 requires certain evidence be proven by the applicant and specific

[67] S.L. 2021-165, Part I, Section 1(1).

findings be made by the Commission that,[68] due to the breadth and scope of this proceeding, the instant docket simply does not afford the opportunity to evaluate. For example, G.S. 62-110.1(d) requires that "[i]n acting upon any petition for the construction of any facility for the new generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical service." Many of the resources included in Duke's Portfolios P1, P2, P3, and P4 are far too speculative at this time to provide the level of detail and certainty necessary for Duke to satisfy its burden of proof in a CPCN proceeding. Due process considerations require that ratepayers be afforded a complete, thorough, and non-expedited opportunity to evaluate the evidence—and all potentially more cost-effective alternatives to the project for which certification is being sought—during a CPCN proceeding that (1) complies with the requirements set forth in the CPCN statute; (2) complies with the Commission's Rules; (3) satisfies the Commission's existing standard for deciding CPCN cases, except to include among the list of factors considered in a CPCN proceeding the CO_2 emissions reduction goals set forth in HB 951 as a

[68] "[T]he decision of whether to grant or deny a CPCN must rest upon substantive evidence; it cannot rest upon speculation or sentiment." *Order Denying Certificate of Convenience and Necessity for Merchant Generating Facility*, p. 8, Docket No. EMP-105, Sub 0, N.C.U.C. (June 11, 2020) (citing *Howard v. City of Kinston*, 148 N.C. App. 238, 246, 558 S.E.2d 221, 227 (2002)). Notably, this particular Commission Order was recently affirmed by the North Carolina Court of Appeals in *State ex rel. Utils. Comm'n v. Friesian Holdings, LLC*, 2022-NCCOA-32, ¶¶ 20-22 (2022) ("[T]he record reflects that the Commission did, in fact, carefully consider and weigh the potential for additional energy generation. Rather than disregard that consideration outright, **the Commission determined it was too speculative to support the approval of Friesian's CPCN** . . . In its discretion, the Commission concluded that **the potential additional generation was subject to too many variables and 'there is nothing in the record to conclude that any of the proposed generating facilities, much less all of them, will actually be constructed and placed into service**'" (emphasis added).

non-dispositive, non-determinative, non-conclusive factor; and (4) is consistent with Commission precedent. Indeed,

d. To the extent Duke is requesting that the Commission direct it and the Public Staff to "develop and propose for comment revisions to . . . related rules for certificating new generating facilities to support execution of the Carbon Plan,"[69] CIGFUR emphasizes that the General Assembly did not indicate any intent for the Carbon Plan to function as a substitute for the CPCN process. Indeed, the statutes governing the CPCN regulatory process were not amended or modified by the enactment of HB 951 and, therefore, continues in effect according to its own terms, pursuant to principles of statutory construction. Unlike the ratified version of HB 951 enacted as Session Law 2021-165, earlier editions of HB 951 *would* have modified the applicability, in whole or in part, of the CPCN requirements set forth in G.S. 62-110.1. That these modifications did not make it into the codified version of this legislation is evidence of legislative intent for CPCN requirements to remain fully preserved and intact.[70]

e. CIGFUR notes that various factual and legal issues related to future recovery of Carbon Plan implementation costs are not yet ripe for Commission decision. Along

[69] Duke's Petition, at ¶ 35.

[70] For example, the Third Edition of House Bill 951, had it been enacted into law, would have exempted Duke from the requirement set forth in Section 62-110.1(d) to provide information regarding its "arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economic electric service," at least to the extent the CPCN sought would be for replacement resources necessary as a result of the early retirement of Duke's coal fleet. H.B. 951, 3d ed., N.C.G.A. (2021 Session), at p. 4, ls. 38-39; p. 7, ls. 29-30, a true and accurate copy of which is identified and attached hereto as Attachment CC. Moreover, the Third Edition of HB 951, had it been enacted into law, would have required the Commission to "provide an expedited decision on an application for a certificate of public convenience [for coal replacement] resources." *Id.* at 7, ls. 10-12. Had the Legislature actually intended these modifications be made to the CPCN process, it would have enacted the pertinent statutory amendments into law. But it did not.

these same lines, CIGFUR further notes that, generally speaking, any determinations at this time regarding whether DEC and/or DEP acted reasonably and prudently in developing, constructing, and placing into service new electric generating facilities at some future date would be premature. Moreover, CIGFUR reiterates that the instant docket is a resource planning proceeding, not a general rate case proceeding and not a CPCN proceeding. With this in mind, CIGFUR emphasizes that neither this docket, nor a future biennial Carbon Plan review proceeding should be treated as a cost recovery proceeding, a prudency review, or an electric generation certification proceeding. Rather, this proceeding is a resource adequacy and planning proceeding, the outcome of which should not in any way be construed as dispositive, controlling, or presumptive of any findings necessary for future generation certification, prudency review, or cost recovery. Indeed, there is no compelling justification why current practice should not continue: consistency with an electric public utility's most recently approved IRP is *considered* as one factor in a CPCN proceeding (and, occasionally, in general rate cases[71]). Consistency with the Carbon Plan should likewise be considered in future CPCN proceedings and future general rate cases, but this factor should not be given any more weight than it has historically been given in CPCN proceedings. If anything, it should be given **less** weight in light of the speculative multi-portfolio approach and unprecedented magnitude of costs at stake in the Carbon Plan.

[71] *See, e.g.*, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Subs 819, 1110, 1146, and 1152, at ¶¶ 45-49 (June 22, 2018).

f. Relatedly, it is worth noting that the existing regulatory processes by which Duke (1) demonstrates a need for capacity additions to serve forecasted load in North Carolina; (2) determines the least-cost next increment of electric generating capacity and energy consistent with the CO_2 emissions reductions goals set forth in HB 951; and (3) seeks cost recovery for its respective North Carolina jurisdictional allocable portion of capital expenditures to construct new generation plant were not altered by HB 951's directive for the Commission to develop a Carbon Plan.

X. Conclusion and Request for Relief

a. Because of the many known unknowns and unknown unknowns, especially variables of the unprecedented magnitude of economic and affordability impacts at issue here, CIGFUR sees value—at least for the immediate near-term until the next biennial Carbon Plan review proceeding anticipated in 2024—in the flexibility afforded by the multi-portfolio approach Duke proposes by way of its Portfolios P1, P2, P3, and P4. Given that many aspects of the Carbon Plan proposed by Duke are replete with uncertainty and speculation, especially with regard to the "new-to-the-Carolinas" technologies, the flexibility afforded by the multi-portfolio approach is essential to ensure we achieve compliance with the carbon reduction goals set forth in HB 951 in the least-cost, most reliable way.

b. For all the reasons set forth herein, CIGFUR recommends that the Commission impose the following limitations on the near-term requests for approval contained in Duke's proposed Carbon Plan filing:

i. In the event the PSCSC disapproves the Carbon Plan in Duke's next South Carolina IRP docket, North Carolina ratepayers should be held harmless from the South Carolina jurisdictional allocable portion of related costs incurred between the date upon which this Commission approves the initial Carbon Plan and the 2024 biennial Carbon Plan/IRP proceeding before this Commission;

ii. That regardless of whether the Commission authorizes the initial project development activities requested by Duke, the Commission should not make a pre-determination of reasonableness and prudence; moreover, ratepayers in the 2020s should not be expected to pay the costs for new generation that may not become used and useful in the provision of electric service until the 2030s or 2040s, if ever;

iii. Duke's request to earn a return on the unamortized balance at its applicable then-authorized, net-of-tax weighted average cost of capital is premature, inappropriate, unreasonable, and inconsistent with Commission precedent; and

iv. If the Commission approves Duke's request to undertake predevelopment activities of offshore wind, SMRs, and new pumped storage hydro, it should impose limits—cost caps, not-to-exceed parameters, and/or other guidelines—to ensure both that ratepayers are protected from cost overruns and that Duke remains incentivized to manage its project development activities in a cost-efficient, reasonable, and prudent manner.

c. For all the reasons set forth herein, CIGFUR further requests that the Commission direct Duke to make a supplemental filing containing an "all-in" cost estimate and bill impact analysis for each customer class through 2035 for all anticipated generation, transmission, and distribution plant investments and operations and maintenance (O&M), related and unrelated to the Carbon Plan, on an annual and cumulative basis. It is important for the Commission, intervenors, and the general public to have a sense of the bigger picture in order to evaluate the reasonableness of the steps Duke recommends be taken toward compliance with HB 951 CO2 emissions reductions goals.

d. For all the reasons set forth herein, CIGFUR further requests that the Commission direct Duke to re-run its EnCompass model and make a supplemental filing containing updated outputs based on the following modifications:

   i. Akin to Duke's alternative portfolios—P1A, P2A, P3A, and P4A—modeled in the event Duke is unable to secure sufficient natural gas supply and pipeline capacity to build out new natural gas plants, CIGFUR recommends that Duke be required to model four additional alternative portfolios—P1B, P2B, P3B, and P4B—in the event the PSCSC disapproves the Carbon Plan in Duke's 2023 South Carolina IRP docket;

   ii. Explicit inclusion of power quality metrics in its evaluation of reliability in each of the proposed portfolios and make a supplemental filing showing whether and how consideration of power quality issues may impact the comparative reliability assessment for each portfolio;

   iii. Inclusion of all cost-drivers referenced in Section III.c. *supra* that appear to have been excluded from Duke's cost and bill impact analyses in the Carbon Plan; and

   iv. The analyses suggested in Section VII.b. and VIII.a. and c., *supra*.

e. For all the reasons set forth herein, CIGFUR recommends that the Commission expressly direct Duke to securitize the remaining net book value of each subcritical coal plant at the time of its retirement, if it is found by the Public Staff and the Commission to be in the economic interest of ratepayers to do so.

f. CIGFUR believes that both existing and proposed demand response programs for non-residential customers are a largely untapped and/or underutilized resource that Duke failed to sufficiently consider in developing its proposed Carbon Plan. For all the reasons set forth herein, CIGFUR recommends that Duke be required to evaluate and report to the Commission the status of implementing a new voluntary demand response program mirroring the Time-of-Use Base Interruptible Program (BIP) with optional Emergency Load Reduction Program (ELRP) add-on offered by Southern California Edison. CIGFUR recommends this program be implemented with a tiered set of demand response intervals, ranging from 15 minutes through one hour or longer, with the associated bill credit being aligned with the system benefit provided through the speed of demand response. CIGFUR further recommends this program contain an option that, in lieu of automatically suffering penalties for failing to shed load, the customer first be allowed an opportunity to purchase power at market rates. In summary, the greater the enrollment flexibility and ability to customize participation so that it is tailored to a non-residential customer's unique needs, and the higher the bill credit incentives, the greater amount of additional capacity that can be expected to be enrolled. This, of course, benefits both the system and ratepayers. Finally, CIGFUR recommends that any program similar to BIP and ELRP contain a seasonal differentiation to provide flexibility for those non-residential customers who are able to shed load more easily in summer, but not winter, or vice versa.

g. For all the reasons set forth herein, CIGFUR recommends that the Commission order Duke to offer new voluntary customer renewable programs, including a temporary expansion/extension of the Green Source Advantage Program (GSA Program) as a short-term bridge in the interim while new customer renewable programs are being developed.

h. For all the reasons set forth herein, CIGFUR recommends that the existing burden of proof and standards for approval of a CPCN and CECPCN application, respectively, be preserved.

XI. CIGFUR highlights the following list of substantive issues that may potentially be appropriate for consideration in an evidentiary hearing:

a. Duke's proposal fails to adequately model or evaluate power quality considerations in determination of portfolio reliability scoring; similarly, Duke's proposal fails to adopt certain reliability and power quality metrics to be evaluated on an ongoing basis to ensure compliance with the maintaining or improving reliability mandate set forth in HB 951.

b. Duke's proposal fails to provide an "all-in" total cost and projected rate impact for all planned spending both related and unrelated to the Carbon Plan. Without more transparency and clarity into the bigger picture of total and cumulative cost and rate impacts, it is impossible to ascertain whether the Carbon Plan as proposed constitutes a "reasonable step" as that term is used in HB 951.

c. Duke's proposal fails to provide sufficient guardrails, spending caps, and other parameters around its proposed near-term supply-side activities. Similarly, Duke's proposal fails to ensure that Duke is bearing some of the risk in the event these investments do not result in assets that eventually become used and useful in the provision of electric service to ratepayers.

d. Duke's proposal fails to capture emissions leakages associated with price-induced demand erosion.

e. Duke's proposal fails to sufficiently leverage flexible load of certain commercial and industrial customers as a demand response resource.

f. Duke's proposal fails to sufficiently leverage non-residential customers' demand for expanding existing and implementing new customer renewable energy programs.

g. Duke's proposal fails to demonstrate that its membership in SEEM could enable it to avoid certain new buildout of generation or otherwise to provide some savings to ratepayers or costs avoided.

h. Duke's proposal fails to satisfy the least-cost requirement in that it does not guarantee it will utilize and maximize securitization of early-retired coal assets for the benefit of ratepayers to the extent required by HB 951.

i. The Carbon Plan is not an appropriate, practical, or legal substitute for CECPCN and CPCN proceedings, respectively, on a project-by-project basis. Individual, unabridged, complete CECPCN and CPCN proceedings will provide each project proposed in Duke's Carbon Plan with the requisite level of scrutiny, including but not limited to a more exhaustive analysis of potentially more cost-effective alternatives to simply building out and rate-basing as much generation and transmission plant as possible.

CIGFUR appreciates the opportunity to submit these comments.

WHEREFORE, CIGFUR respectfully requests that:

I. The Commission direct Duke to continue responding to discovery requests;

II. The Commission take judicial notice of all Commission orders and official filings made to the Commission cited to in these comments;

III. The Commission consider the foregoing comments in its deliberations in the above-referenced docket;

IV. The recommendations set forth in Section X. *supra* be incorporated by the Commission;

V. The issues list set forth in Section XI. *supra* be considered by the Commission; and

VI. For such other and further relief as the Commission may provide.

Respectfully submitted this the 15th day of July, 2022.

BAILEY & DIXON, LLP

/s/ Christina D. Cress
Christina D. Cress
N.C. State Bar No. 45963
434 Fayetteville Street, Ste. 2500
Post Office Box 1351 (zip 27602)
Raleigh, North Carolina 27601
(919) 607-6055
ccress@bdixon.com
Attorneys for CIGFUR II & III

CERTIFICATE OF SERVICE

The undersigned attorney for CIGFUR hereby certifies that she served the foregoing Comments of CIGFUR II & III upon the parties to this proceeding, as listed on the service list available on the NCUC's online docket system, by electronic mail.

This the 15th day of July, 2022.

/s/ Christina D. Cress
Christina D. Cress

VERIFICATION

Nicholas Phillips, Jr., who works as a consultant for Brubaker & Associates, Inc., and who has been appeared before this Commission on numerous occasions on behalf of CIGFUR to provide expert witness testimony, states that he has read the foregoing Comments of CIGFUR II and III and that the facts stated therein are true of his personal knowledge, except such matters as are stated on information and belief, and as to those matters he believes them to be true.

Nicholas Phillips, Jr.

Saint Louis County, State of Missouri

I certify that Nicholas Phillips, Jr. personally appeared before me this day, proved his identity to me by satisfactory evidence, and acknowledged to me that he voluntarily signed the foregoing document for the purpose stated therein.

Date: July 14, 2022

Notary Public

Maria E. Decker
Typed or Printed Name of Notary

(Official Seal)

My commission expires: May 5, 2025

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2025
Commission # 13706793

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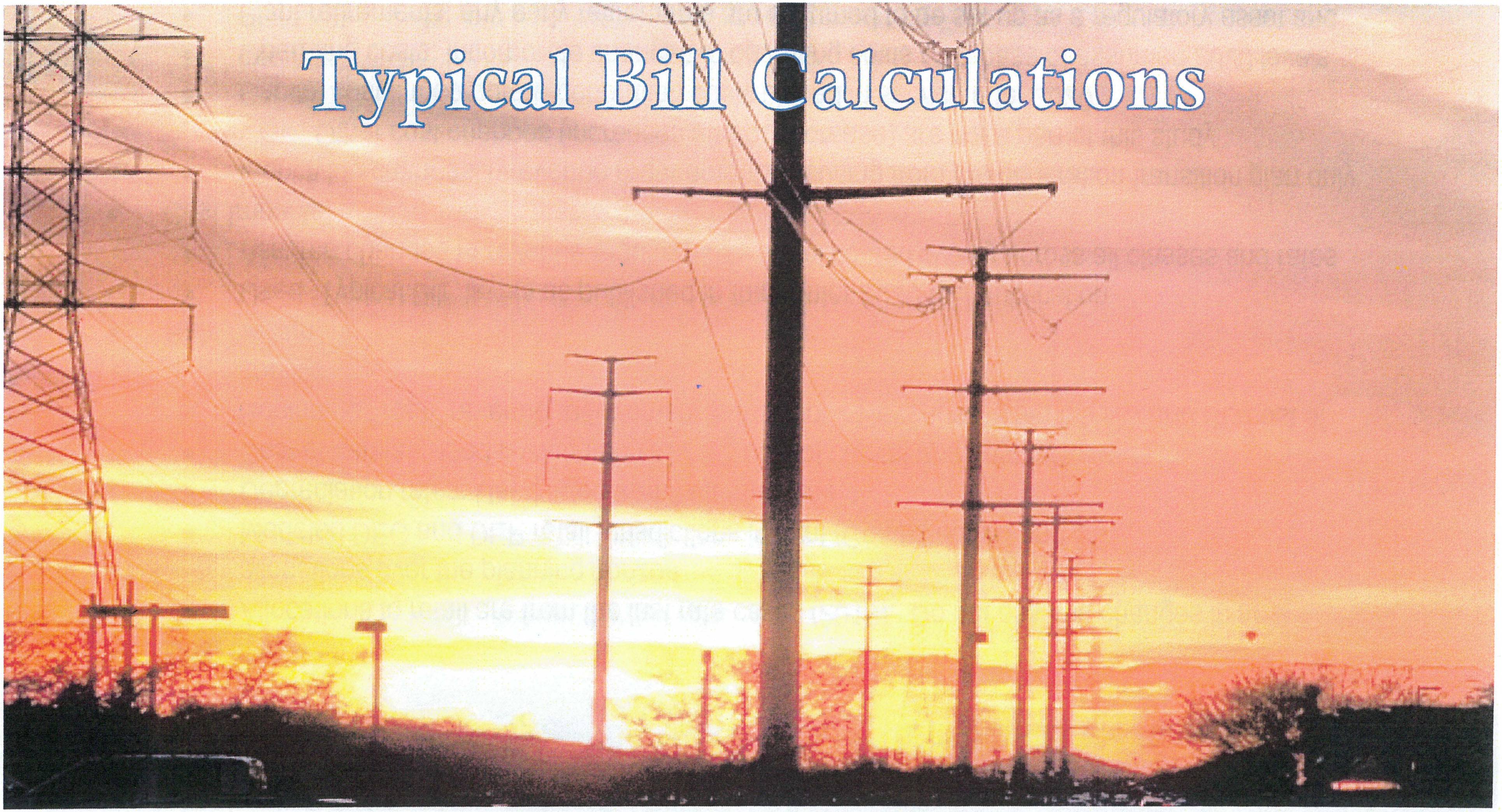
Jul 15 2022

March 2020



Bill Impact Modeling Assumptions

- Cost of service:
  - Allocations to retail are from the last rate cases (2019). Do not assume changes in any allocations over the planning horizon
  - Modeled DEC and DEP retail jurisdictions in total (Combined NC and SC)
  - Depreciation rates: Used rates from last rate case
  - Cost of capital: Used a weighted NC / SC cost of capital from last rate cases
  - Beginning "Total" revenue requirement is the "Book Revenues" from the NC and SC cost of service
- Rate Design
  - Used "Typical Bill" levels as published in the Winter 2020 EEI publication
  - Assume changes to revenue requirements are allocated evenly across all classes and rates
- Cost Impacts
  - Identifying changes in revenue requirements resulting from the generation transition plan only
    - Other cost changes (increases and/or decrease) are not a part of this study
  - Capital costs: Incorporate generation costs placed in service after 2020
  - Operating costs: Incorporate changes in operating costs off a base of assumed 2020 levels
  - Plant retirements: any early retirements are assumed to be set up as a regulatory asset and amortized at same rate as was being depreciated (i.e. no revenue requirement impact)
- Retail sales
  - Total retail sales are aligned with the 2020 IRP's

Estimated Bill Impacts

	DEC		DEP	
	January 1 2020 Typical Bill	2030 Change Base IRP	January 1 2020 Typical Bill	2030 Change Base IRP
RESIDENTIAL				
Household using 1,000 KWh	$ 111	$ 7	$ 116	$ 13
COMMERCIAL				
375 KWh	$ 66	$ 4	$ 70	$ 8
1500 KWH	$ 202	$ 12	$ 185	$ 21
10,000 KWh / 40 KW	$ 896	$ 55	$ 934	$ 105
14,000 KWh / 40 KW	$ 1,019	$ 62	$ 1,153	$ 130
150,000 KWh / 500 KW	$ 11,895	$ 726	$ 13,432	$ 1,512
180,000 KWh / 500 KW	$ 12,561	$ 767	$ 15,241	$ 1,716
INDUSTRIAL				
15,000 KWh / 75 KW	$ 1,416	$ 86	$ 1,666	$ 188
30,000 KWh / 75 KW	$ 2,075	$ 127	$ 2,564	$ 289
50,000 KWh / 75 KW	$ 2,947	$ 180	$ 3,720	$ 419
200,000 KWh / 1,000 KW	$ 17,657	$ 1,078	$ 25,634	$ 2,886
400,000 KWh / 1,000 KW	$ 27,495	$ 1,678	$ 37,958	$ 4,273
650,000 KWh / 1,000 KW	$ 37,683	$ 2,300	$ 50,675	$ 5,705
15,000,000 KWh / 50,000 KW	$ 1,000,725	$ 61,070	$ 1,491,705	$ 167,928
25,000,000 KWh / 50,000 KW	$ 1,414,303	$ 86,310	$ 2,107,917	$ 237,298
32,500,000 KWh / 50,000 KW	$ 1,743,561	$ 106,403	$ 2,435,641	$ 274,192
Average Annual Percentage Change		0.7%		1.2%

Incorporating Transmission and Distribution costs

The 14.7 billion is a 5 year total for total T&D costs for both DEC and DEP. The DEC equivalent is 9 billion.

Of the 9 billion – approximately 3 billion is Grid Improvement plan for DEC

To calculate the rate impact including the T&D costs:

- G.I.P. – used the 5 years totaling ~3 billion in the first five years. No costs were assumed after the 5 years
- Other Distribution – used the expected capital investments in the first first five years. For the remaining study period, used the average annual investment from the first five years
- Transmission – used the expected capital investments in the first five years. For the remaining study period, used the average annual investment from the first five years

Cost Allocations:

- distribution costs (G.I.P. and other expansion/reliability/maint/etc) were allocated to Residential, Commercial, and other
- Transmission costs were allocated to all customer classes

Built the revenue requirement up from the IRP base case

Have not yet considered the depreciation of existing rate base

Bill Impacts

Class	IRP Base Plan Avg Annual Impact		All T&D (Incl Grid Mod) Avg Annual Impact		Total Impacts Avg Annual Impact		Average Monthly Bill			Average Monthly increase in average bill	
	2030	2035	2030	2035	2030	2035	2020	2030	2035	2020 to 2030	2030 to 2035
RESIDENTIAL	0.7%	1.3%	2.3%	1.7%	3.0%	3.0%	$ 111	$ 145	$ 168	$ 4	$ 6
COMMERCIAL	0.7%	1.3%	2.3%	1.7%	3.0%	3.0%	$ 12,561	$ 16,362	$ 19,019	$ 422	$ 664
INDUSTRIAL	0.7%	1.3%	0.3%	0.2%	0.9%	1.6%	$ 1,743,561	$ 1,895,144	$ 2,170,071	$ 16,843	$ 68,732

FROM THE 2020 WINTER EEI TYPICAL BILL PUBLICATION

Residential - 1,000 KWh per month
Commercial - 180,000 KWh / 500 KW
Industrial - 32,500,000 KWh / 50,000 KW

Industrial Bill Impacts

Cumulative Inflation Rates	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IRP Base Case	0%	2%	3%	3%	3%	3%	3%	4%	5%	6%
All costs	0%	2%	4%	4%	4%	4%	5%	6%	7%	9%

IRP Base Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industrial - 15,000 KWh / 75 KW	$ 1,416	$ 1,443	$ 1,457	$ 1,461	$ 1,458	$ 1,454	$ 1,465	$ 1,476	$ 1,485	$ 1,502
Industrial - 30,000 KWh / 75 KW	$ 2,075	$ 2,114	$ 2,135	$ 2,141	$ 2,136	$ 2,131	$ 2,147	$ 2,163	$ 2,176	$ 2,202
Industrial - 50,000 KWh / 75 KW	$ 2,947	$ 3,003	$ 3,032	$ 3,040	$ 3,034	$ 3,026	$ 3,050	$ 3,072	$ 3,090	$ 3,127
Industrial - 200,000 KWh / 1,000 KW	$ 17,656	$ 17,992	$ 18,169	$ 18,215	$ 18,178	$ 18,133	$ 18,271	$ 18,408	$ 18,513	$ 18,735
Industrial - 400,000 KWh / 1,000 KW	$ 27,493	$ 28,016	$ 28,292	$ 28,364	$ 28,306	$ 28,236	$ 28,452	$ 28,665	$ 28,828	$ 29,173
Industrial - 650,000 KWh / 1,000 KW	$ 37,680	$ 38,397	$ 38,775	$ 38,874	$ 38,795	$ 38,699	$ 38,994	$ 39,286	$ 39,510	$ 39,983
Industrial - 15,000,000 KWh / 50,000 KW	$ 1,000,652	$ 1,019,685	$ 1,029,729	$ 1,032,354	$ 1,030,256	$ 1,027,693	$ 1,035,545	$ 1,043,293	$ 1,049,242	$ 1,061,795
Industrial - 25,000,000 KWh / 50,000 KW	$ 1,414,200	$ 1,441,099	$ 1,455,293	$ 1,459,003	$ 1,456,038	$ 1,452,416	$ 1,463,513	$ 1,474,464	$ 1,482,871	$ 1,500,613
Industrial - 32,500,000 KWh / 50,000 KW	$ 1,743,434	$ 1,776,595	$ 1,794,094	$ 1,798,668	$ 1,795,012	$ 1,790,547	$ 1,804,228	$ 1,817,728	$ 1,828,092	$ 1,849,964

All costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industrial - 15,000 KWh / 75 KW	$ 1,416	$ 1,447	$ 1,467	$ 1,477	$ 1,478	$ 1,476	$ 1,491	$ 1,505	$ 1,518	$ 1,539
Industrial - 30,000 KWh / 75 KW	$ 2,075	$ 2,120	$ 2,150	$ 2,165	$ 2,165	$ 2,163	$ 2,184	$ 2,206	$ 2,224	$ 2,255
Industrial - 50,000 KWh / 75 KW	$ 2,947	$ 3,011	$ 3,053	$ 3,075	$ 3,075	$ 3,071	$ 3,102	$ 3,133	$ 3,159	$ 3,203
Industrial - 200,000 KWh / 1,000 KW	$ 17,657	$ 18,043	$ 18,292	$ 18,422	$ 18,425	$ 18,402	$ 18,588	$ 18,773	$ 18,925	$ 19,192
Industrial - 400,000 KWh / 1,000 KW	$ 27,495	$ 28,096	$ 28,484	$ 28,686	$ 28,691	$ 28,655	$ 28,944	$ 29,233	$ 29,470	$ 29,885
Industrial - 650,000 KWh / 1,000 KW	$ 37,683	$ 38,506	$ 39,038	$ 39,315	$ 39,322	$ 39,273	$ 39,669	$ 40,065	$ 40,390	$ 40,959
Industrial - 15,000,000 KWh / 50,000 KW	$ 1,000,725	$ 1,022,590	$ 1,036,709	$ 1,044,075	$ 1,044,248	$ 1,042,946	$ 1,053,474	$ 1,063,973	$ 1,072,608	$ 1,087,727
Industrial - 25,000,000 KWh / 50,000 KW	$ 1,414,303	$ 1,445,204	$ 1,465,159	$ 1,475,568	$ 1,475,813	$ 1,473,973	$ 1,488,851	$ 1,503,690	$ 1,515,893	$ 1,537,261
Industrial - 32,500,000 KWh / 50,000 KW	$ 1,743,561	$ 1,781,656	$ 1,806,257	$ 1,819,089	$ 1,819,390	$ 1,817,122	$ 1,835,465	$ 1,853,758	$ 1,868,802	$ 1,895,144

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retirements										
DE Progress							**Roxboro 3,4** *(1,409 MW)* *Original – 2027*	**Roxboro 1,2** *(1,053 MW)* *Original – 2028*	**Mayo** *(746 MW)* *Original – 2028*	
DE Carolinas			**Allen 1,5** *(426 MW)* *Original – 2023*			**Marshall 1, 2** *(760MW)* *Original – 2034*		**Cliffside 5** *(546 MW)* *Original – 2025*		
Replacement Generation – On-Site *(in service dates)*										
DE Progress							*1st 2x1 CC - 1,224 MW*	*2nd CC 1,224 MW* *120 MW Solar*	*450 MW BESS* *170 MW Solar*	*300 MW BESS*
DE Carolinas			*20 MW BESS* *70 MW Solar*			*200 MW BESS* *4 CTs - 913 MW*	*150 MW BESS* *30 MW Solar*	*150 MW BESS*		
Off-site Renewables										
Procurement Date	*607 MW*	*607 MW*	*607 MW*	*607 MW*	*607 MW*	*607 MW*	*608 MW*			

**Roxboro retirement requires available dispatchable generation sources. If not available, the final 2000 MW of procurements will be reduced by 70%.*

Public Staff - H591 v10 Analysis $250 M Securitization - July 9, 2021[1, 10]	DEP + DEC				DEP						DEC					
	Base with Carbon Policy		H951 Legislative Impact Analysis		Base with Carbon Policy		H951 Legislative Impact Analysis				Base with Carbon Policy		H951 Legislative Impact Analysis			
PORTFOLIO	B[8]		PS 1		B		PS 1				B		PS 1			
							2030		2035				2030		2035	
Year	2030	2035	2030	2035	2030	2035	Total Cost with H951	Impact of H951[9]	Total Cost with H951	Impact of H951	2030	2035	Total Cost with H951	Impact of H951	Total Cost with H951	Impact of H951
System CO_2 Reduction From 2005 Baseline[2]	59%	62%	62%	64%												
Average Annual Percentage Change in Retail Rates (through 2030 | through 2035)					1.1%	1.3%	1.3%	**0.1%**	1.3%	**0.0%**	0.9%	1.5%	1.4%	**0.4%**	1.6%	**0.1%**
Cumulative Percentage Change in Retail Rates (by 2030 | by 2035)					11%	19%	12%	**1.2%**	20%	**0.8%**	9%	23%	13%	**4.4%**	25%	**2.5%**

Year	DEP + DEC B 2050	DEP + DEC PS 1 2050 Total Cost with H951	DEP + DEC PS 1 2050 Impact of H951[9]	DEP B 2050	DEP PS 1 2050 Total Cost with H951	DEP PS 1 2050 Impact of H951	DEC B 2050	DEC PS 1 2050 Total Cost with H951	DEC PS 1 2050 Impact of H951
Present Value Revenue Requirement by 2050 (PVRR) [$B][3]	$82.5	$88.3	**$5.8**	$35.7	$37.1	**$1.4**	$46.8	$51.2	**$4.4**
Estimated Transmission Investment [$B][4]	$1.2	$1.8	**$0.5**	$0.5	$0.4	**-$0.1**	$0.8	$1.4	**$0.6**

Year	DEP + DEC B 2035	DEP + DEC PS 1 2035 Total Cost with H951	DEP + DEC PS 1 2035 Impact of H951	DEP B 2035	DEP PS 1 2035 Total Cost with H951	DEP PS 1 2035 Impact of H951	DEC B 2035	DEC PS 1 2035 Total Cost with H951	DEC PS 1 2035 Impact of H951
Total Solar [MW] by 2035[5]	12,187	15,656	**3,469**	3,372	3,687	**315**	4,890	8,044	**3,154**
New Onshore Wind [MW] by 2035	750	1,050	**300**	600	600	**0**	150	450	**300**
New Offshore Wind [MW] by 2035	0	0	**0**	0	0	**0**	0	0	**0**
New Total Storage [MW] by 2035[6]	2,140	2,391	**251**	1,562	1,332	**-230**	578	1,059	**480**
New Standalone Storage [MW] by 2035	1,313	1,605	**292**	1,152	940	**-212**	161	665	**504**
New PV-Coupled Storage [MW] by 2035	827	786	**-41**	410	393	**-18**	417	394	**-23**
New Gas [MW] by 2035	7,328	6,868	**-460**	4,276	4,274	**-2**	3,052	2,594	**-458**
Total EE and DSM Contribution [MW] by 2035	2,050	2,050	**0**	825	825	**0**	1,225	1,225	**0**
Coal Retirements[7]	Most Economic	Per Legislation		Most Economic	Per Legislation		Most Economic	Per Legislation	

Notes

1] The Public Staff bill impact analysis excludes the following portions of the bill as infeasible to quantify due to unknown factors, likely negligible impacts, or no change from the IRP:
- PBR and MYRR, with the exception of the assumption that the maximum PIM would be claimed in each year; Section 8 small power producers contract revisions; Solar Choice Tariff; solar leasing cap change (62-126.5(d)); fuel rider change (62-133.2(d)); nuclear Early Site Permit costs above $50 million (Section 3.(a)); nuclear Subsequent License Renewals (Section 3.(b)); Green Source Advantage for UNC and military customers change to bill credit options.
-The analysis presented here does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions, such as Duke's Grid Improvement Plan.

2] Combined DEC/DEP System CO_2 Reductions from 2005 baseline

3] Represents specific IRP portfolio's incremental costs included in IRP analysis through 2050, and exclude the cost of CO_2 as a tax.

4] Represents PVRR of network upgrades required to integrate new resources and coal transmission retirement costs. Included in PVRR figures.

5] Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected). Total solar under the legislation may be less than projected due to how Transition MW is defined and Duke's projected renewable capacity online by January 1, 2027.

6] Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro.

7] Most Economic is the retirement plan in the IRP. Per Legislation refers to PS interpretation of required retirement dates: Cliffside 5 is delayed by 5 years; Marshall is accelerated by 8 years. Other retirement dates are unchanged.

8] Portfolio B is from Duke's 2020 IRP, which the Public Staff has recommended the Commission to accept as reasonable for planning purposes (along with Portfolio A, base without carbon policy). Numbers for Portfolio B may not match Duke's filed IRP exactly due to slight differences in in-service years and baseline data.

9] The 'Impact of H951' column shows the incremental cost of H951, which is the difference between the total cost with H951 and the total cost of the Base Case with Carbon Policy (Portfolio B) from Duke's 2020 IRP in the specified year.

10] This analysis includes $250 million in securitization for each utility, rather than the $100 million in version 10. DEC securitizes Allen 1 and 5, Marshall 1, and portions of Marshall 2. DEP securitizes Roxboro.

Public Staff - H591 v10 - $250 M Securitization Detailed Bill Impact Analysis Breakouts[1, 7]	DEP + DEC: Base with Carbon Policy	DEP + DEC: H951 Legislative Impact Analysis	DEP: Base with Carbon Policy		DEP: H951 Legislative Impact Analysis				DEC: Base with Carbon Policy		DEC: H951 Legislative Impact Analysis			
PORTFOLIO	B[5]	PS 1	B		PS 1				B		PS 1			
					2030		2035				2030		2035	
Year			2030	2035	Total Cost with H951	Impact of H951[6]	Total Cost with H951	Impactof H951	2030	2035	Total Cost with H951	Impact of H951	Total Cost with H951	Impact of H951
Average Annual Percentage Change in Retail Rates (through 2030 | through 2035)			1.1%	1.3%	1.3%	**0.1%**	1.3%	**0.0%**	0.9%	1.5%	1.4%	**0.4%**	1.6%	**0.1%**
Cumulative Percentage Change in Retail Rates (by 2030 | by 2035)			11%	19%	12%	**1.2%**	20%	**0.8%**	9%	23%	13%	**4.4%**	25%	**2.5%**
Average Monthly Residential Bill Impact (1,000 kWh/mo) (by 2030 | by 2035)[2]			$9	$17	$11	**$1**	$18	**$1**	$7	$21	$12	**$5**	$24	**$3**
Average Annual Percentage Change in Residential Bills (thru 2030 | thru 2035)			0.8%	1.0%	1.0%	**0.1%**	1.0%	**0.1%**	0.7%	1.2%	1.1%	**0.5%**	1.4%	**0.2%**
Cumulative Percentage Change in Residential Bills (by 2030 | by 2035)			8%	15%	9%	**1.3%**	15%	**0.9%**	6%	19%	11%	**4.5%**	21%	**2.5%**
Average Annual Percentage Change in Commercial Bills (thru 2030 | thru 2035)[3]			1.3%	1.5%	1.5%	**0.2%**	1.6%	**0.1%**	0.9%	1.4%	1.3%	**0.4%**	1.5%	**0.1%**
Cumulative Percentage Change in Commercial Bills (by 2030 | by 2035)			13%	23%	14%	**1.5%**	24%	**1.1%**	8%	21%	12%	**3.9%**	23%	**2.0%**
Average Annual Percentage Change in Industrial Bills (thru 2030 | thru 2035)[4]			1.1%	1.2%	1.1%	**0.1%**	1.2%	**0.0%**	0.9%	1.7%	1.6%	**0.7%**	2.0%	**0.3%**
Cumulative Percentage Change in Industrial Bills (by 2030 | by 2035)			10%	19%	11%	**0.6%**	19%	**-0.1%**	8%	27%	15%	**6.7%**	31%	**4.5%**

Year	DEP + DEC: B 2050	DEP + DEC: PS 1 2050 Total Cost with H951	DEP + DEC: PS 1 2050 Impact of H951	DEP: B 2050	DEP: PS 1 2050 Total Cost with H951	DEP: PS 1 2050 Impact of H951	DEC: B 2050	DEC: PS 1 2050 Total Cost with H951	DEC: PS 1 2050 Impact of H951
Present Value Revenue Requirement (PVRR) [$B]	$82.5	$88.3	**$5.8**	$35.7	$37.1	**$1.4**	$46.8	$51.2	**$4.4**

Notes

1] These allocations to customer classes are based on estimates, and are not as precise as could be determined via a full allocation analysis. Changes in class allocation factors over time are assumed proportional to energy sales.

2] Residential bill impacts are estimated using residential allocation factors.

3] Commercial bill impacts are estimated using commercial allocation factors for small and medium customers.

4] Industrial bill impacts are estimated using industrial allocation factors for small, medium, and large customers.

5] Portfolio B is from Duke's 2020 IRP, which the Public Staff has recommended the Commission to accept as reasonable for planning purposes (along with Portfolio A, base without carbon policy).

6] The 'Impact of H951' column shows the incremental cost of H951, which is the difference between the total cost with H951 and the total cost of the Base Case with Carbon Policy (Portfolio B) from Duke's 2020 IRP in the specified year.

7] This analysis includes $250 million in securitization for each utility, rather than the $100 million in version 10. DEC securitizes Allen 1 and 5, Marshall 1, and portions of Marshall 2. DEP securitizes Roxboro.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

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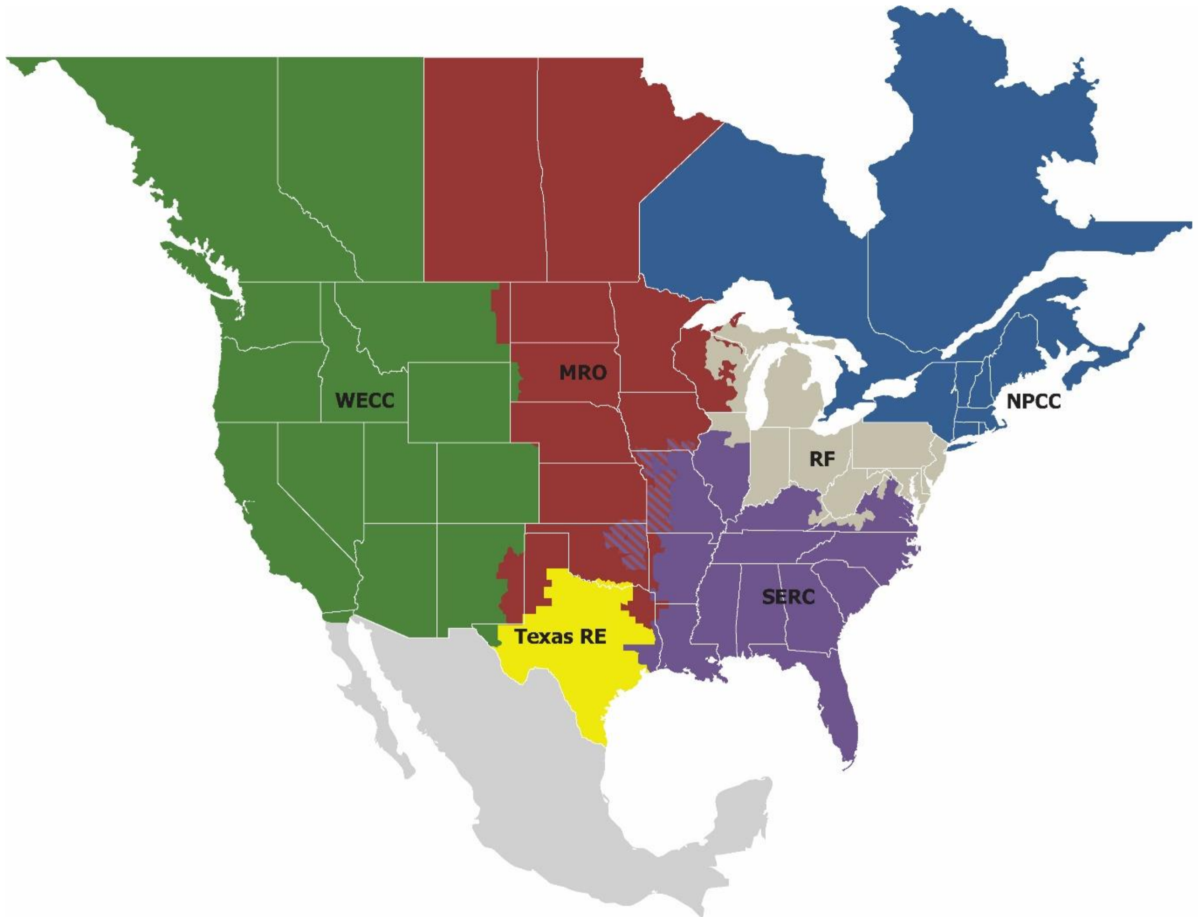
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes as well as highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

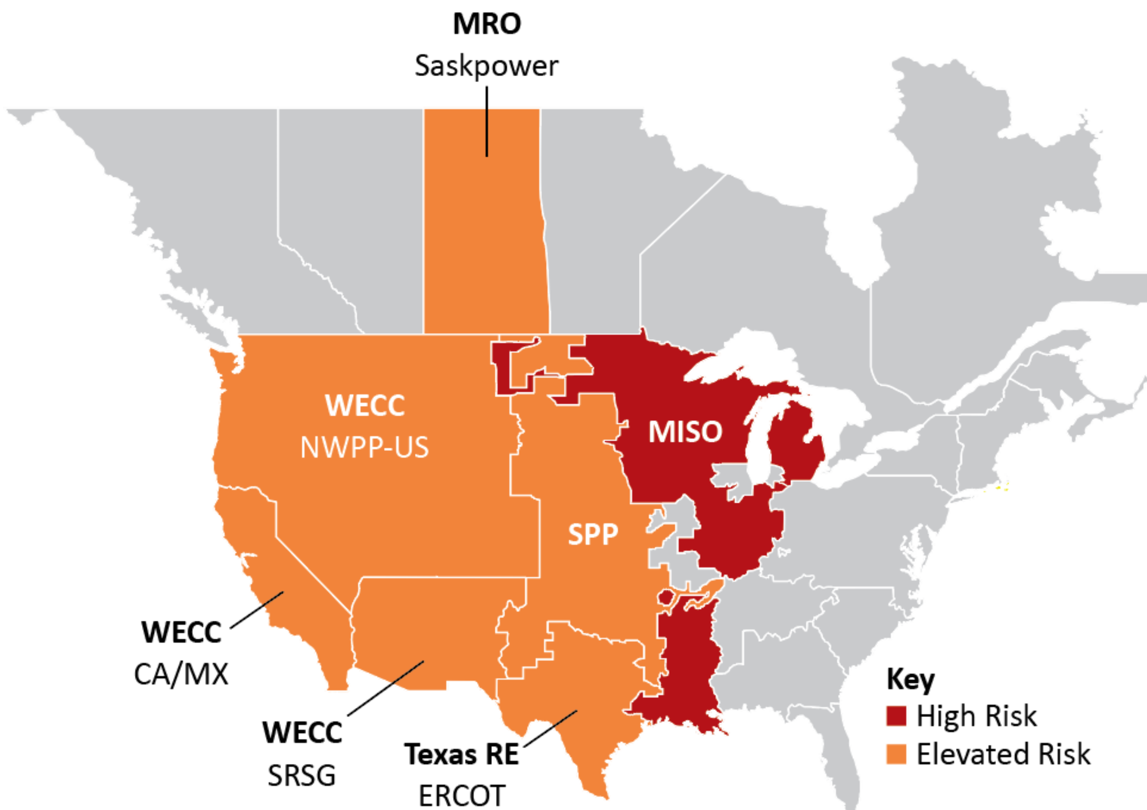


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.
- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.
- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see **Figure 2**). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

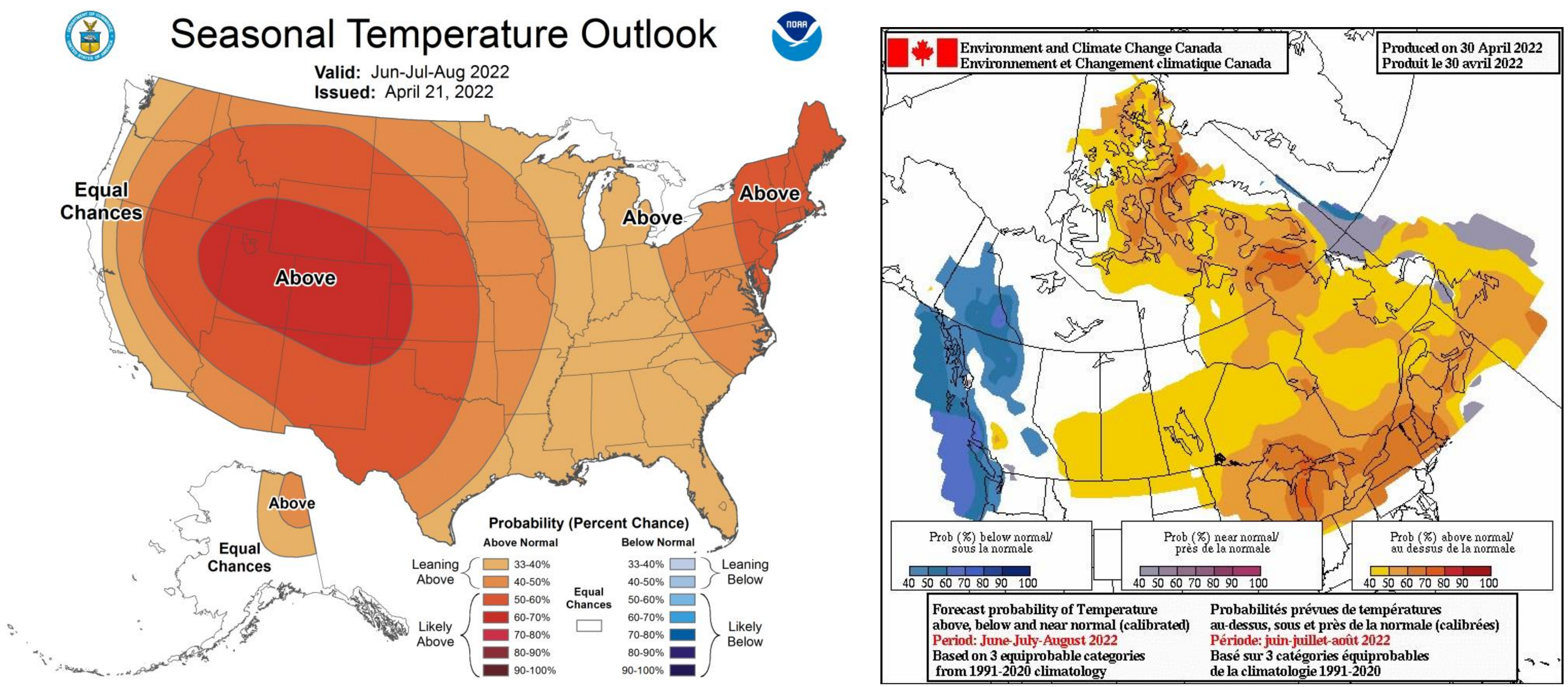


Figure 2: United States and Canada Summer Temperature Outlook[2]

[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

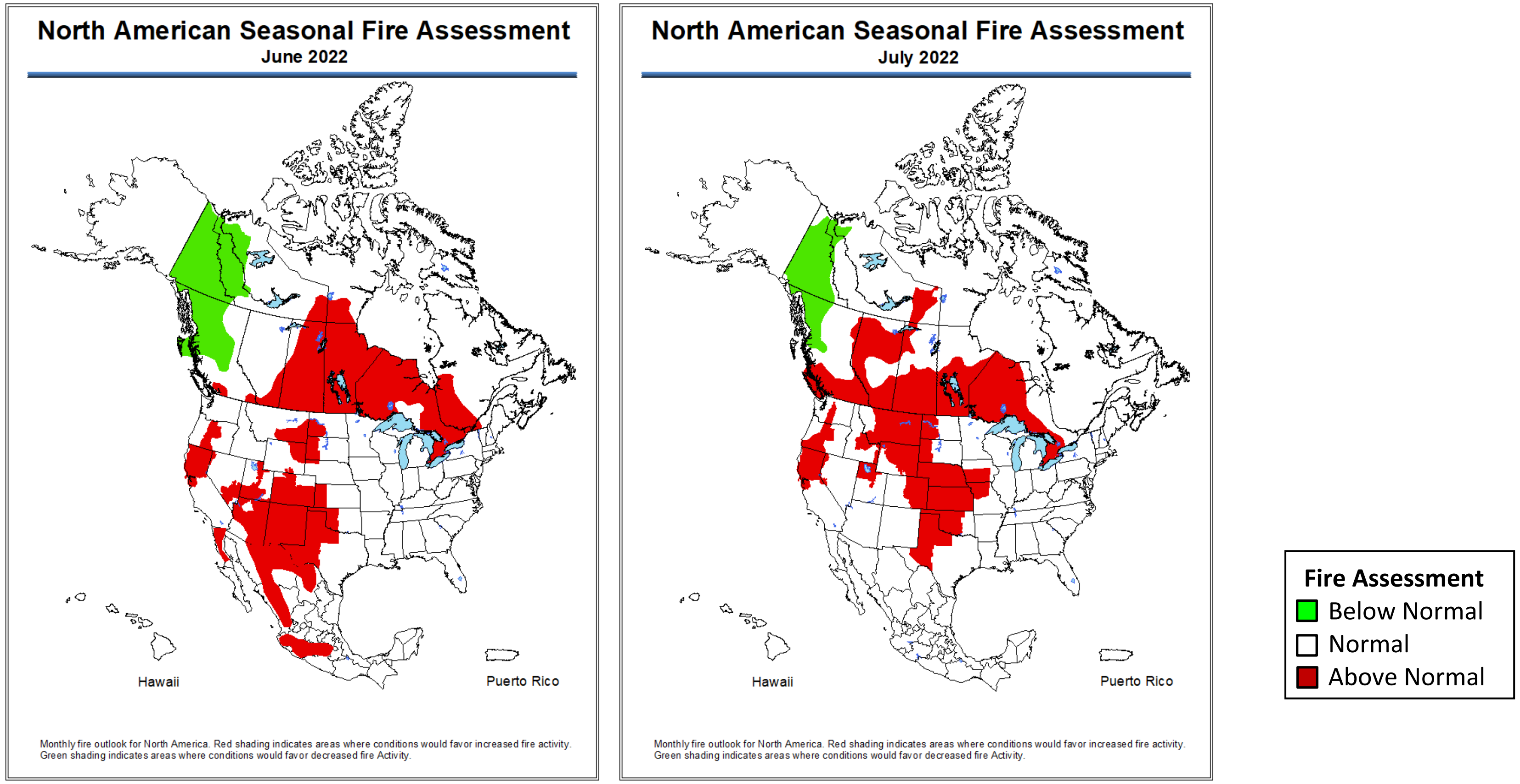


Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation

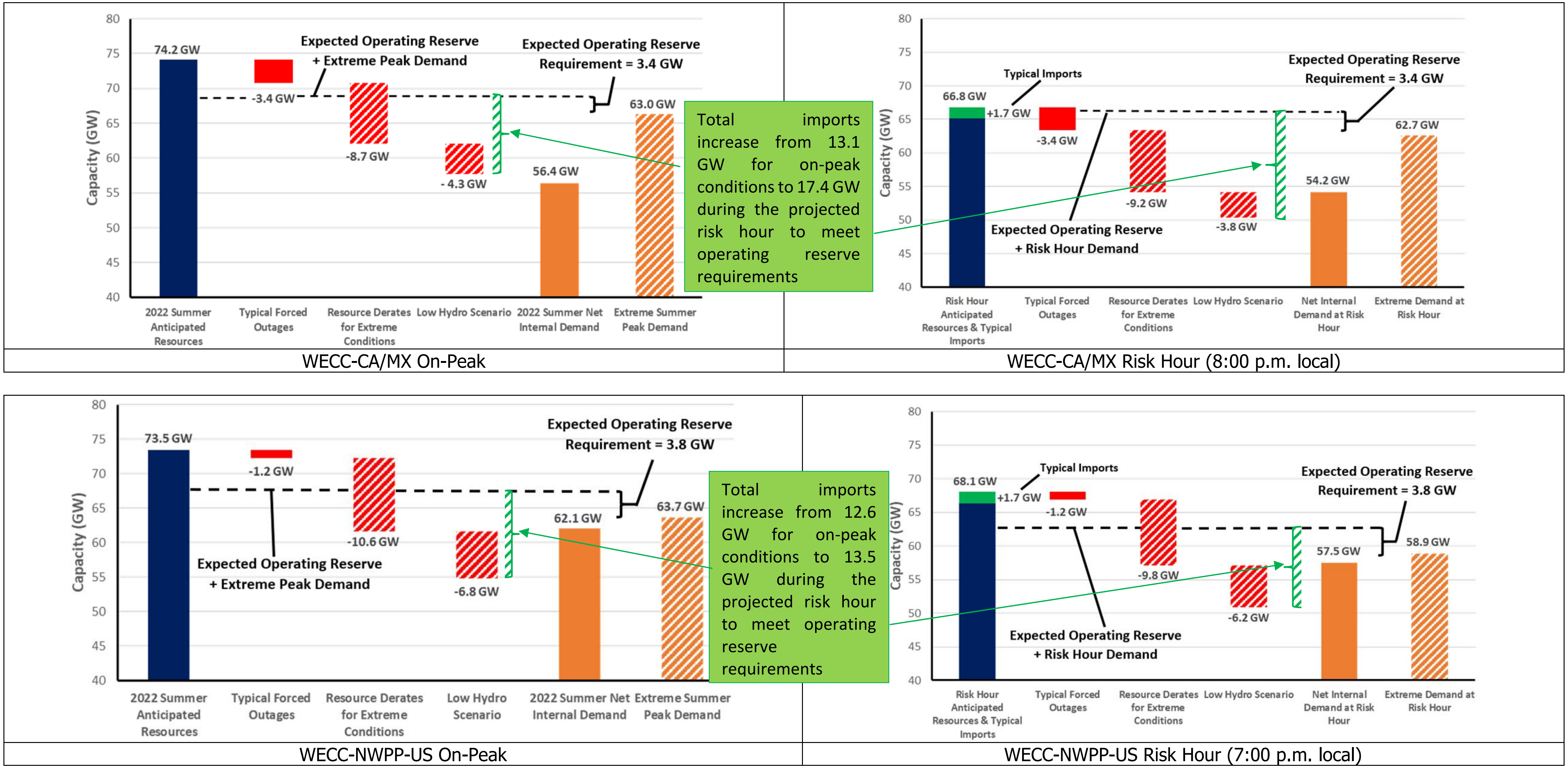


Figure 4: Risk Scenarios for WECC U.S. Assessment Areas

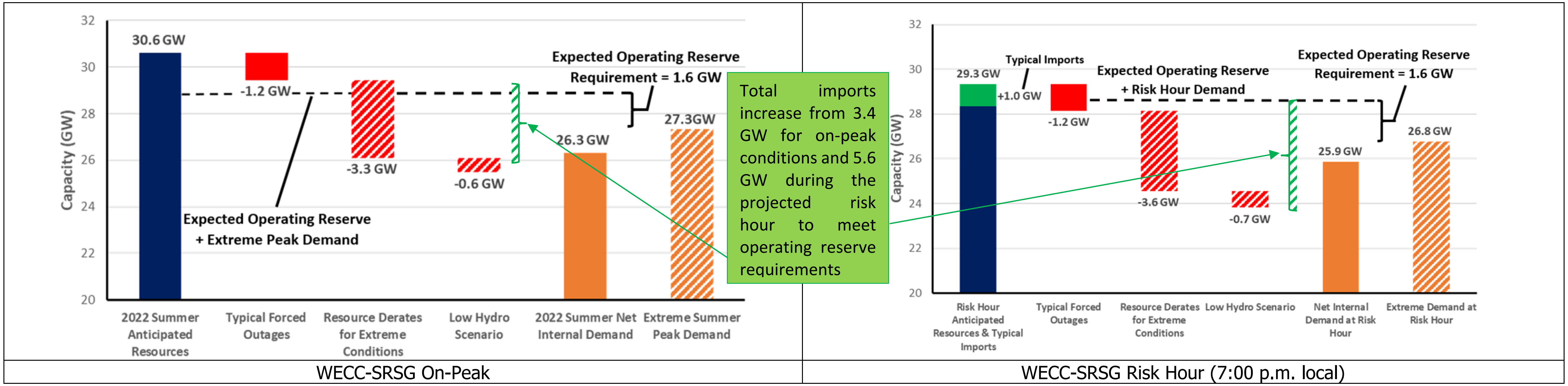


Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

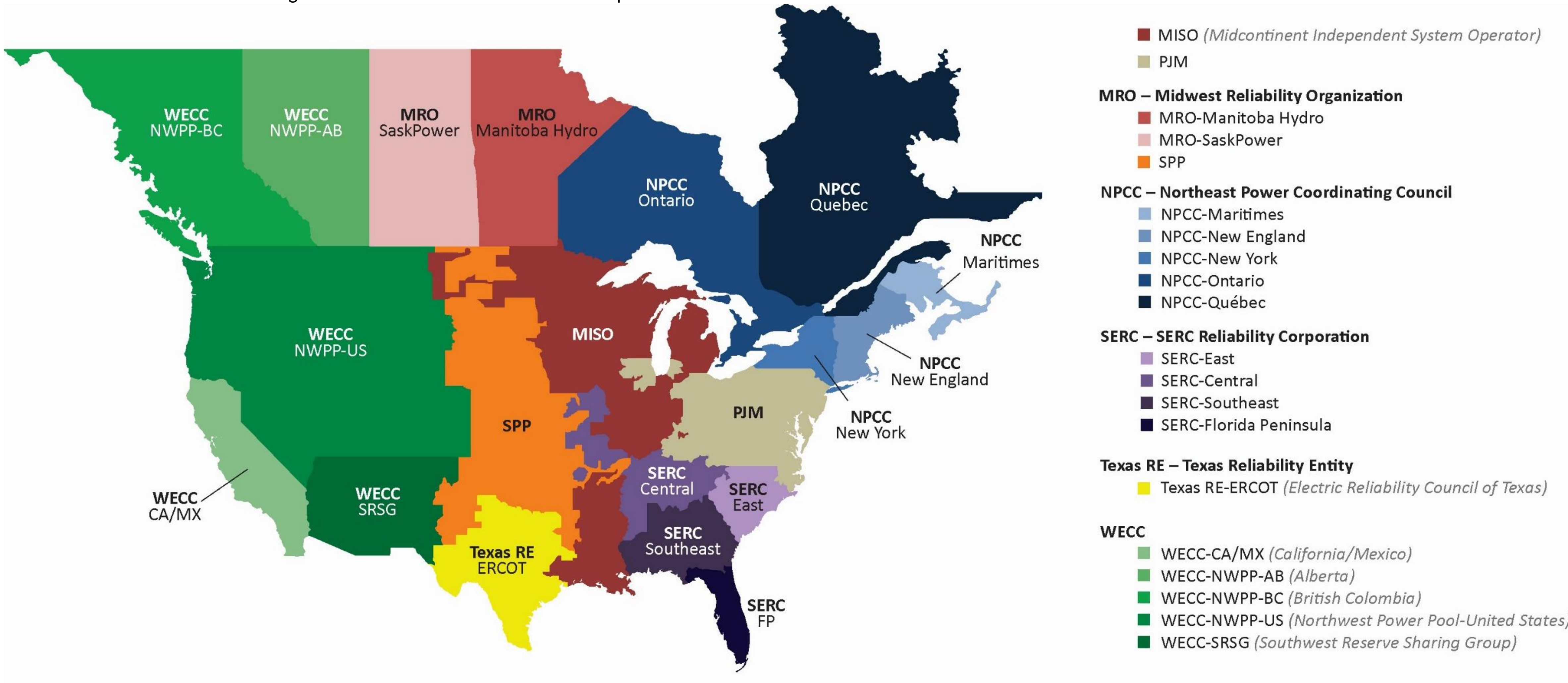
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like these are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

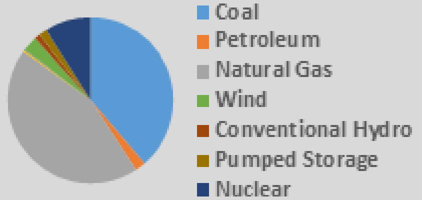
Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



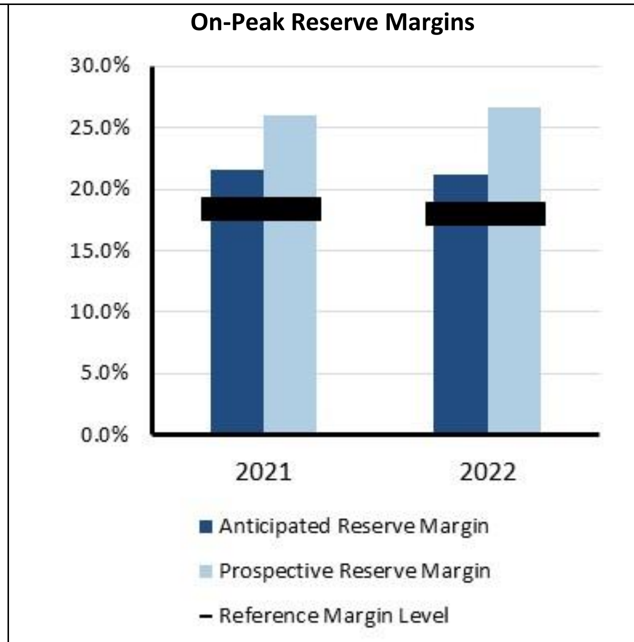


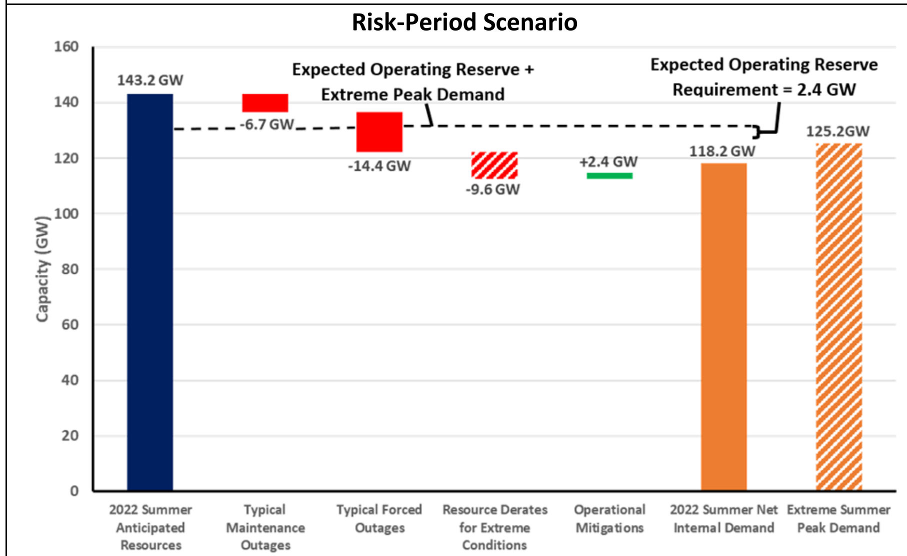
Highlights

- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

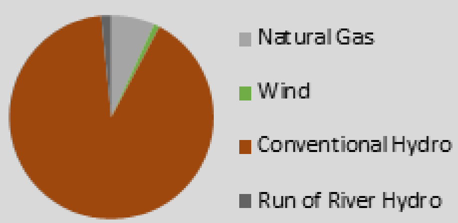
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum of last five years of outages

Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions



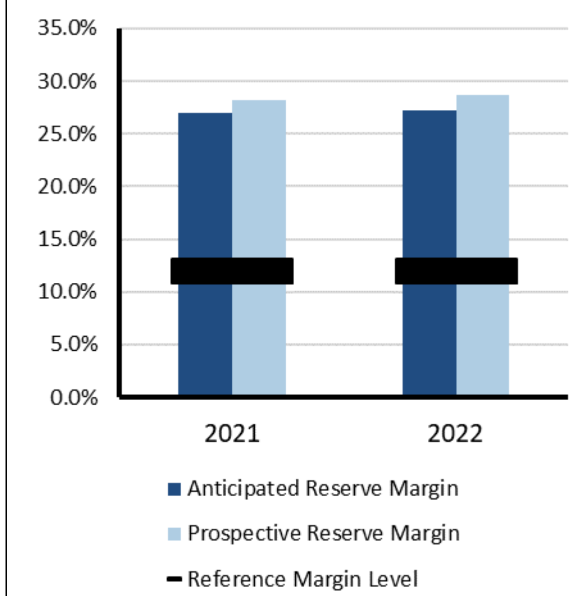
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

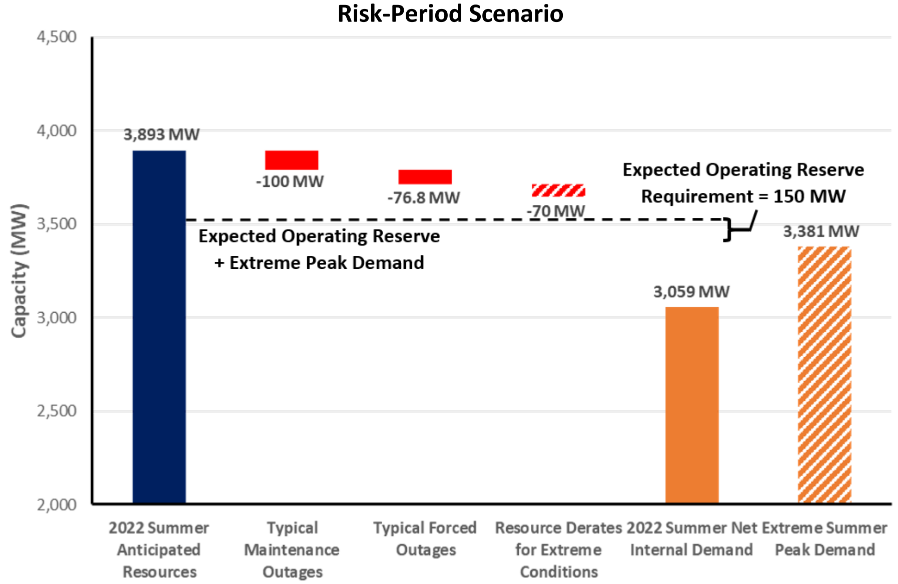
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



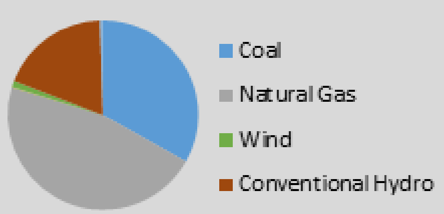
Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates

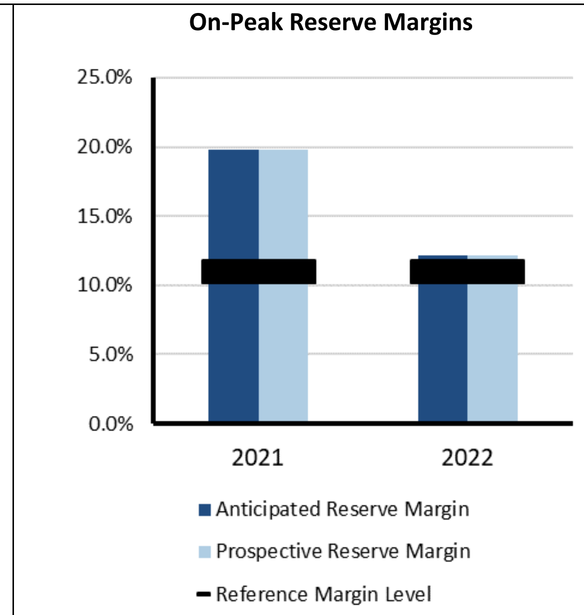


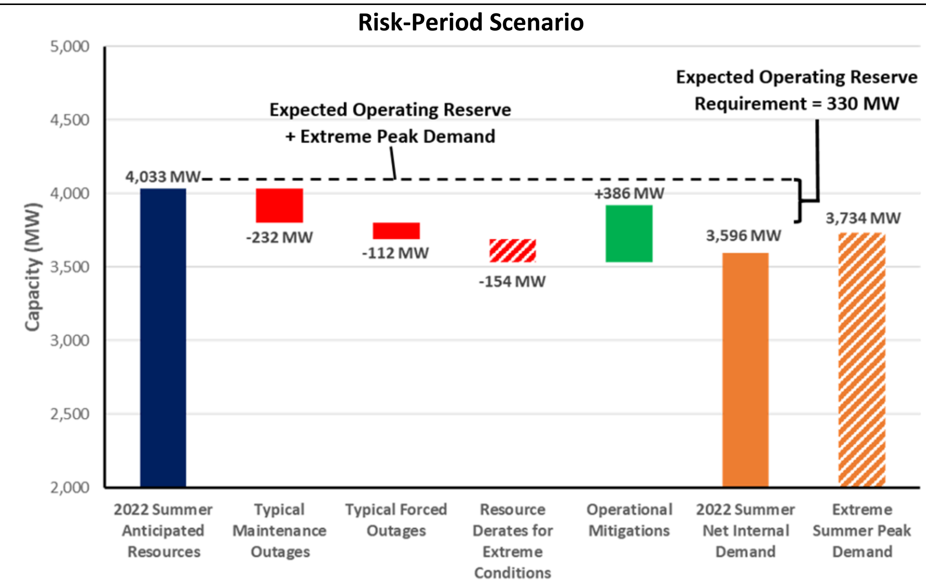
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.





Scenario Description (See Data Concepts and Assumptions)

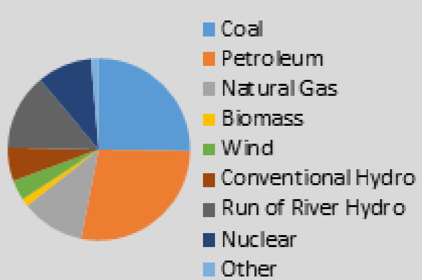
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

Forced Outages: Estimated by using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer

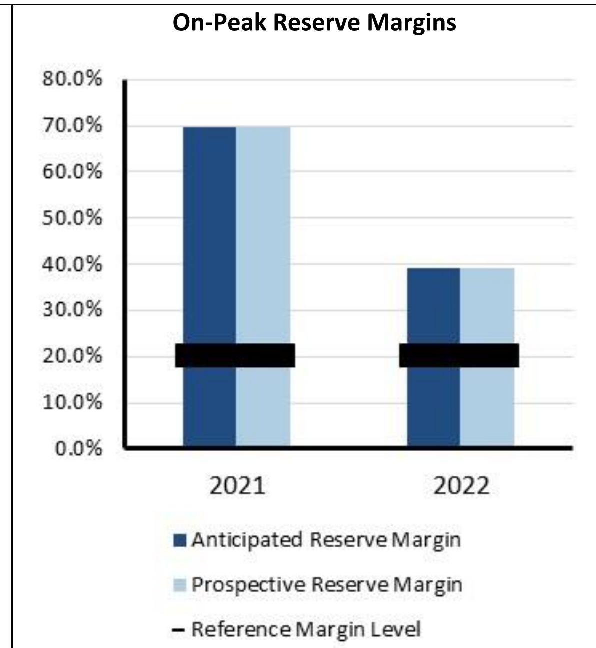


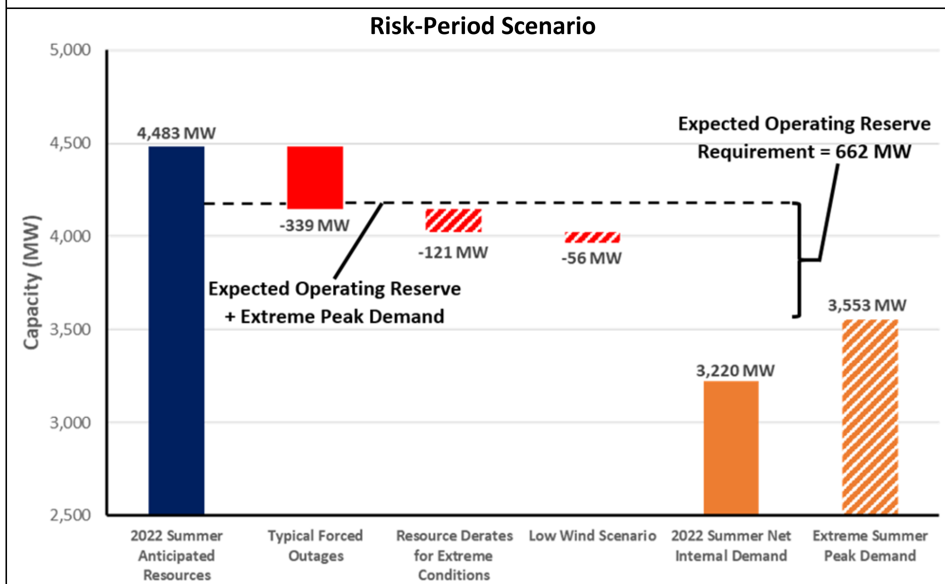
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.





Scenario Description (See Data Concepts and Assumptions)

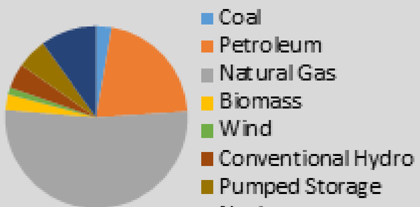
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (99/1) extreme demand forecast

Outages: Based on historical operating experience

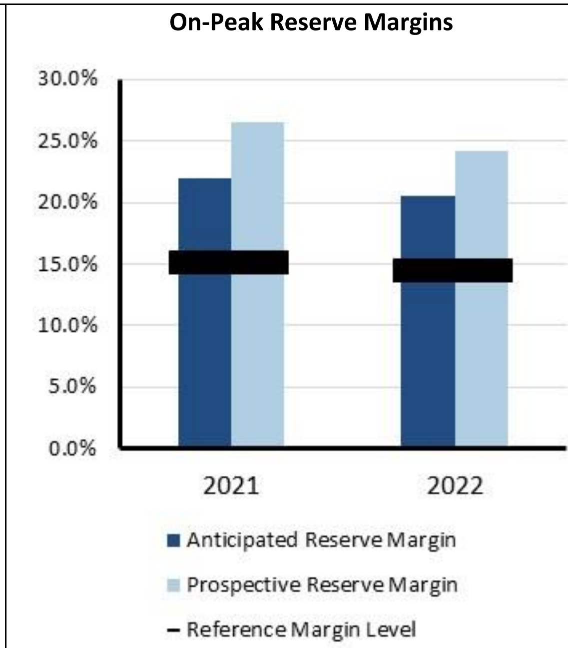
Extreme Derates: Based on historical data for ambient temperature thermal de-rates

Low Wind Scenario: A low-likelihood scenario resulting in no wind resources



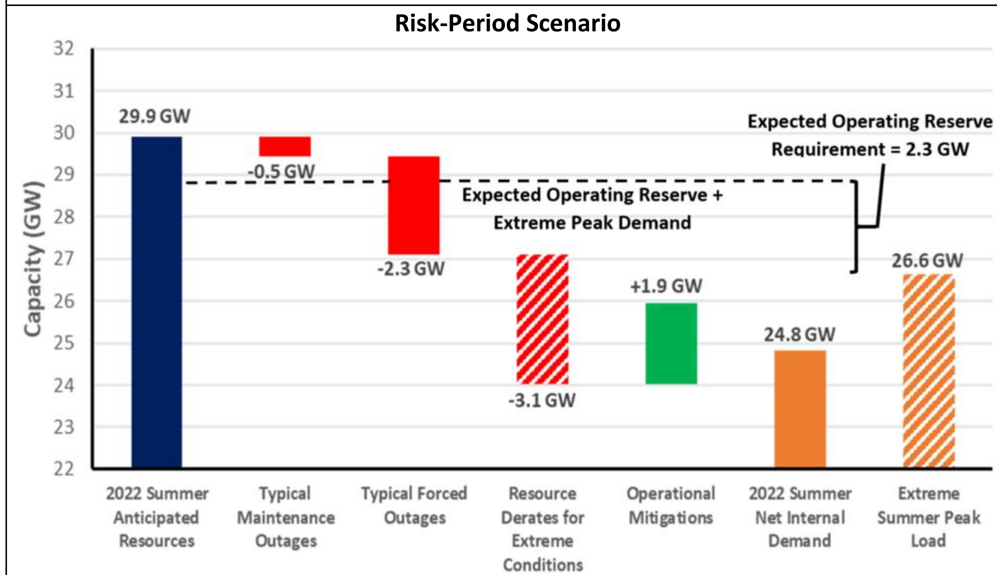
Highlights

- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.



Scenario Description (See [Data Concepts and Assumptions])

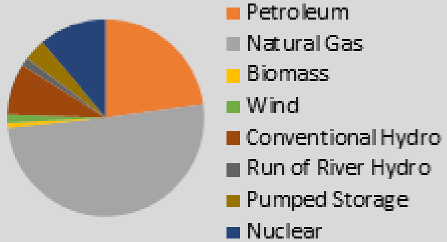
Risk Period: Highest risk for unserved energy occurs at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

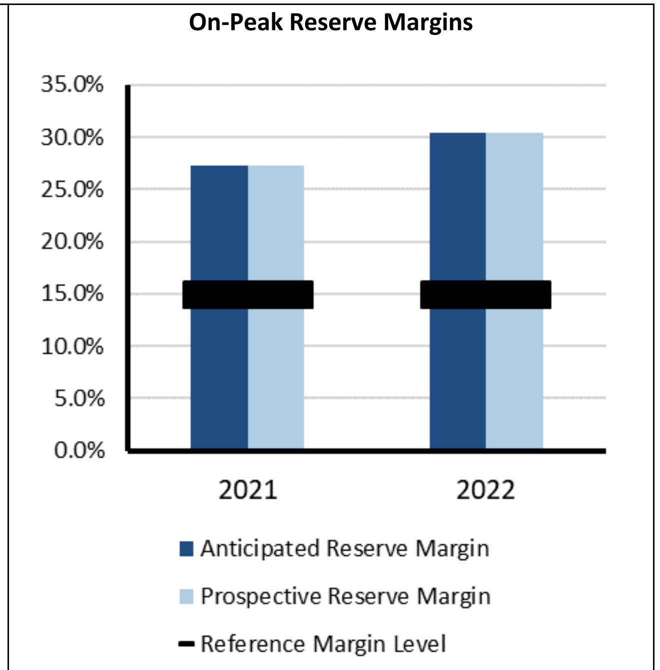
Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



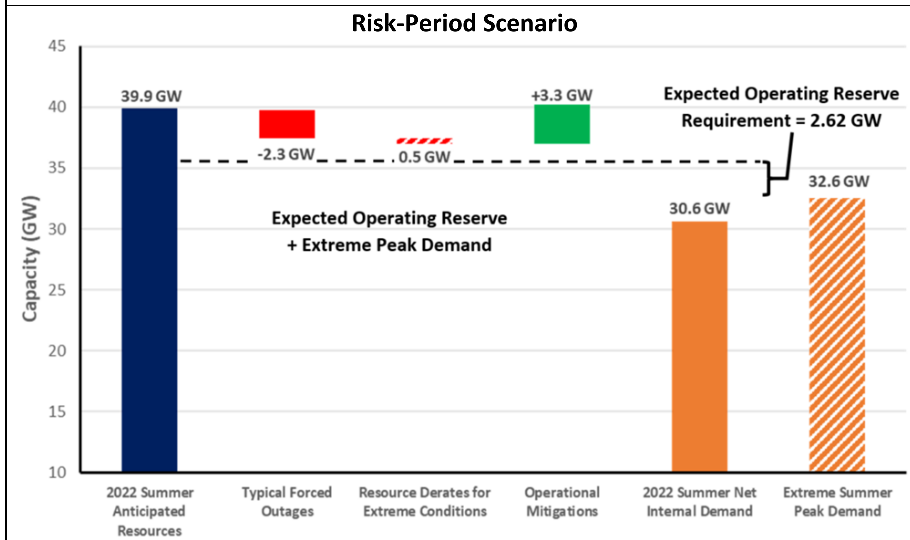
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.



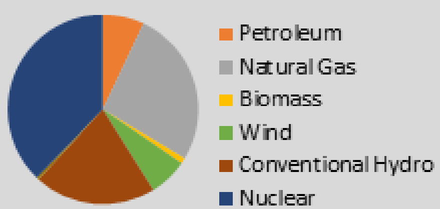
Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Forced Outages: Based on historical 5-year averages

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*



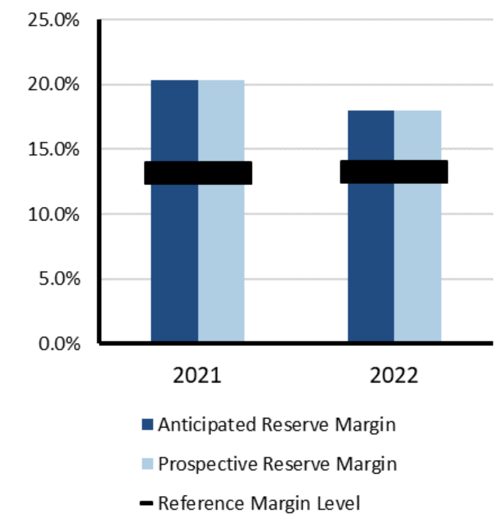
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

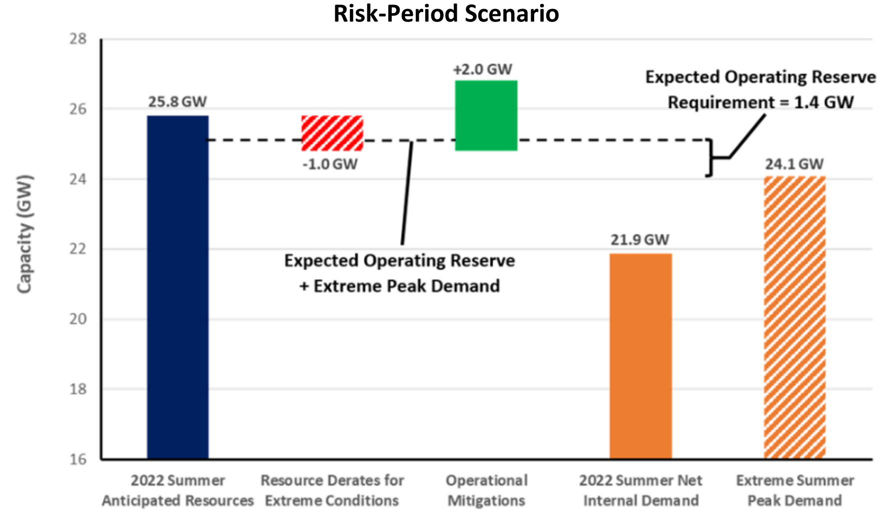
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



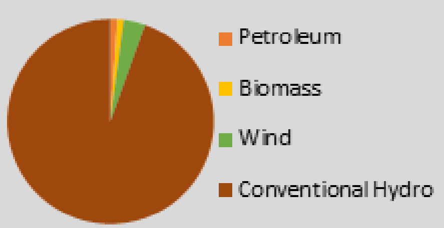
Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



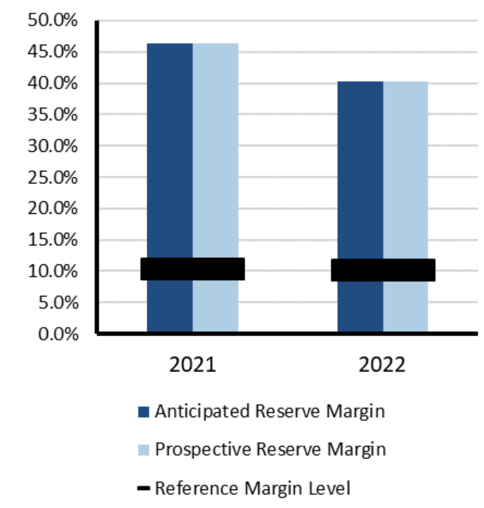
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

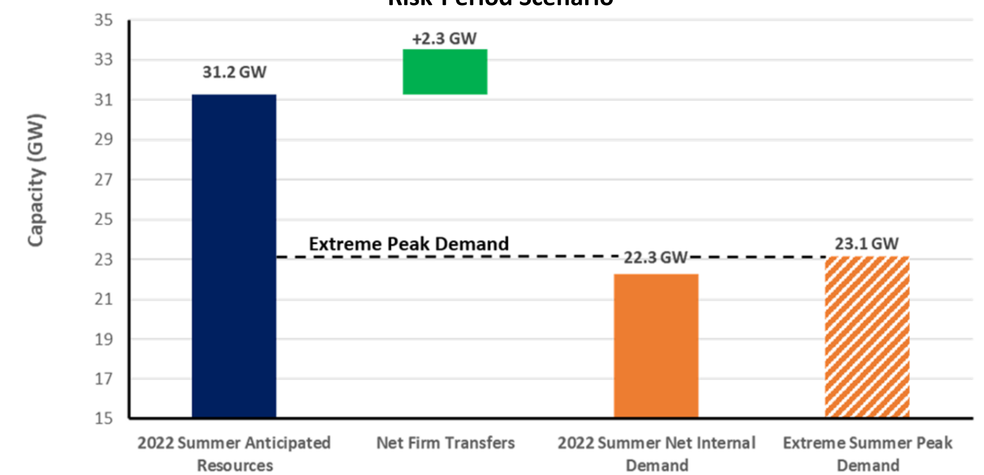
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario

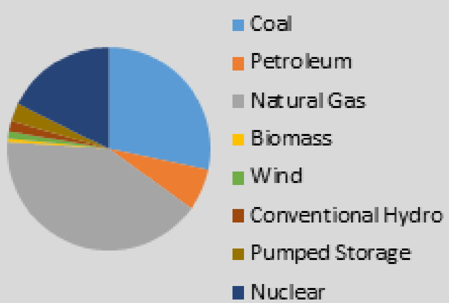


Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Imports anticipated from neighbors during emergencies

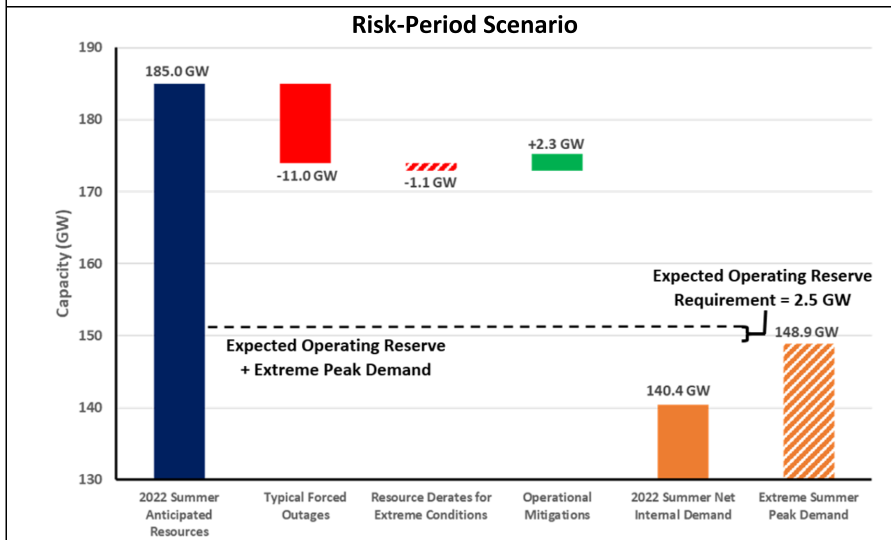


Highlights

- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.



Scenario Description (See [Data Concepts and Assumptions](#))

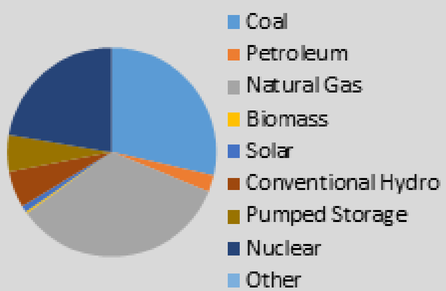
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.3 GW based on operational/emergency procedures

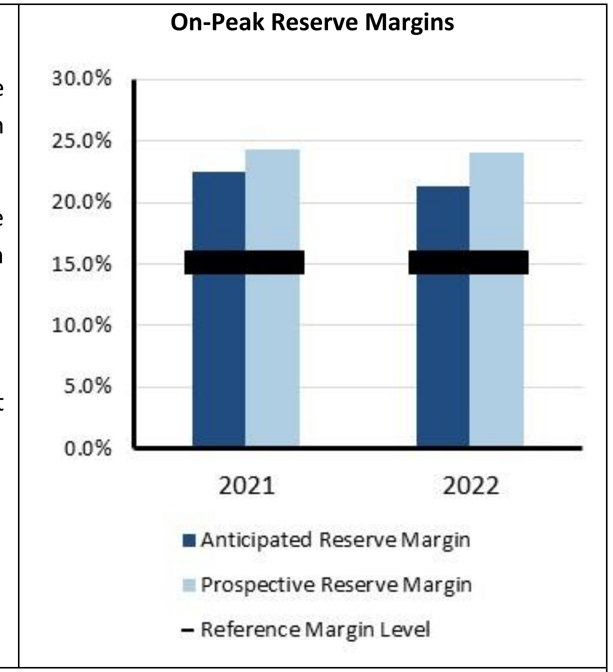


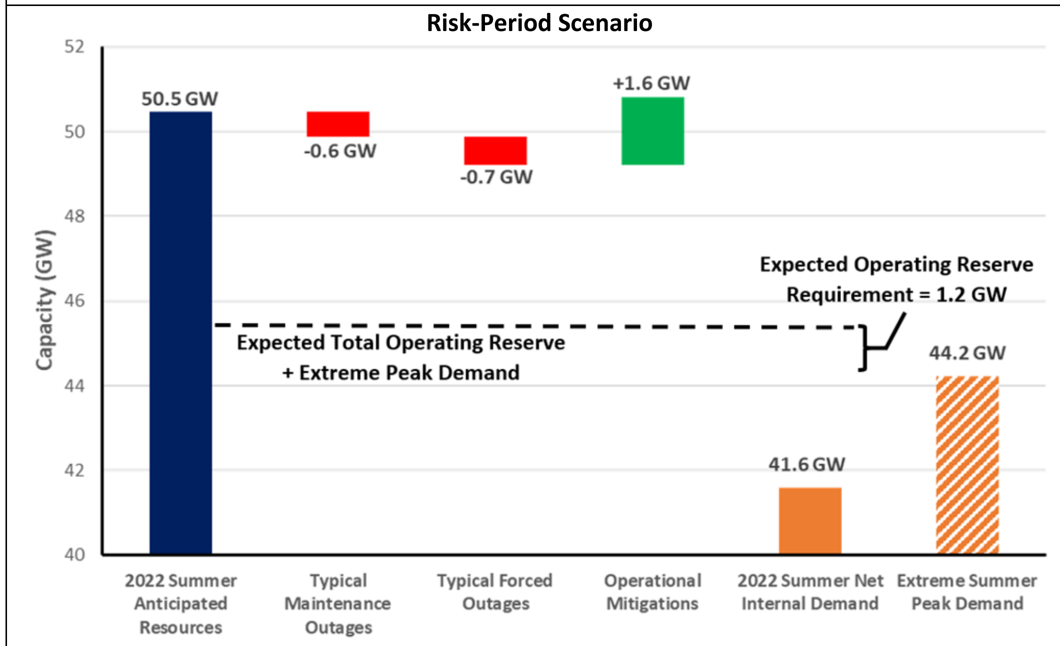
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description (See Data Concepts and Assumptions)

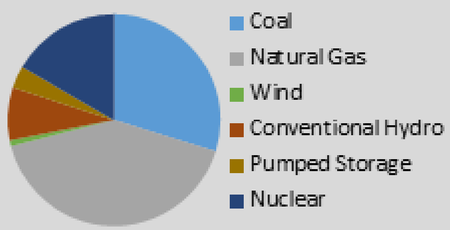
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures

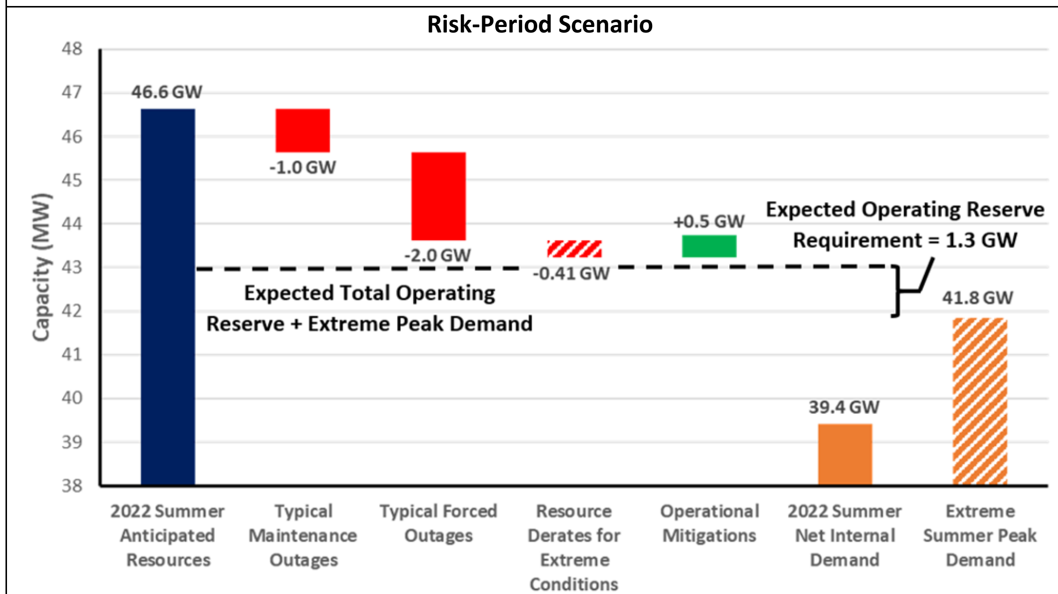


Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.



Scenario Description (See [Data Concepts and Assumptions])

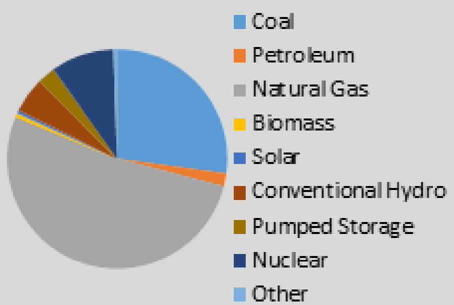
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

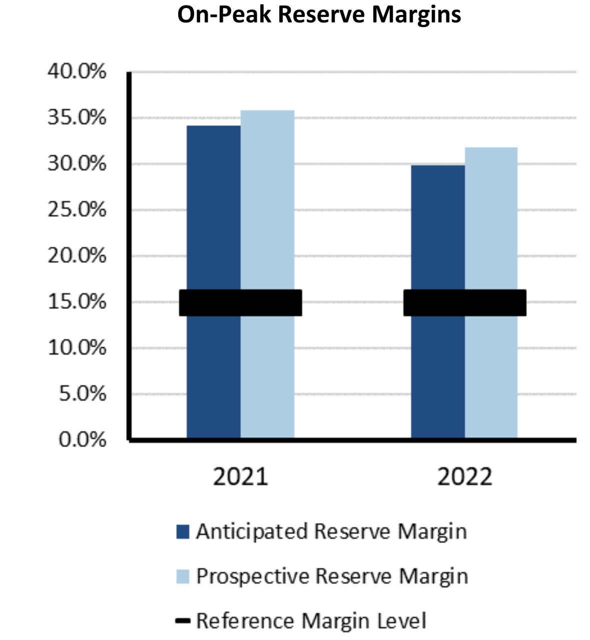


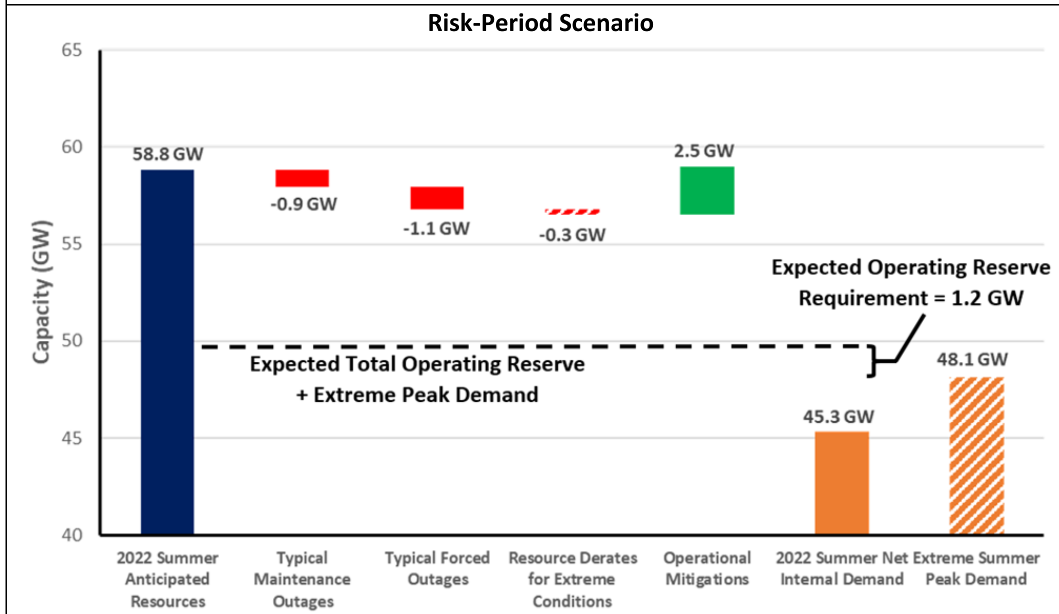
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description (See [Data Concepts and Assumptions])

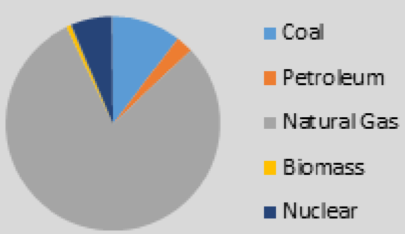
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures

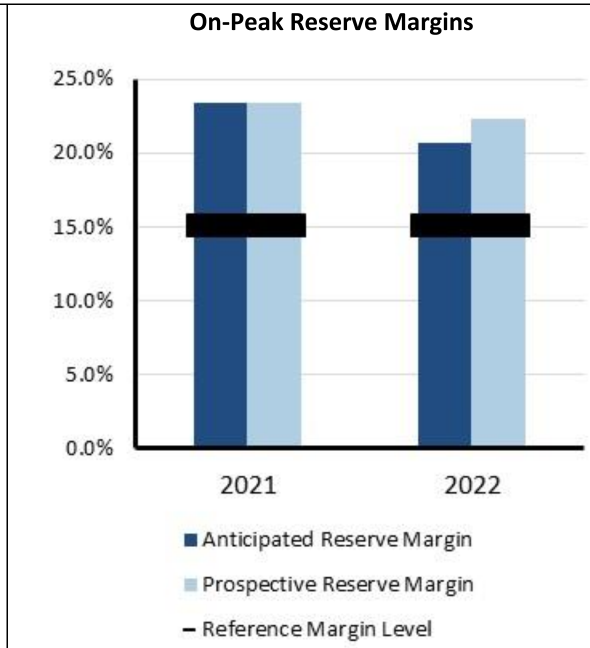


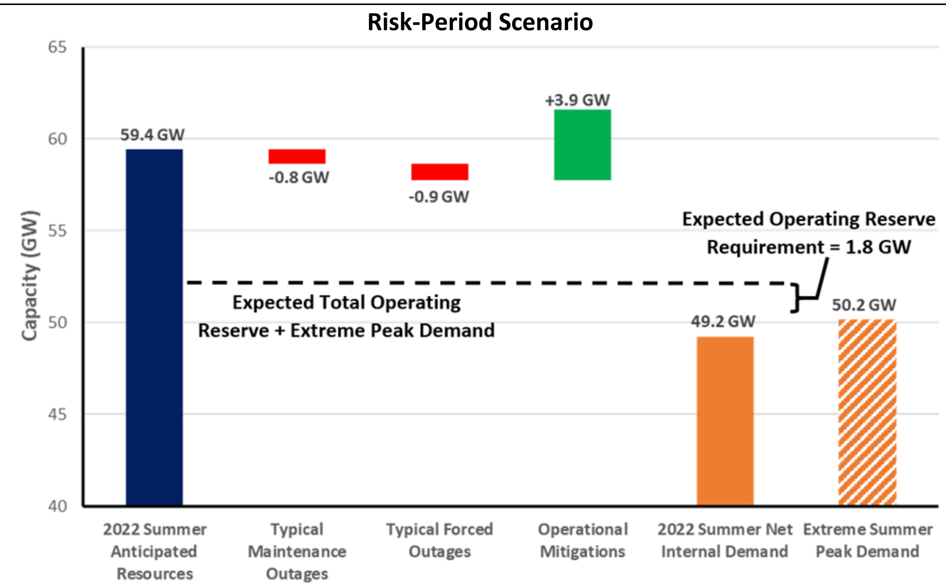
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description (See Data Concepts and Assumptions)

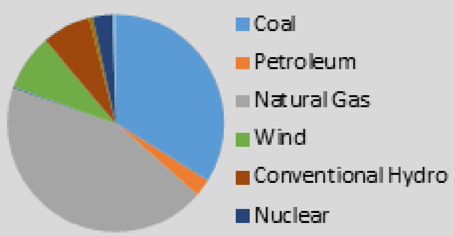
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

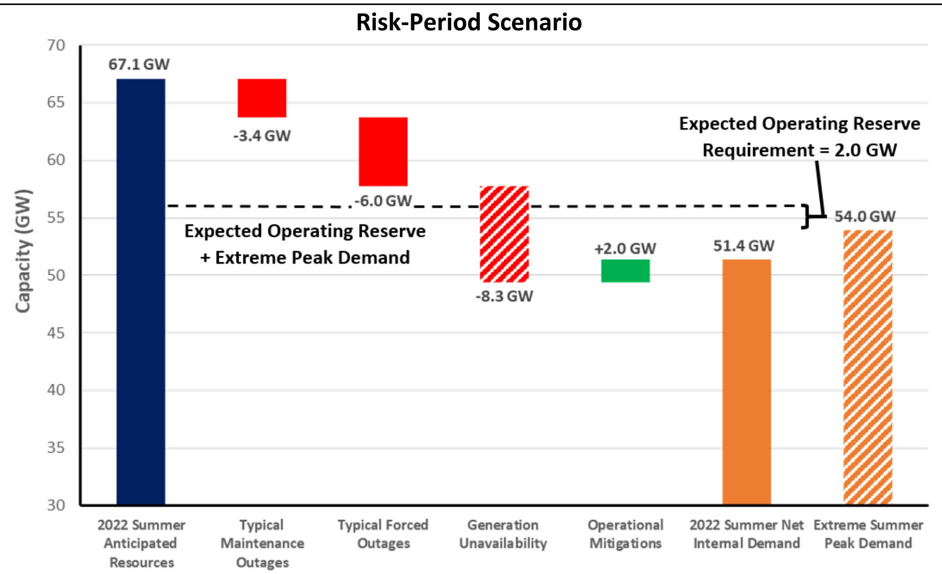


Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.



Scenario Description (See [Data Concepts and Assumptions](#))

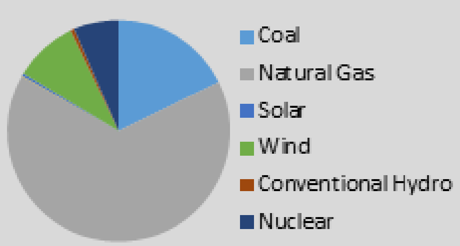
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert



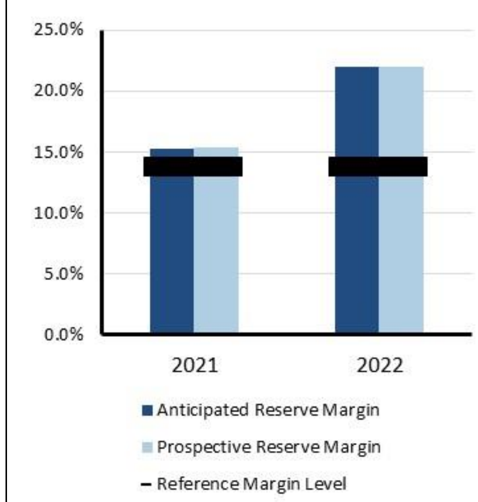
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

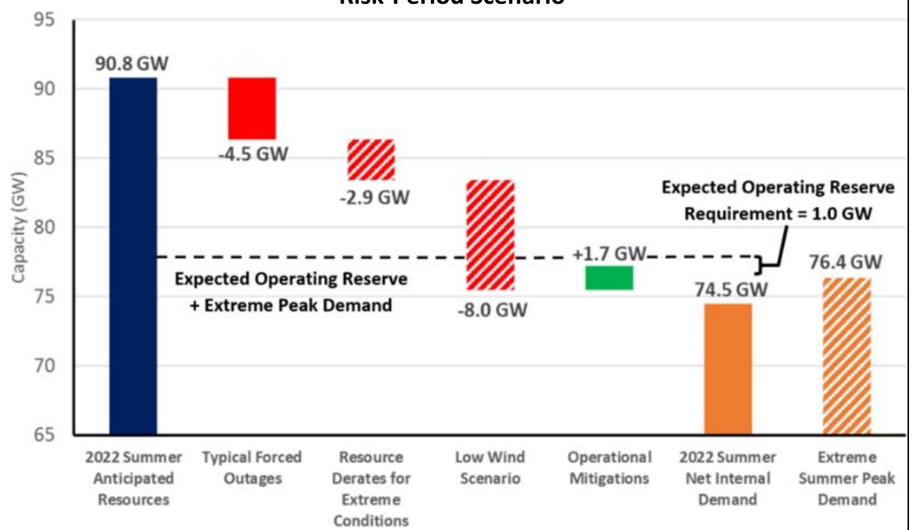
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

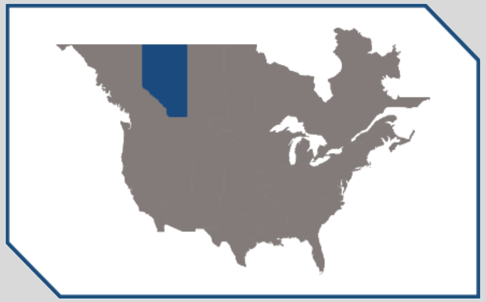
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



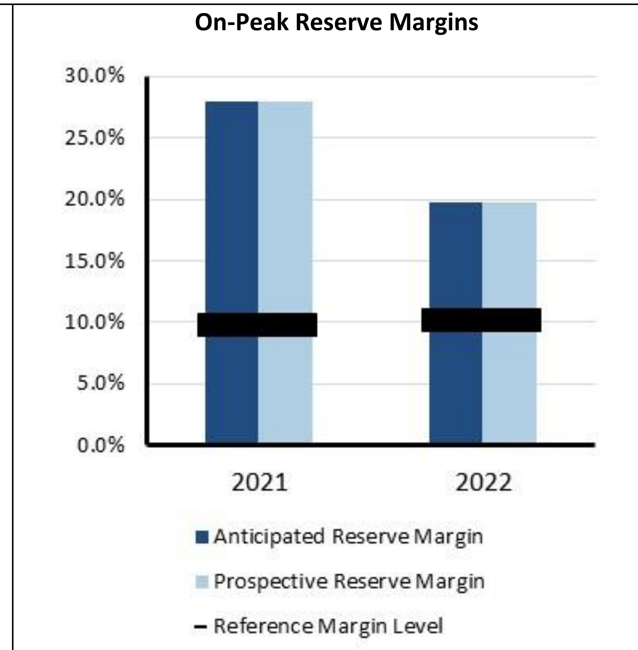
Highlights

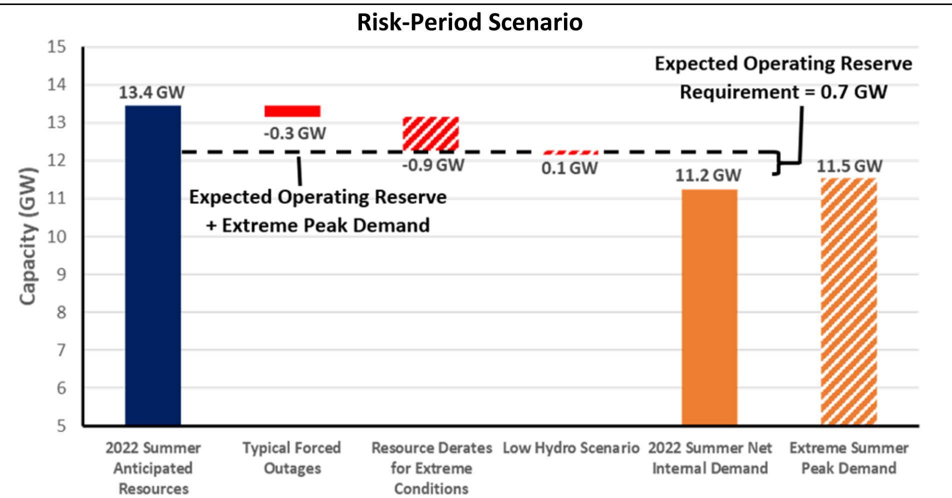
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

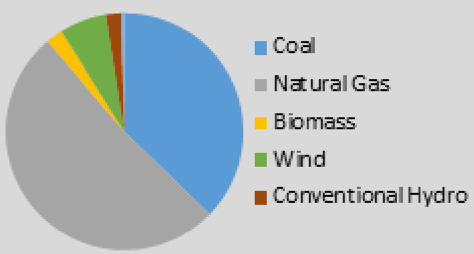
Risk Period: Highest risk for unserved energy at peak demand hour

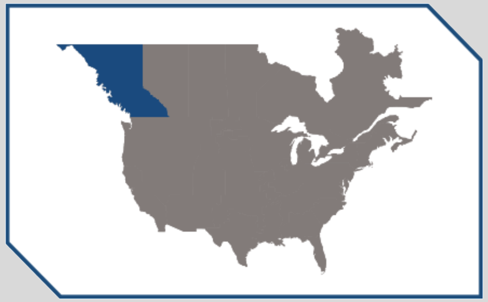
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



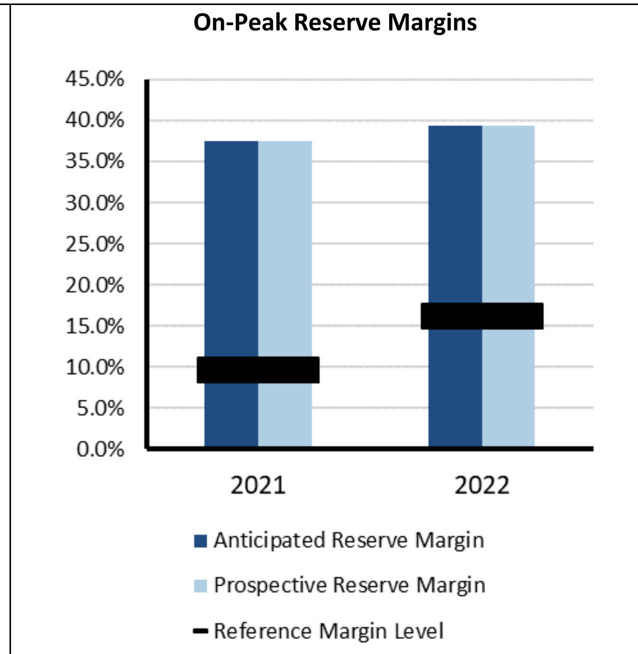


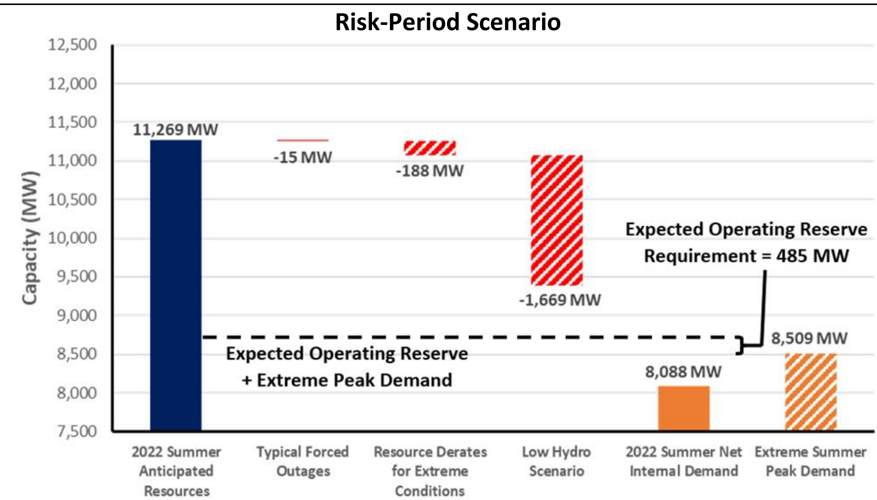
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description (See Data Concepts and Assumptions)

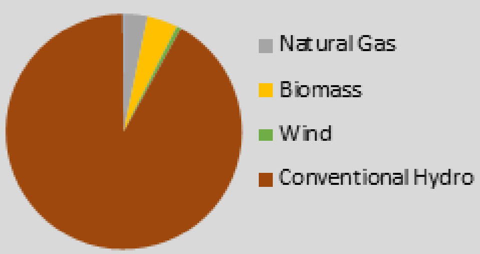
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

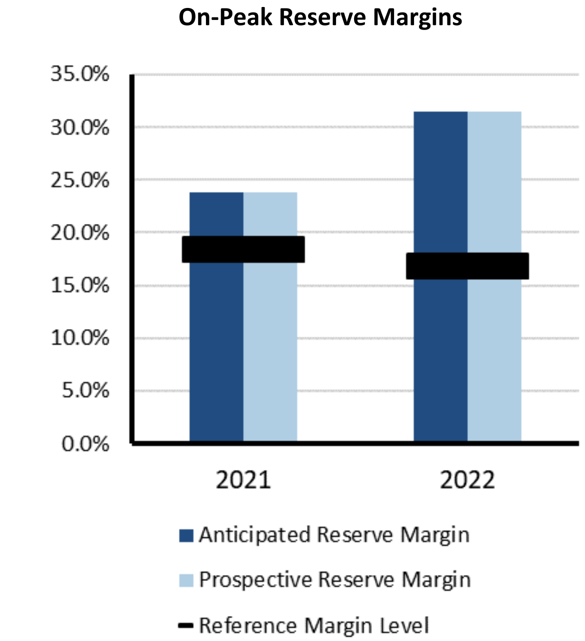


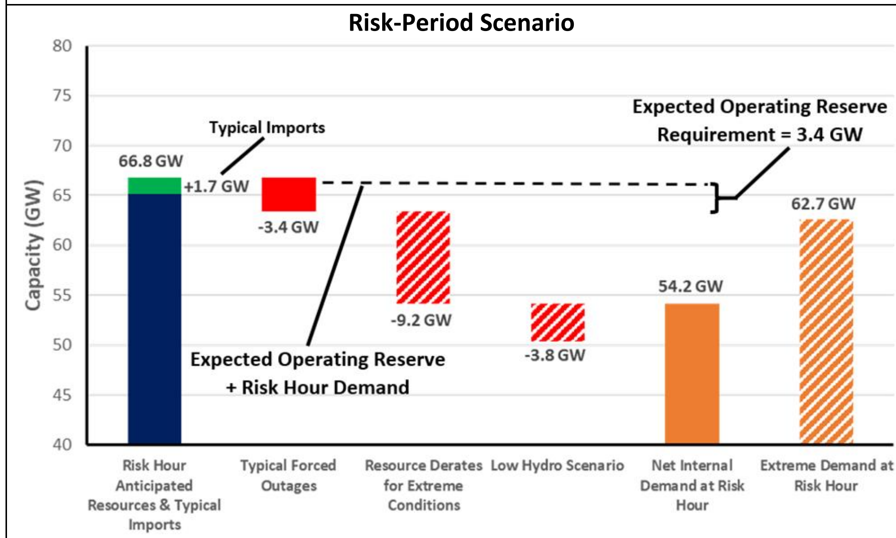
Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

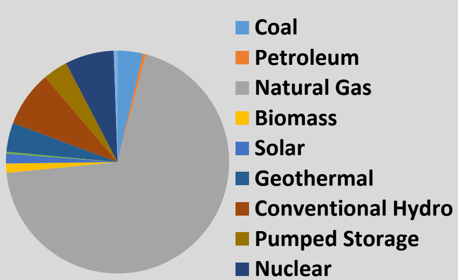
Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

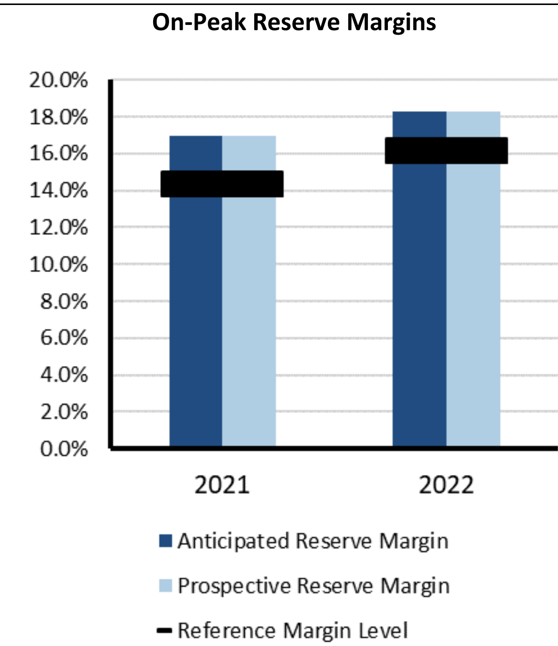


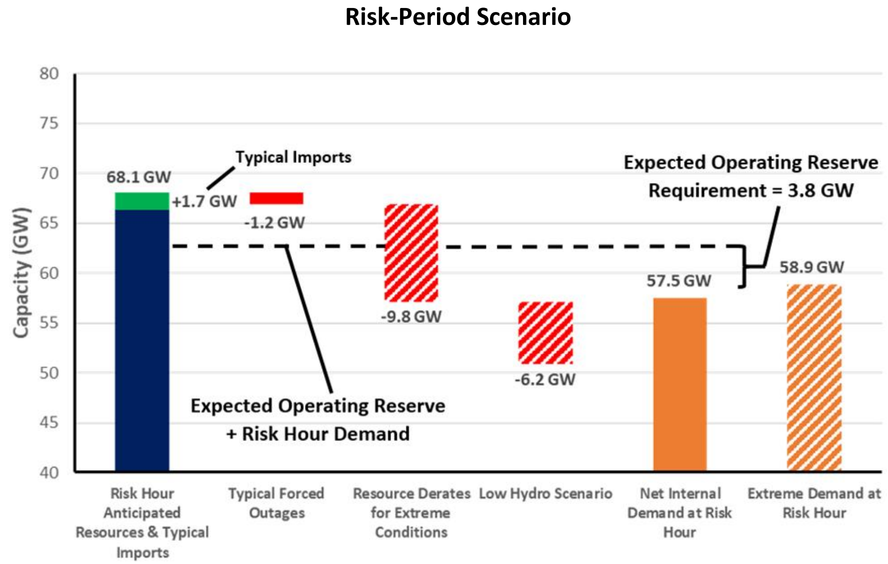
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

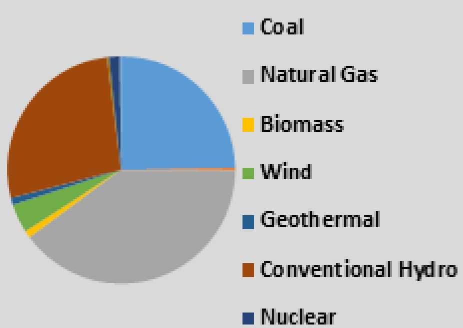
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

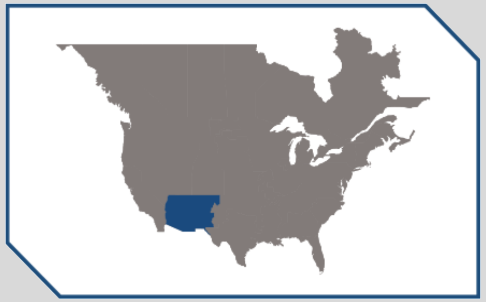
Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



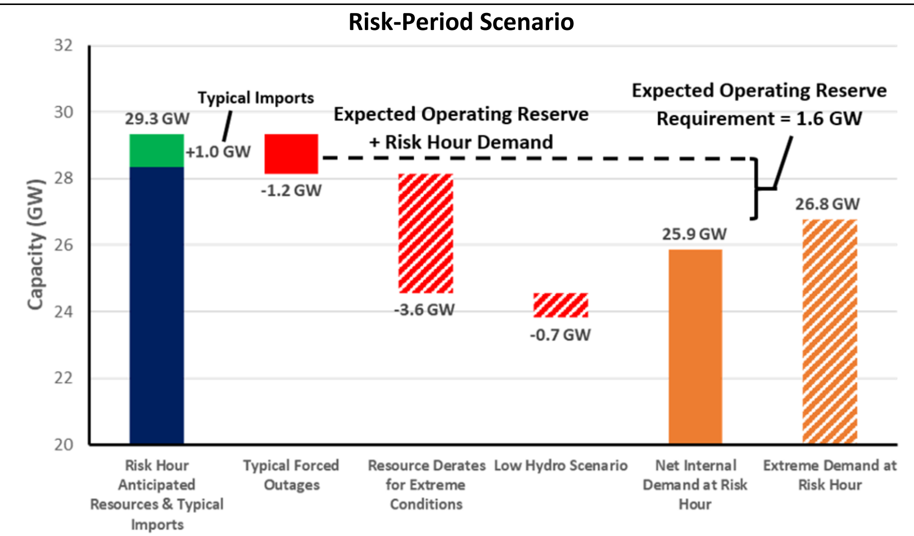


Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.



Scenario Description (See <u>Data Concepts and Assumptions</u>)

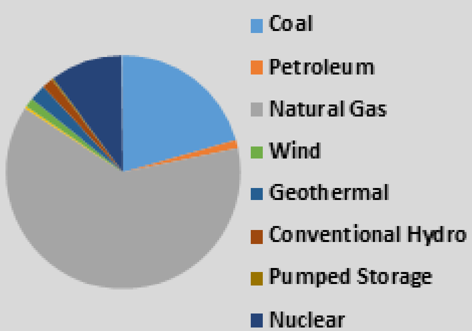
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2021 Long-Term Reliability Assessment* data has been used for most of this 2022 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[7] or total internal demand for the summer and winter of each year.[8]
• Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[7] *Glossary of Terms* used in NERC Reliability Standards
[8] The summer season represents June–September and the winter season represents December–February.
[9] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[10] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[11] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022 summer as shown in **Figure 9**.

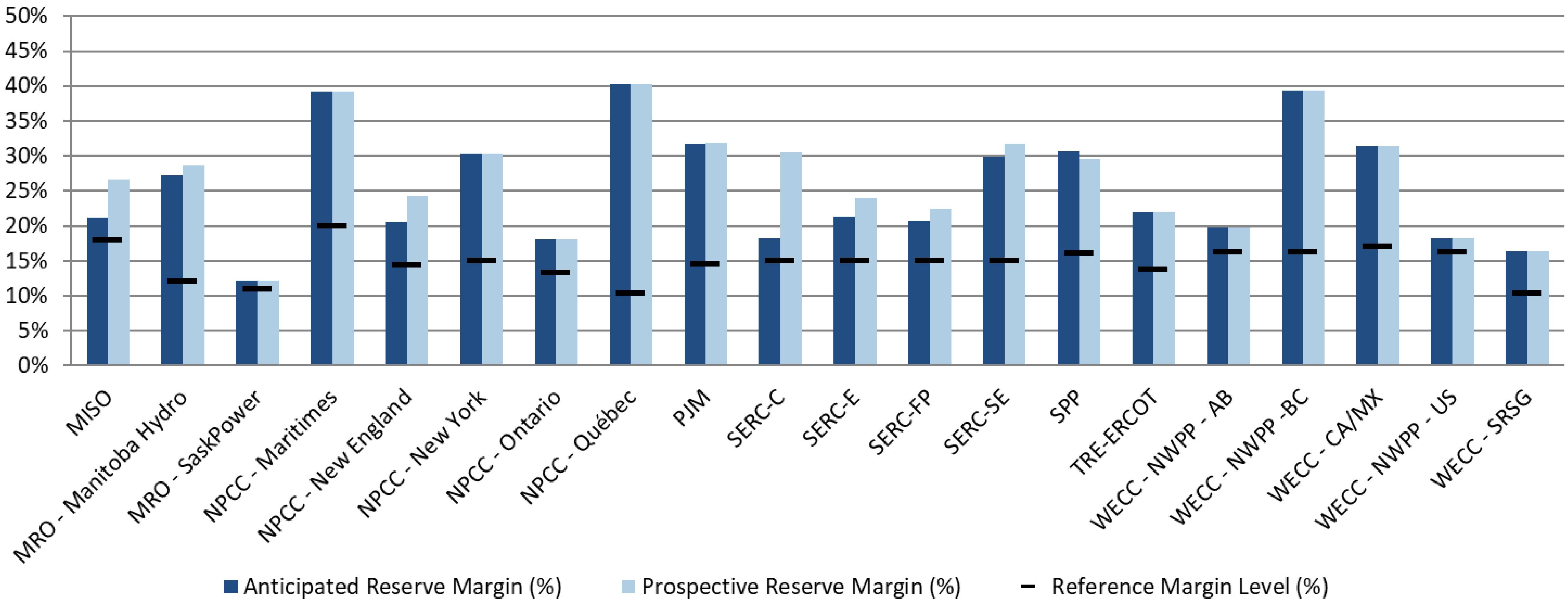
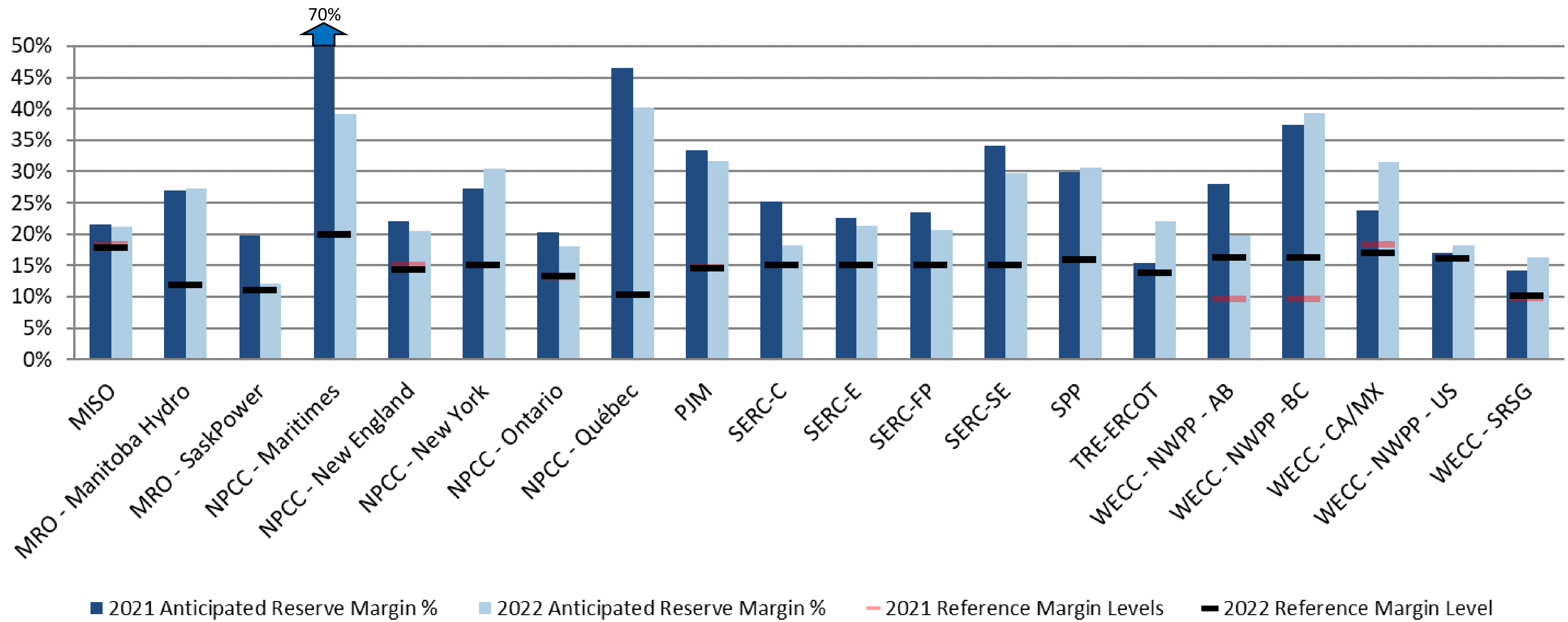


Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[11] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 11**.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

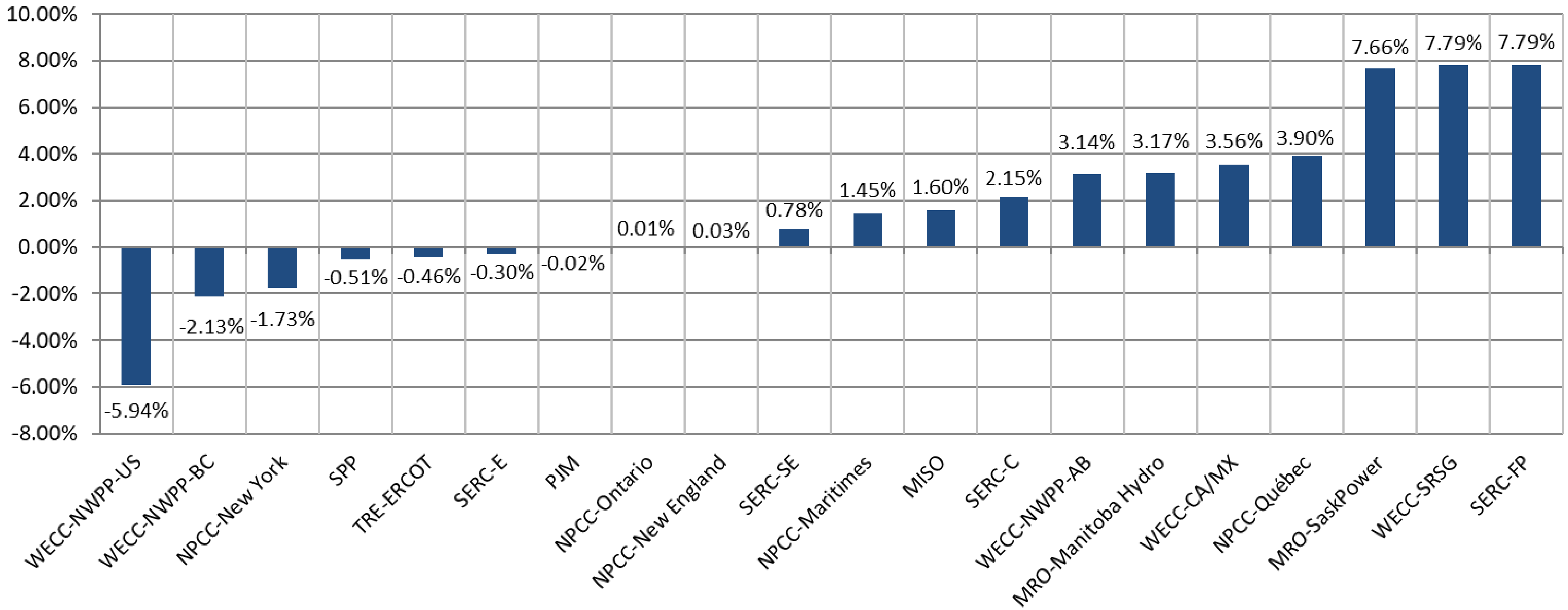


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

[12] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

CIGFUR
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2022 Carbon Plan
CIGFUR Data Request No. 1
Item No. 1-2

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please state whether comparative power quality metrics—specifically short-term disruptions like voltage sags or swells—were considered and analyzed as between each portfolio; if so, please provide the results of such analysis for each portfolio. Please also state whether any assumptions related to power quality were incorporated into the assumptions underpinning the reliability metrics for each portfolio. If not, please state why not.

RESPONSE:

Power quality is not explicitly and directly addressed in the Carbon Plan. Ensuring sufficient capacity and resources that can provide proper operating reserves is addressed in Appendix Q. The Companies are always engaged in Industry forums to understand and apply standards related to power quality such as IEEE standards and NERC standards and guidelines directly and indirectly applying to power quality. Furthermore, power quality is usually evaluated as a localized parameter based on the load, resources and topology in a specific area. It cannot be assessed at the level of the Carbon Plan. It is assumed that the resources to be acquired will meet our Facilities Connections Requirements for power quality. Evaluation of power quality impact is done during interconnection of individual resources.

Responder: Gerald W. Morgan, Lead Engineer

ATTACHMENT E
IS CONFIDENTIAL

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

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Do the Carbon Plan cost estimates and associated rate impact estimates include estimated costs associated with Duke's plans to pursue 20-year subsequent license renewals (SLRs) for the eleven existing nuclear generation units operating at six nuclear stations across the Carolinas and totaling 10,773 MW of generation?

RESPONSE:

The costs associated with SLR were not included because all portfolios assumed the existing nuclear fleet was relicensed. As a result, there were no cost differences and therefore no relative incremental bill impacts across the portfolios. See further explanation of this assumption at PSDR 13-2 a. and b.

Responder: Robert A. Mc Murry, Managing Director, Resource Planning Strategy & Analytics

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Item No. 1-3
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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please state whether the Utilities modeled cost estimates and bill impacts in the event that the Public Service Commission of South Carolina does not approve the Carbon Plan in the 2023 Integrated Resource Plan proceeding and/or otherwise disallows cost recovery from the Utilities' South Carolina ratepayers for any investments considered to be made pursuant to House Bill 951. If not, please state why not.

RESPONSE:

The Companies have not formally assessed the costs or bill impacts of the Carbon Plan in a scenario in which the PSCSC does not approve the Carbon Plan or otherwise disallows Carbon Plan-related investments. As explained in the Carbon Plan, the Companies intend to seek continued alignment between the states. To the extent that alignment cannot be achieved, it will be necessary for each state to separately plan to serve its respective retail load. Nevertheless, the Companies believe that the near-term activities proposed in its Carbon Plan are prudent and reasonable under a future extreme scenario in which the dual-state approach to planning is discontinued. As explained in the Carbon Plan, the Companies expect to have more clarity in the 2024 Carbon Plan proceeding regarding the extent of state alignment, at which point the Commission can determine how to modify and adjust the Carbon Plan.

Responder: Lara Nichols, Vice President, State and Federal Regulatory Legal Support

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Item No. 5-5
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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Does Duke have any concern about constructing transmission in South Carolina to meet HB 951 compliance? If so, please describe the concerns, potential mitigation strategies and what steps are being taken in the Carbon Plan to address this risk.

RESPONSE:

Appendix P (Transmission System Planning and Grid Transformation) extensively addresses the local and regional transmission planning processes that inform the Companies' future transmission expansion plans including potential greenfield transmission. If formal long-term transmission planning studies reflecting generation and transmission projects and system needs driven by the Companies' system-wide energy transition show that greenfield transmission expansion projects are necessary in South Carolina, then Duke Energy will start stakeholder and public engagement, as well as engagement with the appropriate SC agencies, to explain the need for the projects, the potential options for routing, and the customer and economic benefits associated with the projects. DEC or DEP would also comply with applicable statutory requirements in South Carolina relating to constructing new transmission. There are always risks to routing, siting, permitting and constructing greenfield transmission lines; however, Duke Energy will seek to identify and address those risks early via an objective and equitable line routing analysis fully supported by robust stakeholder and public engagement.

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

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

The Company discusses consolidated system operations on p. 27 thru p. 29, as well as in Appendix R. It appears that the proposed execution plan centers around system operation benefits but does not provide an execution plan for merging the two utilities.

a. Does the Company agree with this observation?
b. Please explain why an execution plan for merging the utilities should not be implemented sooner, rather than later.
c. It is the Public Staff's understanding that Duke intends to merge the DEC and DEP balancing areas, and then evaluate the potential merger of the two utilities. Is this observation correct?
    i. If so, please explain why the Companies believe this to be the appropriate path to take.
    ii. If not, please explain which path the Companies intend to pursue and why they believe it to be the proper path to follow.
d. Describe why execution plans for merging the two utilities and merging the balancing areas cannot or should not occur on parallel paths.
e. Please describe how the proposed 2022 Carbon Plan emulates or more closely resembles a joint balancing area versus historic IRP individual balancing areas.

RESPONSE:

a. Yes.

b. Merging the Carolinas utilities impacts cost allocation among jurisdictions and results in costs shifts from the wholesale jurisdiction to the retail jurisdictions, unlike Consolidated System Operations (CSO). A substantial hurdle to merging the utilities is a disproportionate shift of costs from the DEP wholesale jurisdiction to the retail jurisdiction.

c.i. The majority of CSO operations work is also needed for merging the utilities. Furthermore, consolidating operations is a foundational step to achieving carbon reduction, high renewable penetration (*e.g.*, less solar curtailments), and reliability. The project will take several years to implement and therefore, starting immediately on this work is necessary to accommodate the significant increase in solar installations and other distributed energy resources.
c.ii. Not applicable.

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d. Developing execution plans for a merger is not timely until more clarity is gained regarding the direction resource planning will take in South Carolina. CSO execution plans are being developed to allow for future flexibility if merging the utilities is later determined to be most beneficial for both North Carolina and South Carolina customers and stakeholders.

e. Please see in Appendix R section "Modeling of Consolidated System Operations in the Plan" and Table R-1: Consolidated System Operations Benefits.

Responder: Nelson Peeler, Senior Vice President, Transmission and Fuels Strategy and Policy

CIGFUR
Docket No. E-100, Sub 179
2022 Carbon Plan
CIGFUR Data Request No. 1
Item No. 1-1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide a detailed rationale explaining how the decision not to utilize CO_2 offsets in any of the portfolios results in a Carbon Plan that complies with the least-cost requirement set forth in House Bill 951.

RESPONSE:

At this time, no verifiable offset market exists in North Carolina. As such, modeling of a future offset market that may or may not exist after 2030 from now was deemed too speculative and not useful for this initial 2022 Carbon Plan development. Rather, the Companies projected the demand-side programs and supply-side resources needed to achieve zero carbon emission by 2050. If future verifiable carbon offset markets do develop and present lower cost alternatives for achieving up to 5% carbon reduction to reach "carbon neutrality" by 2050, the Companies will consider incorporating such offsets in future Carbon Plan updates and related modeling.

Responder: Glen Allen Snider, Manager Director, IRP & Analytics

ATTACHMENT L
IS CONFIDENTIAL

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

What is the EV load profile/load shape assumed for the purpose of determining the net load forecast? Explain whether and how Duke considered the load flexibility of EVs, including managed charging and vehicle-to-grid (V2G) capabilities, in the net load forecast.

RESPONSE:

The Electric Vehicle (EV) load profiles/shapes are developed using the Vehicle Analytics and Simulation Tool (VAST). A series of load charging profiles are generated in VAST to produce an hourly load forecast broken down by three duties: light, medium and heavy. These three duties are consolidated into a net 8760 EV load shape that is included in the net load forecast (please see the attached files "AGO DR4-15_DEC.xlsx" and "AGO DR4-15_DEP.xlsx").

AGO%20DR4-15_DEC.xlsx

AGO%20DR4-15_DEP.xlsx

Please reference the "Electric Vehicles" section of Appendix F – Electric Load Forecast for more detail regarding the methodology the Companies used to incorporate EVs into the net load forecast.

Managed charging programs and vehicle-to-grid (V2G) capabilities were not considered as part of EV load forecast.

Responder: Bryan M. Wright, Lead Structuring Analyst; Matthew Kalemba, Director, DET Planning & Forecasting

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide any analysis or modeling performed by the Utilities analyzing the effect that electric vehicle-to-grid and electric vehicle-to-home technologies may have on curbing the expected increase in electricity demand. If no such analysis was performed, please state why not.

RESPONSE:

The Companies have not performed any analysis at this time to reflect how vehicle-to-X (V2X) technologies may impact expected load growth. To make valid assumptions about how V2X would potentially curb demand increases, the Companies have undertaken a school bus vehicle-to-grid pilot, and they continue to explore other V2X pilots for the purposes of informing how, when and to what extent bidirectional charging technology can be leveraged above and beyond simple charging curtailment while ensuring that EV operators retain the transportation capability that they require.

Responder: Jay W. Oliver, Managing Director, Grid Systems Integration

CIGFUR
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2022 Carbon Plan
CIGFUR Data Request No. 1
Item No. 1-26
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please state whether the demand response plans described beginning on p. 15 of the Plan (and continuing throughout Appendix G) assume incorporation of CIGFUR's feedback provided during the Comprehensive Rate Design Study, specifically including but not necessarily limited to a request that Duke expand its demand response portfolio of programs to include a program identical to or substantially resembling Southern California Edison's Base Interruptible Program (BIP) and Emergency Load Reduction Program (ELRP)? If not, please state why not.

RESPONSE:

A new Emergency Interruptible Program was not assumed as part of the demand response (DR) suite; rather the Companies assumed significant price responsive loads in the prospective Hourly Pricing programs, and both potential programs (the Emergency DR and modified Hourly Pricing programs) would be available and possibly of interest to customers in the large general service categories. To not duplicate capacity from such potential load responsiveness, the Companies assumed the loads participated as part of the new Hourly Pricing program solely. If customers elect to participate in a new DR program in lieu of an hourly pricing alternative, the assumed capacity contribution from hourly pricing would correspondingly decrease.

Responder: Stacy Phillips, Director Demand Side Management

SOUTHERN CALIFORNIA EDISON'S TIME-OF-USE BASE INTERRUPTIBLE PROGRAM (TOU-BIP)

STEVE CASTRACANE, CEP, MANAGER – ENERGY & REGULATORY AFFAIRS, MESSER AMERICAS

CHRISTINA CRESS, COUNSEL TO CIGFUR

NICK PHILLIPS, PRINCIPAL, BRUBAKER & ASSOCIATES (CIGFUR)

DUKE ENERGY RATE DESIGN STUDY – NON-RESIDENTIAL WORKING GROUP SESSION 3

OCTOBER 12, 2021

CASE STUDY: MESSER AMERICAS STEVE CASTRACANE MANAGER – ENERGY & REGULATORY AFFAIRS

MESSER Gases for Life

Who we are:

- Messer is the largest privately held specialty gas manufacturer
- Some of the primary gases we produce include oxygen, nitrogen, argon, helium, and hydrogen
- We are based in Germany operating worldwide with plants across the United States
- Our products are used in Hospitals, Healthcare, Chemical, Pulp & Paper, Metals, Electronics, Environmental, Food & Beverage, and Energy

Introduction to Messer Americas (YouTube)

2

BIP PROGRAM OVERVIEW – KEY BENEFITS

- An important Interruptible Power Curtailment DR program used by the utility and ISO to keep power flowing to our communities, lowering costs across all ratepayers, and reaching state-wide carbon reduction initiatives
- Participating large power customers agree to remain under a predetermined load level when called upon – Firm Service Level (FSL)
- Integral part of the State's resources to maintain grid reliability and meet Resource Adequacy
- Provides grid system relief during times of either or both Supply and T&D constraints
  - Proven success in reducing rotating outages for other customers during critical times
  - Compliments economic programs and price trigger structures such as HP, RTP, TOU
- Critical role to support variable output from growing mix of renewable power
  - Growing value as fossil fuel plants retire and cost of fuel increases for marginal units and wholesale supply
- Provides cost savings for all customers across all rate classes regardless of participation
  - helping avoid need for additional off system purchases, utility investments in generation, substations, transmission, distribution, and infrastructure
- Avoids added GHG emissions from mitigating need for peaking units
- Customers are issued a monthly bill credit in exchange for giving the utility the call-option for this quick load reduction resource under predefined system triggers regardless on events called
  - Credit is commensurate with response time (i.e. 15 minute and 30 minute options)

3

SCE'S TOU-BIP PROGRAM OVERVIEW

- A TOU-BIP interruption event may occur when:
  - SCE receives a request from CAISO to reduce load for emergency purposes
  - SCE is responding to a local system emergency
  - Program testing or evaluation (usually one test TOU-BIP event per year)

- TOU-BIP interruption events can occur at any time, 24/7/365, subject to the following limitations:
  - One TOU-BIP event per day (up to 6 hours in duration)
  - 10 TOU-BIP events per calendar month
  - 180 hours per calendar year

WHAT HAPPENS WHEN A TOU-BIP EVENT OCCURS?

- Periods of extremely high demand or emergency circumstances may strain the electrical system and cause energy costs to rise.
- When energy supplies are expected to run low, SCE can call the load of customers who have opted in to its TOU-BIP program, providing relief to the electrical system.
- In exchange for temporarily reducing energy usage, participating customers have the potential to earn monthly bill credits.

CUSTOMER'S OBLIGATIONS & POTENTIAL PENALTY

- When a TOU-BIP interruption event occurs, the customer is notified that it has 15 or 30 minutes (based on the option selected by the customer at time of enrollment) to reduce its electrical usage to the customer's Firm Service Level (FSL), which is an amount selected by the customer.

- If the customer exceeds its FSL during a TOU-BIP interruption event, it will incur Excess Energy Charges, which vary based on the customer's voltage level and whether the 15- or 30-minute participation option was selected at time of enrollment.

ENROLLING & UNENROLLING

- Eligible customers may enroll at anytime.
- Participating customers may unenroll during the annual adjustment windows.
- Participating customers may also change their Firm Service Level (FSL) during the annual adjustment windows.

CUSTOMER / PARTICIPATION ELIGIBILITY CRITERIA

- Current SCE customer with monthly demands $\geq$ 200 kW
- On a TOU or RTP rate schedule
- Ability to reduce $\geq$ 15% of maximum demand ($\geq$ 100 kW) during each interruption event
- Have an interval meter for billing and monitoring purposes (SCE will pay for such meter for eligible customers)
- Select an FSL
- Select a 15- or 30-minute notice window for interruption events
- Submit a contract for interruptible service

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HOW TOU-BIP CREDITS ARE CALCULATED

- Participating customers receive monthly bill credits based on the difference between the customer's average peak period kW demand for each month and the customer's FSL.
- Credits vary depending on season, time of day (on-peak or mid-peak), voltage level, and other factors.
- Credits apply whether or not TOU-BIP interruption events are called in a given month.
- Excess energy charges apply only when TOU-BIP Customers fail to reduce load to their designated FSL (as set and selected by the customer)

TOU PERIODS UNDER TOU-BIP

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-Peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-Peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-Off-Peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

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CASE STUDY: MESSER'S EXPERIENCE PARTICIPATING IN TOU-BIP DEMAND RESPONSE PROGRAMS

- Overall Messer has had a great experience participating in SCE's TOU-BIP demand response programs
- "No Free Lunch"
  - Participating in these programs requires more proactive and sophisticated operational planning and emergency response preparedness at our facilities on a 24/7/365 basis, in addition to added shut-down costs to Messer's facilities
  - Penalties to ensure that participating customers show up when called upon to provide load reduction in times of strain on the grid
  - Nevertheless, Messer is glad to play an important role in the resource adequacy mix for SCE's service territory, helping to improve system reliability and lower costs for all ratepayers (by lowering the planning peak and reserve margins).

CASE STUDY: MESSER'S EXPERIENCE WITH TOU-BIP, CON'T.

- SCE's Demand Response program offerings (through TOU-BIP specifically) are high incentive, but also high penalty to ensure that participating customers can be relied upon to reduce load in times of need
- The amount of flexibility in the TOU-BIP program (annual adjustment windows) seems just right to Messer
  - We understand that if the utility offers too much flexibility in these sorts of programs, there will be fewer or no reliability or resource adequacy benefits to the system.

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CASE STUDY: MESSER'S EXPERIENCE WITH TOU-BIP, CON'T.

- Using 2020 as an example, Messer's load was called 5 times last summer due to lower than forecasted renewable generation output, wildfires, down transmission lines, etc.

- As we move forward with the Energy Transition away from fossil fuel and towards cleaner energy sources, industrial customers have an important role to play in resource adequacy and demand response.

- Messer would like to see Duke Energy offer demand response programs much like the TOU-BIP program offered by SCE.

Questions?

Steve Castracane, steven.castracane@messer-us.com

Christina Cress, ccress@bdixon.com

Nick Phillips, nphillips@consultbai.com

THE WITNESS: (Ms. Listebarger) No. That's fine.

COMMISSIONER HUGHES: Is that seat colder than --

COMMISSIONER BROWN-BLAND: I don't think she was feeling quite the hot seat effect of that, but any other questions from the Commission?

(No response)

COMMISSIONER BROWN-BLAND: Are there questions on the Commission's questions? Let me start. I see Ms. Cress.

MS. CRESS: Yes. Thank you, presiding Commissioner Brown-Bland. Good afternoon. My name is Christina Cress. I represent the Carolina Industrial Group for Fair Utility Rates. In this docket, these questions are going to be directed to the entire panel, so please feel free to answer as you see fit.

EXAMINATION BY MS. CRESS:

Q To your knowledge, did customer groups, including certain non-residential customers and non-residential customer groups, like CIGFUR, participate in Duke Energy's comprehensive rate design study?

A (Ms. Holbrook) I wasn't privy to any of that, so

I can't comment. I don't know if anybody else can.

Q Would you accept, subject to check, that they did?

A Yes.

Q Okay. And are you aware that as part of the comprehensive rate design study, certain non-residential customers, stakeholders, provided extensive feedback to Duke regarding new demand response programs and modifications to existing demand response programs? That if incorporated by Duke, would or potentially may prompt those customers who may currently be opted out of DSM/EE to participate in the Company's DSM/EE suite of programs and thus share in the cost recovery through the DSM/EE Rider?

A Again, I wasn't privy to it, but...

A (Ms. Williams) And nor was I.

Q Would you accept, subject to check, per the road map that DEC and DEP filed with the Commission earlier this year, that that did, in fact, occur?

A (Ms. Holbrook) Subject to check, yes.

Q And were you aware that that feedback included a specific proposal for Duke to propose for regulatory approval a new program based on Southern California Edisons Base Interruptible Program and it's related Emergency Load Reduction program?

A Subject to check.

Q Okay. Has Duke, to date, incorporated the feedback that it received from those non-residential customers in the comprehensive rate design study?

A I would imagine that is true. As Ms. Powers noted, it's not quite as easy as just turning on a switch and let's roll out and program. So I imagine that the right parties from those discussions have been in touch with our non-residential program managers to start that, but probably, actually our program developers or solutions to developers to start looking in how best to do something like that.

Q To date, has Duke proposed, for Commission approval, a program that resembles southern California Edison Base Interruptible Program or the Southern California Edison Emergency Load Reduction Program?

A Not to my knowledge, no.

MS. FENTRESS: May I ask. I don't know anything about those programs and I don't believe my witnesses do. Can you give some descriptions of the program so that they could perhaps respond more fully.

MS. CRESS: I'm happy to, you know, ask the questions that I have here. Again, these are based on Commission questions which I was not privy to before today. So if you're not familiar with those programs, then you're not familiar with those programs.

Q But, the important point is Duke has not proposed a program resembling the Southern California Edison suite for approval?

A (Ms. Powers) Yes. Some of the confusion there is I'm not sure if that's strictly a demand response program or are you talking about a new rate, since it was part of the comprehensive rate design workshop? I would think it could be a new rate, which is not really what we cover here in the EE/DSM Cost Recovery Rider, so that's part of our confusion.

I also don't know if some of what was proposed through that program is already incorporated in our current demand response programs, like PowerShare. And so without those kinds of details, I think that's just a perfect example of why saying what one utility does will work at Duke. There are a lot of nuances and we can't speak to the nuances, just based on the title of the program and/or rate that you're referencing. I just don't know.

Q Would you accept, subject to check, that non-residential customers provided feedback during the comprehensive rate design study, that the PowerShare Program specifically do not work for them?

A (Ms. Powers) I haven't heard that, but I have heard that the comprehensive rate design working group was robust. They got lots of stakeholder feedback, and that we were happy to receive it and are working to incorporate all of it.

So there are some, you know, evaluations going to all our demand response programs, and I'm sure if our commercial -- large commercial/industrial customers gave us feedback about a program that would work for them and that would reverse the opt-outs to more opt-ins, then we are enthusiastically engaged in it. It just hasn't gotten to the regulatory level, which is where we are.

MS. CRESS: Great. Well, I'm looking forward to that happening. Thank you.

COMMISSIONER BROWN-BLAND: Mr. Neal.

MR. NEAL: Thank you. Yes. I'm David Neal representing SACE, et al.

EXAMINATION BY MR. NEAL:

Q First, Ms. Powers, again, upon Mr. Hughes' questions early regarding the Collaborative itself, you had agreed that -- even if you don't agree with Mr. Bradley-Wright's conclusions, you would agree that he was -- in his testimony, particularly around pages 14 through 15, comparing the experience of program development when there's been a settlement with Duke, for example, on the Tariff On-Bill Financing and the high energy use pilot, with what he's experienced when there's been recommendations, just in the Collaborative, you would agree that that was part of his testimony, correct?

A (Ms. Powers) That was part of his testimony.

Q And that his conclusion was that there was -- there was improved collaboration and a more successful engagement with those programs that

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Public Staff Data Request No. 3
Item No. 3-25

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Has either Company evaluated any other existing generation other than coal for economic retirement analysis? If so, please provide those results. If not, please describe why not.

RESPONSE:

No, the Companies did not, as a part of the Carbon Plan, evaluate the potential for accelerated retirement of other existing generation. The Companies priority is to mitigate fuel supply and new regulation risk associated with coal and further accelerate CO2 emission reductions by prudently retiring the Companies' coal plants while maintaining reliability and affordability for customers. Most of the existing gas fleet were modeled to be retired by 2050 but were not evaluated for acceleration in the Plan. Furthermore, retirement analysis for other generation resources would have further increased scope and complexity and was not practical for analysis in the Carbon Plan.

Responder: Michael Quinto, Lead Engineer – Carolinas IRP and Analytics

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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please state whether the Utilities have modeled how increasing the net energy metering (NEM) cap above 1 MW would increase adoption of on-site solar and/or on-site solar plus storage for non-residential customers. If not, please state why not.

RESPONSE:

The Companies have not modeled the possible impact of increasing the net metering cap above 1 MW for non-residential customers. The general procedure for developing the net metering forecasts is to use payback as a predictive variable based on the relationship between historical adoptions and payback. The dataset for net metered large non-residential customers is quite small, making it difficult to produce a model based on the price/adoption relationship. With low confidence in a viable quantitative model, the Companies have not modeled any impacts of increasing the net metering cap above 1 MW.

Responder: Bryan J. Dougherty, Principal Structuring Analyst

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide the fuel cost and fuel cost adjustment by year resulting from implementation of Duke's proposed Carbon Plan (and each portfolio and alternative portfolio), showing the base year and all increases to retail rates over the duration of the proposed Carbon Plan. Please show how the fuel cost changes were included in the rate increase analysis provided by Duke in response to CIGFUR's Data Request 1-4 and 1-5.

RESPONSE:

As stated in response to NCSEA-SACE DR4-21d, fuel cost projections used in the Carbon Plan analysis were included in the estimation of average monthly bill impacts as part of the total production cost of the system. Rate impacts attributable to fuel costs alone were not calculated for the Carbon Plan. Projected fuel costs for each Carbon Plan portfolio are included in the data provided on Datasite in the following files:

- Portfolio 1: "PC Results - HB951 - A1 (Cap Plan 2030-No CO2 Tax-Forced Retire-1800 Solar-CT Bat Replace-Nuke Add-Nuke Cycle-49 Purc) - 5-1-22.xlsx"
- Portfolio 2: "PC Results - HB951 - B1 SMC2032 -MVP w OSW -ModExpPlan-CT Batt Repl_NukAdd_Solar Level_5-5-22.xlsx"
- Portfolio 3: "PC Results - HB951 - C1 SMC 2034 - Forced Ret - Feasible Solar_MVP_Base JDA_Add4Nuc_Purc_Battery Replace_Level Solar_4-29-22.xlsx"
- Portfolio 4: "PC Results - HB951 - D1 Battery+SMR+Solar - SMC 2034 - Forced Retire - Feasible Solar_MVP_Base JDA_4-29-22.xlsx"

Responder: Nathan Gagnon, Principal Planning Analyst

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

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide all assumptions made and documentation relied upon by Duke with respect to inflation, anticipated cost drivers (both related and not related to the Carbon Plan), and rate increases (both related and not related to the Carbon Plan) through 2035, and the expected timing and amount of each such rate increase.

RESPONSE:

The following response pertains only to carbon plan related costs.

Please refer to the response to PSDR3-6 for a discussion of the Companies' assumption for general inflation and supporting documentation. Please refer to the response to PSDR3-17 for a discussion of the technology-specific capital cost forecasts used in the Carbon Plan analysis. Please see the "Fuel Supply and Commodity Pricing" section starting on page 39 of Appendix E and the entirety of Appendix N (Fuel Supply) for details on fuel costs used in the Carbon Plan.

Responder: Michael T. Quinto, Lead Engineer

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide a forecast of all (both related and unrelated to the Carbon Plan) costs that would impact DEP and/or DEC customer bills and the anticipated all-inclusive percentage rate increases by year, for each year through 2035; please provide this information broken down between wholesale and retail customer, as well as between each class of retail customer.

RESPONSE:

The Companies do not forecast all the costs that would impact DEP and /or DEC customer bills for the extended time frames as requested (i.e., for each year through 2035), therefore we cannot provide an all-inclusive percentage rate increase by year for the timeframe and customer classes as requested.

Responder: Virginia Boucher, Director, Rates & Regulatory Planning

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

The following questions pertain to how Duke models CO_2 emissions in EnCompass.

a. Please explain how Duke has modeled all CO_2 emissions in EnCompass.
b. Does Duke track more than one type of CO_2 in EnCompass, with different CO2 emissions from generating units located in North Carolina and South Carolina?
c. EnCompass has multiple inputs for CO_2 emissions in each Resources Thermal tab (lb/MMBtu, lb/hr, lb/MWh, lb/MWh/MW, lb/MWh/MW/MW, lb/MWh/MW/MW/MW). Which Release Rate input(s) did Duke utilize for its resources? Please provide all rationale behind Duke's selection.
d. Please explain how the relevant Release Rate was calculated for each Resource or Resource type and provide a summary of the different Release Rates applicable to each carbon emitting resource.
e. Please explain how CO_2 emissions were modeled for Dual Fuel (coal and natural gas) units. Does the model account for different CO_2 emission rates for natural gas and coal?
f. Please explain how CO_2 emissions were modeled for Dual Fuel (natural gas with oil backup) units. This response should address whether Duke used different emission rates for combustion turbines in the winter months, or any months where CTs were assumed to run on oil instead of natural gas.

RESPONSE:

a. Duke models CO2 emission rates separately for each fuel that is consumed. The emission rate is modeled at the fuel instead of at the generator.

b. Duke models only one CO2 effluent for the entire system for both companies. When determining compliance with the NC emissions reduction target, only NC resource CO2 emissions are counted. All future CO2 emitting resources are modeled as if they were located in NC (recognizing that Duke Energy will evaluate the most prudent siting location of new resources, whether located in NC or SC).

c. Duke modeled CO2 emissions at the fuel instead of at the generator. The emissions rate is in lbs/MMBtu.

d. Release rates for each resource are determined dynamically within the model based on the amount of each fuel that is consumed.

e and f. Since CO2 emission rates are modeled at the fuel instead of at the resource, the CO2 emissions of co-fired and peaking resources is dynamically determined by the model based on fuel consumption.

Responder: Gerald Morgan, Lead Engineer – Production Cost Modeling and Data Management

Attachment X
E-100 Sub 179
CIGFUR

ATTACHMENT X
IS CONFIDENTIAL

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide a list of all resources that were forced into the model in each year (i.e., not economically selected). This response should also describe why the particular resource was forced in and provide justification and support for the amount and timing of the resource.

RESPONSE:

Provided in "PS DR 3-11.xlsx" is a table of all resources by year that were not economically selected by the capacity expansion model, but included in the final Carbon Plan portfolios. Some of these resources were forecasted into the portfolio, meaning their inclusion is based on projects that are under development and planned to be interconnected. The rest were not economically selected by the capacity expansion model, but later validated to be appropriate for inclusion either economically validated or necessary to maintain reliability of the system. The basis for inclusion will be described for each resource or resource group below.

PS%20DR%203-11.xlsx

This file does not show existing resources, such as the current fleet, including Lincoln 17 (which is not yet under DEC control), or planned capacity uprates, such as nuclear uprates, which are prescribed into the model as well. It also does not include resources economically selected by the capacity expansion model.

This file presents data on a beginning of year basis, meaning resources are available to the system by Jan 1 of year listed, for the full year capacity and energy requirements.

Solar – Incremental forecasted solar represents projects in various stages of the interconnection process including HB 589 Green Source Advantage ("GSA") and Competitive Procurement of Renewable Energy ("CPRE") Tranches 1 and 2 projects. The Carbon Plan modeling also anticipates that current uncontracted projects under CPRE Tranche 3 would be connected prior to 2026, and the remaining uncontracted HB 589 GSA solar would connect throughout the remainder of the decade. The incrementally forecasted solar assumed in the Carbon Plan is included in Table E-27 in Appendix E.

These resources are represented in the attached file as “Forecasted Standalone Solar” and “Forecasted Solar paired with Storage.”

Battery – The battery projects represent mid- and late-stage development projects with various storage capacity durations deployed through 2027. Near-term deployments in development are important for finding cost-effective and reliable solutions to meet Duke Energy’s customers' energy needs. The forecasted batteries in the Carbon Plan represents a limited amount of grid-connected battery storage projects that will allow for a more complete evaluation of potential benefits to the distribution, transmission, and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale.

These resources are represented in the attached file as “Forecasted Standalone 1-2 Hr Batteries” and “Forecasted Standalone 4+ Hr Batteries.”

Offshore Wind – The second 800 MW block of offshore wind put into service for the start of 2032 was prescribed into Portfolio 2. This resource was prescribed to represent the timeline necessary for integrating a total 1600 MW of offshore wind in meeting the interim CO2 emission reductions target to show the tradeoffs of delaying the achievement of the target to integrate the additional block of offshore wind.

The same 800 MW block of offshore wind for the start of 2032 was prescribed into Portfolio 4. This was done to show the tradeoffs of diversifying the resources used to achieve the CO2 emissions reductions target.

These resources are represented in the attached file as “Portfolio Prescribed Offshore Wind.”

Bad Creek Powerhouse II – Bad Creek PH II was prescribed into all portfolios in the capacity expansion step. As discussed in Appendix E, the capacity expansion model alone is not sufficient for evaluating energy storage resources. For this reason, the Companies included the resource in all portfolios and performed a separate comparative economic analysis for Bad Creek PH II utilizing the production cost model to validate inclusion in the modeling was economic against other long-duration storage options. More discussion on this analysis is included in the Portfolio Verification section of Appendix E. The Companies will continue to evaluate the value of long-duration storage on the system and its ability to provide significant power capacity in addition to facilitating reliable retirement of coal capacity.

This resource is represented in the attached file as “Economically Validated PS.”

Battery-CT Optimization Replacements – As described in Appendix E the capacity expansion model may over value short duration energy storage. To evaluate the preliminary economic selection of these resources, the Companies performed analysis in the detailed production cost model to see if CT capacity was a more economic selection. This process proved a portion of the batteries selected were economically replaced with CTs and these replacement CT resources were included in the final portfolios.

These resources are represented in the attached file as “CT-Battery Economic Replacement.”

Reliability CTs – Portfolio LOLE and Resource Adequacy Validation step of the modeling verified portfolios' in maintaining the 0.1 LOLE reliability standard in 2030 and 2035. For Portfolio 1 through Portfolio 4, no additional capacity was identified to maintain the portfolios resource adequacy. For the alternate fuel supply sensitivity, these portfolios were also tested in this validation step identifying a limited number of resources were needed to maintain the reliability standard. The attach file only provides the final Carbon Plan portfolios and does not address sensitivity analyses.

These resources would have been represented in the attached file as “Reliability CT.”

Portfolio Reliability and CO2 Reduction Requirement Resources for 2050 – These resources were added at the very end of the planning horizon to address insufficiency of resources identified by the capacity expansion model in meeting energy requirements in the production cost model at the end of the planning horizon consistent with the Companies’ reliability and CO2 emissions target requirements. The resources were modeled as nuclear SMRs, but could represent a non-CO2 emitting, dispatchable resource or otherwise adjusting load to meet energy and CO2 requirements of the system in 2050. These resources were added in between 2047 and 2049 to meet these requirements.

These resources are represented in the attached file as “Reliability and CO2 Reduction SMR.”

Responder: Michael Quinto, Lead Engineer – Carolinas IRP and Analytics

AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 3
Item No. 3-11
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please explain whether Duke considered any transmission cost savings from resources that interconnect close to retiring coal facilities. If not, why not?

RESPONSE:

While the Companies do expect that some new resources "would be brownfield additions at existing power stations that can utilize the Companies' existing transmission, infrastructure, and workforce" (Carbon Plan Chapter 4, page 14), these potential cost savings were not factored into the generic transmission network upgrade costs used in the Carbon Plan analysis as reported in Table E-44 (Carbon Plan Appendix Q, page 38). As stated in the Executive Summary of the Carbon Plan, "consistent with past practice, in most cases, the selection and siting of new resources will occur after completion of the modeling process (with such modeling results, including any modifications ultimately required by the Commission, informing the procurement process). This approach will ensure that the most cost-effective resources are selected for the benefit of customers, taking into account a range of site-specific and other factors that are not practical for inclusion in the modeling process." In summary, potential new resource cost savings and transmission cost savings associated with brownfield development at retiring coal sites were not explicitly quantified. However, the Company recognizes this potential benefit for consumers, and once specific sites for resources are identified in the execution phase, such savings will become more known and quantifiable for inclusion in future Plan updates.

Responder: Glen Allen Snider, Managing Director Carolinas IRP and Analytics

Public Staff
Docket No. E-100, Sub 179
2022 Carbon Plan
Public Staff Data Request No. 5
Item No. 5-12

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

The TCS Phase 1 results for solar resources in DEP and DEC identified transmission upgrades. Has Duke completed, or will Duke complete, the incremental amount of new solar generation that may be able to interconnect assuming that no other upgrades take place? In other words, in isolation of the ~$500M in DEC plus DEP upgrades identified in the TCS phase 1 and the existing system, how much additional solar generation can be interconnected before triggering additional network upgrades (just a view of the existing transmission system). The Public Staff notes that this type of hypothetical post processing analysis is not a substitute for a required power flow analysis.

RESPONSE:

Duke Energy has not evaluated how many MWs of solar can be connected to the existing transmission system without additional transmission network upgrades. Duke Energy does have information on where solar developers want to locate facilities through prior generator interconnection requests in the serial queue and more recently in the transitional cluster study queue. Solar developers consider several factors when determining where to request interconnection of solar facilities, such as land availability, land lease rates, zoning, etc. Prior generator interconnection study results were used to determine the transmission expansion plan projects reflected in Table P-3 of Appendix P to the Carbon Plan. Duke Energy deemed the Generator Interconnection Requests and associated study results as the best available information for informing the determination of transmission expansion plan projects.

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

ATTACHMENT BB
IS CONFIDENTIAL

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2021

H 3

HOUSE BILL 951
Committee Substitute Favorable 7/13/21
Third Edition Engrossed 7/15/21

Short Title: Modernize Energy Generation. (Public)

Sponsors:

Referred to:

May 12, 2021

A BILL TO BE ENTITLED

AN ACT TO MODERNIZE NORTH CAROLINA'S GENERATION AND GRID RESOURCES AND RATE MAKING AND TO INVEST IN CRITICAL ENERGY INFRASTRUCTURE FOR THE BENEFIT OF CUSTOMERS.

The General Assembly of North Carolina enacts:

PART I. CERTAIN REQUIREMENTS FOR GRID MODERNIZATION AND INVESTMENT IN CRITICAL ENERGY INFRASTRUCTURE

SECTION 1.(a) Findings. – The General Assembly of North Carolina finds:

(1) In order to ensure predictable and low customer electricity costs, promote economic development, protect the continued long-term reliability of electric service, and protect the environment, it is in the public interest of the State to seek to continue the transition away from coal-fired electricity generation in an orderly and disciplined manner.

(2) Overreliance on coal-fired electricity generation carries financial and operational risks in light of the future potential for limited coal supply options due to coal market consolidation, future potential coal market constraints, and coal price unpredictability. These risks are increased when combined with the effects of likely future stringent federal environmental regulations, including future potential tax or other costs, direct or indirect, imposed on coal-fired electricity generation.

(3) In transitioning away from coal-fired electricity generation, given uncertainty of long-term fuel supply and environmental regulation, it is in the public interest and the policy of the State that maintaining predictable and affordable customer electricity costs and maintaining continued long-term reliability of the electric grid are the most significant factors in determining replacement generating resources.

(4) It is in the public interest for the electric public utilities to accelerate retirement of certain coal-fired electric generating facilities in an orderly and disciplined manner that (i) ensures continued electric system reliability for all customers, (ii) mitigates the financial and operational risks associated with potential rapid coal-fired electric generating facility retirement over a short period of time in the future, (iii) seeks to maximize the overall value and lower the overall cost of such future transition, (iv) seeks to reduce the risk of future rate shock arising from the need for a more compressed transition, (v) delivers to electric

H951-V-3

utility customers financial and operational benefits from diverse and new electric generation technologies, and (vi) will result in a reduction by 2030 of electric power sector CO_2 emissions of at least sixty-one percent (61%) over 2005 levels.

(5) The plan set forth herein is generally consistent with the electric public utilities' current integrated resource plan, and this act will allow the electric public utilities to implement their integrated resource plans in a more efficient manner.

(6) The plan set forth herein will provide an "all of the above" approach to replacing a limited number of coal-fired power plants with a combination of natural gas, nuclear, solar, and storage generating technologies.

(7) It is in the public interest to decrease the number of rate cases and reduce the regulatory lag that currently delays and hinders certain capital investments which would bring or maintain benefit to customers served by the electric public utilities.

(8) To facilitate the investments necessary to transition from coal-fired electricity generation in a manner that ensures predictable and affordable customer electricity costs, the General Assembly declares that it is in the public interest for the North Carolina Utilities Commission to authorize the use of performance-based regulation for electric utilities in order to achieve and encourage all of the following:

a. Alignment of electric public utilities' incentives with customer and societal interests through regulatory mechanisms that reward improved operations and increased program effectiveness.

b. Electric public utilities' innovation in service delivery to customers.

c. Electric public utilities' investments to make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system.

d. More efficient use of energy by customers by decoupling electric public utility revenues from customer consumption.

e. Multiyear rate planning to maintain predictable and affordable rates and reduce regulatory lag on necessary investments.

SECTION 1.(b) Definitions. – For purposes of Part I of this act, the following definitions shall apply:

(1) "Coal retirement and replacement plan" means a plan, as described further in subsection (d) of this section, for retiring a subcritical coal-fired electric generating facility located in North Carolina by December 31, 2030, and the replacement of such facility with a new source of energy and capacity.

(2) "Designated replacement resources" means those resources that are prescribed in subsection (c) of this section and those replacement resources that are approved by the Commission pursuant to subsection (d) of this section to replace the capacity and energy lost by the retirement of the remaining subcritical coal-fired generating facility.

(3) "Energy storage system" or "ESS" means a system, equipment, facility, or technology relating to the electric grid that (i) is capable of absorbing or receiving electrical energy, storing such energy for a period of time, and dispatching electrical energy after storage, and (ii) uses a mechanical, electrical, chemical, electrochemical, or thermal process to store such energy.

(4) "Subcritical coal-fired generating facilities" means the remaining units of the Allen Plant located in Gaston County, Marshall Units 1 and 2 located in

Catawba County, the Roxboro Plant located in Person County, Cliffside Unit 5 located in Cleveland County, and the Mayo Plant located in Person County.

SECTION 1.(c) Subcritical Coal-Fired Generating Facilities; Specific Requirements for Retirement and Associated Designated Replacement Resources. – In order to continue the transition away from coal-fired electricity generation in an orderly and disciplined manner, and to minimize the financial and operational risks to customers of overreliance on coal generation, the electric public utilities shall retire all subcritical coal-fired generating facilities by December 31, 2030, in the manner and subject to the conditions described herein.

(1) Allen Plant. – Except as provided in subdivisions (1) and (2) of subsection (e) of this section, the remaining units of the Allen Plant shall be retired on or before December 31, 2023. On or near the site of the Allen Plant, but in no event outside of Gaston County, the applicable electric public utility shall procure and own designated replacement resources comprised of one or more energy storage systems with a total capacity of approximately 20 megawatts alternating current (MW AC)/80 megawatt hours (MWh). The applicable electric public utility shall exert reasonable efforts to ensure that the designated replacement resources are constructed according to a time line that allows for retirement of the coal-fired generating facility by the targeted retirement dates, and the utility shall provide updates to the Utilities Commission regarding the status of such efforts in its integrated resource plans.

(2) Marshall Units 1 and 2. – Except as provided in subdivisions (1) and (2) of subsection (e) of this section, Marshall Units 1 and 2 shall be retired on or before December 31, 2026. On or near the site of the Marshall Plant, but in no event outside of Catawba County, the applicable electric public utility shall procure and own designated replacement resources comprised of natural gas–fueled simple-cycle combustion turbine generating facilities with a generating capacity totaling approximately 900 MW, provided that the electric public utility shall be permitted to propose a smaller combustion turbine generating facility where the electric public utility determines that technological or other constraints so require. The applicable electric public utility shall exert reasonable efforts to ensure that the designated replacement resources are constructed according to a time line that allows for retirement of the coal-fired generating facility by the targeted retirement dates, and the utility shall provide updates to the Utilities Commission regarding the status of such efforts in its integrated resource plans.

(3) Roxboro Plant. – A coal retirement and replacement plan shall be filed for the Roxboro Plant on or before September 1, 2024. With respect to the designated replacement resource for the Roxboro Plant, the replacement resource shall be a generating facility located on the Roxboro Plant site or, in the event that the applicable electric public utility, in its reasonable discretion, determines that it will be unable or infeasible to procure or construct a generating facility at the Roxboro Plant site, at another location in Person County that satisfies all of the following criteria:

a. The resource has continuous generating and dispatch capabilities and other operating characteristics that provide system reliability benefits that are equal to or greater than the retiring Roxboro Plant.

b. The resource provides effective load carrying capability sufficient to ensure continued reliability of the system.

c. The resource has the ability to deliver continuous power at or near the maximum capacity of the resource for a continuous period of one week or longer without reliance on other grid resources.

(4) Cliffside Unit 5. – A coal retirement and replacement plan shall be filed for Cliffside Unit 5 on or before September 1, 2027. With respect to designated replacement resources for the facility, the replacement resource shall be an energy storage system to be procured and owned by the applicable electric public utility. The applicable electric public utility shall seek to locate a substantial portion of the ESS on the Cliffside Unit 5 site, but shall be permitted to site such ESS on or near other electric public utility property where such siting will provide increased benefit to customers.

(5) Mayo Plant. – A coal retirement and replacement plan shall be filed for the Mayo Plant on or before September 1, 2027. With respect to designated replacement resources for these facilities, the replacement resource for each facility shall be an ESS to be procured and owned by the applicable electric public utility. The applicable electric public utility shall seek to locate a substantial portion of the ESS on the site of the applicable subcritical coal-fired generating facility but shall be permitted to site such ESS on or near other electric public utility property where such siting will provide increased benefit to customers.

SECTION 1.(d) Coal Retirement and Replacement Plans Generally. –

(1) A coal retirement and replacement plan shall include all of the following:

a. The proposed retirement date for the applicable subcritical coal-fired generating facility and the reasons for that proposed retirement date.

b. The proposed type, size, and location of the replacement resource or resources intended to replace the energy and capacity of the subcritical coal-fired generating facility in order to ensure safe, reliable, and cost-effective service to the electric public utility's customers and the projected timing of the commercial operation of such replacement resource or resources.

c. A forecast of capital costs, fuel costs, other operation and maintenance costs, and the capacity factors of the proposed replacement resource, as well as any assumptions about future regulatory compliance costs.

d. In the case of replacement resources that would require a certificate under G.S. 62-110.1 or otherwise, to the extent not already required above, the information that would be required in connection with an application for certificate of a generating facility under G.S. 62-110.1, except that the information required under or in connection with G.S. 62-110.1(d) shall not be required.

(2) After receipt of a coal retirement and replacement plan, the Commission shall do all of the following:

a. Establish a procedural schedule to allow interested parties to intervene in the proceeding, to facilitate discovery of evidence between and among parties to the proceeding, and to receive comments of the parties and the filing of any direct or rebuttal expert witness testimony.

b. Hold one or more public hearings and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in the county in which the subcritical coal-fired generating facility is located.

c. Schedule an evidentiary hearing to allow for the cross-examination of expert witnesses, to resolve all contested issues between the parties to the proceeding, and to address any questions or issues the Commission may raise upon its own motion.

(3) After completion of the process described in subdivision (2) of this subsection, the Commission shall issue an order approving, modifying, or rejecting an electric public utility's coal retirement and replacement plan within 180 days after the filing thereof. The Commission shall approve a coal retirement and replacement plan if it finds all of the following:

a. The coal retirement and replacement plan complies with the applicable requirements set forth in this subsection.

b. The replacement resource proposed in a coal retirement and replacement plan is sized appropriately to (i) ensure sufficient energy on an hourly basis over an annual period and ensure sufficient capacity to serve anticipated peak electrical load plus an adequate planning reserve margin based upon the applicable electric public utility's then current projections of customer load requirements and (ii) provide equivalent ancillary services and ensure compliance with any applicable reliability standards, including the North American Electric Reliability Corporation's (NERC) reliability standards.

c. The electric public utility has reasonably and prudently utilized competitive equipment procurement practices to ensure that the projected cost of the proposed replacement resource is reasonable in accordance with the requirements set forth in subdivisions (3) through (5) of subsection (c) of this section

(4) In a decision issued pursuant to subdivision (3) of this subsection approving any replacement resource, the Commission shall include an approved construction cost for each such replacement resource. If a replacement resource requires a certificate of public convenience and necessity under G.S. 62-110.1 or otherwise, and is approved by the Commission under this section, such replacement resource shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1, and the Commission shall issue a certificate of public convenience and necessity for such replacement resources at the time of its approval, and no further process shall be required under G.S. 62-110.1 except as otherwise addressed herein.

SECTION 1.(e) General Provisions Applicable to Retirement of Subcritical Coal-Fired Generating Facilities. –

(1) Notwithstanding any date established under subsection (c) or (d) of this section that requires retirement of a subcritical coal-fired generating facility, in the event the applicable electric public utility determines that the retirement of any such facility would have the potential to compromise reliability of the electric public utility's service, or otherwise impact the ability of the electric public utility to comply with any applicable reliability requirements, the electric public utility shall file notice with the Commission describing the reliability issues preventing compliance with the requirement for retirement by the date specified and requesting a delay of retirement date. Upon receipt of a notice and request for retirement delay as authorized by this subdivision, the Commission may conduct a hearing regarding such delay and shall issue an order approving or rejecting the request for delay within 90 days of receipt of such notice and request.

(2) In order to ensure the continued reliability of the electric system, no subcritical coal-fired generating facilities shall be retired unless and until the applicable

designated replacement resource has been placed in-service; provided, however, that the electric public utility shall be authorized to retire the subcritical coal-fired generating facility prior to the in-service date of the applicable designated replacement resource if the electric public utility determines that it will be able to maintain reliable service in that circumstance.

(3) In the case of each subcritical coal-fired generating facility that is retired pursuant to this section, the applicable electric public utility shall be permitted to establish a regulatory asset for the remaining net book value of each subcritical coal-fired generating facility and amortize the regulatory asset at the same rate the subcritical coal-fired generating facility was previously being depreciated. The regulatory asset shall be included in rate base for rate-making purposes, and in a future general rate proceeding the Commission shall establish an amortization period for recovery and allow a return on the unamortized balance at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

SECTION 1.(f) General Provisions Applicable to Designated Replacement Resources Purchased and Owned by the Electric Public Utilities Pursuant to Subsection (c) of this Section. –

(1) In order to ensure predictable and affordable customer electricity costs for all customers and to ensure an orderly and disciplined transition, the applicable electric utility shall:

a. In the case of the nonrenewable generating facilities procured pursuant to subsection (c) of this section, utilize competitive procurement for the design, engineering, and construction of such generating facilities.

b. In the case of any renewable energy facilities procured pursuant to subsection (c) of this section, competitively procure and purchase such facilities from third parties utilizing the procedures set forth and in compliance with the requirements of G.S. 62-110.8 for procurements occurring after January 1, 2022; provided, however, that (i) the procuring electric public utility shall own and operate all of the renewable energy facilities procured pursuant to this section and the percentage allocation of ownership between third parties and the electric public utilities for procurements commencing after January 1, 2021, that is specified in subsection (b1) of G.S. 62-110.8 for renewable generating facilities shall not apply to procurements of renewable energy facilities pursuant to subsection (c) of this section and (ii) the cost cap specified in subsection (g1) of G.S. 62-110.8 shall not apply to the procurement of renewable energy facilities pursuant to subsection (c) of this section.

c. In the case of the ESS procured pursuant to subsection (c) of this section, competitively procure and purchase such facilities from third parties utilizing the procurement procedures and requirements for independent oversight set forth in G.S. 62-110.8 for procurements occurring after January 1, 2022; provided, however, that (i) the procuring electric public utility shall own and operate all of the ESS procured pursuant to this section and the percentage allocation of ownership between third parties and the electric public utilities for procurements commencing after January 1, 2021, that is specified in subsection (b1) of G.S. 62-110.8 for renewable generating facilities shall not apply to procurements of ESS pursuant to subsection (c) of this section and (ii) the cost cap specified in subsection (g1) of

G.S. 62-110.8 shall not apply to the procurement of ESS pursuant to subsection (c) of this section.

(2) The designated replacement resources identified in subsection (c) of this section that require a certificate of public convenience and necessity under G.S. 62-110.1, or otherwise, shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1 so long as the applicable electric public utility reasonably and prudently procures such replacement generation in a manner consistent with subdivision (1) of this subsection.

(3) Notwithstanding G.S. 62-110.1, the Commission shall provide an expedited decision on an application for a certificate of public convenience for all such resources. The Commission shall render its decision on an application for a certificate, including any related transmission line needed for the new generation facility, within 90 days of the date the application is filed. An application for a certificate of public convenience and necessity to construct or procure those designated replacement resources identified in subsection (c) of this section that require a certificate of public convenience and necessity and the renewable generating facilities purchased and owned by the electric public utilities pursuant to G.S. 62-110.8 through procurements occurring after January 1, 2021, shall be subject to all of the following:

a. The applicable electric public utility shall provide written notice to the Commission of the date the electric public utility intends to file an application no less than 30 days prior to the submission of the application.

b. When the electric public utility applies for a certificate as provided in this subdivision, it shall submit to the Commission an estimate of the costs of construction of the generating facility in such detail as the Commission may require.

c. G.S. 62-110.1(d) and (e) and G.S. 62-82(a) shall not apply to such applications.

d. The Commission shall hold a single public hearing for such applications and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in the county in which the generating facility is located.

(4) The electric public utilities shall be permitted to recover from its customers the reasonably and prudently incurred cost of all generation facilities and energy storage systems purchased or constructed pursuant to subsection (c) or (d) of this section. In the case of an energy storage system approved by the Commission pursuant to subsection (d) of this section, there shall be a rebuttable presumption that the electric public utility's actual costs are reasonable and prudent if such actual costs are at or below the projected costs approved by the Commission. In the case of a certificated generation facility approved by the Commission pursuant to this subsection or subsection (d) of this section or procured pursuant to G.S. 62-110.8, notwithstanding G.S. 62-110.1(f1), there shall be a rebuttable presumption that the electric public utility's actual costs are reasonable and prudent if such actual costs are at or below the projected costs approved by the Commission, provided that upon the request of the electric public utility or upon its own motion pursuant to G.S. 62-110.1(f), the Commission may conduct an ongoing review of construction of the facility under G.S. 62-110.1(f), in which case the cost recovery provisions of G.S. 62-110.1(f1) shall apply except that the electric

public utility may seek cost recovery in a rate case under either G.S. 62-133 or G.S. 62-133.16. The electric public utilities shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all such costs incurred pursuant to this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include, but are not limited to, operation and maintenance expenses, administration costs, property tax, depreciation expenses, income taxes, carrying costs related to electric plant investments, and regulatory assets at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

SECTION 1.(g) G.S. 62-110.8 reads as rewritten:

"**§ 62-110.8. Competitive procurement of renewable energy.**

(a) Each electric public utility shall file for Commission approval a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs. Renewable energy facilities eligible to participate in the competitive procurement shall include those facilities that use renewable energy resources identified in G.S. 62-133.8(a)(8) ~~but~~ but, except as provided in subsection (b1) of this section, shall be limited to facilities with a nameplate capacity rating of 80 megawatts ~~(MW)~~ alternating current (MW AC) or less that are placed in service after the date of the electric public utility's initial competitive procurement. Subject to the limitations set forth in subsections (b) and (c) of this section, the electric public utilities shall issue requests for proposals to procure and shall procure, energy and capacity from renewable energy facilities in the aggregate amount of ~~2,660 megawatts (MW), and the total amount shall be reasonably allocated over a term of 45 months beginning when the Commission approves the program.~~ 7,327 megawatts alternating current (MW AC), and the total amount shall be reasonably allocated over a term of 106 months beginning when the Commission approves the program; provided, however, that the electric public utilities shall conduct an annual procurement of approximately 777 megawatts alternating current (MW AC) each calendar year beginning in 2021 and concluding in 2026. The electric public utilities shall be permitted to petition the Commission for approval to modify the procurement schedule established herein in the event that administration of annual procurements becomes impractical due to the need to align with then existing interconnection study processes or other factors beyond the utilities' control, and the Commission shall approve such modifications if it determines that the modifications would be in the public interest. The Commission shall require the additional competitive procurement of renewable energy capacity by the electric public utilities in an amount that includes all of the following: (i) any unawarded portion of the initial competitive procurement required by this subsection; (ii) any deficit in renewable energy capacity identified pursuant to subdivision (1) of subsection ~~(b)~~ (b2) of this section; and (iii) any capacity reallocated pursuant to G.S. 62-159.2. In addition, at the termination of the initial competitive procurement period of ~~45 months, the offering of a new renewable energy resources competitive procurement and the amount to be procured shall be determined by the Commission, based on a showing of need evidenced by the electric public utility's most recent biennial integrated resource plan or annual update approved by the Commission pursuant to G.S. 62-110.1(c).~~106 months, the Commission shall determine whether it is in the interest of ratepayers to require further competitive procurement of renewable generating facilities by the electric public utilities under this subsection, and shall also determine the amount to be procured beyond that required by this subsection, and the allocation of ownership between third parties and electric public utilities. The Commission's determination shall be based on the electric public utility's most recent biennial integrated resource plan or annual update accepted or approved by the Commission, provided that such plan assures adequate, reliable utility service.

(b) Electric public utilities may jointly or individually implement the aggregate competitive procurement requirements set forth in subsection (a) of this section ~~and~~ and, with respect to procurements commencing prior to January 1, 2021, may satisfy such requirements for the procurement of renewable energy capacity to be supplied by renewable energy facilities through any of the following: (i) renewable energy facilities to be acquired from third parties and subsequently owned and operated by the soliciting public utility or utilities; (ii) renewable energy facilities to be constructed, owned, and operated by the soliciting public utility or utilities subject to the limitations of subdivision (4) of this subsection; or (iii) the purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the procuring public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources.

(b1) All procurements required by subsection (a) of this section commencing after January 1, 2021, and continuing through December 31, 2026, shall be subject to the following requirements:

(1) Forty-five percent (45%) of the total megawatts alternating current (MW AC) of renewable energy facilities scheduled to be procured in procurements commencing after January 1, 2021, shall be supplied through the execution of power purchase agreements with third parties pursuant to which the electric public utility purchases of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources.

(2) Fifty-five percent (55%) of the total megawatts alternating current (MW AC) of renewable energy facilities scheduled to be procured through procurements commencing after January 1, 2021, shall be supplied from renewable energy facilities purchased from third parties and owned and operated by the soliciting electric public utility. The cap on facility nameplate capacity of 80 megawatts alternating current (MW AC) or less established by subsection (a) of this section shall not apply to facilities procured pursuant to this subdivision.

(b2) Procured renewable energy capacity, as provided for in this section, shall be subject to the following limitations:

(1) ~~If prior to the end of the initial 45-month competitive procurement period the public utilities subject to this section have executed power purchase agreements and interconnection agreements for renewable energy capacity within their balancing authority areas that are not subject to economic dispatch or curtailment and were not procured pursuant to G.S. 62-159.2 having an aggregate capacity in excess of 3,500 megawatts (MW), the Commission shall reduce the competitive procurement aggregate amount by the amount of such exceedance. If the aggregate capacity of such renewable energy facilities is less than 3,500 megawatts (MW) at the end of the initial 45-month competitive procurement period, the Commission shall require the electric public utilities to conduct an additional competitive procurement in the amount of such deficit.~~In the event that it is reasonably projected that, on or before January 1, 2027, the electric public utilities subject to the procurement obligation under subsection (a) of this section will have executed power purchase agreements and interconnection agreements with renewable generating facilities within their balancing authority areas having an aggregate megawatts alternating current (MW AC) capacity in excess of 3,500 megawatts alternating current

(MW AC), exclusive of power purchase agreements entered into pursuant to this section, G.S. 62-159.2, and G.S. 62-126.8B, the Commission shall reduce the total aggregate megawatts alternating current (MW and AC) capacity of renewable generating facilities required for procurement under this section by an amount equal to the difference between (i) the amount of aggregate megawatts alternating current (MW AC) capacity of renewable generating facilities with executed power purchase agreements and interconnection agreements, including all such renewable generating facilities located in the electric public utility's balancing authority area, whether located inside or outside the geographic boundaries of the State but exclusive of power purchase agreements entered into pursuant to this section, G.S. 62-159.2, and G.S. 62-126.8B and (ii) 3,500 megawatts alternating current (MW AC).

(2) To ensure the cost-effectiveness of ~~procured~~ new renewable energy resources, ~~each public utility's procurement obligation~~ the price to be paid under any power purchase agreements for third-party owned resources, combined with the cost of any necessary transmission or distribution upgrade, shall be capped by the public utility's current forecast of its avoided cost calculated over the term of the power purchase agreement. The public utility's current forecast of its avoided cost shall be consistent with the Commission-approved avoided cost methodology.

(3) Each public utility shall submit to the Commission for approval and make publicly available at 30 days prior to each competitive procurement solicitation a pro forma ~~contract~~ power purchase agreement to be utilized for the purpose of informing market participants of terms and conditions of the competitive procurement. Each pro forma ~~contract~~ power purchase agreement shall define limits and compensation for resource dispatch and ~~curtailments.~~ curtailments; provided, however, that curtailment shall be limited to a percentage of the expected output of the generation facility that is determined by the Commission to be in the public interest. The pro forma ~~contract~~ power purchase agreement shall be for a term of 20 years; provided, however, the Commission may approve a contract term of a different duration if the Commission determines that it is in the public interest to do so.

(4) ~~No~~ With respect only to those procurements commencing prior to January 1, 2021, more than thirty percent (30%) of an electric public utility's competitive procurement requirement may be satisfied through the utility's own development of renewable energy facilities offered by the electric public utility or any subsidiary of the electric public utility that is located within the electric public utility's service territory. This limitation shall not apply to any renewable energy facilities acquired by an electric public utility that are selected through the competitive procurement and are located within the electric public utility's service territory.

(c) Subject to the aggregate competitive procurement requirements established by this section, the electric public utilities shall have the authority to determine the location and allocated amount of the competitive procurement within their respective balancing authority areas, whether located inside or outside the geographic boundaries of the State, taking into consideration (i) the State's desire to foster diversification of siting of renewable energy resources throughout the State; (ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and (iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as nondispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs. In the case of renewable energy facilities to be procured and owned by the electric public utilities pursuant to this section, the electric public utilities shall be permitted through the competitive processes described herein to solicit bids for the construction of such renewable energy facilities on or near property owned or controlled by the electric public utility, including the site of any retiring subcritical coal-fired generating facility, where such sites will provide benefits to customers, including through reduced interconnection or infrastructure costs.

(d) ~~The~~ For all procurements commencing prior to January 1, 2022, the competitive procurement of renewable energy capacity established pursuant to this section shall be independently administered by a third-party entity to be approved by the ~~Commission. The third-party entity shall~~ Commission, provided that in the case of any procurement commencing after January 1, 2021, but prior to January 1, 2022, the electric public utilities shall be permitted to directly assist the third-party entity and provide input on all aspects of the procurement and shall collaborate with the third-party entity to develop and publish the methodology used to evaluate responses received pursuant to a competitive procurement solicitation and to ensure that all responses are treated equitably. For all procurements commencing after January 1, 2022, the competitive procurement of renewable energy capacity required pursuant to this section shall be administered by the electric public utilities in accordance with the rules to be adopted pursuant to subdivision (1) of subsection (h) of this section, and subject to oversight and evaluation by a third-party entity to be approved by the Commission. All reasonable and prudent administrative and related expenses incurred to implement this subsection shall be recovered from market participants through administrative fees levied upon those that participate in the competitive bidding process, as approved by the Commission.

(e) ~~An~~ With respect only to those procurements commencing prior to January 1, 2021, an electric public utility may participate in any competitive procurement process, but shall only participate within its own assigned service territory. If the public utility uses nonpublicly available information concerning its own distribution or transmission system in preparing a proposal to a competitive procurement, the public utility shall make such information available to third parties that have notified the public utility of their intention to submit a proposal to the same request for proposals.

(e1) In the case of all procurements commencing after January 1, 2021, neither the electric public utilities nor any of their affiliates shall be permitted to submit bids into the competitive procurement process or to have any financial interest in third-party bidders.

(e2) The renewable generating facilities purchased and owned by the electric public utilities pursuant to this section through procurements occurring after January 1, 2021, shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1 so long as the renewable generating facilities were procured in compliance with the procurement process established under this section.

(f) For purposes of this section, the term "balancing authority" means the entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time, and the term "balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of the balancing authority, and the balancing authority maintains load-resource balance within this area.

(g) An electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets ~~that are~~ procured pursuant to this section prior to January 1, 2021, through an annual rider approved by the Commission and reviewed annually. Provided it is in the public interest, the authorized revenue for any such renewable energy facilities owned by an electric public utility and procured pursuant to this section prior to January 1, 2021, may be calculated on a market basis in lieu of cost-of-service based recovery, using data from the applicable competitive procurement to determine the market price in accordance with the methodology established by the Commission pursuant to subsection (h) of this section. The annual increase in the aggregate amount of these costs that are recoverable by an electric public utility pursuant to this subsection shall not exceed one percent (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year.

(g1) With respect to all procurements commencing after January 1, 2021, an electric public utility shall be permitted to recover from its customers the reasonably and prudently incurred costs paid under power purchase agreements executed pursuant to this section through the rider authorized under subsection (g) of this section; provided, however, costs that may be recovered by the utility for utility-owned renewable generating facilities shall be subject to the same cost caps established under subdivision (2) of subsection (b2) of this section applicable to power purchases of third-party owned resources. An electric public utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all such costs incurred pursuant to this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include, but are not limited to, operation and maintenance expenses, administration costs, property tax, depreciation expense, income taxes, carrying costs related to electric plant investments, and regulatory assets at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

(g2) In determining the most cost-effective proposals in any procurement process under this section, the electric public utility shall take into account the cost of any needed transmission or distribution upgrades but, in the case of any proposals selected by the electric public utility, such transmission or distribution upgrades costs shall not be directly assigned to the bidder but instead shall be included in the electric public utility's rate base for rate-making purposes. In addition, the electric public utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental cost of all such upgrades, along with associated carrying costs based on the electric public utility's then authorized net-of-tax, weighted average cost of capital, until such time as the costs can be reflected in customer rates. In a future general rate proceeding, the Commission shall establish an amortization period for recovery and allow a return on the unamortized balance at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

(h) The Commission shall adopt rules to implement the requirements of this section, as follows:

(1) Oversight of the competitive procurement ~~program.~~program by the Commission and by independent third parties. No later than May 1, 2022, the Commission's rules shall be amended to provide for (i) administration of the procurement process, including establishing the selection methodology and selection of projects, by the electric public utilities subject to the oversight of an independent evaluator retained by the utilities pursuant to a contract approved by the Commission, (ii) approval by the Commission of the electric public utilities' selection methodology and the independent evaluator's review procedures, (iii) detailed reports by the independent evaluator to the Commission regarding the results of each procurement, and (iv) any further changes related to the foregoing, including modification of communication restrictions deemed appropriate by the Commission.

(2) To provide for a waiver of regulatory conditions or code of conduct requirements that would unreasonably restrict a public utility or its affiliates from participating in the competitive procurement ~~process,~~ with respect to procurements occurring under this section prior to January 1, 2021, unless the

Commission finds that such a waiver would not hold the public utility's customers harmless.

(3) Establishment of a procedure for expedited review and approval of certificates of public convenience and necessity, or the transfer thereof, for renewable energy facilities owned by the public utility and procured pursuant to this section. The Commission shall issue an order not later than 30 days after a petition for a certificate is filed by the public utility.

(4) Establishment of a methodology to allow an electric public utility to recover its costs pursuant to ~~subsection (g)~~ subsections (g), (g1), and (g2) of this section.

(5) Establishment of a procedure for the Commission to modify or delay implementation of the provisions of this section in whole or in part if the Commission determines that it is in the public interest to do so.

…."

SECTION 1.(h) The requirements of subsections (a) through (g) of this section shall not apply to an electric public utility serving fewer than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021.

SECTION 1.(i) G.S. 62-133.2 reads as rewritten:

"**§ 62-133.2. Fuel and fuel-related charge adjustments for electric utilities.**

…

(d) The Commission shall provide for notice of a public hearing with reasonable and adequate time for investigation and for all intervenors to prepare for hearing. At the hearing the Commission shall receive evidence from the utility, the Public Staff, and any intervenor desiring to submit evidence, and from the public generally. In reaching its decision, the Commission shall consider all evidence required under subsection (c) of this section as well as any and all other competent evidence that may assist the Commission in reaching its decision including changes in the cost of fuel consumed and fuel-related costs that occur within a reasonable time, as determined by the Commission, after the test period is closed. The Commission shall incorporate in its cost of fuel and fuel-related costs determination under this subsection the experienced over-recovery or under-recovery of reasonable costs of fuel and fuel-related costs prudently incurred during the test period, based upon the prudent standards set pursuant to subsection (d1) of this section, in fixing an increment or decrement rider. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of costs of fuel and fuel-related costs through the date that is 30 calendar days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual hearing pursuant to this section. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case. The burden of proof as to the correctness and reasonableness of the charge and as to whether the cost of fuel and fuel-related costs were reasonably and prudently incurred shall be on the utility. The Commission shall allow only that portion, if any, of a requested cost of fuel and fuel-related costs adjustment that is based on adjusted and reasonable cost of fuel and fuel-related costs prudently incurred under efficient management and economic operations. Efficient management and economic operations include actions and decisions that modify commitment and dispatch to manage seasonal demand, mitigate fuel supply security and transportation risk, and maintain dispatchable capacity value. In evaluating whether cost of fuel and fuel-related costs were reasonable and prudently incurred, the Commission shall apply the rule adopted pursuant to subsection (d1) of this section. To the extent that the Commission determines that an increment or decrement to the rates of the utility due to changes in the cost of fuel and fuel-related costs over or under base fuel costs established in the preceding general rate case is just and reasonable, the Commission shall order that the increment or decrement become effective for all sales of electricity and remain in effect until changed in a subsequent general rate case or annual proceeding under this section.

…."

SECTION 1.(j) This section is effective when it becomes law.

AUTHORIZE FINANCING OF CERTAIN ENERGY TRANSITION COSTS

SECTION 2.(a) Article 8 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-173. Financing for certain energy transition costs.**

(a) Definitions. – The following definitions apply in this section:

(1) Ancillary agreement. – A bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with energy transition bonds.

(2) Assignee. – A legally recognized entity to which a public utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to energy transition property. The term includes a corporation, limited liability company, general partnership or limited partnership, public authority, trust, financing entity, or any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to energy transition property.

(3) Bondholder. – A person who holds an energy transition bond.

(4) Code. – The Uniform Commercial Code, Chapter 25 of the General Statutes.

(5) Commission. – The North Carolina Utilities Commission.

(6) Energy transition bonds. – Bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued by a public utility or an assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved energy transition costs and financing costs, and that are secured by or payable from energy transition property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

(7) Energy transition charge. – The amounts authorized by the Commission to repay, finance, or refinance energy transition costs and financing costs and that are nonbypassable charges (i) imposed on and part of all retail customer bills, (ii) collected by a public utility or its successors or assignees, or a collection agent, in full, separate and apart from the public utility's base rates, and (iii) paid by all existing or future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this State.

(8) Energy transition costs. – A cost other than a monetary penalty, fine, or forfeiture assessed against a public utility by a government agency or court under a federal or State environmental statute, rule, or regulation for retirement of Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant. The total amount that shall be securitized as provided by this subdivision shall be five hundred million dollars ($500,000,000), which shall be allocated among these plants in a

manner that realizes the greatest cost savings to ratepayers as determined by the Commission. Such costs include:

a. An amount determined and approved by the Commission not to exceed the total aggregate unrecovered net book value, plus the costs set forth in sub-subdivisions b., c., and d. of this subdivision, of the subcritical coal-fired electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant.

b. The following costs the public utility has incurred or will incur caused by, associated with, or that remain as a result of the early retirement of electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant:

1. All incremental costs, including capital costs, appropriate for recovery from existing and future retail customers receiving transmission or distribution service from the electric public utility that the utility has incurred or expects to incur as a result of the early retirement of the Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant, including the costs of decommissioning and restoring the site of such early retired electric generating facilities, except for costs incurred pursuant to G.S. 130A-309.200 through G.S. 130A-309.226 or 40 C.F.R. Subpart D, which are not subject to this section.

2. The electric public utility's cost of capital from the date this section becomes effective to the date the energy transition bonds are issued, calculated using the public utility's weighted average cost of capital as defined in its most recent base rate case proceeding before the Commission net of applicable income tax savings related to the interest component. Such costs also include other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

c. Energy transition costs shall be net of applicable insurance proceeds, tax benefits, and any other amounts intended to reimburse the public utility for energy transition activities such as government grants, or aid of any kind and where determined appropriate by the Commission, and may include adjustments for capital replacement and operating costs previously considered in determining normal amounts in the public utility's most recent general rate case proceeding.

d. With respect to energy transition costs that the public utility expects to incur, any difference between costs expected to be incurred and actual, reasonable, and prudent costs incurred, or any other rate-making adjustments appropriate to fairly and reasonably assign or allocate energy transition cost recovery to customers over time, shall be addressed in a future general rate proceeding, as may be facilitated by other orders of the Commission issued at the time or prior to such proceeding; provided, however, that the Commission's adoption of a financing order and approval of the issuance of energy transition bonds may not be revoked or otherwise modified.

(9) Energy transition property. – All of the following:

a. All rights and interests of a public utility or successor or assignee of the public utility under a financing order, including the right to impose, bill, charge, collect, and receive energy transition charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order.

b. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

(10) Financing costs. – The term includes all of the following:

a. Interest and acquisition, defeasance, or redemption premiums payable on energy transition bonds.

b. Redemption premiums or make-whole payments related to the early redemption of the public utility's first mortgage bonds or other debt associated with the retired electric generating facility.

c. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to energy transition bonds.

d. Any other cost related to issuing, supporting, repaying, refunding, and servicing energy transition bonds, including servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of energy transition bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order.

e. Any taxes and license fees or other fees imposed on the revenues generated from the collection of the energy transition charge or otherwise resulting from the collection of energy transition charges, in any such case whether paid, payable, or accrued.

f. Any State and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued.

g. Any costs incurred by the Commission or public staff for any outside consultants or counsel retained in connection with the securitization of energy transition costs.

(11) Financing order. – An order that authorizes the issuance of energy transition bonds; the imposition, collection, and periodic adjustments of an energy transition charge; the creation of energy transition property; and the sale, assignment, or transfer of energy transition property to an assignee.

(12) Financing party. – Bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

(13) Financing statement. – Defined in Article 9 of the Code.

(14) Pledgee. – A financing party to which a public utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to energy transition property.

(15) Public utility. – A public utility, as defined in G.S. 62-3, that sells electric power to retail electric customers in the State.

(b) Financing Orders. –

(1) A public utility shall petition the Commission for a financing order for energy transition costs. The petition shall include all of the following:

a. The energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed.

b. An estimate of the financing costs related to the energy transition bonds.

c. An estimate of the energy transition charges necessary to recover the energy transition costs and financing costs and the proposed period for recovery of such costs.

d. A comparison between the net present value of the costs to customers that are estimated to result from the issuance of energy transition bonds and the costs that would result from the application of the traditional method of financing and recovering energy transition costs from customers. The comparison shall demonstrate that the issuance of energy transition bonds and the imposition of energy transition charges are expected to provide quantifiable benefits to customers.

e. Direct testimony and exhibits supporting the petition.

(2) If a public utility is subject to a settlement agreement that governs the type and amount of principal costs that could be included in energy transition costs, and the principal costs are not already subject to review and approval by the Commission in a separate proceeding, then the public utility shall file a petition with the Commission for review and approval of those principal costs no later than 90 days before filing a petition for a financing order pursuant to this section.

(3) Petition and order. –

a. Proceedings on a petition submitted pursuant to this subdivision begin with the petition by a public utility, initially filed on or before January 1, 2023, subject to the time frame specified in subdivision (2) of this subsection, if applicable, and shall be disposed of in accordance with the requirements of this Chapter and the rules of the Commission, except as follows:

1. Within 14 days after the date the petition is filed, the Commission shall establish a procedural schedule that permits a Commission decision no later than 135 days after the date the petition is filed.

2. No later than 135 days after the date the petition is filed, the Commission shall issue a financing order or an order rejecting the petition. If a petition for a financing order is rejected, the Commission shall include in its order the reasons for the rejection, and the utility shall resubmit a petition within 60 days of the order rejecting the earlier petition. A party to the

Commission proceeding may petition the Commission for reconsideration of the financing order within five days after the date of its issuance.

b. A financing order issued by the Commission to a public utility shall include all of the following elements:

1. Except for changes made pursuant to the formula-based mechanism authorized under this section, the amount of energy transition costs to be financed using energy transition bonds. The Commission shall describe and estimate the amount of financing costs that shall be recovered through energy transition charges and specify the period over which energy transition costs and financing costs shall be recovered.
2. A finding that the proposed issuance of energy transition bonds and the imposition and collection of an energy transition charge are expected to provide quantifiable benefits to customers as compared to the cost that would have been incurred absent the issuance of energy transition bonds.
3. A finding that the structuring and pricing of the energy transition bonds are reasonably expected to result in the lowest energy transition charges consistent with market conditions at the time the energy transition bonds are priced and the terms set forth in such financing order.
4. A requirement that, for so long as the energy transition bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of energy transition charges authorized under a financing order shall be nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in this State.
5. A formula-based true-up mechanism for making, at least annually, expeditious periodic adjustments in the energy transition charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of energy transition bonds and financing costs and other required amounts and charges payable in connection with the energy transition bonds.
6. The energy transition property that is, or shall be, created in favor of a public utility or its successors or assignees and that shall be used to pay or secure energy transition bonds and all financing costs.
7. The degree of flexibility to be afforded to the public utility in establishing the terms and conditions of the energy transition bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs.

8. How energy transition charges will be allocated among customer classes.

9. A requirement that, after the final terms of an issuance of energy transition bonds have been established and before the issuance of energy transition bonds, the public utility determines the resulting initial energy transition charge in accordance with the financing order and that such initial energy transition charge be final and effective upon the issuance of such energy transition bonds without further Commission action so long as the energy transition charge is consistent with the financing order.

10. A requirement that the public utility, simultaneously with the inception of the collection of energy transition charges, reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement in customer rates associated with the utility assets being financed by energy transition bonds. The public utility shall propose the method to reduce its rates in accordance with this sub-sub-subdivision in its petition.

11. A method of tracing funds collected as energy transition charges, or other proceeds of energy transition property, and determine that such method shall be deemed the method of tracing such funds and determining the identifiable cash proceeds of any energy transition property subject to a financing order under applicable law.

12. Establishment of a bond team consisting of representatives of the public utility and its consultant, the Public Staff and its consultant, and the Commission with a designated Commissioner and the Commission's consultant and counsel.

13. A direction for the bond team to work together and make all decisions as to the structuring, marketing, and pricing of the energy transition bonds; the selection of the underwriters; and the approval of the transaction documents. The Commission shall have final decision-making authority on all matters considered by the bond team.

14. Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to a public utility may provide that creation of the public utility's energy transition property is conditioned upon, and simultaneous with, the sale or other transfer of the energy transition property to an assignee and the pledge of the energy transition property to secure energy transition bonds.

d. If the Commission issues a financing order, the public utility shall file with the Commission at least annually a petition or a letter applying the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of energy transition charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of energy transition bonds approved under the financing order. Within 30 days after receiving a public utility's request pursuant to this paragraph, the Commission shall either approve the request or inform the public utility of any mathematical or clerical errors in its calculation. If the Commission informs the utility of mathematical or clerical errors in its calculation, the utility may correct its error and refile its request. The time frames previously described in this paragraph shall apply to a refiled request.

e. Subsequent to the transfer of energy transition property to an assignee or the issuance of energy transition bonds authorized thereby, whichever is earlier, a financing order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust energy transition charges approved in the financing order. After the issuance of a financing order, the public utility retains sole discretion regarding whether to assign, sell, or otherwise transfer energy transition property.

(4) At the request of a public utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding the energy transition bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded energy transition bonds and the issuance of new energy transition bonds, the Commission shall adjust the related energy transition charges accordingly.

(5) Within 60 days after the Commission issues a financing order or a decision denying a request for reconsideration or, if the request for reconsideration is granted, within 30 days after the Commission issues its decision on reconsideration, an adversely affected party may petition for judicial review in the Supreme Court of North Carolina. Review on appeal shall be based solely on the record before the Commission and briefs to the court and is limited to determining whether the financing order, or the order on reconsideration, conforms to the State Constitution and State and federal law and is within the authority of the Commission under this section.

(6) Duration of financing order. –

a. A financing order remains in effect and energy transition property under the financing order continues to exist until energy transition bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such energy transition bonds have been recovered in full.

b. A financing order issued to a public utility remains in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the public utility or its successors or assignees.

(c) Exception to Commission Jurisdiction. – The Commission may not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this Chapter, consider the energy transition bonds issued pursuant to a financing order to be the debt of the public utility other than for federal income tax purposes, consider the energy transition charges paid under the financing order to be the revenue of the public utility for any purpose, or consider the energy transition costs or financing costs specified in the financing order to be the costs of the public utility, nor may the Commission determine any action taken by a public utility which is consistent with the financing order to be unjust or unreasonable.

(d) Public Utility Duties. – The electric bills of a public utility that has obtained a financing order and caused energy transition bonds to be issued must comply with the provisions of this subsection; however, the failure of a public utility to comply with this subsection does not invalidate, impair, or affect any financing order, energy transition property, energy transition charge, or energy transition bonds. The public utility must do all of the following:

(1) Explicitly reflect that a portion of the charges on such bill represents energy transition charges approved in a financing order issued to the public utility and, if the energy transition property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to energy transition charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the energy transition charge and the ownership of the charge.

(2) Include the energy transition charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill.

(e) Energy Transition Property. –

(1) Provisions applicable to energy transition property. –

a. All energy transition property that is specified in a financing order constitutes an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of energy transition charges depends on the public utility, to which the financing order is issued, performing its servicing functions relating to the collection of energy transition charges and on future electricity consumption. The property exists (i) regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to customers by the public utility or its successors or assignees and the future consumption of electricity by customers.

b. Energy transition property specified in a financing order exists until energy transition bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such energy transition bonds have been recovered in full.

c. All or any portion of energy transition property specified in a financing order issued to a public utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the public utility and created for the limited purpose of acquiring, owning, or administering energy transition property or issuing energy transition bonds under the financing order. All or any portion of energy transition property may be pledged to secure energy transition bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in, or pledge of energy transition property by a public utility, or an affiliate of the public utility, to an assignee, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission.

d. If a public utility defaults on any required payment of charges arising from energy transition property specified in a financing order, a court, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the energy transition property to the financing parties or their assignees. Any such financing order remains in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the public utility or its successors or assignees.

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in energy transition property specified in a financing order issued to a public utility, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by the public utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the public utility or any other entity.

f. Any successor to a public utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of public utility restructuring or otherwise, must perform and satisfy all obligations of, and have the same rights under a financing order as, the public utility under the financing order in the same manner and to the same extent as the public utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the energy transition property. Nothing in this sub-subdivision is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities.

g. Energy transition bonds shall be nonrecourse to the credit or any assets of the public utility other than the energy transition property as specified in the financing order and any rights under any ancillary agreement.

(2) Provisions applicable to security interests. –

a. The creation, perfection, and enforcement of any security interest in energy transition property to secure the repayment of the principal and interest and other amounts payable in respect of energy transition bonds; amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not by the provisions of the Code.

b. A security interest in energy transition property is created, valid, and binding and perfected at the later of the time (i) the financing order is issued, (ii) a security agreement is executed and delivered by the debtor granting such security interest, (iii) the debtor has rights in such energy transition property or the power to transfer rights in such energy transition property, or (iv) value is received for the energy transition property. The description of energy transition property in a security agreement is sufficient if the description refers to this section and the financing order creating the energy transition property.

c. A security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of a financing statement with the office of the Secretary of State, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the energy transition property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section.

d. The Secretary of State shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code.

e. The priority of a security interest in energy transition property is not affected by the commingling of energy transition charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all energy transition charges that are deposited in any cash or deposit account of the qualifying utility in which energy transition charges have been commingled with other funds, and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

f. No application of the formula-based adjustment mechanism as provided in this section will affect the validity, perfection, or priority of a security interest in or transfer of energy transition property.

g. If a default or termination occurs under the energy transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any energy transition property as if they were secured parties with a perfected and prior lien under the Code, and the Commission may order amounts arising from energy transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Superior Court of Wake County shall order the sequestration and payment to them of revenues arising from the energy transition charges.

(3) Provisions applicable to the sale, assignment, or transfer of energy transition property. –

a. Any sale, assignment, or other transfer of energy transition property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the energy transition property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and State income tax purposes. For all purposes other than federal and State income tax purposes, the parties' characterization of a transaction as a sale of an interest in energy transition property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of whether the purchaser has possession of any documents evidencing or pertaining to the interest. A transfer of an interest in energy transition property may be created only when all of the following have occurred (i) the financing order creating the energy transition property has become effective, (ii) the documents evidencing the transfer of energy transition property have been executed by the assignor and delivered to the assignee, and (iii) value is received for the energy transition property. After such a transaction, the energy transition property is not subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the energy transition property perfected in accordance with subdivision (2) of this subsection.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser shall not be affected or impaired by the occurrence of any of the following factors:

1. Commingling of energy transition charges with other amounts.
2. The retention by the seller of (i) a partial or residual interest, including an equity interest, in the energy transition property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of energy transition charges.
3. Any recourse that the purchaser may have against the seller.
4. Any indemnification rights, obligations, or repurchase rights made or provided by the seller.
5. The obligation of the seller to collect energy transition charges on behalf of an assignee.
6. The transferor acting as the servicer of the energy transition charges or the existence of any contract that authorizes or requires the public utility, to the extent that any interest in energy transition property is sold or assigned, to contract with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the energy transition charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party.
7. The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes.
8. The granting or providing to bondholders a preferred right to the energy transition property or credit enhancement by the public utility or its affiliates with respect to such energy transition bonds.
9. Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that a public utility has in the energy transition property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order is property in the form of a contract right or a chose in action. Transfer of an interest in energy transition property to an assignee is enforceable only upon the later of (i) the issuance of a financing order, (ii) the assignor having rights in such energy transition property or the power to transfer rights in such energy transition property to an assignee, (iii) the execution and delivery by the assignor of transfer documents in connection with the issuance of energy transition bonds, and (iv) the receipt of value for the energy transition property. An enforceable transfer of an interest in energy transition property to an assignee is perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with sub-subdivision c. of subdivision (2) of this subsection. The transfer is perfected against third parties as of the date of filing.

d. The Secretary of State shall maintain any financing statement filed to perfect any sale, assignment, or transfer of energy transition property under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code. The filing of such a financing statement is the only method of perfecting a transfer of energy transition property.

e. The priority of a transfer perfected under this section is not impaired by any later modification of the financing order or energy transition property or by the commingling of funds arising from energy transition property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision (2) of this subsection, is terminated when they are transferred to a segregated account for the assignee or a financing party. If energy transition property has been transferred to an assignee or financing party, any proceeds of that property must be held in trust for the assignee or financing party.

f. The priority of the conflicting interests of assignees in the same interest or rights in any energy transition property is determined as follows:

1. Conflicting perfected interests or rights of assignees rank according to priority in time of perfection. Priority dates from the time a filing covering the transfer is made in accordance with sub-subdivision c. of subdivision (2) of this subsection.
2. A perfected interest or right of an assignee has priority over a conflicting unperfected interest or right of an assignee.
3. A perfected interest or right of an assignee has priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

(f) Description or Indication of Property. – The description of energy transition property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement is only sufficient if such description or indication refers to the financing order that created the energy transition property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section applies to all purported transfers of, and all purported grants or liens or security interests in, energy transition property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

(g) Financing Statements. – All financing statements referenced in this section are subject to Part 5 of Article 9 of the Code, except that the requirement as to continuation statement does not apply.

(h) Choice of Law. – The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any energy transition property shall be the laws of this State.

(i) Energy Transition Bonds Not Public Debt. – Neither the State nor its political subdivisions are liable on any energy transition bonds, and the bonds are not a debt or a general obligation of the State or any of its political subdivisions, agencies, or instrumentalities, nor are they special obligations or indebtedness of the State or any agency or political subdivision. An issue of energy transition bonds does not, directly, indirectly, or contingently, obligate the State or any agency, political subdivision, or instrumentality of the State to levy any tax or make any appropriation for payment of the energy transition bonds, other than in their capacity as consumers of electricity. All energy transition bonds must contain on the face thereof a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of North Carolina is pledged to the payment of the principal of, or interest on, this bond."

(j) Legal Investment. – All of the following entities may legally invest any sinking funds, moneys, or other funds in energy transition bonds:

(1) Subject to applicable statutory restrictions on State or local investment authority, the State, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission.

(2) Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business.

(3) Personal representatives, guardians, trustees, and other fiduciaries.

(4) All other persons authorized to invest in bonds or other obligations of a similar nature.

(k) Obligation of Nonimpairment. –

(1) The State and its agencies, including the Commission, pledge and agree with bondholders, the owners of the energy transition property, and other financing parties that the State and its agencies will not take any action listed in this subdivision. This paragraph does not preclude limitation or alteration if full compensation is made by law for the full protection of the energy transition charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the public utility. The prohibited actions are as follows:

a. Alter the provisions of this section, which authorize the Commission to create an irrevocable contract right or a chose in action by the issuance of a financing order, to create energy transition property, and make the energy transition charges imposed by a financing order irrevocable, binding, or nonbypassable charges.

b. Take or permit any action that impairs or would impair the value of energy transition property or the security for the energy transition bonds or revises the energy transition costs for which recovery is authorized.

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties.

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair energy transition charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related energy transition bonds have been paid and performed in full.

(2) Any person or entity that issues energy transition bonds may include the language specified in this subsection in the energy transition bonds and related documentation.

(*l*) Not a Public Utility. – An assignee or financing party is not a public utility or person providing electric service by virtue of engaging in the transactions described in this section.

(m) Conflicts. – If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in energy transition property, this section shall govern.

(n) Consultation. – In making determinations under this section, the Commission or public staff or both may engage an outside consultant and counsel.

(o) Effect of Invalidity. – If anyprovision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity of any action allowed under this section which is taken by a public utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement; and any such action remains in full force and effect with respect to all energy transition bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason."

SECTION 2.(b) G.S. 25-9-109 reads as rewritten:

"**§ 25-9-109. Scope.**

(a) General scope of Article. – Except as otherwise provided in subsections (c) and (d) of this section, this Article applies ~~to:~~to all of the following:

(1) A transaction, regardless of its form, that creates a security interest in personal property or fixtures by ~~contract;~~contract.

(2) An agricultural ~~lien;~~lien.

(3) A sale of accounts, chattel paper, payment intangibles, or promissory ~~notes;~~notes.

(4) A ~~consignment;~~consignment.

(5) A security interest arising under G.S. 25-2-401, 25-2-505, 25-2-711(3), or 25-2A-508(5), as provided in ~~G.S. 25-9-110; and~~G.S. 25-9-110.

(6) A security interest arising under G.S. 25-4-208 or G.S. 25-5-118.

(b) Security interest in secured obligation. – The application of this Article to a security interest in a secured obligation is not affected by the fact that the obligation is itself secured by a transaction or interest to which this Article does not apply.

(c) Extent to which Article does not apply. – This Article does not apply to the extent ~~that:~~that any one or more of the following conditions are met:

(1) A statute, regulation, or treaty of the United States preempts this ~~Article;~~Article.

(2) Repealed by Session Laws 2001-218, s. 2, effective July 1, 2001.

(3) A statute of another state, a foreign country, or a governmental unit of another state or a foreign country, other than a statute generally applicable to security interests, expressly governs creation, perfection, priority, or enforcement of a security interest created by the state, country, or governmental ~~unit; or~~unit.

(4) The rights of a transferee beneficiary or nominated person under a letter of credit are independent and superior under G.S. 25-5-114.

(d) Inapplicability of Article. – This Article does not apply ~~to:~~to any of the following:

(1) A landlord's lien, other than an agricultural ~~lien;~~lien.

(2) A lien, other than an agricultural lien, given by statute or other rule of law for services or materials, but G.S. 25-9-333 applies with respect to priority of the ~~lien;~~lien.

(3) An assignment of a claim for wages, salary, or other compensation of an ~~employee;~~employee.

(4) A sale of accounts, chattel paper, payment intangibles, or promissory notes as part of a sale of the business out of which they ~~arose;~~arose.

(5) An assignment of accounts, chattel paper, payment intangibles, or promissory notes which is for the purpose of collection ~~only;~~only.

(6) An assignment of a right to payment under a contract to an assignee that is also obligated to perform under the ~~contract;~~contract.

(7) An assignment of a single account, payment intangible, or promissory note to an assignee in full or partial satisfaction of a preexisting ~~indebtedness;~~indebtedness.

(8) A transfer of an interest in or an assignment of a claim under a policy of insurance, other than an assignment by or to a health-care provider of a health-care-insurance receivable and any subsequent assignment of the right to payment, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(9) An assignment of a right represented by a judgment, other than a judgment taken on a right to payment that was ~~collateral;~~collateral.

(10) A right of recoupment or setoff, ~~but:~~but (i) G.S. 25-9-340

~~a.~~ ~~G.S. 25-9-340~~ applies with respect to the effectiveness of rights of recoupment or setoff against deposit ~~accounts; and~~accounts and (ii) G.S. 25-9-404

~~b.~~ ~~G.S. 25-9-404~~ applies with respect to defenses or claims of an account ~~debtor;~~debtor.

(11) The creation or transfer of an interest in or lien on real property, including a lease or rents thereunder, except to the extent that provision is made ~~for:~~for the following:

a. Liens on real property in G.S. 25-9-203 and ~~G.S. 25-9-308;~~G.S. 25-9-308.

b. Fixtures in ~~G.S. 25-9-334;~~G.S. 25-9-334.

c. Fixture filings in G.S. 25-9-501, 25-9-502, 25-9-512, 25-9-516, and ~~25-9-519; and~~25-9-519.

d. Security agreements covering personal and real property in ~~G.S. 25-9-604;~~G.S. 25-9-604.

(12) An assignment of a claim arising in tort, other than a commercial tort claim, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(13) An assignment of a deposit account in a consumer transaction, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(14) The creation, perfection, priority, or enforcement of any lien on, assignment of, pledge of, or security in, any revenues, rights, funds, or other tangible or intangible assets created, made, or granted by this State or a governmental unit in this State, including the assignment of rights as secured party in security interests granted by any party subject to the provisions of this Article to this State or a governmental unit in this State, to secure, directly or indirectly, any bond, note, other evidence of indebtedness, or other payment obligations for borrowed money issued by, or in connection with, installment or lease purchase financings by, this State or a governmental unit in this State. However, notwithstanding this subdivision, this Article does apply to the creation, perfection, priority, and enforcement of security interests created by this State or a governmental unit in this State in equipment or ~~fixtures; or~~fixtures.

(15) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any storm recovery property as defined in G.S. 62-172.

(16) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any energy transition property as defined in G.S. 62-173."

SECTION 2.(c) This section is effective when it becomes law.

ADVANCED NUCLEAR EARLY SITE PERMIT AND SUBSEQUENT LICENSE RENEWAL

SECTION 3.(a) In order to support a diverse portfolio of advanced energy technologies, reduce future permitting and siting costs, and promote the development of advanced nuclear energy, the electric public utilities operating in this State may jointly or separately incur costs up to an aggregate total of fifty million dollars ($50,000,000) to pursue an Early Site Permit (ESP) from the Nuclear Regulatory Commission for siting of an advanced nuclear facility at a single location in the State. The electric public utilities shall make reasonable efforts to obtain any funding available from any federal agencies in order to offset such costs, and any such funding obtained from a federal agency shall be utilized to offset the costs incurred. Each participating electric public utility may establish a regulatory asset and defer to such regulatory asset the incremental costs incurred in connection with its pursuit of an ESP, along with associated carrying costs based on the utility's then-authorized, net-of-tax, weighted average cost of capital, until such time as the costs can be reflected in customer rates. In a future general rate proceeding, the Commission shall establish an amortization period for recovery, and allow a return on the unamortized balance at the utility's then authorized, net-of-tax, weighted average cost of capital. This section shall not be construed to provide any legislative endorsement for the selection of nuclear resources in future electric public utility integrated resource plans, which shall be reviewed by the Commission in accordance with then-applicable laws and regulations.

SECTION 3.(b) In order to support the continued operation of high capacity factor, low-cost, and emissions free nuclear electric generation, the electric public utilities are directed to prepare and submit Subsequent License Renewal applications with the Nuclear Regulatory Commission for each of the six currently operating nuclear electric generating facility sites in the electric public utilities' balancing area authority. The electric public utilities shall report on the status of the Subsequent License Renewal applications in their integrated resource plan filings.

SECTION 3.(c) This section is effective when it becomes law.

PART II. RATE-MAKING MODERNIZATION/AUTHORIZE PERFORMANCE-BASED REGULATION OF ELECTRIC PUBLIC UTILITIES

SECTION 4.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-133.16. Performance-based regulation authorized.**

(a) Definitions. – For purposes of this section, the following definitions apply:

(1) "Cost causation principle" means establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service.

(2) "Decoupling rate-making mechanism" means a rate-making mechanism intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis by its residential customers.

(3) "Distributed energy resource" or "DER" means a device or measure that produces electricity or reduces electricity consumption and is connected to the electric distribution system, either on the customer's premises, or on the electric public utility's primary distribution system. A DER may include any of the following: energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

(4) "Earnings sharing mechanism" means an annual rate-making mechanism that shares surplus earnings between the electric public utility and customers over the period of time covered by a MYRP.

(5) "Multiyear rate plan" or "MYRP" means a rate-making mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application pursuant to G.S. 62-133, along with an earnings sharing mechanism.

(6) "Performance incentive mechanism" or "PIM" means a rate-making mechanism that links electric public utility revenue or earnings to electric public utility performance in targeted areas consistent with policy goals, as that term is defined by this section, approved by the Commission, and includes specific performance metrics and targets against which electric public utility performance is measured.

(7) "Performance-based regulation" or "PBR" means an alternative rate-making approach that includes decoupling, one or more performance incentive mechanisms, and a multiyear rate plan, including an earnings sharing mechanism, or such other alternative regulatory mechanisms as may be proposed by an electric public utility.

(8) "Policy goal" means the expected or anticipated achievement of operational efficiency, cost savings, or reliability of electric service that is greater than that which already is required by State or federal law or regulation, including standards the Commission has established by order prior to and independent of a PBR application, provided that, with respect to environmental standards, the Commission may not approve a policy goal that is more stringent than is established (i) by State law, (ii) by federal law, (iii) by the Environmental Management Commission pursuant to G.S. 143B-282, or (iv) by the United States Environmental Protection Agency.

(9) "Rate year" means the year of the MYRP for which base rates are effective.

(10) "Tracking metric" means a methodology for tracking and quantitatively measuring and monitoring outcomes or electric public utility performance.

(b) Performance-Based Regulation Authorized. – In addition to the method for fixing base rates established under G.S. 62-133, the Commission is authorized to approve performance-based regulation upon application of an electric public utility pursuant to the process and requirements of this section, so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle, including the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs between customer classes, and interclass subsidization of ratepayers is minimized to the greatest extent practicable by the conclusion of the MYRP period. This section shall not be construed to require the Commission to use the minimum system methodology for the purpose of classifying costs within a customer class when setting a basic facilities charge.

(c) Application. – An electric public utility shall be permitted to submit a PBR application in a general rate case proceeding initiated pursuant to G.S. 62-133. A PBR application shall include a decoupling rate-making mechanism, one or more PIMs, and a MYRP, including both an earnings sharing mechanism and proposed revenue requirements and base rates for each of the years that a MYRP is in effect or a method for calculating the same. The PBR application may also include proposed tracking metrics with or without targets or benchmarks to measure electric public utility achievement. The following additional requirements apply to a PBR application:

(1) The following shall apply to a MYRP:

a. The base rates for the first rate year of a MYRP shall be fixed in the manner prescribed under G.S. 62-133, including actual changes in costs, revenues or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period, plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year. Subsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period; provided that the amount of increase in the second rate year under the MYRP shall not exceed four percent (4%) of the electric public utility's North Carolina retail jurisdictional revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133 excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year. The amount of increase for the third rate year under the MYRP shall not exceed four percent (4%) of the electric public utility's North Carolina retail jurisdictional revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133, excluding any revenue requirement for the capital spending projects placed in service during the first rate year. The revenue requirements associated with any single new generation plant placed in service during the MYRP for which the total plant in service balance exceeds five hundred million dollars ($500,000,000) shall not be included in a MYRP. Instead, the utility may request and the Commission may grant, if it deems appropriate, permission to establish a regulatory asset and defer to such regulatory asset incremental costs related to such electric generation investments to be considered for recovery in a future rate proceeding. In setting the electric public utility's authorized rate of return on equity for an MYRP period, the Commission shall consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

b. In a proceeding authorizing a MYRP, the Commission shall establish a rider to refund amounts related to the earnings sharing mechanism, and to refund or collect amounts related to PIM rewards or penalties, and decoupling adjustments.

c. Within 60 days of the conclusion of each rate year, the Commission shall establish a proceeding to:

1. Examine the earnings of the electric public utility during the rate year to determine if the earnings exceeded the authorized rate of return on equity determined by the Commission in the proceeding establishing the PBR. If the weather-normalized earnings exceed the authorized rate of return on equity plus 50 basis points, the excess earnings above the authorized rate of return on equity plus 50 basis points will be refunded to customers in the rider established by the Commission. If the weather-normalized earnings fall below the authorized rate of return on equity, the electric public utility may file a rate case pursuant to G.S. 62-133. Any penalties or rewards from PIM incentives and any incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f) will be excluded from the determination of any refund pursuant to earnings sharing mechanism.

2. Evaluate the performance of the electric public utility with respect to Commission approved PIMs applicable in the rate year. Any financial rewards shall be collected from customers and any penalties refunded to customers, in each case, through the rider established by the Commission.

3. Evaluate the decoupling rate-making mechanism, and refund or collect, as applicable, a corresponding amount from residential customers through the rider established by the Commission.

(2) The proposed decoupling mechanism shall only be applied to residential customer classes. The Commission shall establish an annual revenue requirement per residential customer and an appropriate distribution of said revenue requirement per customer in each month of the year. The established monthly revenue requirements times the actual number of residential customers each month shall become the target revenue for the residential class. Each month, the electric public utility shall defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class. The changes in revenue requirements for the second and third rate years shall be allocated to the residential customer class and divided by the number of residential customers to determine the appropriate adjustment to the annual revenue requirement per residential customer that is used to establish the target revenues for the residential class in the second and third rate years of a MYRP. The electric public utility may

exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption.

(3) The policy goal targeted by a PIM shall be clearly defined, measurable with a defined performance metric, and solely or primarily within the electric public utility's control.

(4) Any PIM shall be structured to ensure that, pursuant to subdivisions (1) and (2) of this subsection, any penalty shall be refunded to customers and any reward shall be collected from customers and shall be limited such that the total of all potential and actual PIM incentives or penalties does not exceed one percent (1%) of the electric public utility's total annual revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133, excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year, where the PIM is approved. Any incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f) shall be excluded from the limits established in this section and shall continue to be recovered through the demand-side management and energy efficiency (DSM/EE) rider.

(5) Subject to the limitations set out in the preceding subdivision, any PIMs proposed by an electric public utility shall include one or more of the following:

a. Rewards based on the sharing of savings achieved by meeting or exceeding a specific policy goal.

b. Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet a specific policy goal, which shall not be greater than 25 basis points.

c. Fixed financial rewards to encourage achievement of specific policy goals, or fixed financial penalties for failure to achieve policy goals.

(d) Commission Action on Application. –

(1) The Commission shall approve a PBR application by an electric public utility only upon a finding that a proposed PBR would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in this section and rules adopted thereunder. In reviewing any such PBR application under this section, the Commission shall consider whether the PBR application:

a. Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.

b. Reasonably assures the continuation of safe and reliable electric service.

c. Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

(2) In reviewing any such PBR application under this section, the Commission may consider whether the PBR application:

a. Encourages peak load reduction or efficient use of the system.

b. Encourages utility-scale renewable energy and storage.

c. Encourages DERs.

d. Reduces low-income energy burdens.

e. Encourages energy efficiency.

f. Encourages carbon reductions.

g. Encourages beneficial electrification, including electric vehicles.

h. Supports equity in contracting.

i. Promotes resilience and security of the electric grid.

j. Maintains adequate levels of reliability and customer service.

k. Promotes rate designs that yield peak load reduction or beneficial load-shaping.

(3) When an electric public utility files with the Commission an application for a general rate case pursuant to G.S. 62-133 and that application includes a PBR application, the Commission shall institute proceedings on the application as provided in this subdivision. The electric public utility shall not make any changes in any rate or implement a PBR except upon 30 days' notice to the Commission, and the Commission may require the electric public utility to provide notice of the pending PBR application to the same extent as provided in G.S. 62-134(a) and may suspend the effect of the proposed base rates and PBR implementation pending investigation in the same manner as provided in G.S. 62-134(b), provided that, the Commission may suspend the implementation of the proposed base rates for no longer than 300 days. The electric public utility's application shall plainly state the changes in base rates and the time when the change in rates will go into effect and shall include schedules in the same manner required pursuant to G.S. 62-134(a). The Commission shall, upon reasonable notice, conduct a hearing concerning the lawfulness of the proposed base rates and the PBR application. After hearing, the Commission shall issue an order approving or rejecting the electric public utility's PBR application. The Commission shall not be permitted to modify the PBR application. In the event that the Commission rejects a PBR application, the Commission shall nevertheless establish the electric public utility's base rates in accordance with G.S. 62-133 based on the PBR application. If the Commission rejects the PBR application, it shall provide an explanation of the deficiency and an opportunity for the electric public utility to refile, or for the electric public utility and the stakeholders to collaborate to cure the identified deficiency and refile.

(e) Commission Review. – At any time prior to expiration of a PBR plan period, the Commission, with good cause and upon its own motion or petition by the Public Staff, may examine the reasonableness of an electric public utility's rates under a plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust base rates or PIMs as necessary. In addition, the approval of a PBR shall not be construed to limit the Commission's authority to grant additional deferrals between rate cases for extraordinary costs not otherwise recognized in rates.

(f) Plan Period. – Any PBR application approved pursuant to this section shall remain in effect for a plan period of not more than 36 months.

(g) Commission Authority Preserved. – Nothing in this section shall be construed to (i) limit or abrogate the existing rate-making authority of the Commission or (ii) invalidate or void any rates approved by the Commission prior to the effective date of this section. In all respects, the alternative rate-making mechanisms, designs, plans, or settlements shall operate independently, and be considered separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless otherwise incorporated into such plan.

(h) Utility Reporting. – For purposes of measuring an electric public utility's earnings under a PBR application approved under this section, an electric public utility shall make an annual filing that sets forth the electric public utility's earned return on equity, the electric public utility's revenue requirement trued-up with the actual electric public utility revenue, the amount of revenue adjustment in terms of customer refund or surcharge, if applicable, and the adjustments reflecting rewards or penalties provided for in PIMs approved by the Commission.

(i) Commission Report. – No later than April 1 of each year, the Commission shall submit a report on the activities taken by the Commission to implement, and by electric public utilities to comply with, the requirements of this section to the Governor, the Environmental Review Commission, the Joint Legislative Commission on Energy Policy, the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources, and the chairs of the House Committee on Energy and Public Utilities. The report shall include a summary of public comments received by the Commission. In developing the report, the Commission shall consult with the Department of Environmental Quality.

(j) Rulemaking. – The Commission shall adopt rules to implement the requirements of this section. Rules adopted shall include all of the following matters:

(1) The specific procedures and requirements that an electric public utility shall meet when requesting approval of a PBR application.
(2) The criteria for evaluating a PBR application.
(3) The parameters for a technical conference process to be conducted by the Commission prior to submission of any PBR application consisting of one or more public meetings at which the electric public utility presents information regarding projected transmission and distribution expenditures and interested parties are permitted to provide comment and feedback; provided, however, no cross-examination of parties shall be permitted. The technical conference process to be established shall not exceed a duration of 60 days from the date on which the electric public utility requests initiation of such process.
(4) In the event the Commission rejects a PBR application, the process by which an electric public utility may address the Commission's reasons for rejection of a PBR application, which process may include collaboration between stakeholders and the electric public utility to cure any identified deficiency in an electric public utility's PBR application."

SECTION 4.(b) The Commission shall adopt rules as required by G.S. 62-133.16(j), as enacted by subsection (a) of this section, no later than 120 days after the date this section becomes law.

SECTION 4.(c) This section is effective when it becomes law and applies to any rate-making mechanisms filed by an electric public utility on or after the date that rules adopted pursuant to G.S. 62-133.16, as enacted by subsection (a) of this section, become effective.

PART III. CUSTOMER RENEWABLES PROGRAMS

GREEN SOURCE ADVANTAGE

SECTION 5. G.S. 62-159.2 reads as rewritten:

"**§ 62-159.2. Direct renewable energy procurement for major military installations, public universities, and large customers.**

(a) Each electric public utility providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2017, shall file with the Commission an application requesting approval of a new program applicable to major military installations, as that term is defined in G.S. 143-215.115(1), The University of North Carolina, as established in Article 1 of Chapter 116 of the General Statutes, and other new and existing nonresidential customers with either a contract demand (i) equal to or greater than one megawatt (MW) or (ii) at multiple service locations that, in aggregate, is equal to or greater than five megawatts (MW).

(b) Each electric public utility's program ~~application~~ required by this section shall provide standard contract terms and conditions for participating customers and for renewable energy suppliers from which the electric public utility procures energy and capacity on behalf of the participating customer. The ~~application~~ program shall allow eligible customers to select the new renewable energy facility from which the electric public utility shall procure energy and capacity. The standard terms and conditions available to renewable energy suppliers shall provide a range of terms, between two years and 20 years, from which the participating customer may elect. Eligible customers shall be allowed to negotiate with renewable energy suppliers regarding price terms.

(c) ~~Each contracted amount of capacity shall be limited to no more than one hundred twenty-five percent (125%) of the maximum annual peak demand of the eligible customer premises.~~ All agreements executed under this program prior to January 1, 2021, shall remain in full force and effect and shall not be deemed modified or altered in any respect.

(c1) In the case of any participating customer that has not entered into an agreement under this program on or before January 1, 2021, all of the following shall apply:

(1) The reasonably projected first year annual energy output of any renewable energy facility or facilities selected by or procured on behalf of a participating customer shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation. Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility, and participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(2) No single generating facility selected by or procured on behalf of a participating customer shall exceed 80 megawatts alternating current (MW AC) in capacity.

(3) The electric public utility, the participating customer, and the owner of any renewable energy facility or facilities selected by or procured on behalf of a participating customer shall enter into an agreement providing that all environmental and renewable energy attributes generated by such facilities shall be transferred to the participating customer for retirement or retired on the customer's behalf.

(c2) Each public utility shall establish reasonable credit requirements for financial assurance for renewable energy suppliers and eligible customers that are consistent with the Uniform Commercial Code of North Carolina. Major military installations and The University of North Carolina are exempt from the financial assurance requirements of this section.

(d) The program shall be offered by the electric public utilities subject to this section for a period of five years or until December 31, 2022, whichever is later, and shall not exceed a combined 600 megawatts ~~(MW)~~ alternating current (MW AC) of total capacity. For the public utilities subject to this section, where a major military installation is located within its Commission-assigned service territory, at least 100 megawatts (MW) of new renewable energy facility capacity offered under the program shall be reserved for participation by major military installations. At least 250 megawatts ~~(MW)~~ alternating current (MW AC) of new renewable energy facility capacity offered under the programs shall also be reserved for participation by The University of North Carolina. Major military installations and The University of North Carolina must fully subscribe to all their allocations prior to December 31, ~~2020, or a period of no more than three years after approval of the program, whichever is later.~~ 2022. If any portion of total capacity set aside to major military installations or The University of North Carolina is not used, it shall be reallocated for use by any eligible program participant. If any portion of the

600 megawatts ~~(MW)~~ alternating current (MW AC) of renewable energy capacity provided for in this section is not awarded prior to the expiration of the program, it shall be reallocated to and included in a competitive procurement in accordance with G.S. 62-110.8(a).

(e) In addition to the participating customer's normal retail bill, the total cost of any renewable energy and capacity procured by or provided by the electric public utility for the benefit of the program customer shall be paid by that customer. The electric public utility shall pay the owner of the renewable energy facility which provided the electricity. ~~The program customer shall receive a bill credit for the energy as determined by the Commission; provided, however, that the bill credit shall not exceed utility's avoided cost. The Commission shall ensure that all other customers are held neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer.~~ In the case of any customer that enters into an agreement under this program after the effective date of this section, the customer shall be entitled to select one of the following bill credit options:

(1) A bill credit equal to the hourly real time avoided cost or day ahead avoided cost.

(2) A bill credit equal to avoided cost as determined in a manner consistent with the most recent Commission-approved methodology for a period of two, five, or 10 years, as selected by the customer.

(f) Major military installations and The University of North Carolina shall be entitled to participate in the program as described in subsections (b) through (e) of this section, or in accordance with the following terms and conditions:

(1) On or before December 31, 2021, The University of North Carolina may provide written notice to the electric public utility of its intent to participate in the program and its desired capacity amount, not to exceed 250 megawatts alternating current (MW AC) of renewable energy capacity, and major military installations may provide written notice to the electric public utility of their intent to participate in the program and their desired capacity amount, not to exceed 100 megawatts alternating current (MW AC) of renewable energy capacity.

(2) Upon receipt of written notice provided in accordance with subdivision (1) of this subsection, the electric public utility shall competitively procure from independent third parties renewable energy and capacity from one or more renewable energy facilities to provide the total amount of renewable energy capacity requested by The University of North Carolina and major military installations utilizing the competitive procurement process set forth in G.S. 62-110.8 for procurements occurring on or after January 1, 2022. The electric public utility shall enter into a power purchase agreement with one or more renewable facilities selected through such competitive procurement, provided that the price to be paid under the power purchase agreement, inclusive of network upgrades, shall not exceed the electric public utility's avoided cost as determined in a manner consistent with the most recent Commission-approved methodology for a period of 20 years. The applicable power purchase agreement shall allow the procuring electric public utility rights to dispatch, operate, and control the renewable energy facilities in the same manner as the electric public utility's own generating resource. Where necessary, the electric public utility may allocate a renewable energy facility between the major military installations and The University of North Carolina. In the event that an insufficient amount of qualifying bids are received in the initial procurement event or the electric public utility is otherwise unable to procure the requested amount of capacity, the electric public utility may

conduct subsequent procurements at a reasonably determined time to attempt to procure the full amount of requested capacity.

(3) In addition to their normal retail bill, the major military installations and The University of North Carolina shall pay a product charge equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively. The electric public utility shall pay the owner of the renewable energy facility or facilities selected through such competitive procurement at the price established through the competitive procurement. The major military installations and The University of North Carolina shall be entitled to a bill credit equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively.

(4) In the event that the electric public utility is prohibited, for purposes of compliance with a future federal or State law, rule, or regulation relating to air emissions or renewable energy or clean energy, from relying on or otherwise receiving credit for any renewable generating facility procured under this program for a major military installation or The University of North Carolina, the electric public utility shall be entitled after the first two years of the contract term to terminate the agreement with the participating customer on 90 days' written notice to the participating customer if the Commission determines that the offering utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource. In the event of any such termination, to the greatest extent reasonably possible and subject to Commission approval, the utility shall seek to enter into a replacement arrangement with such customer that provides the customer with a set of rights that is as close as possible to the initial arrangement while still allowing the utility to comply with the federal or State law, rule, or regulation related to air emissions or renewable energy or clean energy generation."

SHARED SOLAR/COMMUNITY SOLAR GARDENS

SECTION 6.(a) G.S. 62-126.3 reads as rewritten:

"**§ 62-126.3. Definitions.**

For purposes of this Article, the following definitions apply:

(1) Affiliate. – Any entity directly or indirectly controlling or controlled by or under direct or indirect common control with an electric power supplier.

(2) Commission. – The North Carolina Utilities Commission.

~~(3) Community solar energy facility. – A solar energy facility whose output is shared through subscriptions.~~

(4) Customer generator. – An owner, operator, or customer-generator lessee of a solar energy facility or other renewable energy facility, including any equipment that enhances the use of that facility such as an energy storage device, provided that the storage device is charged solely from that facility, that is taking service under the terms and conditions of a net metering tariff approved by the Commission, including a tariff authorized under G.S. 62-126.4A.

(4a) Customer generator lessee. – A lessee of a solar energy facility.

(5) Electric generator lessor. – The owner of solar energy facility that leases the facility to a customer generator lessee, including any agents who act on behalf of the electric generator lessor. For purposes of this Article, an electric generator lessor shall not be considered a public utility under G.S. 62-3(23).

(6) Electric power supplier. – A public utility, an electric membership corporation, or a municipality that sells electric power to retail electric customers in the State.

(7) Electric public utility. – A public utility as defined by G.S. 62-3(23) that sells electric power to retail electric customers in the State.

(7a) Government customer. – A governmental customer that receives retail electric service from an electric public utility.

(7b) Large commercial or industrial customer. – A commercial or industrial retail customer of an electric public utility whose annual peak demand is more than 5 megawatts.

…

(9) Net metering. – To use electrical metering equipment to measure the difference between the electrical energy supplied to a retail electric customer by an electric power supplier and the electrical energy supplied by the retail electric customer to the electric power supplier over the applicable billing period. A solar choice tariff authorized under G.S. 62-126.4A shall prospectively constitute an electric public utility's net metering arrangement for new customer participation after its effective date.

(10) Offering utility. – ~~Any~~ Except as specifically defined in G.S. 62-126.4A and G.S. 62-126.8A, an offering utility is any electric public utility as defined in G.S. 62-3(23) serving at least 150,000 North Carolina retail jurisdictional customers as of January 1, ~~2017.~~ 2021. The term shall not include any other electric public utility, electric membership corporation, or municipal electric supplier authorized to provide retail electric service within the State. An offering utility's participation in this Article as an electric generator lessor shall not otherwise alter its status as a public utility with respect to any other provision of this Chapter. An offering utility's participation in this Article shall be regulated pursuant to the provisions of this Article.

…

(13a) Small commercial or industrial customer. – A commercial or industrial retail customer of an electric public utility whose annual peak demand is less than or equal to 5 megawatts but excluding government customers.

…."

SECTION 6.(b) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.8B. Shared solar program.**

(a) It is the policy of the State to encourage electric public utilities to provide expanded renewable energy options for North Carolina large commercial or industrial customers, small commercial or industrial customers, units of local government, and residential customers and to foster the use of renewable energy as part of the electric public utilities' generation mix. Therefore, electric public utilities providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, shall jointly or separately complete a competitive procurement seeking new solar resources in a total amount of approximately 750 megawatts alternating current (MW AC) procured over a period of approximately three years. All the following shall apply to such procurements:

(1) The offering utilities shall enter into power purchase agreements (PPA) with the selected solar generating facilities. PPAs shall be for a period of 20 years and shall provide for the purchase of all the energy, capacity, and all environmental and renewable energy attributes. The applicable PPA shall allow the procuring electric public utility rights to dispatch, operate, and

control the renewable energy facilities in the same manner as the electric public utility's own generating resources.

(2) The offering utilities may require the renewable generation facilities procured hereunder to meet commercially reasonable performance standards. The offering utilities and their affiliates shall not participate as bidders in the competitive solicitation process required under this section.

(3) Renewable generation facilities procured pursuant to this subsection shall be new solar generating facilities and located within the respective balancing authority areas of the electric public utilities, whether located inside or outside the geographic boundaries of the State. Each facility shall be connected to the electric public utility's transmission system and shall have a capacity of no more than 80 megawatts alternating current (MW AC). The price paid under the PPA shall not exceed the electric public utility's current forecast of its avoided cost calculated over the term of the PPA, inclusive of any upgrade costs. The electric public utility's current forecast of its avoided cost shall be consistent with the Commission-approved avoided cost methodology.

(b) Each offering utility shall file with the Commission an application requesting approval of a shared solar program. The Commission shall issue a final decision approving, modifying, or rejecting the program within 120 days of receipt of the application. Each shared solar program shall conform with all of the following:

(1) Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility, and participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(2) Capacity under the program shall be opened for a defined initial enrollment period during each program procurement cycle. If any program class is oversubscribed during the initial enrollment period, all of the following shall apply:

a. In the case of large commercial or industrial customers and government customers, the available capacity shall be allocated to all eligible customers that applied on a proportional basis based on the requested subscription amount of each customer.

b. In the case of small commercial or industrial and residential customers, the available capacity shall be allocated through a random selection process.

(3) The total program volume shall be allocated as follows: seventy percent (70%) to large commercial or industrial customers and small commercial or industrial customers, twenty percent (20%) to government customers, and ten percent (10%) to residential customers. To the extent that any customer class has not fully subscribed to its respective allocation within the initial enrollment period, any unsubscribed amount shall be made available to all eligible customers through a second enrollment period and, if oversubscribed during such second enrollment period, shall be allocated through a random selection process. Thereafter, any remaining capacity from such procurement cycle shall be made available on a first come, first served basis.

(4) The reasonably projected first year's annual energy output from a participating customer's capacity allocation from the program shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation.

(5) Once a subscription has been awarded, the subscription shall remain in place until the earlier of the following:

a. The customer terminates their subscription.

b. The customer cancels their retail service.

c. Twenty years after the solar generating facility to which such customer has been subscribed achieved commercial operation.

(6) Each participating customer shall pay a product charge equal to the average contract price for all facilities with which the offering utility has contracted in a particular procurement cycle pursuant to the applicable competitive solicitation.

(7) Each participating customer shall receive a bill credit equal to the product charge for such customer.

(8) All environmental and renewable energy attributes produced by any shared renewables facility associated with the customer's participation in the program shall be retired by the offering utility on behalf of the participating customer or, at the election of a nonresidential participating customer, be conveyed to the customer for retirement, at the customer's expense, in which case, the customer must provide proof of retirement within 90 days. In the event that the utility is prohibited, for purposes of compliance with a future federal or State law or regulation relating to air emissions or renewable energy or clean energy, from relying on or otherwise receiving credit for a renewable generating facility that is procured under this program, the utility shall be entitled after the first two years of the program term to terminate the agreement with such participating customer on 90 days' written notice to the participating customer if the Commission determines that the utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource. In the event of any such termination, to the greatest extent reasonably possible and subject to Commission approval, the utility shall seek Commission approval of a replacement arrangement with such customer that provides the customer with a set of rights that is as close as possible to the initial arrangement while still allowing the utility to comply with such federal or State law or regulation related to air emissions or renewable energy or clean energy generation.

(9) Each participating customer shall pay a reasonable administration fee approved by the Commission in order for the offering utility to recover the administrative costs of the program."

SECTION 6.(c) G.S. 62-126.8 is repealed.

SECTION 6.(d) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.8A. Community solar gardens.**

(a) Procurement. – In order to provide expanded solar energy options for North Carolina small commercial and industrial customers and residential customers and to foster the use of solar energy as part of the electric public utilities' generation mix, electric public utilities subject to this section shall undertake a competitive procurement of solar energy for the purpose of offering a community solar gardens program for participation by small commercial and industrial, government, and residential customers. For purposes of this section, an "offering utility" includes any electric public utility serving more than 100,000 retail electric customers in the State as of January 1, 2021. Aggregate procurement shall be as follows:

(1) Electric public utilities providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, shall

jointly or separately complete a competitive procurement seeking up to 50 megawatts (MW) of new distribution-connected solar generation to be utility-owned. To the extent practicable, approximately equal amounts of solar generation shall be procured under this program in each of their respective service territories.

(2) An electric public utility providing retail electric service to more than 100,000 and fewer than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, may elect to offer a competitive procurement seeking up to 10 megawatts (MW) of new distribution-connected solar generation to be utility-owned. For purposes of this section, such electric utility shall also be an "offering utility."

(b) The initial procurements required by this section shall be completed within 60 days of the date on which the Commission approves the program pursuant to subsection (c) of this section. Each offering utility implementing this section shall attempt to procure at least twenty-five percent (25%) of its total procurement amount from projects that are capable of being placed into service on or before December 31, 2023, for the purpose of offering a community solar gardens program for participation by its small commercial and industrial, government, and residential customers. Each offering utility shall be permitted to require that solar generation facilities procured under this section meet commercially reasonable performance and technical standards. An offering utility and its affiliates shall not participate as bidders in the competitive request for proposals process required under this section. In the event that an insufficient number of eligible solar generating facilities are procured through such process, an offering utility shall be permitted to propose self-developed solar generating facilities if the capital costs are below the cost cap specified in subsection (e) of this section. To the extent that an offering utility is unable to procure viable projects meeting the required criteria and meeting the total procurement amount specified in subdivisions (1) and (2) of subsection (a) of this section through the initial procurement, and there are no self-developed facilities meeting the criteria identified in this section, the offering utility shall be permitted to conduct another procurement at a later date to meet the total procurement amount.

(c) Eligible Projects. – Solar generation facilities procured pursuant to subsection (a) of this section shall be new solar capacity and located in the State of North Carolina. Each such facility shall be interconnected to the relevant offering utility's distribution system.

(d) Application. – Within 180 days of the effective date of this section, each offering utility shall file with the Commission an application requesting approval of a community solar gardens program. Each community solar gardens program shall conform with the following:

(1) The program volume shall be allocated as follows: thirty-five percent (35%) to small commercial and industrial customers, thirty percent (30%) to government customers, and thirty-five percent (35%) to residential customers. To the extent that any customer class has not fully subscribed to its respective allocation within one year of the opening of the application period, any unsubscribed amount shall be made available to all program applicants based on the priority of their applications, or, to the extent necessary, by random selection process.

(2) The reasonably projected first year's annual energy output from a participating customer's capacity allocation from the program shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation.

(3) No single participating customer subscription shall account for more than fifty percent (50%) interest in a single facility, and each facility shall have a minimum of five subscribers.

(4) Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility offering the program. Participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(5) Once a subscription has been awarded, such subscription shall remain in place until the earlier of the following:

a. The customer terminates their subscription.

b. The customer cancels their retail service.

c. Twenty years after the solar generating facility to which such customer has been subscribed achieved commercial operation.

(6) Each participating customer shall pay a monthly product charge equal to its pro rata share of the offering utility's monthly levelized revenue requirement for all of the community solar garden facilities serving the relevant offering utility's community solar garden program.

(7) Each participating customer shall pay a reasonable administration fee approved by the Commission in order for the offering utility to recover the administrative costs of the program.

(8) Each offering utility shall provide to each participating customer a monthly bill credit in an amount equal to its pro rata share of the offering utility's monthly levelized revenue requirement for all of the community solar garden facilities. The renewable energy certificates produced by the community solar garden facility associated with the customer's subscription shall be retired by the offering utility on the customer's behalf, provided that government customers may elect to have certificates transferred by the electric public utilities to an account the customer controls but shall be responsible for the cost of such transfer and must provide proof of retirement of the certificates to the electric public utilities within 90 days of receipt, provided, further that in the event that the offering utility is prohibited, for purposes of compliance with a future federal or State law or regulation relating to air emissions or renewable energy or clean energy from relying on or otherwise receiving credit for any solar generating facility procured under the community solar gardens program, the offering utility shall be entitled after the first two years of the program to terminate such program on 90 days written notice to the participating customers if the Commission determines that the offering utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource.

(e) Cost Recovery. – The capital cost for the construction of projects procured or constructed under this section shall not exceed one dollar and ninety cents ($1.90) per watt AC, inclusive of interconnection costs. If a solar generating facility has been identified for selection and use in the program in accordance with the terms of this section and satisfies the forgoing cost cap, such solar generating facility shall be deemed consistent with the public convenience and necessity for purposes of G.S. 62-110.1, and the Commission shall issue a certificate of public convenience and necessity for such replacement resources in accordance with the process set forth in G.S. 62-111.9(13)(a), and no further process shall be required under G.S. 62-110.1 except as otherwise addressed therein. Each offering utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all solar generating facilities procured or built under this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include operations and maintenance expenses, administration costs, property tax, depreciation expense, income taxes, and carrying costs related to electric plant investments and regulatory assets at the offering utility's then authorized, net-of-tax, weighted average cost of capital.

(f) Bill Credit Adjustment. – If, at any point after the date that is two years from the date on which the program is opened for subscriptions, less than fifty percent (50%) of the available subscriptions have been claimed, any party may petition the Commission to modify a community solar garden program as needed to enhance participation through adjustments to the participating customer product charge and bill credit, and the Commission may so modify the program if the Commission determines that it is in the public interest to do so."

SECTION 6.(e) This section is effective when it becomes law. The applications required to be filed with the Utilities Commission pursuant to G.S. 62-126.8B(b), as enacted by subsection (b) of this section, and G.S. 62-126.8A, as enacted by subsection (d) of this section, shall be filed by the offering utilities no later than 180 days after the effective date of this section.

SOLAR CHOICE TARIFF

SECTION 7.(a) G.S. 62-2 reads as rewritten:

"**§ 62-2. Declaration of policy.**

(a) Upon investigation, it has been determined that the rates, services and operations of public utilities as defined herein, are affected with the public interest and that the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy. It is hereby declared to be the policy of the State of North Carolina:

…

(4) To provide just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and ~~conservation~~ efficient use of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy;

(4a) To provide just and reasonable time-variant rates and other dynamic price offerings to utility customers that are designed to optimize the total cost of energy consumption rather than the total volume of energy consumed;

(4b) To assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities; and to that end to authorize fixing of rates in such a manner as to result in lower costs of new facilities and lower rates over the operating lives of such new facilities by making provisions in the rate-making process for the investment of public utilities in plants under construction;

…."

SECTION 7.(b) G.S. 126-2 reads as rewritten:

"**§ 62-126.2. Declaration of policy.**

The General Assembly of North Carolina finds that as a matter of public policy it is in the interest of the State to encourage time-variant pricing structures to promote net energy metering options and to authorize the leasing of solar energy facilities for retail customers and subscription to shared community solar energy facilities. The General Assembly further finds and declares that in encouraging the time-variant pricing structures to promote net energy metering options and the leasing of and subscription to solar energy facilities pursuant to this act, cross-subsidization should be avoided ~~by holding harmless electric public utilities' customers that do not participate in such arrangements.~~to the greatest extent practicable when balancing the goals of this act. The General Assembly recognizes that due to substantive differences in size, customer bases, access to low-carbon generation, and other factors, this declaration of policy does not apply to electric membership corporations, State-owned electric suppliers, or municipalities that sell electric power to retail customers in the State."

SECTION 7.(c) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.4A. Solar choice tariff.**

(a) Each offering utility shall file for Commission approval a solar choice tariff that shall become the exclusive option available to customers that apply for net metering service after Commission approval pursuant to this section. For purposes of this section, an "offering utility" includes all electric public utilities serving more than 100,000 retail electric customer in the State as of January 1, 2021.

(b) To allow the market for customer-sited renewable energy facilities to continue to mature without disruption and in a sustainable manner for participating and non-participating customers, and the State economy as a whole, the Commission shall approve an offering utility's application to establish a solar choice tariff that meets all of the following objectives:

(1) Provides for monthly netting with net exports credited at Commission-approved avoided cost in light of the costs and benefits of the solar choice tariff achieving the objectives of a net metering program except as provided in subdivision (2) of this subsection.

(2) Provides for monthly netting within each pricing period for time-variant and dynamic pricing structures with net exports credited at Commission-approved avoided cost.

(3) Provides rate design options that align the customer generator's ability to achieve bill savings with long-term reductions in the overall cost the offering utility will incur in providing electric service, including, but not limited to, time-variant and dynamic pricing structures.

(4) Reduces cross-subsidization by non-participants through mechanisms that allow offering utilities the opportunity to recover customer costs and distribution costs, including a minimum monthly bill, grid access fee for oversized systems, and non-bypassable charges to recover storm recovery, cybersecurity, and public purpose charges for ratepayer funded programs like energy efficiency, demand side management, and resiliency. Such recovery mechanisms shall not, however, include a standby charge where billing is based on the capacity of the renewable energy system.

(5) Minimizes, to the greatest extent practicable, any intraclass cross-subsidization identified using the offering utility's most recently approved embedded cost of service study.

(6) Encourages customer adoption of other energy savings, demand reduction, or grid services technologies and participation in cost-effective programs that can be offered in conjunction with a solar choice tariff to help lower the cost of providing service and maximize grid benefits.

(c) Customer generators taking service under a preexisting net metering tariff prior to Commission approval of a solar choice tariff pursuant to this section shall have the option to transition to the new solar choice tariff or continue to take service under the offering utility's pre-existing net metering tariff in effect at the time of interconnection of that customer generator's net metering facility until January 1, 2040. After January 1, 2027, a non-bypassable charge based upon the DC capacity of the facility will be added for customers who remain on a pre-existing net metering tariff. This charge shall be designed to collect the base rate increase approved by the Commission after January 1, 2027, that would otherwise not be collected from customer generators taking service under a pre-existing net metering tariff after January 1, 2027.

(d) Nothing in this section prohibits a customer generator that is participating in the offering utility's net metering tariff or solar choice tariff from also participating in a Commission-approved energy efficiency program, grid services program, or other type of distributed energy resource aggregation program.

(e) An offering utility offering a solar choice tariff approved pursuant to this section shall continue to be authorized to fully recover its cost of service, including, but not limited to, (i) all costs to effectuate the solar choice tariff and (ii) any unrecovered non-fuel and variable operations and maintenance costs due to customer generators' participation in the solar choice tariff. Notwithstanding the foregoing, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, shall be exempt from cost recovery authorized by this subsection."

SECTION 7.(d) G.S. 62-126.5(d) reads as rewritten:

"§ 62-126.5. Scope of leasing program in offering utilities' service areas.

…

(d) The total installed capacity of all solar energy facilities on an offering utility's system that are leased pursuant to this section shall not exceed ~~one percent (1%)~~ five percent (5%) of the previous five-year average of the North Carolina retail contribution to the offering utility's coincident retail peak demand. The offering utility may refuse to interconnect customers that would result in this limitation being exceeded. Each offering utility shall establish a program for new installations of leased equipment to permit the reservation of capacity by customer generator lessees, whether participating in a public utility or nonutility lessor's leasing program, on its system, including provisions to prevent or discourage abuse of such programs. Such programs must provide that only prospective individual customer generator lessees may apply for, receive, and hold reservations to participate in the offering utility's leasing program. Each reservation shall be for a single customer premises only and may not be sold, exchanged, traded, or assigned except as part of the sale of the underlying premises."

SECTION 7.(e) G.S. 62-133.8(a) reads as rewritten:

"(a) Definitions. – As used in this section:

…

(4) "Energy efficiency measure" means an equipment, physical, behavioral, or program change implemented by a retail electric customer after January 1, 2007, that ~~results in less energy used~~ reduces the customer's energy requirements from the electric power supplier needed to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy ~~resources.~~ resources, and energy produced by a customer generator as that term is defined under 62-126.3(4). "Energy efficiency measure" does not include demand-side ~~management.~~ management or the net monthly exports of energy by a customer under a tariff approved pursuant to G.S. 62-126.4(b).

…."

SECTION 7.(f) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.4B. Standby service required in certain circumstances.**

For any customer participating in an offering utility's net metering tariff or solar choice tariff, standby service shall be required for customers installing solar or other behind-the-meter generation with a nameplate generation capacity over 100 kW. For behind-the-meter generation with a planning capacity factor of less than sixty percent (60%), the offering utility shall calculate standby service cost using the customer's standby service demand for the billing month set based on either the nameplate capacity of the installed generation or, where the customer has additional metering equipment installed at the customer's expense, then the standby service demand shall equal the generator gross output that occurs at the billing interval coincident with the customer's maximum demand for the billing month under the participating customer's applicable rate schedule. Notwithstanding the foregoing, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, shall be exempt from the standby charge authorized by this section."

SECTION 7.(g) This section is effective when it becomes law. The solar choice tariff required to be filed with the Utilities Commission pursuant to G.S. 62-126.4A, as enacted by subsection (c) of this section, shall be filed by each offering utility no later than 120 days after the effective date of this section, and the Commission shall issue an order to approve, modify, or deny the program no later than 90 days after the submission of the program by the electric public utility.

POTENTIAL MODIFICATION OF CERTAIN EXISTING POWER PURCHASE AGREEMENTS WITH SMALL POWER PRODUCERS

SECTION 8.(a) In an effort to reduce cost to customers, within 120 days after the effective date of this section, the North Carolina Utilities Commission shall initiate a stakeholder process to provide interested parties the opportunity to establish the rates to be paid by the electric public utilities in connection with the modification of certain existing power purchase agreements of small power producers to present to the Commission that would accomplish both of the following:

(1) Provide small power producers a one-time option to elect, within 180 days of a Commission order authorizing such action, to amend their existing power purchase agreement, extending into a new longer term power purchase agreement for a term equal to the remaining term of the existing power purchase agreement plus an additional 10 years, notwithstanding the contract term limits prescribed in G.S. 62-156(c);

(2) Establish capacity and energy rates to be paid by the electric public utilities that are designed to take into consideration the currently contracted capacity and energy rates, capacity and energy rates to be computed at the time the small power producer elects to exercise the option to amend their existing power purchase agreement as provided for in subdivision (1) of this subsection. In developing these rates, stakeholders shall consider whether use of the developed rates, for purchases from small power producers for an extended future term, are just and reasonable to the electric consumer of the electric utility, and in the public interest.

SECTION 8.(b) For purposes of subsections (a) through (e) of this section, the term "small power producers" means small power producers, as that term is defined under G.S. 62-3(27a), generating solar electricity with a total capacity equal to or less than 5 megawatts alternating current (MW AC) that established a legally enforceable obligation in accordance with the Commission's then applicable requirements on or before November 15, 2016, and have entered into a long-term contract exceeding two years to sell their full output to the interconnected electric public utility under section 210 of the Public Utility Regulatory Policies Act of 1978.

SECTION 8.(c) In conducting the stakeholder process required by this section, the Commission shall convene representatives from all of the following entities:

(1) The Public Staff.

(2) Electric public utilities obligated to purchase capacity and energy from small power producers pursuant to G.S. 62-156.

(3) Small power producers.

SECTION 8.(d) Within 180 days of the Commission's initiation of the stakeholder process, the stakeholders shall present, jointly or separately, their recommendations to the Commission. The Commission shall approve the proposed rates and resulting amended power purchase agreements if the Commission finds that the proposed methodology (i) reduces costs to customers in the short term and over the life of the amended power purchase agreement, evaluated from the date of the amendment through to the end of the amended agreement, (ii) fairly compensates small power producers that elect such treatment, and (iii) is just and reasonable and in the public interest. Notwithstanding the foregoing, it is hereby declared appropriate, in the public interest and promoting of regulatory economy, for small power producers and the electric public utilities to negotiate amendments to the power purchase agreements of such small power producers in lieu of the aforementioned stakeholder process, provided that the intent and objectives of this section are accomplished through such negotiation.

SECTION 8.(e) Notwithstanding the foregoing, it is hereby declared appropriate, in the public interest, and promoting of regulatory economy for small power producers and the electric public utilities to negotiate amendments to the power purchase agreements of such small power producers in lieu of the aforementioned stakeholder process, provided that the intent and objectives of this section are accomplished through such negotiation.

PROHIBIT UNAUTHORIZED EXECUTIVE BRANCH ACTIONS TO PARTICIPATE IN THE REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

SECTION 8.1.

(a) The General Assembly finds the following:

(1) The Regional Greenhouse Gas Initiative (RGGI) is a regional, "market-based" carbon dioxide (CO_2) emissions reduction program among certain states to cap and reduce CO_2 emissions from the fossil fuel-fired electric power generators located within those states. Under the program, fossil fuel-fired electric power generators with a capacity of 25 megawatts (MW) or greater located in signatory states are required to obtain allowances to offset their CO_2 emissions.

(2) Art. 1, § 6 of the State's Constitution provides "[t]he legislative, executive, and supreme judicial powers of the State government shall be forever separate and distinct from each other."

(3) The General Assembly, which comprises the legislative branch, enacts laws that "protect or promote the health, morals, order, safety, and general welfare of society." State v. Ballance, 229 N.C. 764, 769, 51 S.E.2d 731, 734 (1949); see also N.C. Const. art. II, §§ 1, 20. The executive branch, which the Governor leads, faithfully executes, or gives effect to, these laws. See N.C. Const. art. III, §§ 1, 5(4). McCrory v. Berger, 368 N.C. 633, 781 S.E.2d 248 (2016).

(4) The General Assembly has not enacted legislation that would authorize the executive branch to enter into an agreement to participate in RGGI, or similar agreement on behalf of the State, nor implement requirements for emissions limitations and cap and trade attendant with the RGGI program. Absent authorization through an act of the General Assembly, such action by the executive branch would constitute an impermissible infringement of the General Assembly's duty to enact laws that "protect or promote the health, morals, order, safety, and general welfare of society." State v. Ballance, 229 N.C. 764, 769, 51 S.E.2d 731, 734 (1949); see also N.C. Const. art. II, §§ 1, 20.

(b) Until such time as the General Assembly enacts legislation to authorize the State's participation in RGGI, and implementation of emissions limitations and cap and trade requirements attendant with the RGGI program, the executive branch shall be prohibited from taking such action.

PART IV. SEVERABILITY CLAUSE AND EFFECTIVE DATE

SECTION 9. If any provision of this act or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions or applications of this act that can be given effect without the invalid provision or application, and, to this end, the provisions of this act are declared to be severable.

SECTION 10. Except as otherwise provided, this act is effective when it becomes law.