Assessing Transmission Bottlenecks for Renewable Energy Development in North Carolina

by

Pungaliya, Rajat Prashant

Wang, Yiwen

Xue, Yutong

Dr. Timothy Johnson, Advisor

2021

Masters project proposal submitted in partial fulfillment of the requirements for the Master of Environmental Management degree in the Nicholas School of the Environment of Duke University

Executive Summary

The transmission system forms the backbone of the electricity system and plays a pivotal role in ensuring reliable electricity delivery from generators to customers. With a growing need for renewable energy, diversity of resources, and increased resiliency, the transmission network is more important now than ever, despite being expensive and having very long timelines for construction. When the transmission line capacity to deliver electricity exceeds its thermal, voltage, or stability limits, it becomes constrained and limits power flow, resulting in congestion. North Carolina is ranked third for the cumulative amount of solar electric capacity installed in the US. This has led to a constrained grid where building more solar is challenging without triggering major upgrades on the transmission network. At the same time, as the leading state in the southeast solar market, North Carolina is continuously seeking future opportunities of reducing carbon emissions, according to the state's announcement and Duke Energy's Emission Reduction Plans. Our study aims to assess the transmission bottlenecks for renewable energy growth existing in North Carolina.

We first provide an overview of the energy market and regulatory landscape in North Carolina. We also explain the transmission constraints that can impede renewable energy development. Then, we use the case of Friesian Holdings to identify existing transmission bottlenecks in North Carolina, including the regulatory hurdles to obtain the certificate of public convenience and necessity, the participant funding model, a winter peaking system, the current interconnection policy, and the lack of transmission capacity to accommodate more renewable energy.

Next, we explore the bottlenecks identified from the Friesian Case in detail and provide possible solutions to resolve them. To tackle the winter peak issue, we recommend the incorporation of short and long-duration energy storage systems. We also recommend the implementation of Grid Enhancing Technologies (GETs) to increase line carrying capacities and reduce congestion. In terms of interconnection policy, we assess the process required for interconnection applications as well as the current status of interconnection applications in North Carolina based on data from Duke Energy. Our assessment concludes that the current serial interconnection process is slow and clogged with high financial uncertainty. Following Duke Energy's recent efforts on interconnection queue reform, we summarize the changes proposed in the queue reform, especially a transition from a serial to a cluster approach, which is expected to happen in the interconnection study process in the near term.

In the final section, we translate the renewable integration measures taken in California, which has the highest penetration of renewables in their transmission system and determine their applicability for North Carolina. A significant number of new solar project integrations in California come from distributed energy, which contributed significant reduction of demand growth on the transmission system. The net metering policy in both NC and CA provided the opportunity to incentive residents and commercial entities to implement more behind-the-meter generations, which in turn contributes to flattening the load growth on the transmission system. We also explored the non-physical transmission constraints that are results of regulatory mandates in San Joaquin, where under the current “least cost, best fit” framework, no more solar projects can be integrated without violating transmission constraints. We assessed solutions that utilize an energy-only concept to circumvent the regulatory-created transmission constraints to integrate substantially more solar into the area without breaching any physical transmission limitations.

Finally, we summarize the recommendations for relieving the transmission bottlenecks we identified in previous discussion for renewable energy development in North Carolina.

Acknowledgment

We would like to thank our client, the North Carolina Clean Energy Business Alliance (NCCEBA), for giving us the opportunity to work on this exciting project. NCCEBA is a non-profit trade association for the clean energy industry in North Carolina.

We would like to express our sincere thanks to John Gajda, Principal Engineer at Strata Solar, LLC for providing valuable guidance and insights regarding the regulatory landscape in North Carolina and helping us understand the way Duke Energy operates, during our regular meetings. We also would like to extend the thanks to Carson Harkrader, CEO at Carolina Solar Energy for initiating this project as well as Michael Wallace, Vice President of Development Southeast at Ecoplexus Inc., and Tyler Norris, Senior Director of Development at Cypress Creek Renewables for laying a solid foundation for this project.

Last, but not least, we are deeply grateful for the constant support, constructive criticism, and inspiring insights from our advisor Dr. Timothy L. Johnson. This project would not have been possible without him.

Contents

Introduction

The renewable energy industry has grown rapidly with increasing support from policymakers in the last decade. As more renewable energy is integrated into the electric power system, both technical and management challenges have emerged. Transmission bottlenecks are one of those challenges. The transmission system plays a pivotal role in ensuring reliable electricity delivery from generators to customers. The integration of renewable energy has an impact on the stability and flexibility of the transmission system. For example, over-voltage problems can be frequent in areas with a high share of solar generation (Semich Impram, 2020). Therefore, transmission can limit the growth of renewable energy.

North Carolina has been acknowledged as one of the leading states in solar development for years. However, the emission reduction goals published by the state and the local investor-owned utilities may require even greater efforts in renewable energy development. In the following sections, we provide an overview of the current policy, barriers, and prospects of renewable energy development in North Carolina. We aim at identifying the bottlenecks related to transmission networks that may impede renewable energy development in North Carolina and therefore potentially shed light on the improvements that North Carolina can make.

Energy Market in North Carolina

The investor-owned electric utilities in North Carolina are Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion North Carolina Power (Figure 1). The area covered by DEC and DEP (hereafter referred to as Duke Energy when mentioned together) is a regulated electricity market. In the regulated market, Duke Energy serves as a vertically integrated utility that both manages generation resources and owns infrastructure and transmission lines. Dominion North Carolina Power, on the other hand, is in a deregulated electricity market that is managed by a regional transmission organization. Here we focus our analysis on Duke Energy's service territory for renewable energy development in North Carolina.

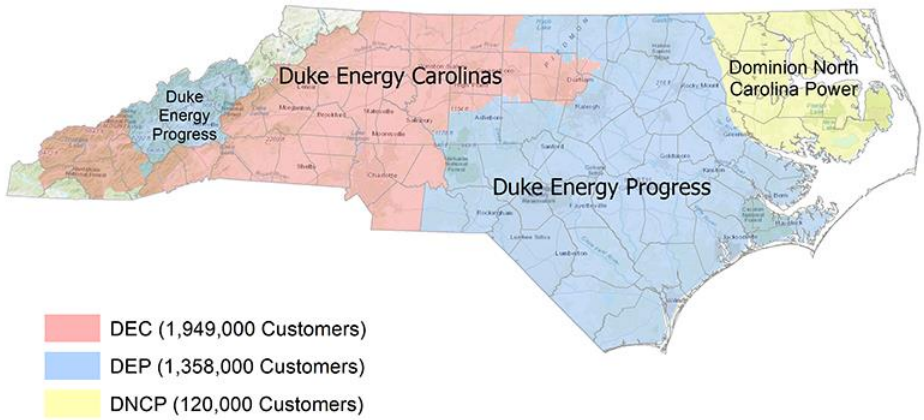

Figure 1 North Carolina Electric Investor-Owned Utility Service Area Map (Source: North Carolina's Public Utility Infrastructure & Regulatory Climate Presented by North Carolina Utilities Commission, 2017)

North Carolina now ranks the 3rd among states in terms of total solar installation, surpassed by Texas in 2020. According to the data published by Solar Energy Industries Association (SEIA) in late 2020 (SEIA, 2021), the total solar installation in North Carolina is 7037.79 MW, which generates 7.5% of the state's electricity.

Although ranking the 3rd for total solar installation until 20202020, North Carolina is falling behind other states in terms of recent growth and future projection as shown by Table 1. The annual solar installation in 2020 in North Carolina ranks 5th. As a comparison, California and Texas rank the 1st and 2nd respectively for both total and annual installation. In SEIA's projection (SEIA, 2021) for the next five years, North Carolina ranks the 9th with 3242.08 MW expected growth in solar installation.

Table 1 Rankings of solar growth of North Carolina, California, and Texas among states (Source: SEIA)

	Ranking of total Installation until 2020	Annual Installation ranking in 2020	SEIA's Growth Projection Ranking	SEIA's Growth Projection over the next 5 years
North Carolina	3rd	5th	9th	3242.08 MW
California	1st	1st	2nd	19,033 MW
Texas	2nd	2nd	1st	20,328 MW

Another study conducted by Southern Alliance for Clean Energy (Jacob, 2020) shows the near-term forecast for North Carolina is constrained. This study excludes the portion of North Carolina under deregulated electricity markets. So far, North Carolina is still the solar leader in southeastern states. However, the forecast notes that South Carolina will overtake North Carolina in terms of solar watts per customer and Florida is catching up in the solar installation.

North Carolina is proactively seeking ways to reduce carbon emissions over the next five years. In Executive Order 80 (EO80): "North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy", Governor Roy Cooper put forth various goals for the state to accomplish by the year 2025. The most relevant one here is the "reduction of statewide GHG emissions to 40% below the 2005 levels" (State of North Carolina, 2018) and accompanying Clean Energy Plan states the target of "the reduction of GHG emissions from the power sector by 70% below the 2005 levels by 2030 and achieving carbon neutrality by 2050" (NC DEQ, 2019). Executive Order 80 also created the "Climate Change Interagency Council" to help the cabinet agencies work together to achieve those goals (State of North Carolina, 2018). In its 2020 Integrated Resource Plan (IRP), Duke announced several possible pathways that it could take to achieve 70% carbon reductions by 2030 (Duke Energy Progress, 2020).

What is congestion?

Congestion occurs when too many objects converge on the same path, similar to cars moving on the road, or electrons moving across power lines (NRG Editorial Voices, 2018). Traffic jams can be frustrating, but electricity congestion can be expensive and may even cause power outages. [Electrical] Grid congestion occurs due to transmission constraints. This is the lack of a transmission line capacity to deliver electricity without exceeding thermal, voltage, and stability limits (ESIG, 2020), on which is it designed to ensure reliability. When the transmission lines carry electricity, they heat up due to the resistance in the conductor. Being metals, they then expand in length, and weather conditions mediate this change, i.e., the wind will lower the heating and the sun or higher atmospheric temperatures will increase the heating in the lines. If there is excess electricity being delivered that the conductor expands so much as it sags down and contacts the environment around it, it is said to have violated its thermal limits (F.Muñoz, 2019). Voltage limits are implemented to regulate the difference between sending and receiving end voltage of the transmission line between the conditions of full load and no load. Voltage drops per Ohm's Law as current increases ($V_{loss} = I * R$) and hence increasing power demand translates into a higher current (I) and greater thermal loss ($I^2 * R$) and voltage drop. These reliability standards are set by North American Electricity Reliability Council (NERC) and are called System Operating Limits (SOL) (North American Electric Reliability Council, 2004). Constraints lead to inefficiencies, in a way that exceeding either of the three limits means losing energy and hence losing money. Energy could be lost due to curtailment of generation or the forcing of power to adjacent lines leading to line losses. Another inefficiency arises when energy from a low-cost generator cannot be dispatched because the transmission lines in that region are too constrained to carry it. Instead, more expensive generators need to be dispatched. This change of power flows to keep the system from overloading a constraint under a specific contingency, is when we would call the system congested.

Transmission constraint may refer to-

1. The imposition of operational limits on parts of the transmission system in order to ensure reliability (Department of Energy, 2020).
2. The inadequacy of transmission system capacity for the delivery of electricity from potential generation resources, to keep reliability criteria intact (Department of Energy, 2020).

Transmission operating limits are identified to comply with the rules and criteria as specified by NERC and approved by FERC. Constraints result from compliance with the reliability criteria, and it is a misconception that transmission constraints indicate reliability problems. However, mitigation could be warranted when these constraints frequently limit the desired power flows and limits are impinged occasionally to avoid shedding firm load (Federal Energy Regulatory Commission, 2011).

During congestion, power flows are reduced to levels that are not desirable by both the market participants and policies set forward by governments for compliance with the reliability criteria. Exercising the transmission system for a high usage does not necessarily mean that congestion can occur, but when higher levels need to be accessed, congestion can create significant obstacles for the delivery of electrons. Transmission congestion does bring economic costs with it. The costs for consumers that lie on the downstream side of congestion may often times be higher than the costs for congestion, or they may be forced to rely on more expensive sources of generation. Congestion may also make it harder to achieve policy goals of more renewable energy resources on the grid (Department of Energy, 2020). This would happen if congestion created long delays in the buildout of required upgrades to support new electricity generating facilities, hence slowing down the overall pace of new renewable energy buildout and lagging behind timed policy goals. Reliability problems may also arise when constraints limit access to reserves by not having enough line capacity to allow the delivery of power and impact operations.

The objectives concerning the resolution of various kinds of congestions are very important for approaching the solutions themselves. Oftentimes, these objectives may conflict. For example, more electricity from renewable energy resources could help states meet their renewable energy policy targets, and more electricity from cheaper generation resources could result in the overall reduction of the cost of providing electricity to the end-users. If both of these objectives could be met by the same resource, then the cost of transmission buildout could be very expensive because generally good potential renewable energy resources are not close to load centers, requiring longer lengths of transmission lines. The transmission network is very dynamic, and the flows on the system change continuously as load, generation, reliability criteria, fuel prices, and congestion change over various periods from a short-term to long-term horizons (Department of Energy, 2015).

The benefits that come with solving transmission congestions are multiple and are served over a long period. They include but are not limited to, improved reliability, more efficient generation dispatch, higher renewable energy usage, and cheaper electricity on the congested side. The transmission network does not only provide these immediate benefits but also strengthens the overall transmission network more flexibly, across very long lives of more than 40 years (Department of Energy, 2020). Flexibility here means the ability of the system operator to gain access to a wider range of the generation fleet, diversity of resources, and availability of different services like energy, capacity, and ancillary services. More flexible and stronger transmission systems, in turn, create newer and more feasible options for the grid operators to use the network in ways that were not initially planned. In the past, such uses have frequently demonstrated to be very valuable and in some instances have exceeded the primary objective of those solutions. Such example includes empowering the grid operators to adjust seamlessly and efficiently to unanticipated yet dynamic changes in the relative prices of fuels, unexpected outages of major transmission and generation facilities, different renewable energy resources, economic risks, environmental compliances, and natural disasters (Department of Energy, 2020).

Furthermore, it is not always feasible to solve every transmission constraint and the congestion that it causes. Evaluation of benefits of mitigation must be done to justify the costs involved. These benefits could lie in monetary, policy, or consumer impact. These evaluations must account for the ever-dynamic power flows on the grid, the duration of designing, siting, permitting, and building the transmission systems, asset life, and all the benefits - technical, economic, environmental, and reliability - over a long-time horizon (Department of Energy, 2015). When action needs to be taken, decision-makers can turn towards various options to provide solutions. These options could include the creation of financial hedging mechanisms for congestion, the establishment of energy efficiency and demand response mechanisms, construction of new generators, construction of new transmission facilities, and changing other market operational rules and mechanisms.

Friesian Case

The Friesian Holdings, LLC (Facility) is an affiliate of Birdseye Renewable Energy- a developer in Charlotte, North Carolina. Friesian was denied the Certificate of Public Convenience and Necessity (CPCN) for the construction of a solar photovoltaic facility with a capacity up to 70-MWAc to be located in Scotland County, North Carolina (DOCKET NO. EMP-105, SUB 0) because of the high network upgrade costs that it incurred, amongst some other reasons. A CPCN is one of the final regulatory approvals that is needed to begin the construction of an electricity-generating facility. Friesian had a CPCN in place in 2016 when it would have been a Qualifying Facility selling its 75 MW AC output to Duke Energy Progress (DEP). But it requested the North Carolina Utilities Commission (Commission), which approves the CPCN, for the change. Friesian changed its agreement from selling to DEP to selling to the North Carolina Electric Membership Corporation (NCEMC)/ Coops under a new Power Purchase Agreement (PPA), at 70 MW AC, and requested a new CPCN. It would use DEP's transmission network to wheel the electricity over to NCEMC and had a Standard Large Generator Interconnection Agreement (LGIA) in place with DEP. The approximate cost of construction of Friesian's solar facility was about $100 million, and the network upgrades which is triggered on DEP's transmission network were about $223 million. These transmission upgrades were needed to keep the transmission network under SOL. The Public Staff intervened and asked the Commission to deny this CPCN (DOCKET NO. EMP-105, SUB 0). They cited several reasons:

1. These $223 million of upgrades, which consisted of the construction of a new 34.5-kV collector station and a 230-kV breaker station, and the reconductoring of 63 miles of DEP transmission lines, would ultimately fall on the ratepayers or the using-and-consuming-public. Current capacity is constrained, and load flow models indicated that additional generating capacity for any project greater than 20 MW could not be added in this region without these upgrades.
2. They believed that Friesian as a solar photovoltaic facility does not provide firm dispatchable capacity and does nothing to help the winter morning peak.

3. They believed that the energy and capacity provided by this Facility were not otherwise needed to support any immediate or future load growth in the DEP East Balancing Area or the southeastern region of the State.
4. They believed that Friesian failed to sufficiently prove that the Facility's output is necessary to meet any of NCEMC's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance requirements.
5. They believed that Friesian failed to support the beneficial economic impacts that it asserts would flow to Scotland County (the region where Friesian proposed the Facility) with either sufficient detail or specific attribution to the Facility.
6. The southeast region of North Carolina, operated by DEP, already contains significant existing solar generation, and the placement of "additional uncontrolled solar generating capacity" might increase and exacerbate system operational issues. Such issues are already faced by the system operator, and this Facility would provide little help to meeting the winter peak load conditions.
7. They insist on using Levelized Cost of Transmission (LCOT) to provide a standard for the justification of the transmission network upgrade costs related to the interconnection of this proposed new Facility.
8. The Synapse Report fails to provide enough evidence that either this Facility, or the associated network upgrades would provide quantifiable ratepayer savings, reduction of emissions, or other health and environmental benefits.

   This report is significant because it demonstrates that adding increasing amounts of solar and energy storage resources is a major part of the least expensive long-term resource plans for the ratepayers of North Carolina. These savings are in comparison to Duke Energy's proposed natural gas-dominated IRPs (Synapse Energy Economics, Inc., 2019).
9. With regards to Governor Cooper's Executive Order 80 and the clean energy goals associated with it, the Public Staff believes that those are only goals and not plans (State of North Carolina, 2018)

Bottlenecks Pointed Out by The Friesian Case

Friesian brings out several important issues that highlight many possible bottlenecks for the development of renewable energy in the state of North Carolina. With an already high amount of solar generation present, as compared to other states, newer facilities are prone to face these similar issues. These are:

1. Challenge for developers to justify the need for more renewable energy to obtain the CPCN.
2. Solar only projects not helping the winter morning peak.
3. Issue of participant funding and how the network upgrade costs are allocated.
4. Interconnection queue being highly congested and slowing down the study of newer projects.
5. Lack of adequate transmission capacity for new renewable energy projects in certain regions of the state.

The Certificate of Public Convenience and Necessity is a regulatory approval required to start the construction of an electricity generation facility. The North Carolina General Statute 62-110.1d (North Carolina General Assembly) requires the Commission to consider the applicant's arrangement of the transaction of power with the electric utilities, and demonstrate the methods for providing economical, efficient, and reliable electric service. The Commission Rule R8-63b3 (North Carolina Utilities Commission) requires the applicant of the merchant plant to provide the description for the need for the electricity generating facility in the state. Hence, sufficient evidence of need is instrumental to the Commission's decision of whether public convenience and necessity required granting the CPCN. This is done to have an orderly expansion of generation and capacity and prevent expensive overbuilding.

The big question here is what the acceptable evidence for the need for renewable energy in the state is, and how can developers justify this.

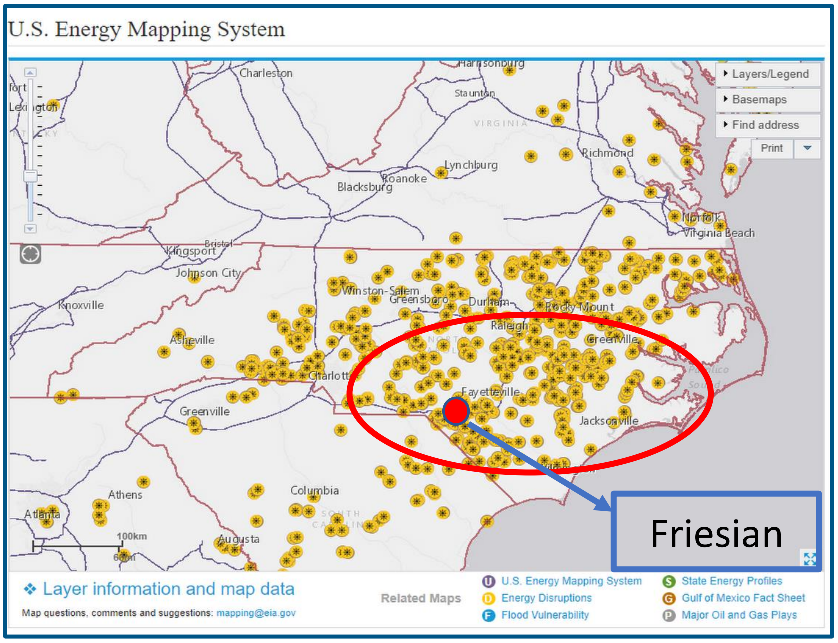

Figure 2 The location of Friesian in regard to a large number of solar projects already present in the region, as of April 2021.

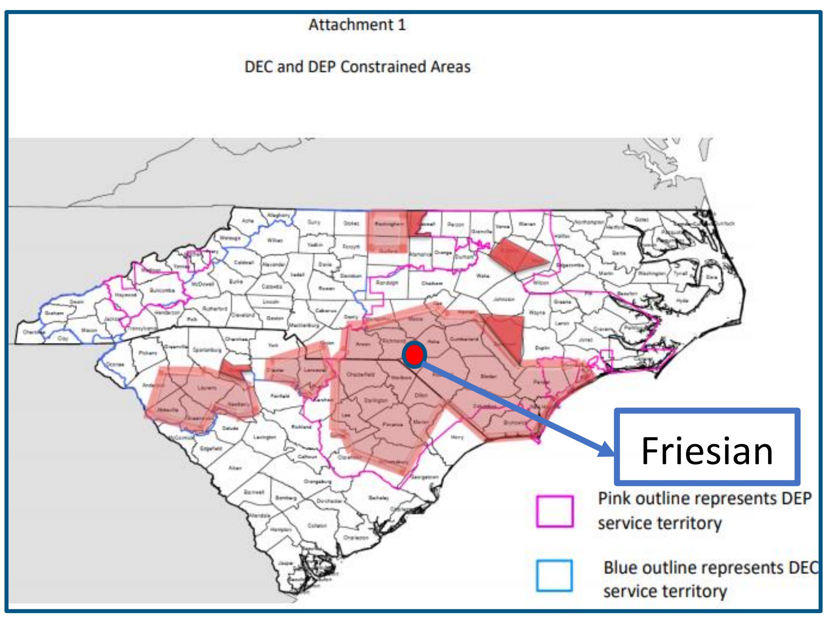

Figure 3 Friesian lies in the shaded area that is marked as constrained by Duke Energy (Duke Energy OASIS, 2019). The pink outline represents Duke Energy Progress's service territory, and the blue outline represents Duke Energy Carolinas'.

Winter Peak and Energy Storage

Peak periods of demand are when the consumers demand electricity at the highest levels. This can occur during a day, month, or season. Across the Carolinas, the peak load occurs in the mornings during the winter seasons and the afternoon during the summer seasons (Susser, 2018). In the Carolinas, the winter peak occurs around 8 am and the summer peak occurs around 5 pm. This corresponds to the need for heating in the winter and cooling in the summer. Peak load also drives the investment decisions that the utilities make to make the infrastructure adequate and resilient to not only match the supply to the demand but also deliver that reliably. The Southern Alliance for Clean Energy (SACE) (John D. Wilson, 2020) analyzed historical demand data throughout the southeast from 1998 to 2018 and tried to understand the key trends as to when and how the utilities in the region are peaking. The two key trends that are relevant here are:

1. The utilities having adjusted their forecasting methods, but they still overestimate the peak demand in the future, despite the nature of peak load shifting from growing to declining.

   This results in them over-building generation and transmission capacities and hence over-charging their using and consuming public.
2. The Southeast region has dual peaks, i.e., different peaks in both summer and winter, although the overall peak still occurs in the summer. The variation in winter peaks seems to be more but there was no evidence of the winter peak growing or declining.

   The annual and the seasonal peaks matter because the strategies for handling them differ. Different generation resources need to be planned and the effect of various demand-side management strategies differ. Solar as a generation resource is more effective in the summer to handle the afternoon peak than it is in the winter to handle the morning peak.

We used the hourly load and generation data from U.S. Energy Information Administration (EIA) (EIA, 2021) to analyze these trends in North and South Carolina combined. It is labeled as Carolinas (CAR) in US Electricity Demand by Region. This data is collected by Form EIA-930, which is a centralized source for hourly operating data from the US electric power system on a current and historical basis (U.S. Energy Information Administration, 2018). Then, we summed the variables over every hour of the day, for each month of the year. For summer, we selected 2019 and not 2020 to avoid any anomalies in usage patterns due to COVID-19. For winter too, we selected 2019 going into 2020. Each point is hence the sum of data of all the days in that month, for that given hour. We selected 2019-2020 data to capture the latest trends in change of electricity consumption.

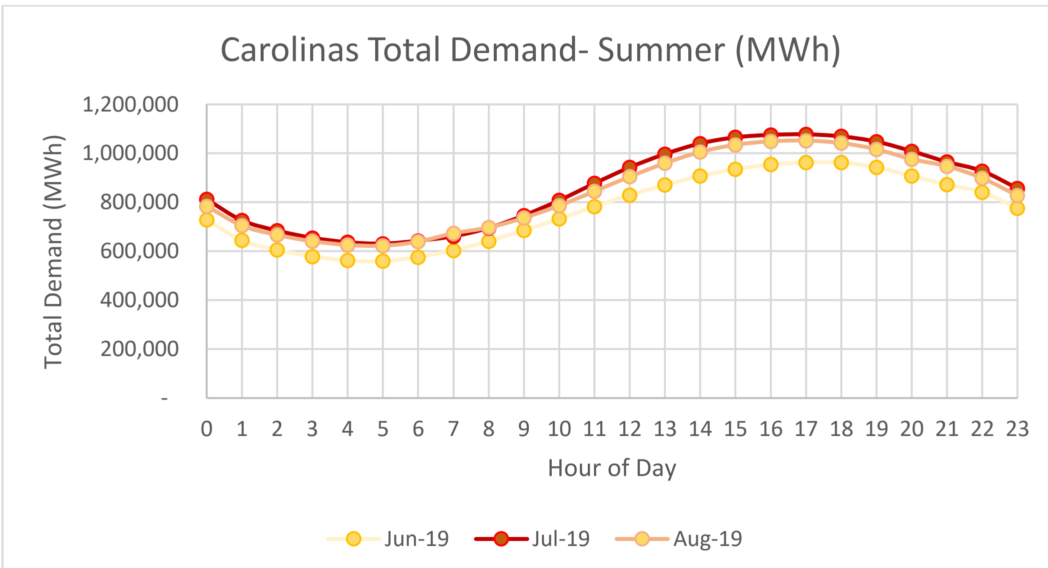

Figure 4 Hourly profile of load (MWh) in the Carolinas in the peak summer months.

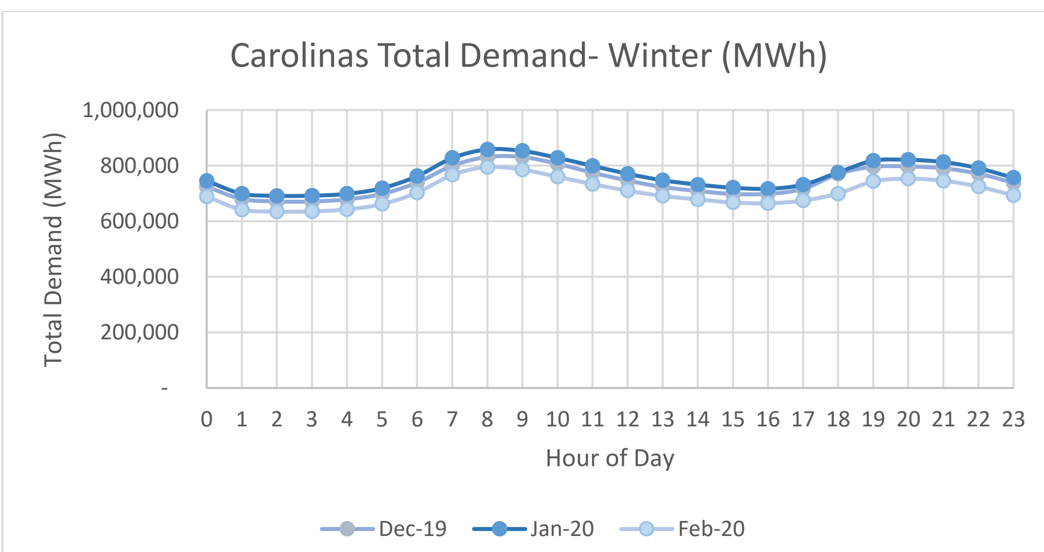

Figure 5 Hourly profile of load (MWh) in the Carolinas in the peak winter months.

After identifying that the summer peak occurs in July, and the winter peak occurs in January, we assessed the generation profiles of all the resources in the mix, particularly solar.

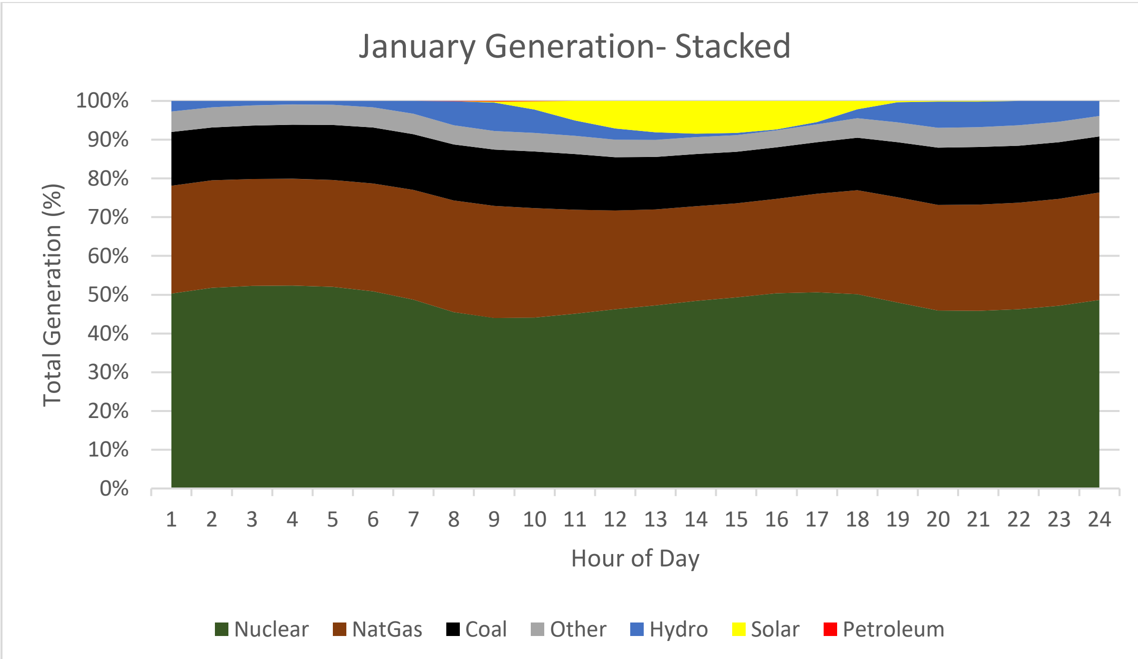

Figure 6 Hourly percentage of generation in the peak winter month of January 2020.

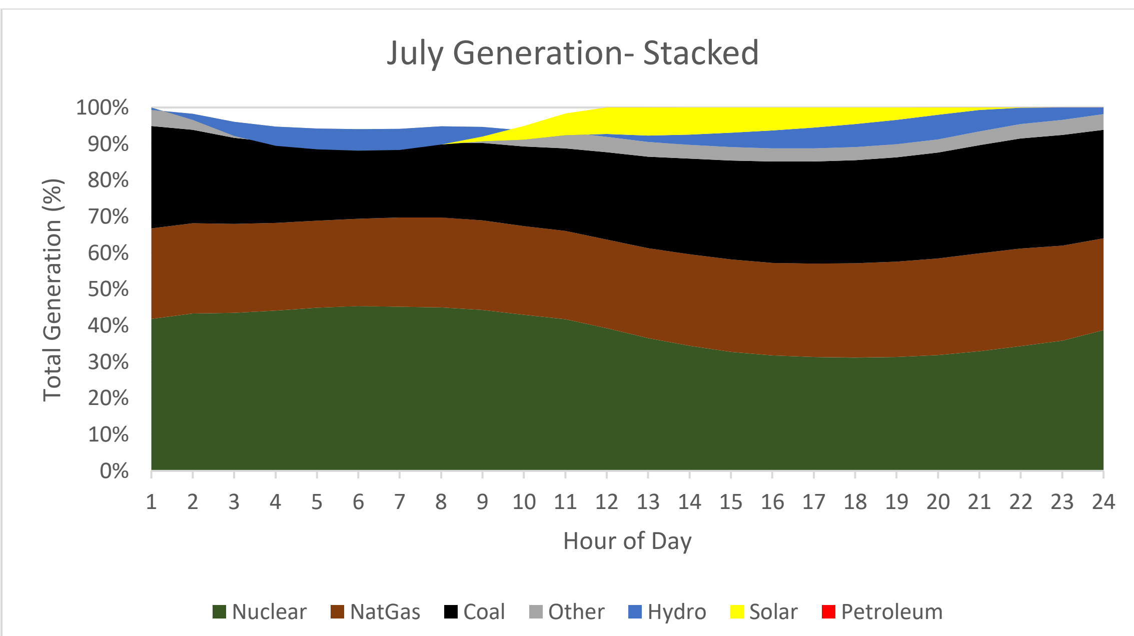

Figure 7 Hourly percentage of generation in the peak summer month of July 2019.
Note the unfilled area before 11 am- that is because pumped hydro is being charged and hence it consumes electricity from the generation fleet.

These figures highlight two important things-

1. As more energy is needed during the summer than during the winter, the percentage of electricity supplied by coal increases by an average of 14.07% of the total generation in winter to 26.35% in the summer. The absolute numbers increase from 2,611,705 MWh for the entire month of January to 6,028,670 MWh for the entire month of July, an increase of 130.8%.
2. The percentage share of electricity from solar on the other hand only increases from 2.28% to 2.65% of the total generation mix.

Table 2 The total generation and percentage generation of each resource during January 2020 and July 2019

Month- Resource	January	July	Percentage Change
Solar (MWh)	423,535	659,344	55.68%
Solar (%)	2.28%	2.65%	
Hydro (MWh)	631,724	286,890	-54.59%
Hydro (%)	3.31%	0.45%	
Other (MWh)	916,962	943,946	2.94%
Other (%)	4.95%	4.27%	
Petroleum (MWh)	5,513	61	-98.89%
Petroleum (%)	0.03%	0.00%	
NatGas (MWh)	5,005,665	5,872,812	17.32%
NatGas (%)	26.99%	26.09%	
Coal (MWh)	2,611,705	6,028,670	130.83%
Coal (%)	14.07%	26.35%	
Nuclear (MWh)	8,941,747	8,780,337	-1.81%
Nuclear (%)	48.37%	40.19%	
Total	18,536,851	22,572,060	21.77%

As evident from these figures and table, coal and natural gas provides about 41% of the total generation in January and 53% in July. These carbon-polluting, firm, and dispatchable capacity resources have to be brought offline eventually to make the system carbon-free.

We then plotted the load curves and the solar generation curves across the day for both January and July. The correlation between the summer load profile and the summer solar generation profile is 0.59 whereas the correlation between the winter load profile and the winter solar generation profile is 0.04. There is rather a negative correlation during the winter at the time when the sun is shining. This raises the question of how to eventually replace the firm and dispatchable capacity resources from carbon-emitting to carbon-free, mainly solar as one of the major generation resources. Adding just solar will not be very helpful over the long horizon because not only will it not provide electricity directly during the winter morning peak, but it will also not provide electricity directly when the sun is not shining during all seasons. Hence, we need to bring energy storage into the equation to make the electricity from solar more flexible and dispatchable.

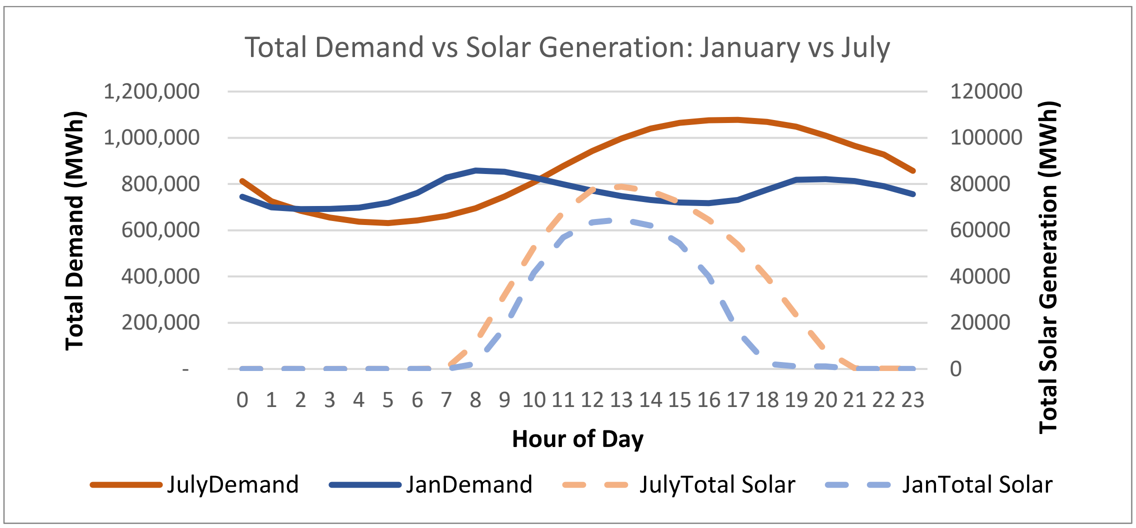

Figure 8 Total load (MWh) and the total electricity generation (MWh) from solar in January 2020 and July 2019.

Peak Shaving

Peak shaving is the reduction of the net amount of electricity used in the system during the peak periods of demand. Net electricity is the total electricity that has to be supplied via the transmission side of the grid and is the difference between the total load and the electricity produced behind the meter or locally. Peak shaving can be done by (Alptekin, 2019):

1. An individual commercial or industrial (C&I) customer- by not using electricity from the grid and
    a. either not using much electricity at all, or,
    b. using a backup generator.
2. The distribution company- by implementing energy efficiency programs to reduce the total load on their system gradually and over time.
3. The system operator- by implementing demand response programs calling for a reduction in electricity use during peak periods and incentivizing the customers to participate to reduce their loads.
4. By adding energy storage, charging it when there is an excess of generated capacity or during off-peak hours, and discharging or dispatching it during the peak periods.

Using energy storage to level off the electricity consumption is also a method of load shifting. This is a short-term reduction in electricity consumption followed by an increase at a later time (GridBeyond, 2018). By reducing the peak load, utilities can plan to invest less in peaker plants that exist to serve only during peak periods, which do not happen very frequently throughout the year. This can not only save the consumers money but also make the electricity consumption more predictable to handle.

To tackle the winter morning peak load and to keep adding more solar in the generation mix of the Carolinas, we calculated the amount of load that could be shaved off from the morning peak hours. The issue of solar projects not contributing to tackling the winter morning peak was brought up in the Friesian case and we attempt to calculate the amount of energy storage that needs to be added to help bring solar online. Energy storage can be charged from solar during off-peak hours and be used as a generation resource to supply electricity during peak hours.

From the load curve for the Carolinas, we saw that the demand for electricity starts to peak at 7 am in the winter month of January, peaks fully at 8 am, and goes down slightly by 9 am. The solar production is almost zero and just starting to pick up during this time. We used these three hours of peak consumption and shifted the load to the three hours of highest solar production. These latter hours also correspond to declining electricity consumption. We assessed shaving 10% of the peak and shift from on-peak to off-peak hours. The total energy storage required for a 10%-3 hour shift is 3,811 MW.

We then ran a sensitivity analysis to consider shaving both shorter and longer duration of peaks- from 1 hour to 12 hours, and from shaving 5% of the total load to shaving 50%. This results in a minimum of 1,718 MW, a maximum of 23,129 MW, and an average of 10,391 MW of energy storage capacity that would be needed.

For reference, according to Duke Energy Progress's Integrated Resource Plan (IRP) (Duke Energy Progress, 2020) filed in 2020 says that Duke plans to install 140 MW of nameplate battery storage in early-to-mid-2020s. A research study by Strategen for California Energy Storage Association (CESA) shows that California will require between 2,000 to 11,000 MW new operational long-duration energy storage by 2030 and 55,000 MW by 2050 to support its 100% clean electricity goals (Strategen, 2020). Hence, in comparison, even though California has about 1.5 times higher electricity consumption, Duke Energy in North Carolina falls short by 13 to 78 times in its energy storage goals.

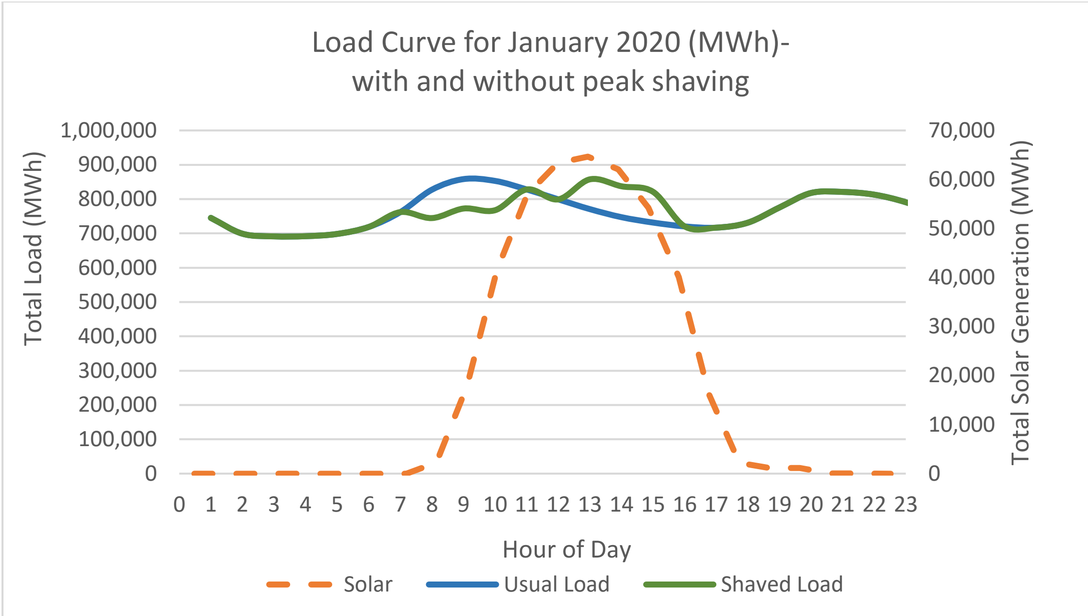

Figure 9 Shaving the peak and shifting it from on-peak to off-peak *hours.*

Table 3 Sensitivity analysis of different sizes (MW) of energy storage needed.

Hours of Shaving		12	10	8	6	4	2	1
Total Load for that duration(MWh)		412,436	348,515	283,889	218,513	185,031	76,835	38,702
Capacity of Energy Storage Required (MW)								
		Hours of shaving						
% of peak shaving		12	10	8	6	4	2	1
	5%	1,718	1,743	1,774	1,821	2,313	1,921	1,935
	10%	3,437	3,485	3,549	3,642	4,626	3,842	3,870
	15%	5,155	5,228	5,323	5,463	6,939	5,763	5,805
	20%	6,874	6,970	7,097	7,284	9,252	7,684	7,740
	25%	8,592	8,713	8,872	9,105	11,564	9,604	9,676
	30%	10,311	10,455	10,646	10,926	13,877	11,525	11,611
	35%	12,029	12,198	12,420	12,747	16,190	13,446	13,546
	40%	13,748	13,941	14,194	14,568	18,503	15,367	15,481
	45%	15,466	15,683	15,969	16,388	20,816	17,288	17,416
	50%	17,185	17,426	17,743	18,209	23,129	19,209	19,351

Storage as Transmission Asset

Energy storage has typically behaved as a source of energy supply. It serves to improve renewable energy production, supply backup power, and provide a lower-emission alternative to fossil fuel-based power generation. It is also increasingly being used as an ancillary service to provide frequency regulation on the grid (Roselund, 2019). Recently, however, utilities and regulators have started looking at energy storage as a part of the energy delivery system, like electric transmission or distribution infrastructure. Storage-as-a-Transmission Asset (SATA) refers to the use of storage to provide reliability services on the transmission side of the grid (Energy Storage Association, 2020). SATA has the potential to either push or pull electricity to enable power flows on the grid. This is done by integrating storage resources on the transmission equipment and is similar to the thought of adding an extra lane to a highway only for the rush hour of traffic. Used in this way, energy storage can not only improve the performance of existing transmission lines by reducing constraints on them but even prove to complement the buildout of newer transmission lines. The planning and regulatory framework currently either prevent this application or inhibits storage from being opted to be used as a transmission-based solution, receive the same benefits, and be allowed to follow the same market rules as transmission assets.

Energy storage can also be used as "dual-use." This refers to the ability of a single energy storage asset to offer both generation and transmission services and be compensated for both. This ability is increasingly being valued by the electricity sector's stakeholders and offers a vast new potential market for various energy storage technologies, while also competing against the conventional solutions of lines and poles (Energy Storage Association, 2020).

Benefits

SATA offers a wide range of benefits to the owners, the operators, the end-users, and the grid. The main reason for using storage as a transmission asset is to provide reliability services by either absorbing or injecting reactive and real power to replicate power flows. For example, it has the potential to replicate the power flows if any component of the transmission system, like the transformers, faced an outage. Storage can prove to be an alternative transmission solution to relieve congestion by replicating power flows instead of the conventional buildout of a new network along a congested corridor (Energy Storage Association, 2020).

Without the need for much siting and permitting, the timeline to deploy storage as transmission assets can be relatively very fast. The area occupied by energy storage systems is about the size of a shipping container as compared to conventional transmission wires and poles, hence posing a smaller physical footprint. Due to this, they can also evade community-based issues like NIMBY-ism (Not In My Back Yard). The dual-use of SATA makes it more cost-competitive as it offers a higher rate of utilization. This is because it can be used for both transmission-based reliability services and generation-based market services.

There need to be reasonable market rules for energy storage to be deployed as transmission assets. There is a need for joint efforts from both FERC and the North Carolina Utilities Commission to open the market for SATA. Given the monopolistic nature of Duke Energy being the sole transmission owner in the state, the potential of SATA needs to be assessed fairly. If storage is deployed as SATA, bypasses the generation interconnection queue process, and is later used as a generation resource, it could create contention for other generation resources owing to receive an unfair advantage.

Grid Enhancing Technologies

Looking again at the roadblocks to integrating more renewables, the transmission comes up to be a major limiting factor, fully evident by the Friesian Holdings case and referring to the transmission system of the southeastern part of North Carolina. Duke Energy highlighted constrained areas in the Carolinas on their OASIS website and there was about 2,800 MW of solar generation waiting in the interconnection queue, as of August 2019 (Duke Energy Progress, 2019). There is a timing gap between how long renewables take to develop (which is months to a few years) and how long transmission takes to develop (which is a few years up to decades). Utility-scale renewable energy facilities are generally more cost-effective on a $/MWh basis than distributed-side energy resources (Lazard, 2020).

The Working for Advanced Transmission Technologies (WATT) Coalition and the Brattle Group (T. Bruce Tsuchida, 2021) analyzed the amount of additional renewable energy that can be interconnected to the grid by deploying Grid-Enhancing Technologies (GETs), using the Southwest Power Pool (SPP) as an illustrative case study. GETs are hardware or software that increase the capacity, efficiency, and/or reliability of transmission facilities. They enhance the operation of the transmission network, make planning more effective, and replace the buildout of new transmission facilities. This helps in bridging the "timing gap" until more permanent transmission expansion solutions can be enacted. This study focused on the combined impact of these three Grid Enhancing Technologies-

1. Topology Optimization: This will reconfigure the re-routing of power flow around congested and/or overloaded facilities and still meet the reliability criteria. The switching infrastructure required to perform this re-routing is already in place and circuit breakers can be controlled remotely by the transmission owner (T. Bruce Tsuchida, 2021).
2. Advanced Power Flow Control: This will inject voltage in series with a facility to alter the effective reactance, thereby pulling power on to under-utilized facilities or pushing power off overloaded facilities. "Flexible Alternating Current Transmission Systems (FACTS)" and "Phase Shifting Transformers (PSTs)"/ "Phase Angle Regulators (PARs)" devices help the system operator control the power flow over a given path. By increasing the reactance, power flows will be pushed away, and vice-versa (T. Bruce Tsuchida, 2021).

3. Dynamic Line Ratings (DLR): They alter the thermal ratings based on real-time weather conditions including air temperature, wind speeds, and the real-time monitoring of consequent line behavior (T. Bruce Tsuchida, 2021).

The main focus of Grid Enhancing Technologies is on operational improvements and they can be implemented in a much cheaper fashion than traditional transmission technologies, and at a faster rate. This is like building an additional lane on the highway to reduce congestion (the long-term investment) or using a GPS (Global Positioning System) system to avoid traffic jams (the operational improvements).

The Brattle study (T. Bruce Tsuchida, 2021) quantified the advantages of the three Grid Enhancing Technologies combined for integrating renewable energy resources (mostly wind) using the Southwest Power Pool as the test bed. The objective was to find the maximum renewable capacity (MW) and energy (MWh) that could be integrated under a business-as-usual scenario, called the "Base Case", and by using Grid Enhancing Technologies, called the "With GETs Case", sequentially by deploying Dynamic Line Rating first, Topology Optimization later, and Advanced Power Flow Control last, by simulating the entire SPP system (T. Bruce Tsuchida, 2021). Then, the economic benefits and reduction of carbon emissions were assessed.

The study found that GETs enabled the addition of new renewables by more than two times to be interconnected to the grid. 9,430 MW of potential renewable capacity was considered which has interconnection agreements executed. 2,580 MW could be integrated with the Base Case and 5,250 MW in the With GETs Case, all without any transmission upgrades. Of the additional 2,670 MW (5,250 MW – 2,580 MW), 2,630 was wind and 40 MW was solar (note that Kansas and Oklahoma regions have one of the highest onshore wind resource potentials in the country). The GETs cost about $90 million, with annual O&M costs of about $10 million. They produced annual production cost savings of about $175 million, resulting in a payback period of about 6 months, annual reduced carbon emission of about 3 million tons, and creating an estimated 650 long-term jobs and 11,300 short-term jobs.

Translating to potential nationwide benefits, GETs could provide annual production cost savings of over $5 billion, annual reduced carbon emission of over 90 million tons, 330,000 short-term and 20,000 long-term jobs, and about $1.5 billion in local taxes and local land lease revenues (T. Bruce Tsuchida, 2021).

Overall:

1. North Carolina and the transmission operator, Duke Energy, should look into using these commercially proven Grid Enhancing Technologies to potentially-
    a. Reduce congestion on their network.
    b. Increase the addition of more renewable energy sources.
    c. Reduce the timing gap between renewable energy development and transmission development.
    d. Reduce carbon emissions from their generation fleet.
    e. Reduce electricity rates for their customers.
    f. Create jobs.
2. The North Carolina Utilities Commission should require GETs to be integrated with the transmission operations and planning of Duke Energy.
3. Renewable energy developers should be allowed to request and have GETs offered as the least-cost solution to interconnect to the grid.

Interconnection Queue

Interconnection Application Process

Interconnection refers to the procedure by which a utility-scale renewable energy project connects to transmission networks as a generating facility. To ensure the reliability of transmission networks, utilities need to conduct transmission studies to evaluate the potential impacts associated with a project before approving interconnection requests. An interconnection queue is the order in which utilities process transmission studies for requesting projects. After a developer initiates an interconnection request, a three-step process shown below is needed to determine the interconnection costs and construction sequencing.

1) Feasibility Study

A feasibility study usually requires power flow modeling and short circuit study. Developers need to provide documents that specify designated and alternative Point of Interconnection (POI) to the transmission or distribution system and configuration. POI is defined as “the physical location on the power system of the change ownership between Duke Energy and the project” (Duke Energy Progress, 2018). The purpose of a feasibility study is to identify violations of the circuit breaker, short circuit capability limits, thermal overload, and voltage limits caused by the interconnection.

2) System Impact Study

In addition to short circuit analysis and power flow analysis, this step also requires stability analysis. Developers need to provide additional information if the POI needs to be changed based on the results of the Feasibility Study. The purpose of the System Impact Study is to evaluate the impacts on the reliability of the transmission system of the projects.

3) Facilities Study

This step requires facilities cost estimation analysis. The facility study determines the nature and costs of the equipment, engineering, and construction work needed to interconnect the projects, such as electrical configurations of the transformers, switchgear, meters, and other substation equipment.

Interconnection Application in North Carolina

The surging solar growth in North Carolina reflects a strong interest in renewable energy in the market but creates challenges to the interconnection process of Duke Energy. During the transmission study process, developers are responsible for informing Duke Energy of the location of the projects and the intended Points of Interconnection. The transmission impacts are then studied by Duke Energy based on the location. Unless a project is located very close to an eligible substation, the distribution feeders often need to be upgraded and reconductored to support the interconnection (Solar and Lease, n.d.). The further away the POI is from the nearest substation, the higher the costs will be needed. This makes developers want to interconnect with a substation as near as possible to the project sites to avoid extra costs.

The capacity of substations for interconnection is constrained by technical specifications. A substation is less available to be interconnected if it is located in an area with many generating facilities. It makes interdependency a crucial issue when the impacts of a requesting project are evaluated. Interdependency describes the condition when the transmission impacts of one project are determined or complicated by other projects. For example, the transmission impacts of projects are interdependent if they request to interconnect with the same substation.

Currently, Duke Energy has been processing interconnection applications in a serial manner. For the convenience of references, we assume there are three interdependent projects in a serial queue as Project A, B, and C. According to the interconnection procedures published by Duke Energy Carolina (Duke Energy Carolinas, 2019), Project B needs to conduct System Impact Studies under two scenarios: Project A is complete, or Project A is withdrawn. In the stage of Facility Study, Project B needs to wait until Project A makes payments for required transmission upgrades. As an alternative, Project B can proceed with the Facility Study but needs to repeat the process if Project A is eventually withdrawn. Likewise, Project C is subject to the impacts of Project B.

Interdependency within a serial interconnection queue makes the decisions of former projects significantly impact latter projects. It is because the sequence of interconnection queues determines cost assignment priority and timing priority. The following part explains how a serial queue has increased the cost allocation uncertainty and slowed down queue speed.

Cost assignment priority: Expensive Upgrade Costs

As mentioned in the previous section, the facilities study required in the final stage of the three-step process identifies and estimates the costs of transmission upgrades needed to maintain network stability. Due to a serial study manner, this cost will only be allocated to the "cost trigger" project whose interconnection requires additional transmission investment. Although the upgrades may also benefit subsequent projects, the "cost trigger" project is restricted from sharing the costs with others in the short term. The transmission upgrade costs are usually unaffordable and can easily make one project financially infeasible. We summarize a few transmission upgrade examples obtained from Duke Energy in Table 4. It can be concluded that many transmission upgrades are needed due to overloading issues such as thermal and voltage constraints. These examples of transmission upgrades typically require over $10 million and take years to complete. One of the examples shown below is Cumberland and Richmond County where transmission lines are overloaded. According to Table 4, a $200 million investment and at least 4 years are expected to upgrade the transmission facilities in this area. The same is true in Brunswick County, where an investment of over $100 million and at least 5 years are needed for upgrades. The projects responsible for the upgrades can either collect funds or withdraw the interconnection application. In either case, they will cause delays to subsequent projects with high uncertainty in timing and financing due to interdependency explained earlier.

Table 4 Examples of Areas Required Transmission Upgrades in North Carolina (Generator Interconnection Requirements and Locational Guidance, 2019)

Location	Utility	Status	Investment Estimated	Time to Complete
Caswell, Guilford, and Rockingham	DEC	Risk of post-contingency thermal loading issues	N/A	N/A
Cumberland and Richmond	DEP	Transmission line overloads	Over $200 million	At least 4 years
Brunswick	DEP	Conflict with the operation of nuclear generators	Over $100 million	At least 5 years
Wayne	DEP	Heavy loadings	Around $42 million	N/A
Nash	DEP	Heavy loadings	Around $15 million	N/A

Timing priority: Slow and clogged interconnection process

In addition to determining cost allocation priority, the serial study process also builds a timing-based priority with an interconnection queue. However, with renewable energy growing and interconnections requests increasing, the current queue in North Carolina is overwhelmed. From the table in the Queue Reform Request submitted by Duke Energy to Federal Energy Regulatory Commission (Table 5), we can see most of the requests are delayed in 2020. A projection by Southern Alliance for Clean Energy (SACE) points out that the interconnection delays are the primary reason why the near-term solar installation potential in North Carolina is constrained (Jacob, 2020). North Carolina's leading position in the southeastern solar markets can therefore possibly be overtaken by South Carolina. Although South Carolina is also within the service territory of Duke Energy with a similar interconnection policy, a slow and clogged interconnection queue is a bigger constraint for North Carolina for further renewable energy development due to a higher solar penetration rate.

Table 5 Duke Carolinas Utilities Timeliness of Generator Interconnection Studies (Duke Energy, Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT, 2021)

Percentage of Delayed Studies	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Feasibility Studies	DEC: 100% DEP: 100%	DEC: 100% DEP: 33%	DEC: 100% DEP: 100%	DEC: 100% DEP: 33%
System Impact Studies	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%	DEC: 100% DEP: 67%
Facilities Studies	DEC: 0% DEP: 75%	DEC: 0% DEP: 75%	DEC: 100% DEP: 100%	DEC: 100% DEP: 100%

** This table includes data for both North Carolina and South Carolina.*

From Duke Energy Progress and Duke Energy Carolina's interconnection queue, we plot the number of projects by application stage in North Carolina in Figure 10 and Figure 11 based on Transmission Queue Reports from DEC and DEP accessed in January 2021 (DEC Generator Queue, 2020; DEP Generator Interconnection Queue, 2021). Figure 10 shows the number of projects in each stage of interconnection applications. The order of stages on the horizontal axis except for "Withdrawn" and "Cancelled/Terminated" is based on the time sequence in the study process. It can be observed that "Withdrawn" projects rank the highest among all categories, even though we consider projects under design and construction as "Completed". As for stages before final decisions (i.e., Withdrawn, Cancelled/terminated, Commercial Operations), the highest portion of projects was stuck in the stage of "System Impact Study". This implies that among the three studies needed for interconnection, the system impact study may be the most time-consuming. The data corresponds to what we discussed about interdependency when projects need to wait until former projects make upgrades payment before processing Facility Study. The unaffordable costs and long awaiting time due to transmission upgrades can therefore be one of the reasons that projects withdraw. Moreover, these withdrawals in turn make the queue more inefficient because time has been spent on the studies of projects that did not achieve commercial operation.

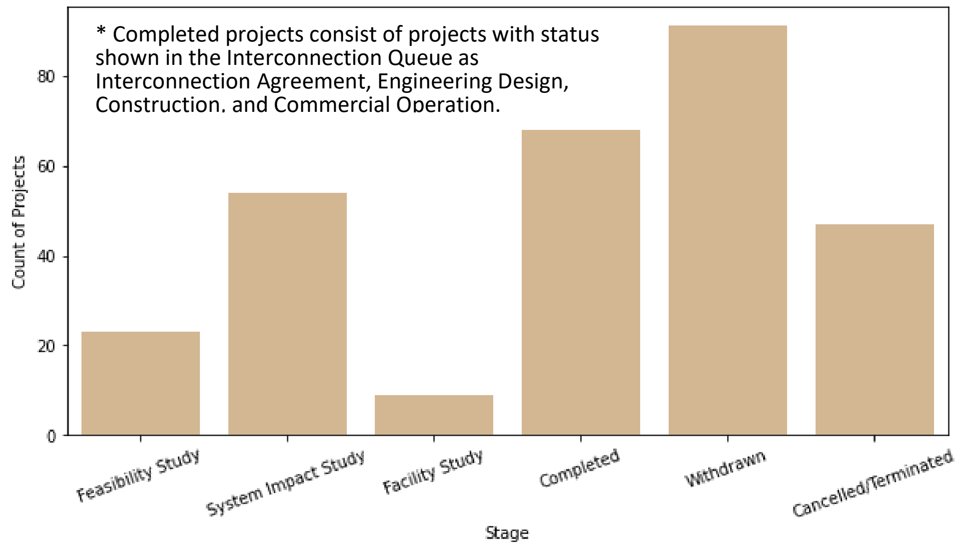

Figure 10 Count of Projects by Application Status
(DEC Generator Queue, 2020; DEP Generator Interconnection Queue, 2021)

Figure 11 shows that the number of withdrawn projects in detail by queue year, which is the year that a project starts the application and enters the queue. It can be concluded that the number of withdrawn projects has been increasing since 2014. Although the number of withdrawn projects seems to slightly decrease after 2018, it is because many projects in recent years are still under study. Because they have not been evaluated for transmission impacts and required upgrades, those projects are still at the risk of withdrawal. We notice that there are projects that initiate the interconnection requests in 2017 but are still in the stage of "System Impact Study" after four years, indicating the extremely low speed of queue.

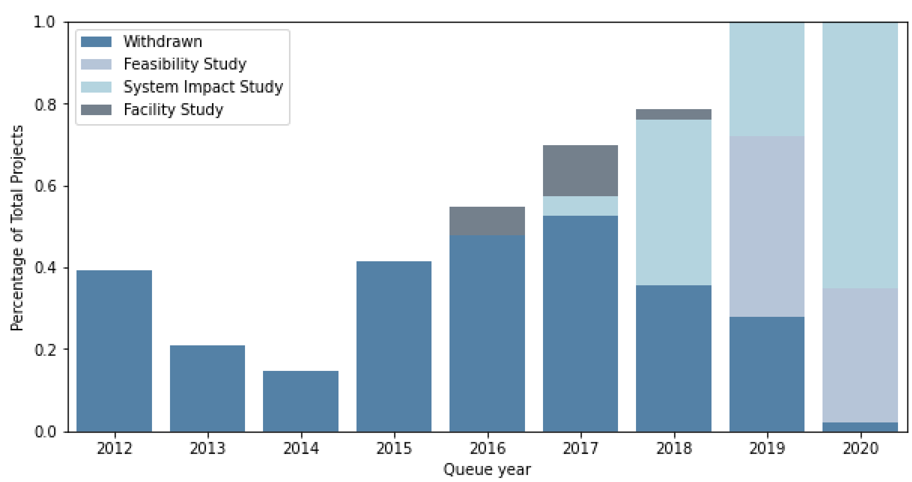

Figure 11 Count of Withdrawn Projects and Projects Under Study by Queue Year
(DEC Generator Queue, 2020; DEP Generator Interconnection Queue, 2021)

Queue Reform

Intending to speed up and reduce disruptions of the interconnection study process, Duke Energy revised the interconnection policy for generating facilities. With over one year's efforts, Duke filed a queue reform proposal in May 2020, also known as the Definitive Interconnection Study Process (Duke Energy, Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT, 2021). After receiving and replying to comments from stakeholders, Duke Energy filed a revised queue reform proposal in August 2020. It was then approved by North Carolina Utilities Commission but still needs to be reviewed by South Carolina Public Service Commission and FERC for adjustments.

From serial to cluster study

Transforming from a serial to cluster study is a strategy is intended to improve the efficiency of the interconnection queue. We summarize the process of the cluster study proposed by Duke Energy in Figure 12 according to the description in the Queue Reform Filing (Duke Energy, Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT, 2021). To improve the timing and certainty of the interconnection queue, Duke Energy plans to have a transition from the current serial to a cluster process. A cluster study process puts project requests into study groups. It provides a window of application to accept transmission requests. Unlike the denotation we have for a serial study as Project A, B, and C, interdependent projects will enter the queue with the same sequence number in a cluster study. Afterward, all projects submitted in the window will be studied as a group. A cluster study process can speed up the application process and increase decision transparency. If transmission upgrades are needed, the costs would be allocated among the cluster based on the MW impact factor of each project.

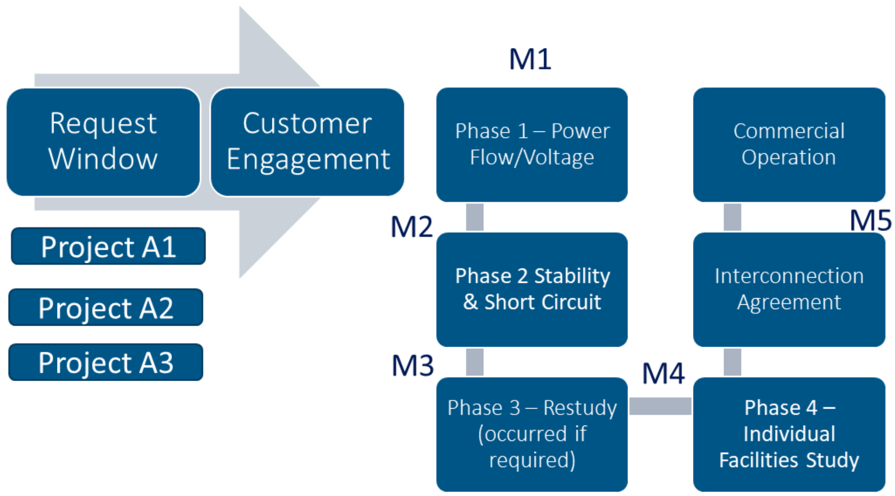

Figure 12 Definitive Interconnection Study Process with Five Milestones (M1-M5)

The advantages of a cluster process are obvious. First of all, the cluster process is far more time-efficient than a serial process. According to the Queue Reform filed to FERC (Duke Energy, Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT, 2021), Duke Energy anticipates that the study portions excluding customer engagement periods between milestones will be 390 days. If restudy is needed, each study adds 5 months to the total time. Although this anticipation is longer than the time normally needed by the current serial process, a cluster study is believed to be more efficient because it evaluates multiple projects simultaneously. Secondly, interdependency can be better understood with sufficient data when projects are studied as a cluster. In addition to speeding up the study process, a better understanding of interdependency ensures the stability and resiliency f transmission networks. Last but not the least, a cluster process facilitates transparency when distributing the transmission upgrade costs among projects. The impacts-based allocation method can avoid withdrawal, for example when small projects trigger unaffordable costs in a serial process.

Readiness-Based Security and Penalty

Increasing application security and withdrawal penalty is another major change proposed in the queue reform as a strategy for ensuring a stable operation of cluster studies. Table 6 summarizes the requirements for applicants in terms of security and penalty by milestone. A highlight of the table is that Duke Energy would divide applicants into two categories by readiness. Projects can demonstrate readiness by providing evidence related to sale contract, resource planning involvement, continued site control, etc. (Duke Energy Interconnection Queue Reform, FERC Stakeholder Meeting, 2021)

Table 6 Security and Penalty for Projects with and without Readiness

	M1 Power Flow Study	M2 Stability	M3 Facilities	M4 Pre-IA	M5 Post- IA	Commercial Operation
With readiness						
Cumulative Security	1 x SD	1 x SD	1 x SD	1 x SD	9 x SD	
Security by milestone	1 x SD	0	0	0	8 x SD	
Penalty	1 x SD	1 x SD	1 x SD	1 x SD	9 x SD	
Without readiness						
Cumulative Security	2 x SD	3 x SD	5 x SD	7 x SD	9 x SD	
Security by milestone	2 x SD	1 x SD	2 x SD	2 x SD	2 x SD	Note: SD = Study Deposit IA = Interconnection Agreement
Penalty*	2 x SD	3 x SD	5 XSD	7 x SD	N/A	

Source: Duke Energy Interconnection Queue Reform FERC Stakeholder Meeting, February 3, 2021

Figure 13 and Figure 14 show an intuitive plot for a comparison between the two categories by assuming a project which has a study deposit of $150,000 (referred to as Project A). Either demonstrating readiness or not, projects are required to have the same amount of security for commercial operation when preceding Milestone 4. However, projects which demonstrate readiness are required to pay a smaller portion of security in the early stage of the application, i.e., between Milestone 1 to Milestone 3. On the other hand, projects without readiness need to pay higher security in the early stage and will be subject to higher penalties if they choose to withdraw. Projects with readiness can have both higher flexibility and lower risk in project financing. Therefore, the new scheme can encourage projects to demonstrate readiness before entering the cluster study and prevent last-stage impacts on the cluster as much as possible.

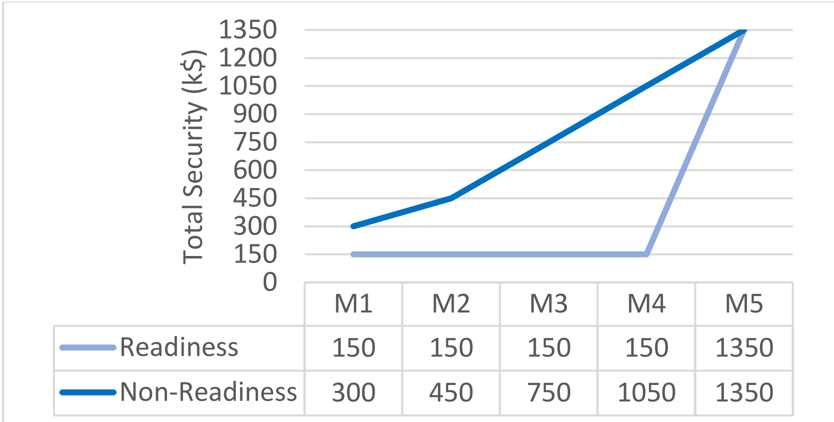

Figure 13 Total Security Required for Project A with and without Readiness

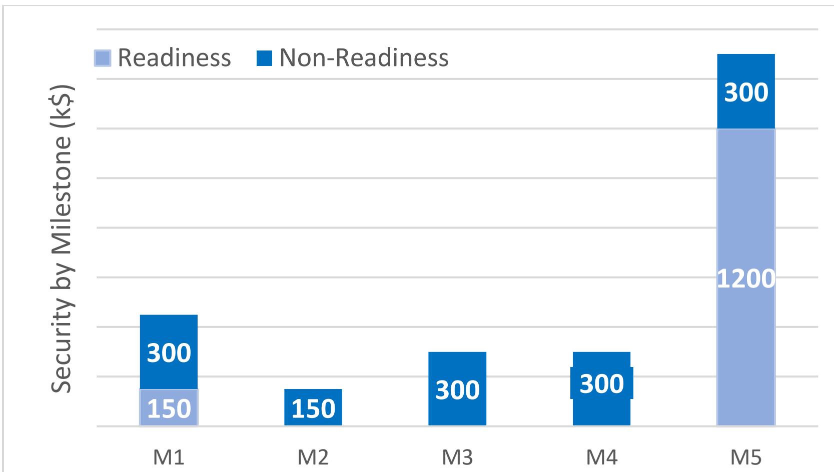

Figure 14 Security Required for Project A with and without Readiness by Milestone

A transition from a serial to cluster process can mitigate part of the bottlenecks for solar development by avoiding delays and increasing certainty, but it is just a modest improvement. As examples shown in Table 4, the delays of interconnection request is not only caused by the serial study approach but also because of the long lead time intrinsically required by transmission upgrades.

Transmission Case Study – California

Introduction to California ISO

Similar to other deregulated wholesale power markets, such as PJM Interconnection, and Midcontinent ISO, the state of California also has its independent system operator, CAISO. As the leading state in the United States regarding renewable integrations (Solar Energy Industries Association, 2021), the state has faced steep challenges throughout the years and developed innovative solutions to resolve the difficulties. Through studying California, North Carolina can gain insights on the nature of upcoming system adjustments when more renewables are deployed within the state.

CAISO conducts annual system planning through obtaining key inputs from the California Public Utilities Commission and California Energy Commission to translate proposed legislative policed into actionable measures that can help the state to meet its policy goals, ensure the grid reliability requirement, and evaluate potential projects that can improve the existing economic benefits for consumers. In each annual transmission planning, CAISO identifies key trending needs within the state and develops actionable steps or recommendations. In the latest report 2019-2020, the ISO has identified several trending needs: The state has observed relatively flat load growth resulting mainly from the statewide encouragement of energy efficiency and behind-the-meter generation (California ISO, 2019 - 2020 Transmission Plan, 2020). Due to the lack of economical-viable storage devices, renewables, particularly solar, are unable to accelerate the retirement rate of non-renewable generation. During low renewable hours, fossil fuel plants still play a vital role in ensuring system reliability. Although the combination of preferred clean generation and conventional sources needs to be continuingly emphasized, the planned upgrades for the transmission system in the 2019-2020 upgrades plan left little room for these integrated projects to materialize (California ISO, 2019 - 2020 Transmission Plan, 2020). The state also conducted simulations based on various levels of potential Renewable Portfolio Standards goals (California ISO, 2019 - 2020 Transmission Plan, 2020). With the state aiming for 60% RPS mandated by SB 100 for 2030, the simulation did not reveal any need for major transmission infrastructure upgrades. The tipping point occurs at 71% RPS goal where major enhancement of the existing power infrastructures will be triggered.

Transmission Planning 2019-2020

The transmission planning each year from CAISO aims to provide three categories of solutions for the power infrastructures: reliability, public policy, and economic needs. The ISO utilizes a three-phase approach, consisting of the development of the study plan, conduct technical analysis, selecting solutions for approval, and solicit prospective developers who are interested in building new transmission facilities identified in the plan (California ISO, 2019 - 2020 Transmission Plan, 2020).

In the study plan, the ISO utilized load forecasting using the California Energy Demand Forecast 2018-2030 (Califonia Energy Commission, 2018). The new forecast addressed two key drivers contributing to the flat and occasionally declining gross load: energy efficiency and behind-the-meter generation. Particularly, behind-the-meter generation, such as roof-top solar, has greatly impacted the load profile and hence shifted the peak "net sales" outside of the traditionally planned timeframe. As more distributed generation resources come online, the peak is expected to continuously adjust itself and require improved modeling efforts to predict. Additionally, certain measures may counter the savings achieved by energy reduction programs such as energy efficiency or demand response. For instance, as the decarbonization efforts continue, the transportation sector is getting rapidly electrified and the demand for energy will be shifted from petroleum to the grid, creating additional peaks in the overall load profile.

Regarding the existing gas-fired power plants, the economic pressure has been exacerbated by the significant addition of clean energy generation resources. Additionally, SB 100 established a long-term plan to move the state into a GHG-free electricity territory (Senate Bill No. 100, 2018). Retirement and eventual elimination of gas-fired generation are inevitable. The California Public Utilities Commission (CPUC) has arrived at a decision (19-04-040) that will grant all fossil-fueled resources a 40-year lifetime and those that exceed the lifetime will be retired (California Public Utilities Commission, IRP Procurement Track, 2019). In the same decision, the commission also allowed the 2030 generation mix to continue to allow natural-gas-fueled generation fleets because the rapid ramping capability and the stability of conventional generation can allow a more seamless renewable integration process. To achieve a 2030 fossil-fuel-free generation mix, the commission indicated that no technology of such capacity has been found or studied.

Another challenge to ensure a smooth transition into a cleaner grid is resource adequacy, a measurement to assess the utility's ability to meet the energy demands from customers (California ISO, 2019 - 2020 Transmission Plan, 2020). For preferred and intermittent clean generation resources, CAISO believed that the state no longer needs "stacking" of additional renewables to meet the system requirements (California ISO, 2019 - 2020 Transmission Plan, 2020). In the past, the state has been adding renewables merely for the capacity figure, resulting in inefficiencies in regions that have already been saturated with renewables. The state is moving into a prudent long-term resource planning process to select the right resources in the right location and with the right attributes. To encourage developers to participate in creating a reliable resource mix, CAISO introduced its Resource Adequacy Enhancements initiative (California ISO, Resource Adequacy Enhancements , 2019). In the program, the ISO is assessing the policies and design changes that encourage the addition of more reliable technologies and award resources that are most dependable to ensure system needs are met throughout the years. Alongside the new initiative, CPUC is also revising its Effective Load Carry Capability (ELCC) (California ISO, 2019 - 2020 Transmission Plan, 2020). ELCC was originally designed to assess the usefulness of certain energy resources based on whether or not it contributes to helping the system meets the greatest demand. During the development of ELCC, bulk generation, such as gas-fired generation, is still the dominant dispatchable resource. Distributed resources, such as solar, are treated as minor incremental additions to the gas generation. However, as the distributed resources are becoming significant, the old method of "minor additions" no longer applies. CPUC and CAISO later reformed the ELCC process for renewables regarding the on-peak and off-peak deliverability assessment to further refine the value of the capacity of each incremental renewable and ensure renewables are deployed to areas that are needed the most.

Lastly, the non-transmission alternatives area was also explored heavily by CAISO as measures to mitigate grid pressure, including the aforementioned energy efficiency and demand response (California ISO, 2019 - 2020 Transmission Plan, 2020) . For most of the planning areas, energy efficiency and demand response are used differently because demand response is considered an energy-limited preferred resource by the transmission planning committee (California ISO, 2019 - 2020 Transmission Plan, 2020). In other words, the initial reliability assessment was conducted using non-limited preferred resources, such as energy efficiency and renewable generating resources. During the initial assessment, if reliability issues were identified in the system, demand response and energy storage will be integrated into a new round of reliability assessment to determine if the identified issues can be resolved using these two additional measures. If these measures were shown to be necessary for the modeling and assessment, these additional resources will be integrated into the main methodology, which will then undergo another round of analysis to ensure compatibility of the new resources and the existing preferred resources.

California Renewable Incentives

Another important aspect of assessing the transmission and distribution constraints within the state of North Carolina is the state incentives for distributed energy resources. Distributed energy plays a significant role in the transmission system because, as identified in the 2019-2020 transmission planning, they are responsible for curtailing the demand growth on the transmission system and helping the state to avoid expensive transmission upgrades (California ISO, 2019 - 2020 Transmission Plan, 2020). For the past three transmission planning periods, the overall load on the transmission system has stayed roughly the same thanks to behind-the-meter generation from both residential and commercial sides. When compared to California, both states stopped offering many of their programs by the end of 2016 (Center for Sustainable Energy, n.d.). In California, the state had California Solar Initiative (CSI), which is similarly structured to Federal Investment Tax Credits (ITC), which was designed to have a declining incentive over the program periods and aimed to gradually ease renewables into the state. These incentives are distributed based on dollars per watt or cents per kilowatt-hour for all customers willing to participate in solar. The declining structure contains tens steps with a specific MW target for each advancement to the next step. The incentive is further divided into 2 types: Expected Performance-Based Buydown (EPBB) and Performance-Based Incentive (PBI). For EPBB, it is intended for smaller systems, normally less than 50kW, such as rooftop solar for residential and small business customers, and the incentive was paid upfront at almost $3/watt at the first step and about

$1/watt at the 10th step. For PBI, it is intended for larger utility-scale projects. Specifically, it is targeted at those over 30 kW installed capacity. The inventive was also correlated with the performance of the actual system over the course of 5 years (California Public Utilities Commission, CSI General market Program, n.d.) (Figure 15).

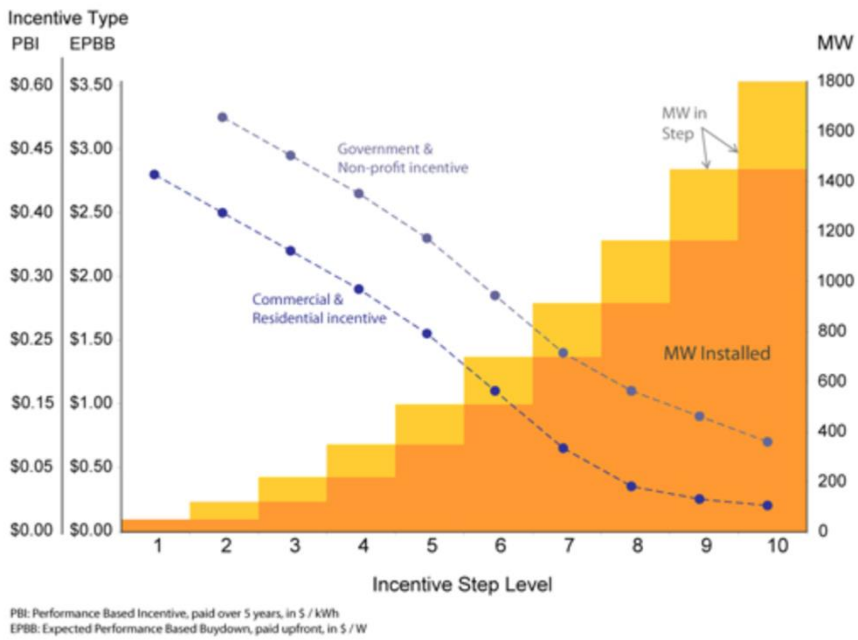

Figure 15 California Initiative Steps (California Public Utilities Commission, CSI General market Program, n.d.)

After the program was discontinued, the state still preserved one of its complementary programs, the Net Energy Metering Program (NEM). The Net Metering program has gone through several changes since its original inception, and the current one is being utilized is called NEM 2.0 (energysage, 2020). When the program first launched, the system worked on a simple principle: for every kWh of excess energy the owner produced and fed to the grid, the owner would receive 1 equivalent of utility-generated electricity bill credit ((energysage, 2020)). The NEM 1.0 was retired after each utility has used solar generation to reach 5% of power demand from customers., or by mid-2017, whichever is sooner. The successor, NEM 2.0, brought multiple policy changes in respect to NEM 1.0 while preserved the core economic inventive: the customer would receive 1 utility-generated equivalent electricity credit for every kWh they feed back to the grid. The three major changes introduced in NEM 2.0 address a couple of fee adjustments, which will be discussed in later sections.

North Carolina Renewable Incentives

In North Carolina, the renewable programs also encompass both state and private support. Since 1977, the North Carolina General Assembly introduced tax credits for the construction or installation of the solar energy system for heating, cooling, or providing hot water purposes. Similar practices also apply to the construction of a wind energy device or methanol gas facilities. These tax credits were provided in both corporate and individual income tax laws and each of these credits have their unique calculation methods and credits cap. In 1999, the first major revision repealed the various tax credits for individual and corporation income and consolidated everything into one credit for any new investment in renewable energy projects. The credit was set to expire by January 1, 2006 but was extended for an additional five years. The extended renewable energy credits also included an increase of the maximum credit for renewable projects that are intended for business purposes; the definition of renewable biomass is also expanded to include more resources. In 2009, the definition of renewable energy property is further expanded to include geothermal heat pumps and the credits themselves are extended to January 1, 2016. The credits later were further modified to include more resources like renewables and adjusted tax credits for donating to nonprofits regarding renewable purposes.

Throughout the years of change, the core of the policy never changed: "If a taxpayer that has constructed, purchased, or leased renewable energy property places it into service in North Carolina during the taxable year, the taxpayer is allowed a tax credit equal to 35% of the cost of the property (North Carolina Department of Revenue, 2014))."

To obtain the tax credits, the owner of a renewable project must ensure the property is in service and producing usable energy. For any business-intended renewables, the project must produce excess energy on top of the owner's business operation, and the said excess should be for sale or purchased by other businesses. The tax credits also vary greatly based on the purpose of the installed renewable equipment. For instance, a Solar Energy Equipment for Domestic Water Heating or Solar Pool Heating is subject to a $1,400 one-time credit. For rooftop solar or wind equipment, the customer can claim $10,500 per installation. For any solar or wind projects intended for business, the owner can claim up to 2.5 million dollars per project (North Carolina Department of Revenue, 2014)(Table 7).

Table 7 North Carolina Solar Credits (North Carolina Department of Revenue, 2014)

Renewable Energy Technology	Credit Limit	
	Nonbusiness Purpose	Business Purpose *
Solar Energy Equipment for Domestic Water Heating or Solar Pool Heating	$1,400 Per Dwelling Unit	$2,500,000 Per Installation
Solar Energy Equipment for Active Space Heating, Combined Active Space and Domestic Hot Water Systems, or Process Heating	$3,500 Per Dwelling Unit	$2,500,000 Per Installation
Solar Energy Systems for Passive Heating	$3,500 Per Dwelling Unit	$2,500,000 Per Installation
Geothermal	$8,400 Per Installation	$2,500,000 Per Installation
Solar Energy Systems for Daylighting	N/A	$2,500,000 Per Installation
Solar Energy Equipment for Electricity Generation	$10,500 Per Installation	$2,500,000 Per Installation
Wind Equipment	$10,500 Per Installation	$2,500,000 Per Installation
Hydroelectric Generators	$10,500 Per Installation	$2,500,000 Per Installation
Biomass Equipment	$10,500 Per Installation	$2,500,000 Per Installation
Combined Heat and Power Property	$10,500 Per Installation	$2,500,000 Per Installation

*The credit limit is $5,000,000 instead of $2,500,000 for an installation of renewable energy property placed in service at an Eco-Industrial Park certified under G.S. 143B-437.08 for a business purpose.

The credits cannot be applied in one year if the credits exceed 50% of the taxpayer's tax liability. The excess credits will be carried over to the following five years. Throughout the 5 years period, if the project is taken out of service, all remaining credits will be automatically seen as voluntarily relinquished. For a project to be considered out of service, it has to stop completely. In other words, capacity reduction, routine maintenance, or temporary suspension will not void the tax credits.

Aside from state support, private industries also provide incentives for customers who display interest in purchasing rooftop panels. In North Carolina, Duke Energy offers a rebate program for residential, business, and non-profits. On a per kW AC installed capacity, residential customers can obtain $600, business owners can receive $500, and the most amount of rebate, $750, will be allocated to non-profits (Duke Energy, Renewable Energy, 2021).

Because of these initiatives, North Carolina has become the most popular state on the East Coast when developers are looking for places to initiate renewable projects. Since the inception of the tax credits, the state has given out more than 1 billion in tax breaks before the program was ended in 2016 (Eanes, n.d.). The large incentive and the prolonged duration of the program encouraged many developers to join the state and helped North Carolina to become the 2nd largest state in the U.S. in total solar installed capacity. Despite its geological disadvantages when compared to western or neighboring states, North Carolina thrived in the solar boom thanks to the tax credits.

At the end of 2020, the North Carolina Department of Revenue indicated that federal rules regarding "bona fide partner" on the tax credits should disqualify existing credits that were transferred from a partnership to the project investors (Hobart, 2019). General Counsel of N.C. Chamber expressed concerns on the tax will hinder the future development of renewables in the state and encouraged disbelief of government from renewable investors (Eanes, n.d.). Similarly, developers also expressed great discontent with the ruling and filed petitions hoping to revert the changes (Hobart, 2019).

Net Metering and Battery Storage

After the tax credits in both North Carolina and California expired, both states moved into the realm of Net Metering to encourage more customers from the distribution side to join the renewable transition (Centrica Business Solution, n.d.). In California, the Net Energy Metering (NEM) 1.0 program ensured that customers got paid for each kWh they produced with a dollar-to-dollar match from the utilities (California Public Utilities Commission, Net Energy Metering Rulemaking (R.) 20-08-020, n.d.). Soon after in 2016, California introduced the 2.0 version of the

NEM program to include additional fixed and variable costs to compensate for the unfairness of utility credits (Verdant, 2021).

For customers who planned to join the NEW program, NEW 2.0 introduced a new one-time interconnection fee that ranges from $75-145 for projects less than 1MW. For projects bigger than 1MW, an $800 interconnection fee will be assessed at the beginning of the project and the customer must pay all transmission/distribution system upgrades. The second fee adjustment was the addition of a "non-bypassable charges". Customers from the NEM program would be required to pay a surcharge on top of their per kWh rate to fund programs for energy efficiency and low-income energy access.

For recurring costs, customers are now required to pay $0.02 – $0.03 for each kWh they consume from the grid (Harina, 2019). These two measurements essentially guaranteed customers will get utility credits that are always lower than the retail rate. Lastly, all NEM customers will be transferred to a time of use (TOU) rate schedule to further reduce the cost of service between all customer bases. Despite the changes, NEM 2.0 quickly ramped up to the peak of NEM 1.0 in 2019 (Figure 16)

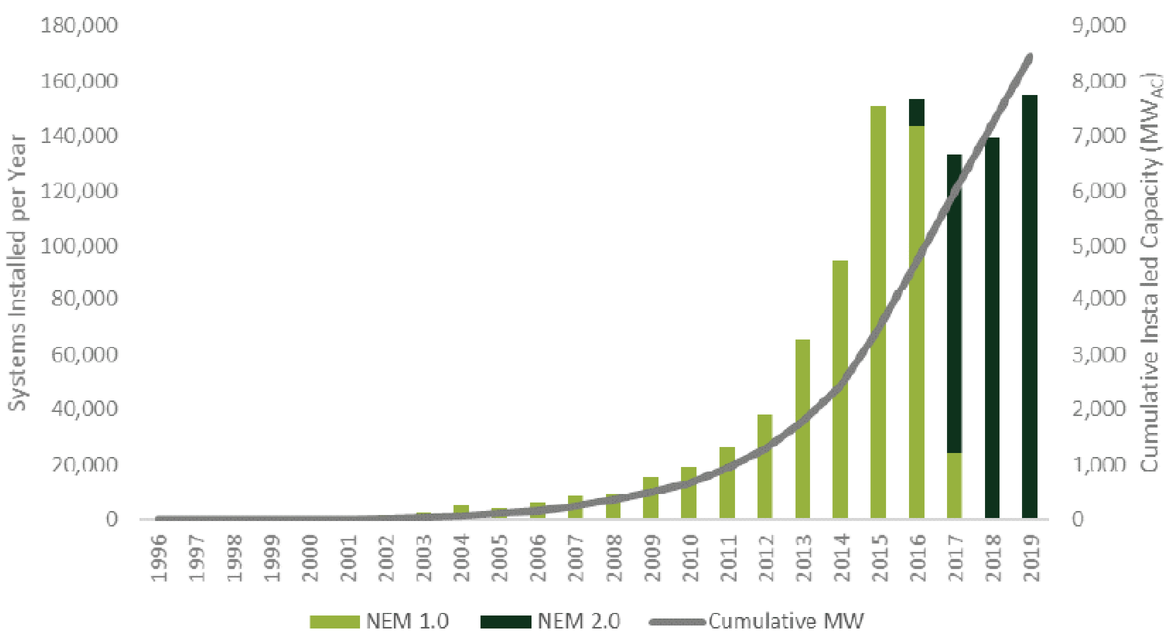

Figure 16 NEM Installation Capacity for 1.0 and 2.0 (Verdant, 2021)

During a survey of both NEM 1.0 and 2.0 customers, it was found that after the installation of NEM, 1.0 customers consume around 14,830 kWh annually while 2.0 customers' consumption fell sharply to 8,425 kWh annually (Verdant, 2021). With the year-over-year demand from the residential sector, the most probable explanation is that 2.0 customers opt for much bigger solar installation capacities, resulting in a sharp reduction in electricity consumption. The significant increase in installed solar capacity introduced new issues in the bill payment, as shown in Table 8 here, which represents the ratio of the bill paid to the cost of service. In other words, if the number is bigger than 1, then utilities are making profits by selling energy to customers.

Table 8 Cost of Service / Bill Payment (Verdant, 2021)

NEM Program		Pre-NEM	Post-NEM	% Change
NEM1.0	Residential	141%	76%	**-46%**
	Non-Residential	121%	111%	-8%
NEM2.0	Residential	108%	12%	**-89%**
	Non-Residential	162%	142%	-12%

As demonstrated in the table, the pre-NEM and post-NEM values are the averages of the 3 biggest power suppliers, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) in CA. Particularly, PG&E, the utility that has suffered most from catastrophic natural disasters, experienced one of the biggest drops in bill payment. For residential customers, the bill payment/cost of service ratio has declined from 138% pre-NEM to 18% post-NEM. During NEM 1.0 period, the ratio dropped from 171% pre-NEM to 88% post-NEM. In the cost breakdown, the utility cost of service was slightly reduced from around $1 billion to $800 million. The residential bill payment, on the other hand, dropped from $1.1 billion to around $100 million. Consequently, utilities are losing a significant amount of money on the net metering program and hence will become reluctant to upgrade the distribution or transmission system to accommodate more solar projects, creating a bottleneck when more solar wants to be brought online. North Carolina currently is using a similar version of the NEM 2.0 policy in the state and is expected to be facing a similar issue as in California. After the NEM 2.0 program ended in 2019, the state contracted Energy and Environmental Economics (E3) to develop a potential successor to the NEM 2.0, and the white paper was released on Jan 28th, 2021 (E3 & Verdant, Alternative Ratemaking Mechanisms for Distributed Energy Resources in California, 2021). In the future, the 3.0 version of NEM attempts to further reduce the value of generated kWh from consumers and encourage customers to preserve the excess generation for their own use instead of selling back to the utility, hence creating incentives for customers to bundle future solar systems with storage attached for optimal cost recovery (Gerza, 2020). The added battery storage, as pointed out in the transmission planning report, will become a valuable grid asset to keep flattening the demand growth and delay additional grid upgrades. The 3.0 program approach from California can be an ideal step for North Carolina to take in the future as well as to handle the large solar integration and reduce congestion.

Energy-only Market

In California, CAISO and Energy + Environmental Economics, LLC (E3) conducted a study to re-evaluate the conventional transmission planning processes, which mainly focuses on energy deliverability during peak hours, which is not ideal for renewables because they cannot produce the maximum output all the time (E3, Planning Transmission for Renewables: Optimizing use of California's transmission system to deliver energy from renewable resources in the San Joaquin Valley, 2017). Hence, the traditional planning process will create artificial congestion in the transmission system: the transmission grid upgrades will only be used during the peak time of the year and sit idle the rest of the time. To allow a better dispatch of renewables, CAISO has begun to look at an energy-only market, which focuses on energy delivery throughout the year instead of peak time only.

The study site is the San Juaquin Valley, and its rich irradiance resources and poor soil quality make it ideal for large-scale solar farms. The goal of the study was to determine the economics of developing solar projects with multiple levels of planned curtailment during peak generation. The study also served as an update to the two special studies from 2015-2017 concerning the feasibility of adding energy-only resources to the grid mix. Under the current framework of Full-Capacity Deliverability Status, any generation resource that meets the requirement will be awarded an adequacy value. Hence, in the following Table 9, the total delivery cost of both conventional planning and energy only can be seen,

Table 9 Energy-Only Cost-Benefit Comparison (E3, Planning Transmission for Renewables: Optimizing use of California's transmission system to deliver energy from renewable resources in the San Joaquin Valley, 2017)

	Solar - Full-Capacity Deliverability Status ($/MWh)		**Solar - Energy Only ($/MWh)**	
	Low Value	*High Value*	*Low Value*	*High Value*
Base LCOE	$ 50.00		$ 50.00	
Levelized Transmission Cost	$ 8.65	$ 17.30	$ -	$ -
Resource Adequacy Value	$ (2.83)	$ (5.66)	$ -	$ -
Curtailment Penalty	$ -	$ -	$ -	$ 5.56
Delivered Cost	**$ 55.82**	**$ 61.63**	**$ 50.00**	**$ 55.56**

Under both high value and low-value scenarios regarding solar generation, energy-only resources showed that savings can be allocated to developers because of the avoidance of transmission cost. Without the artificial transmission constraints, the study found that a substantial amount of solar can be integrated (Figure 17).

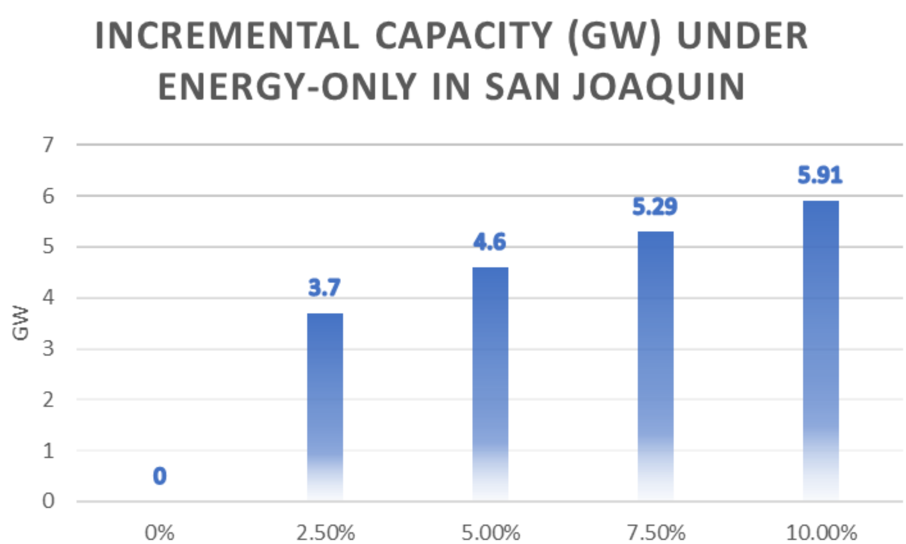

Figure 17 Additional GW Capacity for the Study Site (E3, Planning Transmission for Renewables: Optimizing use of California's transmission system to deliver energy from renewable resources in the San Joaquin Valley, 2017)

Under the most aggressive scenario of 10% curtailment, almost 6GW of additional solar can be integrated, bringing in 14,000GWh of additional generation (net of curtailment) without violating any physical transmission constraints.

Being the third biggest renewable player in the country, North Carolina can also leverage the benefits of an energy-only market and allow more renewable developers to be integrated without triggering cost-prohibitive transmission expenses. The lack of transmission cost can become another lucrative benefit for renewable developers and restore their confidence in the regulatory body after the faith-debilitating event of tax audit occurred in 2020.

Conclusion

The transmission system in North Carolina has demonstrated its strength throughout the past several decades of aggressive renewable integration. A strong system, however, as identified in this paper, is also affected by several design inefficiencies. From the Friesian case, we have identified the necessity of battery storage to alleviate the constraints from winter peak and improvements regarding the streamline of regulatory process from CPCN. From the Duke Energy side, we encourage the said vertically integrated utility to adopt cluster reforms as the current series queue process for renewables not only takes years for processing time but also greatly encourages developers to prematurely withdraw their projects from the queue, leading to lackluster renewable integrations. The cluster study can reduce the processing time, increases the certainty of the project feasibility, and lower the cost of the study overall. To further improve the transmission system, GETs are also widely available in other regions of the country and have demonstrated their capability to optimize the power flow and generate large savings. Lastly, the California case study has identified a potential path forward for North Carolina regarding the net metering program. The state can leverage the existing customer base and push for more battery storage by lowering the utility credits. With more customers opting-in for solar + storage bundles, the overall load growth can be minimized thus delaying or minimizing the costly transmission system upgrades. From the regulatory side, the energy-only approach can help the state to welcome more solar projects to be integrated with the grid without compromising the physical transmission barriers.

Limitations

To assess the transmission bottlenecks for renewable energy development in North Carolina, we started our work by drawing lessons from the Friesian Case and then analyze the transmission planning of California as an area with high renewable penetration rate. This approach enables us to cover both utility-scale and residential renewable energy.

However, the bottlenecks we identify from Friesian Case for utility-scale projects mostly lie in the development stage. There can be other transmission bottlenecks aside from what have been shown in the Friesian Case. Other issues during the operation of renewable projects, such as the uncertainty of curtailment, are also crucial and challenging to be tackled. Besides, our study focused primarily on solar energy development due to North Carolina's special role in southeastern solar markets. It should be noticed that hydroelectric and biomass are also important renewable resources for North Carolina.

For the next step, we expect to evaluate and compare the influence of the transmission bottlenecks identified in this study. Our future work on this topic can be focused on the feasibility and efficiency of our recommended solutions. We are also excited to see the improvement to be brought by undergoing changes, such as emerging technologies and interconnection policy reform, to the renewable market in North Carolina.

References

Alptekin, C. (2019, August 27). *Demand Response & Peak Shaving: Strategies For 2019*. Retrieved from iota: https://www.iotacommunications.com/blog/demand-response/

Califonia Energy Commission. (2018, Feb 21). *2017 IEPR Workshops, Notices and Documents.* Retrieved from https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-report/2017-iepr

California ISO. (2019, October 3). *Resource Adequacy Enhancements .* Retrieved from California ISO: http://www.caiso.com/InitiativeDocuments/SecondRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

California ISO. (2020, March 25). *2019 - 2020 Transmission Plan.* Retrieved from CAISO: http://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf

California Public Utilities Commission. (2019). *IRP Procurement Track*. Retrieved from IRP Procurement Track: https://www.cpuc.ca.gov/General.aspx?id=6442463413

California Public Utilities Commission. (n.d.). *CSI General market Program*. Retrieved from California Public Utilities Commission: https://www.cpuc.ca.gov/General.aspx?id=6058

California Public Utilities Commission. (n.d.). *Net Energy Metering Rulemaking (R.) 20-08-020*. Retrieved from California Public Utilities Commission: https://www.cpuc.ca.gov/nemrevisit/

Center for Sustainable Energy. (n.d.). *California Solar Initiative*. Retrieved from Center for Sustainable Energy: https://energycenter.org/program/california-solar-initiative

Centrica Business Solution. (n.d.). *How net metering boosts the ROI of your solar PV installation*. Retrieved from Centrica Business Solution: https://www.centricabusinesssolutions.com/us/blogpost/how-net-metering-boosts-roi-your-solar-pv-installation

DEC Generator Queue. (2020, December 2). Retrieved from OASIS - Duke Energy Carolinas: https://www.oasis.oati.com/woa/docs/DUK/

DEP Generator Interconnection Queue. (2021, January 17). Retrieved from OASIS - Duke Energy Progress: https://www.oasis.oati.com/cpl/

Department of Energy. (2015). *National Electric Transmission Congestion Study.*

Department of Energy. (2020). *National Electric Transmission Congestion Study.*

DOCKET NO. EMP-105, SUB 0. (n.d.). *DOCKET NO. EMP-105, SUB 0.* Retrieved from https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=413c3883-2ded-49b1-ab31-ed949f3aa7c6.

Duke Energy. (2021, April 20). *Renewable Energy*. Retrieved from NC Solar Rebate Program: https://www.duke-energy.com/home/products/renewable-energy/nc-solar-rebates

Duke Energy. (2021, April 1). *Revisions to Attachment J (Large Generator Interconnection Procedures) to Joint OATT.* Retrieved from https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/20210401-5029(14941652)_--_Duke_Queue_Reform_Filing_(04-01-21).PDF

Duke Energy Carolinas. (2019, June 14). *North Carolina Interconnection Procedures, Forms and Agreements For State-Jurisdictional Generator Interconnections.* Retrieved from Duke Energy Carolinas: https://www.duke-energy.com/_/media/pdfs/rates/ncinterconnections-dec.pdf?la=en

Duke Energy Interconnection Queue Reform, FERC Stakeholder Meeting. (2021, Februray 3). Retrieved from https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/Duke_Energy_Queue_Reform_Stakeholder_Meeting_Presentation-_February_3,_2021.pdf

Duke Energy OASIS. (2019). *DEC and DEP Constrained Areas – Tranche 2.* OASIS.

Duke Energy Progress. (2018). *Duke Energy Progress Facility Interconnection Requirements.* Retrieved from OASIS: https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Duke_Energy_Progress_Facility_Interconnection_Requirements_R1.pdf

Duke Energy Progress. (2019). *DEP-DEC_Generator_Interconnection_Requirements_and_Locational_Guidance_8-5-2019_FINAL.* OASIS.

Duke Energy Progress. (2020). *Duke Energy Progress Integrated Resource Plan 2020 Biennial Report.* Duke Energy.

E3. (2017). *Planning Transmission for Renewables: Optimizing use of California's transmission system to deliver energy from renewable resources in the San Joaquin Valley.* E3.

E3, & Verdant. (2021). *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California.* E3.

Eanes, Z. (n.d.). *News & Record*. Retrieved from State enticed them to invest in N.C. solar projects. Now, they're being audited — by the state: https://greensboro.com/news/state/state-enticed-them-to-invest-in-n-c-solar-projects-now-theyre-being-audited-by/article_cb46adfe-3e20-11eb-94b0-0fdfed6c45e8.html

EIA. (2021). *HOURLY ELECTRIC GRID MONITOR*. Retrieved from https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

Energy Storage Association. (2020). *Storage As a Transmission Asset is Gaining Traction in Many RTOs/ISOs*. Retrieved from https://energystorage.org/storage-as-a-transmission-alternative-is-gaining-traction-in-many-rtos-isos/

energysage. (2020). *California net metering: everything you need to know about NEM 2.0*. Retrieved from energysage: https://news.energysage.com/net-metering-2-0-in-california-everything-you-need-to-know/

ESIG. (2020). *Transmission Planning for 100% Clean Electricity.*

F.Muñoz, F. S. (2019). Case study of the increase in capacity of transmission lines in the Chilean system through probabilistic calculation model based on dynamic thermal rating. *Electric Power Systems Research*, 35-7.

Federal Energy Regulatory Commission. (2011). *Mandatory Reliability Standards for Interconnection Reliability Operating Limits [Docket No. RM10-15-000; Order No. 748] .*

Generator Interconnection Requirements and Locational Guidance. (2019, August 5). Retrieved from Duke Energy: https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DEP-DEC_Generator_Interconnection_Requirements_and_Locational_Guidance_8-5-2019_FINAL.pdf

Gerza, A. (2020, September 15). *The net metering successor tariff 'NEM-3' proceeding in California has officially kicked off*. Retrieved from pv magzine: https://pv-magazine-usa.com/2020/09/15/the-net-metering-successor-tariff-nem-3-proceeding-in-california-has-officially-kicked-off/

GridBeyond. (2018). *The load shifting low-down: Your quick guide*. Retrieved from GridBeyond: https://gridbeyond.com/load-shifting-low-down-guide/

Harina. (2019, Jan 31). *NEM 1.0 to 2.0 – Everything You Need to Know About the Transition*. Retrieved from Aikyum Solar: https://aikyum.com/nem-1-0-to-2-0-everything-you-need-to-know-about-the-transition/

Hobart, K. (2019, April 19). *INSIGHT: North Carolina Audits of Tax Credits Cause Broad Concern*. Retrieved from Bloomberg Tax: https://news.bloombergtax.com/daily-tax-report-state/insight-north-carolina-audits-of-tax-credits-cause-broad-concern

Hudson, K. (2020, July 8). *Electric Substations*. Retrieved from U.S. Energy Atlas: https://atlas.eia.gov/

Jacob, B. (2020, June 23). *Solar in the Southeast Annual Report.* Retrieved from https://cleanenergy.org/wp-content/uploads/Solar-in-the-Southeast-Report-2020.pdf

John D. Wilson, M. S. (2020). *Seasonal Electric Demand in the Southeastern United States.* cleanenergy.org.

Lazard. (2020). *Lazard's Levelized Cost of Enegy Analysis, Version 14.0.* Lazard.

NC DEQ. (2019). *North Carolina Clean Energy Plan.*

North American Electric Reliability Council. (2004). *Operate Within Interconnection Operating Limits SDT Determine Facility Ratings, Operating Limits, and Transfer Capabilities SDT Operating Limit Definition Task Force Meeting.*

North Carolina Department of Revenue. (2014, October 1). *Guidelines for Determining The Tax Credit for Investing in Renewable Energy Property*. Retrieved from North Carolina Department of Revenue: https://files.nc.gov/ncdor/documents/administrative-rules/renewable_energy_credits.pdf

North Carolina General Assembly. (n.d.). *Chapter 62 Public Utilities.* Retrieved from https://www.ncleg.net/enactedlegislation/statutes/html/bychapter/chapter_62.html.

North Carolina Utilities Commission. (n.d.). *CHAPTER 8 ELECTRIC LIGHT AND POWER.* Retrieved from https://www.ncuc.net/ncrules/Chapter08.pdf.

NRG Editorial Voices. (2018). *Transmission congestion & constraints: Market impediment or opportunity?* Retrieved from https://www.nrg.com/insights/energy-education/transmission-congestion---constraints.html.

Roselund, C. (2019, March 1). *Inertia, frequency regulation and the grid*. Retrieved from pv magazine: https://pv-magazine-usa.com/2019/03/01/inertia-frequency-regulation-and-the-grid/

SEIA. (2021, March). *State Solar Spotlight, North Carolina. .* Retrieved from https://www.seia.org/sites/default/files/2021-03/North%20Carolina.pdf

Semich Impram, S. V. (2020). Challenges of renewable energy penetration on power system flexibility: A survey. *Energy Strategy Reviews*, Volume 31, 100539, ISSN 2211-467X.

Senate Bill No. 100. (2018, September 10). *SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse gases.* Retrieved from California Legislative Information: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

Solar and Lease. (n.d.). *How Does a Solar Farm Connect to the Grid?* Retrieved from https://www.solarlandlease.com/solar-farm-connect-grid

Solar Energy Industries Association. (2021). *Top 10 Solar States*. Retrieved from Solar Energy Industries Association: https://www.seia.org/research-resources/top-10-solar-states-0

State of North Carolina. (2018). *North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy.*

Strategen. (2020). *Long Duration Energy Storage for California's Clean, Reliable Grid.*

Susser, J. (2018, March 13). *Why is Peak Demand a Concern for Utilities?* Retrieved from Advanced Energy: https://www.advancedenergy.org/2018/03/13/why-is-peak-demand-a-concern-for-utilities/

Synapse Energy Economics, Inc. (2019). *North Carolina's Clean Energy Future.*

T. Bruce Tsuchida, S. R. (2021). *Unlocking the Queue with Grid-Enhancing Technologies*. Retrieved from watt-transmission.org: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

U.S. Energy Information Administration. (2018, July 1). *HOURLY AND DAILY BALANCING AUTHORITY OPERATIONS REPORT DATA FORMAT AND TRANSMITTAL INSTRUCTIONS EIA-930.* Retrieved from U.S. Energy Information Administration: https://www.eia.gov/survey/form/eia_930/instructions.pdf

Verdant. (2021). *Net-Energy Metering 2.0 Lookback Study.* Berkeley: Verdant Associates, LLC.