Duke Energy Carbon-Free Resource Integration Study

Summary of study results

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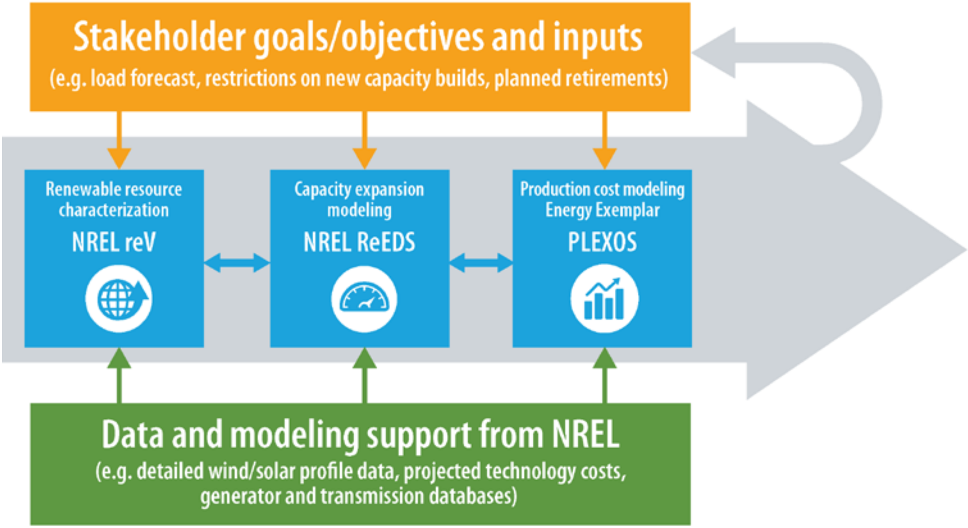
Duke Carbon-Free Resource Integration study

A collaboration between NREL and Duke Energy intended to explore the opportunities and challenges of integrating carbon-free resources in the Carolinas

Two phases of the study:

- **Phase I**: a preliminary net-load analysis of solar adoption in Duke's territory
- **Phase II**: detailed assessment of paths to zero carbon emissions in 2050 using multiple planning tools
  - Part 1: resource assessment
  - Part 2: capacity expansion modeling
  - Part 3: production cost modeling



Overview of Phase II analysis

This presentation will provide an overview of Phase II and then focus primarily on the production cost modeling

- See https://www.nrel.gov/grid/carbon-free-integration-study.html for Phase I report, previous presentations on the Phase II results, and the Phase II report (forthcoming)

The context for interpreting this analysis

Work on Phase II began in January 2020 and thus may not reflect some more recent policies or modeling assumptions

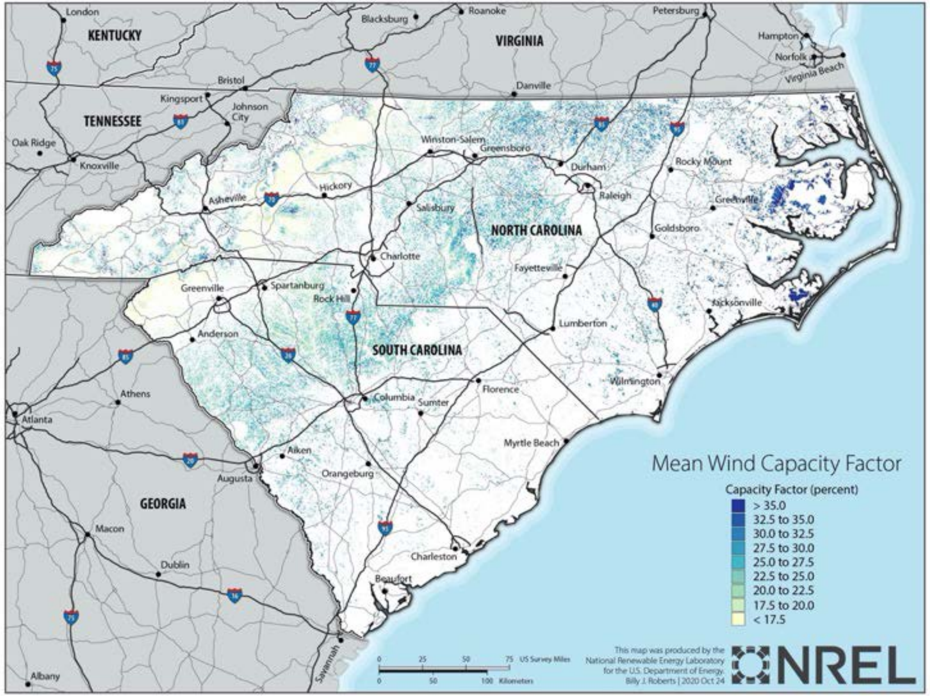
- For example, the schedule for Duke Energy's coal retirements assumed in the ReEDS modeling may not be consistent with more recent proposals to accelerate these retirements
- We explore updates and changes in sensitivity analysis where possible

This study's results may have differences in specific capacity amounts or buildout rates but is **directionally consistent** with other modeling assessments of decarbonization pathways for the Carolinas

- Differences between analyses can results from differences in assumption and scope; for example, this study did not explicitly model supply chain constraints, construction logistics, or the need for detailed transmission planning studies
- This study provides additional insight and robustness into the pathways for integrating carbon-free resources in the region

Phase II, Part 1: Resource Assessment

Objective: Develop hourly solar and wind profiles and assess resource potential, with adapted spatial exclusions as needed for the Carolinas



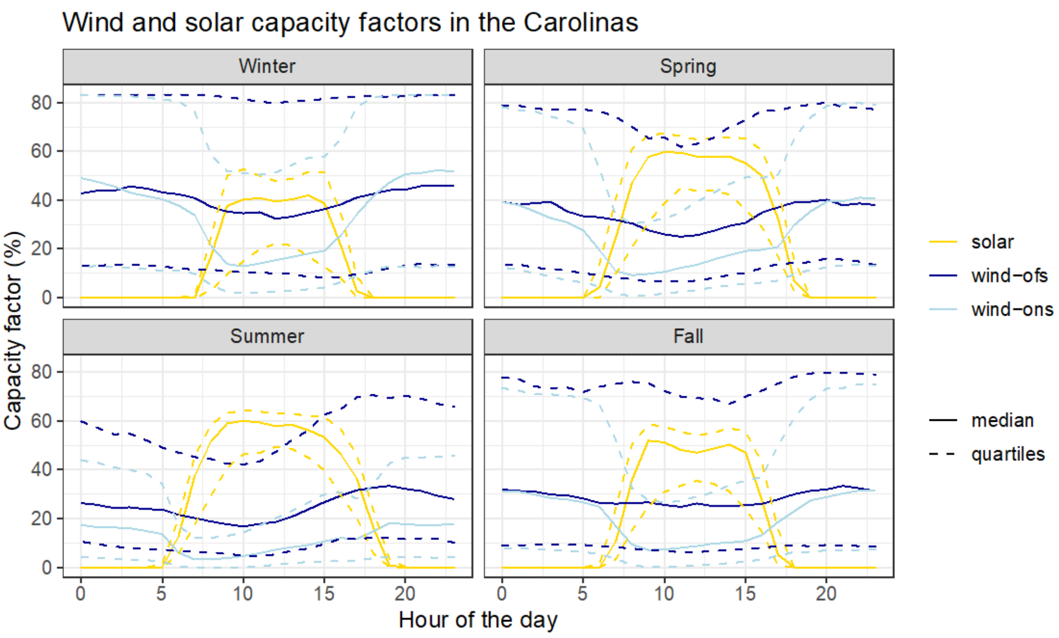
Examples of default exclusion layers:

- Urban areas
- Bodies of water
- Protected lands
- Sloped lands
- Distance from structures (setbacks)

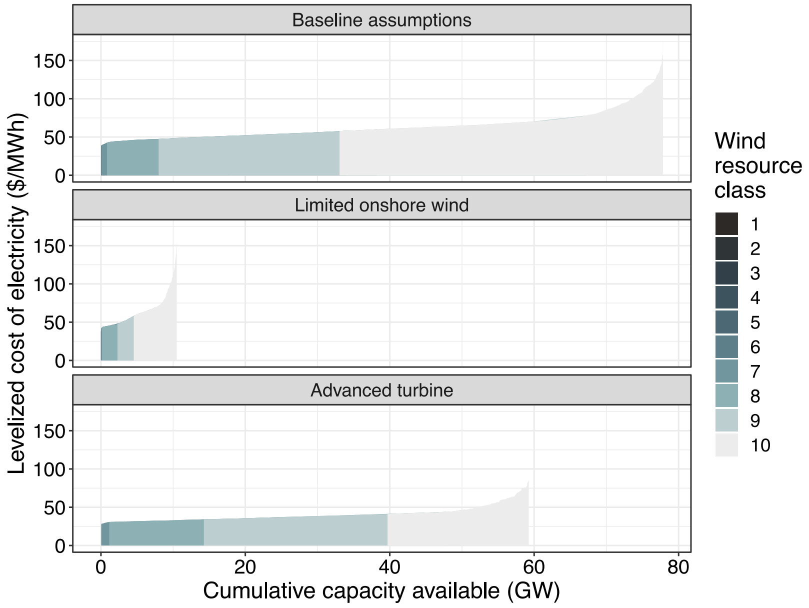
Exclusions added for this project:

- Ridgetop lands
- Military base and radar line-of-sight

Phase II, Part 1: Resource Assessment

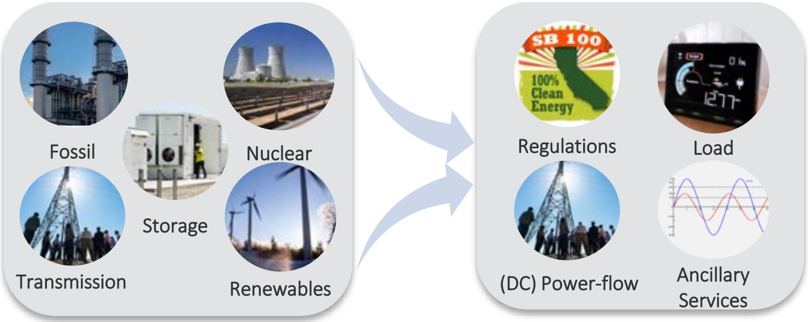


Summary of hourly available capacity factor based on resource profiles from reV



Supply curves for land-based wind

Phase II, Part 2: Capacity Expansion



Objective: Determine the least-cost capacity mix that achieves the decarbonization targets while also satisfying key system requirements

More details on the ReEDS model are available at https://www.nrel.gov/analysis/reeds/about-reeds.html

Analysis performed using NREL's U.S. **ReEDS model**, which includes modeling of:

- **Load balance**: supply = demand in each time-slice
- **Planning reserve**: each region mush have sufficient capacity to meet reserve margin
- **Operating reserves**: regions must supply operating reserve needs
- **Generator constraints**: technology specific constraints such as min gen or ramp rates
- **Transmission**: power flows between regions constrained by available transmission
- **Resource constraints**: renewable resources limited by spatial and temporal availability (with hourly submodule used to inform capacity credit calculations)
- **Policies**: federal, state, and local policies related to clean energy targets, emissions constraints/standards, incentives, etc.

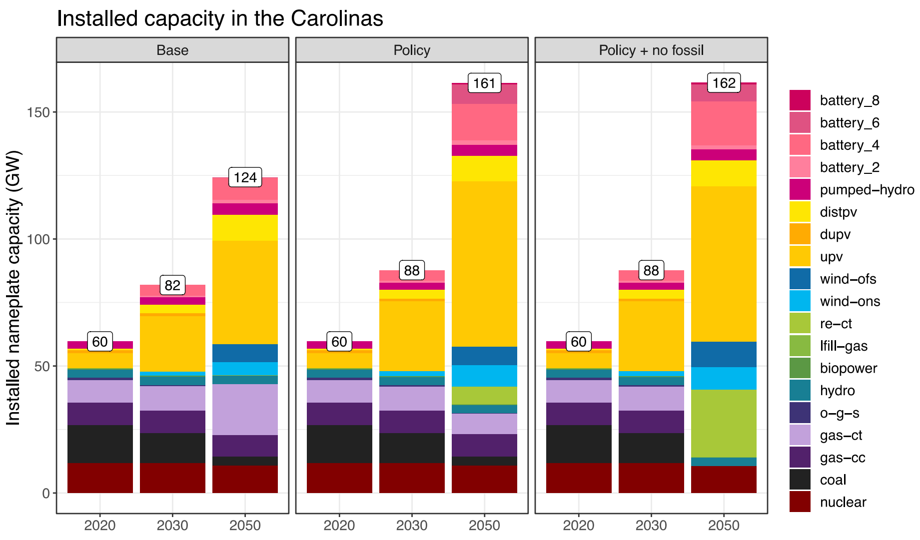
Cost assumptions are based on projections from the Annual Energy Outlook (AEO) and Annual Technology Baseline (ATB)

Phase II, Part 2: Capacity Expansion

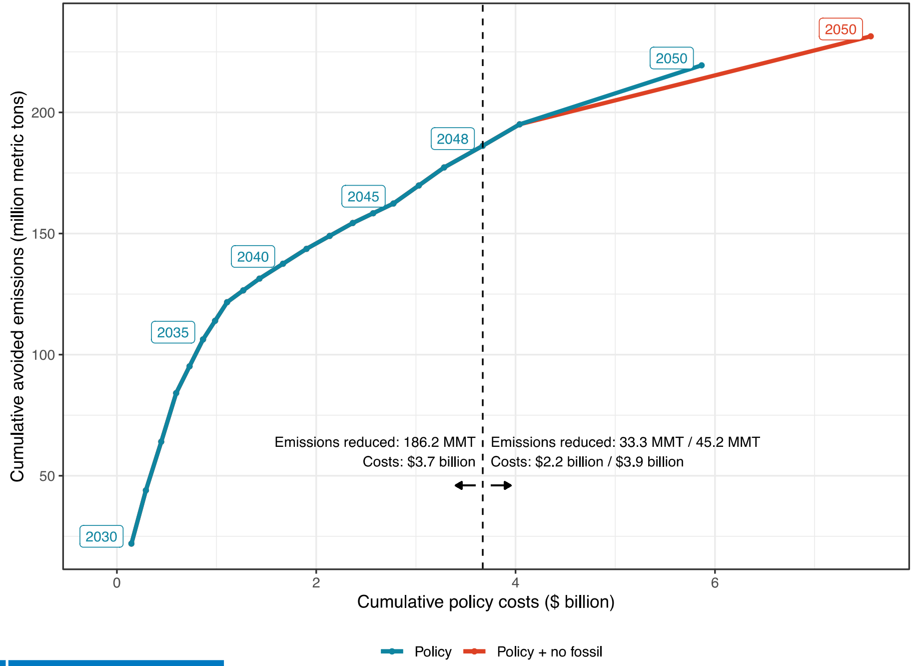
	Base (no emissions constraints in NC)	**Policy** (70% CO_2 reduction in NC by 2030 + net-zero electricity in NC by 2050)
Main cases	Standard modeling assumptions	
	--	All fossil fuel must retire in the Carolinas in 2050 ("No fossil")
Cost sensitivities	Low-cost wind	
	High-cost solar/storage	
	High-cost solar/storage + low-cost natural gas	
Wind availability sensitivities	Limited access (excludes radar line-of-site)	
	State-of-the-art turbine design	
Operational sensitivities	Eastern Interconnect has CO_2 targets (70% in 2030, net-zero in 2050)	
	Duke able to secure firm capacity outside of the Carolinas	
	High electrification case	

Phase II, Part 2: Capacity Expansion

See https://www.nrel.gov/grid/carbon-free-integration-study.html for a previous presentation on the capacity expansion results.



Note: The coal retirement schedule for these results was specified prior to recent updates. A sensitivity exploring runs with additional coal retirements was tested in production cost modeling.

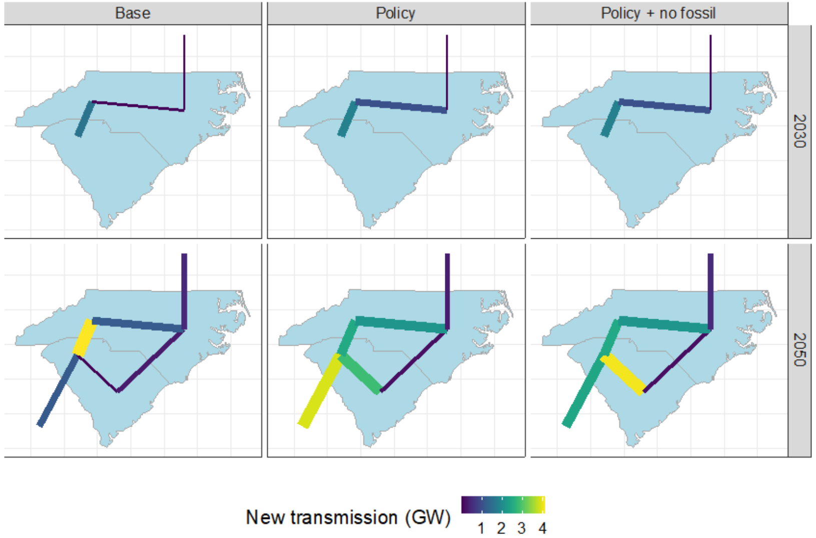


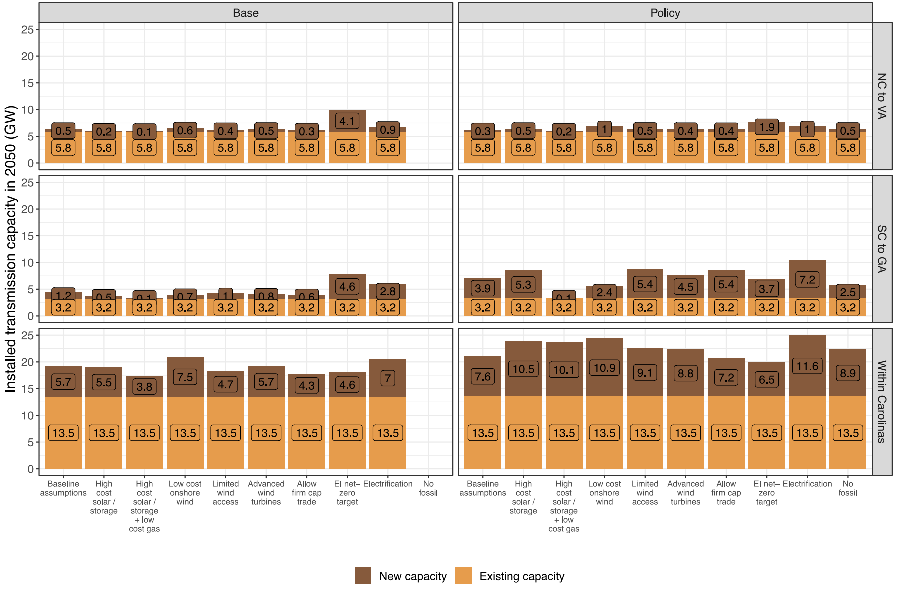
Cumulative CO_2 abatement cost through 2030 and 2050 ($ per metric ton). Values in parentheses indicate range across ReEDS sensitivities.

2030	2050
7 (6-20)	27 (9-34)

Phase II, Part 2: Capacity Expansion

See https://www.nrel.gov/grid/carbon-free-integration-study.html for a previous presentation on the capacity expansion results.





Note: ReEDS only considers interface transmission (i.e., between BAs) and does not evaluate the need for intra-BA transmission investments.

Phase II, Part 3: Production Cost Modeling

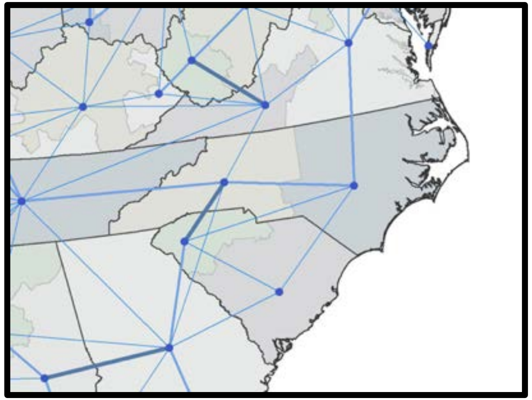
Objective: Test the buildouts from ReEDS for operational feasibility (i.e., sufficient generation is available to meet load and provide operating reserves in every hour)

Provides a check on the capacity expansion results using more detailed representation of the system.

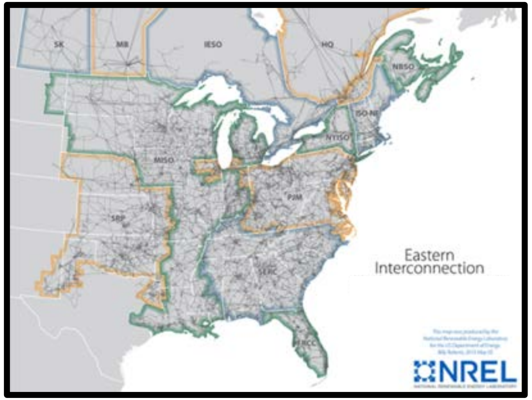
Tested on a subset of ReEDS cases due to the computational burden of production cost modeling.

Aspects not addressed in this study:

- AC power flow
- Stability/transient issues
- Contingency or N-1 security
- Severe outage events



Capacity expansion in ReEDS



Production Cost Modeling in PLEXOS

Differences between ReEDS and PLEXOS

		**PLEXOS** Security-constrained unit commitment & economic dispatch
Model scope / purpose	Find *least cost* technology mix to meet power system requirements over decades	*Simulate* detailed operations of the power system using unit commitment and economic dispatch
Spatial resolution	4 balancing areas in the Carolinas	Nodal or zonal representation
Temporal resolution	18 representative time slices with hourly VRE modeling for capacity credit	Chronological hourly dispatch
Transmission	Between balancing areas	Full transmission system (nodal) or simplified by balancing areas (zonal)
Generator parameters	Average parameters assumed by generator type and vintage	Full heat rates, operational constraints (e.g., min gen levels, ramp rates) specific to each plant
Dispatch	Dispatch according to aggregated time slices	Hourly unit commitment + economic dispatch

Production cost modeling cases

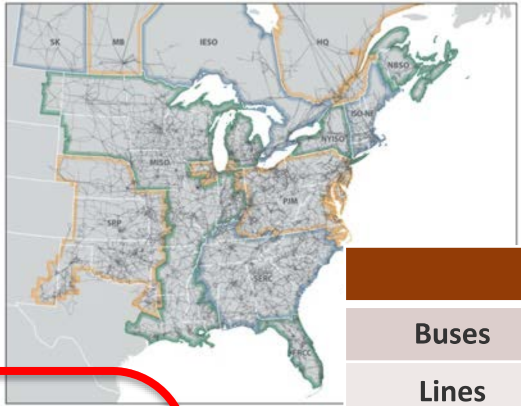
Two categories of production cost modeling cases: nodal and zonal

Nodal: Full transmission representation of Duke Energy's system; each case built by adding ReEDS builds to an existing network model

- <u>2024 buildout + 2012 weather</u> (baseline)
- <u>2030 buildout + 2012 weather</u> (policy case w/ 70% CO_2 reduction in NC)
- <u>2030 buildout modified + 2012 weather</u> (includes accelerated coal retirements)
- <u>2036 buildout + 2018 weather</u> (tests extended cold period; also includes coal retirements and offshore wind)

Zonal: Transmission matches ReEDS aggregation, with only the interfaces between BAs modeled

- <u>2024 buildout + 2012 weather</u> (baseline)
- <u>2050 buildout + 2012 weather</u> (policy case with zero-emissions)

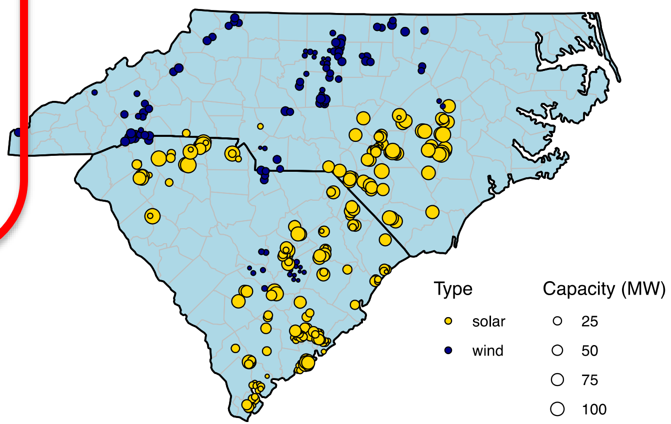


Nodal system

	EI	Duke
Buses	78,463	2,944
Lines	71,328	3,176
Transformers	27,901	890

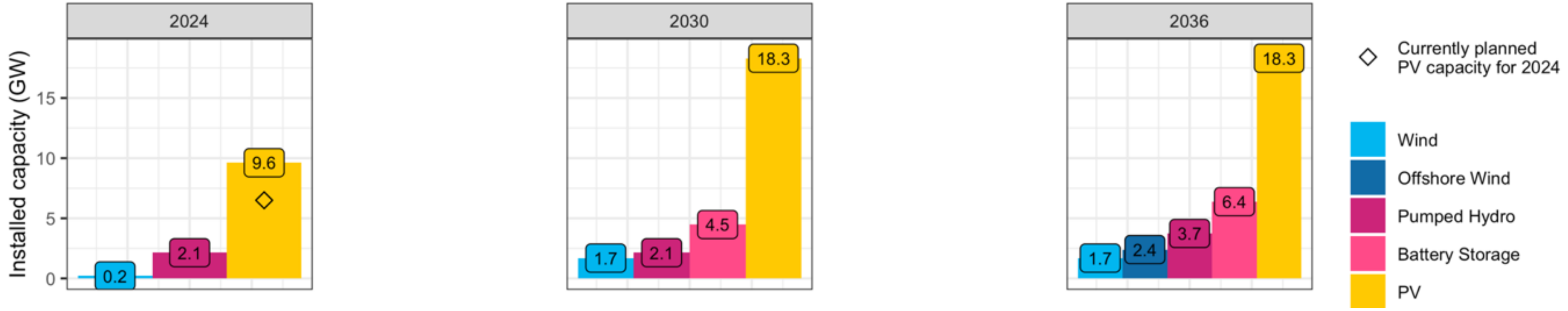
2030 policy case, nodal model

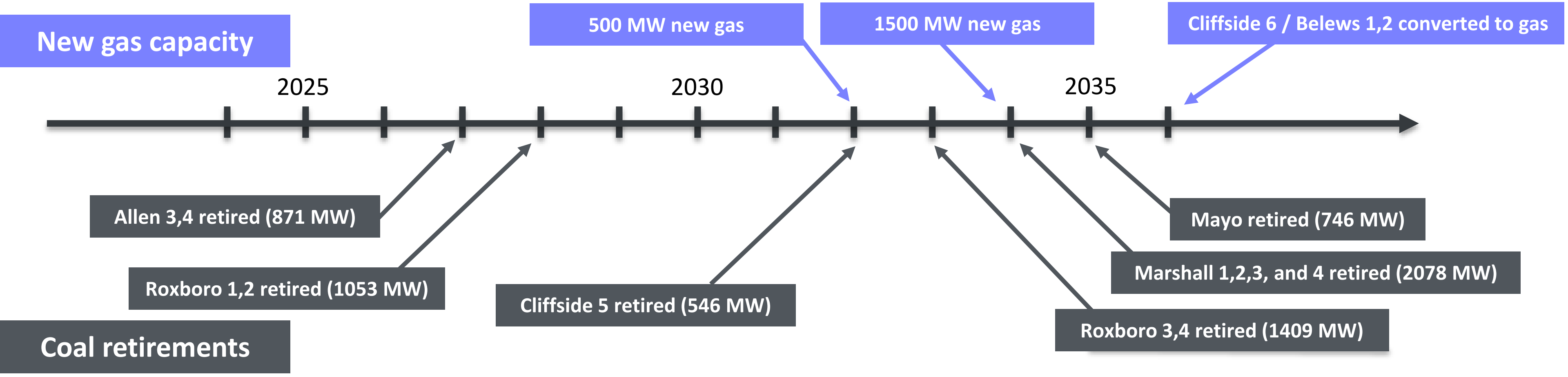
Placement for onshore wind and utility–scale solar



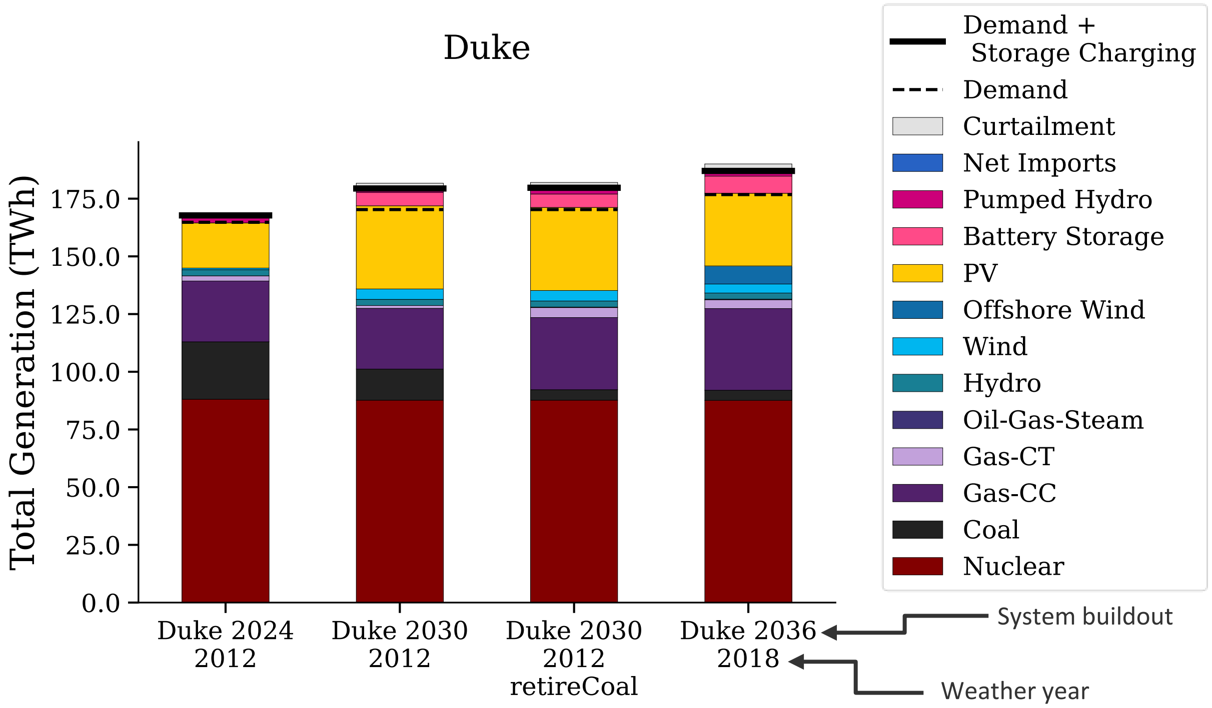
Nodal cases – new capacity and retirements

Note that PV installed capacity reflects AC nameplate capacity after adjustment for inverter-loading ratio and efficiency losses



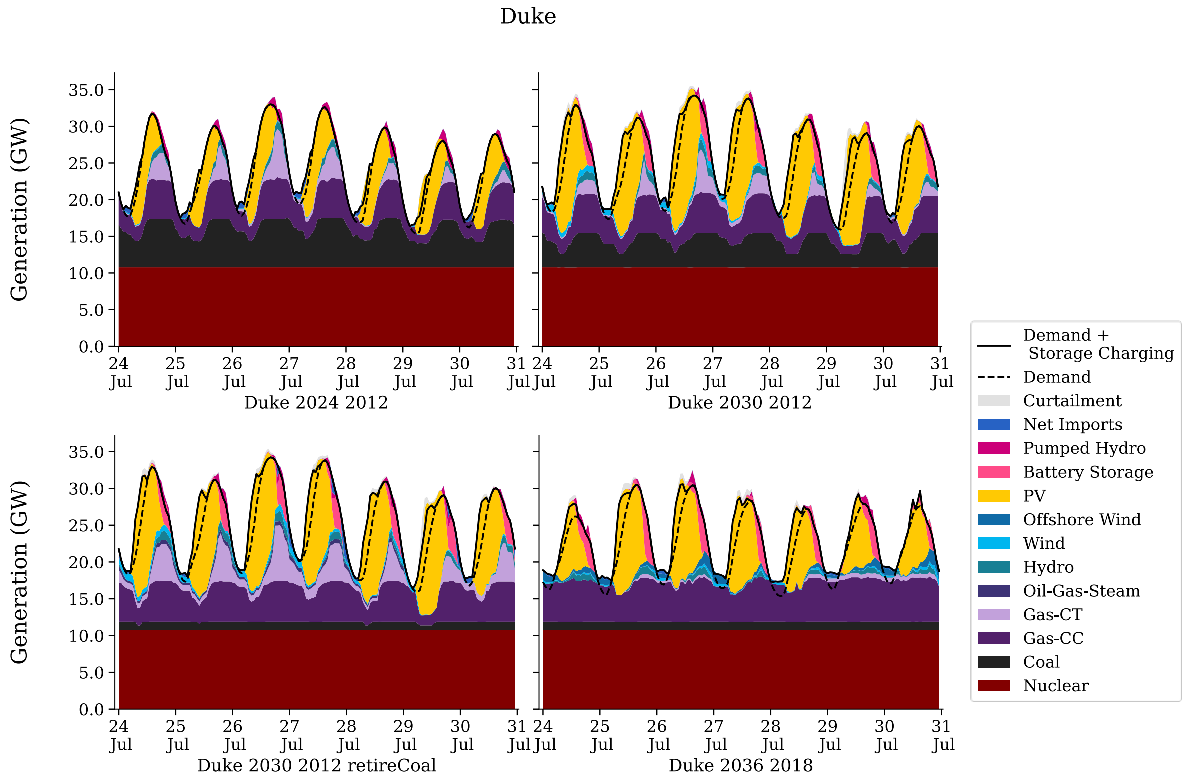


Nodal results – Annual generation



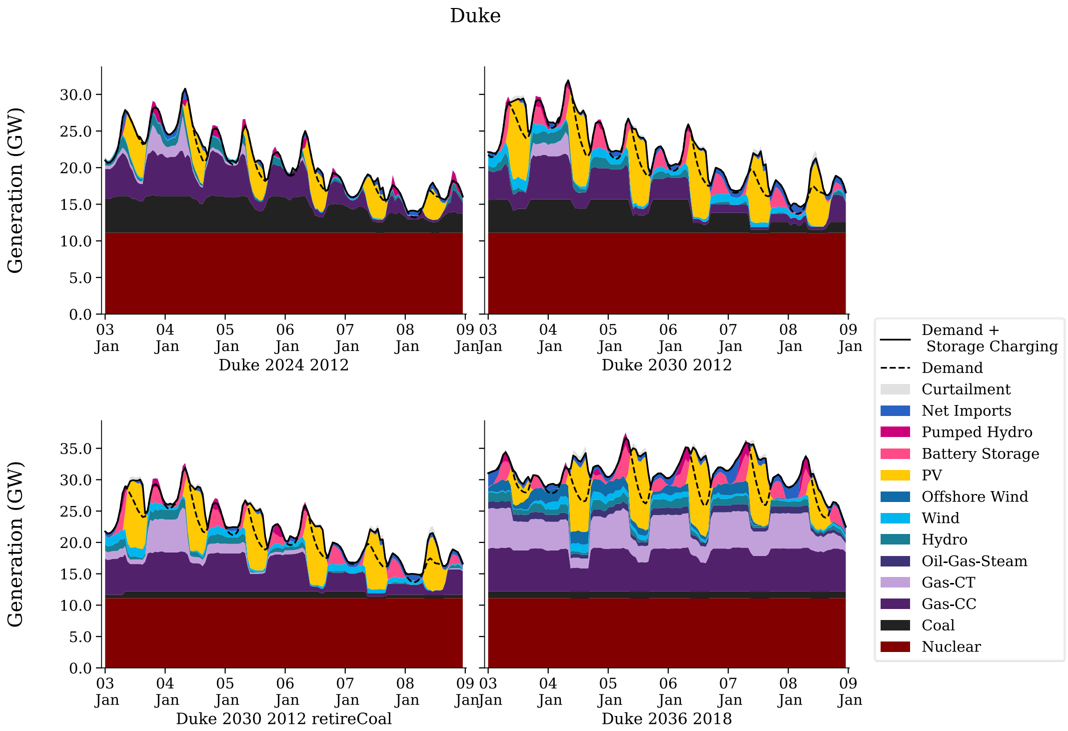
- No unserved energy in the Duke Energy's system (generation meets demand in all hours)
- Nuclear provides consistent generation across scenarios (configured to maximize output)
- Solar moves up from 12% of annual generation in 2024 to 18-21%
- Wind supplies 7% of annual generation in the 2036 case, with the majority coming from offshore wind
- Reduced coal generation partially offset by more generation from natural gas

Nodal results – Summer Peak Dispatch



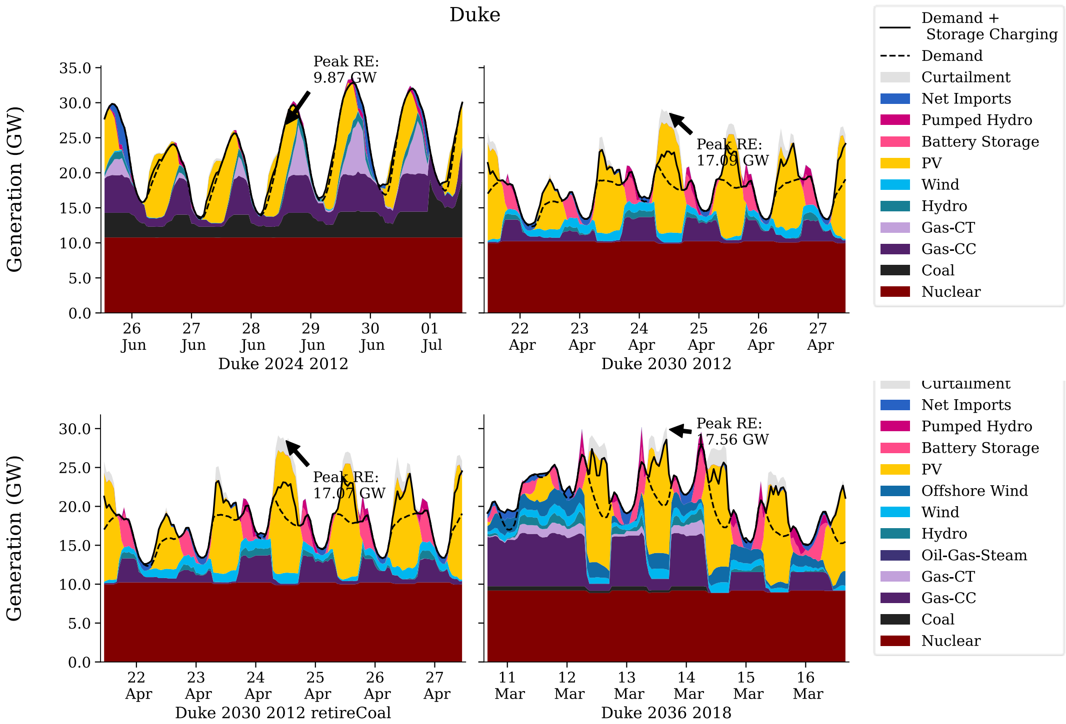
- Coal replaced with natural gas, solar, and in the 2036 buildout wind
  - Gas CTs used heavily in the evening hours after coal is retired
- Storage charges during the morning/daylight hours when solar is prevalent; discharges in the evening when solar ramps down

Nodal results – Winter Peak Dispatch



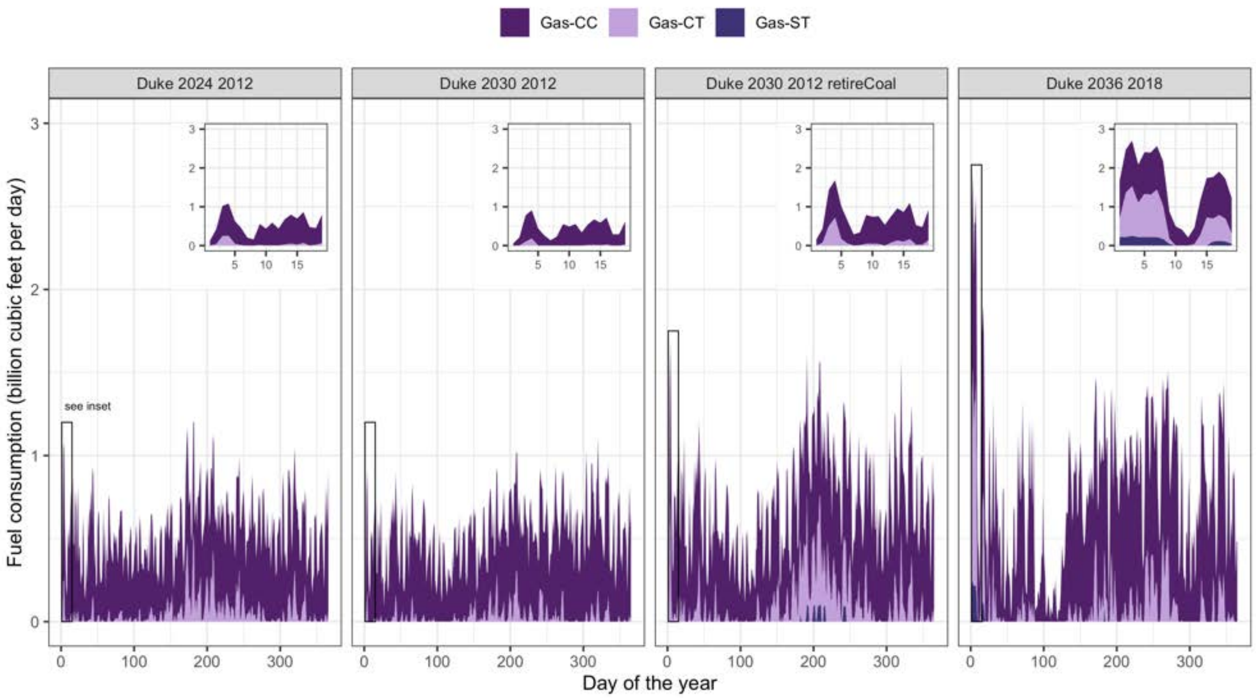
- 2012 weather year had a relatively brief winter peak which can be met primarily through a combination of nuclear, gas, solar, wind, and storage
- 2018 weather year had sustained low solar output + high load due to an extended cold snap
  - Demand peaks around 37 GW (annual peak)
  - Heavy use of Gas CC and CTs to meet demand
  - Storage charges during the day, discharges overnight
  - Offshore wind and imports help to meet remaining energy needs

Nodal results – Peak RE Generation



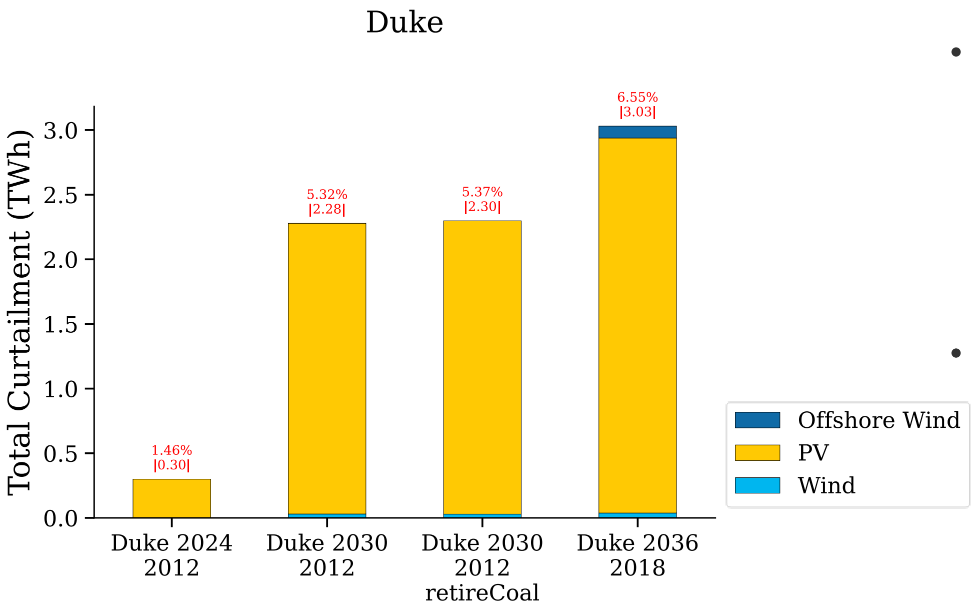
- Peak RE generation currently in summer but shifts toward spring in higher deployment
- Higher RE cases illustrate the reliance on ramping/cycling of remaining thermal units, highlighting the need to understand these impacts

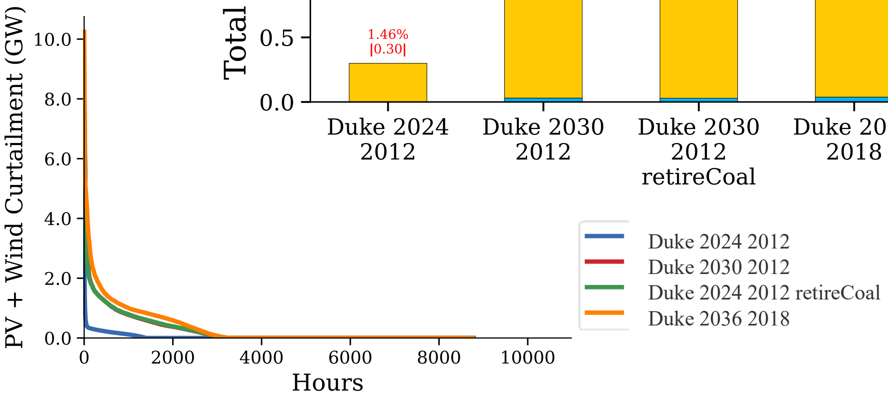
Nodal results – Daily Natural Gas Offtakes



- Natural gas offtakes increase as natural gas is utilized to make up for coal generation
- Demand for natural gas increases sharply in the winter, particularly when modeling an extended winter peak period (2018)
- Pipeline constraints or the cost of procuring firm pipeline capacity may limit the ability to utilize gas in this way
  - Need for new pipeline capacity could potential be reduced by gas storage
  - Gas demand could be reduced by replacing with alternatives (e.g., hydrogen or renewable turbines, seasonal storage)
- This usage pattern reflects the importance of planning for the winter peak

Nodal results – Curtailment

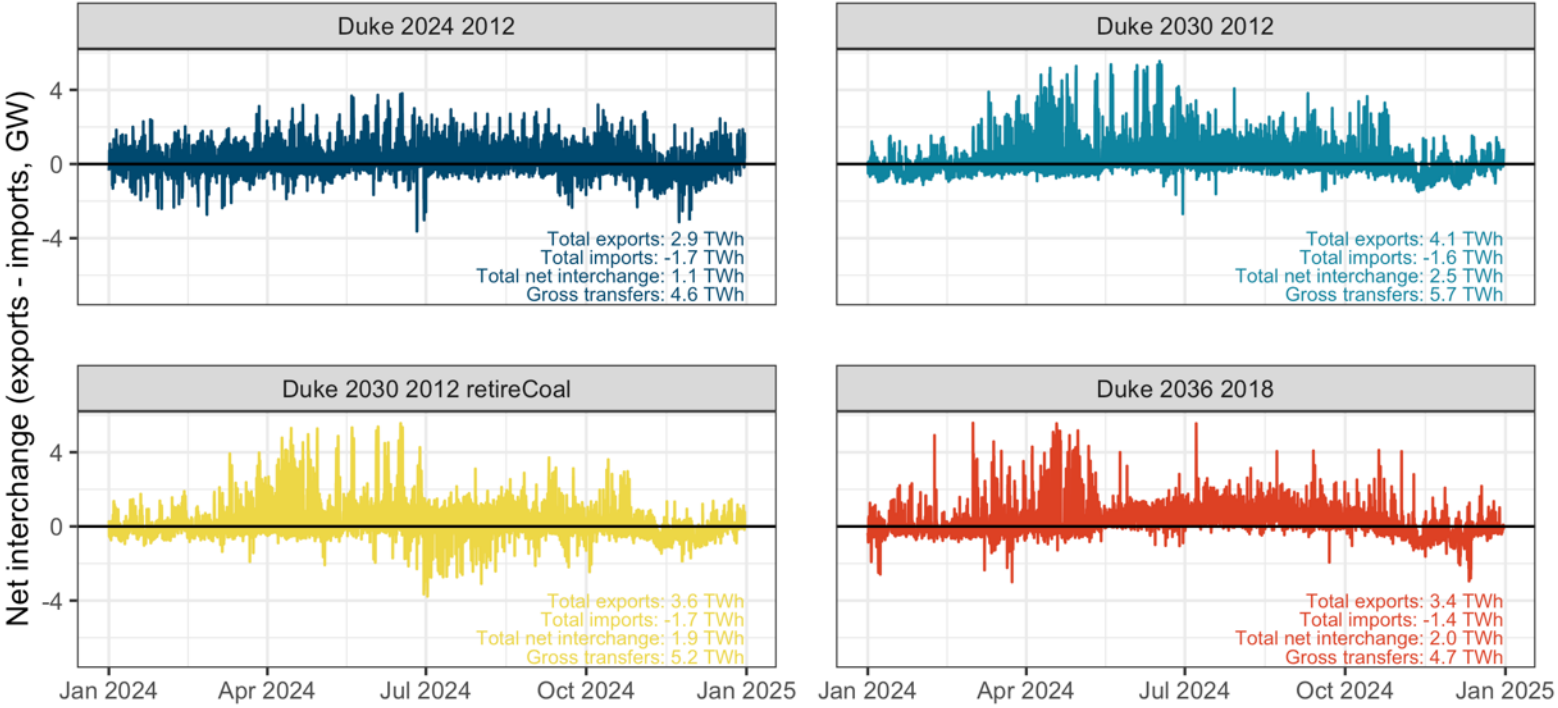




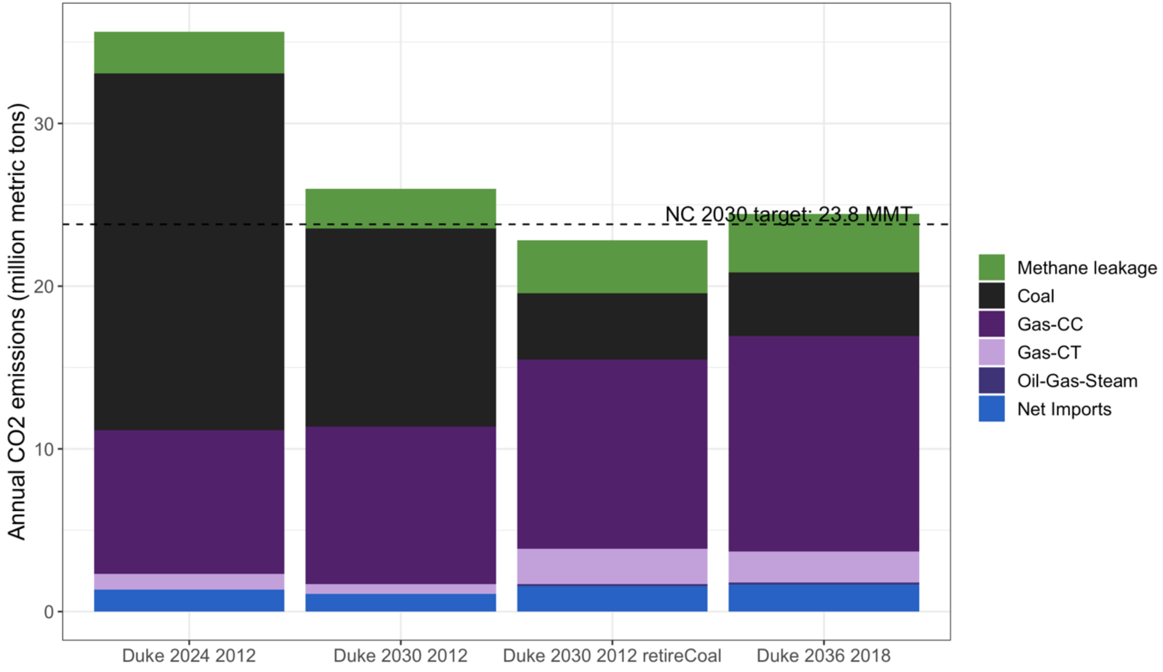
- Curtailment increases with higher contributions of renewable resource
  - Dominated by solar, but some curtailment from wind and later offshore wind as well
- Peak curtailment in top curtailment hour doubles from 5 GW to 8-10 GW
  - 2036 system has ~990 hours with instantaneous hourly curtailment greater than 1 GW
- Curtailment provides economic value to the system

Nodal results – Transmission Flows

- Net interchange doubles from 2024 to 2030
  - Total imports is relatively similar, but occurs in few hours with greater magnitude
  - Increase in total exports from Duke Energy to neighbors



Nodal results – Emissions



- Emissions estimates include direct emissions as well as emissions from methane leakage
  - CO_2 equivalent from methane leakage calculated assuming leakage rate of 2.3% (Alvarez et al., 2018) and 100 GWP potential
  - Note that the NC target does consider methane leakage
- Direct emissions fall below 2030 target in all 2030/2036 buildout cases modeled
  - This target and the baseline used to derive may be different from the levels used in the Duke Carbon Plan
- Total emissions fall with coal retirements, but emissions from natural gas increase (both direct and from fugitive methane)
- Imports increase slightly with higher transfers from neighboring regions

Production cost modeling cases

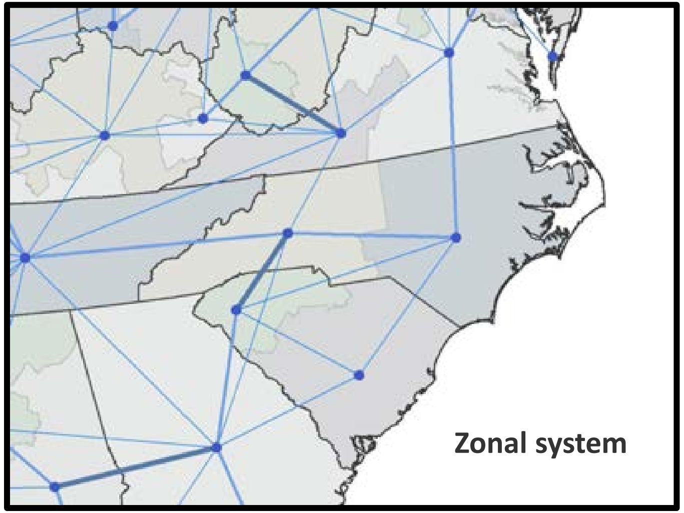
Two categories of production cost modeling cases: nodal and zonal

Nodal: Full transmission representation of Duke Energy's system; each case built by adding ReEDS builds to an existing network model

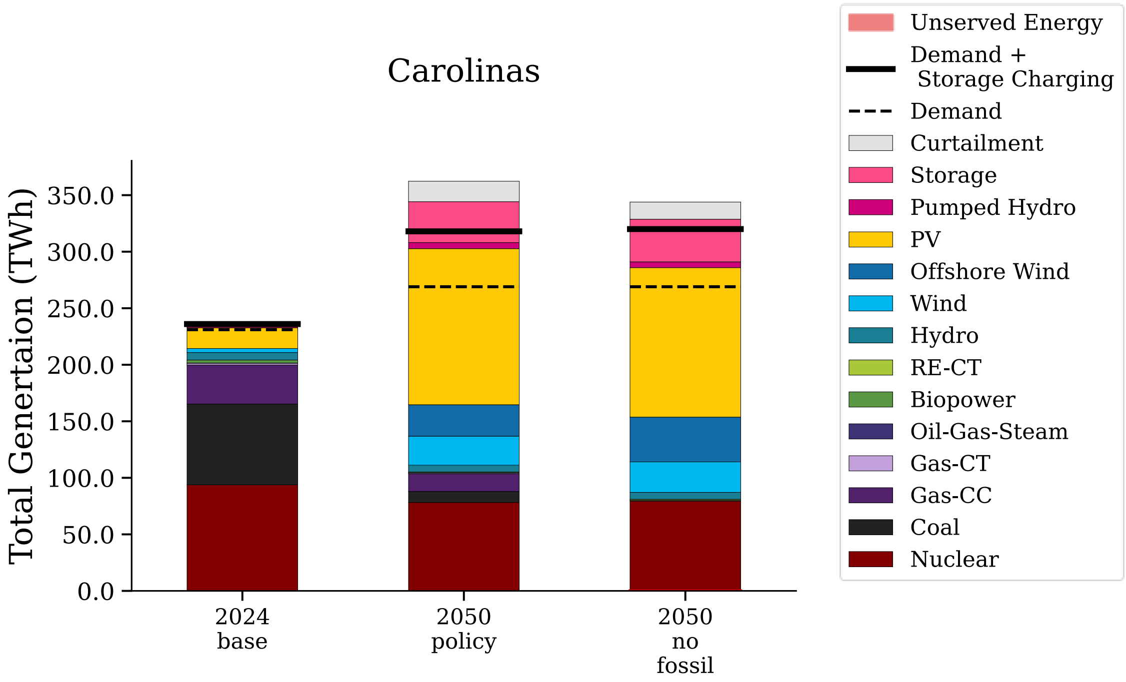
- 2024 buildout + 2012 weather (baseline)
- 2030 buildout + 2012 weather (policy case w/ 70% CO_2 reduction in NC)
- 2030 buildout modified + 2012 weather (includes accelerated coal retirements)
- 2036 buildout + 2018 weather (tests extended cold period; also includes coal retirements and offshore wind)

Zonal: Transmission matches ReEDS aggregation, with only the interfaces between BAs modeled

- 2024 buildout + 2012 weather (baseline)
- 2050 buildout + 2012 weather (policy case with zero-emissions)

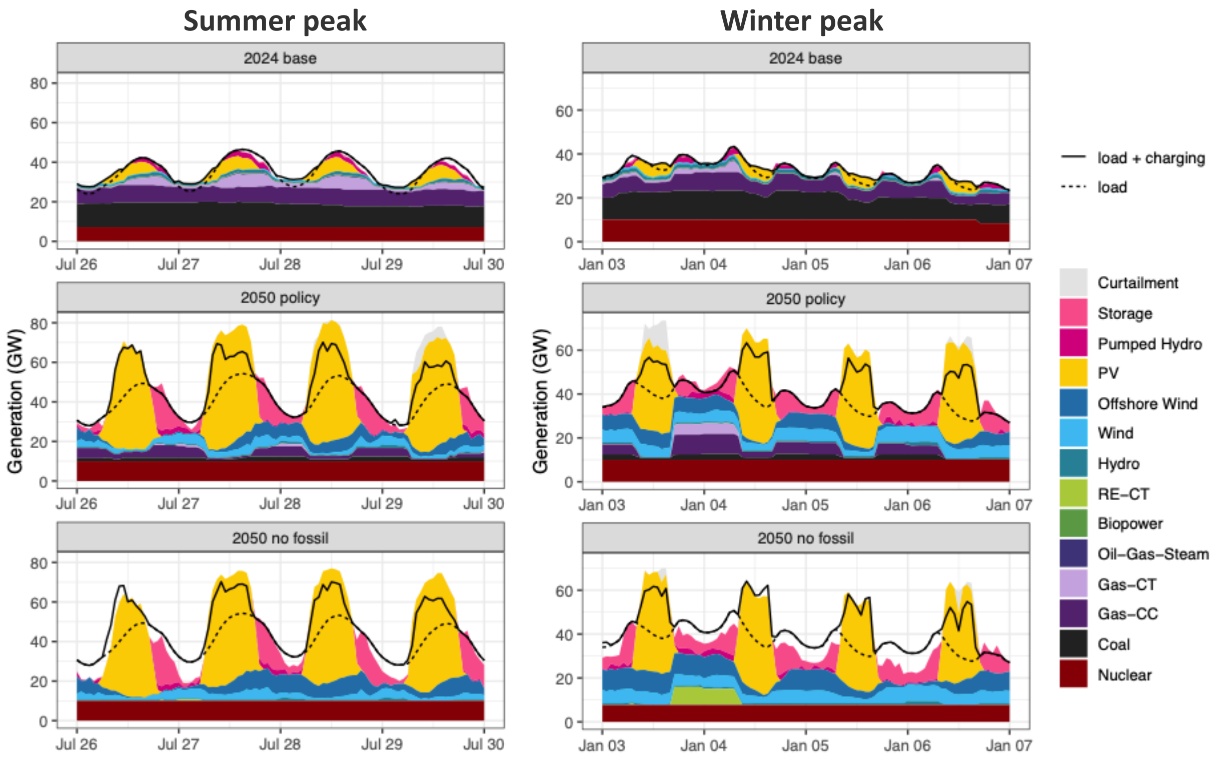


Zonal results: Annual Generation



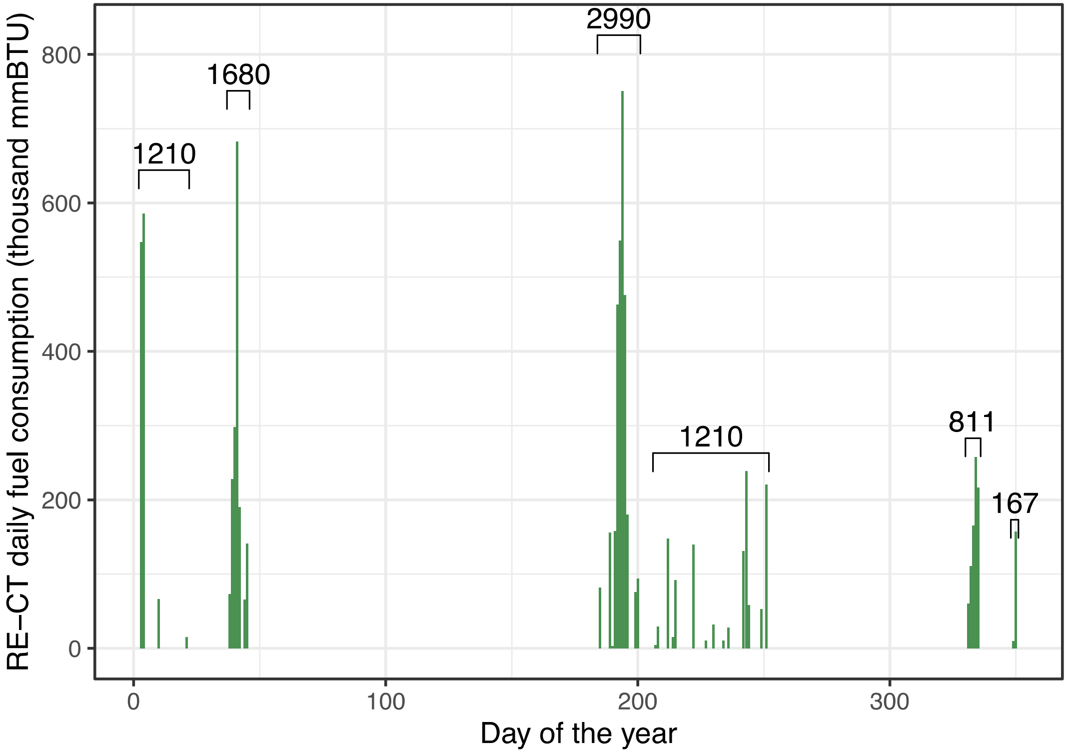
- Note that results are for the entire Carolinas (not just Duke Energy)
- No unserved energy in the Carolinas
- 2050 energy mix is a mix of solar + storage (~46%), existing nuclear (~26%), land-based wind (~8%), and offshore (9-14%)
- If all fossil is retired, system also relies on zero-emissions peaking resources (renewable CTs) to meet demand in hours of stress (<1% total generation)

Zonal results: Peak Dispatch



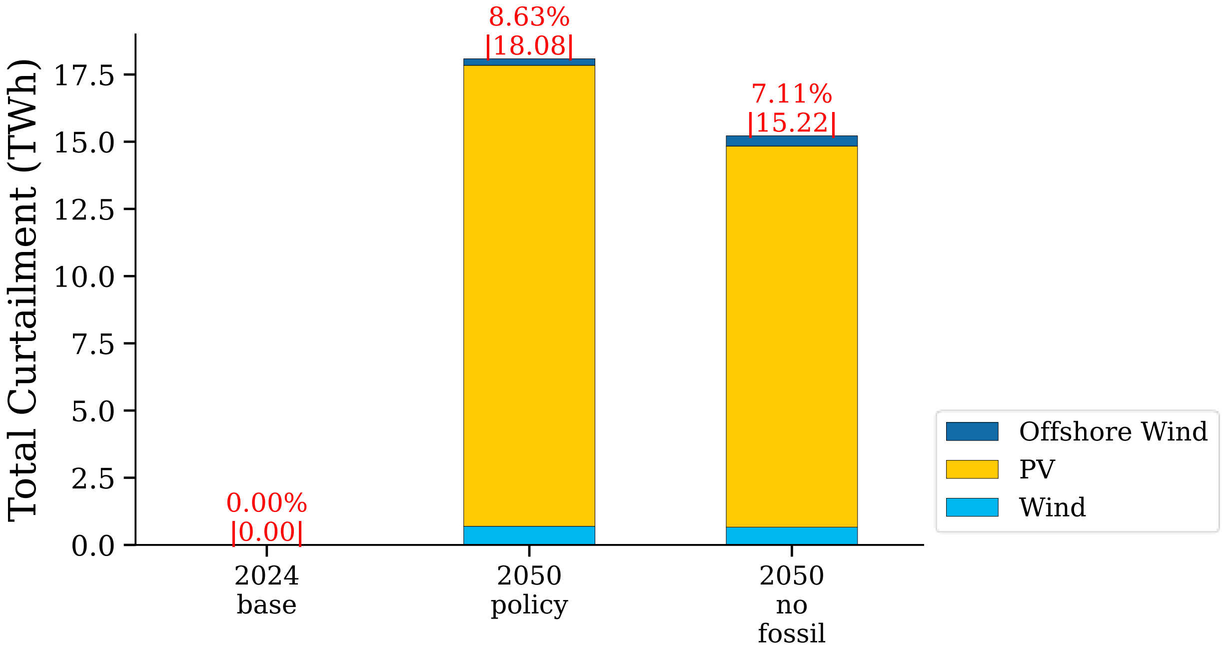
- Storage charges during the day when solar is available, discharges in the evening/overnight
- RE-CTs used to supply high demand during winter peak period
  - Also used in the summer, depending on solar output
- “No fossil” system relies more on imports during the evening/overnight period

RE-CT fuel consumption



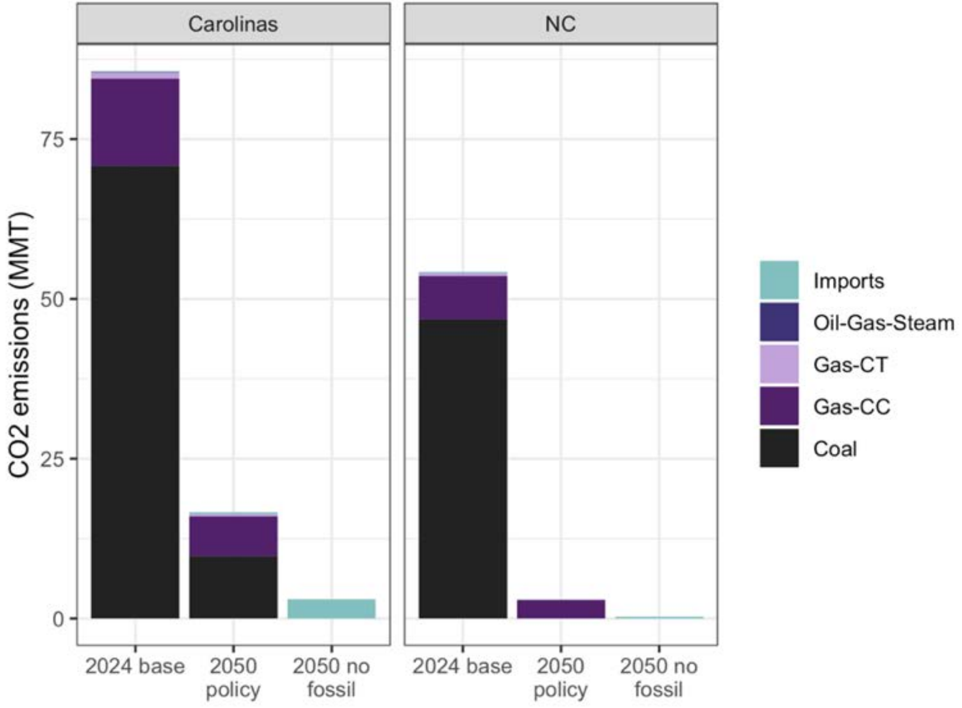
- RE-CTs in the “no fossil” case are used to meet peaking requirements
  - Low annual capacity factor
  - High use when deployed
- Plot illustrates the quantity of renewably-sourced fuel that needs to be provided to sustain output in those periods
  - Could be H2, biofuel, or some other peaking resource
  - Implies sufficient pipeline infrastructure or storage capacity to supply ~3 million mmBTU at a time
- Other technologies such as seasonal storage could also fill this role

Zonal results: Curtailment



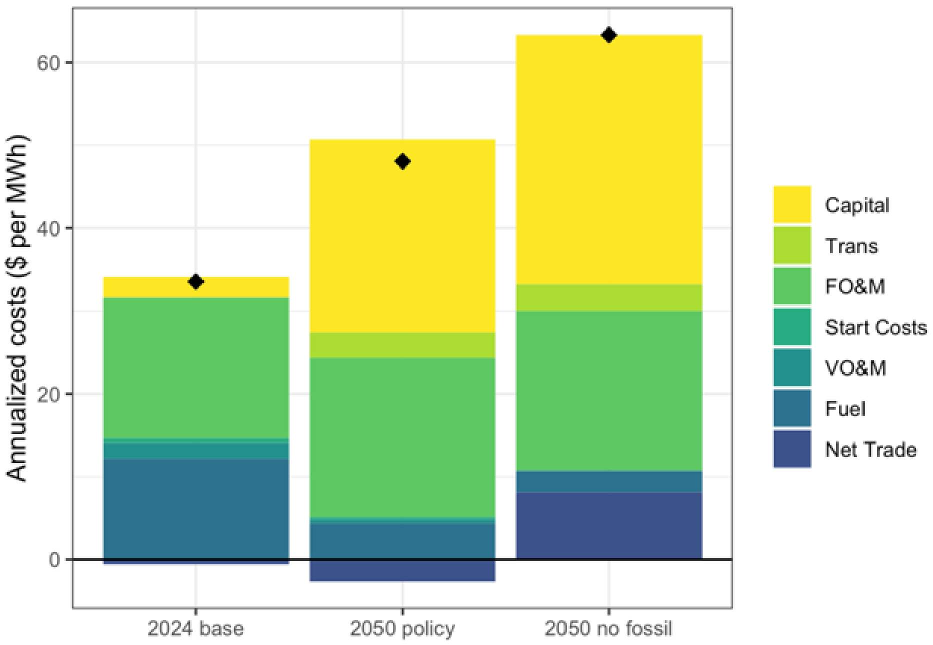
- More curtailment expected in carbon-free system
  - Buildout chosen based on minimizing costs, indicates that curtailment is more economically viable than some of the alternatives
- No fossil case reduces curtailment due to greater deployment of storage

Zonal results: CO_2 emissions



- Emissions in "2050 policy" case due to remaining fossil units outside of Duke Energy territory in South Carolina
- Accounting for imported emissions—either from South Carolina or from neighboring regions without zero-carbon goals—is likely to be important for achieving zero in a system that utilizes more imports than today

Zonal results: Total system costs



- Annual operating costs decline as the system deploys more low marginal cost resources; these declines are accompanied by increases in amortized capital expenses
- Additional costs of “no fossil” case reflect the increasing costs of replacing all fossil peaking capacity, as well as the cost increases associated with dealing with the last 5-10% of emissions

Summary of key findings

1. Duke Energy can approach the **2030 emissions target in North Carolina through investment in a combination of PV, wind, and storage along with maintaining its existing nuclear fleet**

2. A **zero-emissions electricity sector target in 2050** can be achieved through investment in land-based and offshore wind, solar PV, and battery storage, coupled with maintaining the existing nuclear fleet and procuring other zero-emissions firm-capacity resources

3. **Investment in new transmission and expanded power exchange** with neighbors can play an important role in achieving both the 2030 target and a net-zero power system

4. Low- and zero-carbon systems in the Carolinas will likely result in **greater challenges to meeting the system load in the winter**

5. As Duke transitions to carbon-free generation resources, it can expect that the **capital share of total bulk system costs or expenditures will increase** while the operational share decreases

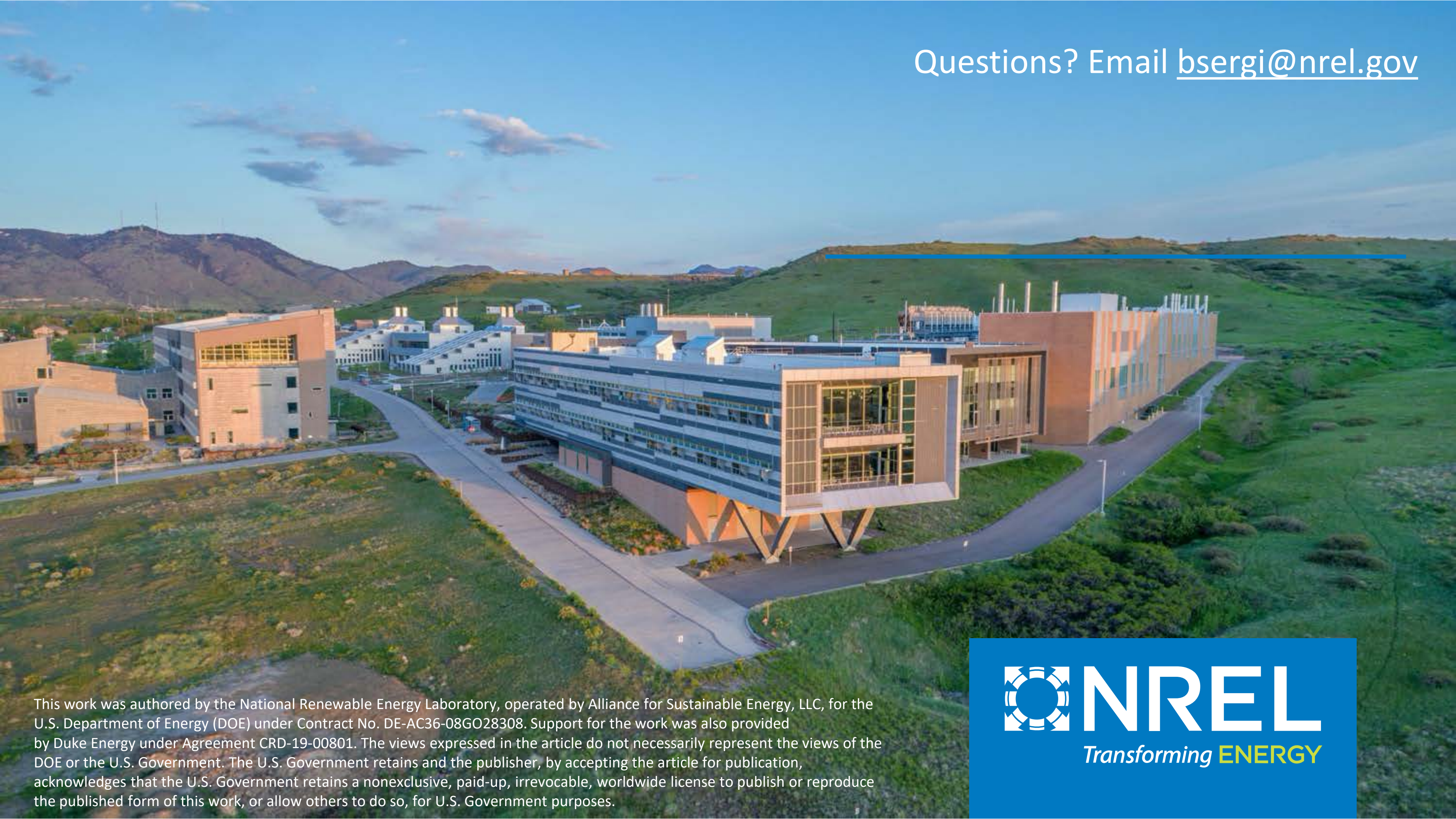
Discussion

These findings are directionally consistent with previous assessments of decarbonization pathways in the Carolinas, but specific outcomes may differ depending on modeling assumptions

This research highlights the path toward a decarbonized system, but more analysis is needed to study the feasibility and implementation of that pathway. Some additional elements to consider:

- Supply chain, workforce, or logistical constraints to building new generation capacity
- Additional siting restrictions or considerations
- The evaluation of transient/dynamic stability, as well as contingency and N-1 security
- Other technologies (e.g., seasonal energy storage) or constraints (e.g., detailed gas pipeline modeling)

This work is not intended to replace Duke Energy's IRP process



Questions? Email bsergi@nrel.gov

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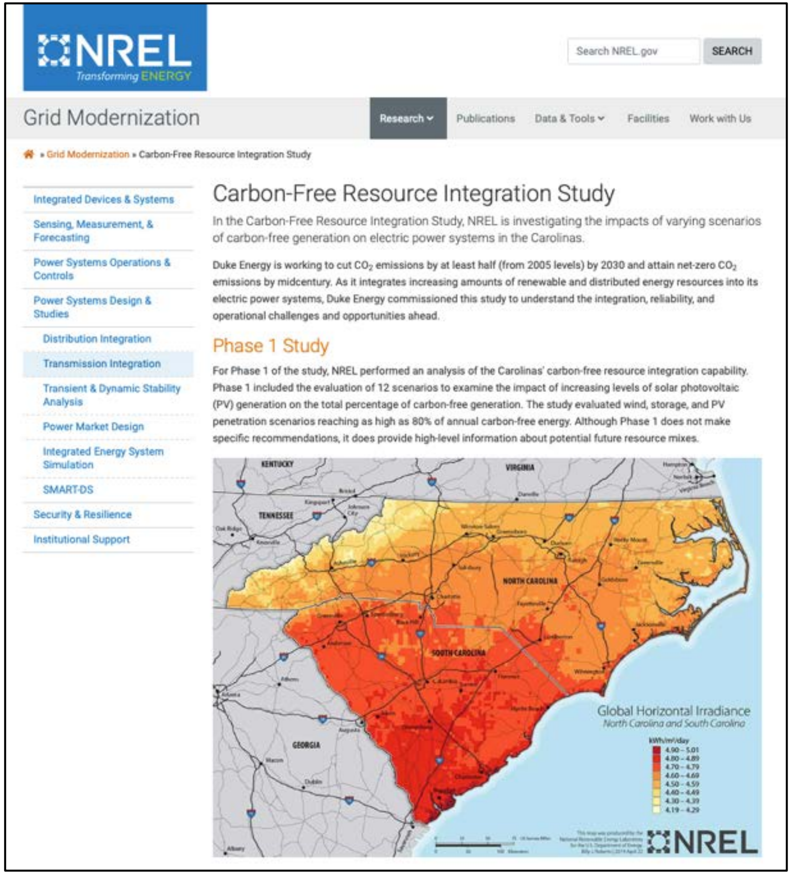
NREL Transforming ENERGY

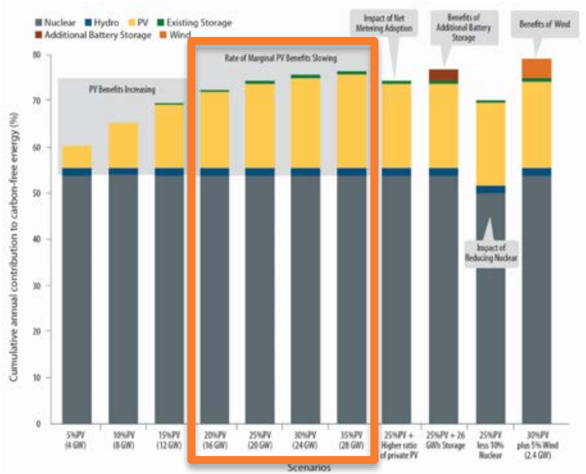
Stakeholder engagement

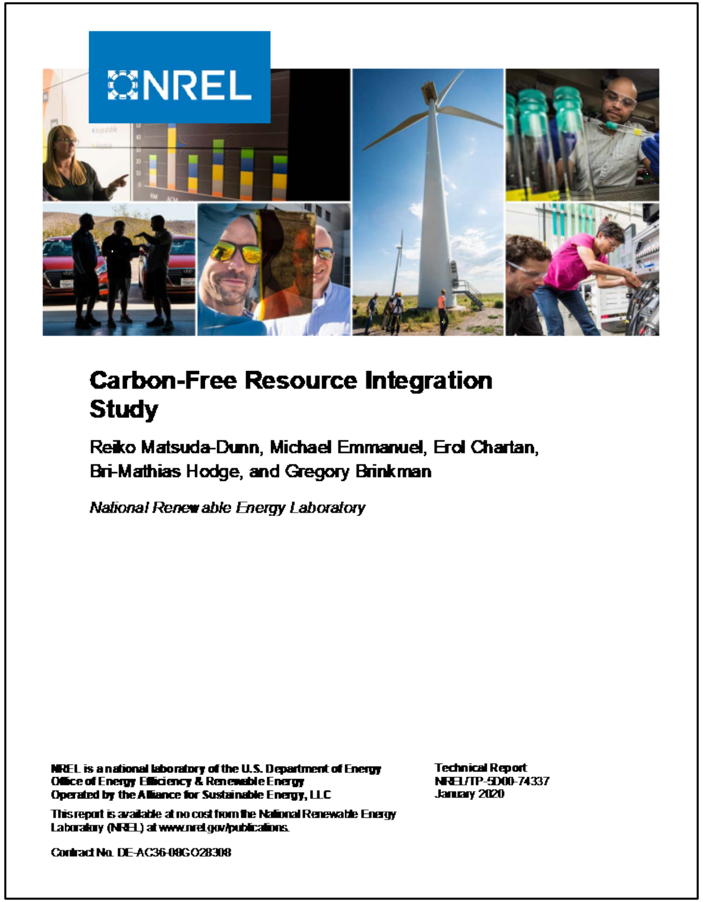
- Two joint NREL-Duke Energy webinars discussing modeling assumption and results, along with an additional webinar discussing Phase I results
- Involvement in the NC DEQ Clean Energy Working Group and modeling through Duke University/ICF
- Engagement with the Southeastern Wind Coalition Utility Advisory Group
- Creation of a website that includes study publications, webinar presentations, and FAQs from the capacity expansion results based on feedback from stakeholders: https://www.nrel.gov/grid/carbon-free-integration-study.html



Phase I Overview

- Net load analysis of varying solar penetrations in the Carolinas
- Simple analysis intended to frame more detailed analysis in Phase II





NREL

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Technical Report
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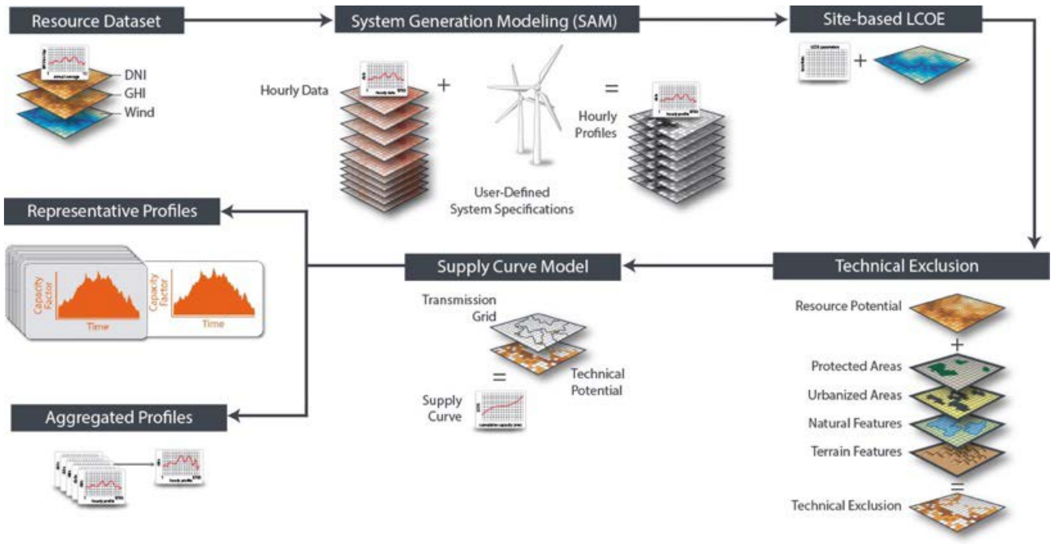
January 2020

Resource characterization



Assessed using NREL's geospatial **renewable energy potential** (reV) model

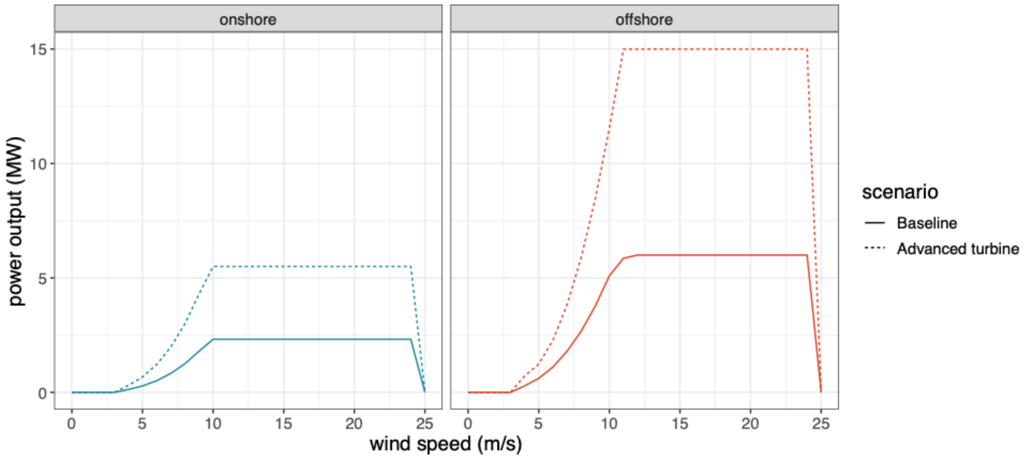
Resource quality evaluated using **hourly wind and solar** data sets representing 2012 weather year

Available land for developed reduced based on **exclusions,** including features such as:

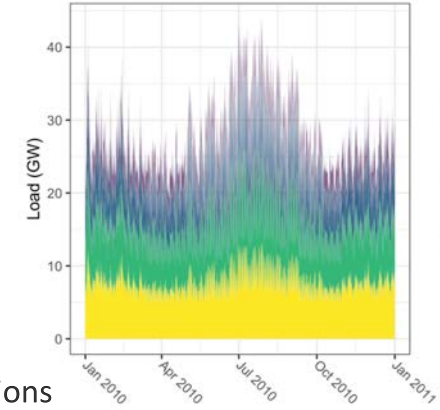
- Urban areas
- Bodies of water
- Protected lands
- Sloped lands
- Distance from structures
- Ridgetop lands (above 3,000 ft)
- Military base and radar line-of-sight

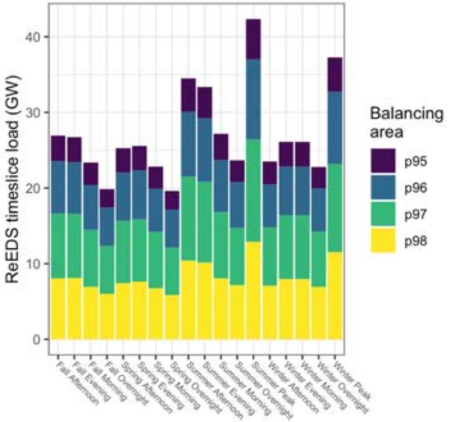
Wind turbine performance assumptions

	Onshore wind		Offshore wind	
	Baseline	Advanced sensitivity	Baseline	Advanced sensitivity
System Capacity (MW)	2.3	5.5	6.0	15
Hub Height (m)	110	120	100	150
Rotor Diameter (m)	113	175	155	240
Losses (%)	16.7	11.8	16.7	16.9



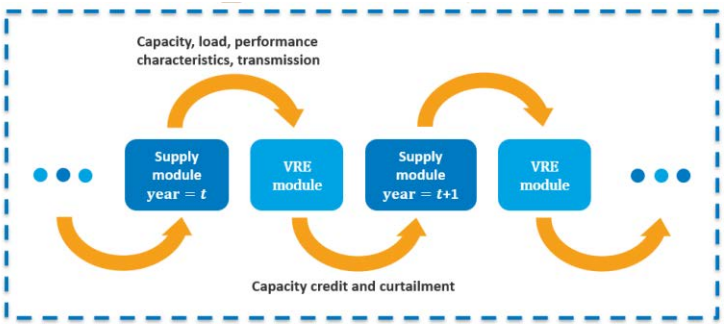
ReEDS modeling assumptions





Main assumptions

- Operations modeled using representative time-slices
- Spatial resolution: 134 balancing areas / 356 RE resources regions
- Model solves each year sequentially (myopic, no perfect foresight)
- NREL ATB 2020 capital cost + AEO 2020 fuel projections
- Surrounding state policies implemented (e.g. VA Clean Economy Act)



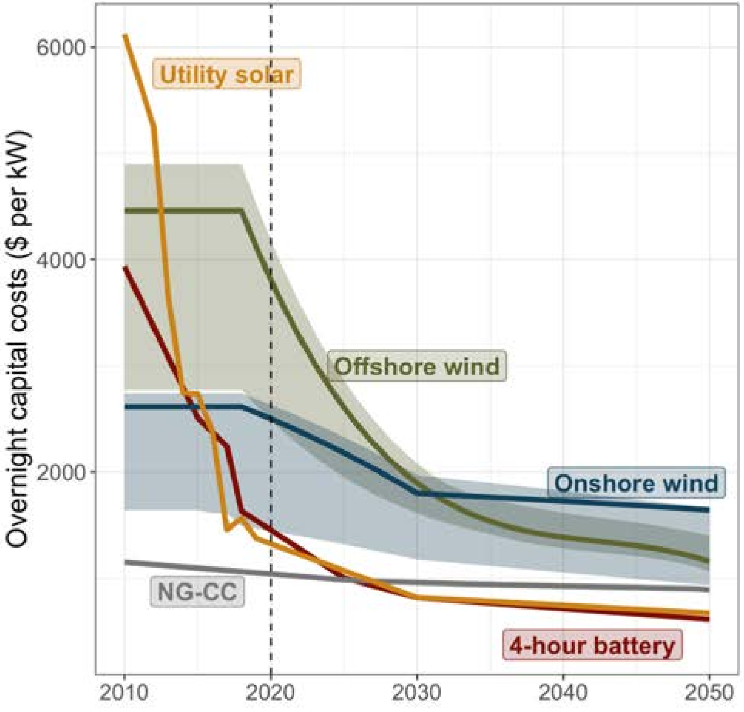
Key modifications of ReEDS for this project

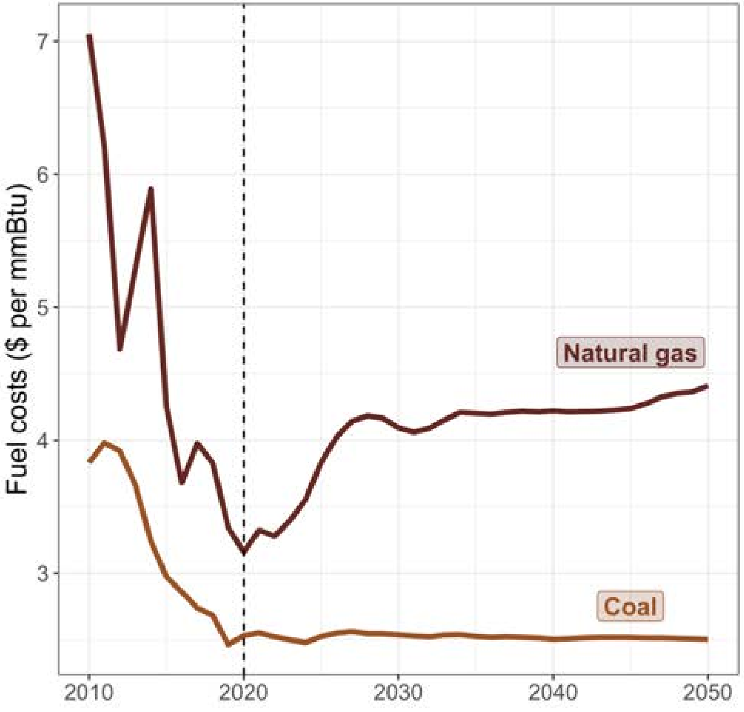
- Adoption of an 18th timeslice representing the winter morning peak
- Nuclear plants assumed to have licenses extended
- Coal retirement dates based on book like from Duke's last depreciation study (model can retire coal and other existing fossil earlier than their retirement dates)
- Assumption cost adder to natural gas combined cycle plants built in the Carolinas (proxy for the cost of firm pipeline capacity)
- Modified exclusion areas for onshore wind supply curves

Summary of ReEDS Cost Assumptions

NREL ATB (2020):
https://atb-archive.nrel.gov/electricity/2020/data.php

EIA AEO (2020):
https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf





Coal retirements

Boiler type	Plant name	Retirement date in ReEDS
Subcritical	Allen 1	2023
	Allen 2	2023
	Allen 3	2023
	Allen 4	2027
	Allen 5	2027
	Roxboro 1	2028
	Roxboro 2	2028
	Cliffside 5	2032
	Roxboro 3	2033
	Roxboro 4	2033
	Marshall 1	2034
	Marshall 2	2034
	Mayo 1	2035
Supercritical	Marshall 3	2034
	Marshall 4	2034
	Belews Creek 1	2038
	Belews Creek 2	2038
	Cliffside 6	2048

Retired by 2030 target

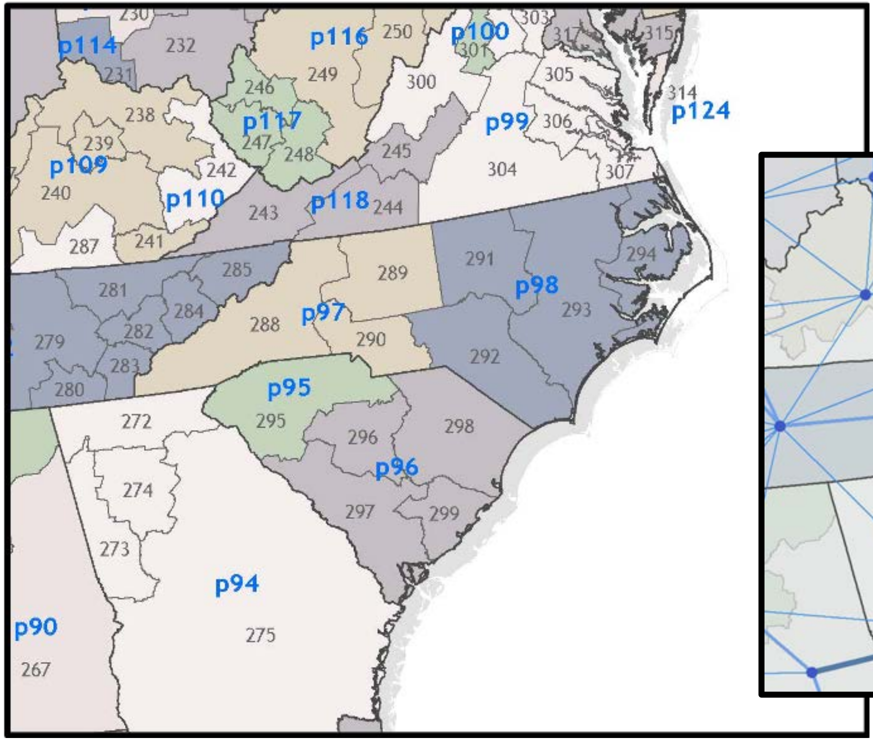
Additional retirements tested via sensitivity

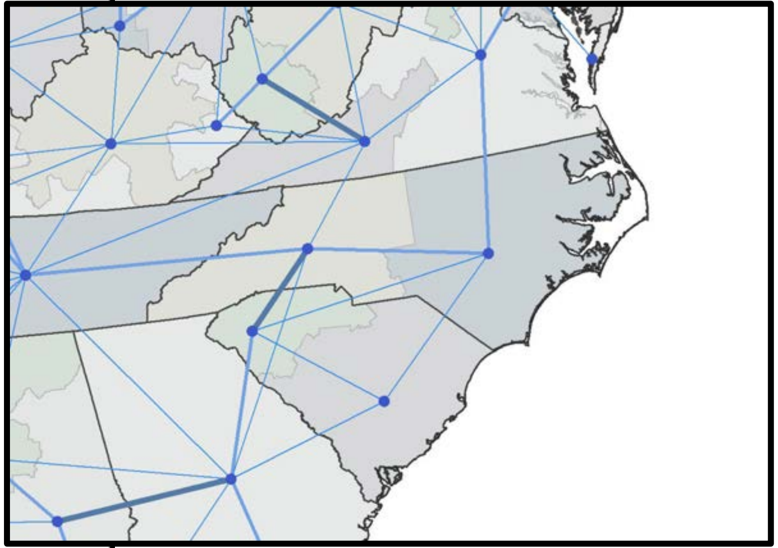
ReEDS approach to modeling the Carolinas

Carolinas modeled as four balancing areas (BAs) where load and planning constraints must be met

Transmission represented between BAs, but not within

Wind resource modeled at finer spatial resolution



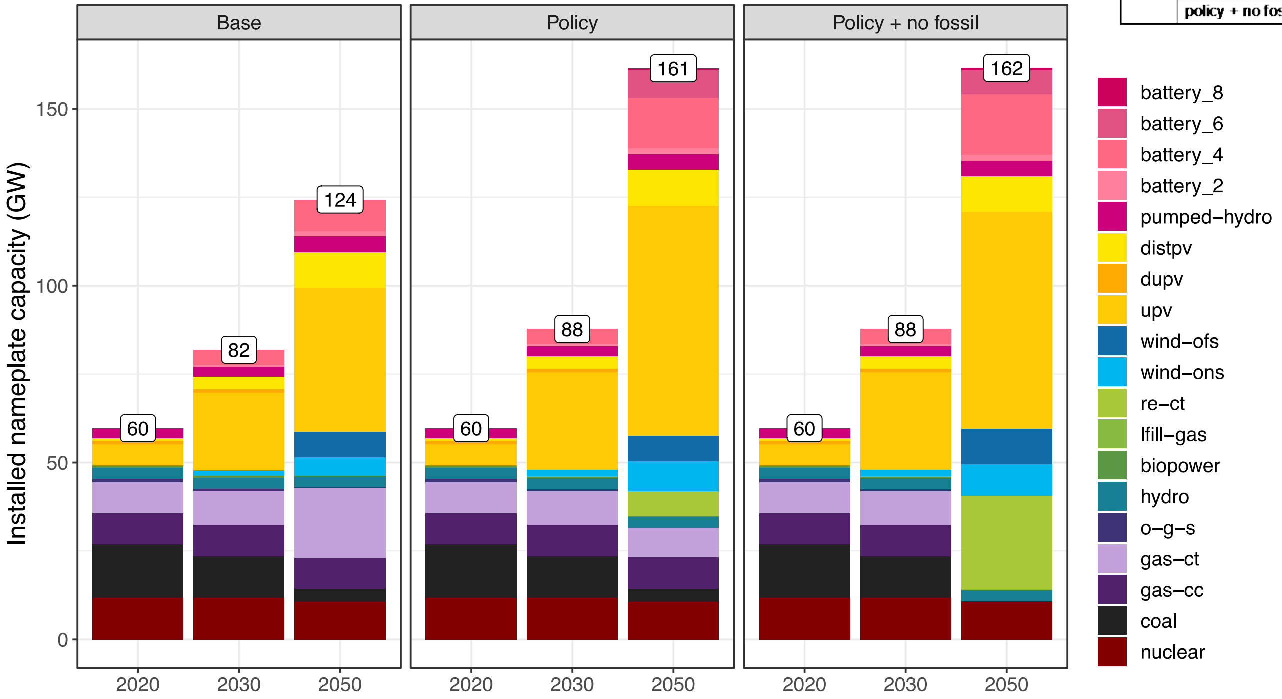


Capacity buildout

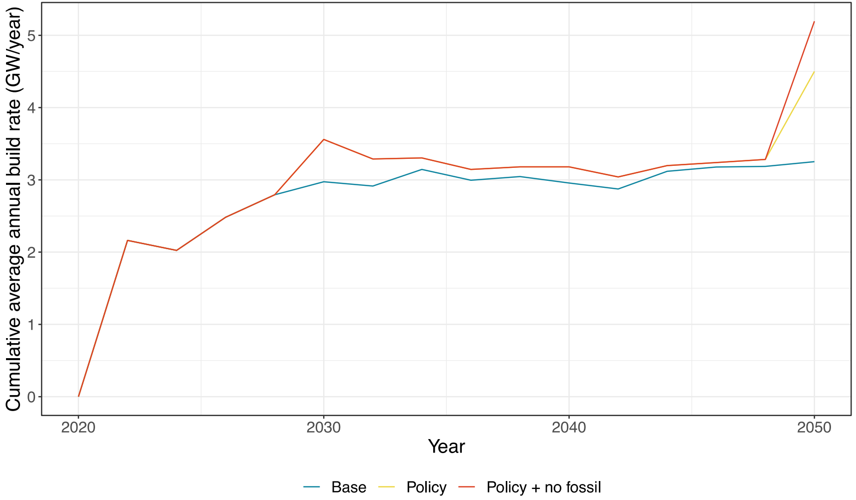
Installed capacity by technology (GW)

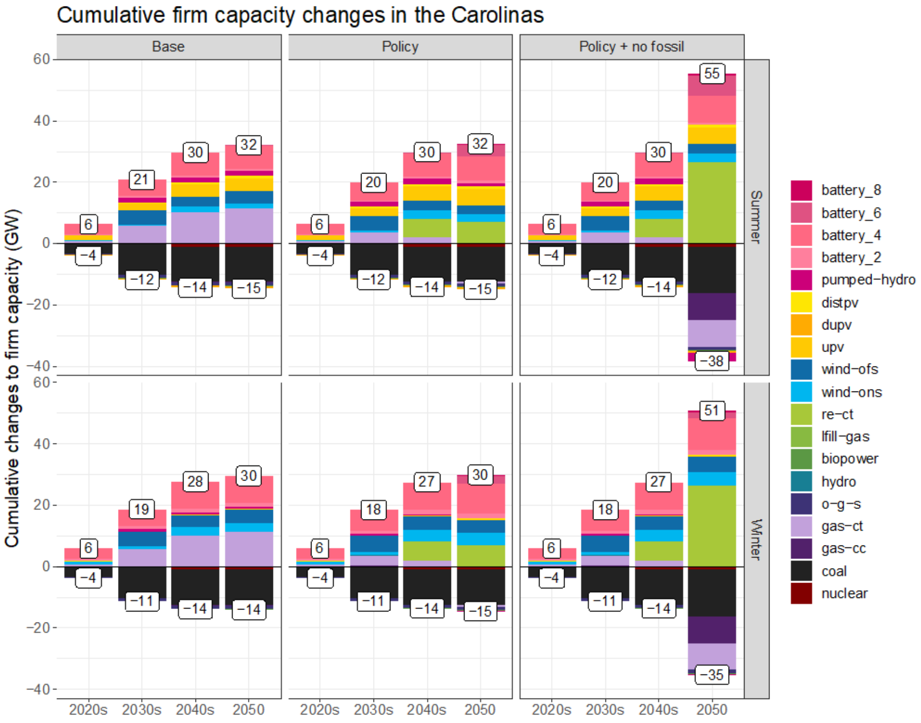
Year	Scenario	Solar	Onshore wind	Offshore wind	Natural gas	RE-CT	Batteries
2020	base	7.6	0.21		18		0.01
	policy	7.6	0.21		18		0.01
	policy + no fossil	7.6	0.21		18		0.01
2030	base	26	1.5		18		4.8
	policy	32	1.9		18		4.8
	policy + no fossil	32	1.9		18		4.8
2050	base	51	5.1	7.2	29		10
	policy	75	8.5	7.2	17	7	24
	policy + no fossil	71	8.9	10		27	26

Installed capacity in the Carolinas

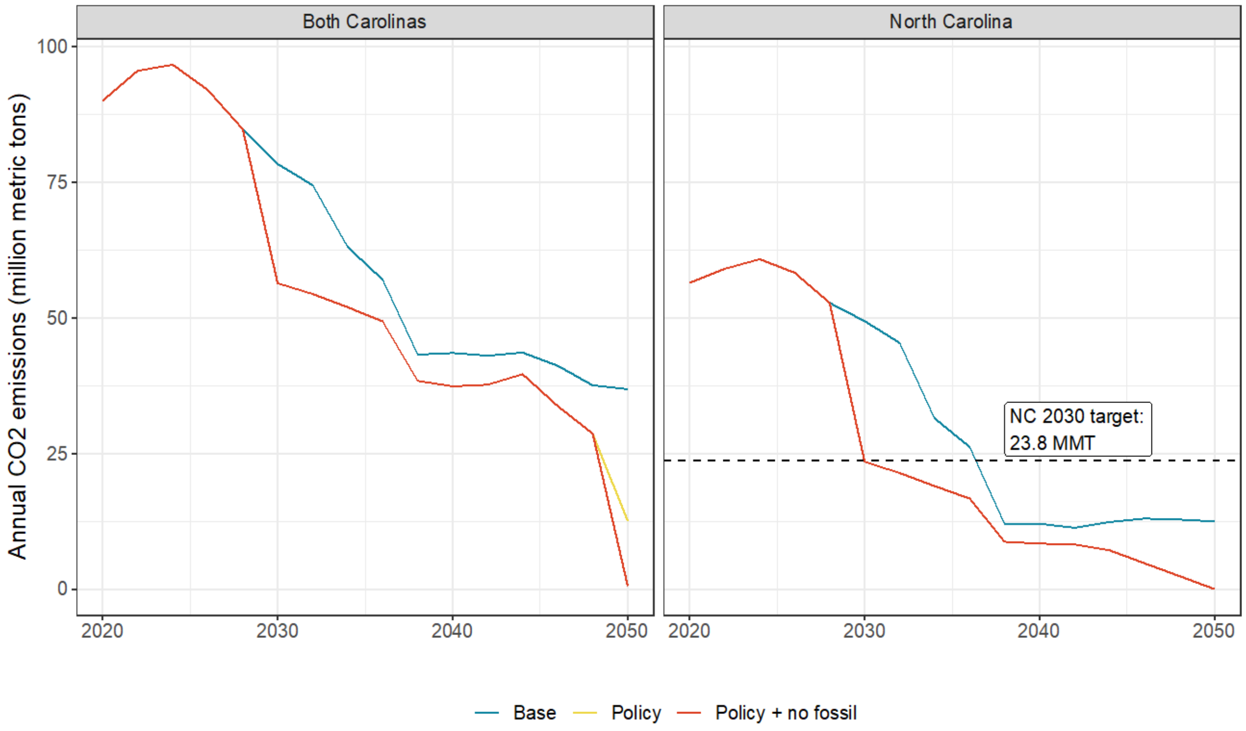


New capacity builds

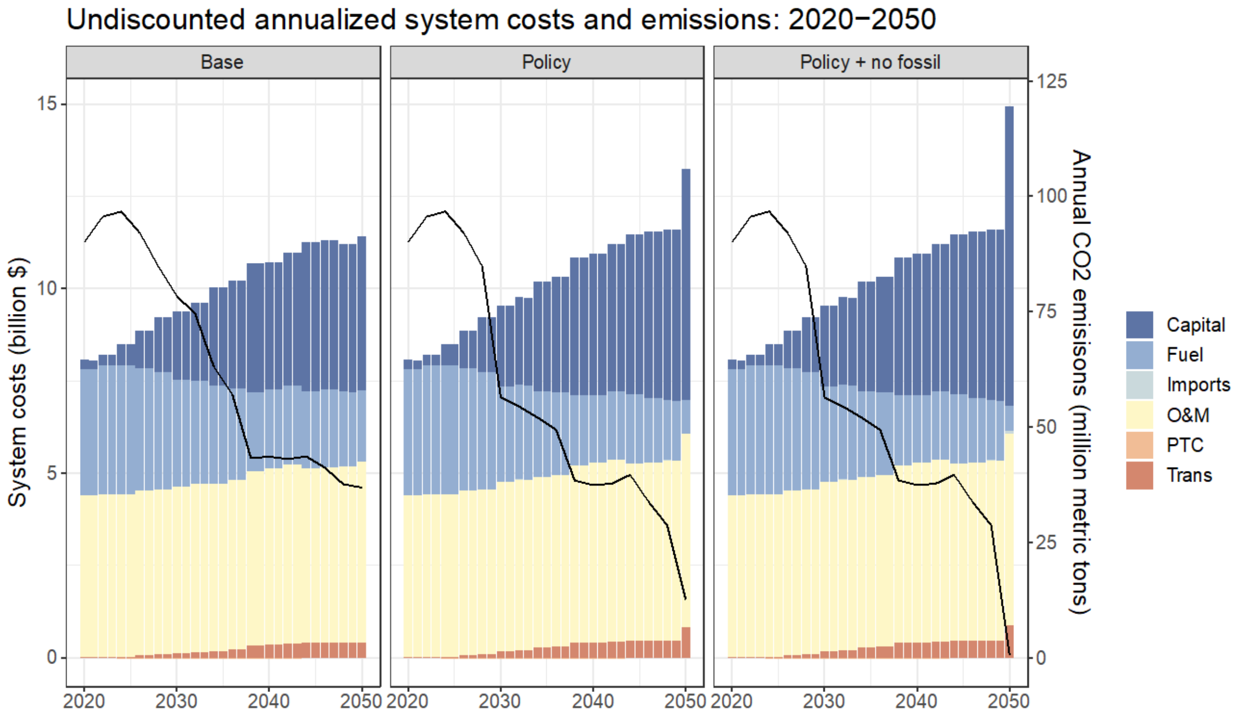




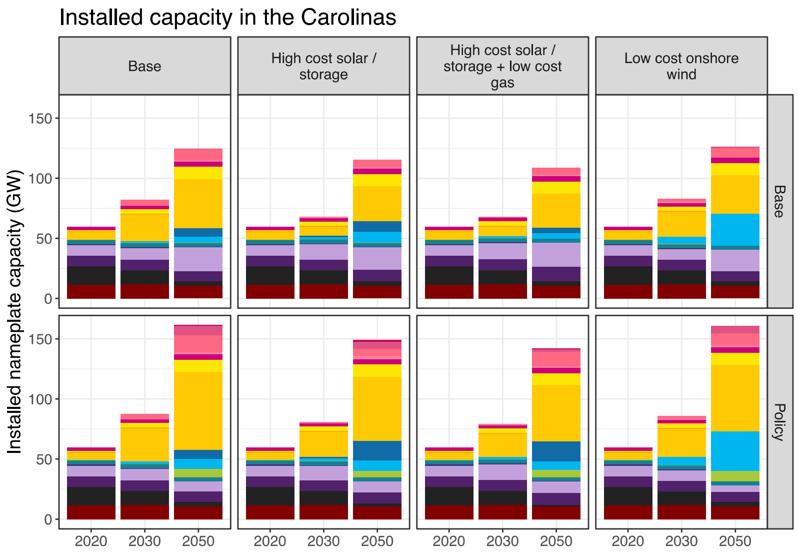
Annual CO_2 estimates from ReEDS

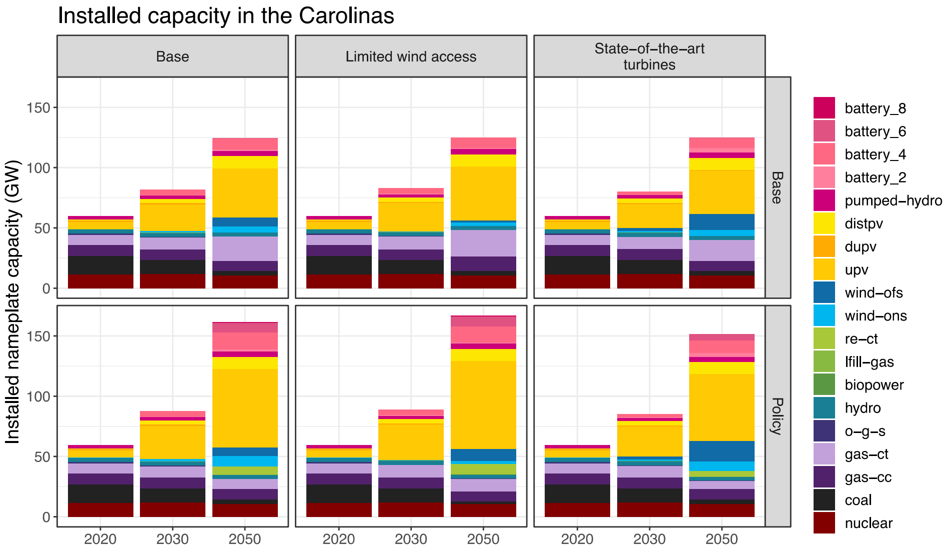


Annual CO_2 estimates and cost estimates from ReEDS



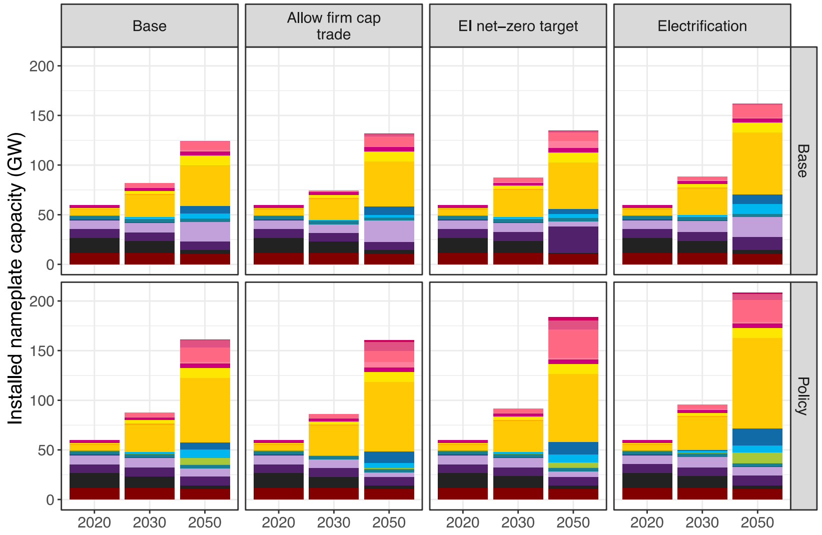
Sensitivity analysis in ReEDS



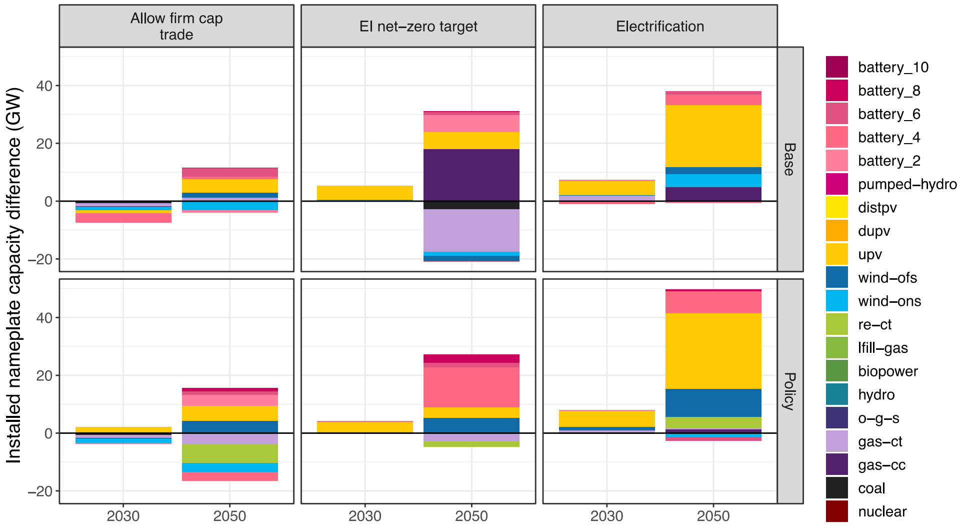


Sensitivity analysis in ReEDS

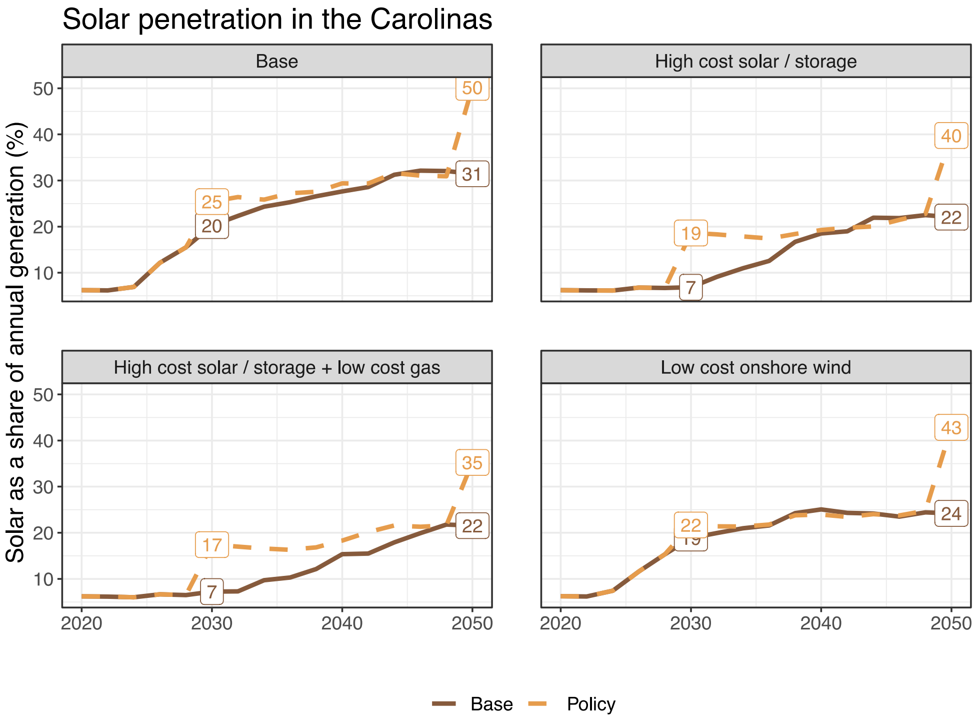
Installed capacity in the Carolinas

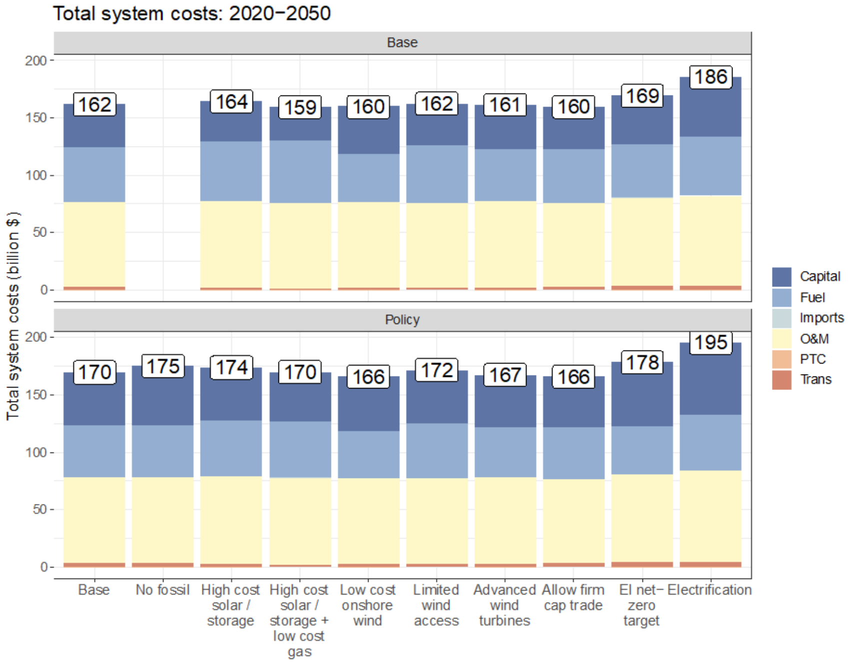


Difference in installed capacity in the Carolinas (relative to base assumptions)

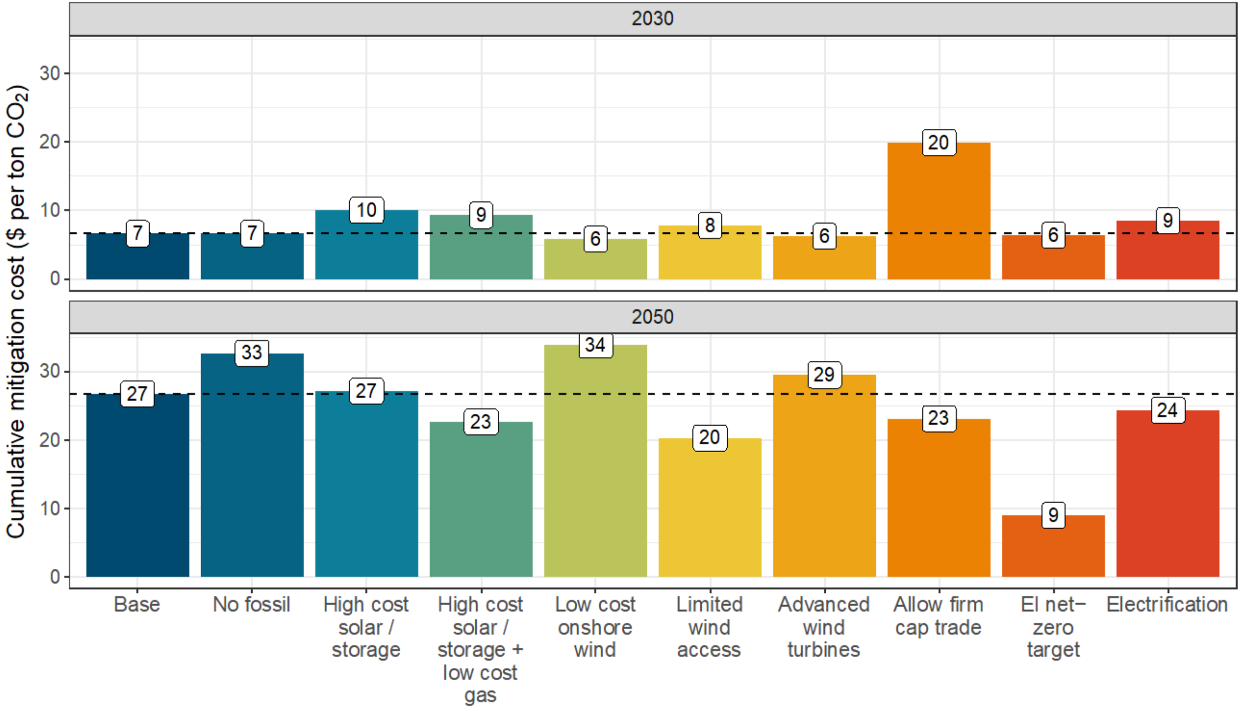


Sensitivity analysis in ReEDS





Cost of mitigation across sensitivities



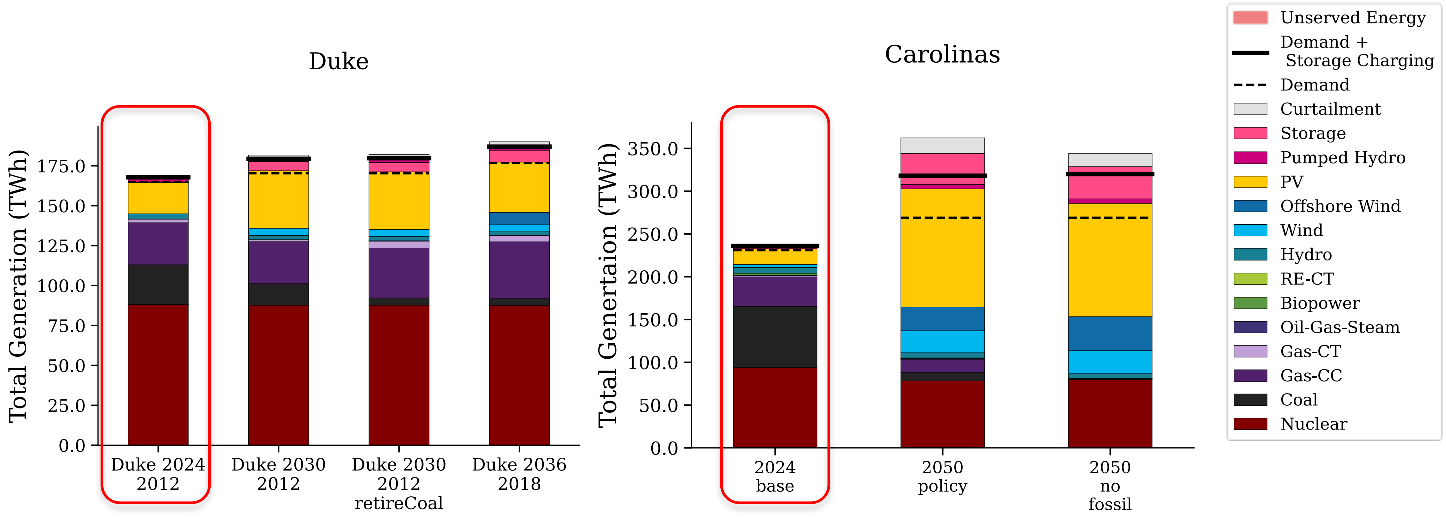
Nodal vs. zonal model

Nodal model

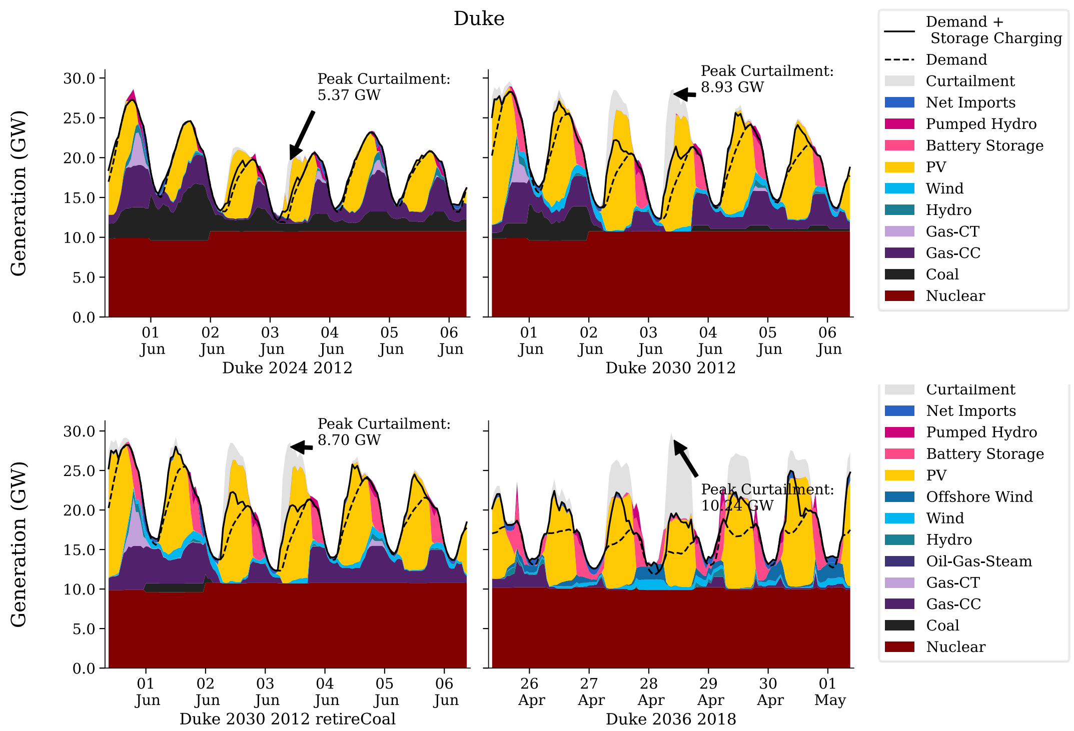
- 2024/2030 cases for Duke Energy
- Full transmission and generator representation
- Better captures the existing system

Zonal model

- 2024/2050 cases for the Carolinas
- Aggregated transmission and generator representation (matches ReEDS)
  - Potentially too flexible for curtailment, storage operations, etc.
- 2050 system likely to be substantially different from present day nodal model

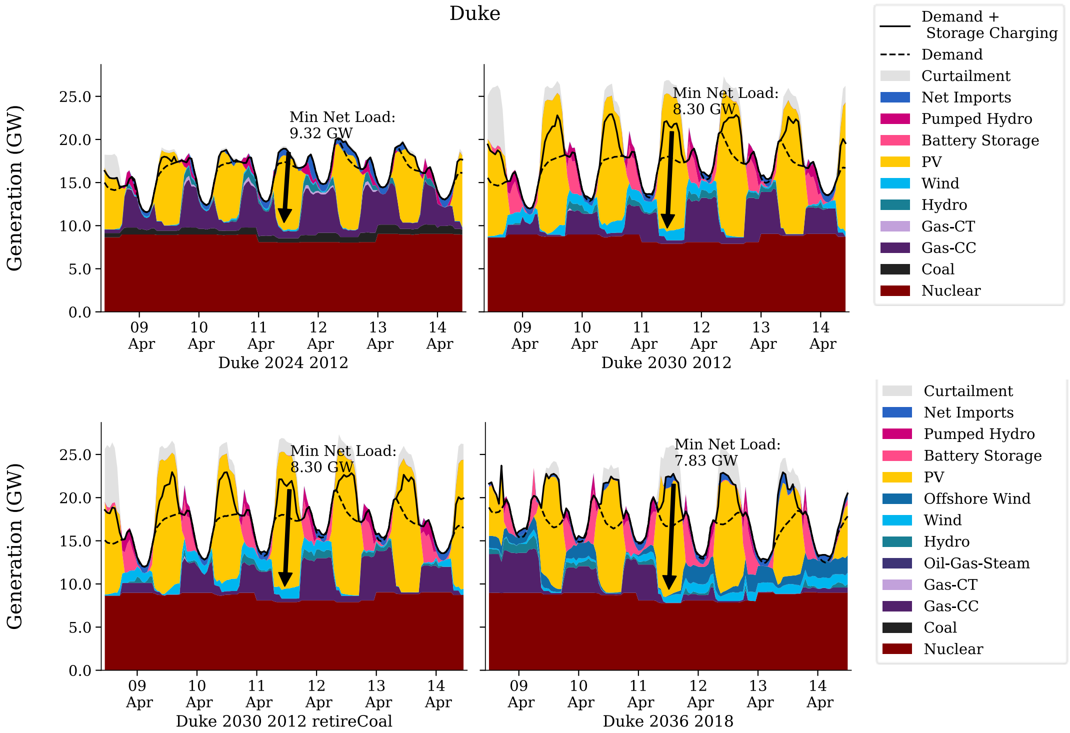


Nodal results – Peak Curtailment



- Maximum curtailment level doubles from 5 to 10 GW from 2024 to 2036 period
- More discussion on total curtailment levels to follow

Nodal results – Minimum Net Load

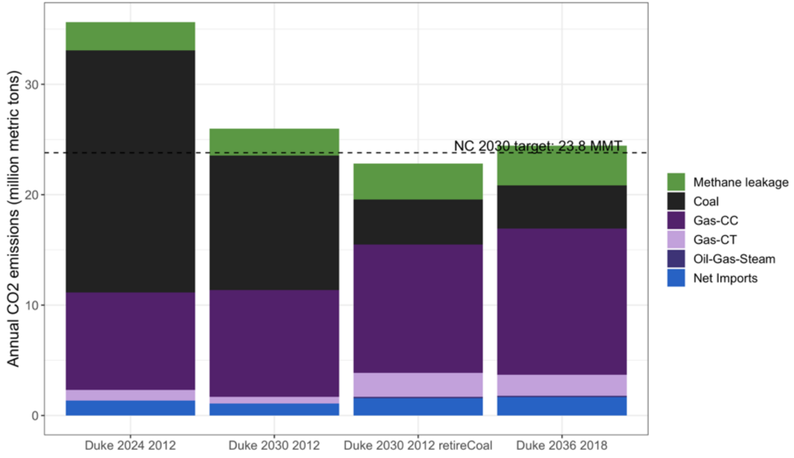


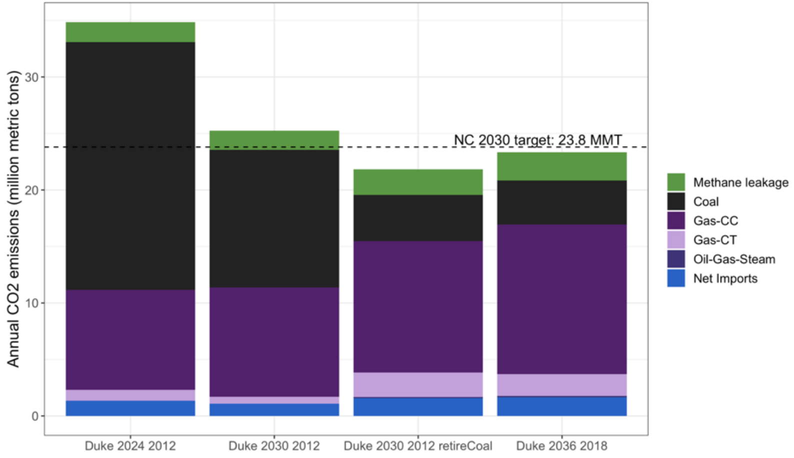
- Min net load period consistently occurs in the spring: relatively low load combined with higher RE availability
- Minimum net load level decreases with more RE generation, pushes other units to ramp down

Methane leakage

- North Carolina legislation focuses on direct emissions from electric generation utilities, but accounting for methane leakage may also be important from a climate perspective

- CO_2 equivalent from fugitive methane estimated assuming different leakage rates and a 100-year global warming potential
  – **Base (top):** 2.3% from Alvarez et al., 2018
  – **Low case (bottom):** 1.61% based on federal target to reduce methane emissions 30% by 2030





Zonal model, alternate dispatch