BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. EMP-105, SUB 0

Testimony of Evan D. Lawrence and
Dustin R. Metz
On Behalf of the Public Staff
North Carolina Utilities Commission

December 6, 2019

Q. MR. LAWRENCE, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Evan D. Lawrence. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix A to my testimony.

Q. MR. METZ, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix B to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our testimony is to make recommendations to the Commission on the request for a Certificate of Public Convenience and Necessity (CPCN) filed by Friesian Holdings, LLC (Applicant, or Friesian), on May 15, 2019, to construct a 70 megawatt AC (MW_{AC}) solar photovoltaic (PV) merchant electric generating facility in Scotland County, North Carolina (the Facility).

The purpose of our testimony is as follows:

1. To discuss the compliance of the application with N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-63;
2. To discuss any concerns raised by the application; and
3. To make a recommendation regarding whether the Commission should grant the requested certificate.

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION FACILITY PROPOSED TO BE CONSTRUCTED BY THE APPLICANT.

A. The Applicant proposes to construct a 70 MW_{AC} solar PV electric generating facility in Scotland County, North Carolina. The Facility will utilize single axis tracking, ground mounted, solar PV modules.

Approximately 290,000 solar PV modules will be installed along with thirty 2.5 MW inverters. A 34.5 kV collector substation will be constructed adjacent to an existing Duke Energy Progress (DEP) 230 kV transmission line. The Applicant will lease approximately 544 acres for the Facility. The point of interconnection (POI) will be located at a substation to be owned by the Applicant.

In its initial application, the Applicant indicated that the anticipated construction cost of the Facility is approximately $100 million, not inclusive of Network Upgrades. The Network Upgrades for this Facility are estimated to cost approximately $223.5 million. The expected life of the Facility is a minimum of twenty years with an expected commercial operation date (COD) of December 2023.

Q. HAS THE APPLICANT COMPLIED WITH THE COMMISSION'S FILING REQUIREMENTS?

A. Yes. The application for the Facility was filed on May 15, 2019 along with the accompanying exhibits and testimony of Brian C. Bednar. On May 30, 2019, the Applicant filed enlarged, high resolution maps showing additional details not included in the original map.

On May 31, 2019, the Public Staff notified the Commission that it considered the application to be complete and requested that the Commission issue a procedural order setting it for hearing. On June 13, 2019, the Commission issued an Order requiring public notice, scheduling a public hearing on August 15, 2019, for the purpose of receiving public witness testimony, an evidentiary hearing on August 27, 2019, for the purpose of receiving expert witness testimony, and addressing other necessary procedural matters.

On July 23, 2019, the Applicant filed an Affidavit of Publication, stating the publication was completed on July 17, 2019. No complaints by members of the public have been received.

Q. WHAT ADDITIONAL PROCEDURAL MATTERS HAVE BEEN TAKEN SINCE THAT TIME?

A. On August 5, 2019, in response to a motion by the Public Staff, the Commission issued an *Order Suspending Procedural Deadlines and Allowing Filing of Pre-Hearing Briefs,* suspending the procedural schedule established pursuant to the Commission's June 13 Order and allowing the parties to file briefs addressing certain issues.

On August 26, 2019, the Applicant, DEP, the Public Staff, and the North Carolina Clean Energy Business Alliance (NCCEBA) filed briefs; on September 9, 2019, the Applicant, DEP, the Public Staff, and NCCEBA, jointly with the North Carolina Sustainable Energy Association (NCSEA), filed reply briefs.

On October 3, 2019, the Commission issued an *Order Scheduling Oral Arguments* in this proceeding for the purpose of receiving arguments from the parties addressing the issues noted in the

Commission's August 5 Order, and, additionally, the questions of whether and, if so, how the July 14, 2017 decision of the U.S. Court of Appeals for the D.C. Circuit in Orangeburg v. FERC, 862 F.3d 1071 (2017), applies to the issues noted in the Commission's August 5 Order.

On October 21, 2019, this matter came before the Commission for oral argument as scheduled.

On October 25, 2019, the Commission issued an *Interlocutory Order on Legal Issues, Scheduling Hearing, Allowing Filing of testimony, and Establishing Discovery Guidelines (Interlocutory Order),* in which the Commission stated its agreement with the arguments of DEP and the Public Staff that "the Commission may consider the costs for future network upgrades that are required to accommodate a proposed electric generating facility when considering an application for a CPCN pursuant to N.C .Gen. Stat. § 62-110.1 and Commission Rule R8-63." In the Interlocutory Order, the Commission also directed the Applicant to file Supplemental testimony on or before November 26, 2019, the Public Staff and other intervenors to file testimony on or before December 6, 2019, the filing of rebuttal testimony by the Applicant on or before December 13, 2019, and to set the matter for evidentiary hearing on December 18, 2019.

On November 26, 2019, the Applicant filed the supplemental direct testimony of Rachel Wilson, Brian Bednar, and Charles Askey.

Q. HAS THE STATE CLEARINGHOUSE COMPLETED ITS APPLICATION REVIEW?

A. No. At this time, the State Clearinghouse has not filed a letter in this docket in response to the Commission's June 13, 2019 Order.

Q. HAS THE APPLICANT PREVIOUSLY BEEN GRANTED A CPCN?

A. Yes. On November 7, 2016, the Commission granted a CPCN to Friesian Holdings, LLC, for a 75 MW solar PV project in Docket No. SP-8467, Sub 0. On August 2, 2018, the Applicant requested to amend the CPCN and alter the footprint of the site. The footprint and location for the CPCN granted on November 7 is substantially similar to the footprint and location for this project. The previous CPCN was granted under Commission Rule R8-64, which is for facilities seeking the benefits provided to a qualifying small power producer, or qualifying facility (QF). The CPCN in Docket No. SP-8467, Sub 0, was relinquished by the Applicant, however, with the filing of the CPCN application as a merchant plant under Commission Rule R8-63 in this docket.

PUBLIC CONVENIENCE AND NECESSITY

Q. PLEASE BRIEFLY SUMMARIZE YOUR UNDERSTANDING OF WHAT SHOULD BE CONSIDERED IN DETERMINING WHETHER

AN APPLICANT FOR A MERCHANT FACILITY HAS SUFFICIENTLY DEMONSTRATED A NEED FOR ITS PROPOSED FACILITY?

A. In Docket No. EMP-92, Sub 0, the Commission held that it is reasonable for the Commission to require substantial evidence of the need for a merchant generating facility in the State and/or region, as required by Commission Rule R8-63(b)(3). The Commission discussed its prior holdings in Docket No. E-100, Sub 85, in which it found that a flexible standard for demonstrating need was appropriate, but that a Power Purchase Agreement (PPA) or other contractual agreement was not necessary.[1]

The Commission further weighed the following factors regarding the need for the proposed facility:

> (1) the standard of need for a merchant plant is different from the standard of need for a public utility electric generation facility; (2) DEC's and DEP's IRPs project the need for significant electric load growth in the Carolinas; and (3) [the Applicant] has demonstrated expertise in accurately evaluating wholesale market needs and negotiating with wholesale buyers to meet those needs.[2]

Q. WHAT STEPS HAS THE APPLICANT TAKEN TO DEMONSTRATE A NEED FOR THE PROPOSED FACILITY?

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[1] In the Matter of Investigation of Certification Requirements for New Generating Capacity in North Carolina, Docket No. E-100, Sub 85, *Order Adopting Rule*, at pp. 6-7 (May 21, 2001).

[2] In the Matter of Application of NTE Carolinas II, LLC, for a Certificate of Public Convenience and Necessity to Construct a 500-MW Natural Gas-Fueled Merchant Power

A. The Applicant has entered into a PPA for the sale of energy and renewable energy certificates (RECs), with the North Carolina Electric Membership Corporation (NCEMC). The Applicant cites the need of RECs for compliance with the state's renewable energy goals and states that "[t]he Facility will provide a significant amount of RECs for use by the NCEMC to demonstrate compliance with Senate Bill 3."

On July 18, 2019, NCEMC filed comments expressing its support for issuance of the CPCN for the Facility, and indicating that the Facility will help achieve multiple goals. These goals include supplying members with affordable, reliable, and safe power, assisting with REPS compliance, and "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."

Q. DO YOU AGREE THAT SIGNING A PPA SUFFICIENTLY DEMONSTRATES A NEED FOR THE FACILITY?

A. Not necessarily. Execution of a PPA demonstrates that a facility (has found an off-take for the production (energy generation and, in this case, RECs) that satisfies a monetary return on investment to investors, while also striking a balance of the delivered commodity

Plant in Rockingham County, North Carolina, Docket No. EMP-92, Sub 0, *Order Approving Certificate with Conditions*, at pp. 16-17 (January 19, 2017).

(energy or capacity) cost ($/MWh or $/MW) to the purchaser. An executed PPA does demonstrate at least in part the potential viability of the project, but having an executed PPA is not, in and of itself, a sufficient criterion on which to base a recommendation for approval or disapproval of a CPCN. For example, in Docket No. EMP-92, Sub 0, Mr. Metz testified and recommended approval of a merchant plant that did not have a signed PPA in place at the time of the review of the application.[3] The specific facts and circumstances surrounding the demonstration of need are evaluated on a case-by-case basis.

Q. DID THE APPLICANT ALSO PRESENT ADDITONAL INFORMATION REGARDING NEED FOR THE FACILITY IN THE STATE AND/OR REGION?

A. Yes. Friesian witness Wilson presented the analysis that she conducted on behalf of NCSEA in reviewing the 2018 Integrated Resource Plans (IRPs) filed by Duke Energy Carolinas, LLC (DEC) and DEP in Docket No. E-100, Sub 157. Relying on the report entitled "North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan," Ms. Wilson testified that "that the least expensive long-term resource plan for North Carolina ratepayers is one that adds increasing amounts of solar and storage resources over the 15-year analysis period from 2019 to 2033."[4] She

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[3] See discussion of PPA negotiations in Initial Testimony of Michael C. Green, p. 8 lines 27-30, July 29, 2016.

[4] Testimony of Rachel Wilson at 2.

further testified that even including the likely long-term transmission investments necessary to incorporate higher penetrations of solar, ratepayers will realize substantial savings relative to the IRPs proposed by DEC and DEP that rely heavily on new natural gas generation.

Q. DOES THAT FACT THAT DEP'S IRP INDICATES A CAPACITY NEED ON ITS SYSTEM SUFFICIENTLY DEMONSTRATE A NEED FOR THE FACILITY?

A. No, utilization of an IRP as a sole determination for establishing the need for any individual capacity addition is an incorrect usage and interpretation of the IRP process. In other words, one cannot assume that any generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold. The IRP is a capacity expansion model used to solve for system objectives subject to multiple constraints, and stressed through different sensitivities to meet long-term load in the most economical manner.[5]

The DEP system, where the Facility is proposed to be constructed, is currently winter peaking and planning. As a preliminary matter, the Facility is a merchant facility that proposes to sell its output to NCEMC, so its output is not proposed to meet any of DEP's future

[5] N. C. Gen Stat. § 62-2(a)(3a).

capacity needs. New capacity needs identified in the IRP are not absolute, and are subject to change in one or more of the following categories: (i) generation type, (ii) total MW of generation, and (iii) year of need. The need for generation set forth in DEP's IRP is largely a result of the winter planning scenario.

This reality is best illustrated by the most recent DEP IRP update filed on October 29, 2019, in Docket No. E-100, Sub 157, Load, Capacity, and Reserve Table 9-A (Winter) and Table 9-B (Summer). As seen on line 21 of both Tables, it is the winter planning scenario that is requiring new generation to be added to DEP's system. As new generation is added to meet winter demand, the reserve margins in the summer are nearly double those found in the winter (17.1% - 22.4% winter vs. 25.2% - 37.1% summer throughout the planning horizon). This misalignment of reserve margins is driven, at least in part, by the historical interconnection of significant renewable generation on DEP's system.[6] This issue has been discussed extensively in numerous other dockets, including the IRPs, avoided cost proceedings, and interconnection dockets.

One of the limitations noted by the Public Staff and other parties in past IRP proceedings is the inability of intermittent, non-dispatchable

[6] DEP's expected winter peak load in 2020 is 14,522 MW, combined with an estimated 3,005 MW of solar nameplate capacity. This results in 21% solar penetration albeit not coincident to the peak hour. The summer peak load is slightly less than the winter peak in the same year and results in a 23% solar penetration. See DEC and DEP 2019 IRP Update Reports in Docket No. E-100, Sub 157, Table 8 (DEC), and Table 9 (DEP).

renewable facilities to produce energy when needed during winter peak hours. Historically, solar facilities in North Carolina are able to produce only 3% of their total nameplate rating at the time of the winter coincident peak load.[7] DEP's IRP shows a need for dependable capacity to meet winter peak loads. A generation resource such as that proposed by Friesian in this case is able only to minimally contribute to winter morning peak loads and provide limited value to grid operators.

Q. THE APPLICANT HAS CITED OTHER PLANNED GENERATION IN DEP'S IRP AS JUSTIFICATION FOR THE NEED FOR CAPACITY ADDITIONS. DOES IDENTIFIED GENERATION IN THE IRP ALWAYS MATERIALIZE?

No. Identified new capacity additions in the IRP frequently move due to the dynamics of changing conditions, including load forecast uncertainty. The 2016 IRP identified 1,221 MW (winter rating) of combined cycle (CC) generation in December of 2021, as well as a subsequent combustion turbine (CT) the following year. By the time of the 2018 IRP, the need for the CC plant had shifted out four years to 2025 and the CT had shifted out six years. In addition, the 2016 IRP assumed retirement of the Robinson Nuclear Station, but by the filing of the 2018 IRP, it was no longer scheduled for retirement.

[7] See March 7, 2019, Comments of the Public Staff on DEC/DEP IRPs in Docket No. E-100, Sub 157, at 88.

Similar trends also are observable between the 2014 IRP and the 2018 IRP. In 2014, a smaller CC with a winter nameplate rating of 907 MW was identified for a 2021 in-service date, versus the 2018 IRP which called for a CC with a winter nameplate rating of 1,341 MW in 2025.

The IRP is a planning tool and as with any plan, or projection, there is increasing uncertainty with each year in the future the model attempts to predict based on changes in load growth, technologies, policies, electric and natural gas transmission constraints, and other variables. The generation resource, the needed capacity, and the year in which the need is identified is dynamic, and only when the utility seeks to construct new generation capacity and is required to obtain a CPCN from the Commission under N.C. Gen. Stat. § 62-110.1 do the timing and characteristics of the facility definitively take shape. It is also our understanding that the CC plants identified in DEP's IRP are dependent upon completion of the Atlantic Coast Pipeline (ACP), the timing and status of which is still the subject of litigation.[8]

[8] "U.S. Supreme Court will weigh in on a key Atlantic Coast Pipeline permit." Raleigh News & Observer, October 4, 2019. Online at: https://www.newsobserver.com/news/politics-government/article235795832.html.

NETWORK UPGRADES

Q. PLEASE EXPLAIN WHAT IS CONSIDERED A NETWORK UPGRADE.

A. Network Upgrades generally include any additions to the capacity of the Company's distribution or transmission network to accommodate new load demands or the interconnection of a generating facility. For purposes of this testimony, we will use the term "Network Upgrades" to encompass both "Network Upgrades" as defined in the Federal Energy Regulatory Commission (FERC) Joint Open Access Transmission Tariff, or FERC OATT, and "Upgrades" as defined under the North Carolina Interconnection Procedures ("NCIP").

Q. HAS DEP PREVIOUSLY INDICATED THAT NETWORK UPGRADES ARE NECESSARY IN ORDER TO INTERCONNECT ADDITIONAL GENERATION TO THE ELECTRIC GRID IN THE GENERAL AREA WHERE FRIESIAN IS PROPOSED TO BE CONSTRUCTED?

A. Yes. In his November 19, 2018, testimony in Docket No. E-100, Sub 101, DEP witness Gary Freeman stated that:

> DEP has determined that significant transmission network upgrades will be needed to interconnect additional generation in the southeastern North Carolina area of DEP East. These upgrades have been triggered by the cumulative amount of generation located in southeastern North Carolina, where the need for the increased generation to flow northwest toward the large load centers, such as Wake County, has caused several transmission

> line segments to now reach their power flow limits. This congested area in DEP East has over 100 in-service or under construction solar generating facilities totaling 1,347 MW. This includes 16 transmission-connected projects totaling 898 MW and 99 distribution-connected solar projects totaling 449 MW. Notably, there are over 3,500 of MW of additional generating facilities in the queue that are seeking to interconnect in this congested area.[9]

Witness Freeman identified transmission upgrades on five specific lines needed to support the interconnection of additional solar resources, including re-conductoring of over 63 miles of transmission lines to increase capacity. Mr. Freeman indicated in 2018 that these upgrades would cost in excess of $200 million dollars.

Q. PLEASE PROVIDE A SUMMARY OF THE NETWORK UPGRADE ESTIMATES PRODUCED BY DEP.

A. DEP's initial Facilities Study[10] report to the Applicant, dated October 17, 2017, identified upgrades to six separate transmission lines totaling approximately 73 miles, with an estimated Network Upgrade cost of $112 million. Friesian and DEP executed a Large Generator Interconnection Agreement (LGIA) on June 21, 2019, and while the scope of work did not change, the estimated cost of the Network Upgrades increased to approximately $223.5 million due to continued revisions to the estimate and steps, such as scheduling

[9] Direct Testimony of Gary R. Freeman in Docket No. E-100, Sub 101, at 20; November 19, 2018.

[10] NCIP Section 4.4.4 states "The Facilities Study Report shall specify and estimate the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the System Impact Studies and to allow the Generating Facility to be interconnected and operated safely and reliably."

multiple crews during the truncated timeline to ensure that the requested December 2023 in-service date can be met.

Q. HAVE ANY OF THESE TRANSMISSION LINE UPGRADES BEEN PROPOSED AS A RELIABILITY PROJECT THROUGH THE NORTH CAROLINA TRANSMISSION PLANNING COLLABORATIVE?

A. No. These transmission lines were not previously identified as needing upgrades due to reliability issues in any of the reports issued by the North Carolina Transmission Planning Collaborative (NCTPC) because the LGIA had not been executed at the time of study evaluations. It is our understanding, however, that because the LGIA between Friesian and DEP has now been executed, the Network Upgrades associated with the Friesian project will be added to the NCTPC 2020 Transmission Plan, consistent with its treatment of other generation being added to the systems of the NCTPC participants.

Q. DID THE PROJECTED COMPLETION DATE FOR FRIESIAN CHANGE BETWEEN THE FACILITIES STUDY AND THE EXECUTION OF THE LGIA?

A. No. The Applicant initially built contingencies into its own construction timeline, and requested an in service date that would have accommodated the timeline DEP needed to complete the system upgrades. DEP also removed some contingencies from its own timeline to help accommodate the schedule. Because much of the work required to upgrade the transmission system can only occur during 12 weeks in the spring and fall, a single weather event, such as a hurricane or late snow or ice storm, has the potential to delay this project for several months.

Q. DID FRIESIAN'S RECLASSIFICATION FROM A QUALIFYING FACILITY TO A MERCHANT PLANT CHANGE ANY OF THE REQUIRED UPGRADES?

A. No, but as a QF, the facility would be subject to the cost allocation rules under the NCIP, and as such, would be responsible for payment of interconnection costs and all network upgrade costs it imposes on the utility. As a merchant plant, it is subject to FERC–jurisdictional interconnection procedures and cost allocation rules under Duke's FERC OATT.

Q. ARE RETAIL RATEPAYERS RESPONSIBLE FOR ANY NETWORK UPGRADE COSTS FOR INTERCONNECTION REQUESTS UNDER THE NCIP?

A. No. Pursuant to Section 5.2 of the standard North Carolina Interconnection Agreement for State-Jurisdictional Generator Interconnections, included as Appendix A to the NCIP "[u]nless the Utility elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, on-going operations, maintenance, repair, and replacement shall be borne by the Interconnection Customer."

Q. AS A MERCHANT PLANT, HOW WILL THE TRANSMISSION NETWORK UPGRADE COSTS BE PAID?

A. The Applicant is required to pay for the cost of the Interconnection Facilities and Network Upgrades assigned to it under the terms of the Friesian LGIA. However, once the Facility achieves commercial operation, DEP is obligated to refund to Friesian the cost of the Network Upgrades (currently estimated at approximately $223.5 million) plus interest at the FERC interest rate (approximately $25 million). Pursuant to Appendix A of the LGIA, these refunds would be made "either in the year immediately preceding the Transmission Provider's North Carolina retail rate case next occurring after the achievement by Interconnection Customer of the Commercial Operation Date or by 12/31/2023."[11]

Q. WHAT POTENTIAL IMPACT WILL THIS REPAYMENT HAVE ON DEP'S RETAIL RATEPAYERS?

A. Under Commission Rule R8-63(a)(2), the construction costs of the merchant plant do not qualify for inclusion in the rate base of a public utility. However, the costs associated with Network Upgrades to DEP's transmission system to accommodate the merchant plant Network Upgrade costs required are related to DEP transmission system, and as such, when Friesian is repaid, the cost of the Friesian

[11] See Amendment 1 to the Standard Large Generation Interconnection Agreement between Friesian and DEP dated June 21, 2019.

Network Upgrades (and interest) will become a capital asset in rate base. Consistent with the cost allocation mechanisms in Duke's OATT, the resulting revenue requirement (including the depreciation expense, O&M costs, a calculation rate of return on plant-in-service and interest charges) will be recovered from North Carolina retail customers through base rates (approximately 60%), South Carolina retail customers through base rates (approximately 10%) and wholesale customers through the FERC transmission formula rate (approximately 30%).[12] Assuming the $223.5 million in estimated network upgrade costs is correct, DEP projects an estimated 0.5% increase on North Carolina retail rates and an estimated 11% increase on wholesale transmission rates.[13]

Q. DOES THE PUBLIC STAFF BELIEVE THAT INCURRING SUCH A SIGNIFICANT COST ASSOCIATED WITH INTERCONNECTING THE FACILITY IS IN THE PUBLIC INTEREST?

A. N.C. Gen. Stat. § 62-110.1(d) states: "In acting upon any petition for the construction of any facility for the generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical electric service." The Public Staff does not believe

[12] Initial Pre-Hearing Brief of DEP in Docket No. EMP-105, Sub 0, at pp. 6-7. (August 26, 2019)

[13] Id. at 7.

that this facility meets the statutory requirement for economical electric service.

Q. HAS THE PUBLIC STAFF EVALUATED UPGRADE COSTS IN PREVIOUS CPCNS?

A. Yes, we have.

Q. PLEASE PROVIDE EXAMPLES OF PREVIOUSLY EVALUATED UPGRADE COSTS?

A. Looking at utility and merchant CPCNs reviewed over the past five years, the Pubic Staff reviewed system upgrade costs for proposed generation facilities in Docket No. EMP-92, Sub 0 (NTE Reidsville), Docket No. E-2, Sub 1089 (Asheville CC), Docket No. E-7, Sub 1134 (Lincoln County CT), Docket No. EMP-93, Sub 0 (Wilkinson Solar), Docket No. EMP-101, Sub 0 (Edgecombe Solar), Docket No. EMP-103, Sub 0 (Albemarle Beach Solar), and Docket No. EMP-104, Sub 0 (Fern Solar). The relevant discovery from the NTE Reidsville case is appended to this testimony as **Lawrence/Metz Confidential Exhibit 1**. In addition, the testimony filed in the Lincoln County CT case identified Public Staff concerns with specific transmission related costs.[14] In the cases of Wilkinson Solar, Edgecombe Solar, Albemarle Beach Solar, and Fern Solar, these projects were proposed to be sited in Dominion Energy North

[14] E-7 Sub 1134, Testimony of Dustin R. Metz, p. 8 and 12-13.

Carolina's service territory and subject to the PJM Open Access Transmission Tariff, under which cost responsibility for Network Upgrades are borne by the interconnection customer, and are generally not eligible for reimbursement by either PJM or DENC.[15]

Q. WHAT IS THE APPROPRIATE WAY TO EVALUATE TRANSMISSION UPGRADE COSTS?

A. We believe an appropriate way to evaluate the reasonableness of such costs is on the basis of levelized cost of transmission (LCOT). These costs are presented in terms of \$/MWh and calculated by dividing the annualized cost of the transmission assets over the typical transmission asset lifetime by the expected annual generator output in MWh. The LCOT is a useful analytical tool to evaluate network upgrade costs across and within generation technologies. It does not include operations and maintenance costs or revenue requirements. It is also important to note that these costs are based on historical projects, many of which were likely connected to available capacity and may have required relatively minimal system upgrades. Thus, they are a guide for historical LCOT; varying assumptions can be made regarding where the LCOT will be for solar projects or any generation type in the future.

[15] PJM OATT Section 217: Cost Responsibility for Necessary Facilities and Upgrades. Online at: https://pjm.com/directory/merged-tariffs/oatt.pdf, last accessed December 5, 2019.

Q. ARE THE NETWORK UPGRADE COSTS ASSOCIATED WITH THE FRIESIAN PROJECT EXCESSIVE COMPARED TO OTHER SOLAR PROJECTS ACROSS THE COUNTRY?

A. Based on the Public Staff's investigation, it appears so. A 2019 study[16] by Lawrence Berkeley National Laboratory (LBNL Study) reviewed interconnection cost studies to place them in perspective nationwide. The LBNL Study, attached as **Lawrence/Metz Exhibit 2,** compiled transmission upgrade costs associated with 303 generation projects reported in MISO's interconnection queue as of 2019,[17] amounting to 49 GW, and 338 generation projects reported in PJM's interconnection queue as of 2019,[18] amounting to 64 GW. They also reviewed 2,399 constructed projects, amounting to 148 GW, that were recorded by EIA Form 860 from 2005-2012. The LBNL Study uses publicly available interconnection studies to calculate the costs associated with bulk transmission upgrades (similar to the term "Network Upgrades" as used in this testimony)

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[16] Gorman, W., Mills, A., & Wiser, R. (2019). Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy. *Energy Policy, 135.* DOI: https://doi.org/10.1016/j.enpol.2019.110994. Preprint version accessed at http://eta-publications.lbl.gov/sites/default/files/td_costs_formatted_final.pdf.
The Public Staff also attended a webinar discussing the study on November 13, 2019.

[17] The MISO dataset originally contained 2,209 projects; 1,255 withdrawn projects were removed, and of the remaining 954 projects, 303 had public reports of interconnection costs.

[18] The PJM dataset originally contained 4,152 projects; 2,467 withdrawn projects were removed, and of the remaining projects, 338 had "reliable" public reports of interconnection costs.

and point of interconnection (POI) upgrades necessary to connect these resources.

Table 1 below shows the results for the solar projects studied in each jurisdiction, alongside the Friesian project. While individual projects within the MISO, PJM, and EIA dataset may have been assigned upgrade costs higher than the average, it is clear that the Friesian project upgrades are significantly higher than those projects reviewed in the LBNL Study. The Public Staff emphasizes that the upgrade costs found in the LBNL Study are being used here as a guide to help put the Friesian network upgrade costs in context.

Table 1

Project	**Friesian[19]** (a)	**MISO (Solar)** (b)	**PJM (Solar)** (c)	**EIA (Solar)** (d)
Nameplate (MW_{AC})	70	3,277	10,057	2,187
Network Upgrades ($M)	$ 223	$ 180	$ 1,170	$ 220
Network Upgrades ($/kW)	$ 3,186	$ 56	$ 116	$ 103
LCOT ($/MWh)	$ 62.94	$ 1.56	$ 3.22	$ 2.21

Notes
(a) For Friesian, Network Upgrades represent estimated costs from LGIA. Projected capacity factor is from the CPCN application, and 0.4% annual degradation is assumed. To ensure parity with the study results, we assume a 4.4% discount rate and a 60-year transmission asset life for the LCOT calculation.
(b) From Table 2 of the LBNL Study, representing 33 solar projects totaling 3,277 MW.
(c) From Table 3 of the LBNL Study, representing 134 solar projects totaling 10,057 MW.
(d) From Table 4 of the LBNL Study, representing 304 solar projects totaling 2,187 MW.

[19] Friesian has estimated a 28% annual capacity factor for a single axis tracking system. Any decrease in the capacity factor will increase the LCOT.

Q. ARE THE NETWORK UPGRADE COSTS ASSOCIATED WITH THE FRIESIAN PROJECT HIGH COMPARED TO OTHER PROJECTS IN NORTH CAROLINA?

A. Yes. Table 2 below compares the Friesian project with two merchant plant projects for which the Commission issued CPCNs in the past five years (NTE Kings Mountain[20] and NTE Reidsville,[21] both natural gas-fired combined cycle plants), along with the estimated upgrade costs associated with Q398, a projected future combined cycle plant in DEP's FERC Interconnection Queue.[22] Q398 is not dependent upon any of the upgrades assigned to Friesian. The results of the LBNL Study specific to natural gas generators in PJM are also presented; the LCOT of combined cycle plants is generally lower than a solar plant due to differences in capacity factors. However, the difference in upgrade costs on a $/kW basis of recently investigated merchant plants and the Friesian project is also a cause for concern.

[20] Docket No. EMP-76, Sub 0.

[21] Docket No. EMP-92, Sub 0.

[22] Q398 and Q399 are two, 1235 MW combined cycle plants DEP is evaluating in the Interconnection Study Process. DEP's 2019 IRP calls for separate combined cycle units to come online in 2025 and 2027. See Docket No. E-100, Sub 157.

Table 2

Project	Friesian	NTE Kings Mtn (a)	NTE Reidsville (b)	Q398 (c)	PJM (Natural Gas) (d)
Nameplate (MW_{AC})	70	480	500	1,235	38,733
Network Upgrades ($M)	$ 223	$ 20	$ 59	$ 256	-
Network Upgrades ($/kW)	$ 3,186	$ 43	$ 118	$ 197	$ 37
LCOT ($/MWh)	$ 62.94	$ 0.33	$ 0.92	$ 1.53	$ 0.34

Notes

(a) A 70% capacity factor is assumed, and a 4.4% discount rate is used to maintain parity with the LBNL Study results.

(b) Includes $3.5 M in interconnection costs. A 70% capacity factor is assumed, and a 4.4% discount rate is used to maintain parity with the LBNL Study results. Network Upgrade cost information derived from August 26, 2019, Initial Pre-Hearing Brief of DEP in Docket No. EMP-105, Sub 0, footnote 11.

(c) Facility characteristics and upgrade size found in the System Impact Report for Q398.

(d) From Table 3 of the LBNL Study, representing 98 natural gas projects totaling 38,733 MW.

Q399, the second proposed DEP combined cycle plant is dependent upon a significant portion of Friesian's Network Upgrades.[23] The Public Staff agrees with Friesian Witness Askey that without the Friesian upgrades, future generation resources seeking to interconnect in this part of the DEP system will be assigned substantial upgrade costs. However, the likelihood of new generation such as Q399 being built in this part of DEP's system is too

[23] The April 11, 2019 System Impact Study for the DEP Q399 project, attached as **Lawrence/Metz Exhibit 3**, indicates that it is interdependent on $256 million of upgrades assigned to Q398 project, $209 million assigned to Friesian, and would trigger approximately $38.5 million of its own upgrade costs.

speculative at this time to provide support for the Friesian CPCN application, since it is heavily dependent upon future IRPs showing a continued need for additional capacity, contingencies such as the completion of the ACP, as well as DEP demonstrating that Q399 is in the public interest in a CPCN application, as opposed to other resource alternatives.

Due to the uncertainty surrounding these potential future resources, and the fact that DEP has not filed any CPCN applications for the future capacity needs, it is not appropriate at this time to assume that the Network Upgrades in question will be built regardless of the outcome of this proceeding. The Public Staff has advocated in multiple other proceedings to not grant certain CPCNs due to the uncertainty related to the need for a new generation resource.[24]

EMISSIONS REDUCTIONS UNDER EXECUTIVE ORDER 80

Q. PLEASE DESCRIBE EXECUTIVE ORDER 80.

A. Governor Cooper signed Executive Order 80 (EO80) on October 29, 2018. The Executive Order states that North Carolina will strive to reduce statewide greenhouse gas emissions to 40% below 2005 levels by 2025. The Executive Order further requires the Department of Environmental Quality (DEQ) to develop a North Carolina Clean

[24] In Docket No. E-7, Sub 1134, Public Staff recommended that the Commission deny the CPCN for the Lincoln County CT, and in Docket No. E-2, Sub 1089, the Public Staff recommended that the Commission deny the CPCN for the supplemental CT that the Company was requesting along with the Asheville combined cycle units.

Energy Plan (Clean Energy Plan) that "fosters and encourages the utilization of clean energy resources." The Plan was submitted to the Governor on September 27, 2019. With regard to current emissions, it states:

> NC has already reduced significant amounts of GHG emissions from the electric power sector. The State's Clean Smokestacks Act, REPS, PURPA and market drivers have decarbonized the electric power sector at a faster pace than many other states. According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels. These reductions have been achieved in the absence of explicit carbon policies in the State. DEQ estimates that with full implementation of HB589, the GHG reduction level from the electric power sector will reach roughly 50% by 2025 and remain at this level out to 2030.[25]

In addition to the goals set out in EO80, the Clean Energy Plan states the following three goals:

> - Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.
> - Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes.
> - Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.[26]

[25] Clean Energy Plan at 56.
[26] Id. at 12.

In achieving a 70% reduction in GHG emissions relative to 2005 levels by 2030, the Clean Energy Plan states that “NC’s values such as electricity affordability, equity, and reliability should be fully considered.”[27]

The Clean Energy Plan details a number of recommendations to achieve these goals including decarbonizing the power sector, requiring integrated resource plans that incorporate the cost of carbon, and “[c]onsider ways to provide greater transparency of system constraints and optimal locations for distributed resources.”[28]

The Clean Energy Plan further details ways to increase interconnection of distributed energy resources (DERs) by grouping studies or the issuance of more detailed maps for the Competitive Procurement of Renewable Energy (CPRE) Program that will facilitate the interconnection of cost effective projects. It specifically states, that if CPRE and grouping studies cannot improve the economics of a project “the legislature could provide guidance to the NCUC to establish a process for utilities to build out clean energy transmission solutions, which could ultimately be put into rates for all customers while expanding the delivery of clean energy within the state.”[29]

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[27] Id. at 58.
[28] Id. at 14-15.
[29] Id. at 105.

Q. DO YOU AGREE WITH WITNESS WILSON THAT THE FRIESIAN NETWORK UPGRADES ARE IMPORTANT TO ACHIEVING THE EMISSIONS REDUCTION GOALS IN THE CLEAN ENERGY PLAN?

A. Witness Wilson claims that achieving the emissions reductions stated in the Clean Energy Plan will require solar and other clean energy additions. Witness Wilson states that the level of penetration shown in the Synapse model will be challenging to achieve without the Network Upgrades required by Friesian if additional solar cannot be interconnected that are dependent on the Friesian Network Upgrades.[30]

Furthermore, witness Bednar states Birdseye's analysis of the DEP queue shows that 3,898 MW are proposed in the constrained area.[31] In addition, in response to a Friesian data request, Duke has stated that the Friesian Network Upgrades could partially facilitate the interconnection of more than 1,000 MW of additional solar generation.[32]

The Public Staff does not dispute that achieving the emissions reductions stated in the Clean Energy Plan will require solar and other clean energy additions, but finds the remaining assertions to

[30] Testimony of Rachel Wilson, at 13.
[31] Testimony of Brian C. Bednar, at 4.
[32] Testimony of Charles Askey, Exhibit A to Exhibit B, Response to Question 1.

be speculative. The later queued solar projects in the region have not been fully studied and may require additional upgrades, over and beyond the Friesian upgrades that may render them economically unviable. In addition, due to technological changes, there also may be other alternatives identified that help to avoid or defer costly transmission upgrades.

The Public Staff recognizes that solar, as well as other low-carbon resources, play an important role in reducing carbon emissions in the State, and has consistently supported QF development in North Carolina, including solar QFs. North Carolina has the second most solar capacity of any state in the country, and hundreds of solar projects have interconnected. In particular, the Public Staff notes that as of November 2018, there were already over 100 in-service or under construction solar generating facilities totaling 1,348 MW in the DEP East area where the Friesian facility is triggering substantial upgrades.[33]

The Clean Energy Plan states that a comprehensive approach to system planning is the preferred policy option. The Plan states in its detailed policy and action recommendations that "[t]hese goals will not be achieved overnight, nor through implementation of *one or two actions*; rather it will require a collection of actions to set us on a path

[33] See November 9, 2018, Duke Energy presentation entitled "Stakeholder Discussion: Network Congestion Next Steps." at Slide 4. Attached as **Lawrence/Metz Exhibit 4**.

of modernization that prepares our residents, governments, and businesses to be competitive, proactive, and responsible stewards of our environment."[34] (emphasis added).

The Public Staff agrees that costly investments in the siting of new transmission and generation should be evaluated and decided through comprehensive system planning, utilizing processes such as the IRP, ISOP, distribution system planning, and competitive bidding processes like the CPRE Program or short-term market solicitations, rather than by individual CPCN applications. With ever-growing rate pressures on electric customers, comprehensive system planning will produce more efficient, cost-effective results for customers than piece-meal planning and construction.

Q. WILL THE FRIESIAN UPGRADES RESULT IN LOWERED EMISSIONS IN NORTH CAROLINA?

A. We definitely do not know. Friesian has provided no specific analysis showing the upgrades required for this project will lower emissions in the State or lead to better health outcomes. Rather, witness Wilson relies on the Synapse alternative IRP Report (Wilson Exhibit RW-2) to support the assertion that significant emissions reductions, ratepayer savings, and better health outcomes will be accomplished

[34] Clean Energy Plan at 51.

through the addition of 14 GW of solar capacity and almost 6 GW of battery capacity in the DEP and DEC service territories.[35]

Q. DOES THE PUBLIC STAFF SUPPORT COMPREHENSIVE UTILITY PLANNING TO MEET CLEAN ENERGY GOALS?

A. Yes. The Public Staff strongly agrees that major infrastructure upgrades will most likely be needed to incorporate new technology and additional clean energy from distributed energy resources (DERs). The Public Staff believes, however, that holistic planning and decision-making frameworks, such as the IRP and the complementary Integrated Systems Operation Planning (ISOP), are the appropriate forum for planning to meet the emissions goals of both the Clean Energy Plan and any other major environmental goals, such as Duke's stated goal to be net carbon neutral by 2050.[36] This is consistent with the Clean Energy Report, which recommends the use of such tools to achieve emissions reductions goals in a cost effective manner.

[35] Wilson at 5. Witness Wilson did not run a specific scenario in the Synapse model that shows that the Friesian upgrades will defer the need for new fossil fuel plants or lead to the early retirement of existing emitting sources. Furthermore, the Synapse study eliminates the addition of any new natural gas plants.

[36] On September 17, 2019, Duke Energy announced an updated climate strategy See press release at: https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050. In addition, Duke Energy North Carolina President Stephen De May said the 2019 IRP Updates don't reflect the new goal, and that the 2020 IRPs will reflect the proposed changes: https://www.wral.com/duke-energy-net-zero-carbon-emissions-by-2050/18640706/.

RESPONSE TO WITNESS BEDNAR

Q. PLEASE RESPOND TO WITNESS BEDNAR'S DISCUSSION OF THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE) PROGRAM TRANCHE 1 RESULTS.

A. On page 11 of witness Bednar's testimony, he states that because CPRE Tranche 1 did not meet its procurement goals "with projects that trigger no network upgrades, it is reasonable to assume that even a small portion of the Duke de-carbonization goals of 5,100 MW will trigger wide-ranging network upgrades…." The Public Staff disputes this characterization of Tranche 1 as not meeting its target due to Network Upgrades.

As discussed in the Tranche 1 CPRE Final Report, there were a number of factors that resulted in large numbers of the projects withdrawing or being removed from consideration. For example, in DEC's territory, 60% of third-party proposals that were initially selected in the Primary Competitive Tier declined to post proposal security, effectively withdrawing their bid. When an additional 18 third-party proposals were called up from the Competitive Tier Reserve, 12 declined to post proposal security.[37] It is not clear why these projects chose to withdraw even after being selected for Step 2 evaluation, as none of them would have been required to pay their

Network Upgrade costs had they been selected. Because the applicants (all of which were solar facilities) withdrew their bids, it is impossible to say if any of these projects would have been assigned significant Network Upgrades that would have caused them to be disqualified for exceeding avoided cost. As such, the final Tranche 1 Report does not appear to support witness Bednar's conclusion.

Q. CAN YOU SPEAK TO THE 1,561 MW OF ADDITIONAL SOLAR GENERATION FOR WHICH, ACCORDING TO WITNESS BEDNAR THE FRIESIAN PROJECT WILL FACILITATE INTERCONNECTION?

A. Yes. These 108 projects are currently behind Friesian in the interconnection queue and have been identified as directly interdependent on the system upgrades that are required for Friesian to interconnect. While we do not dispute this claim, it is important to mention that each of the 108 projects may require their own upgrades in addition to those contemplated in this proceeding. It is also unreasonable to expect that all of these projects will be built. The reasons given by Witness Bednar that makes southeast North Carolina an ideal area to develop a solar facility are the very reasons why there are so many projects already built in the area, so many more projects wanting to build in the area, and why these upgrades are required at all. The solar generation in this region is the driving force behind the need for the upgrades.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION ON THE APPLICATION FOR A CPCN?

A. The Public Staff recommends that the Commission deny the requested CPCN. We do, however, encourage the Applicant to continue to work with DEP and evaluate the possibility of lower cost interconnection options, such as changes to the capacity, design, or operational characteristics of the facility to allow it to interconnect at that location without triggering upgrades, or to evaluate other locations that can accommodate the facility without requiring such substantial upgrade costs.

Q. DOES THIS CONCLUDE YOUR JOINT TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

EVAN D. LAWRENCE

I graduated from East Carolina University in Greenville, North Carolina in May of 2016 earning a Bachelor of Science degree in Engineering and a concentration in Electrical Engineering. I started my current position with the Public Staff in September of 2016. Since that time my duties and responsibilities have focused around the review of renewable energy projects, rate design, and renewable energy portfolio standards compliance. I have filed affidavits in Dominion Energy North Carolina's 2017 and 2018 REPS cost recovery proceeding, testimony in DEP's 2019 REPS cost recovery proceeding, an affidavit in DEC's 2019 REPS cost recovery proceeding, testimony in New River Light and Power's (NRLP) most recent rate case proceeding, and testimony in proceedings for applications for Certificates of Public Convenience and Necessity (CPCNs) by merchant electric generating facilities (EMPs). Additionally, I am currently serving as a co-chairman of the National Association of State Utility and Consumer Advocates (NASUCA) DER and EE committee.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I am currently enrolled at North Carolina State University, working toward a Masters of Engineering degree.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

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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

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Office of Electricity Delivery and Energy Reliability
National Electricity Division
U.S. Department of Energy

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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).

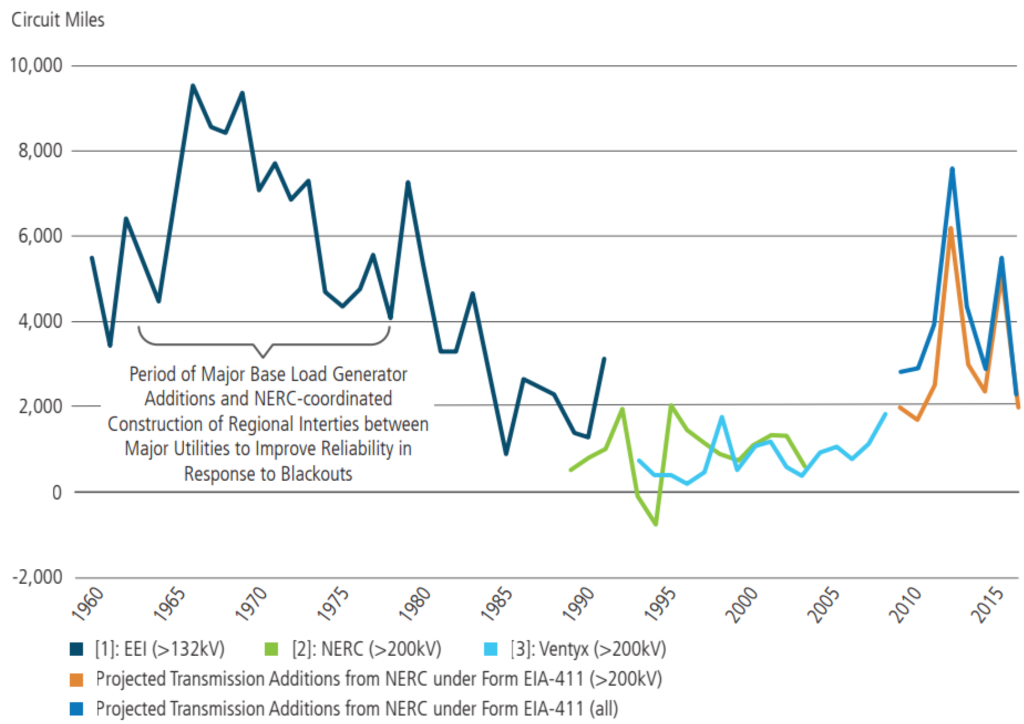
2. Background and Prior Work

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.

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

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

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[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.

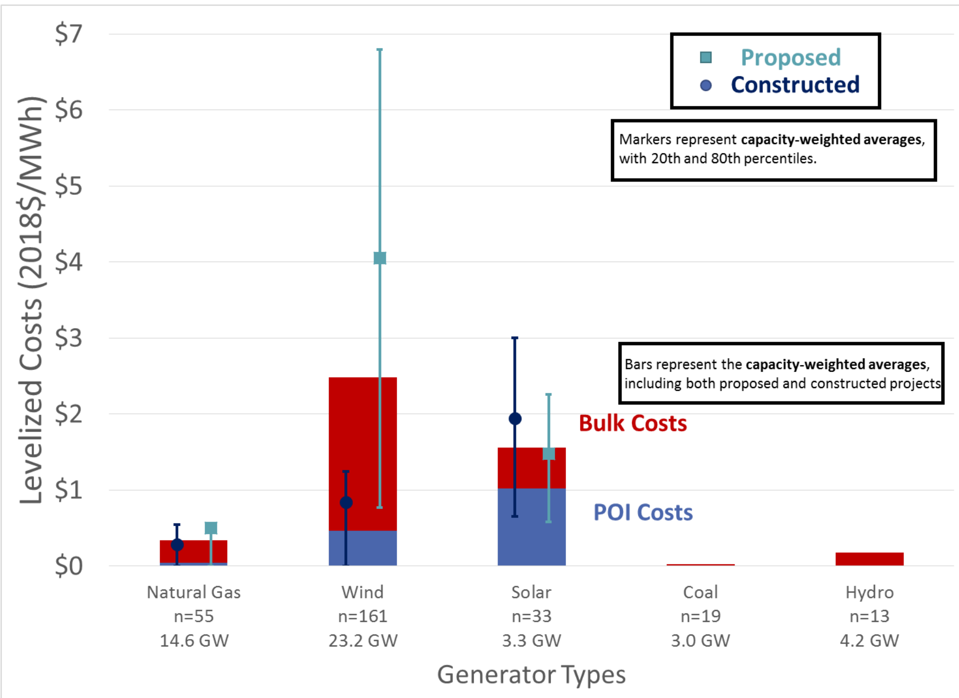


Figure 2. Range of levelized costs for selected utility-scale projects in MISO

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.

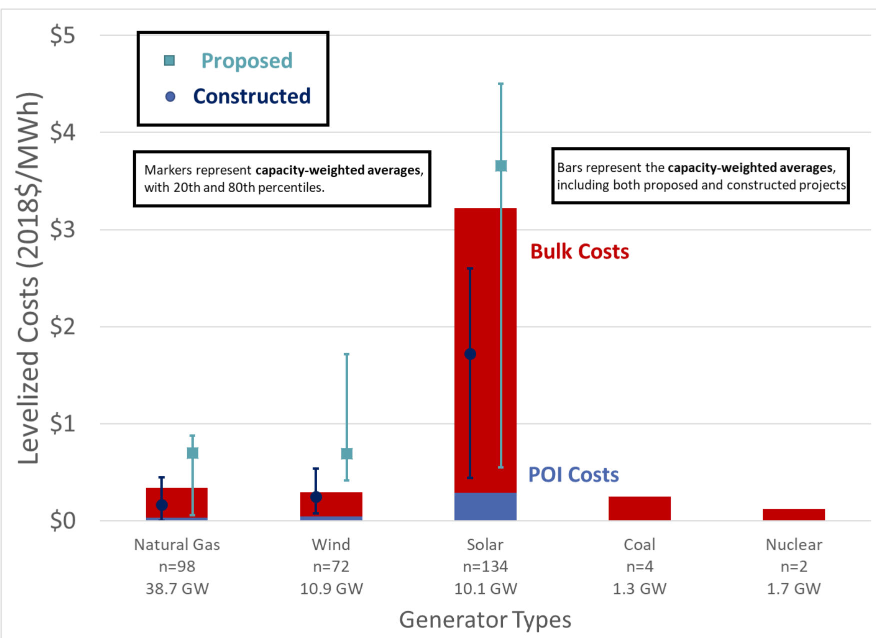


Figure 3. Range of levelized costs for selected utility-scale projects in PJM

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.

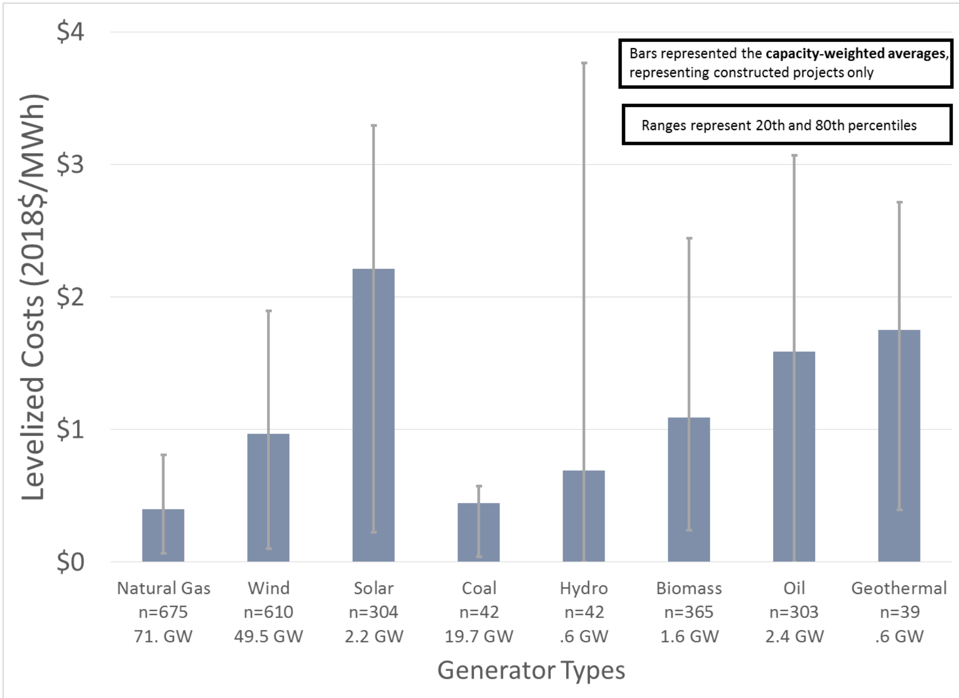
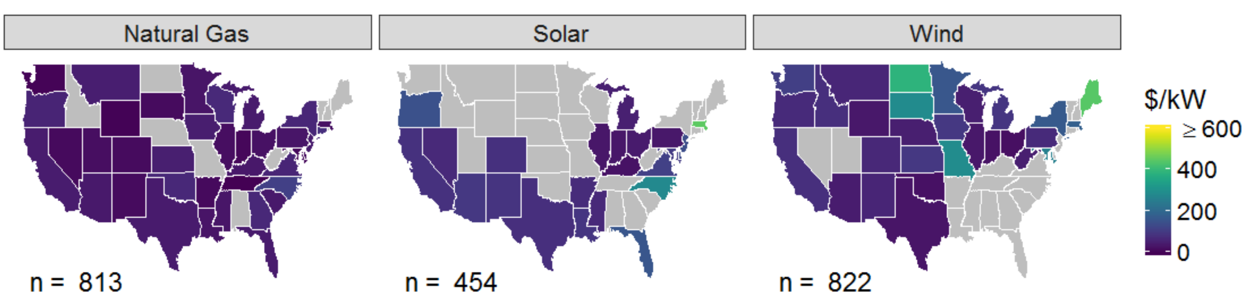


Figure 4. Range of levelized costs for selected utility-scale projects in EIA dataset

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

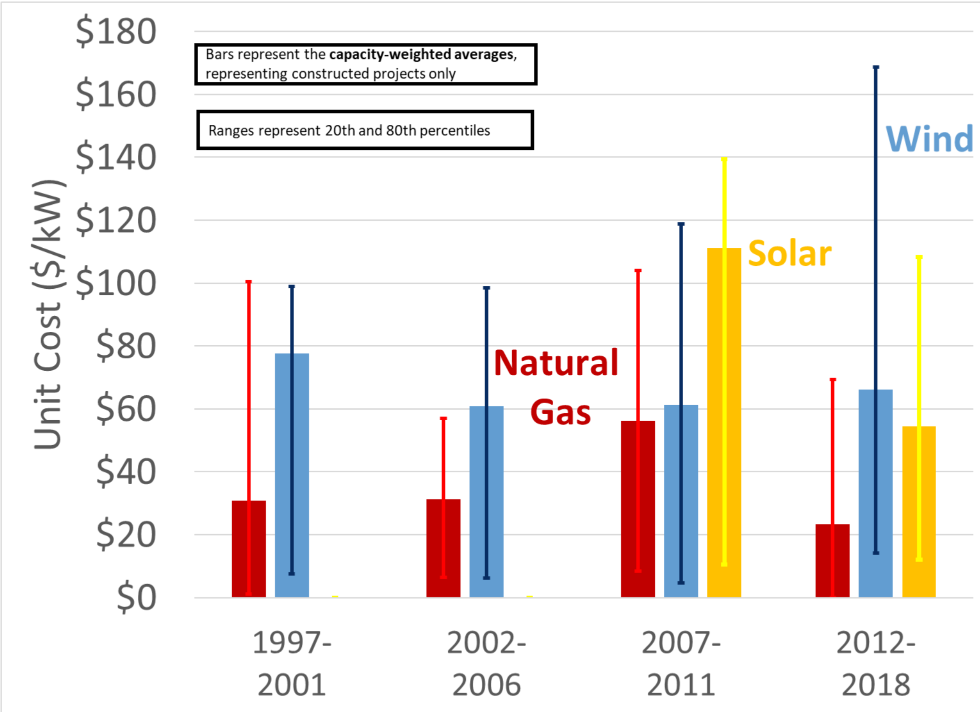


Figure 6. Average unit cost by queue entry year for constructed utility-scale projects

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.

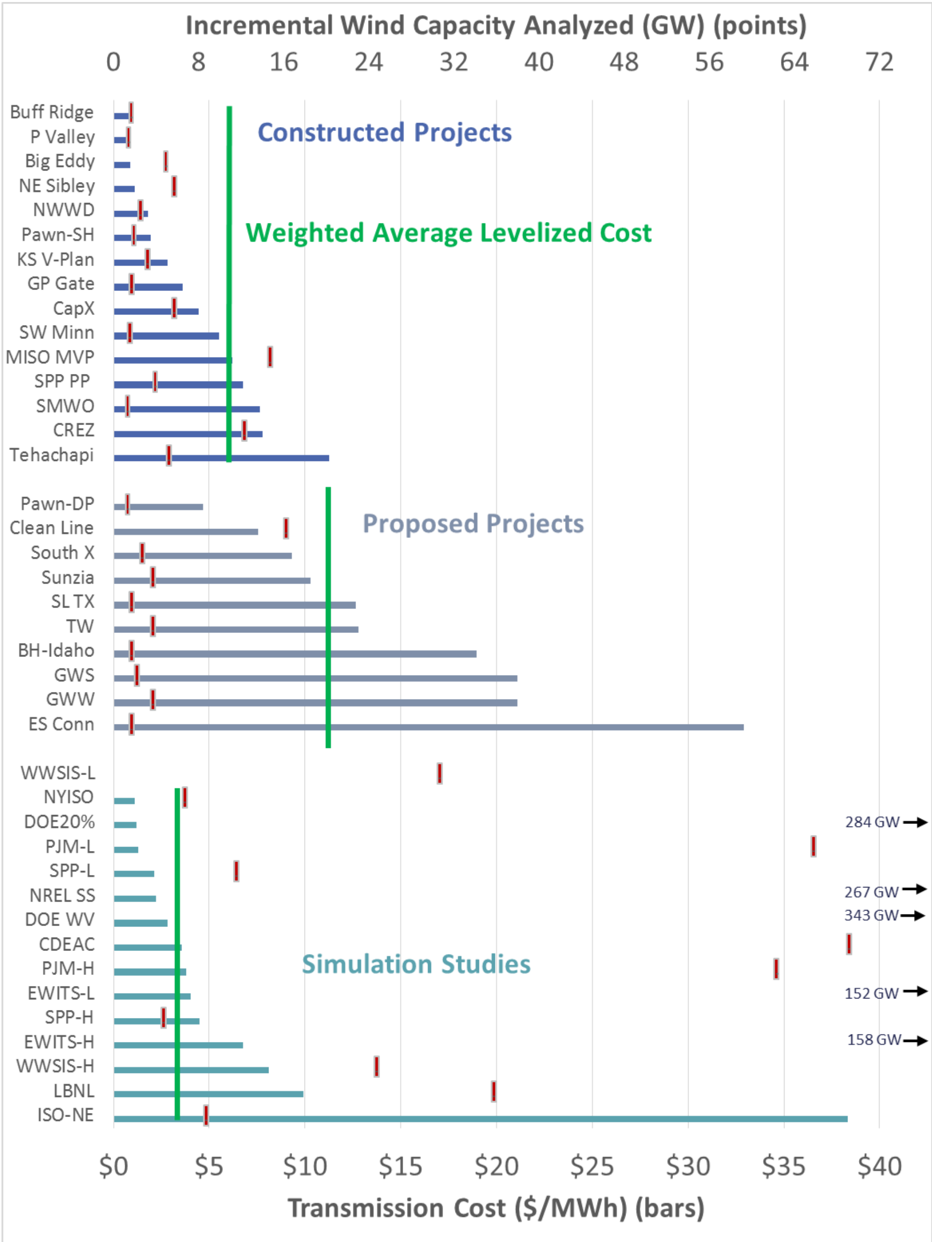


Figure 7. Wind LCOT from constructed and proposed projects and simulation studies

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.

[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.

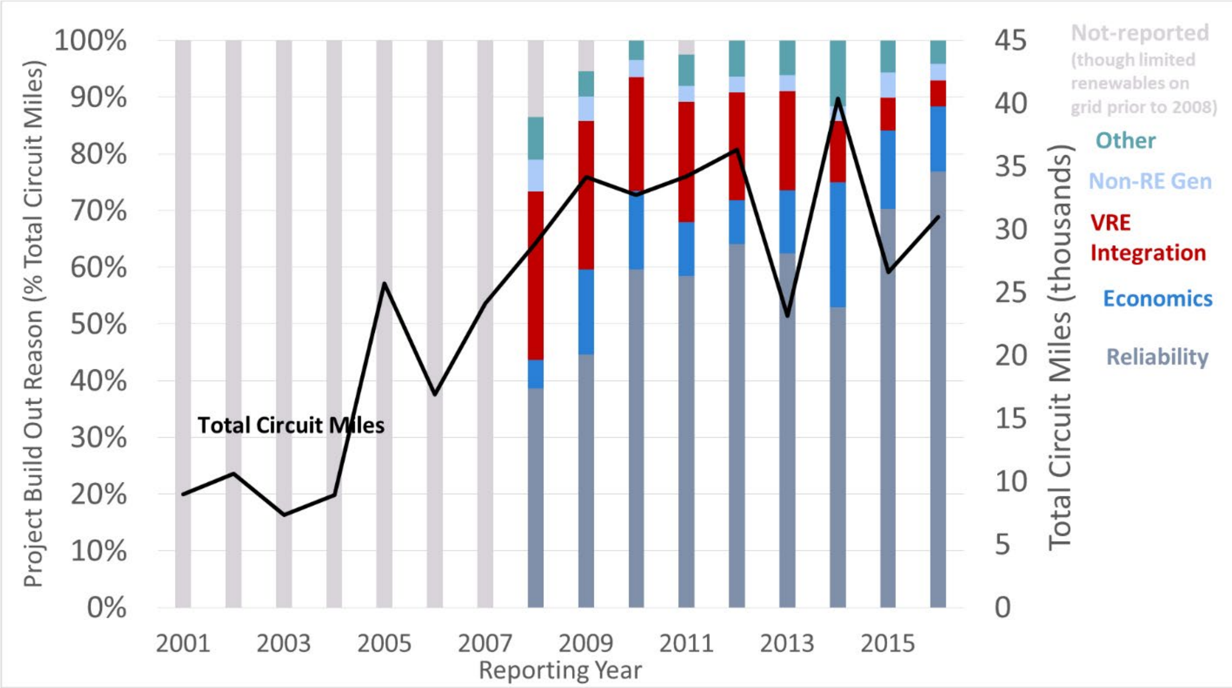
Two lines constitute $5.3 billion of California's $7.2 billion transmission investment: Sunrise Powerlink for utility-scale solar and Tehachapi for wind. The Sunrise project was particularly expensive owing to construction constraints (see Section 4.2.2); it represents 28% of the costs but only accounts 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.

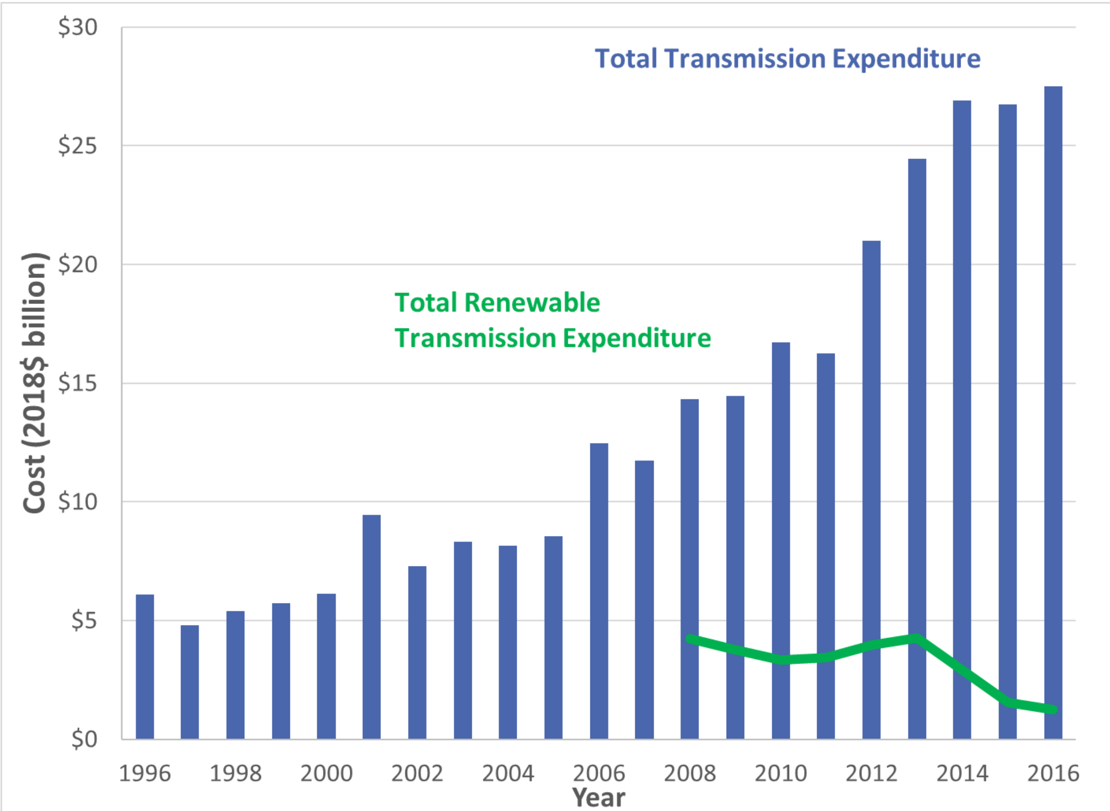


Figure 10. Estimated U.S. transmission expenditure 1996–2016

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.

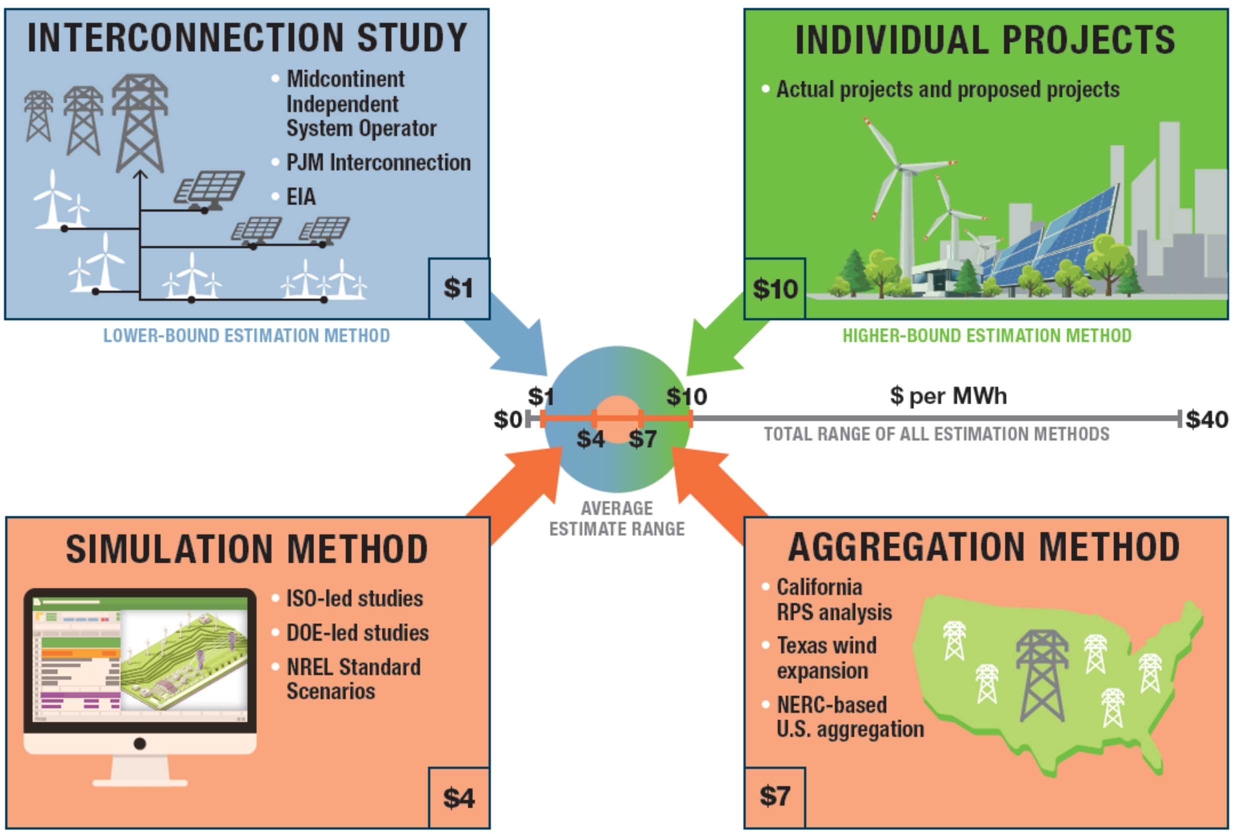


Figure 11. Summary of LCOT for utility-scale wind and solar integration

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.

[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

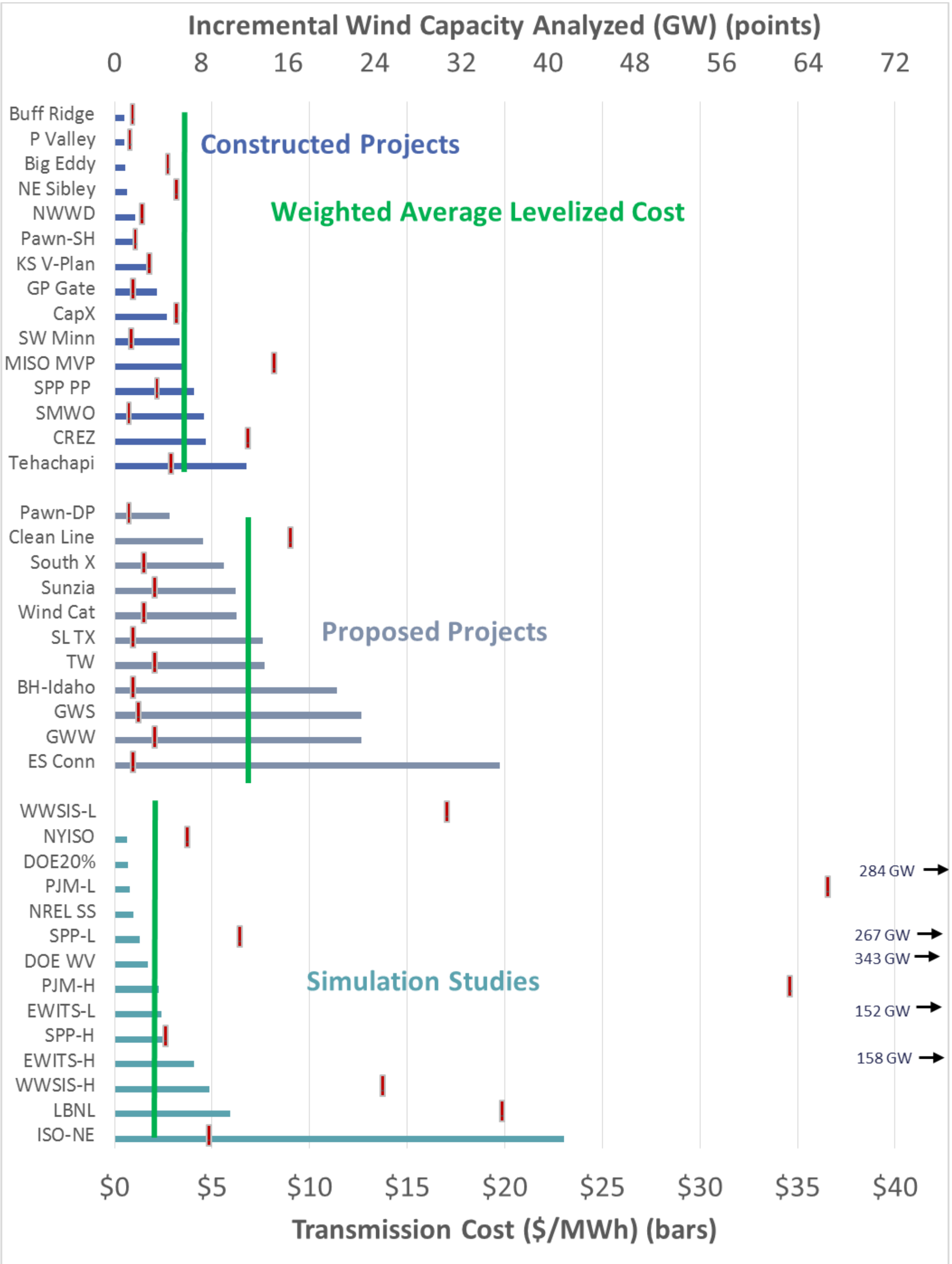

Figure A-1. Utility-scale wind chart (at 2% discount rate)

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
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

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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.

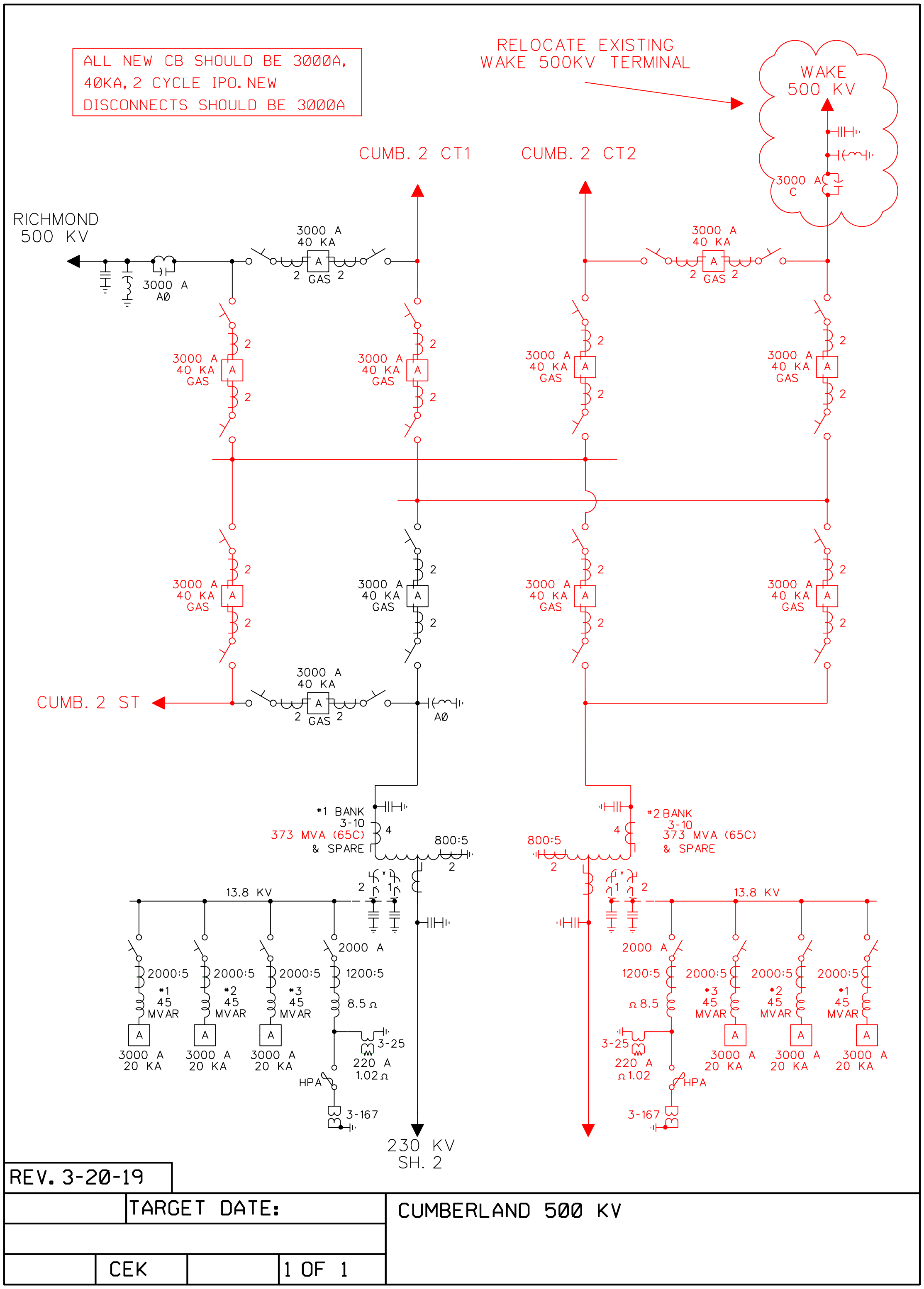
Power-flow	$38,500,000	
Stability	$0	
Short Circuit - Duke Energy	$1,800,000	
Short Circuit - Affected Systems	$tbd	
Interconnection	$15,000,000	
Total Estimate	$55,300,000	(plus any Affected System costs)

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

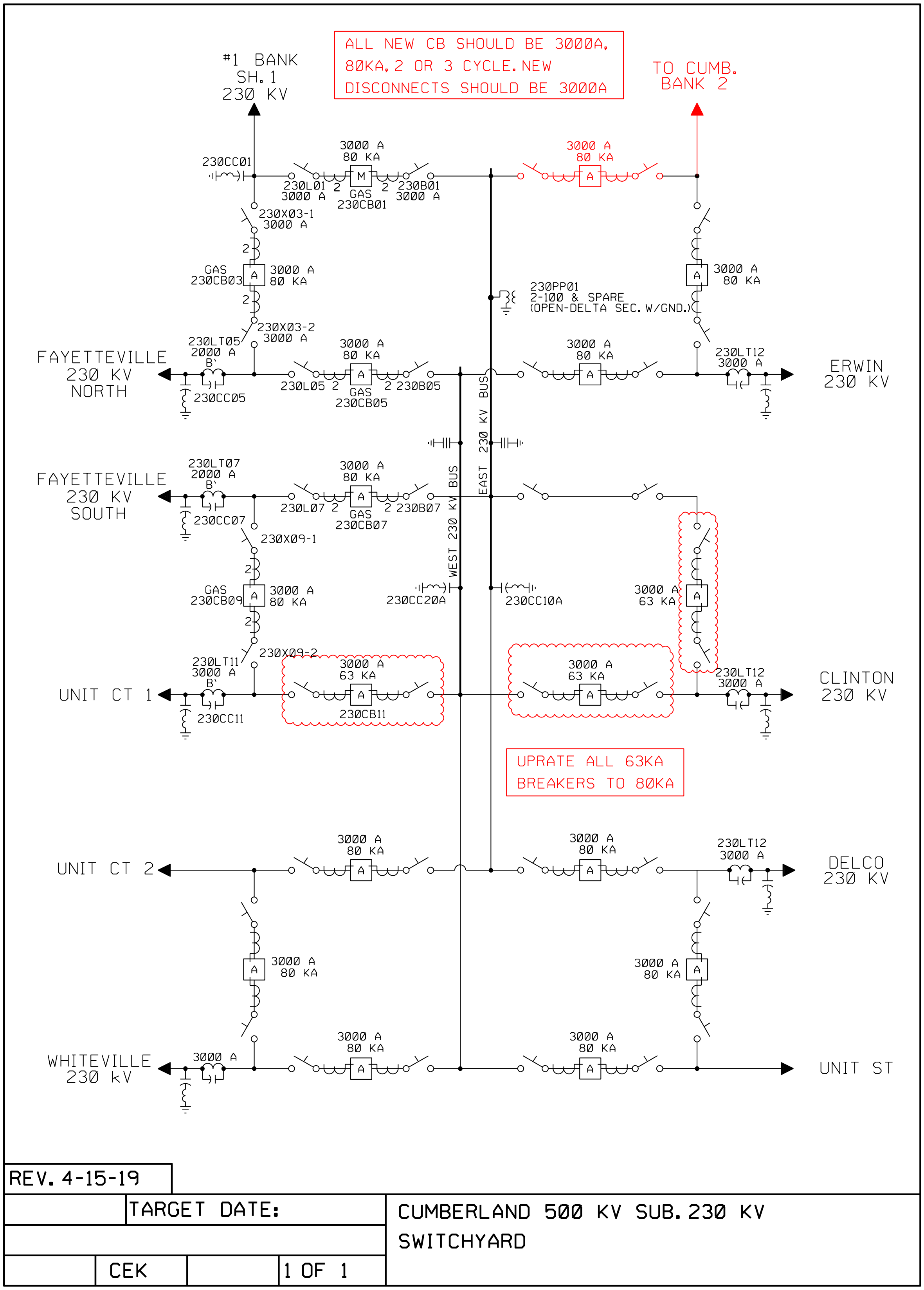
Reviewed by: Mark Byrd
Mark Byrd, PE, Duke Energy Progress

APPENDIX I : FIGURES

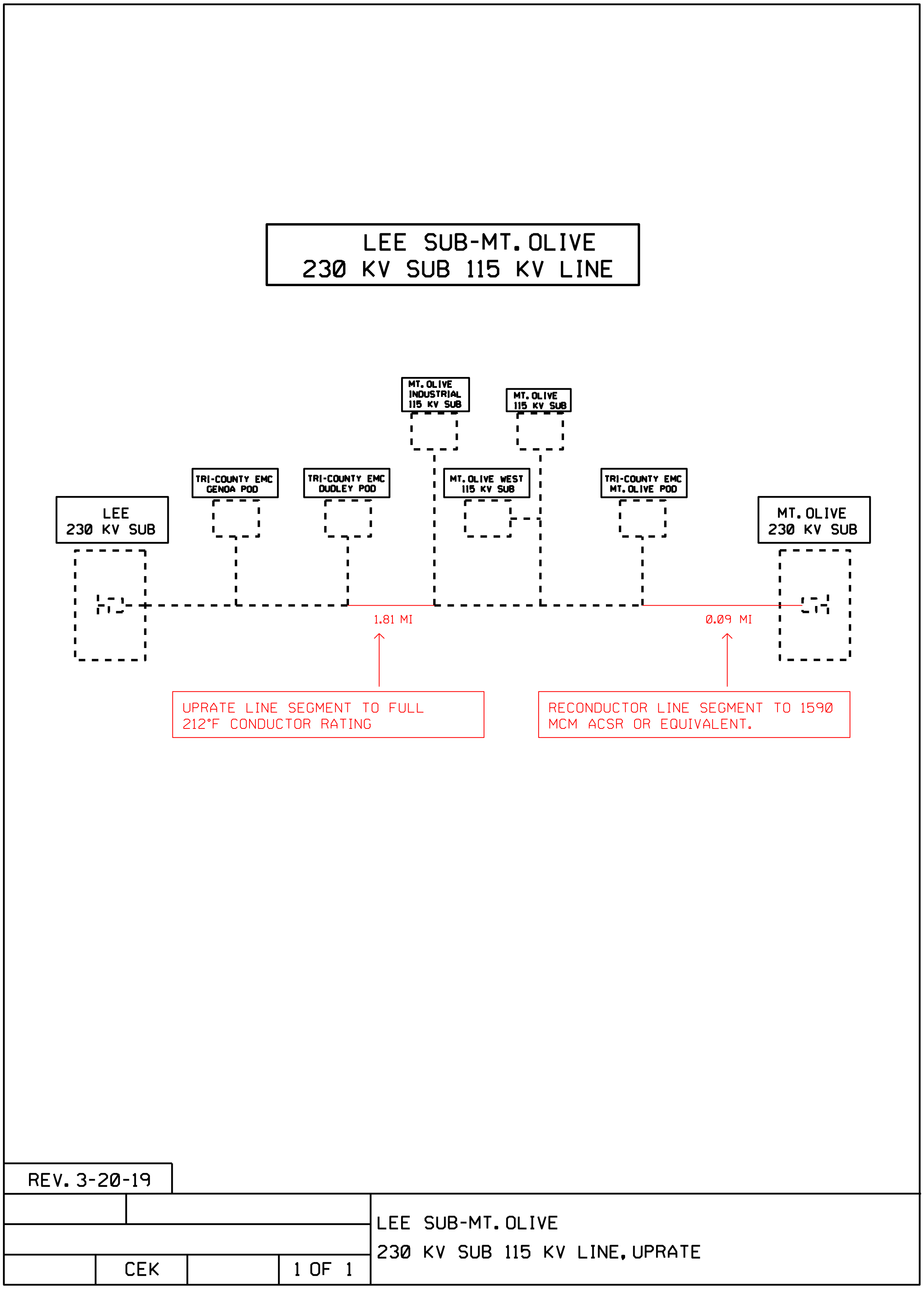
-Figure 1-



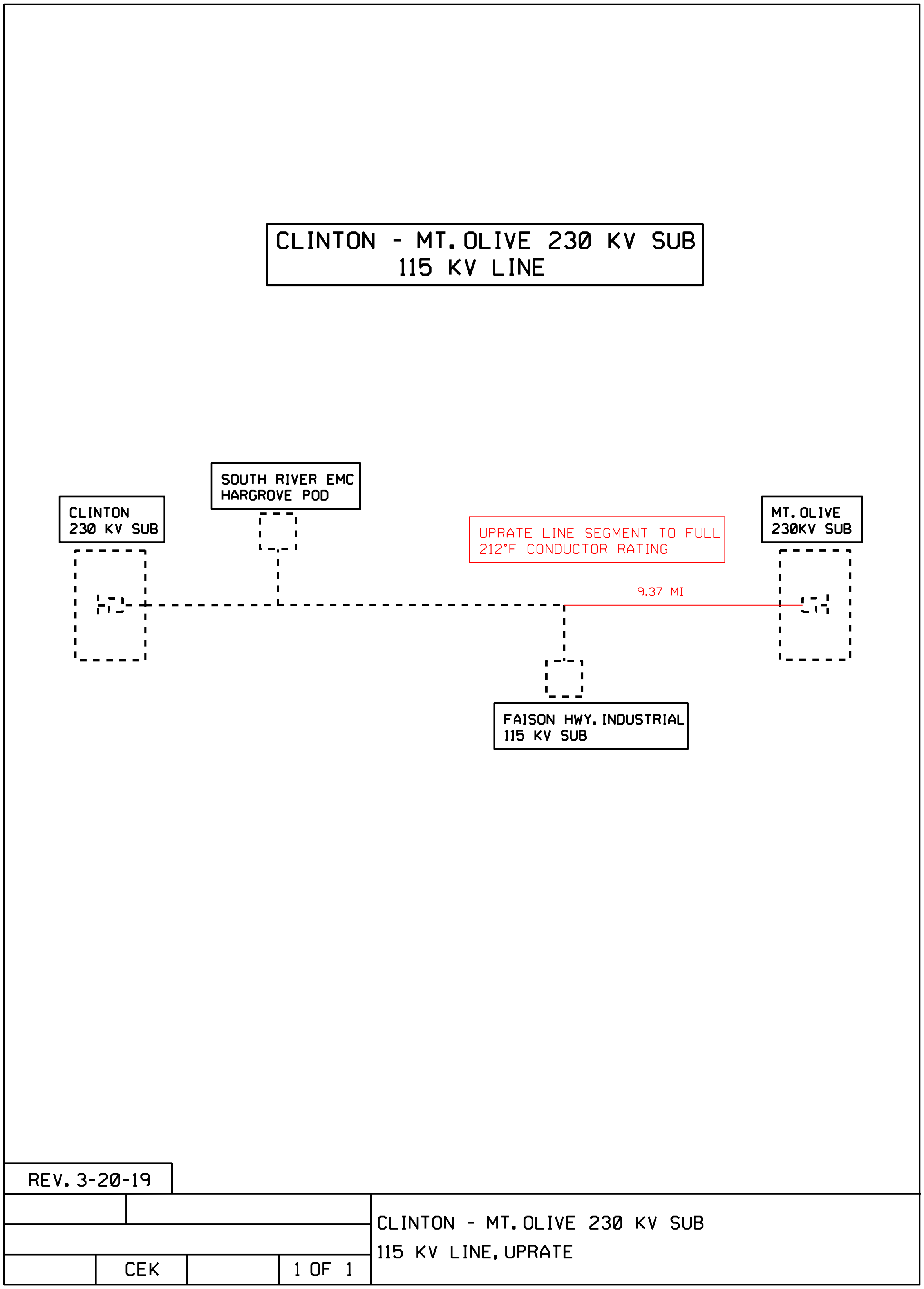
-Figure 2-


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
230CC01
3000 A
80 KA
230L01
230B01
GAS
230CB01
230X03-1
GAS
230CB03
230PP01
2-100 & SPARE
(OPEN-DELTA SEC. W/GND.)
230X03-2
230LT05
2000 A
FAYETTEVILLE
230 KV
NORTH
230L05
230B05
230CB05
230CC05
230LT12
ERWIN
230 KV
EAST 230 KV BUS
WEST 230 KV BUS
230LT07
FAYETTEVILLE
230 KV
SOUTH
230L07
230B07
230CB07
230CC07
230X09-1
230CB09
230CC20A
230CC10A
63 KA
230X09-2
230LT11
UNIT CT 1
230CB11
230CC11
CLINTON
230 KV
UPRATE ALL 63KA BREAKERS TO 80KA
UNIT CT 2
DELCO
230 KV
WHITEVILLE
230 kV
UNIT ST
REV. 4-15-19
TARGET DATE:
CUMBERLAND 500 KV SUB. 230 KV SWITCHYARD
CEK
1 OF 1

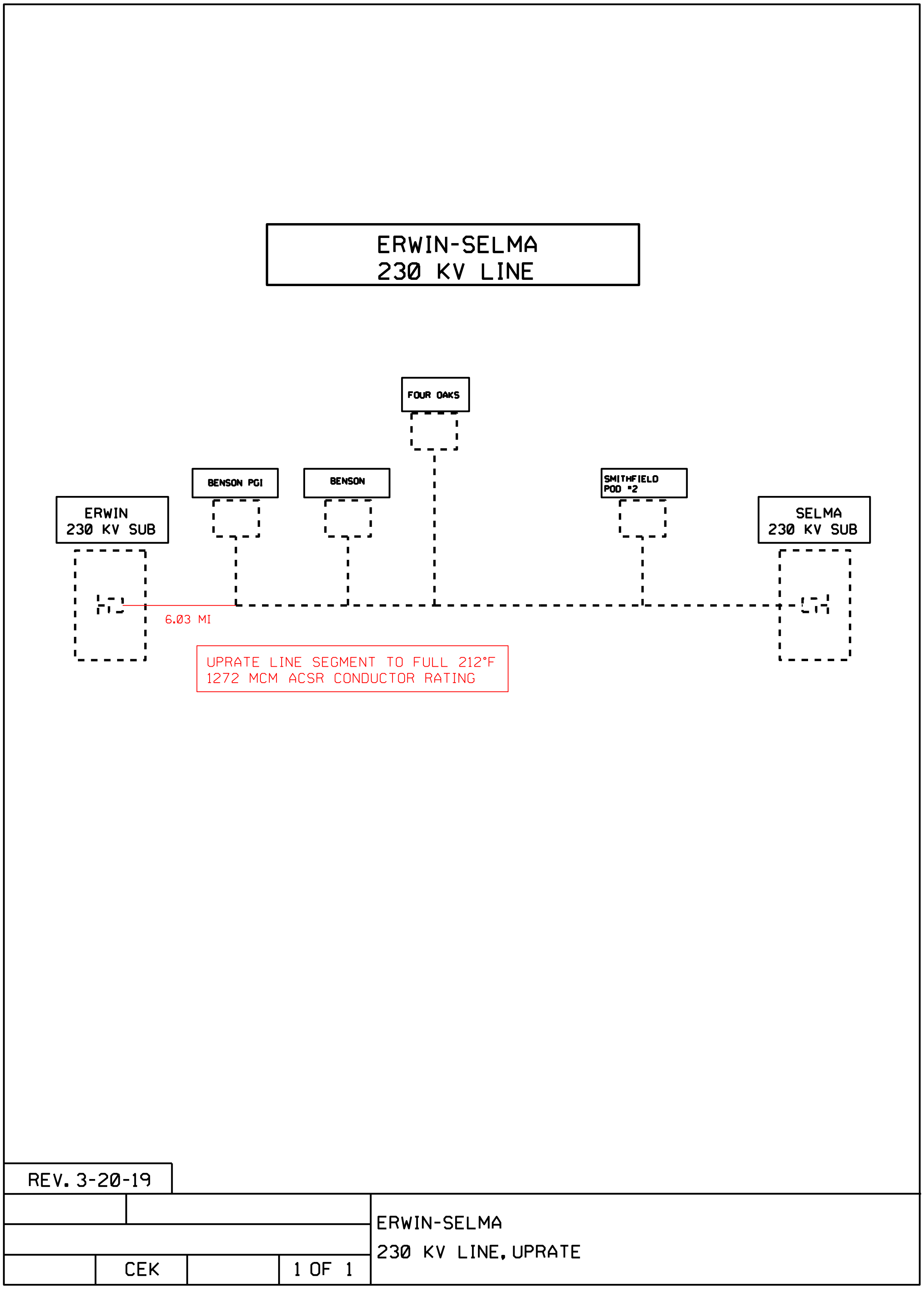
-Figure 3-


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

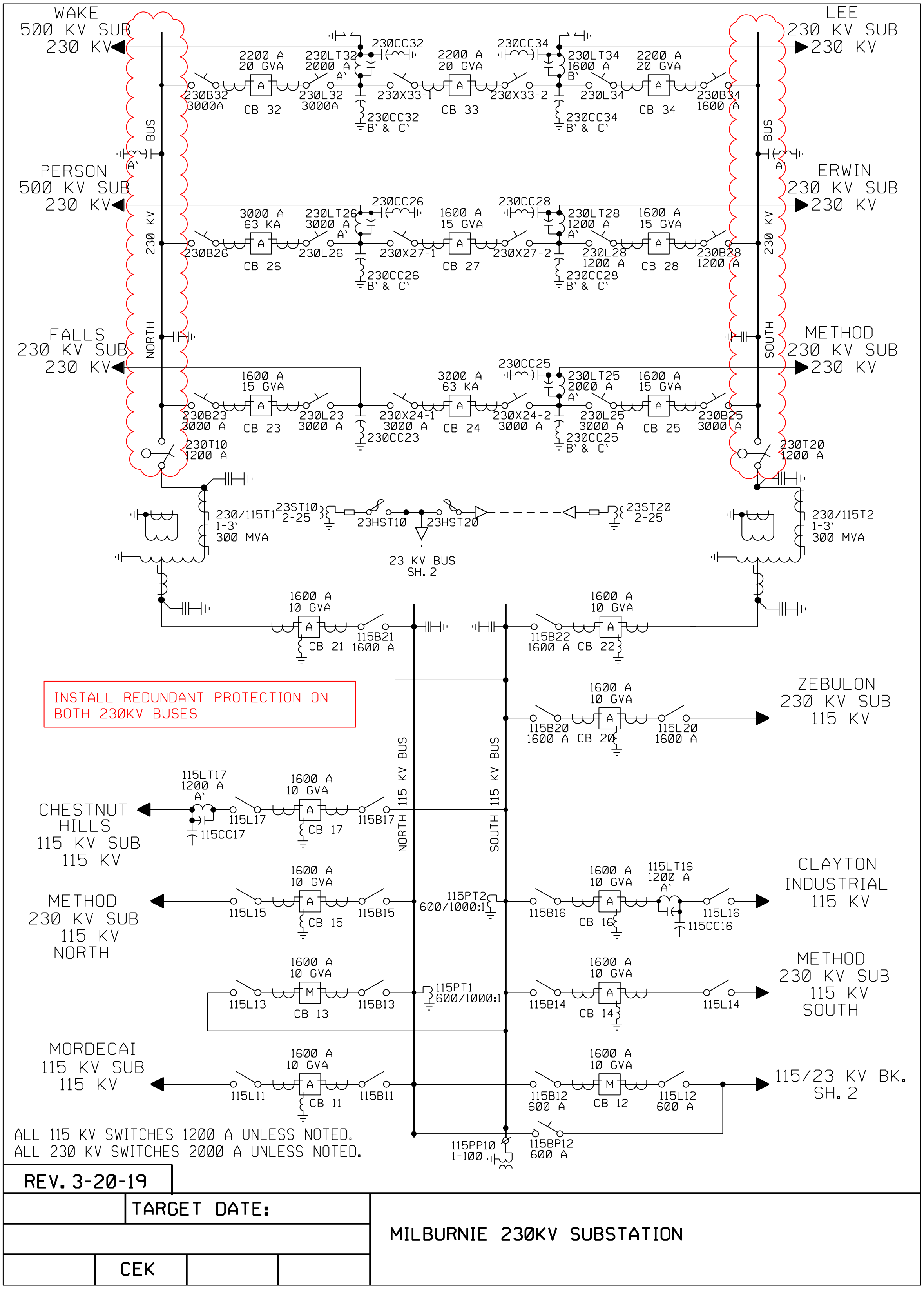
-Figure 4-


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
CB 21
CB 22
INSTALL REDUNDANT PROTECTION ON
BOTH 230KV BUSES
ZEBULON
230 KV SUB
115 KV
CB 20
CHESTNUT
HILLS
115 KV SUB
115 KV
CB 17
NORTH 115 KV BUS
SOUTH 115 KV BUS
METHOD
230 KV SUB
115 KV
NORTH
CB 15
CLAYTON
INDUSTRIAL
115 KV
CB 16
METHOD
230 KV SUB
115 KV
SOUTH
CB 13
CB 14
MORDECAI
115 KV SUB
115 KV
CB 11
CB 12
115/23 KV BK.
SH. 2
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

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.