STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-105, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Friesian Holdings, LLC, for a Certificate of Public Convenience and Necessity to Construct a 70-MW Solar Facility in Scotland County, North Carolina	))))	ORDER DENYING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT GENERATING FACILITY

HEARD: Wednesday, December 18, 2019, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, and Jeffrey A. Hughes.

APPEARANCES:

For Friesian Holdings, LLC:

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For Duke Energy Progress, LLC:

Jack E. Jirak, Associate General Counsel, Duke Energy Corporation, P.O. Box 1551 / NCRH 20, Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association:

Peter Ledford and Benjamin Smith, North Carolina Sustainable Energy Association, 4800 Six Forks Road Suite 300, Raleigh, North Carolina 27609

For North Carolina Clean Energy Business Alliance:

Benjamin L. Snowden, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge and Layla Cummings, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On November 7, 2016, in Docket No. SP-8467, Sub 0, the Commission issued Friesian Holdings, LLC (Friesian or the Applicant), a certificate of public convenience and necessity (CPCN) pursuant to N.C. Gen. Stat. § 62-110.1(a) and Commission Rule R8-64 for the construction of a 75-MW solar photovoltaic electric generating facility to be located on Leisure Road near Academy Road, Laurinburg, in Scotland County, North Carolina (the Facility). In addition, the Commission accepted the registration of the Facility as a new renewable energy facility pursuant to Commission Rule R8-66.

On August 2, 2018, Friesian filed a request to amend the CPCN previously issued for the Facility.

On May 15, 2019, in both Docket Nos. SP-8467, Sub 0 and EMP-105, Sub 0, Friesian filed a statement requesting that the Commission (1) allow Friesian to withdraw the requested amendment; and (2) consider a new application for a CPCN pursuant to Commission Rule R8-63 in Docket No. EMP 105, Sub 0, for this same facility (the Application). The Commission treated this filing as a request to cancel the previously issued CPCN in Docket No. SP-8467, Sub 0. And, on June 14, 2019, the Commission issued an order allowing withdrawal of the requested amendment, canceling the previously issued CPCN, and closing the docket.

Also on May 15, 2019, Friesian prefiled the direct testimony and exhibits of Brian C. Bednar, Friesian's Manager and Authorized Agent, as well as President of Birdseye Renewable Energy, LLC (Birdseye), an affiliate of Friesian. The testimony explained that Friesian seeks approval to build a 70-MW solar PV facility beginning in the summer of 2023, and that the Facility would interconnect with the electric transmission system owned by Duke Energy Progress, LLC (DEP or Duke).

On May 31, 2019, the Public Staff filed a Notice of Completeness stating that it had reviewed the application as required by Commission Rule R8-63(d) and considered the Application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order.

On June 13, 2019, the Commission issued an Order that, *inter alia*, scheduled hearings, established a procedural schedule for the filing of petitions to intervene and of testimony, and directed Friesian to publish notice of the public hearing once a week for four consecutive weeks, beginning at least 30 days prior to July 26, 2019.

On June 21, 2019, the North Carolina Electric Membership Corporation (NCEMC) filed a petition to intervene, which the Commission granted on July 2, 2019. On July 18, 2019, NCEMC filed comments.

On July 18, 2019, Friesian filed the final, executed confidential Power Purchase Agreement (PPA) to replace the draft, confidential PPA that was originally filed as Confidential Exhibit No. 7 with the Application on May 15, 2019.

On July 23, 2019, DEP filed a petition to intervene, which the Commission granted on August 2, 2019.

On July 29, 2019, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which the Commission granted on August 20, 2019.

On August 1, 2019, the Public Staff filed a motion identifying and asking that the Commission consider several prehearing legal issues and seeking the establishment of a date for the filing of prehearing briefs and the suspension of the schedule for the filing of expert witness testimony. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On August 5, 2019, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a petition to intervene, which the Commission granted on August 16, 2019.

On August 5, 2019, the Commission issued an Order suspending the procedural schedule previously established and allowing the parties to file briefs addressing the following legal issues:

> (1) The appropriate standard of review for the Commission to apply in determining the public convenience and necessity for a certificate to construct a merchant generating facility pursuant to N.C.[G.S.] § 62-110.1 and Commission Rule R8-63;
>
> (2) Whether the Commission has authority under state and federal law to consider as part of its review of the Application the costs associated with the approximately $227 million dollars in transmission network upgrades and interconnection facilities necessary to accommodate the FERC jurisdictional interconnection of the merchant generating facility, and the resulting impact of those network costs on retail rates in North Carolina; and
>
> (3) Whether the allocation of costs associated with interconnecting the Friesian project and any resulting additional capacity made available that is then utilized by State-jurisdictional interconnection projects is consistent with the Commission's guidance provided in the Commission's June 14, 2019, Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, issued in Docket No. E-100, Sub 101, in which the Commission directed the utilities as follows: "to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses . . . associated with supporting the generator interconnection process under the NC Interconnection Standard."

On August 26, 2019, Friesian, the Public Staff, DEP, and NCCEBA each filed briefs; on September 9, 2019, Friesian, the Public Staff, DEP, and NCCEBA and NCSEA (jointly) each filed reply briefs.

On October 3, 2019, the Commission issued an Order scheduling oral argument whereat the parties were to address the issues noted in the Commission's August 5 Order, and, additionally, the question of whether and, if so, how the July 14, 2017 decision of the U.S. Court of Appeals for the D.C. Circuit in *Orangeburg v. FERC*, 862 F.3d 1071 (2017), applies to the issues noted in the Commission's August 5 Order.

On October 21, 2019, this matter came on for oral argument as scheduled.

On October 25, 2019, the Commission issued an interlocutory order notifying the parties of the Commission's preliminary decision on the legal issues addressed by the parties' prehearing briefs and at oral argument. In sum, the Commission "agree[d] with the arguments of DEP and the Public Staff that the Commission may consider the costs for future network upgrades that are required to accommodate a proposed electric generating facility when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63," and noted that "[t]he Commission's final order on the merits of the CPCN application [would] include the Commission's full discussion and conclusions relevant to these issues . . . ." The Commission further ordered the procedural schedule resumed, setting a hearing for the purpose of receiving expert witness testimony for December 18, 2019, at 10:00 a.m., and allowing for the timely filing of supplemental direct testimony and exhibits.

On November 26, 2019, Friesian filed the supplemental direct testimony and corresponding exhibits of three witnesses: Charles Askey, Senior Project Manager in the Power Engineering & System Planning Group at Timmons Group; Brian Bednar; and Rachel Wilson, Principal Associate with Synapse Energy Economics, Inc. (Synapse).

On December 6, 2019, the Public Staff filed the joint testimony and exhibits of Evan Lawrence and Dustin Metz, both engineers in the Electric Division.

Also on December 6, 2019, and in lieu of testimony, DEP filed statement of position letters from Stephen De May, North Carolina President of Duke Energy, and Jack E. Jirak, Associate General Counsel for Duke Energy Corporation. These filings were unsworn and have not been subjected to cross-examination.

Statements of position letters were also filed in this docket by Helen Livingston in her individual capacity; Maggie Clark, Senior Manager of State Affairs, Solar Energy Industries Association (SEIA), on behalf of SEIA; James McDougald, Economic Development Director for the Town of Maxton; Ray Britt, Chairman of the Bladen County Board of Commissioners; and Bob Davis, Chair of the Scotland County Board of Commissioners.

On December 12, 2019, Friesian filed the rebuttal testimony and exhibits of witnesses Askey, Bednar, and Wilson.

This matter came on for hearing on December 18, 2019. Friesian presented the testimony and exhibits of witnesses Askey, Bednar, and Wilson, who testified as a panel. The Public Staff presented the testimony and exhibits of witnesses Lawrence and Metz, who also testified as a panel. None of the other intervenors, including DEP and NCEMC, presented witnesses or testimony, or offered any exhibits.

On December 20, 2019, the Public Staff filed a copy of the presentation given by the National Renewable Energy Laboratory (NREL) on its Carbon-free Resource Integration Report on the Duke System given to the Carbon Reduction Stakeholder Group hosted by the North Carolina Department of Environmental Quality (DEQ) at the Nicholas Institute on December 11, 2019, as a late-filed exhibit.

On January 8, 2020, DEP filed a response to a Commission question related to the increase in the cost of the network upgrades as a late-filed exhibit.

On February 10, 2020, Friesian, the Public Staff, and NCSEA separately filed proposed orders and briefs.

On April 16, 2020, DEP filed a supplemental late-filed exhibit.

On April 20, 2020, Friesian filed a Motion for Expedited Consideration of its Application.

On April 21, 2020, the Commission issued a Notice of Decision.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, the items upon which the Commission takes judicial notice, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. Friesian is a limited liability company registered to do business in the State of North Carolina. Friesian is an affiliate of Birdseye Renewable Energy, LLC.

2. Friesian's Application for a CPCN authorizing the construction of a 70-MW solar photovoltaic electric generating facility to be located on approximately 544 acres in Scotland County, North Carolina (the Facility), was filed pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63.

3. The Application has sufficiently completed State Clearinghouse Review.

4. While the Facility would be located in DEP service territory, the output from the Facility would be wheeled by DEP to NCEMC pursuant to a power purchase agreement (PPA) between Friesian and NCEMC for the sale of the output and renewable energy certificates (RECs) generated by the Facility. Friesian fails to sufficiently establish that the Facility's output is necessary to meet any of NCEMC's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance requirements to be given substantial weight in support of the Application.

5. Friesian fails to support the beneficial economic impacts that it asserts would flow to Scotland County with either sufficient detail or specific attribution to the Facility to be given substantial weight in support of the Application.

6. In its determination of need the Commission may consider factors other than Friesian's plan for the output of the Facility, including the long-term energy and capacity needs in the State and region, as well as system reliability concerns.

7. It is undisputed that the energy and capacity provided by the Facility are not otherwise needed to support any immediate or future load growth in the DEP East Balancing Area or the southeastern region of the State.

8. The placement of additional uncontrolled solar generating capacity in a region of the DEP system that currently contains significant existing solar generation may increase and exacerbate system operational issues already being faced by DEP's system operators and would provide minimal contribution to meeting winter peak load conditions.

9. The Facility proposes to interconnect with DEP's transmission network and begin commercial operation in December 2023. Friesian and DEP executed a Large Generator Interconnection Agreement (LGIA) in June 2019. Capacity on the transmission lines to which the Facility would connect is currently constrained, and load flow models indicate that additional generating capacity cannot be added in the pertinent portion of DEP's service territory without requiring substantial upgrades, including the construction of a proposed new 34.5-kV collector station and 230-kV breaker station, and the reconductoring of 63 miles of DEP transmission lines.

10. The generating plant of the Facility is estimated to cost $100 million to construct. The transmission network upgrades required to support the Facility (Network Upgrades) are estimated to cost $223.5 million to construct.

11. It is appropriate for the Commission to consider the total construction costs of a facility, including the cost to interconnect and to construct any necessary transmission network upgrades, when determining the public convenience and necessity of a proposed new generating facility.

12. The use of the levelized cost of transmission (LCOT) provides a benchmark as to the reasonableness of the transmission network upgrade cost associated with interconnecting a proposed new generating facility.

13. The potential for the Network Upgrades to lead to additional proposed generating capacity to be placed in service is too uncertain and speculative to be given substantial weight in support of the Application.

14. The Synapse Report does not provide sufficient evidence that either the Facility or the associated Network Upgrades would provide quantifiable ratepayer savings, emission reductions, or other environmental or health benefits.

15. Until such time as compliance with Executive Order 80 and the policy recommendations in the Clean Energy Plan are fully investigated and considered in the context of Duke's integrated resource planning (IRP) process, any benefits associated with the construction of the Facility and the Network Upgrades are not sufficiently known and measurable to be given substantial weight in support of the Application.

16. Given the uncertainties stated in Findings of Fact Nos. 13, 14, and 15, more deliberate and comprehensive planning is the appropriate method, at this time, to identify and plan for upgrades to the system that are in the public interest.

17. The General Assembly, in enacting House Bill 589 (HB589), intended to establish a process to identify and support the location of additional renewable generation in the State in a manner that is most cost-effective to ratepayers.

18. Reform of the North Carolina Interconnection Procedures to involve the clustering of projects for interconnection study purposes is consistent with N.C.G.S. § 62-110.1(b) and is appropriate to help ensure that interconnection customers are receiving appropriate pricing signals to locate their projects in the most cost-effective interconnection locations, as well as to reduce congestion that otherwise results when the need for significant upgrades is identified.

APPLICABLE LEGAL STANDARD

Article 6 of Chapter 62 provides, in relevant part, that

> no public utility or other person shall begin the construction of any . . . facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service . . . without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction.

N.C.G.S. § 62-110.1(a). In considering whether to approve a facility proposed under this statute the Commission must focus upon an element of public need for the facility and emphasize a policy that favors the orderly expansion of electric generating capacity that both creates a reliable and economical power supply *and* prevents the costly overbuilding of generation resources. *See State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 279-80, 435 S.E.2d 553, 561 (1994); *State ex rel. Utils. Comm'n v. High Rock Lake*

Ass'n, 37 N.C. App. 138, 140-41, 245 S.E.2d 787, 790, *disc. rev. denied*, 295 N.C. 646, 248 S.E.2d 257 (1978).

That said, the North Carolina Supreme Court has long recognized the flexibility of the public convenience and necessity standard, requiring that the distinct facts of each case be considered:

> In our opinion, these statutes give the Commission not only the authority but impose upon it the duty to pass upon [the matter] and to determine whether or not it is in the public interest . . . .
>
> The doctrine of convenience and necessity has been the subject of much judicial consideration. No set rule can be used as a yardstick and applied to all cases alike. This doctrine is a relative or elastic theory rather than an abstract or absolute rule. The facts in each case must be separately considered and from those facts it must be determined whether or not public convenience and necessity require [the action].

State ex rel. Utils. Comm'n v. Casey, 245 N.C. 297, 302, 96 S.E.2d 8, 12 (1957) (citation and quotation marks omitted).

Finally, the decision of whether to grant or deny a CPCN must rest upon substantive evidence; it cannot rest on speculation or sentiment. *Cf. Howard v. City of Kinston*, 148 N.C. App. 238, 246, 558 S.E.2d 221, 227 (2002). The burden is on the applicant to provide this substantive evidence and demonstrate that the CPCN should be granted.

The Commission has carefully considered and weighed all the evidence and arguments presented in this proceeding, and concludes that Friesian has failed to show that the Application is in the public interest and that public convenience and necessity requires that the Application be granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are informational, procedural, and jurisdictional in nature and are not in dispute.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-8

The evidence supporting these findings of fact is found in the Application; the testimony of Friesian witnesses Askey, Bednar, and Wilson; and the joint testimony of Public Staff witnesses Lawrence and Metz.

Witness Bednar testified that Friesian entered into a power purchase agreement (PPA) with NCEMC on July 15, 2019, under which NCEMC will purchase all of the Facility's output. Witness Bednar also stated that the Facility will provide a significant number of renewable energy certificates (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS or Senate Bill 3), which among other things requires rural electric cooperatives and municipal electric suppliers to meet a 10% REPS requirement. Witness Bednar testified that these plans for the sale of the Facility's energy and capacity demonstrate its need. Tr. vol. 2, 21-22. Witness Bednar further offered the economic development impact to the communities of Scotland County, and other Tier 1 counties, as an additional reason to support granting the CPCN. Tr. vol. 2, 37.

In their joint testimony, Public Staff witnesses Lawrence and Metz asserted that having an executed PPA does not in-and-of-itself sufficiently demonstrate that a merchant generating facility is entitled to a CPCN; need is instead to be evaluated on a case-by-case basis. Tr. vol. 3, 116. They testified that the Commission had previously held that it is reasonable to require substantial evidence of the need for a merchant generating facility, and that a flexible standard for demonstrating need was appropriate, but that an executed PPA or other contractual agreement was not necessary. *Id.* at 114. Witnesses Lawrence and Metz further stated that the Public Staff has previously recommended approval of CPCN applications in the absence of a signed PPA. Tr. vol. 3, 165. They acknowledged that they were not aware of any prior case in which the Public Staff has taken the position that it is taking in the present case, that the PPA contract itself is not a sufficient demonstration of need. *Id.* at 174. They further acknowledged that they were not aware of any Commission precedent to this effect. *Id.* at 165.

Public Staff witnesses Lawrence and Metz also acknowledged that DEP's integrated resource plan (IRP) indicates a capacity need over the planning period but argued that "one cannot assume that any generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold," noting that the IRP is a capacity expansion model used to solve for multiple constraints and scenarios to help determine the generation resources needed to meet long-term load in the most economical manner. *Id.* at 117-18. They further testified that the DEP system is winter peaking and winter planning, and while DEP's IRP demonstrates a need for dependable capacity to meet winter peak loads, the addition of intermittent, non-dispatchable renewable solar facilities will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.* at 118-19.

Witnesses Lawrence and Metz also testified that DEP had not previously identified the transmission lines in question as needing upgrades due to reliability issues in any of the reports issued by the NC Transmission Planning Collaborative (NCTPC). Witness Metz acknowledged that transmission in the area where the Facility is proposed to be located has been identified as constrained, meaning that it has limited ability to accommodate new generating resources, but argued that being constrained was not necessarily disadvantageous. He noted that constrained areas can occur throughout a utility's system, and the NERC standards require transmission planners to evaluate risk in order to target critical areas in the electrical grid for investments. Tr. vol. 4, 22-23.

Friesian witness Askey offered the results of an analysis conducted by the Timmons Group of the system impact study developed by DEP to evaluate the impacts to the system of adding the Friesian capacity at the proposed location. He interpreted the study to show that multiple line segments are loaded at over 95% or 100% of their contingency ratings, triggering the need for upgrades. He further noted that, even without additional generating capacity being added, the system is within five to ten percent of the contingency loading levels under the scenarios modeled, indicating that the system in that area is at the upper end of its operational range. Tr. vol. 2, 67-70.

Witness Askey stated that DEP's system is technically NERC-compliant but he believes that deferral of the Network Upgrades will leave the transmission system in southeastern North Carolina in a "maxed-out state" and could leave the grid more vulnerable to disruption than it would be if the Network Upgrades are constructed. *Id.* at 79-83.

Discussion and Conclusions

Commission Rule R8-63(b)(3) requires an applicant for a CPCN for a merchant plant to provide "a description of the need for the facility in the state and/or region, with supporting documentation." Additionally, before the Commission can award a CPCN for a generating facility, N.C.G.S. § 62-110.1(d) requires the Commission to consider the "applicant's arrangement with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical electric service." Thus, a sufficient demonstration of need for a proposed new generating facility is fundamental to the Commission's decision of whether public convenience and necessity requires granting the CPCN.

As noted above, that demonstration generally is to focus on dual concerns: the orderly expansion of generation and capacity, and the prevention of costly overbuilding. And the required demonstration of need may also differ depending on whether the CPCN is sought for a generating facility by a regulated utility, a small power producer seeking to sell its output to the utility as a qualifying facility (QF), or a merchant generating facility.[1]

[1] For example, an electric public utility under Rule R8-61(b)(1) must, in addition to demonstrating need for a facility in its IRP, submit additional information supporting the need for the facility related to resource and fuel diversity, information on energy and capacity forecasts, and an explanation of how the proposed facility meets the identified energy and capacity needs. For QFs, the Commission has previously stated that federal law has essentially established a "public need" for their construction, based on the obligations established under the Public Utility Regulatory Policies Act of 1978 (PURPA) requiring a utility to purchase the output from a QF at its avoided cost rates. *See* Order on Motion to Dismiss*, Application of Empire Power Company for a Certificate of Public Convenience and Necessity Pursuant to G.S. 62-110.1(a)*, No. SP-91, Sub 0 (N.C.U.C. Apr. 23, 1992). Because of the federally mandated purchase of the output of QFs, when Friesian first applied for a CPCN to develop and operate the Facility as a QF, the Commission did not consider the need for the Facility because the federal mandate takes the place of (or amounts to) need.

Similarly, considerations relating to the total costs of the Friesian project, discussed at greater length later in this order, were not operative in the Commission's determination of Friesian's application in Docket No. SP 8467, Sub 0. PURPA directs that for a QF which will sell its energy and capacity to a regulated utility, the total costs

To this end, the flexibility of the CPCN standard necessarily includes analyzing the need for the merchant generating facility to be placed not just within the State but a certain region, as well as evaluating whether the applicant has accurately assessed and met wholesale market needs. All said, it is "the duty [of the Commission] to pass upon [the project] and to determine whether or not it is in the public interest . . . ." *Casey*, 245 N.C. at 302, 96 S.E.2d at 12; *see also* Order Granting Certificate*, Application of Rowan Generating Company, LLC, for a Certificate of Public Convenience and Necessity to Construct a Generating Facility in Rowan County, North Carolina*, No. EMP-3, Sub 0, 8 (N.C.U.C. Oct. 12, 2001) (stating that the Commission is "mindful that issues regarding the appropriate amount of merchant plant generation in the State remain to be decided.").

Friesian witness Bednar testified that the PPA with NCEMC is dispositive on the issue of need. As it traditionally has, the Commission affords some weight to the existence of the PPA as a demonstration of need. But the Commission agrees with Public Staff witnesses Metz and Lawrence that while having "[a]n executed PPA does demonstrate at least in part the potential [financial] viability of the project, . . . [it] is not, in and of itself, a sufficient criterion on which to base a recommendation for approval or disapproval of a CPCN." Tr. vol. 3, 116. Rather, the existence of a PPA or other plans for sale of energy and capacity from the facility must be balanced against other existing factors that may be considered when determining the overall need for the Facility. As evidenced by prior Commission orders, the question may include the facility's compliance with State or federal laws,[2] the provision of lower-cost, economic power alternatives,[3] or whether the generation addition helps address reliability and service quality issues.[4]

Friesian witness Bednar also testified that the Facility would provide a significant number of renewable energy credits (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standards (REPS).

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for the QF's project are immaterial so long as the price the regulated utility will pay to the QF for energy and capacity do not exceed the utility's own "avoided cost." If the total costs of the project cannot be recouped by the QF from charges that are calculated based on the purchasing utility's avoided cost, then any resulting loss is essentially invisible when viewed from the perspective of the total electricity generation, transmission, and distribution system.

[2] *See, e.g.,* Order Granting Certificate and Accepting Registration of New Renewable Facility, *Application of Atlantic Wind, LLC, for a Certificate of Public Convenience and Necessity*, No. EMP-49, Sub 0 (N.C.U.C. May 3, 2011; Order Granting Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for Approval of a Solar Photovoltaic Distributed Generation Program*, No. E-7, Sub 856 (N.C.U.C. Dec. 31, 2008).

[3] *See, e.g.,* Order Issuing Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct a 402-MW Natural Gas-Fired Combustion Turbine Generating Facility in Lincoln County, North Carolina*, No. E-7, Sub 1134 (N.C.U.C. Dec. 7, 2017).

[4] *See, e.g.,* Order Granting Certificate with Conditions, *Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Haywood County, North Carolina*, No. E-2, Sub 1127 (N.C.U.C. Apr. 6, 2017); Order Granting Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Progress, LLC for A Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Madison County, North Carolina*, No. E-2, Sub 1185 (N.C.U.C. May 10, 2019).

Friesian witness Wilson similarly stated that "NCEMC likely analyzed its . . . renewable generation supply needed for REPS compliance . . . and concluded that contracting with Friesian was a cost-effective way to meet those needs." But neither witness Bednar nor witness Wilson provided any corroborating evidence that the RECs that would be procured by NCEMC from Friesian are necessary for this purpose or that NCEMC has an actual need for RECs.

Relatedly, on July 18, 2019, NCEMC filed an unsworn comment in this docket, stating that "the [Friesian] Project — specifically, the parties' execution of the Project PPA — will simultaneously advance NCEMC's pursuit of BEF [a set of 'strategic business objectives' called 'A Brighter Energy Future'] and further its ability to achieve REPS compliance." But the letter filed by NCEMC is merely a restatement of NCEMC's three business objectives. It does not set out a specific, or even a general, strategy for attaining "A Brighter Energy Future," it contains no programs, policies, goals, objectives, or metrics, and it does not speak at all to NCEMC's targets for REPS compliance. In short, neither NCEMC nor Friesian presented sufficient evidence supporting the general assertion that the RECs generated by the Facility will facilitate NCEMC's compliance with its REPS obligations or meet its business objectives. *See* N.C.G.S. § 62-65(a).

Moreover, an examination of both NCEMC's most recent, verified NC REPS Compliance Plan, filed August 29, 2019, in Docket No. E-100, Sub 163, and the database in the North Carolina Renewable Energy Tracking System (NC-RETS) — both of which the Commission took judicial notice, *see* Tr. vol. 3, 78 — show that NCEMC has fully satisfied its RECs requirements without the Facility and, thus, does *not* need the Facility's RECs to achieve or maintain compliance for the near future. Indeed, the Friesian PPA, which was executed in June of 2019, is not referenced or identified in NCEMC's REPS Compliance Plan. Based on the foregoing, the Commission is not persuaded that the generation by the Facility of a significant number of RECs for use by NCEMC for REPS compliance demonstrates a need for the Facility in the region.

Friesian witness Bednar testified that the construction of the Facility will result in the creation of jobs and tax revenue in Scotland County. However, when the Commission pressed witness Bednar to provide support for the economic impact calculations, he was unable to do so. *See* Tr. vol. 3, 87-89.

On the topic of general need for new generating facilities in this region, the Commission notes that **[BEGIN CONFIDENTIAL]**

[END CONFIDENTIAL].

To this end, the Commission recognizes, as testified to by Public Staff witnesses Lawrence and Metz, that DEP's IRP indicates a capacity need over the planning period. However, the Commission also notes the Public Staff's testimony that "one cannot assume that *any* generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold[.]" *Id.* at 117 (emphasis added). Rather, the IRP involves a capacity expansion model that solves for multiple system constraints and scenarios ultimately to determine the generation resources needed to meet load projections over the planning period. As Public Staff witness Metz and Lawrence testified, and as Friesian witness Askey acknowledged on cross-examination, the DEP system is winter peaking and winter planning at this time, and while DEP's IRP demonstrates a need for additional capacity to meet winter peak loads, the addition of uncontrolled, intermittent solar generation will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.*; *see also* Tr. vol. 2, 176-79. Thus, the Commission is persuaded by the Public Staff that the capacity need identified in DEP's IRP does not support a determination of need for the Facility.

Importantly, the Applicant has identified no reliability or service quality concerns necessitating the Facility. To the contrary, Friesian witness Bednar acknowledged that DEP states that the continued addition of solar generation in the DEP East Balancing Area would instead exacerbate existing reliability challenges and increase the potential for NERC compliance issues. *See* Tr. vol. 2, 165-67. He also acknowledged that DEP's growing experience in managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation is integrated into the system will increase the likelihood of emergency curtailments of solar generation in DEP. *Id.* at 167-69.

In sum, while the Commission gives some weight to the PPA as support for the need for the Facility, the Commission balances this evidence against the Applicant's failure to substantiate either the need for RECs generated by the Facility or its economic impacts, that the Facility is not likely to satisfy the capacity need identified in the DEP IRP, and that the Facility is not proposed to address reliability or service quality concerns and may actually exacerbate existing reliability and service quality issues being experienced in the DEP East Balancing Area. Based on the weight of the evidence, the Commission concludes that the Applicant has failed to demonstrate a need for the Facility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence supporting these findings of fact is found in the Application and the testimony of Friesian witnesses Bednar and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

According to the Application and as Friesian witness Bednar testified, the Facility would be constructed on approximately 544 acres in Scotland County, North Carolina, southwest of Laurinburg. The Facility would interconnect with the DEP transmission grid through a newly constructed 34.5-kV collector station directly adjacent to the DEP

Laurinburg-Bennettsville 230-kV transmission line. *See also* Application Exhibit 5. Witness Bednar testified that the Facility is expected to have a useful life of approximately 20 years and that the estimated construction costs for the generating plant are approximately $100 million. Tr. vol. 2, 19-21.

Witness Bednar also described the factors that Birdseye uses to identify the lowest cost sites for solar development in the State, including the Facility. He listed several favorable attributes present in the southeastern region of the State, including the abundance of open, flat land, low population density, proximity to transmission infrastructure, and favorable geology for the low-cost installation of solar foundations. Given these attributes, the region has already attracted significant solar development and is now severely constrained, with no new generation resources able to be added without substantial upgrades to DEP's transmission system. Tr. vol. 2, 24-34.

Public Staff witnesses Lawrence and Metz testified that under the Large Generator Interconnection Agreement (LGIA) executed between DEP and Friesian in June 2019 (*see* Public Staff's August 26, 2019 Prehearing Brief, Exhibit 1), the Facility requires approximately $4 million in Interconnection Facilities that are directly attributable to the Facility, including a new 230-kV breaker station. In addition, the Facility will also require extensive transmission network upgrades (Network Upgrades). The Network Upgrades are currently estimated to cost $223.5 million, and include reconductoring 63 miles, and uprating 10 miles, of DEP transmission lines. *Id.; see also* Tr. vol. 3, 122.

Witnesses Lawrence and Metz explained that the LGIA obligates Friesian to pay for the Interconnection Facilities, to provide DEP with security for the associated Network Upgrades, and to pay DEP's invoices for costs incurred to construct the Network Upgrades. Upon commercial operation and under Duke's Open Access Transmission Tariff (OATT), however, Friesian would be entitled to receive repayment from DEP of the entire balance of the Network Upgrades cost plus interest at the monthly interest rates posted by FERC. Under the LGIA, specifically, DEP must repay Friesian via lump sum cash repayment by the earlier of either DEP's next North Carolina general rate case or by December 31, 2027, with interest.

DEP then would seek to include approximately 30% of the costs in its FERC formula rates charged to its wholesale customers, resulting in an increase in transmission rates of approximately 10% above the average annual rate on a pro-rata basis across all of DEP's wholesale transmission customers. *Id.* at 101, 124-25. At the retail level, the remaining 70% of the costs would be recovered from DEP's retail customers through base rates, with 60% recovered through North Carolina base rates and 10% recovered through South Carolina base rates. Based on calculations completed by DEP, this cost recovery would result in an order of magnitude increase in retail rates for DEP's North Carolina retail customers of approximately 0.5% per year on a pro-rata basis. *Id.* at 124-26.

Public Staff witnesses Lawrence and Metz stated that the Public Staff generally evaluates interconnection and system upgrade costs in other merchant and utility CPCN proceedings. In several of those proceedings Public Staff noted some concerns regarding certain transmission-related costs but did not ultimately recommend denial of the CPCNs. Witnesses Lawrence and Metz also testified that for a number of these previously reviewed merchant generating facilities, however, several were proposed to be sited in the service territory of Dominion Energy North Carolina (DENC). *Id.* at 126-28*.*

Public Staff witnesses Lawrence and Metz argued that a levelized cost of transmission (LCOT) analysis provides a tool to evaluate the reasonableness of the upgrade costs associated with certain generating technologies. They cited to a 2019 study by Lawrence Berkeley National Laboratory (LBNL Study) that reviewed interconnection cost studies for renewable energy facilities on a nationwide basis, doing so by calculating LCOT value. Witnesses Lawrence and Metz explained that LCOT value is calculated by dividing the annualized cost of the required new transmission assets over the typical transmission asset lifetime by the expected annual generator output in MWh, with the outputs presented in a $/MWh value. The LBNL Study compiled transmission upgrade costs for 303 projects in the MISO region (amounting to a total of 49 GW); 338 projects in PJM (amounting to a total of 64 GW); and another 2,399 projects from various locations as reported to EIA. *Id.* at 129-30*; see also* Lawrence/Metz Exhibit 2.

In terms of solar generating facilities, the LBNL Study found that network upgrade costs for solar projects in MISO averaged $56/kW, with an LCOT value of $1.56/MWh; in PJM they averaged $116/kW, with an LCOT value of $3.22/MWh; and in the other locations (from the EIA data) they averaged $103/kW, with an LCOT value of $2.21/MWh. Witnesses Lawrence and Metz testified that, by comparison, the cost of the Network Upgrades is $3,186/kW, with an LCOT value of $62.94/MWh. Lawrence and Metz also compared the LCOT value for Friesian with that of other merchant generators in North Carolina for which the Commission had issued CPCNs. The LCOT values for the NTE Kings Mountain (Docket No. EMP-76, Sub 0) and NTE Reidsville (Docket No. EMP-92, Sub 0) facilities were significantly lower than the LCOT value projected for Friesian at $0.33/MWh and $0.92/MWh respectively. Tr. vol. 3, 130-33.

In rebuttal, Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff compared an individual project to average values presented by total volumes of renewable generation derived from large data sets. She further indicated that the Public Staff's calculation of LCOT for Friesian should be adjusted to include all of the projects that are behind Friesian in the interconnection queue and thus the Public Staff should have summed the total number of MW associated with those projects into its analysis, as well as the transmission costs associated with those projects. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16.

Witness Wilson also testified that the Regional Energy Deployment System (ReEDS), developed by the National Renewable Energy Laboratory (NREL), considers generation and transmission capacity costs in its capacity-expansion model in order to minimize busbar and system-level costs for electric-sector planning purposes. Based on the 2018 Standard Scenarios presented by the ReEDS model, North Carolina in an optimized scenario could add another 900 MW of solar above current levels and associated transmission necessary for integration by 2022. *Id.*

Likewise, Friesian witness Askey testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Witness Askey also stated that there are significant differences in LCOT calculations for Friesian compared to those for regional transmission organizations (RTOs) like MISO and PJM, which are regulated by FERC and outside of any state regulatory compact. In the context of RTOs, costs associated with transmission upgrades to accommodate new generation may be evaluated as part of system-wide baseline upgrades, as network improvements, and as directly assigned costs, and that the cost allocation may vary as a result of the different assignment of costs. Therefore, he concluded, it is difficult for any entity other than the RTO itself to determine the LCOT for a generating facility interconnecting to the grid. Witness Askey thus testified that comparing the LCOT for the Network Upgrades provides little discernable value. Tr. vol. 2, 91-92.

Upon questioning, however, witness Askey acknowledged that the largest transmission network upgrade that a merchant facility has accepted responsibility for within PJM was $125 million and that the project involved a gas-fired facility. Witness Askey indicated that a solar facility within PJM would not accept financial responsibility for network upgrades in the range of $425 million even under the model that subsequent projects coming online would contribute to the cost. Tr. vol 3, 83-84.

Discussion and Conclusions

The Commission may consider all costs that are required to construct a proposed electric generating facility, including the cost to construct the generating plant as well as the cost to construct interconnection facilities and network upgrades, when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63. To this end, the Commission, when evaluating whether public convenience and necessity requires granting the CPCN in this case, will consider the total construction cost of the Facility, which includes the cost of the generating plant, the interconnection facilities, and the Network Upgrades.

The plain language of N.C.G.S. § 62-110.1 authorizes the Commission to consider all costs associated with the construction of the proposed generating facility. Specifically, the statue provides that, "[a]s a condition for receiving a certificate, the applicant shall file an estimate of *construction costs in such detail as the Commission may require . . .* and no certificate shall be granted unless the Commission has approved the estimated construction costs *and* made a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity." N.C.G.S. § 62-110.1(e) (emphases added). When the language of a statute is clear and unambiguous it must be given its plain and definite meaning. *Carolina Power & Light Co. v. City of Asheville [(CP&L I)]*, 358 N.C. 512, 518, 597 S.E.2d 717, 722 (2004).

Nothing in the statute delineates or otherwise limits which costs that the Commission may consider when evaluating an application for a CPCN. *See Midrex Techs., Inc., v. N.C. Dep't of Revenue*, 369 N.C. 250, 258, 794 S.E.2d 785, 792 (2016) (courts must "give effect to the words actually used in a statute and should neither delete words used nor insert words not used . . . .") (citation and quotation marks omitted). Thus, the Commission may consider all costs of a proposed facility, including those necessary to interconnect to the system and transmit the energy produced by the generating facility, i.e., all costs that are necessary to make useful operation of the facility at the outset. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790 (the statute "directs the Utilities Commission to consider . . . the construction costs *of the project* before granting a certificate of public convenience and necessity for a new facility") (emphasis added).

The CPCN statute also obligates the Commission to analyze "the long-range needs for expansion of facilities . . . including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission and other arrangements with other utilities and energy suppliers to *achieve maximum efficiencies for the benefit of the people of North Carolina . . . .*" N.C.G.S. § 62-110.1(c) (emphasis added); *see also State ex rel. Utilities Com'n v. Carolina Power & Light Co. [(CP&L II)]*, 359 N.C. 516, 522, 614 S.E.2d 281, 285 (2005). And, "[i]n acting upon any petition for the construction of any facility for the 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 electric service*." N.C.G.S. § 62-110.1(d) (emphasis added). Without consideration of the total construction cost of a proposed generating facility, the Commission cannot ensure that any build-out will represent maximum efficiencies and provide cost-effective electric service for citizens and other ratepayers. *See CP&L II*, 359 N.C. at 522, 614 S.E.2d at 285.

Additionally, assuming *arguendo* that the language of the CPCN statute is ambiguous, the Commission concludes that the legislature must have intended that the Commission would consider all costs triggered by the siting of a generating plant. The "best indicia of that intent" includes "what the act seeks to accomplish." *Diaz v. Div. of Soc. Servs.*, 360 N.C. 384, 387, 628 S.E.2d 1, 3 (2006) (citation omitted); *accord CP&L I*, 358 N.C. at 518, 597 S.E.2d at 722 ("the reviewing court must construe the statute in an attempt not to defeat or impair the object of the statute . . . ."). The very reason the CPCN statute was enacted was to stop the costly overexpansion of facilities to serve areas that did not need them. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790; *see also State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 280, 435 S.E.2d 553, 561 (1994).

This conclusion is further informed when reading "[the CPCN] standard *in pari materia* with N.C.G.S. § 62-2 which contains ten [now twelve] specific policies . . . ." *Empire Power*, 112 N.C. App. at 274, 435 S.E.2d at 557. Several of these policies support that the legislature intends the Commission to encourage cost-efficient siting of generation facilities, and thus that the Commission has the authority to consider all costs borne as a result of that siting decision.

Friesian and intervenors NCCEBA and NCSEA have argued that even if the Commission has the statutory authority to consider the transmission upgrade costs, any such consideration is preempted by the Federal Power Act, 16 U.S.C.S § 791a, et seq. (FPA or the Act), and FERC's jurisdiction under that Act. In brief, these parties contend that because FERC has sole jurisdiction to determine the manner in which the costs of the Network Upgrades will be paid and then assigned to various parties and interests, the Commission is thereby forbidden to consider both *the fact* that the Facility will cause such costs to be incurred and the *magnitude* of such costs in themselves or proportionally.

It is well-established that states have traditionally assumed jurisdiction and authority over the generation of electricity, and thus over decisions addressing the need for and the siting of all necessary facilities. *See Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 194, 75 L. Ed. 2d 752, 760 (1983); *see also FERC v. Elec. Power Supply Ass'n [(EPSA)]*, 577 U.S. ___, ___, 193 L. Ed. 2d 661, 668 (2016). Similarly, "states have traditionally assumed all jurisdiction [over the approval or denial of] permits for the siting and construction of electric transmission facilities." *Piedmont Environmental Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009), *cert. denied*, 558 U.S. 1147, 175 L. Ed. 2d 972 (2010); *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 F.E.R.C. ¶ 61,080, P.433 n.543, 61 Fed. Reg. 21,540, 21,626 n.543 (1996) ("Among other things, Congress left to the States authority to regulate generation and transmission siting."). Indeed, the FPA only gives FERC the authority to interfere with this jurisdiction — i.e., delegates to FERC federal jurisdiction which preempts state jurisdiction — when the transmission both falls inside a national interest corridor and one of five "carefully drawn" circumstances applies. *See* 16 U.S.C.S. § 824p(b)(1); *see also Piedmont*, 558 F.3d at 313-14.

Even in a traditionally state-occupied realm, however, Congress may supersede state or local action either explicitly or implicitly. *See generally Pacific Gas*, 461 U.S. at 203-04**,** 75 L. Ed. 2d at 765; *see also New York v. FERC*, 535 U.S. 1, 18, 152 L. Ed. 2d 47, 62 (2002); *Anderson v. Sara Lee Corp.*, 508 F.3d 181, 191 (4th Cir. 2007). There, State action is preempted only to the extent that it: "actually conflicts with federal law"; makes compliance with both federal and state law impossible; or "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Pacific Gas*, 461 U.S. at 204, 75 L. Ed. 2d at 765 (citations and quotation marks omitted). And on review there is no "presumption one way or the other." *New York*, 535 U.S. at 18, 152 L. Ed. 2d at 63.

The FPA gives FERC the

> exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce . . . [and] assigns to FERC responsibility for ensuring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable . . . ."

Hughes v. Talen Energy Marketing, LLC, 578 U.S. ___, ___,194 L. Ed. 2d 414, 419-20 (2016); *see also* 16 U.S.C. § 824(b)(1). "This statutory text . . . unambiguously authorizes FERC to assert jurisdiction over two separate activities — transmitting and selling [the power in the wholesale market]." *New York*, 535 U.S. at 19-20, 152 L. Ed. 2d at 63; *see also* 16 U.S.C. § 824(a).

The FPA also gives FERC jurisdiction over "any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of [FERC]" as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification." 16 U.S.C. § 824e(a). Admittedly, this jurisdiction might well encompass allocating the cost of transmission facilities to retail ratepayers once those facilities have been constructed. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 63-64 (D.C. Cir. 2014) (finding that this "does not interfere with the traditional state authority that is preserved by Section 201" of the FPA); *see also Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 104 F.E.R.C. ¶ 61,103 (2003).

But nothing in the FPA extends this jurisdiction over, and precludes, the States' consideration of the cost of required transmission network upgrades when determining the most prudent and cost-effective locations for generating facilities to be placed or whether the generation is needed in the first instance. *See Virginia Uranium, Inc. v. Warren*, 139 S. Ct. 1894, 1907, 204 L. Ed. 2d 377, 389 (2019) (typically, "any '[e]vidence of pre-emptive purpose,' whether express or implied, must . . . be 'sought [and found] in the text and structure of the statute at issue."); *see also id.* at 1900, 204 L. Ed. 2d at 381 (". . . it is our duty to respect not only what Congress wrote but, as importantly, what it didn't write."). Nor do any of FERC's regulations or orders decidedly extend the same. *See generally Hillsborough County v. Automated Med. Labs., Inc.*, 471 U.S. 707, 717, 85 L. Ed. 2d 714, 724 (1985) ("We are even more reluctant to infer pre-emption from the comprehensiveness of [agency] regulations than from the comprehensiveness of statutes . . . .").

Rather, "the law places beyond FERC's power, and leaves to the States alone . . . control over in-state facilities used for the generation of electric energy." *Hughes*, 578 U.S. at ___, 194 L. Ed. 2d at 420 (citations omitted). This authority includes deciding *where* to site those generation facilities and "[t]here is little doubt that . . . state public utility commissions or similar bodies are empowered to make the initial decision regarding the need for power." *Pacific Gas*, 461 U.S. at 205-06, 75 L. Ed. 2d at 760 (citations omitted); *see also Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("State and municipal authorities retain the right to forbid new entrants from providing new capacity . . . to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission"; it is the "consumer-constituents of state commissions . . . [that] will appropriately bear the costs of that decision, including paying more for system reliability from older and less efficient units."). This authority thus necessarily includes consideration of all the information that might impact that siting decision — including the construction of transmission system upgrades required to accommodate that additional generation.

FERC implicitly recognized the same in Order No. 888. *See* Order No. 888, 61 Fed. Reg. at 21,626 n.543. FERC further declared that its Final Rule "[was] not [to] affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service . . . [and] utility generation and resource portfolios." *Id.* at n.544 (cited in *New York*, 535 U.S. at 24, 152 L. Ed. 2d at 66).

Later, FERC issued Order No. 1000 in an effort to manage electric transmission grids on a regional level. *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 F.E.R.C. ¶ 61,051 (2011). Therein, FERC recognized that States could continue to regulate electric transmission lines, explicitly stating:

> We acknowledge that there is longstanding state authority of certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule . . . are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

Order No. 1000 at ¶ 107; *see also MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (7th Cir. 2016) (it was a "proper goal" for FERC "to avoid intrusion on the traditional role of the States in regulating the siting and construction of transmission facilities"), *cert. denied*, 137 S. Ct. 1223, 197 L. Ed. 2d 463 (2017). It makes little sense then that the Commission would continue to have authority over the siting, permitting, and construction of all generation and transmission facilities — including for integrated resource planning purposes — but would not have the authority to consider all information that might impact the propriety of siting and constructing those facilities.

That conclusion is also consistent with and supported by language in the Supreme Court's decision in *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 90 L. Ed. 2d 943 (1986). Though the question now before the Commission presents in a different procedural guise than the ratemaking proceedings that were at issue in *Nantahala*, Justice O'Connor's discussion of the distinction between a decision to purchase power and the price at which such power is purchased is nevertheless pertinent. In holding that this Commission impermissibly invaded FERC's exclusive jurisdiction when it attempted to establish retail rates that did not recognize and accept the FERC-determined allocation of low-cost "entitlement power," the Court noted that such a case was *not* the same as an unconstrained decision whether or not to enter into a transaction involving the purchase of power in the first instance, stating:

> Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price*.

Id. at 972, 90 L. Ed. 2d at 958 (emphasis in original). In other words, because the utilities in *Nantahala* were bound by FERC's allocation of available low-cost "entitlement power," they were not free to purchase a greater amount of such low-cost power, in preference to higher cost power from other wholesale suppliers, and consequently this Commission was likewise bound by such allocation in setting retail rates for such utilities.

The important distinction between the facts in *Nantahala* and those presented to the Commission here is that the decision posed to the utilities in *Nantahala* — that is, whether, and how much power, to purchase — was constrained by FERC determinations. In this case, however, the question to be decided is not so constrained. FERC has not ordered, directly or indirectly, that the Friesian facility be constructed, that it be sited at any particular location in the state, that its energy and capacity be sold to any particular purchaser, that such energy and capacity be sold at any particular price, or any other of the numerous other details of the Friesian project. Whether it is in the public convenience and necessity that Friesian be constructed at all is conceptually the same type of decision as that embodied in the above-quoted passage from *Nantahala*.

Two years after the *Nantahala* decision, in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 101 L. Ed. 2d 322 (1988), the Supreme Court reiterated that distinction, quoting from *Nantahala* and elaborating thus:

> Appellees seek to characterize this case as falling within facts distinguished in *Nantahala*. Without purporting to determine the issue, we stated in *Nantahala*: "[W]e may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price* . . . ." As we assumed, it might well be

> unreasonable for a utility to purchase unnecessary quantities of high-cost power, even at FERC-approved rates, if it had the legal right to refuse to buy that power. But if the integrity of FERC regulation is to be preserved, it obviously cannot be unreasonable for MP & L to procure the particular quantity of high-priced Grand Gulf power that FERC has ordered it to pay for. Just as Nantahala had no legal right to obtain any more low-cost TVA power than the amount allocated by FERC, it is equally clear that MP & L may not pay for less Grand Gulf power than the amount allocated by FERC.

Mississippi Power, 487 U.S. at 373-74, 101 L. Ed. 2d at 340 (internal citation omitted). Once again, the utility's decision whether, and how much power, to purchase was legally constrained by FERC's determination of the wholesale power allocation and the wholesale rates. Thus, in both *Nantahala* and *Mississippi Power* the matter of whether the affected utility would or would not, or should or should not, enter into an arrangement or agreement governed by FERC-established rules and orders had already been decided before the state regulatory bodies considered those arrangements in ratemaking proceedings.

The two cases stand for the proposition that a state cannot, through its retail ratemaking, attempt to nullify or vary an action taken or cost incurred by the regulated utility in consequence of and in compliance with FERC rules and determinations. By contrast, the question now before this Commission is, in substance, the same as would have been the case if the Mississippi Public Service Commission, cognizant of likely or anticipated FERC policy and practice, had decided that a CPCN should not be granted to permit Mississippi Power & Light Co. to participate in the joint construction of the Grand Gulf nuclear power plant.[5] And, accordingly, both *Nantahala* and *Mississippi Power* support the determination that whether or not power shall be procured at all — in this case by means of the construction of a new generating facility — is not limited by FERC's jurisdiction to determine the price of such power or the assignment of the costs of procuring it.

That said, no party disputes that southeastern North Carolina exhibits many attributes favorable for the development of solar generating facilities and that those attributes have resulted in significant solar development in that region. As a result, however, the transmission infrastructure in that portion of the DEP system is approaching a tipping point where additional generation in certain portions of the system will require significant upgrades to the network. The Commission shares the concern of the Public Staff regarding the appropriateness of siting additional generation in this region, in this

[5] It is of interest that the Mississippi Public Service Commission had originally granted a CPCN to Mississippi Power & Light Co. to participate in the Grand Gulf nuclear plant development before any of the matters in controversy in the case took place. This fact was noted by the Supreme Court as part of the factual background for the case, *see Mississippi Power*, 487 U.S. at 358-59, 364, 101 L. Ed. 2d at 330-31, 333-34, but there is nothing in the Court's decision to suggest that the Mississippi commission would have been intruding on FERC's jurisdiction had it simply chosen to deny the CPCN due to uncertainties or concerns about the ultimate costs that would have been incurred by or assigned to Mississippi Power & Light Co.

manner, and at this time, given the significant cost implications for the provision of electric service in North Carolina.

This concern is especially prudent given a comparison of the cost of comparable new solar energy facilities. To this end, the Commission views the LCOT analysis performed by the Public Staff as a benchmark of the reasonableness of the Network Upgrades relative to other similar transmission investments made to interconnect generating facilities in North Carolina.[6] And the LCOT analysis performed by the Public Staff shows just how unprecedented the cost of the Network Upgrades are to costs realized on a national basis. To that end, the Commission accepts that the calculated LCOT value of the Network Upgrades is $62.94 MWh, and far surpasses — it is 19.5 times higher than — the next highest mean range value reported by the Study for solar generating facilities calculated in MISO, PJM, or more broadly by EIA.[7]

The Commission has also reviewed the other North Carolina merchant plant projects discussed by Public Staff witnesses Lawrence and Metz, as well as the cost estimates for other Duke transmission projects as reported by the North Carolina Transmission Planning Collaborative (NCTPC) for the last 14 years — of which the Commission took judicial notice at the hearing. *See* Tr. vol. 3, 77-78. During those 14 years, the typical Duke transmission project had a mean cost in the range of $20 to $42 million, and the two most expensive Duke transmission projects were estimated to cost $85 million (Richmond to Fort Bragg Woodruff Street 230 kV line) and $95 million (Orchard Tie 230/100 kV tie station). The NTE Reidsville combined cycle plant's interconnection costs were estimated at $53 million. At an estimated construction cost of $223.5 million, the Network Upgrades would far and away be the single costliest transmission project in North Carolina in recent times, perhaps the most expensive ever.

No party through the time of the hearing — or any time prior to the filing of the parties' proposed orders — challenged the accuracy of the estimated $223.5 million plus

[6] The Commission notes that the LBNL Study specifically states that the cost information in the report is generalized and should be used to inform high-level decisions and directives. LBNL Study at 27.

[7] The Commission also rejects, as Friesian argues, that uncertain future generation must be included when calculating the Friesian Facility's LCOT value. To the contrary, the LCOT analysis provides a useful comparison of actual incurred costs with the proposed transmission upgrade costs associated with specific generation resources. The LCOT analysis does not evaluate the loading of existing lines and whether they are fully subscribed, but instead provides a high-level comparison of costs that have been incurred around the nation to interconnect solar facilities. To assume that those lines can, or will certainly, accommodate additional generation resources goes beyond the scope of the LBNL Study. Insofar as the Commission were to accept DEP's estimate that the Network Upgrades will facilitate another 1,000 MW of generator interconnections (for a total of 1,070 MW) — which, as discussed further below, is uncertain — the cost would still be a relatively high $208/kW, still close to double the highest average cost of any of the groupings studied.

Likewise, the Commission agrees with the Public Staff that DEP's estimate overlooks the likelihood that these future projects will themselves require additional costly upgrades. Without studying the future projects comprehensively as part of a group or cluster, however, how much additional generation would be able to interconnect, and whether additional upgrade costs could impact the LCOT calculations, is uncertain.

interest.[8] Further, no party presented a witness, such as a Duke transmission expert, who could credibly address the potential that the actual cost for the Network Upgrades could be substantially more or less than $223.5 million, let alone be cross-examined. As such, the Commission accepts this estimate for the purposes of its decision making.

Also, the Commission is concerned about the potential for the Network Upgrades cost to increase further. Witness Bednar admitted this possibility. He discussed that labor competition for high voltage transmission and station work might well drive various costs even higher. *See* Tr. vol. 2, 39 (noting a "dramatic increase in interconnection costs"), 41-42 ("from 2017 to today, my sources within the [Engineering, Procurement, and Construction] community [state] that it's not unusual for high voltage and transmission costs to have risen 30 to 40 percent broadly, nationwide, based . . . upon shortages of general construction capacity . . . ."), 44-45. So too might an increase in material costs — witness Bednar candidly testified to a "5 to 10 percent increase . . . on [the price of] cable and wire" every six months for "a cumulative in two and a half years of [a] 35 percent" cost increase. *Id.* at 45. He also acknowledged that each of Birdseye's other projects had seen their estimated interconnection costs increase. *Id.* at 46.

As such the Commission believes that the current estimated cost — already significant — could be understated. This belief also rests upon the scale and complexity of the upgrades in question, which, according to witness Bednar, includes crossing the

[8] On January 8, 2020, DEP filed a late-filed exhibit. That filing describes the basis for the almost doubling of costs from the initial estimate of $116 million: "a more detailed understanding of the scope and . . . developed using the Company's [recently] updated cost and scheduling systems." DEP also indicates therein that already-experienced increases in labor costs and costs due to environmental compliance factored into the $223.5 million estimate. In addition, a contingency of approximately $39.5 million was included in that estimate. January 8, 2020 DEP Late-Filed Exhibit, 1.

On April 16, 2020, DEP filed a supplemental late-filed exhibit. That filing sought to revise DEP's earlier estimate from $223.5 million to $187.3 million. The filing explains the basis for the $37.1 million reduction as driven primarily by: lowered vendor rates; material assumption variances, and the use of a wood product matting in lieu of a composite material in some locations; and reduction of the earlier contingency amount — which was itself $39.5 million.

But neither of these late-filed exhibits were subject to examination nor is it clear through what witness they might be introduced. Indeed, not only did no party, including DEP, choose to call an appropriate witness at the hearing to explain the bases for these now three estimates, the late-filed exhibits themselves are merely letters from Duke's Associate General Counsel, who was neither a witness in this case nor was ever likely to be one. Rather than assuage the Commission, the various swings in the estimated cost of the transmission network upgrades raise further concern.

Appendix B of the LGIA indicates that Duke will provide Friesian with "Class III Estimates" of the project's costs; the January 8, 2020 DEP Late-Filed Exhibit, however, describes its estimate as a "Class 4 estimate"; and the April 16, 2020 DEP Supplemental Late-Filed Exhibit describes its estimate as a Class 3 Estimate. It is the Commission's understanding that no matter whether the current estimate is a Class 3 or 4 type estimate, these types of estimates have low accuracy. Even the lower of the two most recent estimates allows, as a Class 3 Estimate, for the possibility that actual costs could be understated as much as 30 percent. In other words, the most recent estimate could still increase another $56 million — i.e., more than the most recent downward adjustment, and to a number higher still than the accepted $223.5 million estimate.

All said, whether $187.3 million, $223.5 million, or more, the Commission's analysis and ultimate conclusion would remain the same.

Cape Fear River four times, *see id.* at 40 & 47; the work having to occur during 12 weeks each year when the existing transmission lines in question can be taken out of service, where a single weather event, such as a hurricane or late snow or ice storm, has the potential to substantially delay the work, *id.* at 66-68, 124; and the short window — by the 2023 in-service date — in which to complete the upgrades. Each concern risks driving the cost higher.

The Commission recognizes and acknowledges the jurisdiction of the FERC with respect to the allocation of the costs associated with interconnecting a merchant generating facility such as the Facility. Nevertheless, the cost of the Network Upgrades dwarfs the costs of the generating plant, and the scale of the costs associated with the Facility relative to the size and projected revenue from the Facility raises concerns regarding economic viability of the project. Indeed, as witness Bednar admitted, the Homer and Fair Bluff projects — proposed generating facilities in the interconnection queue behind, and thus interdependent with, the Facility — would not be viable were they responsible for paying for the Network Upgrades. *See* Tr. vol. 2, 137-38.

For these reasons, the Commission concludes that siting the Facility in this region of the State and at the particular point of interconnection is not consistent with the requirements of N.C.G.S. § 62-110.1(d) for the provision of "reliable, efficient and economical electric service."

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence supporting these findings of fact is found in the testimony of Friesian witnesses Askey, Bednar, and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Friesian witness Bednar testified that he expects "that the Friesian upgrades will be utilized by a minimum of 1,000 MW of later queued generation in the constrained area" of DEP's system in which the Facility proposes to interconnect. Tr. vol. 2, 42. Witness Bednar further testified that he believes the Network Upgrades are necessary to support significant addition of solar generation resources in North Carolina due to the importance of the constrained area to further solar development in the State. Tr. vol. 2, 45. He stated that the Network Upgrades represent the only "immediately-actionable" proposal to address transmission-related constraints in this region of the State. Tr. vol. 2, 43-44.

Friesian witness Askey testified that data request responses from Duke identified approximately 1,561 MW that is currently interdependent on the Network Upgrades and that DEP stated that the "Friesian upgrades will at least partially facilitate the interconnection of more than 1,000 MW of additional generation." Tr. vol. 2, 171-72. He conceded, however, that there may well be additional transmission network upgrades that are required to interconnect those other projects.

Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff is deficient in that it fails to take into consideration all of the projects that are behind

Friesian in the interconnection queue. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16. Friesian witness Askey similarly testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Tr. vol. 2, 91-92.

With respect to transmission constraints, Friesian witness Askey testified that, based on information provided by DEP, substantial transmission network upgrades will be needed to accommodate any new generating resources that are planned for the southeastern region of North Carolina. He testified that one of DEP's two 1235-MW combined cycle plants that are being evaluated for siting in Cumberland County is interdependent on and would benefit from the Network Upgrades. Tr. vol. 2, 266. He also stated that even if the DEP facilities being studied are not built, the Network Upgrades will be required to connect new generation resources in the State. *Id.* at 175.

In their joint testimony, Public Staff witnesses Lawrence and Metz acknowledged that Q399, the queue position of the second proposed combined cycle plant under consideration by DEP, is interdependent upon a significant portion of the Network Upgrades, as well as upon other significant transmission upgrades that may be required. The Public Staff refused to assign significant weight to the potential for the Network Upgrades to reduce the upgrade costs associated with future planned generation, however, because such an analysis is "heavily dependent upon future IRPs showing a continued need for additional capacity, contingencies such as the completion of the [Atlantic Coast Pipeline], as well as DEP demonstrating that [the] Q399 [project] is in the public interest in a CPCN application, as opposed to other resource alternatives." Tr. vol. 3, 132-33.

Friesian witness Wilson testified that a substantial buildout of new renewable energy resources is in the public interest for North Carolina ratepayers, notwithstanding the cost upon those ratepayers of the $223.5 million in Network Upgrades needed to support the Facility. In her direct testimony, witness Wilson cited a study in which she was a primary author entitled *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan* (Synapse Report), included in her testimony as Exhibit RW-1. In support of her argument, witness Wilson testified that the type of generating portfolio recommended by the Synapse Report results in least cost energy and has additional benefits in the form of reduced air emissions and improved public health. Tr. vol. 2, 98. The Synapse Report was previously presented in Docket No. E-100, Sub 157 in response to the Commission's solicitation of comments on the 2018 IRPs submitted by DEP and Duke Energy Carolinas (collectively, Duke). The Synapse Report presents a "Clean Energy scenario" that models a significant addition of solar and storage resources to the Duke portfolio over the 15-year IRP planning horizon. *Id.* at 99-100. In the Clean Energy scenario, by 2033, there are 14 gigawatts (GW) of solar capacity and almost 6 GW of battery capacity added in the Duke service territories. *Id.* at 120.

Witness Wilson stated that the Clean Energy scenario represents a savings of almost $8 billion in terms of the net present value of revenue requirements over the duration of the 15-year planning period. Witness Wilson calculated that the health benefits of the Clean Energy scenario range from $195 to $440 million by 2024, due to avoided emissions of sulfur dioxide, oxides of nitrogen, and particulate matter. *Id.*

Witness Wilson also admitted that the Synapse Clean Energy scenario does not include the costs of any new transmission or upgrades to existing transmission required to interconnect renewables, including the Friesian project. *Id.* at 104, 120; *see also* Tr. vol. 3, 22-23. Further, she stated:

> My study is an economic one, and it looks at the least cost resource alternative to a comparison portfolio, which in this case is Duke's 2018 IRP, and determines that additional solar and storage resources are to the benefit of ratepayers. *It doesn't look at where those renewables are sited, [or] costs that it might take to integrate them*, and those costs are going to change over time, certainly.

Tr. vol. 3, at 25-26 (emphasis added).

Public Staff witnesses Lawrence and Metz explained that Governor Cooper's Executive Order 80 (EO80) states that North Carolina will strive to reduce greenhouse gas emissions (GHG) by 40% below 2005 levels by 2025. *Id.* at 133. EO80 further required DEQ to develop a Clean Energy Plan for the State. The Clean Energy Plan set a goal to reduce electric sector GHG emissions by 70% below 2005 levels by 2030 and obtain carbon neutrality by 2050. The Plan states that "NC's values such as electricity affordability, equity, and reliability should be fully considered." *Id.* at 134-35.

Friesian witness Wilson stated that achieving the goals of the DEQ Clean Energy Plan to reduce carbon emissions by 70% from 2005 levels by 2030 will be difficult if no additional solar resources can be interconnected in the areas dependent on the Network Upgrades. Tr. vol. 2, 108. She also testified that in order to achieve the types of emissions reductions that are being contemplated by the State of North Carolina, projects like Friesian must move forward. Tr. vol. 3, 26.

However, witnesses Lawrence and Metz testified that the Clean Energy Plan stated that the State is already on track to meet the goals of EO80. Regarding the current trend in the State's emissions, the report states:

> NC has already reduced significant amounts of GHG emissions from the electric power sector. The State's Clean Smokestacks Act, REPS, PURPA and market drivers have decarbonized the electric power sector at a faster pace than many other states. According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels. These reductions have been achieved in the absence of explicit carbon policies in the State. DEQ estimates that with full

> implementation of HB589, the GHG reduction level from the electric power sector will reach roughly 50% by 2025 and remain at this level out to 2030.

Id. at 134.[9]

Witness Metz also testified that DEP is working with the National Renewable Energy Laboratory (NREL) to determine the quantity of renewables that can interconnect to the system. Tr. vol. 4, 83. Witness Metz explained that there are two phases of the study:

> Phase 1 scope quantify the amount of carbon free electricity, estimate a curtailment[, ramping,] and system flexibility limits, evaluate its shifts, and daily seasonal net load timing supply. There's another phase coming because Phase 1 did not consider unit commitment and economic dispatch[,] system stability cost[,] or transmission impacts. Phase 2 will address those concerns.

Id. at 104.

Discussion and Conclusions

The Commission has carefully considered the evidence presented by the Applicant as to secondary benefits that would follow the construction of the Facility and concludes that, at this time, those benefits are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

Friesian asserts that the Network Upgrades would enable significant, additional future generating capacity to interconnect to the DEP network. Friesian points to a data request response received from Duke as support that the Network Upgrades would enable the interconnection of more than 1,000 MW of additional solar generation in the southeastern portion of North Carolina and the northeastern portion of South Carolina. *See* Tr. vol. 2, 122-23, 170-71; Tr. vol. 3, 136. The Duke data request response also states that "[b]ased on the assessment completed by DEP for interconnection requests received through September 30, 2017, there are 108 interconnection requests totaling 1,561 MW that have been identified as being interdependent on the upgrades assigned to Friesian." Friesian witness Wilson also testified that the Network Updates might facilitate the interconnection of an additional 900 MW of future solar generation as well. *See* Tr. vol. 2, 114-15.

But whether the additional generation will be developed and placed in service is subject to many variables in addition to interconnection cost. And there is nothing in the record from which the Commission can conclude that any one of the proposed generating facilities, much less all of them, will actually be constructed and placed in service. Without

[9] *See also* Tr. vol. 3, Official Exhibits, Public-Staff Frisian Panel Cross Examination Exhibit 7, DEQ Clean Energy Plan, at 267.

more, the Commission concludes that whether the Network Upgrades are or will be needed to enable significant, additional future generation is too uncertain to be given significant evidentiary weight by the Commission.

Friesian's assertion also includes that the Network Upgrades would facilitate and reduce the cost of DEP-owned proposed generating capacity. While the Load, Capacity, and Reserves Tables in DEP's 2018 IRP and 2019 IRP Update indicate the addition of two facilities with approximately 1,300 MW of combined cycle capacity in 2025 and 2027, these resources are undesignated at this time. DEP has not yet taken steps to determine resource alternatives to meet the undesignated need shown in the IRP, such as issuing a request for proposals (RFP) or filing a CPCN application for the facilities. DEP itself did not cite this benefit in its December 6, 2019 letters to the Commission, and DEP did not provide a witness in this proceeding to explain whether the Network Upgrades would benefit any planned DEP facilities.

Further, DEP's interconnection queue report dated January 27, 2020, shows that 12 interconnection requests are pending for a total of 14,560 MW of new, DEP-owned gas-fired generating plants, while DEP's IRP shows that the Company plans to build a much smaller amount of new gas-fired generation, 7,852 MW, through 2034. DEP does not have a CPCN granted or an application for a CPCN or any such plant pending. After reviewing the queue report, the Commission concludes that DEP has as yet no firm plans to build a gas-fired generator in Cumberland County but is instead studying several alternative sites throughout its territory, including sites in Wake, Wilson, Person, and Johnston Counties. The Commission therefore concludes that whether the Network Upgrades are or will be needed in the near term for any planned or proposed DEP generating facilities to provide service to DEP customers is likewise too uncertain to be given significant evidentiary weight by the Commission.

Friesian next calls upon the Synapse Report. But its Clean Energy scenario does not model the Friesian Facility or the Network Upgrades at all, making it of limited relevance. Also, the Report's Clean Energy scenario calls for the addition of more than 14 GW of solar generating capacity and almost 6 GW of battery capacity in the DEP and DEC territories over the next 15 years. Yet, insofar as the Commission were to accept DEP's estimate, the Network Upgrades would only *partially*[10] facilitate a small fraction, some 1,000 MW, of the solar generating capacity necessary to achieve the benefits claimed by the Synapse Report. For purposes of this proceeding, witness Wilson did not quantify the estimated benefits along these narrower, more pertinent, lines. More concerning, her Clean Energy scenario fails to include the cost of transmission network upgrades in its model. If these upgrades had been contemplated, the model likely would have produced different, and less favorable, results regarding the benefits to ratepayers. For each of these reasons, the Commission must afford limited evidentiary weight to the benefits included in the Synapse Report and discussed by witness Wilson.

[10] *See* Tr. vol. 2, 56, 171 ("partial facilitation means that it will address the interdependencies, but there may be additional upgrades associated with those projects that [are required] to allow them to also interconnect").

Friesian's reliance on the DEQ Clean Energy Plan exhibits similar shortcomings. As the Public Staff notes, the Clean Energy Plan contains several recommendations to ensure the addition of reliable and affordable energy resources. These goals are statewide goals. Importantly, according to DEQ, the State's electricity sector is currently *on pace* to meet the Governor's EO80 emissions reduction target in 2025.

The Clean Energy Plan also contains several recommendations for stakeholder processes and comprehensive planning tools to achieve its goals to add cost-effective, affordable clean energy resources to North Carolina's generating portfolio. Specifically, it states:

> DEQ will enlist assistance from academic institutions to deliver a report to the Governor by December 31, 2020, that recommends carbon reduction policies and the specific design of those policies to best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability. The report will evaluate policy designs for the following: (1) accelerated coal retirements, (2) a market-based carbon reduction program, (3) clean energy policies such as an updated REPS, an EERS Short term and clean energy standard, and a (4) a combination of these policy options.

Tr. vol. 3, Official Exhibits, Clean Energy Plan, Public Staff-Friesian Panel Cross-Examination Exhibit No. 7, 213. Relatedly, Duke is also currently working with NREL to develop a Carbon-free Resource Integration Study to analyze and quantify the impact of new renewables on the DEP and DEC systems. *See* December 20, 2020 Public Staff Late-Filed Exhibit No. 1.

In sum, the Commission concludes that the benefits alleged by the Applicant to follow the construction of the Facility are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact is found in the prehearing brief of the Public Staff, the testimony of Friesian witness Bednar, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Public Staff witnesses Lawrence and Metz testified regarding the need for comprehensive system planning, including the IRP process, the integrated systems operation planning (ISOP) process being developed by the utilities, distribution system planning, and competitive bidding processes like the CPRE Program or short-term market solicitations, rather than individual CPCN applications. The Public Staff believes that as rate pressures on electric customers continue to increase, comprehensive system planning will produce more efficient, cost-effective results than the piece-meal planning and construction approach currently being used. Tr. vol. 3, 137-38.

In its prehearing brief, the Public Staff noted that, in its June 14, 2019 Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, in Docket No. E-100, Sub 101 (2019 Sub 101 Order), the Commission directed the utilities, "to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses (including reasonable overhead expenses) associated with supporting the generator interconnection process under the NC Interconnection Standard." Prehearing brief at 11-12, quoting from 2019 Sub 101 Order at 18. The Public Staff noted the Commission's recognition of the arguments raised by Duke and others that the current serial study process was not sustainable and that comprehensive queue reform was necessary to better align the NC Interconnection Standard and Duke's FERC OATT with regard to studying projects, assigning upgrade costs, and collecting the costs of those projects. As such, the Commission found that the commitment by Duke to implement a stakeholder process to develop a group study proposal was reasonable and appropriate. *Id.*

Also in its prehearing brief, the Public Staff noted that a significant portion of the additional generating capacity that would benefit from the Network Upgrades would not be responsible for any of the network upgrade costs and that this disparity highlights the need for the queue reform measures proposed by Duke. *Id.*

Friesian witness Bednar acknowledged the benefits of comprehensive system planning but believed that deferral of the Network Upgrades is "ill-advised," noting that the timing of the IRP and ISOP processes creates risks of bringing new generation online, will result in additional study costs, and will increase the cost of the upgrades when they are ultimately constructed. Tr. vol. 2, 43. He cited the statements of position filed by Duke Energy, in which Duke stated that the need for the upgrades would not go away, and that "if the Friesian Network Upgrades are not constructed at this time, there will be a further substantial delay of any additional generating facilities in this area of DEP." *Id.* at 44, quoting from December 6, 2019, letter from Jack Jirak on behalf of DEP.

Witness Bednar testified that the Application involves unique circumstances and that the construction of the Network Upgrades will provide substantial benefits to the DEP transmission system and the State as a whole. Regarding the potential impacts of the Network Upgrades on the current queue reform efforts underway by Duke, witness Bednar testified that the Network Upgrades would minimize short-term challenges associated with Duke's queue reform plans, as well as allow for the interconnection of a substantial amount of renewable resources in the region. Tr. vol. 2, 46-47.

On cross-examination, Public Staff witness Metz stated that the Public Staff is generally supportive of a transition from the current serial queue to a grouping study model, and stated that on a going-forward basis, the grouping study approach would help to address some of the concerns raised in this proceeding. Witness Metz conceded that the transition process will be complex and that such a transition could be further delayed if the Network Upgrades are not approved. But he further stated that the transmission network upgrades required by the Facility are substantial and represent a tipping point. Tr. vol. 4, 42-47.

Discussion and Conclusions

The circumstances presented by the Facility illustrate the significant issues related to the continued development of renewable energy, as well as the implications for the electric systems, in North Carolina. As previously discussed in the Commission's 2019 Sub 101 Order, North Carolina has achieved nation-leading success in the siting and development of renewable energy generating facilities over the past decade, and the majority of the capacity added utilized existing transmission and distribution capacity on the DEP, DEC, and DENC systems. However, this success has come at a cost with the transmission system constraints in southeastern North Carolina and the system operational challenges that the utilities have begun to experience. In enacting HB589, the General Assembly both recognized these challenges and accordingly encouraged the siting of renewable energy resources in locations where the system could most efficiently accommodate them. *See* N.C.G.S. § 62-110.8(c).

The Commission recognizes the activities underway to consider and address the issues highlighted by the Facility. Both the DEQ Carbon Reduction Stakeholder Group and Phase 2 of the NREL Carbon-Free Resources Integration Study intend to analyze and quantify the impact of new renewables on the DEP and DEC systems and both are likely to result in recommendations. Similarly, there exists the promise of future queue reform that seeks to enable Duke to perform a cluster study process. *See* Order Requiring Queue Reform Proposal and Comments, *Petition for Approval of Revisions to Generator Interconnection Standards*, Docket No. E-100, Sub 101 (N.C.U.C. August 27, 2019). Each of these activities, in addition to the IRP and ISOP processes, can inform or support various long-term options being evaluated and provide a framework to identify the most cost-effective solutions. *See* N.C.G.S. § 62-110.1(d).

The Commission is unable to find sufficient support in the record for witness Bednar's assertion that the Network Upgrades are inevitable and that any delay in their construction will only result in increased costs to customers. To the contrary, the Commission instead credits the testimony of Public Staff witnesses Metz and Lawrence that the potential to defer costs may provide benefits to customers, depending on the carrying cost of capital, changes in commodity prices, and labor rates. Tr. vol. 3, 216-20. Additionally, due to technological changes, there also may be other alternatives identified that ultimately help to defer, minimize, or avoid altogether, the need for costly future network upgrades. *Id.* at 137. More importantly, the Commission sees value in deferring any decision related to upgrade of the system in the southeastern region of the State, pending the outcome of the activities underway.

Relatedly, in its October 23, 2019 Order Granting Motion to Delay in Docket No. E-100, Sub 101 (October 23 Order), the Commission specifically directed Duke to (1) file an updated version of its queue reform proposal as modified based on feedback from stakeholders, along with a redline version of the North Carolina Interconnection Procedures, or (2) notify the Commission that no modifications are needed. The October 23 Order also established a further procedural schedule, which was subsequently extended by order of the Commission in response to request by the parties, requiring parties to file comments on Duke's proposal and for Duke to file reply comments. Duke filed its proposal on May 15, 2020. The Commission recognizes the significance of the transition period in this process.

In sum, the Commission concludes that it is prudent to await the results of the work being undertaken in North Carolina on these issues and to consider the results of these studies and proposals in the context of the IRP process. The IRP process is the more appropriate forum to consider benefits associated with upgrades to the system, in addition to and in the context of reliability, resilience, and affordability.

CONCLUSION

After having carefully considered and weighed the evidence and arguments presented in this proceeding, the Commission concludes that Friesian has failed to persuade the Commission that granting the Application is in the public interest and required by public convenience and necessity and, therefore, denies Friesian's Application.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

This the 11th day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.