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INFORMATION SHEET

PRESIDING: Chair Mitchell, Commissioners Brown-Bland, Gray, Clodfelter, Duffley, and Hughes
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: Thursday, December 19, 2019
TIME: 1:30 p.m. – 4:15 p.m.
DOCKET NO.: EMP-105, Sub 0
COMPANY: Friesian Holdings, LLC
DESCRIPTION: Application for a Certificate of Public Convenience and Necessity to Construct a 70-MW solar Facility in Scotland County, North Carolina
VOLUME: 4

APPEARANCES

FOR FRIESIAN HOLDINGS, LLC:
Karen M. Kemerait, Esq.
Steven J. Levitas, Esq.

FOR DUKE ENERGY PROGRESS, LLC:
Jack E. Jirak, Esq.

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Peter Ledford, Esq.
Benjamin Smith, Esq.

FOR NORTH CAROLINA CLEAN ENERGY ALLIANCE:
Benjamin L. Snowden, Esq.

FOR THE USING AND CONSUMING PUBLIC:
Tim Dodge, Esq.
Layla Cummings, Esq.

WITNESSES
Panel of Evans and Lawrence

FILED
JAN 10 2020
Clerk's Office
N.C. Utilities Commission

EXHIBITS

Applicant Cross Exhibits 1 – 5 /A
Confidential Lawrence/Metz Exhibit 1 (filed under seal) /A
Lawrence/Metz Exhibits 2, 3 and 4 /A

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PUBLIC COPY: Dodge, Levitas, Smith, Snowden, Kemerait, and Jirak
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REPORTED BY: Kim Mitchell
DATE FILED: January 9, 2020

TRANSCRIPT PAGES: 131
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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/2019 DOCKET NO.: EMP-105, Sub 0

ATTORNEY NAME and TITLE: Karen Kemerait

FIRM NAME: ______

ADDRESS: ______

CITY: ______ STATE: ______ ZIP CODE: ______

APPEARING FOR: Applicant Friesian

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/19 DOCKET NO.: EMP-105 sub 0

ATTORNEY NAME and TITLE: Steven Levitas

FIRM NAME: Kilpatrick Townsend

ADDRESS: 4208 Six Forks Road Suite 1400

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: Friesian Holdings LLC

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12-18-19 DOCKET NO.: EMP-105, Sub 0

ATTORNEY NAME and TITLE: Jack Jirak

FIRM NAME: Duke Energy

ADDRESS: ______

CITY: ______ STATE: ______ ZIP CODE: ______

APPEARING FOR: Duke

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: Dec. 18, 2019 DOCKET NO.: EMP-105 Sub 0

ATTORNEY NAME and TITLE: Peter Ledford, General Counsel

FIRM NAME: NC Sustainable Energy Association

ADDRESS: 4800 Six Forks Road, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NC Sustainable Energy Association

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12-18-2019 DOCKET NO.: EMP 105, S-50

ATTORNEY NAME and TITLE: Ben Smith Regulatory Counsel

FIRM NAME: N/A

ADDRESS: 4800 Six Forks Rd, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NCSEA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ✓

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/19 DOCKET NO.: EMP 105 Sub 0

ATTORNEY NAME and TITLE: Ben Snowden, counsel

FIRM NAME: Kilpatrick Townsend Stockton

ADDRESS: 4208 Six Forks Rd. Suite 1400

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NCCEBA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ✓

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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SIGNATURE: Ben L Snowden

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NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE 12-18-19 DOCKET # : EMP-105, Sub 0

PUBLIC STAFF MEMBER Tim Dodge / Layla Cummings

ORDER FOR TRANSCRIPT OF TESTIMONY TO BE **EMAILED** TO THE PUBLIC STAFF - PLEASE INDICATE YOUR DIVISION AS WELL AS YOUR EMAIL ADDRESS BELOW:

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Tim Dodge & Layla Cummings

Signature of Public Staff Member

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

EXHIBIT
1
Applicant Cross
I/A

DOCKET NO. E-100, SUB 85

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Investigation of Certification Requirements)
for New Generating Capacity in North Carolina) ORDER ADOPTING RULE

BY THE COMMISSION: On November 17, 1999, the Commission initiated a proceeding in this docket by issuing an Order requesting comments on whether a generic rulemaking proceeding should be undertaken to address a number of concerns, including the filing requirements for a certificate of public convenience and necessity to construct new electric generating capacity intended to serve wholesale load on a merchant plant basis. Interested parties -- including utilities, consumer advocates and independent power producers (IPPs) -- intervened, and the Commission received written comments from them. The Commission subsequently issued an Order on April 26, 2000, holding the proceeding in abeyance "pending resolution of electric industry restructuring issues by the legislature or until some future event warrants further consideration of the issues raised..."

Such an event warranting further consideration in this docket occurred earlier this year. At the January 23, 2001 meeting of the Study Commission on the Future of Electric Service in North Carolina, the Study Commission redirected its focus to encouraging a robust and competitive wholesale market, and, consistent with that new focus, Senator Hoyle, as Co-Chair of the Study Commission, asked the Utilities Commission to review the requirements for certification of new electric generating capacity in North Carolina with a view toward streamlining the process. G.S. 62-110.1(a) requires that any electric generating facility to be directly or indirectly used for furnishing public utility service, whether constructed by a public utility or other person, must have a certificate of public convenience and necessity from the Utilities Commission before construction. There was no Commission Rule specifically addressing the filing requirements for merchant plants.

The Commission issued its Order Initiating Further Proceedings in this docket on February 7, 2001. By that Order, the Commission requested proposals and comments on what filing requirements are appropriate for certification of merchant plants, what new or revised Commission Rules should be adopted to implement such filing requirements, and how Commission procedures for certification of merchant plants may be streamlined. The Public Staff filed a proposed Rule R8-63 in this docket on March 14, 2001. Comments and reply comments have been filed by the following parties, all of whom have been allowed to intervene and participate herein: the Public Staff; the Attorney General (AG); Duke Power, a Division of Duke Energy Corporation (Duke); Carolina Power & Light Company (CP&L); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power

(Dominion); Piedmont Natural Gas Company, Inc. (Piedmont); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Groups for Fair Utility Rates (CIGFUR); Enron America (Enron); Dynegy Inc. (Dynegy); Calpine Eastern Corporation (Calpine); PG&E National Energy Group (PG&E); the Public Works Commission of the City of Fayetteville; and the Electric Power Supply Association.

The Commission has carefully weighed and considered all of the comments. On the basis thereof, the Commission will adopt a new Commission Rule R8-63 as reflected in the attached Appendix A. The Commission will not try to summarize all of the comments, but will instead identify and discuss some of the major disagreements in the comments and some of the key provisions of the new Rule. These are discussed below:

Definition of Merchant Plant. The Public Staff's proposed Rule defined a merchant plant as an electric generating facility, other than a qualifying facility under PURPA, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility. There was little controversy as to this definition. CUCA suggested refining the definition to provide that a utility selling at retail may not own a merchant plant except through a separate subsidiary, but that suggestion raises issues that are pending in other Commission proceedings and are better handled there.

The Commission adopts the Public Staff's proposed definition as Rule R8-63(a)(2). This definition determines the scope and applicability of the new Rule adopted herein.

Prefiling of Information. At present, Commission Rule R8-61 requires all applicants proposing an electric generating facility with a capacity of 300 MW or more to prefile certain preliminary information at least 120 days before filing the certificate application itself. The Public Staff's proposed Rule would exempt merchant plants from the prefiling requirement of Rule R8-61. There was no outright opposition to the Public Staff's proposal. CP&L and Duke proposed eliminating the prefiling for utilities as well as merchant plants. They asked that Rule R8-61 be revised to allow the information that must now be prefiled 120 days before an application to be filed with the application instead, thus making the change applicable to all applications.

The Commission adopts the Public Staff's recommendation as Rule R8-63(a)(3). Eliminating the prefiling requirement of Rule R8-61 for merchant plants is a major step toward speeding up and streamlining the certification of merchant plants in North Carolina. The Commission will not adopt the recommendation of the utilities. If a utility is building a merchant plant, it will come under the new Rule adopted herein and will be exempt from prefiling. The question of whether a utility building a retail, rate-base generating plant should be exempt from the prefiling requirement of Rule R8-61 presents different issues and is not within the scope of this proceeding, which is focused on merchant plants. The utilities may pursue their argument in an appropriate docket if they wish.

Information Required as to the Applicant and the Proposed Facility. There is much disagreement as to exactly what information should be required in the application for a certificate for construction of a merchant plant. Among other items, the Public Staff's proposed Rule R8-63(b)(1)(A) and (B) would require that the applicant file financial information such as an annual report or a balance sheet and income statement; estimated construction costs; a proposed site layout of plant equipment and transmission interconnections; a list of other federal, state, and local permits and applications and their status; and a general description of transmission facilities to be used or the need for rights-of-way for new transmission.

The Public Staff argued that its proposed Rule would require only the fundamental information about the applicant and facility that the Commission needs in order to grant a certificate. The Public Staff agreed that merchant plants should be easier to certify than utility plants, but said that there are still significant issues and risks. The Public Staff argued that the information required by its proposed Rule is not extensive and will provide a minimum level of assurance. The AG agreed with the Public Staff. The AG supported streamlining but said that certain information is necessary for the Commission to fulfil its statutory duties. The AG argued that the Commission "will better serve the public by requiring sufficient information in applications for meaningful public consideration and comment."

Duke and some of the IPP intervenors -- such as Enron, Dynegy and PG&E -- opposed many of these proposed filing requirements. Duke would eliminate the requirement that an applicant provide its annual report or its balance sheet and income statement, saying that the Commission need not evaluate an applicant's creditworthiness. Duke would compress the information about the facility itself, eliminating such things as a site layout and a description of transmission facilities. Enron, Dynegy and PG&E generally commented that the above filing requirements are unnecessary, that the Commission need not micro-manage or exercise independent oversight as to these items because they will all be addressed by the developer through his due diligence and general plant development, and that the market will consider all these items and only viable plants will get built.

CUCA would go even further than other parties in eliminating information required in the certificate application. CUCA would only require a basic description of the applicant and facility, and even that could include "reasonable ranges" for size and in-service date to allow for modifications of plans. CUCA commented that information as to estimated construction costs should be limited to "confirmation that the costs...are 'consistent with projects of similar type and size.'"

The Commission takes its charge to streamline certification of merchant plants very seriously. However, the Commission has certain statutory duties with respect to the construction of electric generation. Statutes require that certain basic information be provided and that the Commission stay informed as to the state of electric generation in North Carolina. Moreover, by statute, the Commission's certification process serves a public notice function. On balance, the Commission decides to adopt the filing requirements proposed by the Public Staff, except as modified hereinafter. In doing so, the Commission wishes to stress several points. First, the Commission does not believe that the filing requirements adopted herein are onerous or that they will frustrate developers. Indeed, it would appear from the comments that developers will have to come up with all of this information anyway; nothing really new is being required. While this rulemaking process was pending, three applicants for merchant plant certificates, not wanting to wait, filed certificate applications based on the Public Staff's proposed Rule. The Commission takes this as an indication that these filing requirements are not overly burdensome and will not chill merchant plant development in the State. Further, the Commission does not intend to micro-manage merchant plant development. Finally, the Commission emphasizes that any applicant may ask for a waiver of any filing requirement if reason exists and good cause for a waiver is shown. The Commission believes that this decision reflects an appropriate balance between streamlining the certification process and meeting statutory obligations and the public interest.

Information on Market Power. The Public Staff's proposed Rule R8-63(b)(1)(B)(vii) would require that an application for a merchant plant certificate include information about other generating facilities and/or sites intended for such facilities in the region that the applicant or an affiliate owns and/or controls. The Public Staff commented that such information will help the Commission "obtain a comprehensive view of the developing wholesale market." The AG commented that it is necessary to consider market power information such as this in a certificate proceeding in order to encourage wholesale competition. CIGFUR also wanted information about market power in the application and stated that the Commission should deny certification if market power concerns are not resolved.

Duke and CP&L opposed this filing requirement. They argued that the requirement is vague and irrelevant and would needlessly complicate the certificate process. Calpine would either eliminate or at least clarify the requirement. Calpine found some of the proposed language unclear, and the Public Staff responded with some clarifications in its reply comments. PG&E would eliminate information on affiliated facilities or sites, arguing that anti-trust and market abuses are the purview of other fora. CUCA wanted market power addressed in an appropriate forum but said that market power concerns should not impede the streamlining of certification in this docket.

The Commission concludes that some information bearing on market power is appropriate and should be required in merchant plant certificate applications. The Commission will require information on other facilities of the applicant or one of the applicant's affiliates. For these purposes, the region is defined as the Southeastern Electric Reliability Council region. Information as to certificates that have been granted for other plants not yet constructed, though not included in the Public Staff's proposed Rule, will also be required. The Commission is less convinced as to the importance of information on other sites intended for such facilities in the region, and such information will not be required at this time. It should be noted that the Commission has recently undertaken a survey in a separate docket of how many possible sites are suitable for merchant plant development in the State.

Information on Natural Gas Capacity and Supply. The Public Staff's proposed Rule R8-63(b)(1)(B)(iv) would require that certificate applications for gas-fired merchant plants include information about the proximity of existing natural gas facilities, any new dedicated natural gas facilities to be constructed, and any contracts or tariffs for interstate pipeline capacity. The Public Staff commented that North Carolina has limited natural gas interstate pipeline capacity and that it would be unwise to certify a plant if the plant could only operate part-time due to capacity limits.

CUCA commented that the Public Staff is over-regulating, that the market will not allow a plant to be built if its gas supply is inadequate, and that requiring too much information will discourage new electric generation. This filing requirement was also opposed by parties such as Enron, Dynegy, PG&E, and Calpine. They argued that requiring information about arrangements for pipeline capacity is excessive, that the Commission should not weigh the commercial viability of each project's fuel strategy, and that a plant will simply not be built if it doesn't have capacity.

Piedmont intervened and commented on the arrangements of gas-fired merchant plants for pipeline capacity and gas supply. First, Piedmont agreed that an application should provide details as to proposed natural gas capacity and supply and that the public interest requires examination of such arrangements since available capacity is already subscribed and there is already high demand for existing gas supply. Second, Piedmont commented that gas-fired merchant plants can cause swings in operational pressure and flow of pipelines, which may affect service to the North Carolina LDCs. Piedmont argued that the Commission should require applicants to show that they will not adversely impact existing natural gas service in the State. Third, Piedmont argued that the Commission should, as part of the certification process, require that applicants for merchant plant certificates get service from the local LDC, rather than bypass the LDC and connect directly with an interstate pipeline.

PG&E objected to Piedmont's proposals as "bad business and bad law." Calpine also objected, arguing that the impact of a new generating facility on existing gas service is not an appropriate issue for a certificate proceeding and that requiring a new facility to get service from the local LDC may be in conflict with federal law. CUCA stated that bypass is legal in North Carolina and that Piedmont is only out to "protect its monopoly..."

For the reasons previously cited, the Commission adopts the Public Staff's recommendation. Again, the Commission does not mean to micro-manage merchant plant development but feels that this is appropriate information to keep the Commission informed as to the development of electric generation in the State. The Commission shares Piedmont's concerns about the operational and economic impact of gas-fired merchant plants on the gas pipeline system and on other customers. However, the Commission feels that such issues can and should be addressed in individual certificate proceedings. Although the Commission has expressed concerns as to bypass of local LDCs by new merchant plants, the Commission believes that this is an issue best addressed in certificate cases where individual fact situations are presented.

Showing of Need. The issue of what must be shown to establish the need for a merchant plant is one of the main concerns that prompted this proceeding to streamline certification procedures. In its 1992 decision regarding Empire Power Company in Docket No. SP-91, the Commission dismissed a certificate application for a merchant plant, stating that as a minimum filing requirement "an IPP proposing to sell its electricity to a North Carolina utility must first obtain and allege as part of its certificate application either a contract or a written commitment from the utility." The Commission addressed this old requirement in the order initiating the present proceedings. In the February 7, 2001 Order in this docket, the Commission recognized that the environment in which the Empire decision was made has changed in many crucial ways, and the Commission commented that "Empire is not a decision whose reasoning the Commission would follow per se today because the reasoning behind it does not reflect the situation in the industry today." The Order left open the issue of what new requirement would be adopted.

In the comments that have been filed herein, no party advocated that the Empire requirement be retained. The Public Staff's proposed Rule R8-63(b)(1) would require that applications for certificates for merchant plants include a showing of need as follows: "A description of the need for the facility in the state and/or region, with supporting documentation. This documentation shall include, as appropriate, either (i) contracts or preliminary agreements for the output of the facility, or (ii) information demonstrating that there is a need for the applicant's power in its intended market." Public Staff stated that this would be "an adequate but much less specific showing of need."

Duke would simplify the statement of need even more by eliminating the reference to contracts or preliminary agreements. Duke said that that sounds too much like the old Empire requirement. Duke would have an applicant simply show that there is a need for the generation in its intended market. Dominion commented that no showing of need should be required at all because retail customers do not need protection from over-expansion of generation. If any showing of need is retained, Dominion stated that it should be quite general. CP&L stated that an appropriate standard for showing need would be whether reserve margins will fall below some threshold level within the region.

CUCA and Dynegy both supported a general statement of need in the state and/or region. Enron would keep the first sentence proposed by the Public Staff but delete the second as too restrictive. Calpine suggested adopting a presumption that need could be shown by forecasts or declining reserve margins. PG&E urged the Commission to find a presumption of need in recent federal law encouraging wholesale competition or to adopt a very low threshold, such as general growth in the region. PG&E wanted to limit intervention on the issue of need to the Public Staff and AG, but CP&L opposed the idea of limiting intervention.

It is the Commission's intent to facilitate, and not to frustrate, merchant plant development. Given the present statutory framework, the Commission is not in a position to abandon any showing of need or to create a presumption of need. However, the Commission believes that a flexible standard for the showing of need is appropriate. The Commission adopts the first sentence of the Public Staff's recommendation but will not adopt the second sentence. The Commission agrees with Duke that the reference to "contracts or preliminary agreements" in the second sentence brings to mind the old Empire requirement and might raise doubts as to whether the Commission has truly abandoned that requirement. The Commission has abandoned the contract requirement of Empire as inappropriate in today's environment.

Utility-Affiliate Pricing. In connection with recent mergers, Duke, CP&L, and Dominion each agreed to codes of conduct which address utility-affiliate pricing. The Commission approved these codes of conduct and ordered the utilities to comply with them. In general, these codes of conduct require that, for inter-company exchanges, an affiliate must pay the utility the higher of fully allocated cost or market price and the utility must pay its affiliate the lower of fully allocated cost or market. In this proceeding, Duke argued that the pricing rules in these codes of conduct effectively preclude utility affiliates from developing merchant plants in North Carolina and that the Commission should use the present rulemaking proceeding to change the rules. Duke would add a provision to this new Rule to the effect that utilities may purchase from merchant plants owned by their affiliates at market rates approved by the Federal Energy Regulatory Commission and that such rates will be deemed reasonable for retail ratemaking purposes.

The Public Staff, AG, and CIGFUR all pointed out that such a provision would be contrary to the codes of conduct that Duke and other utilities agreed to in recent merger proceedings and that the provision raises important issues that are beyond the scope of this proceeding. The Commission agrees that Duke's proposal raises issues beyond the scope of this proceeding and should be considered in other dockets.

Procedure upon Receipt of Application. The Commission wants to avoid delays in processing applications for merchant plant certificates. The Public Staff's proposed Rule R8-63(d) would allow 10 days after receipt of an application for the Public Staff to examine it and give notice whether it is complete or is deficient in some way. The Commission would require any missing information to be provided and then issue a procedural order scheduling a hearing once everything is filed. The Public Staff said that this procedure would allow deficiencies to be handled promptly and would allow a procedural order to be issued without waiting for the matter to be placed on a Commission agenda. Duke and CP&L would allow "any party in interest" to point out deficiencies in an application.

The Commission generally adopts the Public Staff language. Allowing a procedural order to be issued without the matter being placed on a Monday morning Commission agenda should expedite handling. The Commission will allow parties other than the Public Staff to point out deficiencies in an application, consistent with the procedure that Rule R1-17(f)(1) now provides for general rate case applications. However, in recognition of its unique responsibilities, the Commission will require that the Public Staff file notice within 10 days of every application filing stating its opinion as to whether the application is complete or deficient and, if deficient, in what way it is deficient. This filing by the Public Staff will prompt the Commission's procedural order.

Scheduling a Hearing. The Public Staff's proposed Rule R8-63(b)(3) would require that supporting testimony be filed with the application and proposed Rule R8-63(d) would provide that the Commission issue an order "setting the matter for hearing" once a complete application is filed. The Public Staff stated that a public hearing is required by G.S. 62-110.1(e) and that it would save time to require prefiled testimony along with the application and to schedule a hearing on every application right at the outset.

CUCA, citing G.S. 62-82(a), argued that the Commission should announce a presumption that certificates will be issued without a hearing and that a complaint demonstrating good cause should be required before a hearing will be held. CUCA would therefore eliminate the pre-filing of testimony. CP&L agreed that there should be a presumption that no hearing is required unless good cause is shown.

Once again, the Commission's interest is in expediting the processing of merchant plant applications. There is a conflict between G.S. 62-110.1(e) and G.S. 62-82(a). Both deal with applications for a certificate for an electric generating facility but G.S. 62-110.1(e) states, "The Commission shall hold a hearing on each such application..." while G.S. 62-82(a) only requires that a hearing be held "upon complaint..." G.S. 62-110.1(e) is the more recent enactment, having been added in 1975. The Public Staff, citing G.S. 62-110.1(e), would schedule a hearing in every case right from the start. They explain, "If not set at the outset, there is a clear potential for delay if a hearing is later determined to be appropriate." Both Duke and Enron filed proposed rules that agree with the Public Staff on this point. The Commission agrees that scheduling a hearing on every application up front will tend to streamline procedures for certification of merchant plants.

Revocation of the Certificate. The Public Staff's proposed Rule R8-63(e) would provide for revocation of a certificate, after notice and opportunity for correction, under certain circumstances, e.g., if other permits are not obtained, if reports are not filed or fees not paid, or if material inaccurate information has been filed. Dynegy expressed concerns about the revocation provisions, arguing that any revocation should be discretionary, that any revocation should be triggered only by significant noncompliance or malfeasance, and that due process guarantees of notice and hearing should be observed. In its reply comments, the Public Staff revised its proposal in response to such concerns. The only other comment on this issue was by CUCA, which would allow for revocation only pursuant to G.S. 62-80 and the conditions set forth in the order granting the certificate.

The Commission adopts the revised language of the Public Staff, which makes very specific and strict provisions for revocation.

Transfer of the Certificate. The Public Staff's proposed Rule R8-63(e) would require the certificate holder to notify the Commission of any plans to sell, transfer, or assign the certificate and facility. PG&E commented that it should be clear that notice of transfers would be for information only and that the Commission has no authority to approve or deny a sale or assignment of a certificate. The Public Staff commented that the Commission has authority to impose appropriate conditions on certificates, including a condition that any subsequent transfer be subject to Commission approval. The Public Staff feels that the Commission needs some continuing authority as to how the merchant plant is being used after the certificate is issued, both for planning purposes and for preventing market power abuses. The Public Staff did not propose that approval of transfers be required by this Rule, but the Public Staff apparently intends to propose such a condition as individual certificate applications are decided.

The Commission adopts the requirement that a certificate holder give notice of any plans to sell, transfer or assign the certificate and facility. This requirement of notice is not as controversial as the further issue raised by the Public Staff -- whether the Commission should assert authority to approve transfers. That issue is an appropriate matter for individual certificate cases and will be considered if and when it arises in such dockets.

Other Certificate Conditions. CUCA commented that a merchant plant certificate should be subject to a condition that the applicant receive and maintain other regulatory approvals and a condition that the applicant abstain from trying to exercise eminent domain power. The Public Staff agreed to CUCA's suggestion for a condition as to eminent domain. The AG suggested that the matter of putting conditions in certificates be considered later so as not to hold up this proceeding. As indicated in the previous discussion, the Commission agrees with the AG and will decide what conditions to attach to certificates as individual certificate cases come to decision.

In conclusion, the Commission has carefully considered all of the proposed Rules and comments herein, and the Commission hereby adopts new Rule R8-63, attached hereto as Appendix A. The Commission believes that this Rule streamlines the certification process for merchant plants while providing the Commission with the information it needs under current law. This new Rule eliminates the 120-day prefiling requirement, clarifies application filing requirements, replaces the old contract requirement with a new liberal standard for showing need, and lays out procedures to bring applications to decision promptly. The development of a competitive wholesale market is in an early stage in this State. There is still a role for the Commission to ensure an adequate and reliable supply of electricity. At this point, incremental steps are appropriate. However, the Commission will monitor practice under the new Rule, and the Commission stands ready to consider further ideas for maximizing the benefits of the emerging market while reducing risks of the transition to a new industry structure.

IT IS, THEREFORE, ORDERED that the Commission adopts new Commission Rule R8-63, attached hereto as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.

This the 21st day of May, 2001.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

rg052101.01

Rule R8-63. Application for certificate of public convenience and necessity for merchant plant; progress reports.

(a) Scope of Rule.

(1) This rule applies to an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) by any person seeking to construct a merchant plant in North Carolina.

(2) For purposes of this rule, the term "merchant plant" means an electric generating facility, other than one that qualifies for and seeks the benefits of 16 U.S.C.A. 824a-3 or G.S. 62-156, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133.

(3) Persons filing under this rule are not subject to the requirements of Rule R1-37 or Rule R8-61.

(b) Application.

(1) The application shall contain all of the information hereinafter required, with each item labeled as set out below. Any additional information may be included at the end of the application.

(A) The Applicant:

(i) The full and correct name, business address, and business telephone number of the applicant;

(ii) A description of the applicant, including the identities of its principal participant(s) and officers, and the name and business address of a person authorized to act as corporate agent or to whom correspondence should be directed; and

(iii) A copy of the applicant's most recent annual report to stockholders, which may be attached as an exhibit, or, if the applicant is not publicly traded, its most recent balance sheet and income statement. If the applicant is a newly formed entity with little history, this information should be provided for its parent company, equity partner, and/or the other participant(s) in the project.

(B) The Facility:

(i) The nature of the proposed generating facility, including its type, fuel, size, and expected service life; the anticipated beginning date for construction; the expected commercial operation date; and estimated construction costs;

(ii) A detailed description of the location of the generating facility, including a map with the location marked;

(iii) The proposed site layout of all major equipment and a diagram showing the generator, plant distribution system, startup equipment, and provisions for transmission interconnection;

(iv) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(v) A list of all needed federal, state, and local approvals related to the facility and site, identified by title and the nature of the needed approval; a copy of such approvals or a report of their status; and a copy of any application related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any;

(vi) A general description of the transmission facilities to which the facility will have access or the necessity of acquiring rights-of-way for new facilities; and

(vii) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.

(C) Statement of Need: A description of the need for the facility in the state and/or region, with supporting documentation.

(2) The application shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant.

(3) The application shall be accompanied by prefiled direct testimony incorporating and supporting the application.

(4) The Chief Clerk will deliver ten (10) copies of the application to the Clearinghouse Coordinator in the Department of Administration for distribution to State agencies having an interest in the proposed generating facility.

(c) Confidential Information. If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(d) Procedure upon Receipt of Application. No later than ten (10) business days after the application is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the application is not complete, the applicant will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue a procedural order setting the matter for hearing, requiring public notice, and dealing with other procedural matters.

(e) The Certificate.

(1) The certificate shall specify the name and address of the certificate holder; the type, size, and location of the facility; and the conditions, if any, upon which the certificate is granted.

(2) The certificate shall be subject to revocation if (a) any of the federal, state, or local licenses or permits required for construction and operation of the generating facility is not obtained or, having been obtained, is revoked pursuant to a final, non-appealable order; (b) required reports or fees are not filed with or paid to the Commission; and/or (c) the Commission concludes that the certificate holder filed with the Commission information of a material nature that was inaccurate and/or misleading at the time it was filed; provided that, prior to revocation pursuant to any of the foregoing provisions, the certificate holder shall be given thirty (30)

days' written notice and opportunity to cure.

(3) The certificate must be renewed if the applicant does not begin construction within two years after the date of the Commission order granting the certificate.

(4) A certificate holder must notify the Commission in writing of any plans to sell, transfer, or assign the certificate and the generating facility.

(f) Reporting. All applicants must submit annual progress reports and any revisions in cost estimates, as required by G.S. 62-110.1(f) until construction is completed.

Applicant Crobb
Exhibit 2 1/A

EXHIBIT
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Jul 18 2019

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-105, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of the Application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity	**NCEMC'S INITIAL COMMENTS**

On May 15, 2019, Friesian Holdings, LLC ("Friesian") filed an application for a certificate of public convenience and necessity ("CPCN") for a 70-MW_{AC} solar photovoltaic facility in Scotland County, North Carolina ("Project"). Therein, Friesian indicated that it anticipated execution of a Project-related purchase power agreement ("Project PPA") between it and North Carolina Electric Membership Corporation ("NCEMC"). The Project PPA has now been executed.

NCEMC is a generation and transmission ("G&T") cooperative. To supply power to its member distribution cooperatives, NCEMC produces and sells power that it produces at NCEMC-owned electric generation resources; NCEMC also purchases and resells power, pursuant to wholesale contracts, from power providers such as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion Energy North Carolina, and others like Friesian.

As a G&T cooperative, NCEMC continuously strives to supply power to its members that is affordable, reliable, and safe. Beginning a decade ago, NCEMC also began assisting its members with their compliance obligations under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"). This assistance frequently took the form of purchasing renewable energy certificates from utility-scale solar facilities. More recently, NCEMC developed and began to pursue strategic business objectives under an initiative it christened "*A Brighter Energy Future*" ("BEF"), which entails supplying power that is not only affordable, reliable, and safe, but also increasingly low carbon (see attached BEF overview). Once constructed, the Project – specifically, the parties' execution of the Project PPA – will simultaneously advance NCEMC's pursuit of BEF and further its ability to achieve REPS compliance.

For the foregoing reasons, NCEMC supports issuance of a CPCN for the Project.

This the 18th day of July, 2019.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

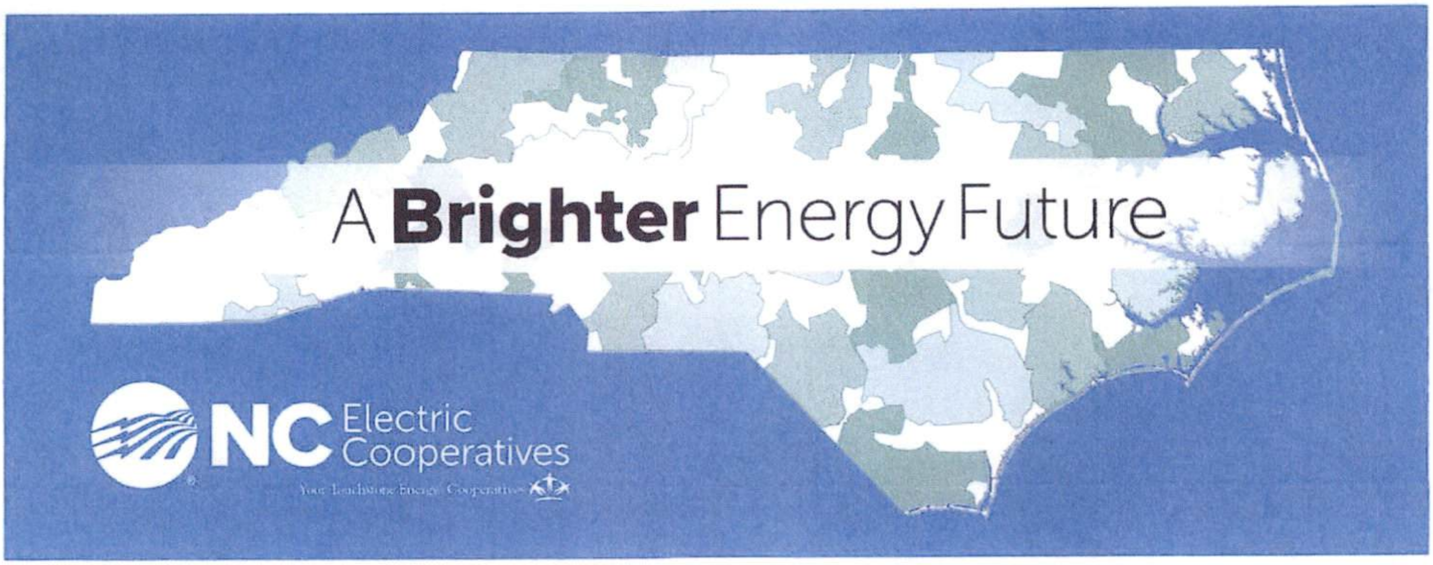
By: ______________________________

Michael D. Youth
Government & Regulatory Affairs Counsel
Post Office Box 27306
Raleigh, North Carolina 27611
Telephone: (919) 875-3060
Email: michael.youth@ncemcs.com

CERTIFICATE OF SERVICE

It is hereby certified that the foregoing document has been served upon all parties of record by electronic mail, or depositing the same in the United States mail, postage prepaid.

This the 18th day of July, 2019.



A **Brighter** Energy Future

NC Electric Cooperatives

Your Touchstone Energy Cooperatives

Driven by service and inspired by innovation, North Carolina's Electric Cooperatives are building a brighter energy future for 2.5 million North Carolinians. Working together, this group of 26 electric cooperatives is developing and delivering new energy solutions that put cooperative consumers and the vitality of our state first. The roots of these forward-focused energy solutions grow from three values North Carolina's Electric Cooperatives believe in:

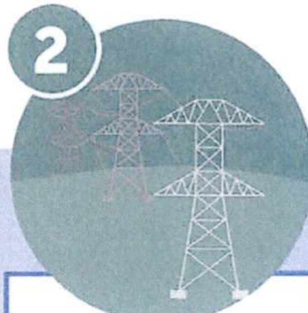
1. Creating a low-carbon emissions environment through sustainability and continued investment in low- and zero-emissions resources.
2. Integrating technology to make distribution grids more resilient, robust and flexible for an energy future that includes consumers' participation through demand response programs and new energy resources distributed across the grid.
3. Improving efficiency of the overall energy sector by electrifying processes formerly powered by fossil fuels. Electric vehicles are a primary example of this conversion.

1 Low Carbon

Low Carbon Intensity

Industrial Process Conversion

Sustainability



2 Grid Flexibility

Distributed Energy Resources

Microgrids

Distribution Operators

3 Beneficial Electrification

Electric Transportation

Agribusiness

Economic Development

KeyCite Yellow Flag - Negative Treatment
Proposed Legislation

West's North Carolina General Statutes Annotated
Chapter 62. Public Utilities (Refs & Annos)
Article 1. General Provisions (Refs & Annos)

N.C.G.S.A. § 62-2

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1/A

§ 62-2. Declaration of policy

Effective: January 1, 2008
Currentness

(a) Upon investigation, it has been determined that the rates, services and operations of public utilities as defined herein, are affected with the public interest and that the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy. It is hereby declared to be the policy of the State of North Carolina:

(1) To provide fair regulation of public utilities in the interest of the public;

(2) To promote the inherent advantage of regulated public utilities;

(3) To promote adequate, reliable and economical utility service to all of the citizens and residents of the State;

(3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills;

(4) To provide just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy;

(4a) To assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities; and to that end to authorize fixing of rates in such a manner as to result in lower costs of new facilities and lower rates over the operating lives of such new facilities by making provisions in the rate-making process for the investment of public utilities in plants under construction;

(5) To encourage and promote harmony between public utilities, their users and the environment;

(6) To foster the continued service of public utilities on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety and for the promotion of the general welfare as expressed in the State energy policy;

(7) To seek to adjust the rate of growth of regulated energy supply facilities serving the State to the policy requirements of statewide development;

(8) To cooperate with other states and with the federal government in promoting and coordinating interstate and intrastate public utility service and reliability of public utility energy supply;

(9) To facilitate the construction of facilities in and the extension of natural gas service to unserved areas in order to promote the public welfare throughout the State and to that end to authorize the creation of expansion funds for natural gas local distribution companies or gas districts to be administered under the supervision of the North Carolina Utilities Commission; and

(10) To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:

a. Diversify the resources used to reliably meet the energy needs of consumers in the State.

b. Provide greater energy security through the use of indigenous energy resources available within the State.

c. Encourage private investment in renewable energy and energy efficiency.

d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

(b) To these ends, therefore, authority shall be vested in the North Carolina Utilities Commission to regulate public utilities generally, their rates, services and operations, and their expansion in relation to long-term energy conservation and management policies and statewide development requirements, and in the manner and in accordance with the policies set forth in this Chapter. Nothing in this Chapter shall be construed to imply any extension of Utilities Commission regulatory jurisdiction over any industry or enterprise that is not subject to the regulatory jurisdiction of said Commission.

Because of technological changes in the equipment and facilities now available and needed to provide telephone and telecommunications services, changes in regulatory policies by the federal government, and changes resulting from the court-ordered divestiture of the American Telephone and Telegraph Company, competitive offerings of certain types of telephone and telecommunications services may be in the public interest. Consequently, authority shall be vested in the North Carolina Utilities Commission to allow competitive offerings of local exchange, exchange access, and long distance services by public utilities defined in G.S. 62-3(23)a.6. and certified in accordance with the provisions of G.S. 62-110, and the Commission is further authorized after notice to affected parties and hearing to deregulate or to exempt from regulation under any or all provisions of this Chapter: (i) a service provided by any public utility as defined in G.S. 62-3(23)a.6. upon a finding that such service is competitive and that such deregulation or exemption from regulation is in the public interest; or (ii) a public utility as defined in G.S. 62-3(23)a.6., or a portion of the business of such public utility, upon a finding that the service or business of such public utility is competitive and that such deregulation or exemption from regulation is in the public interest.

Notwithstanding the provisions of G.S. 62-110(b) and G.S. 62-134(h), the following services provided by public utilities defined in G.S. 62-3(23)a.6. are sufficiently competitive and shall no longer be regulated by the Commission: (i) intraLATA long distance service; (ii) interLATA long distance service; and (iii) long distance operator services. A public utility providing such services shall be permitted, at its own election, to file and maintain tariffs for such services with the Commission up to and including September 1, 2003. Nothing in this subsection shall limit the Commission's authority regarding certification of providers of such services or its authority to hear and resolve complaints against providers of such services alleged to have made changes to the services of customers or imposed charges without appropriate authorization. For purposes of this subsection, and notwithstanding G.S. 62-110(b), "long distance services" shall not include existing or future extended area service, local measured service, or other local calling arrangements, and any future extended area service shall be implemented consistent with Commission rules governing extended area service existing as of May 1, 2003.

The North Carolina Utilities Commission may develop regulatory policies to govern the provision of telecommunications services to the public which promote efficiency, technological innovation, economic growth, and permit telecommunications utilities a reasonable opportunity to compete in an emerging competitive environment, giving due regard to consumers, stockholders, and maintenance of reasonably affordable local exchange service and long distance service.

(b1) Broadband service provided by public utilities as defined in G.S. 62-3(23)a.6. is sufficiently competitive and shall not be regulated by the Commission.

(c) The policy and authority stated in this section shall be applicable to common carriers of passengers by motor vehicle and their regulation by the North Carolina Utilities Commission only to the extent that they are consistent with the provisions of the Bus Regulatory Reform Act of 1985.

Credits

Added by Laws 1963, c. 1165, § 1. Amended by Laws 1975, c. 877, § 2; Laws 1977, c. 691, § 1; Laws 1983 (Reg. Sess., 1984), c. 1043, § 1; Laws 1985, c. 676, § 3; Laws 1987, c. 354; Laws 1989, c. 112, § 1; Laws 1991, c. 598, § 1; Laws 1995, c. 27, § 1, eff. July 1, 1995; Laws 1995 (Reg. Sess., 1996), c. 742, §§ 29 to 32, eff. June 21, 1996; S.L. 1998-132, § 18, eff. Sept. 9, 1998; S.L. 2003-91, § 1, eff. May 30, 2003; S.L. 2005-95, § 1, eff. June 21, 2005; S.L. 2007-397, § 1, eff. Jan. 1, 2008.

Notes of Decisions containing your search terms (0)
View all 58

N.C.G.S.A. § 62-2, NC ST § 62-2

The statutes and Constitution are current through S.L. 2019-238 of the 2019 Regular Session of the General Assembly, subject to changes made pursuant to the direction of the Revisor of Statutes.

End of Document

112 N.C.App. 265
Court of Appeals of North Carolina.

STATE of North Carolina ex rel. **UTILITIES COMMISSION**, Public Staff North Carolina **Utilities Commission**, and Carolina Power and Light Company and Duke Power Company as Intervenors
v.
EMPIRE POWER COMPANY, Applicant for Certificate of Public Convenience and Necessity.

No. 9210UC724.
|
Oct. 19, 1993.

Synopsis

The **Utilities Commission** dismissed petition for certificate of public convenience and necessity, submitted by independent power producer. Appeal was taken. The Court of Appeals, McCrodden, J., held that: (1) Commission's authority with respect to certificates was not restricted to section of statute specifically dealing with approval of such certificates; (2) provision requiring that hearing be commenced within three months of filing of application was directory rather than mandatory, and did not compel issuance of certificate after period had expired; and (3) there were no material issues of fact requiring Commission to hold hearing.

Affirmed.

West Headnotes (11)

[1] **Public Utilities**
Statutory basis and limitation

State **Utilities Commission** is creature of legislature and exercises only that authority conferred on it by statute.

[2] **Electricity**
Generating facilities in general

Although state **Utilities Commission** may not deviate from specific statutory provisions governing approval of certificates of public convenience and necessity for construction of electricity generating facilities, Commission may rely upon other statutory provisions to interpret and implement process. G.S. §§ 62–82, 62–110.1.

1 Cases that cite this headnote

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[3] **Constitutional Law**
Encroachment on legislature

Electricity
Generating facilities in general

Utilities Commission's establishment of minimum filing requirements, in connection with application for certificate of public convenience and necessity to construct electricity generating facility, was not unconstitutional exercise of legislative powers by administrative board; commission was held to legislative standard, consisting of requirement that public convenience and necessity support construction of facility, and by ten specific policies regarding electric power generation, set forth in statute. G.S. §§ 62–2, 62–110.1.

1 Cases that cite this headnote

[4] **Electricity**
Generating facilities in general

Utilities Commission action, in rejecting petition for certificate of convenience and necessity, was not an unconstitutional exercise of police power of state interfering with ability of petitioner to engage in lawful business, on its own land, with private funds; energy generation business was traditionally one subject to public regulation, in order to ensure reliable and economic power supply and avoidance of costly overbuilding.

[5] **Electricity**
Generating facilities in general

Utilities Commission had not exceeded jurisdictional time limit, so as to be required to issue a certificate of convenience and necessity for the construction of electricity generating facility, even though it had not ordered hearing within ten days of last day of publication of notice of filing of petition; under statute imposing requirement automatic issuance of certificate would be defeated by Commission's receipt of a complaint within ten days of date of publication of notice, and such complaint was received. G.S. § 62–82(a).

1 Cases that cite this headnote

[6] **Electricity**
Generating facilities in general

Utilities Commission did not comply with requirement that it was to "commence" hearing on petition for certificate of convenience and necessity to construct electric generating facility within three months of filing of application, by scheduling within period oral argument on an opponent's motion to dismiss, to be held outside period. G.S. § 62–82(a).

2 Cases that cite this headnote

[7] **Statutes**
Mandatory or directory statutes

Statutory time periods during which action is required to be taken are generally considered to be directory rather than mandatory, unless legislature expresses a consequence for failure to comply within time period.

4 Cases that cite this headnote

[8] **Public Utilities**
Hearing and rehearing

Statute providing that **Utilities Commission** must commence hearing on petition for certificate of public convenience and necessity, within three months after filing of application, was directory rather than mandatory, and did not compel issuance of certificate following noncompliance with time period; in same statute legislature had specified that Commission was required to issue certificate in event hearing was not ordered or complaint received with respect to petition within ten days of last publication of notice of application, and absence of corresponding mandatory language in connection with three months provision indicated it was directory. G.S. § 62–82(a).

3 Cases that cite this headnote

[9] **Public Utilities**
Hearing and rehearing

Utilities Commission was not required to hold hearing, prior to dismissal of an application for certificate of public convenience and necessity. G.S. §§ 62–82, 62–110.1.

[10] **Electricity**
Generating facilities in general

Independent power producer was not entitled to certificate of public convenience and necessity to construct electrical power generation facility, on grounds that it had established need for proposed facility and application; producer had cited proposal to sell long-term wholesale peaking capacity and energy to utility, which utility had already refused, and producer had relied upon outdated information covering power needs across entire state, as well as local area. G.S. § 62–110.1.

[11] **Electricity**
Generating facilities in general

Utilities Commission could dismiss petition for certificate of public convenience and necessity, thus taking action essentially equivalent to summary judgment, when there was no genuine issue as to material fact; petition had been based upon needs of utilities in area to purchase energy from provider, and utilities had denied such needs. G.S. § 62–110.1; Rules Civ.Proc., Rule 56(a), G.S. § 1A–1.

****554** ***268** Petitioner Empire Power Company (Empire) is an independent power producer (IPP). IPP's, relatively new entrants into the power generation business, supply power on a contract basis to public utilities and others for resale.

On 31 October 1991, Empire, pursuant to N.C.Gen.Stat. § 62–110.1(a) (1989), submitted an application for a certificate of public convenience and necessity (CPCN), to construct a 600 megawatt combustion turbine electric generating facility, to be called Rolling Hills, in Rockingham County. On 19 November 1991, pursuant to N.C.Gen.Stat. § 62–82(a) (1989), the North Carolina **Utilities Commission** (the Commission) issued an order requiring petitioner to publish four weeks of public notice in Rockingham County. The order also required petitioner to serve a copy of its application and the public notice on each of the utilities to which it planned to sell electricity. On 22 November 1991, petitioner filed a verification that on 21 November 1991, it had served copies of the application and public notice on Carolina Power & Light (CP & L), ***269** Duke Power Company (Duke), and North Carolina Power. In a subsequent filing on 8 January 1992, petitioner asserted that it did not seek to sell to North Carolina Power. On 22 and 29 November and 6 and 13 December 1991, petitioner published its public notice, and on 30 December 1991, filed an affidavit of publication with the Commission. CP & L and Duke filed complaints and petitions to intervene in the proceeding on 20 and 23 December 1991, respectively. CP & L filed a motion to dismiss on 17 January 1992, followed by petitioner's motion for summary judgment, ****555** filed 4 February 1992. On 5 February 1992, the Commission heard arguments on both the motion to dismiss and the motion for summary judgment. The Commission entered an order 23 April 1992, dismissing petitioner's application, and finding that the decision rendered petitioner's motion for summary judgment moot. From this order, petitioner appeals.

Attorneys and Law Firms

Broughton, Wilkins, Webb & Jernigan, P.A. by William Woodward Webb and Sara M. Biggers, Raleigh, for petitioner-appellant.

Robert P. Gruber, Executive Director, by Gisele L. Rankin, Staff Atty., Raleigh, for respondent-appellee, Public Staff—North Carolina Utilities Com'n.

Len S. Anthony and Hunton & Williams by Frank A. Schiller, Raleigh, for respondent-appellee, Carolina Power and Light Co.

Steve C. Griffith, Jr., William Larry Porter, Karol P. Mack, and Kennedy, Covington, Lobdell & Hickman by Myles E. Standish, Charlotte, for respondent-appellee, Duke Power Co.

Opinion

McCRODDEN, Judge.

Petitioner's appeal, consisting of twelve assignments of error, requires our determination of three issues: (I) whether the Commission's dismissal of the petition for a CPCN exceeded the constitutional and legislative limits of the Commission's authority and jurisdiction over petitioner's application; (II) whether, once the Commission failed to order a hearing within ten days of publication, as required by N.C.G.S. § 62–82(a), the law required it to issue a CPCN to petitioner; and (III) whether the Commission had the authority, jurisdiction, and justification to dismiss petitioner's application. Within each of these general issues, petitioner presented additional questions which we will address in the order in which petitioner raised them.

***270** We initially note that N.C.Gen.Stat. § 62–94(b) (1989) governs our review of the Commission's decision. That statute provides that an appellate court may reverse or modify a decision of the Commission if the decision prejudices substantial rights of petitioner, because the Commission's findings, inferences, conclusions, or decisions are:

(1) In violation of constitutional provisions, or

(2) In excess of statutory authority or jurisdiction of the Commission, or

(3) Made upon unlawful proceedings, or

(4) Affected by other errors of law, or

(5) Unsupported by competent, material and substantial evidence in view of the entire record as submitted, or

(6) Arbitrary or capricious.

N.C.G.S. § 62–94(b). This Court will uphold a decision of the Commission unless we find error based on one of the enumerated grounds of section 62–94(b). *State ex rel. Utilities Comm. v. Southern Bell,* 88 N.C.App. 153, 177, 363 S.E.2d 73, 87 (1987). The issues raised by petitioner relate to subsections (1) and (2), *i.e.,* whether the Commission's action violated constitutional provisions or was in excess of its statutory authority or jurisdiction.

I.

[1] We first determine the scope of the Commission's authority and jurisdiction pursuant to Chapter 62. Petitioner contends that the Commission's authority and jurisdiction in determining certification cases for IPP's are limited to that expressly granted in N.C.G.S. §§ 62–82 and 110.1 (the CPCN sections). We agree with petitioner that the **Utilities Commission** is a creature of the legislature and exercises only that authority conferred upon it by statute, *Utilities Com. v. Motor Lines,* 240 N.C. 166, 168, 81 S.E.2d 404, 406 (1954), but we do not agree with petitioner's narrow interpretation of the statute.

In its 23 April 1992 order, the Commission allowed CP & L's motion to dismiss on the ground that petitioner failed to show, as it must under section 62–110.1, that public convenience and necessity required construction of the Rolling Hills facility. Petitioner contends that the Commission's dismissal of its application and ***271** its establishment of minimum filing requirements constituted ****556** an impermissible deviation from the process specifically provided in sections 62–82 and 110.1, and any deviation from these sections is beyond the Commission's authority and jurisdiction.

Section 62–110.1 concerns the Commission's role in receiving and acting upon CPCN applications, and states 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) (emphasis added). Section 62–82 concerns the special procedure to be followed when reviewing a CPCN application. Specifically, section 62–82(a) provides that when a CPCN application is filed:

> [T]he Commission shall require the applicant to publish a notice thereof once a week for four successive weeks in a daily newspaper of general circulation in the county where such facility is proposed to be constructed and thereafter the Commission upon complaint shall, or upon its own initiative may, upon reasonable notice, enter upon a hearing to determine whether such certificate shall be awarded. Any such hearing must be commenced by the Commission not later than three months after the filing of such application.... If the Commission or panel does not, upon its own initiative, order a hearing and does not receive a complaint within 10 days after the last day of publication of the notice, the Commission or panel shall enter an order awarding the certificate.

N.C.G.S. § 62–82(a).

[2] Petitioner maintains that the CPCN sections provide a sufficiently complete set of instructions, so that the Commission would not need to refer to other more general laws contained in Chapter 62. Petitioner cites *State ex rel. Utilities Comm. v. Edmisten,* 291 N.C. 451, 232 S.E.2d 184 (1977), in support of its argument that the general powers of the Commission, granted pursuant to the various sections of Chapter 62, cannot be inferred into statutes which are more specific in their application, *i.e.,* N.C.G.S. §§ 62–82 and 62–110.1. In *Edmisten,* the Supreme Court found that the language of N.C.Gen.Stat. § 62–134(e) was clear and unambiguous, and thus the Commission could not employ a more general statute, ***272** N.C.Gen.Stat. § 62–3(24), to alter the meaning and thus nullify section 62–134(e). We find the instant case distinguishable from *Edmisten* since we determine, as illustrated in part II of this opinion, that sections 62–110.1 and 62–82 do not provide the Commission with complete instructions for the process of awarding and denying certificates to applicants. Therefore, the Commission may turn to the more general sections of Chapter 62, specifically, N.C.Gen.Stat. § 62–31 (1989) and N.C.Gen.Stat. § 62–60 (1989), for guidance in interpreting the process not addressed in sections 62–82 and 62–110.1. In so doing, however, the Commission may not, and we find it did not, deviate from the process which is stated clearly and unambiguously in sections 62–82 and 62–110.1: the Commission required petitioner to publish notice once a week for four weeks; the notice was last published on 13 December 1991, and the Commission received two complaints within ten days following the last day of publication of petitioner's notice.

Within Chapter 62, sections 62–31 and 62–60 confer rule-making and judicial powers upon the Commission. However, petitioner argues that the CPCN sections narrowly circumscribe the Commission's jurisdiction over it since it is not a "public utility," and therefore the Commission should be limited to only those procedures specifically stated in sections 62–82 and 62–110.1. Since neither section 62–82 nor section 62–110.1 specifically provides for the dismissal of CPCN applications or the establishment of minimum filing criteria, petitioner maintains that the Commission should be prevented from employing those procedures. Assuming *arguendo* that petitioner is not a public utility, we nevertheless determine that the Commission's exercise of its judicial powers in ruling upon CPCNs for non-utilities is not limited exclusively ****557** to sections 62–82 and 62–110.1. Nothing in section 62–82(a) suggests that the North Carolina legislature intended to limit the Commission's exercise of its section 62–31 and section 62–60 powers in such a way as to exclude CPCN applications.

Furthermore, we have already determined that, although the Commission may not deviate from the provisions expressly stated in sections 62–82 and 62–110.1, the Commission may rely upon other sections in Chapter 62 to interpret and implement the process. Any other interpretation of the statute would leave the Commission without procedure in instances in which the General Assembly did not anticipate all of the facts and circumstances arising in the Commission's review of an application. Because the CPCN sections ***273** do not contain complete instructions, they cannot be the sole source of the Commission's authority and jurisdiction over applications for certificates. For example, sections 62–82 and 62–110.1 contain no provisions concerning the Commission's authority to hear dispositive motions, motions on evidentiary matters, or motions related to discovery. We conclude that the Commission may resort to other parts of Chapter 62 for the processing of applications. This allows it to effectuate the purpose of the Chapter, which is to promote the policy of the State as set forth in N.C.Gen.Stat. § 62–2 (1989). *Utilities Comm. v. Edmisten,* 294 N.C. 598, 242 S.E.2d 862 (1978).

[3] Relying on these same assignments of error, petitioner also argues that the Commission's order dismissing petitioner's application was unconstitutional because it constituted an improper exercise of legislative powers. We agree with petitioner that the General Assembly cannot delegate to an administrative board the power to legislate. *Farlow v. Bd. of Chiropractic Examiners,* 76 N.C.App. 202, 211, 332 S.E.2d 696, 702, *disc. review denied,* 314 N.C. 664, 336 S.E.2d 621 (1985). We do not agree, however, that the Commission's establishment of minimum filing requirements constituted an unconstitutional exercise of legislative powers. In *Adams v. Dept. of N.E.R. and Everett v. Dept. of N.E.R.,* 295 N.C. 683, 249 S.E.2d 402 (1978), an instructive case for us, the Supreme Court addressed the legislature's delegation of authority to develop and adopt guidelines for the coastal areas of North Carolina to the Coastal Resources Commission. The Court stated:

> In the search for adequate guiding standards the primary sources of legislative guidance are declarations by the General Assembly of the legislative goals and policies which an agency is to apply when exercising its delegated powers. We have noted that such declarations need be only "as specific as the circumstances permit." When there is an obvious need for expertise in the achievement of legislative goals the General Assembly is not required to lay down a detailed agenda covering every conceivable problem which might arise in the implementation of the legislation. It is enough if general policies and standards have been articulated which are sufficient to provide direction to an administrative body possessing the expertise to adapt the legislative goals to varying circumstances.

Id. at 698, 249 S.E.2d at 411 (citation omitted).

***274** With regard to electric generating facilities, the General Assembly set forth a specific standard for the Commission, *i.e.,* whether public convenience and necessity requires the construction of the proposed facility. We read this standard *in pari materia* with N.C.G.S. § 62–2 which contains ten specific policies, among which are promoting the inherent advantages of regulated public utilities and adequate, reliable, and economic utility service, including the entire spectrum of demand side option as resources necessary to meet future growth, and fostering continued service of public utilities on a well-planned and coordinated basis. We believe that the standard of public convenience and necessity and the policies of the State are sufficient to guide the Commission in deciding a CPCN case and that the legislature's delegation of this authority is not unconstitutional.

****558** [4] Petitioner next contends that the Commission's deviation from the process prescribed by sections 62–82 and 62–110.1 constituted an unconstitutional exercise of the police power of the State, and thus the Commission should not be able to prevent petitioner from engaging in lawful business, on its own land, with private funds. The cases cited by petitioner are distinguishable from the instant case, and we therefore find this argument meritless. *State v. Harris,* 216 N.C. 746, 6 S.E.2d 854 (1940), cited by petitioner, involved the licensing of individuals in the dry cleaning business. The Supreme Court distinguished between industries requiring scientific or technical knowledge and skill and those which are "ordinary trades and occupations, harmless in themselves, in many of which men have engaged immemorially as a matter of common right...." *Id.* at 756, 6 S.E.2d at 861. The Court found that the dry cleaning business fit in the latter category, and thus strictly reviewed the statute. The Court stated that an exercise of police power may be valid if the proposed restriction has a reasonable relation to the evil it purports to remedy. *Id.* at 759–60, 6 S.E.2d at 863.

The facts in the instant case show that petitioner does not intend to engage in the type of "ordinary trade or occupation" referred to in *Harris,* such as the Court considered the dry cleaning business to be in 1940. Because the supply and sale of electricity to other utilities is not an ordinary trade or occupation, we will not strictly construe the statute. We find that the licensing of IPPs has a reasonable relation to the creation of a reliable and economical power supply and the avoidance of the costly overbuilding ***275** of generation resources. *See State ex rel. Utilities Comm. v. Eddleman,* 320 N.C. 344, 358 S.E.2d 339 (1987).

Petitioner also cites *In re Hospital,* 282 N.C. 542, 193 S.E.2d 729 (1973), in which the Supreme Court overturned N.C.Gen.Stat. § 90–291, which required a certificate of public convenience and necessity before beginning construction of a hospital, finding that the General Assembly had not established a reasonable relationship between the regulation of private facilities for medical care and the public health. After that opinion, however, the legislature repealed the statute on which the case was based and enacted N.C.Gen.Stat. §§ 131E–175 to –190 (1992), which requires certificates of need in the development of new institutional health services and which rendered moot the holding of *In re Hospital.* Moreover, even if the case were not moot, the Supreme Court distinguished the public utility business from the medical industry, stating:

> In the public utility businesses competition, deemed unnecessary, is curtailed by the requirement that one desiring to engage in such business procure from the **Utilities Commission** a certificate of public convenience and necessity. However, in those fields the State has undertaken to protect the public from the customary consequences of monopoly by making the rates and services of the certificate holder subject to regulation and control by the **Utilities Commission**. No comparable power to regulate hospital rates and services has been given to the Medical Care Commission.

Id. at 550, 193 S.E.2d at 734–35 (citations omitted). Indeed, one of the purposes of Chapter 62 is to "promote the inherent advantages of regulated public utilities." N.C.G.S. § 62–2(2). Although we need not reach the question of whether petitioner is a public utility, we find that the statute indicates that there is a substantial public purpose in the licensing of power generating facilities such as that proposed by petitioner.

Finally, we summarily dismiss petitioner's argument that, if the Commission may find authority from sections other than 62–82 and 62–110.1, the entire CPCN process would be fraught with uncertainty. We find section 62–82, when read in conjunction with other provisions of Chapter 62, sufficiently clear to avoid the confusion suggested by petitioner.

***276** II.

[5] In petitioner's next assignment of error, it contends that section 62–82 presents ****559** a jurisdictional time limit, during which the Commission must order a hearing in order to maintain jurisdiction over the CPCN process. We do not agree with petitioner's analysis of section 62–82 that, if the Commission does not order a hearing, it must award a certificate within ten days of the last day of the publication of the notice. Section 62–82(a) provides, "[i]f the Commission or panel does not, upon its own initiative, order a hearing *and* does not receive a complaint within 10 days after the last day of publication of the notice, the Commission or panel shall enter an order awarding the certificate." (Emphasis added). We find it unnecessary to determine whether the phrase *within ten days of the last day of the publication* applies only to the period of time within which the Commission must receive a complaint, as suggested by the doctrine of the last antecedent, *HCA Crossroads Residential Ctrs. v. N.C. Dept. of Human Res.,* 327 N.C. 573, 578, 398 S.E.2d 466, 469 (1990), because it is clear that the Commission's receipt of Duke's and CP & L's complaints to petitioner's application defeated the automatic issuance of the certificate.

[6] Petitioner also argues that the Commission failed to commence a hearing within three months after the filing of the CPCN application, and therefore, the Commission is without jurisdiction to act in any manner other than to award a certificate to petitioner. We agree that the Commission failed to commence a hearing within the three-month period, as required by section 62–82(a). Section 62–82(a) requires that "[the] hearing must be commenced by the Commission *not later than three months after filing of such application.* " (Emphasis added). Since petitioner filed its application on 31 October 1991, the three-month time period for commencing a hearing began to run from this date. On 22 January 1992, the Commission scheduled oral argument on CP & L's motion to dismiss for 5 February 1992.

Black's Law Dictionary defines the word "commence" as "to initiate by performing the first act" or "to institute or start." *Black's Law Dictionary,* 6th Edition 268 (1990). We find unpersuasive the Commission's argument that the order of 22 January 1992, scheduling oral argument to be held on 5 February 1992 which is outside the three-month time period, constituted a commencement of the hearing. If we were to find that the mere scheduling of a hearing ***277** constituted a commencement, the Commission could schedule a hearing in the indefinite future, which is clearly not the intent of the statute. The General Assembly intended that the determination whether to award a CPCN certificate be an expedient procedure; section 62–82 provides that the procedure for "rendering decisions" during the hearing of a CPCN application shall take precedence over all other matters on the Commission's calendar, except for rate cases conducted pursuant to N.C.Gen.Stat. § 62–81 (1989).

[7] Since the Commission failed to commence a hearing within three months, petitioner maintains the Commission was left with jurisdiction *only* to grant a certificate to petitioner. We disagree. Whether the time provisions of section 62–82(a) are jurisdictional in nature depends upon whether the legislature intended the language to be mandatory or directory. *Art Society v. Bridges,* 235 N.C. 125, 130, 69 S.E.2d 1, 5 (1952). Many courts have observed that statutory time periods are generally considered to be directory rather than mandatory unless the legislature expresses a consequence for failure to comply within the time period. *See Meliezer v. Resolution Trust Co.,* 952 F.2d 879, 883 (5th Cir.1992); *Thomas v. Barry,* 729 F.2d 1469, 1470 n. 5 (D.C.Cir.1984). If the provisions are mandatory, they are jurisdictional; if directory, they are not.

[8] Section 62–82 clearly specifies that one provision is mandatory, and that is the one that *requires* that a certificate be issued if the Commission does not order a hearing at all and there is no complaint filed within ten days of the last date of publication. However, the statute is silent as to the consequences, if any, which would result from the Commission's failure to commence a hearing within the three-month time period. When the General Assembly, ****560** in the same statute, expressly provides for the automatic issuance of a certificate under different circumstances (the Commission does not order a hearing and no complaint is filed), the only logical conclusion is that the General Assembly only intended for an automatic issuance to occur in that specific situation. *Cf. Campbell v. Church,* 298 N.C. 476, 482, 259 S.E.2d 558, 563 (1979) (an exchange of real property between a redevelopment commission and a church must comply with the advertisement and bid requirements of N.C.Gen.Stat. § 160A–514(d), since the statute contained certain instances, of which an exchange was not included, where advertisement and bids are not required).

***278** Petitioner relies upon *HCA Crossroads,* which held that an agency's failure to act on a certificate of need within the time period provided by N.C.Gen.Stat. § 131E–185 divested the agency of jurisdiction to take any action other than issuing the certificate. *HCA Crossroads* is inapplicable to the case at hand because the Court addressed a statute (N.C.G.S. § 131E–185) which contains specific language stating that the "Department shall issue ... a certificate of need with or without conditions *or reject the application within the review period.* " *HCA Crossroads,* 327 N.C. at 577, 398 S.E.2d at 469 (emphasis added); N.C.G.S. § 131E–185(b). The absence of any such explicit language in section 62–82(a) distinguishes this case from *HCA Crossroads.*

The Commission's automatic issuance of a certificate, when complaints and motions to intervene have been filed in the matter and a sufficient showing of public need has not been made, would be contrary to the purpose of section 62–110.1(a). The primary purpose of the statute is to provide for the orderly expansion of the State's electric generating capacity in order to create the most reliable and economical power supply possible and to avoid the costly overbuilding of generation resources. *Eddleman,* 320 N.C. at 362, 358 S.E.2d at 351. In order to give effect to this purpose, we find the language in section 62–82 to be directory and, thus, not jurisdictional.

III.

[9] We likewise reject petitioner's final set of arguments further questioning the authority, jurisdiction, and justification of the Commission's action. The first of these arguments is that section 62–82(a) requires the Commission to hold a hearing before it can dismiss a CPCN application. Petitioner bases its interpretation upon its earlier argument that the Commission's powers over CPCN applications are limited to those enumerated in sections 62–82 and 62–110.1. As previously stated, however, where section 62–82 is silent, the Commission may refer to the judicial powers of Chapter 62 to supplement its procedure for awarding or denying certificates. Section 62–60 describes the Commission's authority as that of a court of general jurisdiction in which it "shall render its decision upon questions of law and fact in the same manner of a court of record." The Commission's dismissal of the application was, therefore, a proper exercise of its authority. We also note that, although petitioner initially opposed CP & L's motion to dismiss on the basis ***279** that section 62–80 did not authorize it, it later filed a motion for summary judgment, arguably abandoning its position concerning the authority of the Commission.

[10] We also do not agree with petitioner's argument that the Commission erred in dismissing its application because, according to petitioner, it had established the need for its proposed facility in its application. Before awarding a certificate, the Commission must comply with section 62–110.1 which requires a showing of public convenience and *necessity* by the applicant. Subsection (d) mandates the Commission's consideration of 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." Petitioner's application stated that it had an outstanding proposal to sell long-term wholesale peaking capacity and energy to Duke for delivery beginning as early as 1994. Duke, however, had ****561** refused this proposal. Additionally, the application, citing dated testimony from previous Commission hearings, generally asserted that there was a need for its proposed facility across the state as well as within the Duke service territory. We find that this forecast of evidence on the issue of need was inadequate and that the Commission's dismissal was proper.

[11] Petitioner argues that the Commission's dismissal of its application was similar to granting summary judgment and was in error, because the issue of public convenience and necessity was a genuine issue of material fact. Although the determination of public convenience and necessity is essentially a factual inquiry, summary judgment is appropriate when there is no genuine issue as to any material fact. N.C.Gen.Stat. § 1A–1, Rule 56(a) (1990). The Commission based its order dismissing petitioner's application upon the following facts: petitioner is an IPP and, as such, proposed to construct a 600 megawatt electric generating facility in Rockingham County; it based public need for this facility upon the allegation that Duke and/or CP & L needed such a facility; neither Duke, CP & L, nor any other public utility, however, had committed to purchase the output of petitioner's proposed facility; and in fact both Duke and CP & L objected to petitioner's application. Petitioner failed to raise any genuine dispute concerning these facts.

The **Utilities Commission** is required to regulate the expansion of electric utility plants in North Carolina and, before issuing a ***280** CPCN, must establish a public need for a proposed generating facility. *In re Duke Power Co.,* 37 N.C.App. 138, 245 S.E.2d 787, *disc. review denied,* 295 N.C. 646, 248 S.E.2d 257 (1978). Petitioner failed to raise a genuine issue of material fact that public need required construction of the Rolling Hills facility, and the Commission's dismissal of its application was appropriate. The Commission's decision was without prejudice to petitioner's right to file another application at some future date.

In finding that there was no genuine issue of material fact as to the public need for the Rolling Hills facility, we have no need, and we decline, to address petitioner's question of whether the Commission appropriately linked the need for petitioner's power to a requirement, first stated in the Commission's order, that petitioner have a contract to sell such power.

For the foregoing reasons, we affirm the Commission's dismissal of petitioner's application for a certificate of public convenience and necessity.

Affirmed.

WELLS and JOHN, JJ., concur.

All Citations

112 N.C.App. 265, 435 S.E.2d 553, Util. L. Rep. P 26,349

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DUKE ENERGY.

EXHIBIT
Applicant Cross
5
I/A

STEPHEN G. DE MAY
North Carolina President

Duke Energy
410 S. Wilmington Street
Raleigh, NC 27601

Mailing Address:
P.O. Box 1551/NCRH 12

December 6, 2019

VIA Electronic Filing

Ms. Kimberly A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: North Carolina President Letter Regarding Friesian CPCN Application
Docket No. EMP-105, Sub 0

Dear Ms. Campbell:

On behalf of Duke Energy Progress, LLC ("DEP" or the "Company" and together with Duke Energy Carolinas, LLC, the "Duke Utilities"), I would like to take this opportunity to summarize certain benefits that would result from the Network Upgrades that will be constructed at this time should the North Carolina Utilities Commission ("Commission") elect to grant a certificate of public convenience and necessity to Friesian Holdings, LLC ("Friesian") for its proposed 70-MW AC solar photovoltaic facility in Scotland County, North Carolina.

The decision facing the Commission in this proceeding presents a unique and complex set of circumstances, and the Company appreciates the uncharted nature of this decision and the significance of the costs at issue. Such decision, however, is properly viewed as the product of substantial success, as it arises due to the enormous amount of effort invested to achieve nation-leading amounts of interconnected solar resources in North Carolina. This success has now and will likely in the future introduce complex policy questions that require substantial regulatory and policy engagement. In this particular case and during this pivotal time of transition in North Carolina's energy policy, the Company believes that the Commission should consider the benefits of the Network Upgrades in rendering its decision in this proceeding. Such benefits, which are summarized in more detail in a separate letter being filed in parallel by counsel for DEP, include the following: (1) allowing for the interconnection of a substantial amount of renewable resources in the southeast portion of DEP's service territory, (2) avoiding queue paralysis and substantial delays in interconnection for certain projects, (3) and minimizing certain short-term challenges associated with the Duke Utilities' queue reform plans.

Throughout the Friesian interconnection process, the Company has invested immense resources to work collaboratively with Friesian to achieve a positive outcome, all in accordance with applicable interconnection procedures. But due to the unique circumstances of this case, the outcome of this process will have a ripple effect on many other broader policy issues. With respect to these broader policy issues, the Duke Utilities are similarly committed to continuing to work in a collaborative fashion, engaging regulators, customers and other stakeholders as we chart a course into the energy future while balancing reliability, affordability and sustainability. We are proud of the work that we have accomplished to make North Carolina No. 2 in the nation in solar capacity and are committed to continuing to think creatively and collaboratively regarding the pathways to more sustainability in the future. Construction of the Network Upgrades in question at this time will result in benefits that will, in turn, smooth the road on the journey into the future.

Once again, the Company is also submitting a second letter that provides more details regarding the benefits of the Network Upgrade that I refer to above. Our intent is to provide useful information to the Commission as it considers the important issues presented in this proceeding.

Sincerely,

Stephen De May, North Carolina President

cc: Parties of Record

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DUKE ENERGY.

December 6, 2019

VIA Electronic Filing

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: DEP Letter Regarding Friesian CPCN Application
Docket No. EMP-105, Sub 0

Dear Ms. Campbell:

Duke Energy Progress, LLC ("DEP" or the "Company") would like to take this opportunity to submit this letter in lieu of testimony in the above-captioned docket, in which the North Carolina Utilities Commission ("Commission") is considering the application of Friesian Holdings, LLC ("Friesian") for a certificate of public convenience and necessity for a 70-MW AC solar photovoltaic facility in Scotland County, North Carolina ("Friesian Generating Facility"). In addition to this letter, the Company is also filing a letter regarding these matters from the North Carolina President, Stephen De May.

Pursuant to its obligations under its Federal Energy Regulatory Commission-approved Joint Open Access Transmission Tariff ("OATT"), the Company has devoted considerable resources to the interconnection process for the Friesian Generating Facility, including engaging in extensive evaluation, negotiation and engineering in connection with the substantial upgrades to the transmission network that are needed to safely and reliably interconnect the Friesian Generating Facility (such upgrades, the "Friesian Network Upgrades"). The Company has worked collaboratively with Friesian over the past year to meet Friesian's commercial objectives, all within the framework of the OATT.

As has been discussed at length in this proceeding, the need for the Friesian Network Upgrades is driven by the fact that the transmission capacity of the lines at issue has been fully consumed by the substantial amount of solar generation already connected by the Company in the southeast portion of the DEP service territory. Specifically, in the geographic area in the southeast portion of the DEP service territory in which the Friesian Generating Facility is located, there are over 100 in-service or under construction solar generating facilities totaling 1,347 MW. To put this in perspective, the amount of solar generation that is installed in this one portion of the DEP service territory exceeds the amount of solar generation installed in the states of Kentucky, Tennessee, Mississippi, Alabama, Arkansas and Louisiana combined.

Under the existing serial study process, the first generating facility to trigger the need for a Network Upgrade is assigned the total cost of the Network Upgrade. And much like the addition of generating capacity, the addition of transmission capacity is "lumpy," meaning that the next increment of transmission capacity added typically exceeds the exact amount needed to accommodate the particular generating facility. Thus, such Network Upgrades typically provide transmission network capacity that is in excess of what is needed by the triggering interconnection request, which additional capacity may be utilized by later-queued projects.

While the cost of the Friesian Network Upgrades and the rate impact on retail customers is significant, there are benefits that will arise from completion of the project, including the following.

1. Interconnection of Additional Renewable Generating Resources

As the Commission is aware, the comprehensive planning process for the DEP and Duke Energy Carolinas, LLC ("DEC" and together with DEP, the "Duke Utilities") 2018 IRP and 2019 IRP Updates demonstrates that a combination of renewable resources, demand-side management and energy efficiency programs, and additional base load, intermediate and peaking generation are required over the next fifteen years to reliably meet customer demand. Additionally, in mid-September 2019, Duke Energy Corporation announced its new, enterprise-wide climate strategy, including updating its CO_2 reduction goals to at least 50% reduction by 2030 (from 2005 levels) and achieving net-zero for electricity generation by 2050. For the Duke Utilities, the base case in both the 2018 IRP and the 2019 IRP Update plans achieves at least 50% CO_2 reduction by 2030. However, DEC and DEP plan to work with regulators, customers and other stakeholders to determine how best to achieve reductions greater than 50% by 2030 and ultimately achieve net-zero emission by 2050 in a manner that balances reliability, affordability and sustainability. In a similar vein, the recently released North Carolina Clean Energy Plan from the North Carolina Department of Environmental Quality establishes a goal of 70% greenhouse gas emissions ("GHG") reductions by 2030 and carbon neutrality by 2050.

Regardless of the precise GHG emissions target, substantial amounts of new renewable resources will be needed. For instance, the base case from the 2019 IRP Update—which achieves 51% CO_2 reduction by 2030—requires 3,000+ MW of additional solar resources over current amounts. Substantial Network Upgrades will undoubtedly be needed to accommodate the addition of a substantial amount of new grid resources. While the Company's analysis to date has not attempted to identify what specific Network Upgrades will be needed, the Friesian Network Upgrades are representative of the types of Network Upgrades that may be required in the future to achieve CO_2 reduction targets.

The Friesian Network Upgrades will provide sufficient transmission capacity to allow the interconnection of additional solar generating facilities in the southeast portion of the DEP service territory. In other words, later-queued projects[1] will be able to utilize the Friesian Network Upgrades until the next transmission overload is identified. The Company estimates that the Friesian Network Upgrades could accommodate the interconnection of more than 1,000 MW of additional solar resources in the southeast portion of the DEP service territory (though additional distribution capacity may be needed in the case of distribution-connected projects). All things being equal, these additional solar generating resources will contribute towards achieving emissions reduction targets. While there are many different paths by which the Duke Utilities could achieve various levels of CO_2 emissions reductions, the additional solar resources accommodated by the Friesian Network Upgrades will move the Duke Utilities closer to the various targets.

2. ***Avoidance of Interconnection Queue Paralysis***

If the Friesian Generating Facility is not granted a CPCN and is therefore not constructed, the need for the Friesian Network Upgrades will not go away. Under the current serial process, the Company will be required to assign the Friesian Network Upgrades (or a portion thereof) to the next project in the interconnection queue (as determined in accordance with the required study processes). Because the vast majority of the later-queued projects are state-jurisdictional and, in many cases, smaller projects, it is highly unlikely that any single project will be able to absorb the cost of the Friesian Network Upgrades. Therefore, the most likely outcome in the short term would be a cascading series of withdrawals resulting in complete paralysis of the interconnection queue in this portion of DEP's service territory.[2]

3. ***Timing Issues***

If the Friesian Network Upgrades are not constructed at this time, there will be a further substantial delay in the interconnection of any additional generating facilities in this area of DEP. More specifically, due to the scope of the Friesian Network Upgrades and the small window in the spring and fall during which the Company is able to construct the project while maintaining reliability, the Company projects that it will take 4-5 years to complete the construction process. And the construction timeline does not account for any additional time needed to negotiate with a new counterparty and refresh engineering and cost estimates (approximately 1-2 years). Therefore, even if another project can be found that has the ability to absorb the cost of the Friesian Network Upgrades (which is highly unlikely except in the case of later-queued combined cycles),[3] such upgrades will likely not be completed until 2026 or 2027 at the earliest.

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[1] For the sake of clarity, there are two proposed Duke-owned combined cycle generating units located in Cumberland County in the interconnection queue after the Friesian Generating Facility. The first of the two is not dependent on the Friesian Network Upgrades but the second unit is interdependent on the Friesian Network Upgrades.

[2] Though neither of the combined cycle generating units identified in FN 1 have been certified, it is theoretically possible that the Friesian Network Upgrades could ultimately be constructed in connection with the second unit, in which case retail customers would bear a portion of the cost of such upgrades.

[3] See FN 1 and 2.

4. ***Queue Reform Transition***

The Company is working diligently to develop a cluster study process that will allocate future necessary Upgrades in a more equitable manner. However, one of the key challenges of implementation of such queue reform will be successfully navigating the period of transition from the serial study process to the cluster study process. If the Friesian Network Upgrades are not constructed at this time, the transition process will be much more complex and the transition process may be delayed.

Conclusion

In conclusion, the Company recognizes the benefits of completion of the Friesian Network Upgrades at this time, while also acknowledging that this is a complex policy question to be decided by the Commission. It should also be noted, however, that this is a unique set of circumstances. While it is true that additional substantial Network Upgrades may be required in the future due to the Duke Utilities' nation-leading interconnection success, there will likely be additional options in the future for addressing such potential Network Upgrades. For instance, the Company's queue reform proposal, if implemented, will provide an alternative pathway that would permit the allocation of such Network Upgrades costs across many projects. The current competitive procurement framework also provides another structure by which Network Upgrades are identified and funded. Alternatively, other policy approaches may be deemed appropriate or necessary in the future in order to most efficiently solve similar transmission capacity constraints. The bottom line is that there is not necessarily a "one size fits all" approach to these issues and the Company is committed to continuing to explore all potential pathways, but believes that the Commission should, in this case and given these unique circumstances, consider the broader benefits associated with the Friesian Network Upgrades.

Thank you for your consideration of these comments and please do not hesitate to let me know if you have any questions.

Sincerely,

Jack E. Jirak

cc: Parties of Record
Stephen De May

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's North Carolina President Letter Regarding Friesian CPCN Application and Letter Regarding Friesian CPCN Application, in Docket No. EMP-105, Sub 0, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 6th day of December, 2019.

Jack E. Jirak
Associate General Counsel
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1A

Lawrence/Metz
Exhibit 2
Docket No. EMP-105, Sub 2

Electricity Markets and Policy Group
Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy

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Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy

Prepared for the
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Author Contributions

W.G. led the research. W.G., A.M., and R.W. designed the analysis framework. W.G. and A.M. led the literature review. W.G., A.M., and R.W. led the writing of the paper.

Competing Interests

The authors declare no competing interests.

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Abstract

Estimating the overall costs of transmission needed to integrate variable renewable energy (VRE) onto the grid is challenging. An improved understanding of these transmission costs would support electricity system planning as VRE penetrations increase. This paper brackets VRE transmission capital costs using multiple approaches based on interconnection studies, actual transmission projects, capacity-expansion simulation models, and aggregated U.S. VRE-related transmission expenditures. Each approach possesses advantages and drawbacks, and combining the approaches lends confidence to the results. The resulting range of average levelized VRE transmission costs is $1–$10/MWh, which is generally lower than earlier estimates in the literature. These transmission capital costs can increase the direct plant-level levelized cost of VRE by 3%–33%, based on levelized costs of energy of $29–$56/MWh for utility-scale wind and $36–$46/MWh for utility-scale solar. As VRE deployment continues to expand, policy makers can use this information to (1) assess the benefits of transmission avoidance and deferral when comparing distributed energy resources versus utility-scale projects, (2) evaluate the potential costs of large-scale public transmission investments, and (3) better analyze system-level costs of utility-scale VRE technologies. Future research can expand on the framework presented here by providing a review of operation and maintenance costs for transmission systems.

Keywords. Transmission investment; renewable energy; wind; utility solar; levelized cost of energy

1. Introduction

Over the last decade, variable renewable energy (VRE) technologies, such as wind and solar, have proliferated in the United States (Bolinger and Seel 2018; Wiser and Bolinger 2017). Numerous stakeholders support continued growth of cost-competitive VRE, and many researchers have studied the potential for high VRE penetrations on the electrical grid (Sørensen 2008; BNEF 2018; Elliston, Diesendorf, and MacGill 2012; Connolly et al. 2011; Mathiesen, Lund, and Karlsson 2011; Lund and Mathiesen 2009; Liu et al. 2011; Shoshanna 2011; Mai, Hand, et al. 2014) . To make VRE investment decisions, policy and electric-sector decision makers face numerous tradeoffs related to location constraints, solar/wind resource potential, supporting infrastructure requirements, and so forth (Mills, Phadke, and Wiser 2011). Analysts typically incorporate these tradeoffs into project benefit calculations (estimates of VRE energy and capacity value) and project cost calculations (estimates of VRE integration costs such as supply-demand balancing and transmission investment) (Mills and Wiser 2012). Although direct costs are relatively easy to estimate, understanding system-integration costs is more challenging (Ueckerdt et al. 2013). Still, many researchers have attempted to systematically quantify some key system-integration costs, such as supply-demand balancing, which results from the variability and uncertainty of VRE energy production (Hirth, Ueckerdt, and Edenhofer 2015; Milligan et al. 2011).

Researchers have given less attention to the transmission costs related to VRE grid integration even though the levelized transmission infrastructure costs of VRE can be significant (Wiser et al. 2017). The potential for higher costs relative to traditional generation resources is due to VRE resource quality being much more location dependent and VRE capacity factors being lower than for traditional generation. Lower capacity factors translates to lower utilization of transmission and a higher transmission cost per unit of energy generated (Mai, Mulcahy, et al. 2014; Kahn 2008; Weiss, Hagerty, and Castaner 2019). Transparent transmission costs would facilitate decisions that support cost-effective and fair VRE integration, particularly because electric ratepayers typically bear at least a portion of an electric system's transmission costs (MISO 2012; Lasher 2014). However, policy makers have limited access to clear, generalizable transmission-cost estimates. Analysts often use levelized cost of energy (LCOE) methods to compare the costs of generation resources; however, these relatively simple methods typically focus on costs up to the busbar only and ignore the complex system wide infrastructure investments needed to integrate a new resource fully (Lazard 2018); (Rhodes et al. 2017).

Estimating transmission costs for VRE integration is difficult, idiosyncratic, and dependent on geographical context for several reasons. First, it is difficult to attribute costs for system-level assets such as transmission infrastructure to individual generation resources.[3] Transmission investments generally serve multiple purposes, including reliability support and economic congestion relief, while facilitating the integration of new generators (EIA 2017). Conventional generators as well as VRE resources use expanded transmission networks. Second, immense geographic heterogeneity in system needs and costs can make it difficult to generalize costs across different projects. Finally, a project's

[3] Although this paper focuses on transmission infrastructure, a review of distribution infrastructure investment was also performed. Those results are available upon request.

incremental transmission needs have to be weighed against locations with the best VRE resources. For example, siting wind turbines in distant, windy locations that require larger transmission investments presents economic tradeoffs versus siting them closer to load where wind resources are poorer (Hoppock and Patiño-Echeverri 2010; Lamy et al. 2016; Silva Herran et al. 2016; Fischlein et al. 2013). Furthermore, liberalized electricity markets frequently present a coordination problem between investments in the regulated electrical grid (e.g., transmission network) and investments in new power generation (Wagner 2019). Project developers may prioritize utility-scale VRE development in high-resource areas to improve project economics rather than consider the combination of system-level transmission and generation costs that would minimize the overall social cost.

Some capacity-expansion models, such as the Regional Energy Deployment System (ReEDS),[4] consider generation and transmission capacity costs and aim to minimize busbar and system-level costs for electric-sector planning purposes (Eurek et al. 2016; MacDonald et al. 2016). These models can support optimal investment decisions. However, they typically simplify the transmission analysis, and actual transmission construction may differ from optimized model outcomes, especially because system planners rarely can consider transmission and generation investments jointly and holistically.

This study fills a gap in existing knowledge by exploring the magnitude of transmission costs for utility-scale wind and solar projects in the United States. It appears to be the first study that uses various sources to triangulate these costs. Electric-sector stakeholders could use the results to improve grid planning and assess tradeoffs between VRE resource potential, location, and transmission costs. Section 2 provides more background on transmission network investments and summarizes prior estimates of transmission costs. Section 3 details the study methods. Section 4 presents the results, including analysis of interconnection studies (4.1), bulk transmission projects and studies (4.2), and aggregated transmission expenditure (4.3). Section 5 discusses the results and limitations. Section 6 concludes with implications for public policy.

[4] Most other capacity-expansion models used by utilities do not jointly optimize transmission and generation capacity investments. Other examples that include co-optimization of generation and transmission investments are found in (MacDonald et al. 2016; Nelson et al. 2012; Maloney et al. 2019; Spyrou et al. 2017).

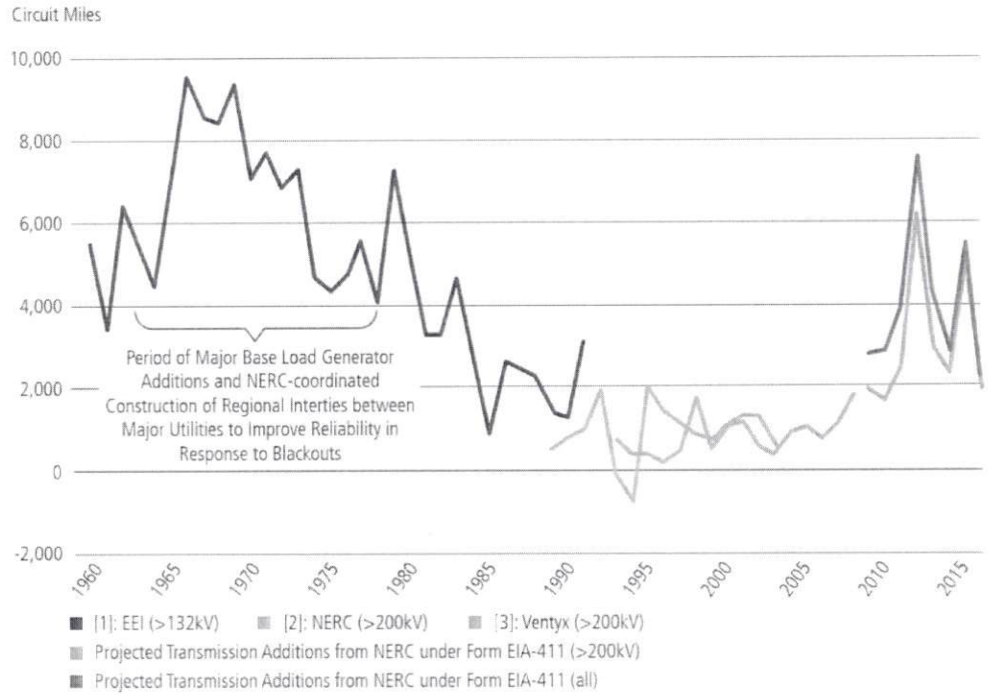
2. Background and Prior Work

The U.S. transmission network is expanded via three main channels. First, regional entities conduct transmission planning processes with the objective of meeting reliability, economic, and/or public policy goals. Second, generation project developers often trigger transmission system expansion through generation interconnection requests. Finally, merchant transmission developers propose and construct new transmission projects to connect generation projects to consumers. This paper considers costs from all these channels.

Analysts traditionally classify transmission investments into three categories: spur, point of interconnection (POI), and bulk transmission. Spur transmission investments are the short, radial transmission lines that connect generators to the bulk transmission grid. Bulk transmission investments are the networked infrastructure investments that move power from all generators to all load centers across a geographic area. POI investments are the facilities that connect spur transmission lines to bulk transmission grids (Andrade and Baldick 2017).

These distinctions relate to how electric-system users bear investment costs. For instance, generation project developers typically incur costs for spur and POI investments. Generators might also incur network-upgrade costs if an interconnection study identifies necessary bulk system expansion. However, a generation project developer typically will not incur costs from projects developed via the transmission planning process, such as the Competitive Renewable Energy Zone (CREZ) in Texas and Multi-Value Project (MVP) in Midcontinent Independent System Operator (MISO) territory.

This paper focuses on transmission costs for utility-scale wind and solar resources, although traditional generation resources historically have required large transmission investments. Figure 1, which shows historical transmission buildout peaking in the 1960s and 1970s in part to facilitate a period of baseload generator additions (Fares and King 2017), suggests that large transmission expenditures were needed to integrate new conventional generation (U.S. Department of Energy 2015). Today, economic and policy benefits are driving demand for VRE, and high future VRE penetrations likely will require large transmission investments (Cochran, Mai, and Bazilian 2014; Mai, Hand, et al. 2014).



Source: DOE QER: Energy Transmission, Storage, and Distribution Infrastructure (2015)

Figure 1. Historical transmission construction

Previous studies have provided some information on VRE-related transmission costs. A review of U.S. transmission planning studies found median wind transmission costs of \$15/MWh or \$300/kW, roughly 15%–20% of a wind project's cost at the time (Mills, Wiser, and Porter 2012). Two Intergovernmental Panel on Climate Change reports estimated wind transmission costs of \$0–\$30/MWh for Organization for Economic Co-operation and Development (OECD) countries (Intergovernmental Panel on Climate Change 2011; 2014). A European study found transmission costs of \$7.5–\$30/MWh at 30% VRE penetration (Heptonstall, Steiner, and Gross 2017). A study of the MISO service area found wind-related transmission costs of \$0.4-\$9.7/MWh or \$33–\$762/kW using interconnection studies (Lamy et al. 2016). However, basing costs on interconnection reports tends to neglect the costs of region-wide transmission investments. A study of the western United States found transmission costs of \$9/MWh or \$314/kW when considering the integration of wind, solar, geothermal, biomass, and hydro resources (Mills, Phadke, and Wiser 2011). Finally, a study of utility-scale wind and solar transmission costs found costs of \$0.83–\$75/MWh for proposed western U.S. projects, with wind transmission costs often at least \$20/MWh (Kahn 2010; 2008).

The present study builds on this existing literature. It benefits from the availability of more VRE-related transmission data, because utility-scale wind and solar energy deployment has grown rapidly in the last 10 years (EIA 2019). In previous studies, many project costs were based on budget estimates or modeling rather than the actual project costs this paper can take advantage of. The present study also takes a more comprehensive approach to all transmission needed for utility-scale wind and solar energy buildout, drawing on interconnection studies, actual transmission projects, simulation/optimization models, and aggregated U.S. utility-scale wind and solar transmission expenditures. This multifaceted approach enables realistic system-level cost estimates. Finally, this study's integration of utility-scale wind and solar transmission costs enables comparison of transmission requirements between the two resource types, whereas most previous studies focused on only one of these types.

3. Methods

This section describes the study's approaches to transmission-cost estimation and its levelized transmission cost calculations.

3.1 Approaches

This study combines four complementary approaches to provide robust estimates of VRE transmission costs (Table 1). The interconnection study approach draws on studies from two regional transmission operators—PJM in the East and MISO in the Midwest—as well as the U.S. Energy Information Administration (EIA) Form 860 interconnection costs from 2005–2012 (EIA 2018c). These sources cover many planned and built generation projects over the past 10 years. In general, they include POI and bulk system costs required for transmission interconnection that are assigned to particular generators. They do not include spur transmission line costs. In addition to facilitating transmission cost attribution, this is the only approach of the four that enables comparison of costs related to VRE and non-VRE resources. However, interconnection studies do not always include bulk transmission investments associated with delivering significant amounts of electricity across long distances.

Table 1. Four approaches to estimating VRE transmission costs

Attribute	Interconnection Studies	Simulation Studies	Aggregation Method	Actual Projects
Geography considered	MISO, PJM, and EIA	Select regions within U.S.	Entire U.S.	
Project scopes	Generation project	Transmission system		Transmission project
Cost Responsibility	Developer	Developer (spur line) and socialized (bulk)		Socialized
Costs considered	Actual/study costs (POI and bulk system)	Modeled costs (bulk system and spur)	Actual costs (bulk system)	
VRE amount	Small penetration	Large penetration		Both small and large penetrations
Generation types	All types	Utility-scale wind and solar only		
Key challenges	Limited bulk costs	Unrealistic optimizations	Coarse analysis Ambiguous cost responsibility	Selection bias Ambiguous cost responsibility

The other three approaches address these large bulk transmission costs. The actual project approach benefits from using cost data for built or proposed large-scale transmission projects that have corresponding estimates of VRE capacity integration. However, compared with the interconnection study approach, this approach provides less information about cost attribution to particular generation resources versus other transmission investment drivers such as reliability and economic congestion relief. Furthermore, although project capital costs are generally transparent and concrete, the amount of VRE integrated owing to the transmission investment can be ambiguous and difficult to determine.

The simulation study approach draws on regional grid-modeling studies that estimate directly the transmission investments needed to integrate VRE. In contrast with the actual project approach—which entails selection bias because only VRE projects requiring long-distance transmission are included—the simulation study approach accounts for VRE that does and does not need new transmission for successful integration. However, the simulation study approach relies on equipment cost assumptions that may be imprecise[5], and it typically uses optimization to estimate the lowest-cost (but often unrealized in practice) solution.

The aggregation approach uses the actual transmission costs needed to integrate VRE in California and nationwide. The California costs are estimated using California Energy Commission (CEC) data on transmission investments related to renewable portfolio standard (RPS) compliance (CEC 2018), California's cumulative VRE deployment, California Public Utilities Commission records, budgets of completed projects, and Edison Electric Institute (EEI) reports. Compared with the other approaches, this approach provides more certainty that transmission costs are primarily related to VRE integration because CEC states that listed transmission projects were required for RPS compliance. In addition, this approach enables estimation of the total regional transmission costs associated with integrating all VRE and thus avoids the selection bias that occurs when estimates are based on individual projects.

Finally, aggregated national cost estimates draw on data from EIA Form 411, EEI, and EIA's electric power monthly dataset. EIA Form 411, which is compiled by the North American Electric Reliability Corporation (NERC), contains data on proposed high-voltage transmission projects back to the early 2000s and reports reasons for transmission buildout (e.g., reliability, VRE integration, economics, non-renewable integration) starting in 2008 (EIA 2017). The historical capital cost of transmission for VRE is calculated based on the amount of proposed VRE-driven transmission and EEI's estimate of historical transmission investment. Then, EIA's data on total amount of U.S. VRE generation installed are used to calculate a levelized capital cost of the transmission infrastructure.

3.2 Levelization Calculation

This study calculates the levelized capital cost of transmission (LCOT) mainly by dividing the annualized capital cost of a transmission project or aggregation of projects (left term of equation 1) by the amount of annual VRE estimated to flow across the system (right term of equation 1).

$$LCOT = \left[\frac{C*r}{[1-(1+r)^{-n}]}\right] \div [K * CF * 8760] \qquad \text{Eq. 1}$$

Where
C = capital cost of transmission investment
r = discount rate
n = transmission asset lifetime (in years)

[5] Simulation studies often rely on average costs of transmission across a given region or territory and thus oftentimes cannot take into account detailed geographic constraints which might influence actual transmission costs.

K = incremental capacity (in MW) of VRE integrated by transmission infrastructure
CF = capacity factor of VRE resource

If a capacity factor is not reported in the primary source document, the calculation uses recent region-specific values from Lawrence Berkeley National Laboratory analysis (Bolinger and Seel 2018; Wiser and Bolinger 2017); see Appendix C for the specific values. The assumed real discount rate is 4.4%, and the assumed transmission asset life is 60 years (Larsen 2016).[6] The discount rate, which has a significant effect on the results, is based on the cost of capital faced by the electric utility industry. Currently, utilities are earning close to an 11.25% return on equity and can access debt with an interest rate of 3.6% for transmission projects. Using a 55/45 debt-to-equity structure, this results in a 4.4% real weighted average cost of capital (WACC; adjusted for inflation).[7] This discount rate is lower than rates used in prior studies and represents the market opportunity cost of capital, effectively the value that affects customer rates. Prior studies use discount rates as high as 10%, which almost doubles levelized transmission costs (Mills, Wiser, and Porter 2009).

Because public policy analysis often uses societal costs of capital rather than investor costs of capital, this study includes a sensitivity calculation on the discount rate. Borenstein suggested a real social discount rate of 1%–3% (Borenstein 2008). This study's sensitivity analysis uses 2%; see Appendix A and B. Finally, the study reports levelized cost estimates in 2018 dollars, adjusting capital costs for years before 2018 based on historical gross domestic product (GDP) implicit price deflators (BEA 2018) and those for years after 2018 based on a GDP chain-type price index (EIA 2018a).

Although the study applies the method above to the vast majority of its calculations, it uses an adjusted method when estimating VRE-related transmission costs over time based on aggregate U.S. data and the National Renewable Energy Laboratory's (NREL's) standard scenarios data; see Equation 2 (Borenstein 2012). The equation calculates the net present value (NPV) of a time series of transmission costs while discounting the incremental VRE growth over the same period.

$$LCOT = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{q_n}{(1+r)^n}} \qquad \text{Eq. 2}$$

Where
C = real expenditures in period n
r = discount rate
N = total discount period (in years)

[6] Changing the assumed lifetime from 60 to 30 years would increase estimates of VRE-related transmission costs by roughly 25%.

[7] The debt cost is a U.S. power industry average (Damodaran 2018). The return on equity includes a base utility return on equity of 9.75% plus a 150 basis point adder for Federal Energy Regulatory Commission (FERC) transmission incentives (EEI 2018; Strunk and Sullivan 2013). The debt-to-equity ratio is from EEI, while the marginal tax rate is based on the 2018 tax law and Tax Foundation analysis (Pomerleau 2018). The Fischer equation is applied to convert from nominal to real after-tax WACC.

q = renewable energy output (in MWh) in period n

The study only analyzes transmission capital costs owing to the difficulty of obtaining consistent operation and maintenance (O&M) costs. Section 5 discusses the implications of this limitation.

4. Results

This section presents results by cost-estimation approach: interconnection study (4.1), actual project and simulation study (4.2), and aggregated costs (4.3).

4.1 Interconnection Costs

This subsection presents the interconnection cost results by individual data source—MISO (4.1.1), PJM (4.1.2), and EIA (4.1.3)—followed by a combined analysis (4.1.4).

4.1.1 MISO

MISO's public record of generator interconnection applications includes 2,209 generation projects (MISO 2018). The present analysis drops the 1,255 projects that were withdrawn by generators and, of the remaining 954 projects, uses 303 that include public reports of interconnection costs. These 303 projects amount to 49 GW of generation resources.

Table 2 shows the generator types analyzed, their interconnection costs, and their levelized costs of transmission (LCOTs). Utility-scale wind projects total 23 GW at an average LCOT of $2.5/MWh. Utility-scale solar projects total 3.3 GW at an average LCOT of $1.6/MWh. These VRE LCOTs are at least an order of magnitude larger than the LCOTs of other generation resources, largely because of differences in assumed transmission utilization. For instance, the average solar unit cost ($/kW) is only 50% higher than the average natural gas unit cost, but the average solar LCOT is 350% higher, because capacity factors are lower for solar than for natural gas. For comparison, the nationwide utility-scale generation LCOEs reported by Lazard are $41–$206/MWh for natural gas, $29–$56/MWh for wind, and $36–$46/MWh for solar (Lazard 2018).

Table 2. MISO interconnection costs for selected utility-scale projects

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	55	$0.55	14,642	$38	$31	$55	$0.34	$0.28	$0.50
Wind	161	$4.51	23,232	$194	$66	$317	$2.48	$0.85	$4.05
Solar	33	$0.18	3,277	$56	$70	$53	$1.56	$1.95	$1.48
Coal	19	$0.01	2,991	$4	$4	NA	$0.03	$0.03	NA
Hydro	13	$0.06	4,234	$13	$13	NA	$0.18	$0.18	NA

Note: Biomass, energy storage, oil, and nuclear are excluded from this table owing to limited observations in the dataset. Overall, projects based on these four technologies have a weighted-average unit cost of $57/kW.

Figure 2 shows the range of interconnection costs by generator type for constructed/under construction projects (dark blue lines) and proposed projects (teal lines). Wind's estimated costs are notably higher for proposed projects ($4/MWh) than for constructed projects ($0.85/MWh). Higher costs for proposed projects might occur because projects requiring less transmission are built before those requiring more, or because many proposed projects will not be built (as suggested by the number of projects withdrawn from interconnection queues), and those that ultimately withdraw might have higher estimated transmission costs.

Figure 2 also disaggregates POI and bulk transmission costs, showing that POI costs constitute a smaller proportion of total transmission costs for all generators except solar. The interconnection studies used for this analysis do not include spur transmission line costs.

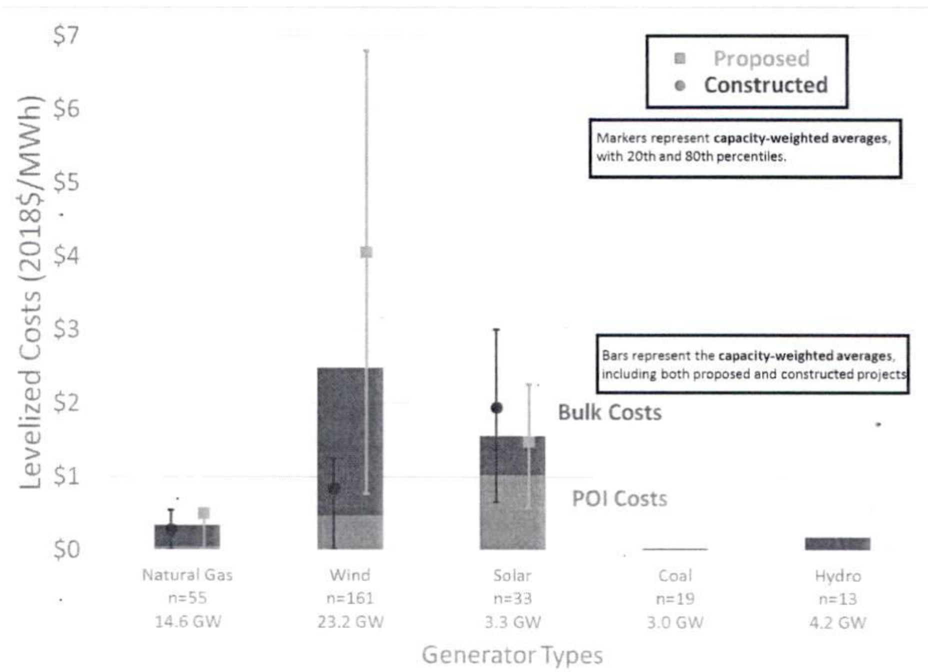


Figure 2. Range of levelized costs for selected utility-scale projects in MISO

4.1.2 PJM

Of 4,152 generation projects in PJM's public record of interconnection applications, generators withdrew 2,467 (PJM 2019), and 338 of the remaining projects have reliable public reports on their interconnection costs—amounting to 64 GW of generation resources.[8] Table 3 shows the

[8] Of the 1,685 non-withdrawn projects, 460 do not have a public report online, and the analysis omits 267 others owing to their small size (< 10 MW). The analysis omits an additional 560 projects that represent incremental, rather than new-build, generation projects owing to challenges in confirming the capacities integrated as a result of the interconnections. A sensitivity analysis shows that including these projects with estimates for their incremental capacity yields little change in the capacity-weighted average cost. For this reason, there is no reason to believe that the costs of the 398 analyzed new-build projects are fundamentally different from the costs of the incremental projects. Finally, 60 projects were aggregated due to them being identified as being located on the same interconnection site.

interconnection cost results for PJM. Wind projects total 11 GW at an LCOT of \$0.3/MWh. Solar projects total 10 GW at an average LCOT of \$3.2/MWh.

Figure 3 shows the PJM range of costs by generator type. Proposed projects are more expensive than constructed ones, and bulk transmission costs constitute most of the total transmission costs. Wind interconnection costs are significantly lower in PJM than in MISO, whereas solar costs are higher.

Table 3. PJM interconnection costs for selected utility-scale projects

				Unit Cost (\$/kW)			Levelized (\$/MWh)		
Generator Type	Projects	Costs (\$2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	98	\$1.43	38,733	\$36.92	\$18.40	\$76.63	\$0.34	\$0.17	\$0.70
Wind	72	\$0.25	10,859	\$22.73	\$19.07	\$54.10	\$0.30	\$0.25	\$0.69
Solar	134	\$1.17	10,057	\$116.17	\$61.83	\$131.90	\$3.22	\$1.72	\$3.66
Coal	4	\$0.05	1,303	\$36.26	\$36.26	NA	\$0.25	\$0.25	NA
Nuclear	2	\$0.03	1,674	\$19.63	\$19.63	NA	\$0.12	\$0.12	NA

Note: Hydro, biomass, energy storage, and oil are excluded from this table owing to limited observations in the dataset. Overall, projects based on these four technologies have a weighted-average unit cost of \$33/kW.

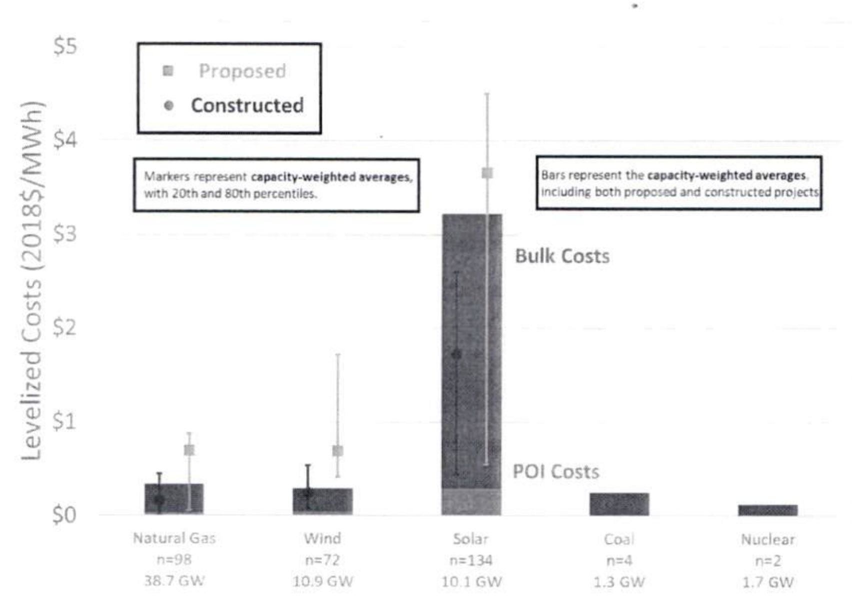


Figure 3. Range of levelized costs for selected utility-scale projects in PJM

4.1.3 EIA

The EIA dataset includes 3,281 constructed generation projects (no proposed projects). The analysis drops 327 projects that are duplicated across years or have data-quality issues, and another 555 that are smaller than 1 MW. The 2,399 projects that remain total 148 GW of generation resources. Table 4 shows the generator types analyzed and their interconnection costs. Wind projects total 50 GW at an average LCOT of $1.0/MWh. Solar projects total 2.2 GW at an average LCOT of $2.2/MWh.

Figure 4 shows the EIA range of costs by generator types. Wind interconnection costs in the EIA dataset are lower than in MISO and higher than in PJM, whereas EIA solar costs are higher than in MISO and lower than in PJM.

Table 4. EIA interconnection costs for selected utility-scale projects

Generator Type	Projects	Costs ($2018 B)	MW	Unit Cost ($/kW)	Levelized ($/MWh)
Natural Gas	675	$3.13	71,006	$44.04	$0.40
Wind	610	$3.45	49,526	$69.61	$0.97
Solar	304	$0.22	2,187	$102.73	$2.21
Coal	42	$1.28	19,671	$65.01	$0.44
Hydro	42	$0.03	639	$50.44	$0.69
Biomass	365	$0.16	1,609	$99.73	$1.09
Oil	303	$0.14	2,397	$58.11	$1.59
Geothermal	39	$0.07	554	$128.24	$1.75

Note: Nuclear and energy storage are excluded owing to few observations in the dataset.

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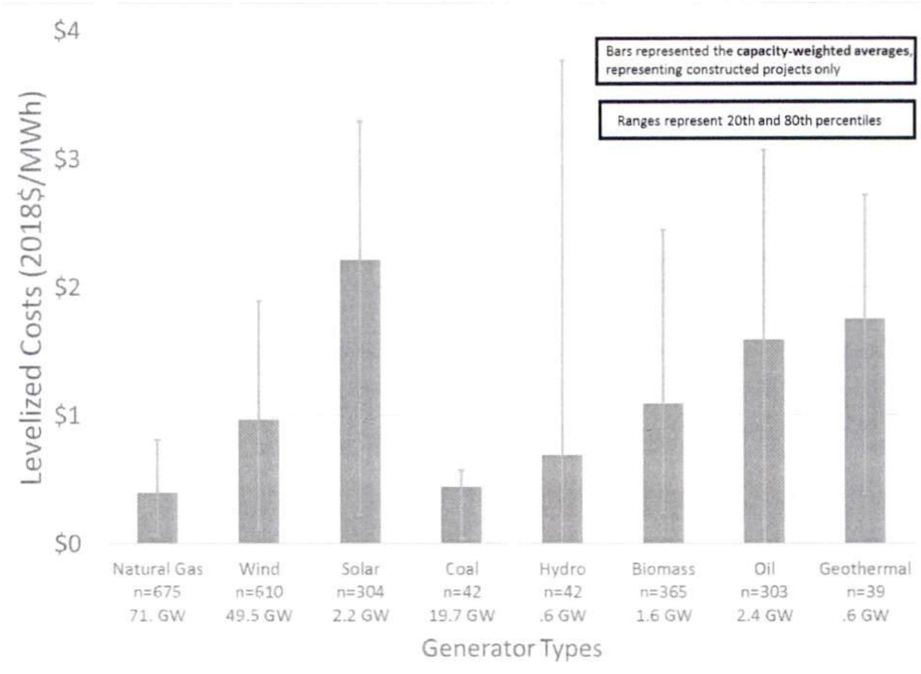
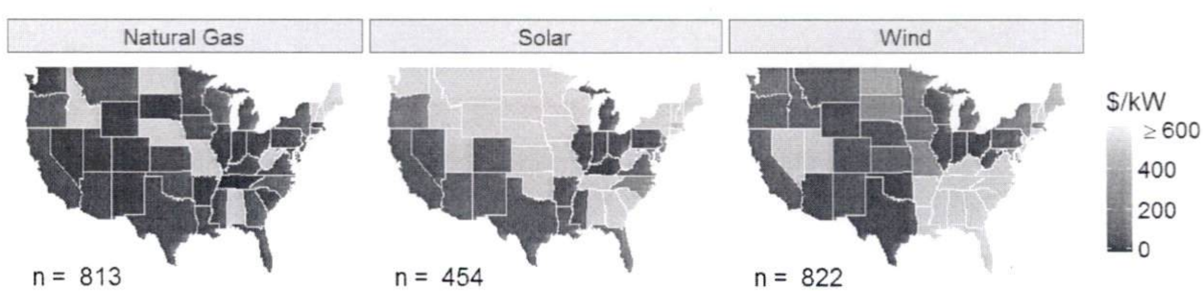


Figure 4. Range of levelized costs for selected utility-scale projects in EIA dataset

4.1.4 Combined Analysis

These results combine the MISO, PJM, and EIA data to assess how location and queue date correlate with transmission costs. Figure 5 highlights differences in project-related transmission costs by resource type and state. For wind, North and South Dakota, Maine, and Missouri have projects with the most expensive transmission needs, perhaps reflecting the limited preexisting transmission infrastructure and electrical load in these states. Figure 6 shows unit costs by the date each constructed project entered the interconnection queue. There is little evidence of significant cost trends over time, although solar costs may have declined.



Note: Gray states represent states not present (containing less than three observations) in the datasets.

Figure 5. Average unit transmission cost by state and utility-scale resource type

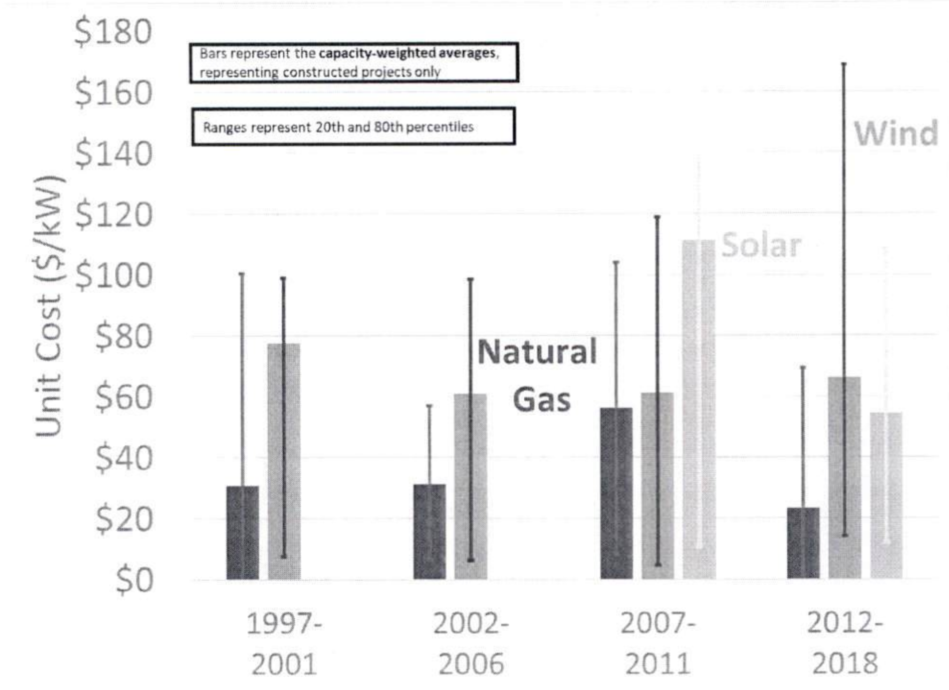


Figure 6. Average unit cost by queue entry year for constructed utility-scale projects

4.2 Bulk System Costs from Actual Projects and Simulation Studies

This subsection presents results from actual projects and simulation studies for utility-scale wind (4.2.1) and solar (4.2.2).

4.2.1 Wind

Figure 8 compares the levelized capital cost of transmission buildout for wind-related constructed transmission projects, proposed transmission projects, and simulation studies (see Appendix A for the specific projects and studies included in this review). All analyses assign full capital cost responsibility to the incremental wind resource being integrated into the transmission system; this is a highly conservative assumption, because transmission investments often serve multiple needs and provide benefits beyond VRE integration. Overall, these sources demonstrate a wide range of transmission costs, from $0–$38/MWh.[9]

Of the 40 actual constructed or proposed transmission projects associated with wind integration, Figure 8 displays the 26 projects that integrate greater than 500 MW of wind and are closer to or finished with construction. The constructed projects have a weighted-average wind LCOT of $5.4/MWh (10%–18% of Lazard's onshore wind LCOE), ranging from $0.9–$11.2/MWh. The proposed projects—which are in early-stage construction or have progressed in the regulatory process but have not secured all

[9] See supplemental information for unit cost ($/kW) data

approvals necessary for completion—are more expensive than the constructed projects, with a weighted-average LCOT of $11.5/MWh (21%–40% of Lazard's onshore wind LCOE).

Transmission costs from the simulation studies are generally lower than those from the actual projects, with a weighted-average LCOT of $3.3/MWh (6%–11% of Lazard's onshore wind LCOE). Of the simulation studies shown, NREL's Standard Scenarios Study ("NREL SS") includes particularly detailed data and is the most recent study to assess transmission investments (Eurek et al. 2016). Using a set of cost assumptions, NREL simulates 26 scenarios and tracks the spur line and bulk system transmission investments needed for the optimal generation mix, resulting in LCOTs of $2.6–$4.6/MWh and a weighted average of $3.1/MWh. However, these estimates assign all transmission costs to wind without netting out costs that are required regardless of wind capacity. Comparing transmission costs in NREL's low wind cost scenario (which builds 366 GW of wind) with those in the low natural gas price scenario (which builds 99 GW of wind) results in an incremental wind transmission cost of $2.2/MWh.[10] Figure 7 reports this value.

[10] This calculation subtracts the NPV of the total transmission capital cost in the low natural gas price scenario from the cost in the low wind cost scenario ($42.9 billion – $21.4 billion = $21.5 billion). Then, the total levelized incremental wind generation in the low natural gas price scenario is netted out from the generation in the low wind cost scenario (16,706 TWh – 7,074 TWh = 9,632 TWh). Finally, $21.5 billion divided by 9,632 TWh results in $2.2/MWh.

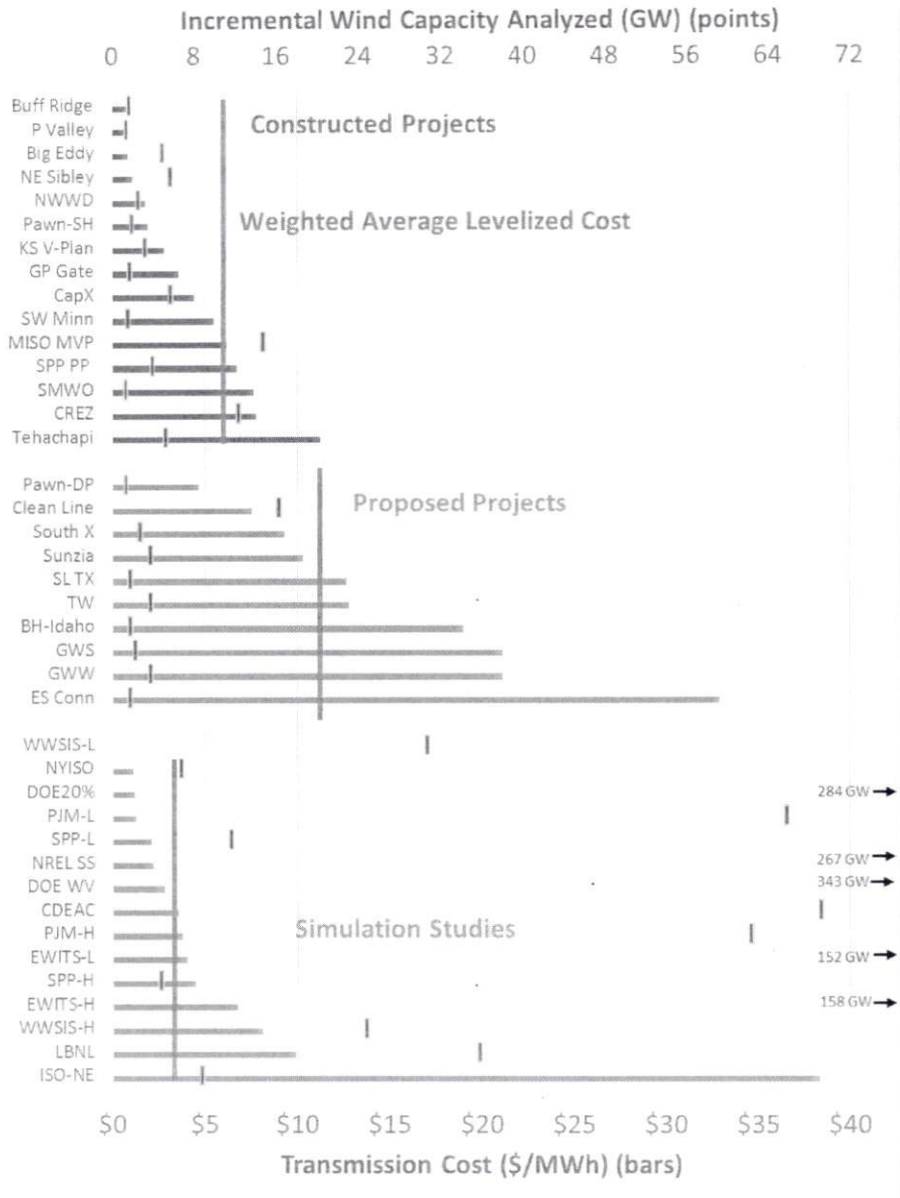


Figure 7. Wind LCOT from constructed and proposed projects and simulation studies

4.2.2 Solar

Figure 8 shows the solar transmission cost results. See Appendix B for a bibliography of studies and reports used. As with wind, the solar transmission cost range is large, from $0–$40/MWh.[11] However, the solar sample is significantly smaller, with only four major studies and four transmission projects with enough certainty to report. Utility-scale solar development has only recently started to expand. In 2010, 40 GW of utility-scale wind had been installed but only 1 GW of utility-scale solar. By 2017, 88

[11] See supplemental information for unit cost ($/kW) data

GW of utility-scale wind had been installed compared to 25 GW of utility-scale solar (EIA 2018b). Combined with the fact that utility-scale solar is not as locationally constrained as wind—and thus many utility-scale solar projects may not require significant transmission[12]—this disparity in capacity deployed might partially explain the disparity between the number of solar and wind projects and studies available. The lack of data hinders analysis of solar transmission costs, particularly with regard to selection bias: focusing on solar projects that require transmission infrastructure will yield transmission cost estimates that are biased high.

These caveats notwithstanding, the four reviewed transmission projects have a weighted-average cost of $15/MWh (33%–42% of Lazard's utility-scale solar LCOE). The large expense associated with the Sunrise Powerlink project in California pushes this average up owing to sensitive national land and difficult terrain that required expensive underground lines—conditions that likely will not apply to most utility-scale solar projects (Akin and Holland 2012; Kahn 2008). Overall, because of the small number of projects and the associated selection bias, these utility-scale solar transmission cost estimates are not highly reliable.

The simulation study solar transmission costs are much lower, with a simple average of $5.3/MWh (12%–15% of Lazard's LCOE) and a range of $0–$15/MWh.[13] Some of these studies noted that the transmission projects analyzed also would improve key reliability issues while providing access to other generation resources such as geothermal and wind; assigning full cost responsibility to solar therefore overstates solar's contribution to transmission costs. The Nevada study and the NREL study identified the amount of utility-scale solar, wind, and other resources that would be facilitated by transmission expansion. In these cases, the present study's solar transmission cost contribution is based on the proportion of solar capacity served by the transmission expansion.

As discussed for wind in Section 4.2.1, NREL's Standard Scenarios Study is particularly useful for analyzing utility-scale solar transmission costs. The study shows LCOTs of $3.1–$7.4/MWh and a weighted average of $4.9/MWh. However, these estimates assign all transmission costs to utility-scale solar without netting out costs that are required regardless of utility-scale solar capacity. Comparing transmission costs in NREL's low photovoltaic (PV) cost scenario (which builds 668 GW of utility-scale solar) with those in the high renewable cost scenario (which builds 118 GW of utility-scale solar)[14] results in an incremental utility-scale solar transmission cost of $1.8/MWh.[15] Figure 8 reports this value.

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[12] Distributed solar is more likely to avoid than to impose transmission costs.

[13] A simple average removes the heavy weighting the U.S. Department of Energy's SunShot Vision Study otherwise would have had. That study suggested that a high-solar future would have the same transmission costs as a low-solar future, but—for the present study—this result was not deemed sufficient to justify pushing the average estimate toward $0/MWh.

[14] Comparing these two scenarios also helps ensure that the incremental transmission difference is likely not driven by wind transmission expansion, because the wind capacity built in each scenario is about the same (165–187 GW).

[15] This calculation subtracts the NPV of the total transmission capital cost in the high renewable cost scenario from the cost in the low PV cost scenario ($36.5 billion – $21.1 billion = $15.4 billion). Then, the total levelized incremental solar generation in the high renewable cost scenario is netted out from the generation in the low PV cost scenario (12,000 TWh – 3,330 TWh = 8,670 TWh). Finally, $15.4 billion divided by 8,670 TWh results in $1.8/MWh.

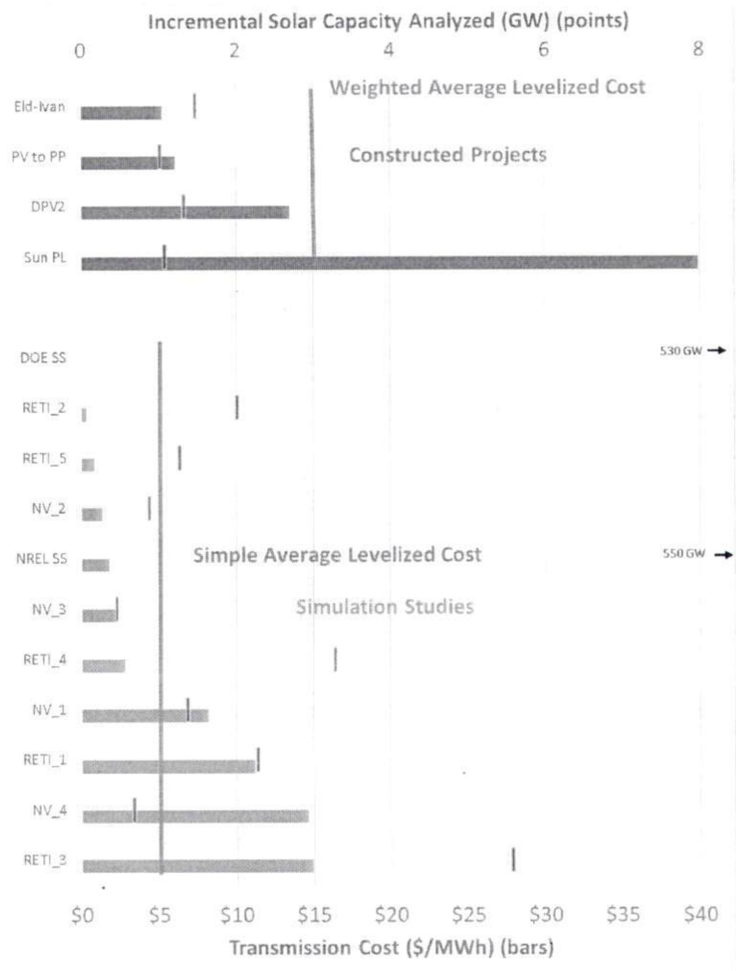


Figure 8. Solar LCOT from constructed projects and simulation studies

4.3 Aggregated Transmission Costs for Renewables

This subsection presents the aggregated VRE transmission cost results for California (4.3.1) and nationwide (4.3.2).

4.3.1 California RPS Transmission Cost Aggregation

Table 5 summarizes the projects with transmission investments required to meet California's 33% RPS target (CEC 2018).[16] Spending for these projects totals $7.3 billion (in $2018; annualized to $347 million), while about 42,000 GWh of California-sourced utility-scale wind and solar generation are

[16] The present analysis focuses on the 33% RPS target, because California's 50% RPS target is further in the future, and less certainty exists about whether more transmission expenditures might be needed to meet the higher target. In any case, the target allows for inclusion of small hydropower, geothermal, and biomass facilities. Although some of the analyzed transmission lines may facilitate integration of those resources, most upgrades apparently are for utility-scale wind and solar projects.

required to meet the 33% target (CEC 2017).[17] Based on these two values, the total LCOT to meet the utility-scale wind and solar targets is $8.3/MWh.[18]

Table 5. California transmission projects to meet RPS

Transmission Project	California ISO Status	In-Service Date	RPS target	Cost Source	Cost Million ($2018)
Sunrise Powerlink 500 kV line	Approved	2012	33%	Sempra	$2,023
Sycamore Canyon-Peñasquitos 230 kV Line	Approved Policy with Reliability Benefits	2018	33%	CPUC	$271
Tehachapi 500 kV line	Approved	2016	33%	EEI	$3,270
Colorado River-Valley 500 kV line	Approved	2013	33%	EEI	$852
Eldorado-Ivanpah 230 kV line	LGIA	2013	33%	EEI	$373
South of Contra Costa 230 kV Reconductoring	LGIA	2012	33%	Estimated	$50
Carrizo-Midway 230 kV Reconductoring	LGIA	2013	33%	Estimated	$53
Path 42 230 kV Reconductoring	Approved Policy	2016	33%	EEI	$32
IID: Path 42 230 kV Reconductoring and additional upgrades	N/A	N/A	33%	LBNL	$41
LADWP: Barren Ridge 230 kV line	N/A	2016	33%	LADWP	$312

ISO = Independent System Operator, LADWP = Los Angeles Department of Water and Power, LGIA = Large Generator Interconnection Agreement.

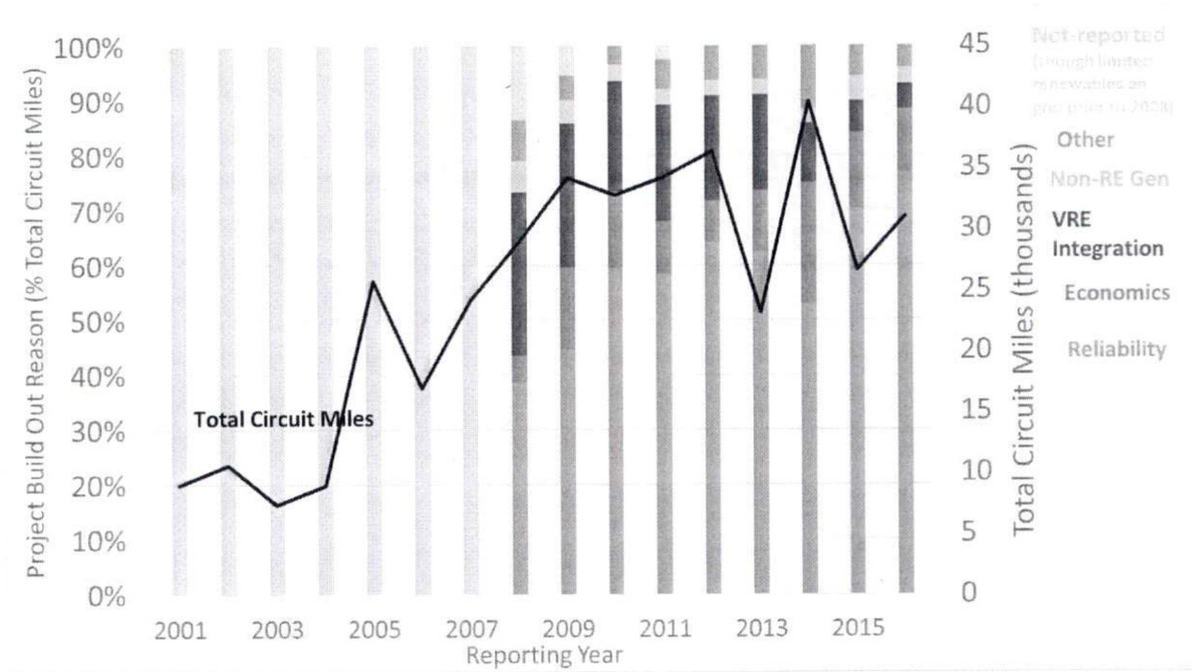
Two lines constitute $5.3 billion of California's $7.2 billion transmission investment: Sunrise Powerlink for utility-scale solar and Tehachapi for wind. The Sunrise project was particularly expensive owing to construction constraints (see Section 4.2.2); it represents 28% of the costs but only accounts for 6% of the energy. Thus, although the aggregate calculation spreads more high transmission costs over a larger amount of VRE generation, a few large investments can significantly affect the average cost of transmission.

4.3.2 U.S.-Wide Transmission Cost Aggregation

From 2001–2016, the total circuit miles of proposed U.S. transmission projects increased, shown as the black line in Figure 9, which covers the next 10-year window within each reporting year (e.g., the 2003 point includes proposed projects from 2004–2013). The colored bars in Figure 9 show the reasons for transmission line investments back to 2008 in percentage of total circuit miles proposed; reliability increased as a reason while VRE integration decreased over the 2008–2016 period (EIA 2017). Before 2008, EIA did not report the major reason for transmission investment.

17 More than 50,000 GWh of utility-scale wind and solar are contributing to California's RPS, but a portion of this energy is sourced from outside of the state. This analysis includes only California generation and transmission (as listed in Table 5).

18 Prior to 2008, 5,500 MWh of wind already on the system might have required transmission buildout not included in CEC's report. Excluding this resource increases the LCOT to $9.5/MWh. However, the original estimate of $8.3/MWh only includes generation from California resources, whereas some of this transmission expenditure likely was made to facilitate importation of out-of-state resources. The LCOT estimate decreases to $7/MWh if out-of-state generation is used.



Note: Data compiled by NERC into EIA Form 411

Figure 9. Total U.S. transmission 10-year proposed buildout

Combining the data from Figure 9 with FERC form 1 estimates of nationwide transmission expenditure from 2008–2016 enables estimation of annual transmission expenditures for VRE integration (FERC 2018). Figure 10 shows transmission expenditure by investor-owned utilities (IOUs), grossed up to account for co-ops and public power utilities, from 1996–2016, along with estimates of the proportion of expenditure associated with VRE integration from 2008–2016.[19] Although total transmission expenditure increased during this timeframe, the percentage of transmission proposals affiliated with VRE dropped from 30% to 5% (Figure 9), which makes the VRE transmission expenditure drop (green line in Figure 10). These data suggest a VRE LCOT of $6.2/MWh.

[19] This expenditure is grossed up to account for investment from co-ops, public utilities, and merchant investors, as described below.

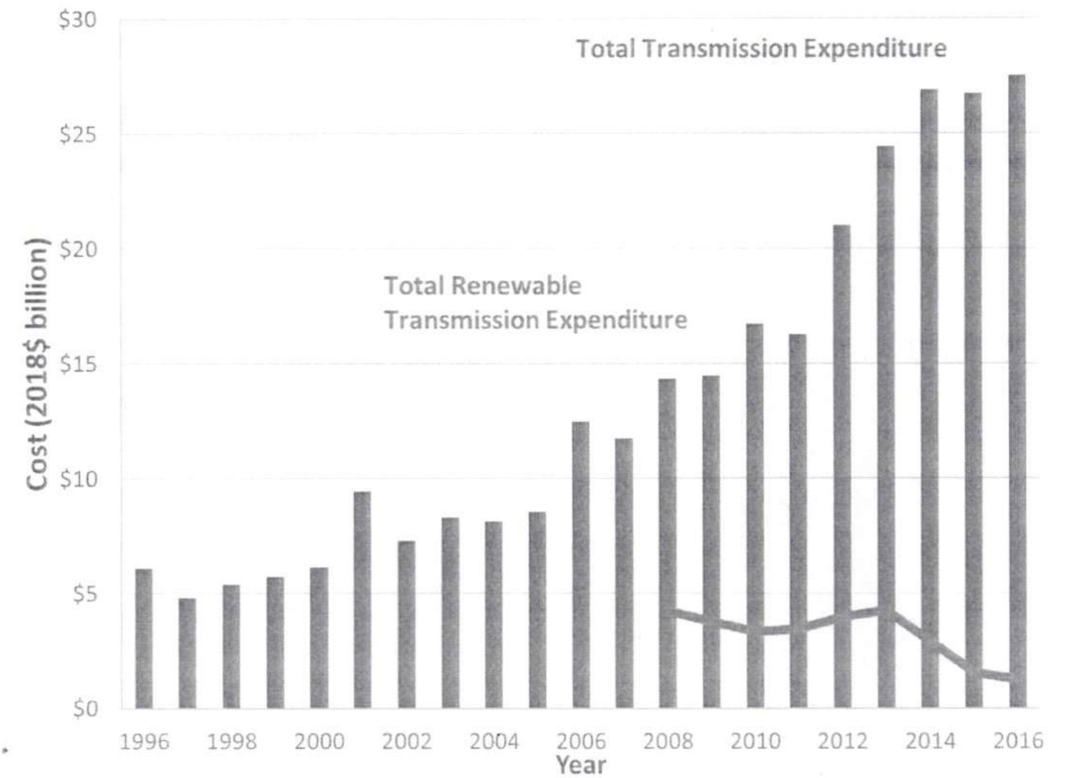


Figure 10. Estimated U.S. transmission expenditure 1996–2016

This analysis hinges on two assumptions: (1) the drivers for proposed transmission lines are highly correlated with the drivers of historical actual transmission line investments, and (2) total U.S. transmission expenditure can be estimated by linearly extrapolating IOU expenditure based on total load served. An analysis of privately available data from the company C Three—tracking U.S. transmission expenditure and including data for co-ops and public utilities as well as IOUs—explores the validity of these assumptions (North American Electric Transmission Projects Database 2018).[20] C Three attributes 19% of $98.4 billion in total investment over the 2008–2016 period to VRE, compared with 15% of $188 billion shown in Figure 10. The similar proportions of transmission expenditure attributed to VRE impart confidence in the Figure 10 estimates. In addition, the C Three data attribute 80% of the $98.4 billion in total investment to IOUs; Figure 10 uses this value to gross up FERC-derived IOU transmission expenditures to account for expenditures by co-ops, public utilities, and merchant developers.

[20] These data are not used in this study's final analysis, because they have many missing expenditures for various transmission projects and thus likely would understate absolute costs. However, the relative costs from these data used to validate the final analysis generally appear to be valid.

5. Discussion

Figure 11 summarizes the utility-scale VRE LCOT results derived from the four estimation approaches. Based on these results, the *average capital cost* of transmission investments is \$1–\$10/MWh, with individual projects ranging from \$0–\$40/MWh. However, it is important to understand why the different approaches produce different results and to understand the key challenges to interpreting the results.

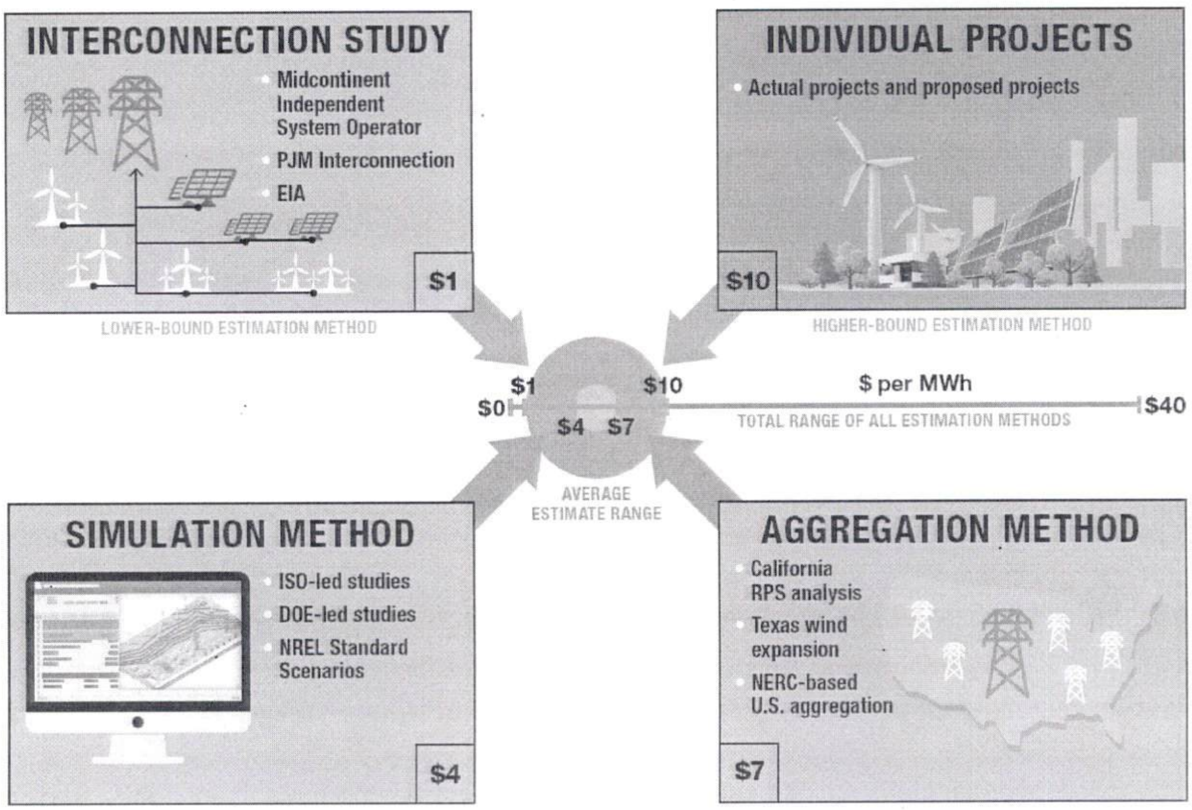


Figure 11. Summary of LCOT for utility-scale wind and solar integration

Two main issues might result in overestimation of VRE transmission costs when the analytical approach focuses on individual actual or proposed transmission projects. First, determining the appropriate cost responsibility for VRE transmission is difficult owing to the multiple purposes and benefits of transmission, which include increasing reliability and reducing congestion. This study assumes all transmission project costs are attributable to VRE and ignores other reasons for building transmission. The resulting overestimate of VRE transmission costs is amplified by VRE's relatively low capacity factors, which yield a lower overall utilization of transmission projects fully assigned to VRE integration. Second, there is a selection bias when focusing on VRE projects that require transmission upgrades rather than all VRE projects, some of which might not need new transmission. Clearly some VRE can be developed without significant transmission investment. Before the CREZ projects in Texas, for instance, 4,500 MW of wind had already been integrated into the Texas system (EIA 2018c).[21] Yet the CREZ projects represent the single major transmission expenditure to integrate wind in the region; if this transmission cost is levelized by all the wind on the Electric Reliability Council of Texas (ERCOT) system, the LCOT decreases from $7.8/MWh to $4.1/MWh (American Wind Energy Association 2017). VRE resources can also exploit transmission lines connected to retiring thermal generators. For instance, LADWP has suggested creating a renewable power hub in Utah owing to the imminent retirement of 1.9 GW of coal capacity (Reyes 2018). In cases like these, VRE projects result in little to no incremental transmission capital investments.

Furthermore, this study mostly analyzes bulk transmission construction in the Plains and Midwest. Although other regions have made a few transmission investments, wind in regions such as the Pacific Northwest has required little transmission investment thus far (NPCC 2013). If the wind built in Oregon and Washington is levelized by the region's single large wind transmission project (Big Eddy), the total cost for wind-based transmission is only $0.6/MWh (EIA 2018c). New England appears to have integrated close to 1,300 MW of wind without large transmission investments, but is now experiencing transmission barriers that will likely require large transmission projects to increase wind penetration further (ISO-NE 2017).

For these reasons, the actual project approach provides an upper bound of estimated transmission costs, although long-term transmission needed to integrate more remote resources might increasingly require these types of transmission projects. The project-level approach may particularly overstate the transmission needed for utility-scale solar, because this study considers only a few solar transmission projects, and solar has less locational dependence than wind does. For example, North Carolina—the state with the second-largest utility-scale solar capacity—appears not to have any significant transmission projects built to integrate these resources.[22]

The simulation study approach overcomes some drawbacks of the actual project approach, but its tendency to underestimate VRE transmission costs make it most suitable for estimating lower bounds to these costs. Simulation studies tend to represent idealized regional or national systems with co-optimized transmission and generation expansion. Because multiple regional entities oversee real-world transmission investments with complex regulatory models and permitting processes, simulation and optimization approaches likely yield lower-bound cost estimates. Furthermore, although NREL ReEDS model studies include spur and bulk transmission investments, many other studies do not specify which costs are incorporated in their estimates. Not incorporating spur and POI costs could further underestimate overall cost estimates.

Interconnection studies also do not account comprehensively for all transmission costs, and thus they likely underestimate total transmission costs. These studies tend to include POI and bulk transmission

[21] This value is a sum of Texas' wind capacity as of 2007.

[22] However, much of North Carolina's utility-scale solar is made up of plants smaller than 5 MW, which might have triggered distribution upgrades rather than transmission lines.

costs associated with different generation types, but they do not include spur costs. Furthermore, the costs reported for interconnection tend not to include all the required bulk transmission investment needed to integrate generation resources. Costs from large transmission projects that result from systemwide regional planning are typically spread over an entire load area (e.g., MISO's MVP and ERCOT's CREZ). Interconnection reports do not include these costs, because the costs are not typically the responsibility of a specific generation resource, and the transmission typically provides systemwide benefits beyond VRE integration.

Finally, the coarse aggregation approach might underestimate or overestimate VRE transmission costs. This study's U.S.-wide aggregation, for example, relies on the assumption that all line miles have the same cost, ignoring the fact that the capacity/voltage of the transmission investment also impacts the total cost. In general, higher-voltage lines are more expensive per mile than their lower-voltage counterparts (SPP 2016). According to EIA's Form 411 data, transmission proposed for VRE integration uses a higher percentage of higher-voltage lines compared with transmission proposed for other reasons—as might be expected owing to the need to transmit large amounts of VRE from remote areas to load centers. This issue suggests that the U.S.-wide aggregation might underestimate the cost of VRE transmission projects. Conversely, the U.S.-wide aggregation approach might overestimate VRE transmission costs because it does not account for future VRE deployment facilitated by U.S. transmission investments. The analysis includes transmission cost estimates through 2016 but freezes the amount of VRE integrated by those investments at 2016 levels. However, a lag likely exists between transmission investment and VRE integration, so conservatively freezing the VRE level likely omits LCOT reductions due to further VRE integration.

These caveats suggest that using any one approach to generalize VRE transmission costs is inadequate. However, using multiple approaches bounds average VRE transmission costs, producing a cost range with a relatively high level of confidence. The key caveats to our high-end estimates tend to suggest that those estimates are too high (e.g. selection bias and strict cost responsibility on our actual project estimates) while the key caveats to our low-end estimates tend to suggest that those estimates are likely too low (e.g. simulations being unrealistically optimized and interconnection studies not including large bulk investment costs).

Furthermore, these costs are relevant for understanding potential future transmission investment costs. While the approaches rely on costs from current and historical transmission buildout, which could theoretically differ from future transmission costs at increasing VRE penetrations,[23] this study does not identify strong and widespread evidence to suggest time trends in transmission investment costs. This study also does not consider how the declining cost of energy storage could change the competitive landscape for transmission development. Onsite energy storage could be both a

[23] At lower VRE penetration levels developers might be able to exploit resource locations that have lower transmission costs and once those cheaper locations have been exhausted, costs might rise to integrate resources located in transmission constrained regions.

complement or substitute for transmission projects and future research might aim to better understand this tradeoff for VRE integration (Khastieva et al. 2019).

Lastly, this paper only considers transmission capital costs to integrate VRE and does not include transmission O&M costs. Some sources estimate average annual U.S. transmission O&M costs at 5%–10% of a project's original capital cost (Larsen 2016); (FERC n.d.). Adding this average annual O&M cost to the annualized financial calculations would approximately double the LCOT presented above. However, applying the average O&M cost to incremental transmission costs likely would overestimate LCOT, because O&M costs do not easily map onto individual projects and likely do not increase linearly with transmission investment. Furthermore, the interconnection studies reviewed for this analysis do not mention assigning lifetime O&M costs to individual generators, suggesting transmission operators do not consider these costs to be the responsibility of generation projects. Nevertheless, because of the potential large share of costs due to O&M, future work should consider adding transmission O&M cost estimates to the capital cost estimates.

6. Conclusions and Policy Implications

The average VRE LCOT range estimated in this study, \$1–\$10/MWh, represents a substantial expense in relation to the LCOEs of utility-scale wind (\$29–\$56/MWh) and solar (\$36–\$46/MWh). Transmission can increase direct plant-level LCOE by 3%–33%.

This study's levelized capital cost estimates for VRE-related transmission are generally lower than prior estimates. At the same time, the study's unit costs (\$/kW) are generally in line with prior estimates,[24] highlighting the sensitivity of the levelized results to assumptions regarding project lifetime, discount rate, and capacity factor. This study assumes long lives for transmission assets, discount rates based on the cost of capital for U.S. utilities, and regionally specific capacity factors based on empirical observations.

The results show no large, consistent disparity in the capital cost of transmission between utility-scale solar and wind resources. The smaller number of solar observations could suggest that solar integration is less transmission constrained than wind integration. Future research that benefits from more development of utility-scale solar projects should track the development of solar-related transmission expenses.

The multiple analytical approaches used in this study lend confidence to the resulting range of average VRE transmission capital costs. However, this generalized information is not applicable to individual investment decisions. Rather, it is useful for informing high-level decisions and directions. First, the results might be used in studies assessing the benefits of transmission avoidance and deferral. This information is often important in public policy debates comparing distributed energy resources to utility-scale projects (Kahn 2008). Second, the results might be used when evaluating the potential costs of large-scale public transmission investments (e.g., CREZ in Texas and MVP in the Midwest). Increasingly, region-wide coordination in transmission investment likely will be needed, and these results can inform policy makers about the magnitude of transmission costs compared with potential resource costs. Finally, the results provide insight into a system-level cost component that is not always adequately assessed in studies of high-VRE futures.

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24 See supplemental information for detailed unit cost (\$/kW) data

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Appendix A. Details of wind studies/costs reviewed

Table A-1. Source information for wind studies and projects

Transmission Project Name	Acronym in Figure 7	Source name (for MW)	Author	Year	Source Name (for cost)	Author	Year
ISO-NE Wind Integration Study	ISO-NE	New England Wind Integration Study	ISO-NE/GE/Enernex	2010	ibid	ibid	ibid
Analysis of Western Renewable Energy Zones	LBNL	Exploration of resource and transmission expansion decisions in the Western Renewable Energy Zone initiative (table 4)	Mills et. al.	2011	ibid	ibid	ibid
Western Wind and Solar Integration Study	WWSIS-H	Western Wind and Solar Integration Study (Table 3)	GE	2010	ibid	ibid	ibid
Eastern Wind Integration and Transmission Study	EWITS-H	Eastern Wind Integration and Transmission Study (Table 2)	Enernex	2011	ibid	ibid	ibid
SPP Wind Integration study	SPP-H	2016 Wind Integration Study	SPP	2016	ibid	ibid	ibid
Eastern Wind Integration and Transmission Study	EWITS-L	Eastern Wind Integration and Transmission Study (Table 2)	Enernex	2024	ibid	ibid	ibid
PJM Renewable Integration Study	PJM-H	PJM Renewable Integration Study Task 3A Part C Transmission Analysis	GE	2014	ibid	ibid	ibid
CDEAC Study	CDEAC	20% Wind Energy by 2030 (pg. 95 cites CDEAC)	DOE	2008	ibid	ibid	ibid
DOE Wind vision 2015	DOE WV	WindVision: A New Era for Wind Power in the United States (pg. 3)	DOE	2015	ibid	ibid	ibid
NREL Standard Scenarios (w/ ReEDs)	NREL SS	2018 Standard Scenarios Report: A U.S. Electricity Sector Outlook	NREL	2018	ibid	ibid	ibid
SPP Wind Integration study	SPP-L	2016 Wind Integration Study	SPP	2016	ibid	ibid	ibid
PJM Renewable Integration Study	PJM-L	PJM Renewable Integration Study Task 3A Part C Transmission Analysis	GE	2014	ibid	ibid	ibid
20% Wind Energy by 2030 Study	DOE20%	20% Wind Energy by 2030 (pg. 143)	DOE	2006	ibid	ibid	ibid
NYISO Wind Integration Study	NYISO	NYISO Wind Generation Study (Final Draft)	NYISO	2010	ibid	ibid	ibid
Western Wind and Solar Integration Study	WWSIS-L	Western Wind and Solar Integration Study (Table 3)	GE	2010	ibid	ibid	ibid
Tehachapi	Tehachapi	Wind Tech Market Report 2015	LBNL	2016	Transmission Project at a Glance: 2016	EEI	2017
CREZ	CREZ	Estimation of Transmission Costs for New Generation	UT Austin Energy Institute	ibid	ibid	ibid	ibid
Southwest Minnesota wind outlet	SMWO	Transmission Projects Supporting Renewable Resources	EEI	2009	ibid	ibid	ibid
SPP Priority Projects	SPP PP	Wind Tech Market Report 2013	LBNL	2014	Third Quarterly Project Tracking Report 2017	SPP	2017
MISO Multi-Value Projects	MISO MVP	Wind Tech Market Report 2016	LBNL	2017	Regionally Cost Allocated Project Reporting Analysis: MVP Project Status March 2018	MISO MTEP17	2018
SW Minnesota Wind Expansion Project	SW Minn	Transmission Project at a Glance: 2007	EEI	2007	ibid	ibid	ibid
CapX	CapX	Wind Tech Market Report 2013	LBNL	2014	Transmission Project at a Glance: 2016	EEI	2017
Grand Prairie Gateway	GP Gate	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Kansas V-Plan	KS V-Plan	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Pawnee - smoky hill	Pawn-SH	Transmission Project at a Glance: 2012	EEI	2013	ibid	ibid	ibid
Northwest-woodward District	NWWD	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Nebraska Sibley Line and Iatan - Nashua Line	NE Sibley	Transmission Project at a Glance: 2013	EEI	2014	ibid	ibid	ibid
Big Eddy – Knight and Central Ferry – Lower Monumental	Big Eddy	Wind Tech Market Report 2014	LBNL	2015	BPA energizes 500-kV Big Eddy–Knight line, halts Montana-to Washington project	Transmission Hub	2015
Pleasant Valley Transmission	P Valley	Transmission Project at a Glance: 2009	EEI	2009	ibid	ibid	ibid
Buffalo Ridge Incremental Generation Outlet	Buff Ridge	Xcel Energy completes major transmission projects	TEI Times	2010	ibid	ibid	ibid
Empire State Connector	ES Conn	Wind Tech Market Report 2016	LBNL	2017	Empire State Connector "HVDC" Transmission Project to Deliver Zero Carbon Energy from Upstate New York Directly to NYC	Cision PR Newswire	2016
Gateway West	GWW	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Gateway South	GWS	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017
Boardman-Hemingway	BH-Idaho	Wind Tech Market Report 2016	LBNL	2017	Project Fact Sheet: Boardman to Hemingway Transmission Line Project	Idaho Power	2017
Transwest Express	TW	Wind Tech Market Report 2016	LBNL	2017	http://www.transwestexpress.net/about/index.shtml	Web	2018
Southline Transmission Project	SL TX	Wind Tech Market Report 2016	LBNL	2017	Southline Transmission Project Frequently Asked Questions	Developer	2017
Sunzia	Sunzia	Wind Tech Market Report 2016	LBNL	2017	SunZia Transmission seeks approval of 500-kV project in New Mexico	Transmission Hub	2018
Southern Cross	South X	Wind Tech Market Report 2016	LBNL	2017	Report on the Economic and Fiscal Impacts of the Southern Cross Transmission Project, Louisiana	Moss Adams	2016
Clean Line Projects	Clean Line	Wind Tech Market Report 2016	LBNL	2017	Assortment of project websites	nergy Partners	2018
Pawnee—Daniels Park	Pawn-DP	Wind Tech Market Report 2016	LBNL	2017	Transmission Project at a Glance: 2016	EEI	2017

Table A-2. Levelized capital cost of transmission for wind (actual transmission projects)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Tehachapi	California	4,500	EEI	2017	$726.67	$11.24
CREZ	Texas	11,553	UT Austin	2017	$610.32	$7.80
Southwest Minnesota wind outlet	Midwest	600	EEI	2009	$598.83	$7.65
SPP Priority Projects	Southwest	3,200	SPP	2017	$437.49	$6.77
MISO Multi-Value Projects	Midwest	14,000	MISO MTEP17	2017	$485.39	$6.20
SW Minnesota Wind Expansion Project	Midwest	800	EEI	2007	$431.64	$5.52
CapX	Midwest	5,000	EEI	2017	$347.44	$4.44
Grand Prairie Gateway	Midwest	1,000	EEI	2017	$283.06	$3.62
Kansas V-Plan	Plains	2,500	EEI	2009	$220.68	$2.82
Pawnee - smoky hill	West	1,200	EEI	2013	$126.48	$1.96
Northwest-woodward District	Plains	1,800	EEI	2009	$140.37	$1.79
Nebraska Sibley Line and Iatan - Nashua Line	Midwest	5,000	EEI	2014	$85.20	$1.09
Big Eddy – Knight and Central Ferry – Lower Monumental	West	4,200	News	2015	$58.20	$0.90
Pleasant Valley Transmission	Midwest	700	EEI	2009	$67.89	$0.87
Buffalo Ridge incremental Generation Outlet	Midwest	940	News	2010	$67.00	$0.86

Table A-3. Levelized capital cost of transmission for wind (proposed transmission projects)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Empire State Connector	Northeast	1,000	Web	2016	$1,560.41	$32.89
Gateway West	West	3,000	EEI	2017	$1,362.51	$21.07
Gateway South	West	1,500	EEI	2017	$1,362.51	$21.07
Boardman-Hemingway	West	1,000	Idaho Power	2017	$1,226.26	$18.96
Transwest Express	Plains	3,000	Web	2018	$1,000.00	$12.78
Southline Transmission Project	West	1,000	Project FAQ	2017	$817.51	$12.64
Sunzia	West	3,000	Web	2018	$666.67	$10.31
Southern Cross	Texas	2,000	Moss Adams	2016	$728.19	$9.31
Clean Line Projects	Plains	16,000	Web	2018	$590.63	$7.55
Pawnee—Daniels Park	West	600	EEI	2017	$303.16	$4.69

Table A-4. Levelized capital cost of transmission for wind (studies)

Transmission Project / Study Name	Region	Estimated Potential Wind Capacity (MW)	Cost Source	Source Year	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
ISO-NE Wind Integration Study	Northeast	8,000	ISO-NE	2009	$2,593 33	$38 35
Analysis of Western Renewable Energy Zones	West US	35,000	LBNL	2011	$641 08	$9 91
Western Wind and Solar Integration Study	West US	24,030	GE / NREL	2010	$524.16	$8.11
Eastern Wind Integration and Transmission Study	East US	151,938	EnerNex / NREL	2024	$511.61	$6.77
SPP Wind Integration study	Plains	3,963	SPP	2016	$353 32	$4 52
Eastern Wind Integration and Transmission Study	East US	158,628	EnerNex / NREL	2024	$276.74	$4 03
PJM Renewable Integration Study	East US	61,590	PJM	2011	$249 55	$3 80
CDEAC Study	All US	68,400	DOE 20% Wind pg 95	2006	$271.65	$3 55
DOE Wind vision 2015	All US	343,000	DOE	2015	$215 01	$2 81
NREL Standard Scenarios (w/ ReEDs)	All US	267,592	NREL	2018	$80.14	$2 23
SPP Wind Integration study	Plains	10,797	SPP	2016	$166 88	$2.13
PJM Renewable Integration Study	East US	65,045	PJM	2011	$86 24	$1 31
20% Wind Energy by 2030 Study	All US	284,000	DOE	2006	$90 39	$1.18
NYISO Wind Integration Study	East US	6,000	NYISO	2010	$71 57	$1 09
Western Wind and Solar Integration Study	West US	29,940	GE / NREL	2010	$0 00	$0 00

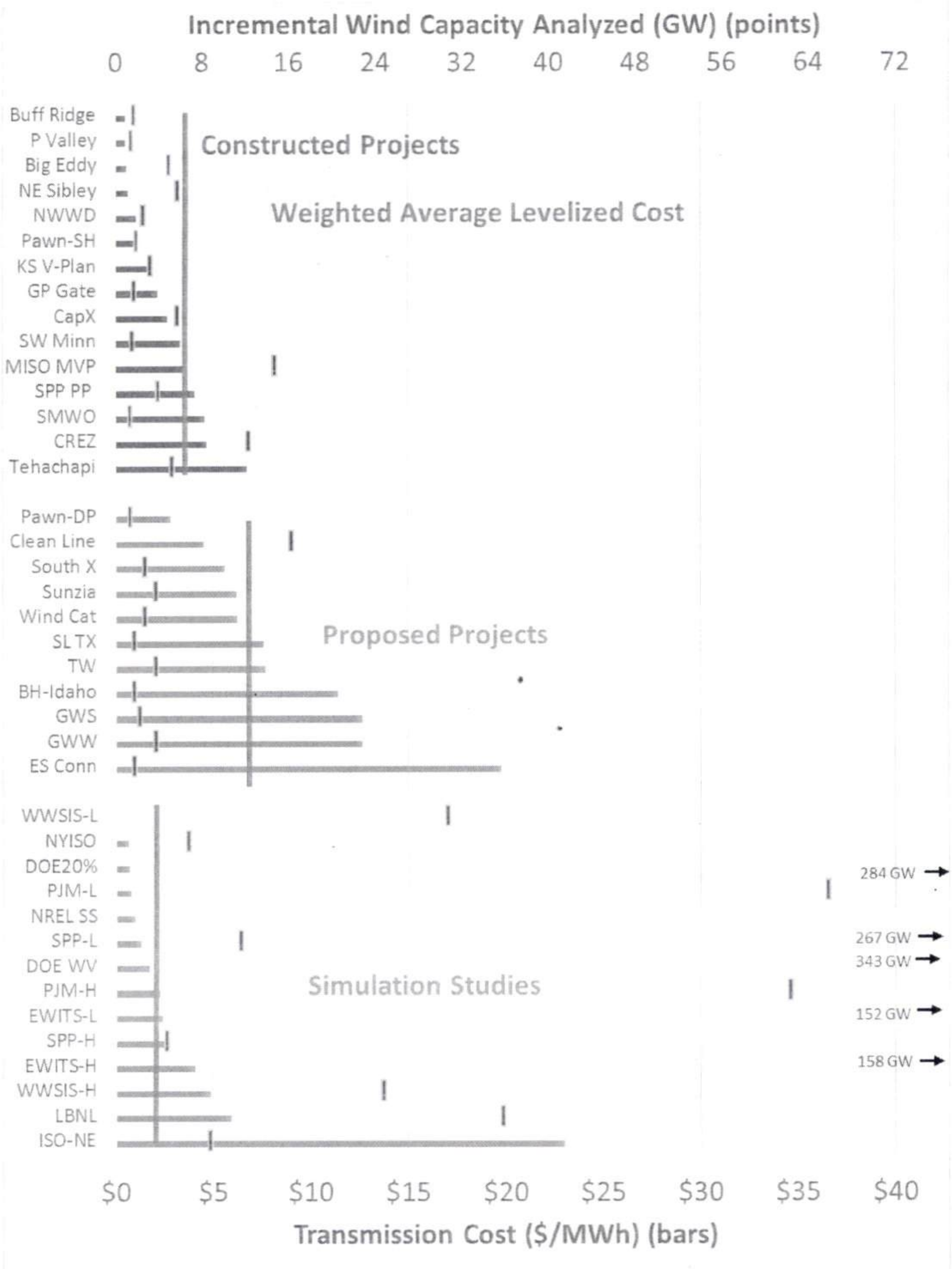

Figure A-1. Utility-scale wind chart (at 2% discount rate)

Appendix B. Details of solar studies/costs reviewed

Table B-1. Source information for utility-scale solar transmission projects and studies

Transmission Project Name	Acronym in Figure 8	Source name (for MW)	Author	Year	Source Name (for cost)	Author	Year
Sacramento River / Lassen / Round Mountain	RETI_3	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Solano TAFA	RETI_5	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Riverside and Victorville/Barstow TAFA	RETI_2	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
Imprerial Valley TAFA	RETI_1	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
San Joaquin Valley TAFA	RETI_4	Transmission Capability and Requirements Report Transmission Technical Input Group Renewable Energy Transmission Initiative 2.0	CPUC/CEC	2016	ibid	ibid	ibid
South Project	NV_4	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
El Dorado and Clayton extension	NV_1	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
Harry Allen Transformer	NV_3	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
Nevada Study: Harry Allen to Mead	NV_2	Economic Analysis of Nevada's Renewable Energy and Transmission Development Scenarios	Synapse	2012	ibid	ibid	ibid
NREL Standard Scenarios (w/ ReEDs)	NREL SS	2018 Standard Scenarios Report: A U S. Electricity Sector Outlook	NREL	2018	ibid	ibid	ibid
DOE Sunshot Vision Study	DOE SS	SunShot Vision Study	DOE	2012	ibid	ibid	ibid
Sunrise Powerlink	Sun PL	Sunrise Powerlink Inspires Innovation	T&D World Magazine	2014	ibid	ibid	ibid
Devers - Valley No. 2 Transmission Project DPV2	DPV2	Decision 16-08-017 August 18, 2016 application for west of denvers upgrade project	CPUC	2016	Transmission Project at a Glance: 2014	EEI	2014
Palo Verde Substation - Pinnacle Peak Substation	PV to PP	Transmission Project at a Glance: 2016	EEI	2017	ibid	ibid	ibid
Eldorado-Ivanpah	Eld-Ivan	Website: https://www.sce.com/about-us/reliability/upgrading-transmission/eldorado	SCE	NA	Transmission Project at a Glance: 2014	EEI	2014

Table B-2. Levelized capital cost of transmission for utility-scale solar (studies)

Transmission Project / Study Name	Region	Estimated Potential Solar Capacity (MW)	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Sacramento River / Lassen / Round Mountain	California	5,500	$756.56	$14.93
South Project	West	600	$741.69	$14.64
Imprerial Valley TAFA	California	2,200	$567.42	$11.20
El Dorado and Clayton extension	West	1,300	$415.10	$8.19
San Joaquin Valley TAFA	California	3,200	$143.04	$2.82
Harry Allen Transformer	West	380	$111.84	$2.21
NREL Standard Scenarios (w/ ReEDs)	All US	549,756	$28.03	$1.79
Harry Allen to Mead	West	800	$68.29	$1.35
Solano TAFA	California	1,200	$43.34	$0.86
Riverside and Victorville/Barstow TAFA	California	2,000	$17.68	$0.35
DOE Sunshot Vision Study	All US	530,000	$0.00	$0.00

Table B-3. Levelized capital cost of transmission for utility-scale solar (actual projects)

Transmission Project / Study Name	Region	Estimated Potential Solar Capacity (MW)	Unit Cost ($2018/kW)	Levelized Cost ($2018/MWh)
Sunrise Powerlink	California	1,000	$2,023.44	$39.94
Devers - Valley No. 2 Transmission Project DPV2	California	1,250	$681.58	$13.45
Palo Verde Substation - Pinnacle Peak Substation	Southwest	1,000	$306.56	$6.08
Eldorado-Ivanpah	California	1,400	$266.24	$5.26

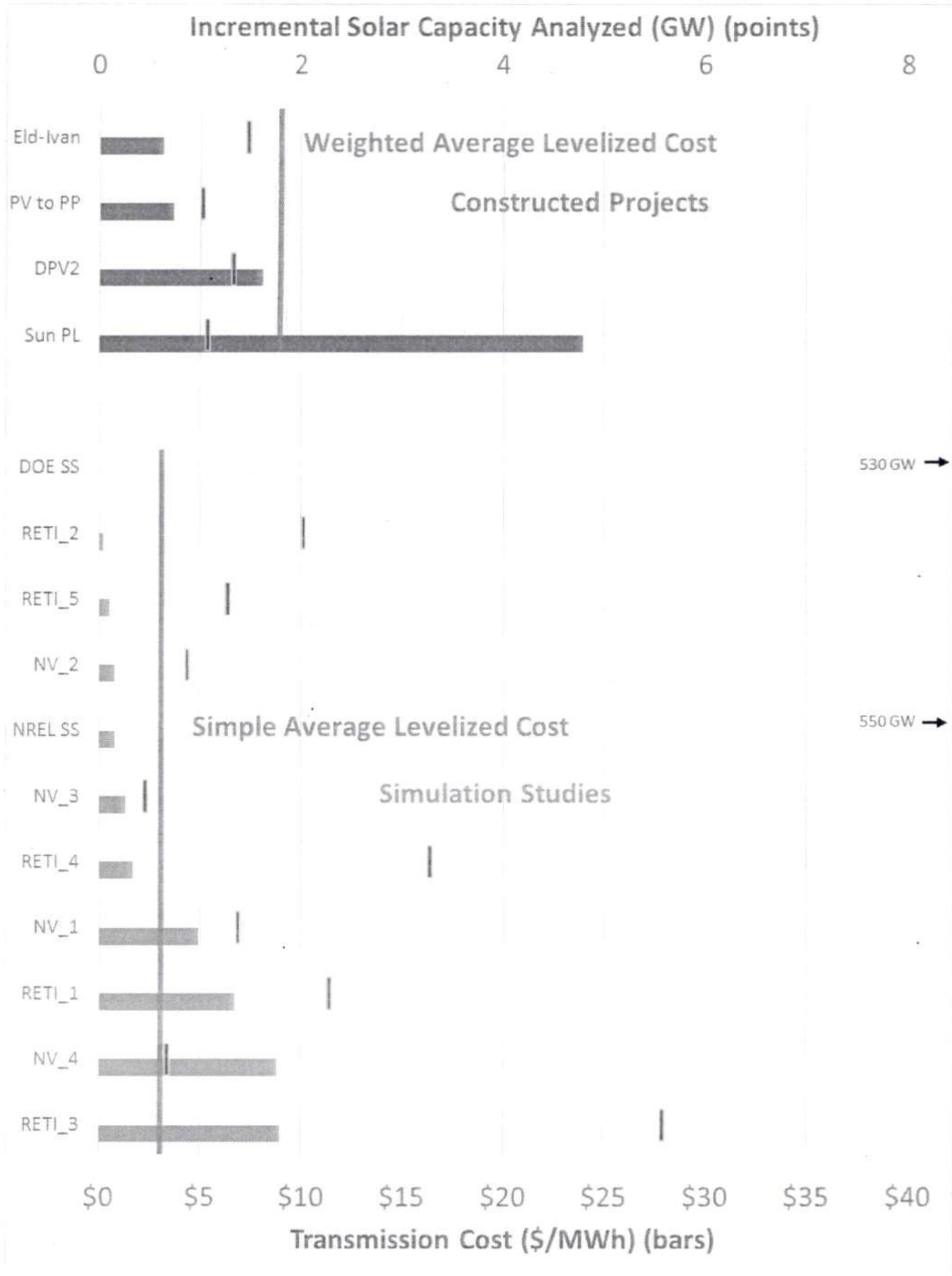

Figure B 1. Utility-scale solar chart (at 2% discount rate)

Appendix C. Additional Information

Table C-1. Capacity Factors Used for Levelization

Region	Wind	Utility Solar	Natural Gas	Coal	Hydro	Nuclear
Northeast	26%	18%	60.0%	80.0%	40.0%	90.0%
California	35%	28%	60.0%	80.0%	40.0%	90.0%
West	35%	28%	60.0%	80.0%	40.0%	90.0%
Southwest	35%	28%	60.0%	80.0%	40.0%	90.0%
Texas	43%	23%	60.0%	80.0%	40.0%	90.0%
Midwest	43%	20%	60.0%	80.0%	40.0%	90.0%
West US	35%	28%	60.0%	80.0%	40.0%	90.0%
East US	36%	20%	60.0%	80.0%	40.0%	90.0%
All US	42%	26%	60.0%	80.0%	40.0%	90.0%
Plains	43%	20%	60.0%	80.0%	40.0%	90.0%

Lawrence/Metz /A
Exhibit 3
Docket No. EMP-105, Sub 0

Generator Interconnection System Impact Study Report

Cumberland County, NC
1235 MW Combined Cycle Plant
Queue #399

April 11, 2019
Duke Energy Progress
Transmission Department

Table of Contents

1 PURPOSE

The purpose of this Facilities Study is to assess the impacts of a generator interconnection request on the reliability of the Duke Energy Progress (DEP) transmission system with respect to power flow, short circuit, and stability. Estimates of the cost and time required to interconnect the generation as well as to resolve the impacts as determined in this analysis are also included. The DEP internal system analysis consists of an evaluation of the internal DEP transmission system utilizing documented transmission planning criteria. The request is described in Table 1 below.

Table 1: Interconnection Requests

DEP Generator Interconnection Queue No.	MW	Requested In-Service Date	County	Interconnection Facility
399	1235	3/1/2023	Cumberland County, NC	Cumberland 500 kV Substation, 500 kV switchyard

2 ASSUMPTIONS

The following results are from the DEP internal power-flow models that reflect specific conditions of the DEP system at points in time consistent with the generator interconnection requests being evaluated. The cases include the most recent information for load, generation, transmission, interchange, and other pertinent data necessary for analysis. Future years may include transmission, generation, and interchange modifications that are not budgeted and for which no firm commitments have been made. Further, DEP retains the right to make modifications to modeling cases as needed if additional information is available or if specific scenarios necessitate changes. For the systems surrounding DEP, data is based on the ERAG MMWG model. The suitability of the model for use by others is the sole responsibility of the user. Prior queued generator interconnection requests were considered in this analysis.

The results of this analysis are based on Interconnection Customer's queue requests including generation equipment data provided. If the facility technical data or interconnection points to the transmission system change, the results of this analysis may need to be reevaluated.

This study was based on the following assumptions:

- CUSTOMER would construct, own and operate the electrical infrastructure that would connect their generation to DEP's facilities, including any step-up transformers and lines from the generators, but excluding the circuit breaker(s) in the new breaker station where applicable.

3 RESULTS

3.1 Power Flow Analysis Results

Facilities that may require upgrade within the first three to five years following the in-service date are identified. Based on projected load growth on the DEP transmission system, facilities of concern are those with post-contingency loadings of 95% or greater of their thermal rating and low voltage of 92% and below, for the requested in-service year or the in-service year of a higher queued request. The identification of these facilities is crucial due to the construction lead times necessary for some system upgrades. This process will ensure that appropriate focus is given to these problem areas to investigate whether construction of upgrade projects is achievable to accommodate the requested interconnection service.

The subject queue request, as well as nearby existing and prior-queued generation and their assigned transmission upgrades, were modeled and assumed to be operating at full output.

All relevant contingency categories from NERC Standard TPL-001-4 have been analyzed in this study. Contingency analysis study results show that interconnection of these generation facilities **DOES** result in potential thermal overloads on the DEP system. The following facilities will need to be upgraded to accommodate the proposed generation:

Table 2: Network Upgrades Assigned to This Request

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Q399	Cumberland 500/230 kV transformer bank	-	-	Add new 500/230 kV 1120 MVA (65C) transformer at Cumberland and buswork	25.0	4
Q399	Lee Sub – Mt. Olive 115 kV Line	Mt. Olive Industrial Tap-Structure 76-2	1.81	Uprate line to full 212F conductor rating	1.0	3
Q399	Lee Sub – Mt. Olive 115 kV Line	Tri-County Mt. Olive Tap-Mt. Olive 115kV Sub	0.09	Reconductor with 1590 MCM ACSR	1.5	2
Q399	Clinton-Mt. Olive 115 kV Line	Faison Hwy Industrial-Mt. Olive 115 kV Sub	9.37	Uprate line to full 212F conductor rating	5.0	3
Q399	Erwin-Selma 230 kV Line	Erwin 230 kV Sub-Benson PGI Tap	6.03	Uprate line to full 212F conductor rating, and uprate CT ratio at Erwin	3.0	3
Q399	Clayton Industrial – Selma 115kV Line	Smithfield-Selma	3.36	Redundant bus protection at Milburnie 230	3.0	4
	Total				**38.5**	4

The results in this study are dependent on assumptions regarding prior-queued interconnection requests and transmission plans. In particular, this request is Contingent upon the network upgrades described in Table 3 for prior-queued requests and Table 4 from the utility transmission plan. If any prior-queued requests drop out of the queue or other assumptions change, these study results **may change significantly**.

Table 3: Contingent Network Upgrades Assigned to Prior Requests

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Q398	Cumberland-Erwin 230kV line	New line	35	Construct new line with 6-1590 ACSR conductor	120	5
Q398	Cumberland-Clinton 230kV line	New line	35	Construct new line with 3-795 ACSS conductor	130	5
Q398	Clinton-Mount Olive 115kV line	Clinton-SREMC Hargrove POD, SREMC Hargrove POD-Faison Highway Industrial	6.9	Uprate line to full 212F conductor rating	3.5	4
Q398	Lee Sub-Mount Olive 115kV line	Mount Olive-Mount Olive West Tap, Mount Olive Tap-Mount Olive Industrial	3.5	Uprate line to full 212F conductor rating	1.8	3
Q398	Cumberland-Delco 230kV line	NA	NA	Uprate CT ratio at Cumberland sub terminal from 1200A to 1600A	0.1	2
Q398	Harris-Apex US#1 230kV line	New Hill – Apex US1	NA	Uprate 2000A switch to 3000A	0.5	2
Q380	Erwin - Fayetteville East 230kV line	All	23	Reconductor to 6-1590 ACSR	83.5	4
Q380	Fayetteville - Fayetteville DuPont SS 115kV line	Hope Mills Ch. St. – Roslin Solar	3	Reconductor to 3-1590 ACSR	8.4	3
Q380	Cape Fear - West End 230kV line	West End – Center Ch. – Sanford Garden St – Sanford US1	26	Reconductor to 6-1590 ACSR	89.7	4
Q380	Erwin - Fayetteville 115kV line	Fay Slocomb Tap – Beard - Wade	9	Reconductor to 3-1590 ACSR	27.2	3

Table 4: Contingent Network Upgrades in the Utility Transmission Plan

Assignee	Facility	Sections	Length (mi)	Upgrade	Cost Estimate ($M)	Time To Complete (years)
Utility	None					

3.2 Stability Analysis Results

A stability analysis was performed to determine the impact of the proposed generation addition on the DEP transmission system and other nearby generation. All queue requests, as well as nearby existing and prior-queued generation, were modeled and assumed to be operating at full output. The proposed plant was modeled considering the specific layout and number of generators (two 465 MVA gas-fired combustion turbine generators and one 575 MVA heat recovery steam generator). The model included representation of the proposed generator step-up transformers (8% @ 339/452/565 MVA for each CTG and 8% @ 468/624/780 MVA for the STG). The interconnection to the DEP transmission system was via three separate, radial 500kV transmission lines from the power island to the Cumberland 500kV switchyard, one for each generator.

Prolonged oscillations following system disturbances on the DEP Transmission System can occur under certain system conditions due to the minimal natural damping available. The installation of power system stabilizers (PSS) on the proposed generation is required to mitigate these oscillations. Therefore, the Customer will need to include a power system stabilizer with the excitation systems for all three proposed generating units. The PSS for the two CTs will be required to be enabled. This will require a tuning study and commissioning of the PSS for each CT prior to commercial operation. For the ST, the PSS would be disabled until needed in the future, so no tuning study or commissioning would be required initially. The installation of power system stabilizers for this new generation is consistent with the SERC Power System Stabilizer Guideline.

A representative set of faults was simulated to determine if there would be any adverse impact to the transmission system because of the proposed generation. The stability evaluation did not identify any stability related problems. All generators stayed on-line and stable for all simulated faults. If the Customer data changes from that provided, these results will need to be reevaluated.

3.3 Power Factor Requirements

DEP's Large Generator Interconnection Procedure (LGIP) requires the proposed generation to be capable of delivering the requested MW to the Point of Interconnection (POI) **at a 0.95 lagging power factor**. For analysis of the power factor requirement, the Customer-supplied data regarding generator capabilities and transformer impedances were used. The results of the analysis indicate that the proposed plant design **DOES MEET** the 0.95 lagging power factor requirement at the POI for the requested MW delivery level. Table 2 below summarizes the approved MW at the POI, along with the MVAR capability at the POI required to meet the 0.95 lagging power factor requirement at the POI.

Table 5: MW Approved and MVAR Capability Required at the POI and Minimum Capacitor Size Required to Meet Power Factor Requirements

DEP Generator Interconnection Queue No.	MW Requested	MW Approved at POI	MVAR Capability Required at POI
399	1235	1235	406

3.4 Short Circuit Analysis Results

A short circuit analysis was performed to assess the impact of the proposed generation addition on transmission system equipment capabilities. The analysis indicates that some short circuit equipment capabilities will be exceeded as result from the proposed generation additions and associated transmission upgrades. In particular, 3 breakers in the 230kV switchyard of the Cumberland 500kV substation need to be upgraded to 80kA. This assumes that all breakers installed in the Cumberland 230kV switchyard for Q398 are also rated to interrupt 80kA.

Location	Equipment	Count	Upgrade	Cost Estimate ($M)
Cumberland 500kV	230kV Breakers	3	Replacement	1.8

In addition, short circuit increases of at least 3% were tabulated at wholesale customer Points of Delivery (PODs) in the area. Wholesale customers have been notified of the impact and their Affected System Studies must be completed before Q399 can be completed.

The results of the short circuit study are based on Customer provided generation equipment data and location. Also, the prudent use of engineering assumptions and typical values for some data were used. If the units' technical data or interconnection points to the transmission system changes, the results of this analysis may need to be reevaluated.

3.5 Harmonics Assessment

No harmonics issues are expected for synchronous generators.

3.6 Interconnection of Customer's Generation

The point of interconnection for Queue #399 is the Cumberland 500kV Substation. The one-line is provided as Figure 1.

The customer should verify that the MVA ratings of their connecting lines are sufficient to accommodate delivering the total MVA output to the point of interconnection at the required 0.95 power factor.

3.7 Estimate of Interconnection Cost

Q399

The power island for Q399 is assumed to be approximately one (1) mile from the Cumberland 500 kV Substation. Three (3) 500 kV tie lines will be constructed from the power island to the Cumberland 500 kV Substation and terminated on new 500 kV buses at Cumberland. The terminations at Cumberland can be seen in Figure 1. The estimates include the assumption that DEP will acquire and use a portion of the property that the Customer will secure for the addition of the facility.

Tie Lines

Description:	DEP will construct three (3) 500 kV tie lines from the Q399 power island to the Cumberland 500 kV Substation and terminate them on the 500 kV buses at Cumberland (See Figure 1).
Estimated Cost:	$15,000,000

Total Interconnection Cost Estimate: **$15,000,000**

4 SUMMARY

This Generator Interconnection System Impact Study assessed the impact of interconnecting a new generation facility with requested summer/winter ratings of 1130/1235 MW. Power flow analysis found multiple overloading issues requiring long lead time network upgrades. Stability and power factor analyses found no issues. Short-circuit analyses by Affected Systems are still pending. Interconnection upgrades to the DEP Transmission System are necessary to accommodate Q399.

DEP will require approximately 48 months to complete the interconnection and network upgrades after a firm written agreement to proceed is obtained from the customer.

Power-flow	$38,500,000	
Stability	$0	
Short Circuit - Duke Energy	$1,800,000	
Short Circuit - Affected Systems	$tbd	
Interconnection	$15,000,000	
Total Estimate	$55,300,000	(plus any Affected System costs)

Study Completed by: Bill Quaintance
Bill Quaintance, PE, Duke Energy Progress

Reviewed by: Mark Byrd
Mark Byrd, PE, Duke Energy Progress

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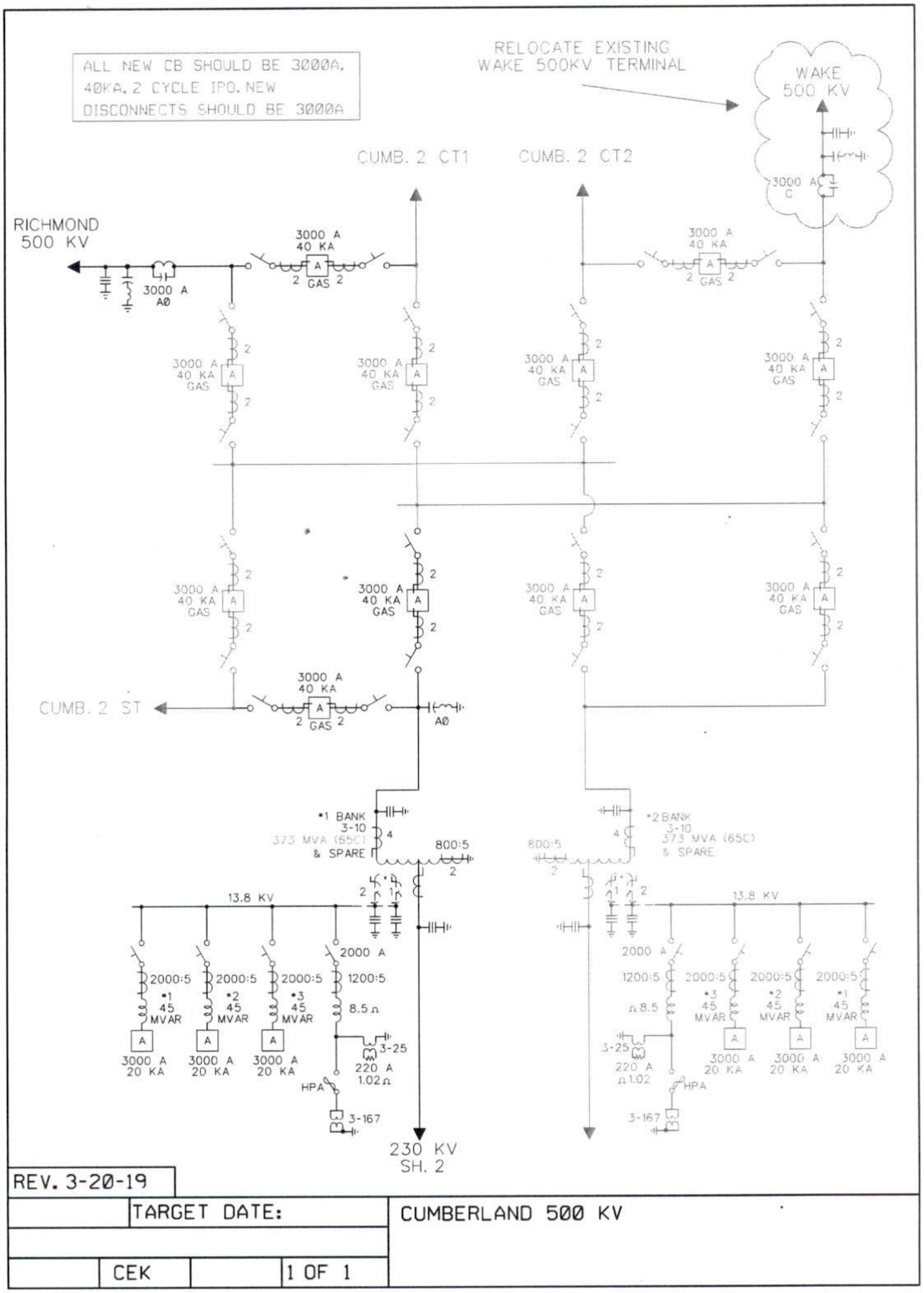
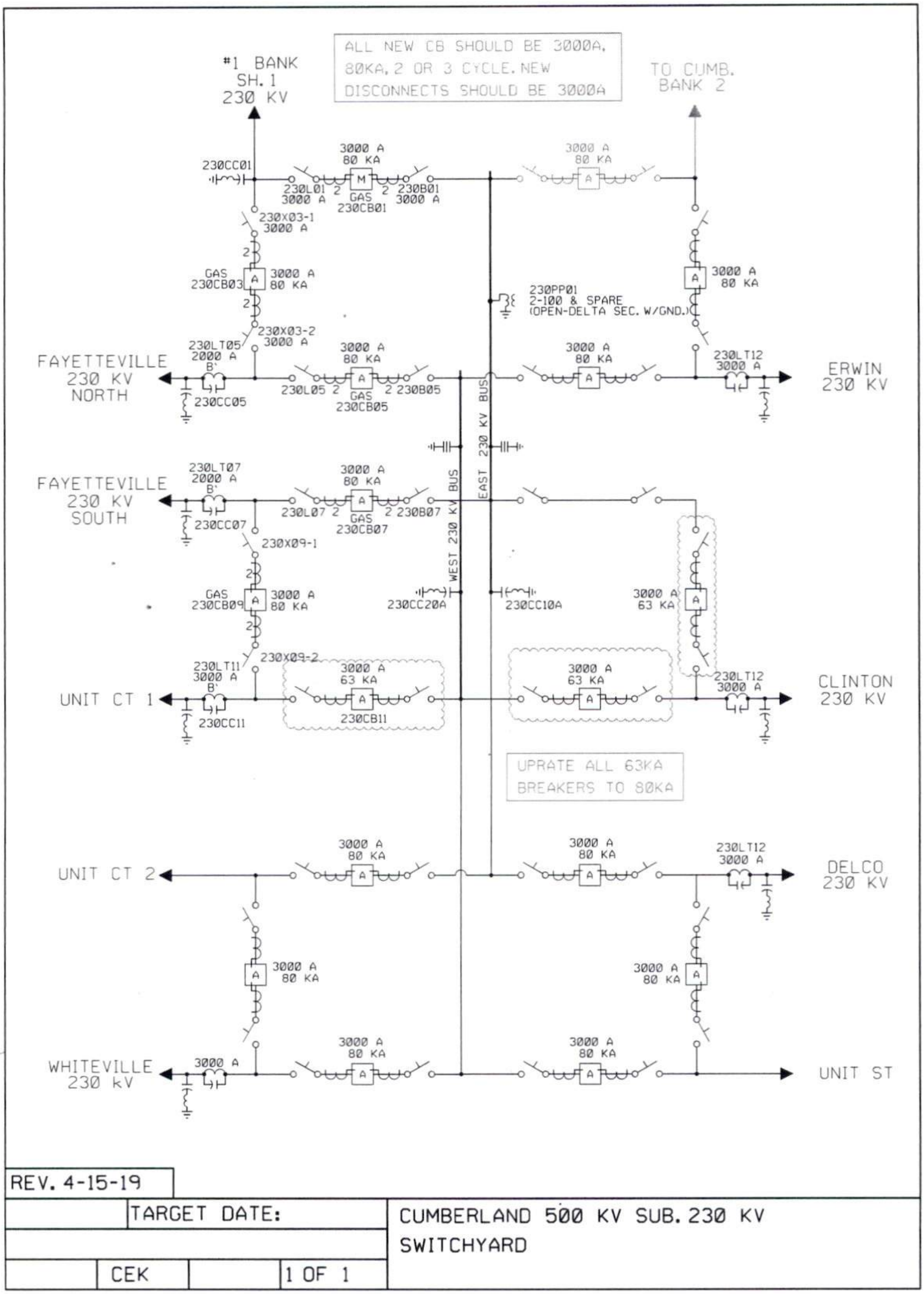
Dec 06 2019

APPENDIX I : FIGURES

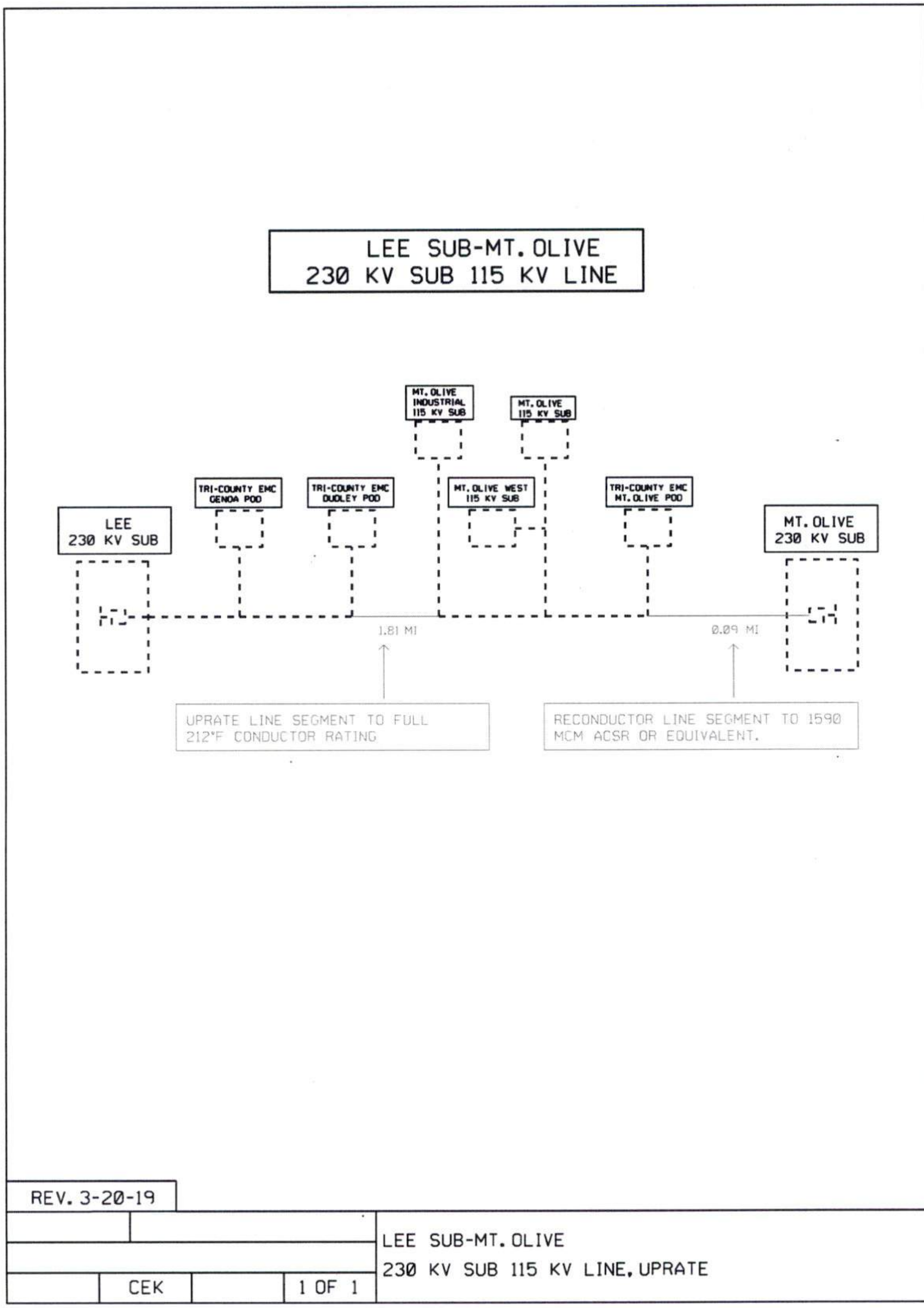
-Figure 1-



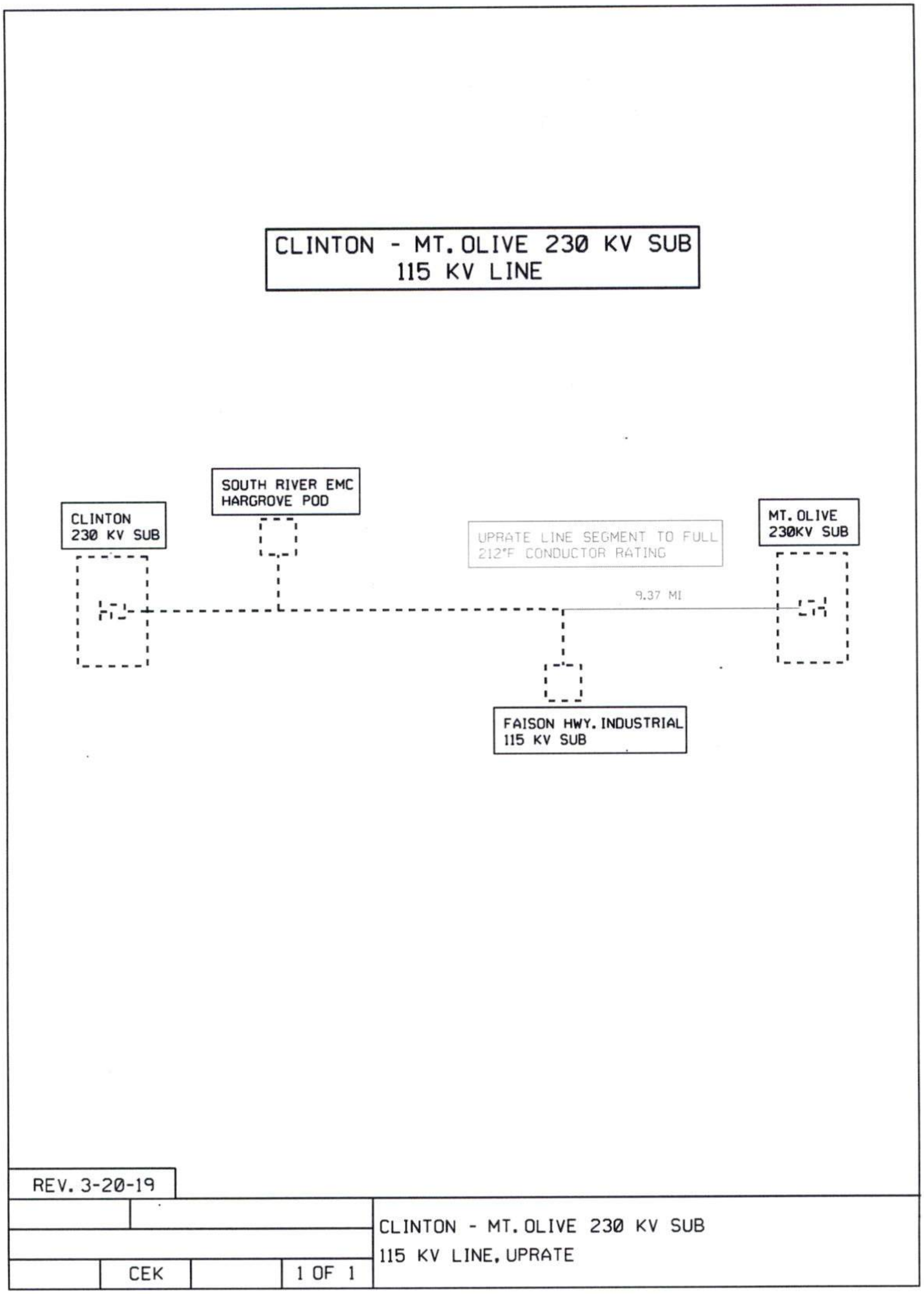
-Figure 2-


ALL NEW CB SHOULD BE 3000A, 80KA, 2 OR 3 CYCLE. NEW DISCONNECTS SHOULD BE 3000A
#1 BANK SH. 1 230 KV
TO CUMB. BANK 2
FAYETTEVILLE 230 KV NORTH
ERWIN 230 KV
FAYETTEVILLE 230 KV SOUTH
UNIT CT 1
CLINTON 230 KV
UPRATE ALL 63KA BREAKERS TO 80KA
UNIT CT 2
DELCO 230 KV
WHITEVILLE 230 kV
UNIT ST
WEST 230 KV BUS
EAST 230 KV BUS
230PP01 2-100 & SPARE (OPEN-DELTA SEC. W/GND.)
REV. 4-15-19
TARGET DATE:
CUMBERLAND 500 KV SUB. 230 KV SWITCHYARD
CEK
1 OF 1

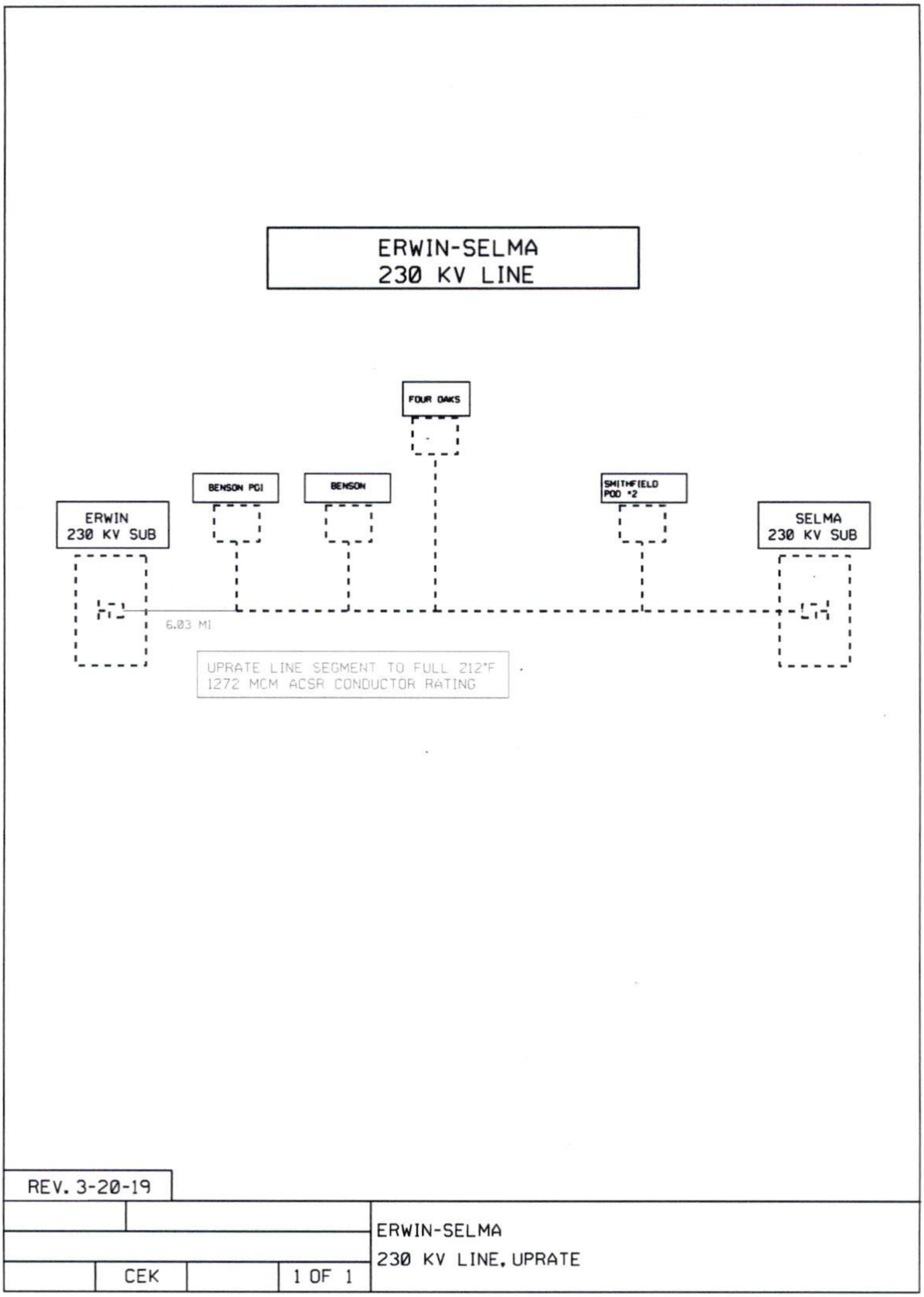
-Figure 3-


LEE SUB-MT. OLIVE
230 KV SUB 115 KV LINE
MT. OLIVE INDUSTRIAL 115 KV SUB
MT. OLIVE 115 KV SUB
TRI-COUNTY EMC GENOA POD
TRI-COUNTY EMC DUDLEY POD
MT. OLIVE WEST 115 KV SUB
TRI-COUNTY EMC MT. OLIVE POD
LEE 230 KV SUB
MT. OLIVE 230 KV SUB
1.81 MI
0.09 MI
UPRATE LINE SEGMENT TO FULL 212°F CONDUCTOR RATING
RECONDUCTOR LINE SEGMENT TO 1590 MCM ACSR OR EQUIVALENT.
REV. 3-20-19
CEK
1 OF 1
LEE SUB-MT. OLIVE
230 KV SUB 115 KV LINE, UPRATE

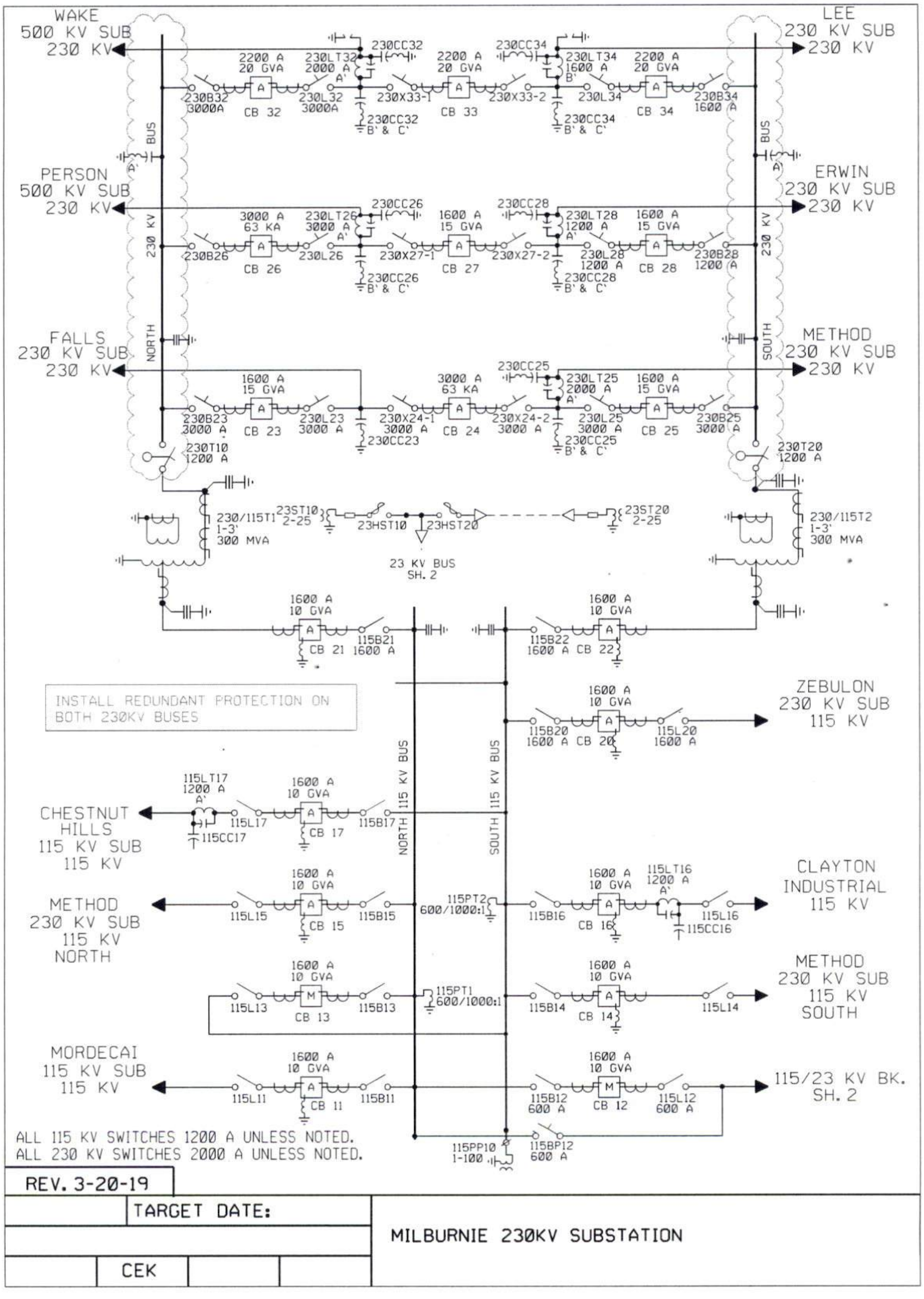
-Figure 4-


CLINTON - MT. OLIVE 230 KV SUB
115 KV LINE
SOUTH RIVER EMC
HARGROVE POD
CLINTON
230 KV SUB
UPRATE LINE SEGMENT TO FULL
212°F CONDUCTOR RATING
MT. OLIVE
230KV SUB
9.37 MI
FAISON HWY. INDUSTRIAL
115 KV SUB
REV. 3-20-19
CLINTON - MT. OLIVE 230 KV SUB
115 KV LINE, UPRATE
CEK
1 OF 1

-Figure 5-


ERWIN-SELMA
230 KV LINE
FOUR OAKS
BENSON PGI
BENSON
SMITHFIELD POD *2
ERWIN
230 KV SUB
SELMA
230 KV SUB
6.03 MI
UPRATE LINE SEGMENT TO FULL 212°F
1272 MCM ACSR CONDUCTOR RATING
REV. 3-20-19
ERWIN-SELMA
230 KV LINE, UPRATE
CEK
1 OF 1

-Figure 6-


WAKE
500 KV SUB
230 KV
LEE
230 KV SUB
230 KV
PERSON
500 KV SUB
230 KV
ERWIN
230 KV SUB
230 KV
FALLS
230 KV SUB
230 KV
METHOD
230 KV SUB
230 KV
230 KV NORTH BUS
230 KV SOUTH BUS
CB 32
CB 33
CB 34
CB 26
CB 27
CB 28
CB 23
CB 24
CB 25
230/115T1
1-3'
300 MVA
230/115T2
1-3'
300 MVA
23 KV BUS
SH. 2
INSTALL REDUNDANT PROTECTION ON
BOTH 230KV BUSES
NORTH 115 KV BUS
SOUTH 115 KV BUS
ZEBULON
230 KV SUB
115 KV
CHESTNUT
HILLS
115 KV SUB
115 KV
CLAYTON
INDUSTRIAL
115 KV
METHOD
230 KV SUB
115 KV
NORTH
METHOD
230 KV SUB
115 KV
SOUTH
MORDECAI
115 KV SUB
115 KV
115/23 KV BK.
SH. 2
CB 21
CB 22
CB 20
CB 17
CB 16
CB 15
CB 14
CB 13
CB 12
CB 11
ALL 115 KV SWITCHES 1200 A UNLESS NOTED.
ALL 230 KV SWITCHES 2000 A UNLESS NOTED.
REV. 3-20-19
TARGET DATE:
MILBURNIE 230KV SUBSTATION
CEK

Lawrence/Metz 1A
Exhibit 4
Docket No. EMP-105, Sub 0

DUKE ENERGY.

Stakeholder Discussion: Network Congestion Next Steps

November 9, 2018

Background: How did we get here?

- Duke continues to achieve nation-leading amounts of solar interconnections
  - For projects sized between 2 MW and 20 MW, Duke has interconnected more than twice the total amount of solar projects than the next closest state.
  - Duke has interconnected 9 times more 4-5 MW solar projects interconnected than the next closest state
  - Duke has ~190 2 MW standard offer projects committed in SC

Background: How did we get here?

- Duke has long communicated that there is limited capacity on its transmission network and that, due to the proliferation of solar resources in concentrated geographic areas, available network capacity was rapidly approaching exhaustion.
  - Existing transmission assets have a finite amount of capacity.
  - Once the transmission network capacity is fully consumed, network upgrades are required to accommodate additional generating facilities
- Both transmission and distribution connected solar projects have contributed to these congestion issues

Background: Areas of Congestion

- As previously communicated, the areas of most significant congestion at this time are in DEP's territory in southeastern NC and northeastern SC.
  - The congested area in DEP East has over 100 in-service or under construction solar generating facilities totaling 1,348 MW This includes:
    - 16 transmission-connected projects totaling 898 MW
    - 99 distribution-connected solar projects totaling 449 MW
    - Over 1,100 of MW remain in the queue (as of early 2017)
- Localized constraint areas also exist in DEC in both NC and SC
- As the penetration levels of solar continue to increase, there will be additional areas of congestion in both DEP and DEC service territory.

Background: What network upgrades are needed?

- The identified Network Upgrades to support interconnection of additional solar resources in this particular area consist primarily of re-conductoring transmission lines to increase capacity.
- Over 63 miles of transmission reconductoring will be required:
  - Cape Fear – West End 230kV line (~26.6 miles) and 4.4 miles to uprate
  - Erwin-Fayetteville East 230kV line (~23 miles)
  - Erwin-Fayetteville 115kV line (~8.7 miles)
  - Fayetteville – Faye DuPont 115kV line (~3.2 miles)
  - Rockingham – West End 230kV West line (uprate ~8 miles of line)

Background: How long will it take to design, engineer, procure and construct these network upgrades?

- Reconductoring this amount of transmission line is an enormous undertaking.
  - Rebuilding a line requires the line to be removed from service.
  - Line outages typically cannot be supported during peak load season (summer/winter) for the stability of the grid; therefore, work is limited to a 12 week spring season and a 12 week fall season
  - To expedite completion, multiple line crews will be involved on a single project in the 12 week seasons (spring & fall) intervals.
  - Current cost estimates--$200 million.
  - Current targeted completion date: End of 2022 (subject to change)

Background: Allocating cost of the network upgrades

- Cost responsibility for the upgrade has been assigned in accordance with the serial study process required under the NC and SC interconnection procedures and the FERC OATT.
- Work cannot begin until applicable Interconnection Agreement(s) have been executed.

Background: Impact on later-queued projects

- Until the identified Network Upgrades are placed in service, the other projects in the congested area cannot be interconnected in a safe and reliable manner in accordance with Good Utility Practice.
  - Once again, due to high penetration rates of solar resources, there is insufficient transmission capacity to absorb incremental solar generating facilities.
  - Constraints also prevent the interconnection of distribution-connected projects.

Options for State Jurisdictional Projects in Congested Area

- What is the most equitable process/next steps for state-jurisdictional projects that cannot interconnect until these particular Network Upgrades have been placed in service?
  - Important to note that in many cases, the impacted projects are not only interdependent on the identified network upgrades, but also have identified distribution level interdependencies that must be resolved.

Options for State Jurisdictional Projects in Congested Area

- **Option #1**: Despite overall interdependency issues, continue to process Interconnection Requests through to SIS Report for all projects that would otherwise be Project As and Project Bs from a distribution system perspective only and all projects that would be Project Bs from a transmission system perspective.
- SIS Report will be "contingent" on identified assumptions about earlier queued projects absorbing Network Upgrades.
- Benefit of this approach is providing more information to projects regarding potential costs to make interim determination on viability .
  - Projects still cannot interconnect until Network Upgrades are placed in service.
- FS is not worth the resources since any results would need to be re-assessed at a later date to ensure accuracy.
- No financial security required

Options for State Jurisdictional Projects in Congested Area

- **Option #2**: Re-designate all impacted projects as "on-hold" on the basis of the identified transmission-level interdependencies.
- Would allow Duke study resources to be devoted to projects outside of congested areas to proceed with quicker and simpler paths to interconnection.
- Study resources would not be allocated to perform "contingent" SIS that might need to be re-performed entirely if any identified assumptions turn out to be incorrect.
- Impacted projects will not receive details about viability of the distribution interconnection. Could wait "on-hold" for 5 years only to learn of distribution constraints such as LVR, voltage, or transformer capacity.