Duke Energy Carbon-Free Resource Integration Study

Capacity Expansion Findings and Production Cost Modeling Plan

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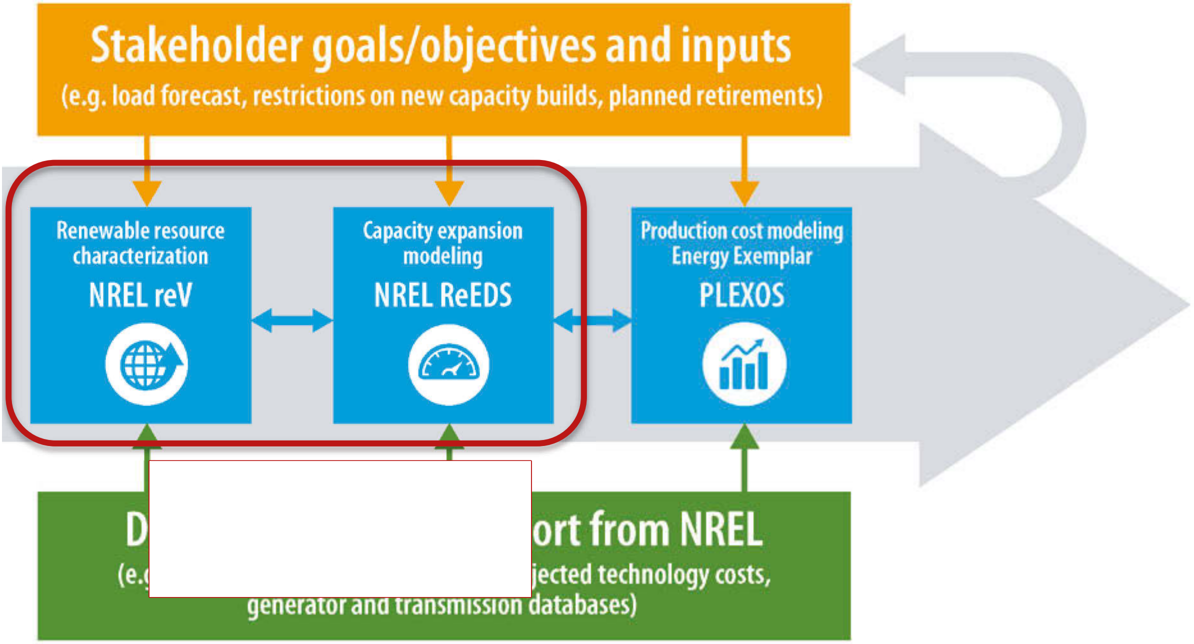
Duke low-carbon integration study (Phase II)



Stakeholder goals/objectives and inputs

(e.g. load forecast, restrictions on new capacity builds, planned retirements)

Renewable resource characterization

NREL reV

Capacity expansion modeling

NREL ReEDS

Production cost modeling Energy Exemplar

PLEXOS

D ort from NREL

(e. jected technology costs, generator and transmission databases)

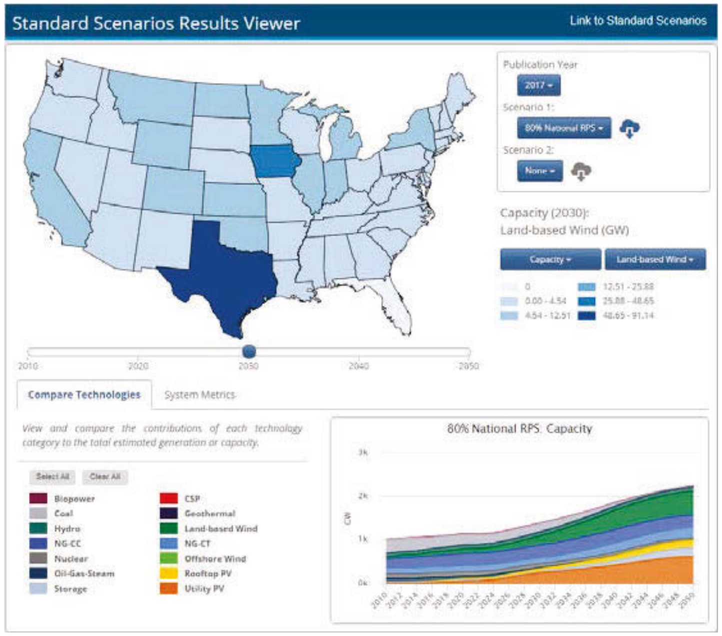
- Three-part study
  1. Characterize available resource capacity (reV)
  2. Explore buildout scenarios to meet policy objectives (ReEDS)
  3. Test operational performance of system buildouts (PLEXOS)
- Slides today will present results from the reV and ReEDS analysis
  - **The projected system buildouts from ReEDS are subject to change based on the findings in the production cost modeling**

Use of ReEDS for the Duke project

ReEDS is NREL's flagship capacity expansion tool. Details of the model were presented to Duke stakeholders on May 5

- **Main assumptions**
  - NREL ATB 2020 capital cost assumptions / 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 (top 20 hours)
  - 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



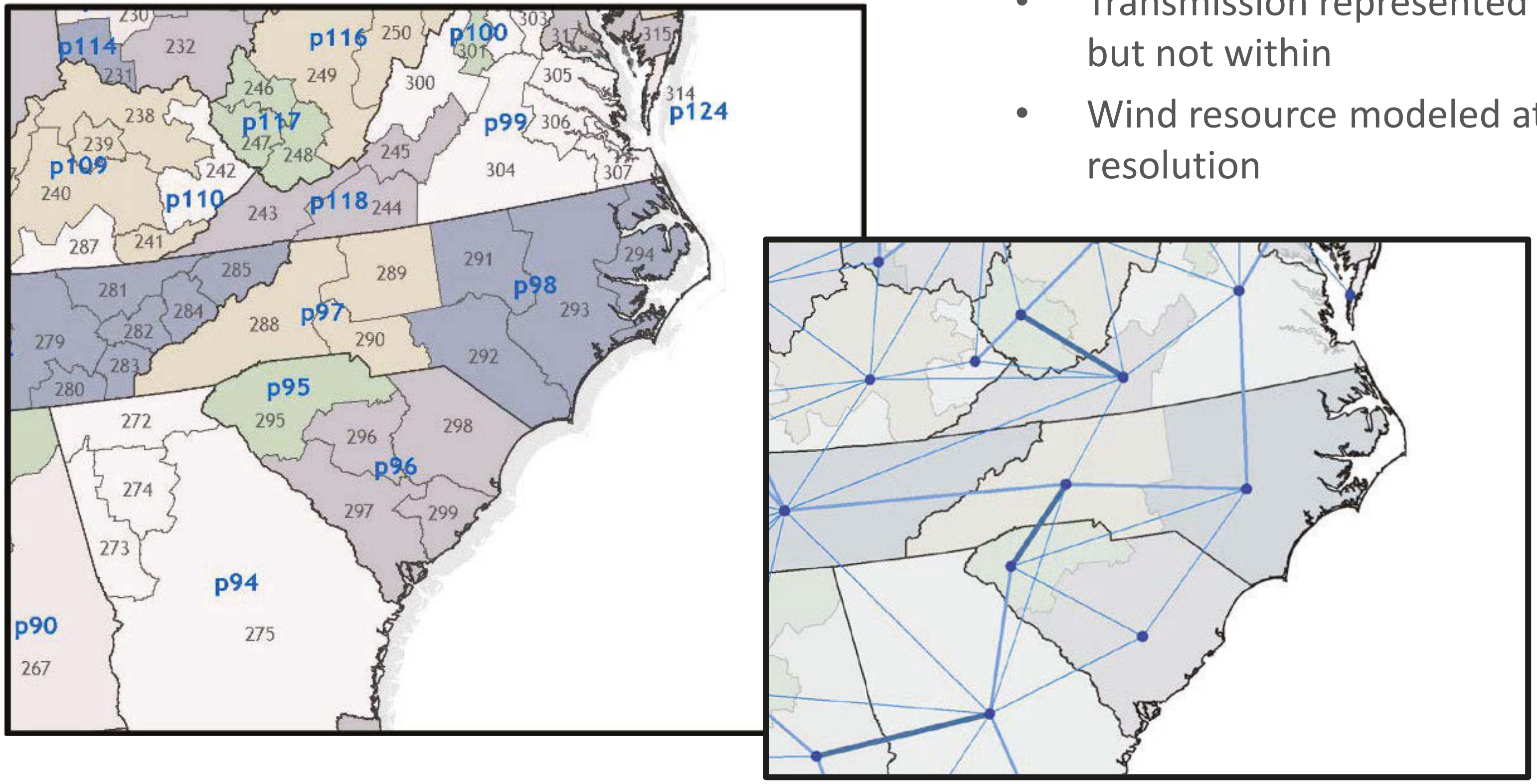
Publication Year: 2017

Scenario 1: 80% National RPS

Scenario 2: None

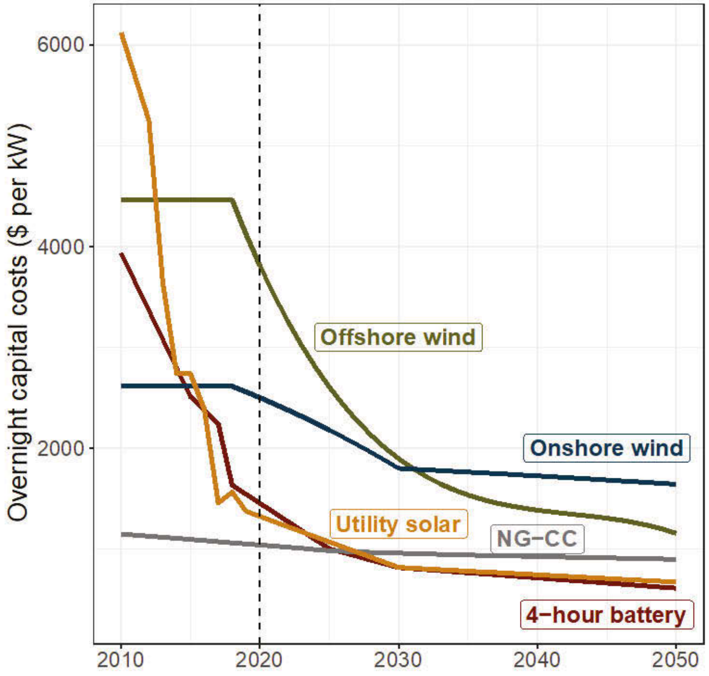
View and compare the contributions of each technology category to the total estimated generation or capacity.

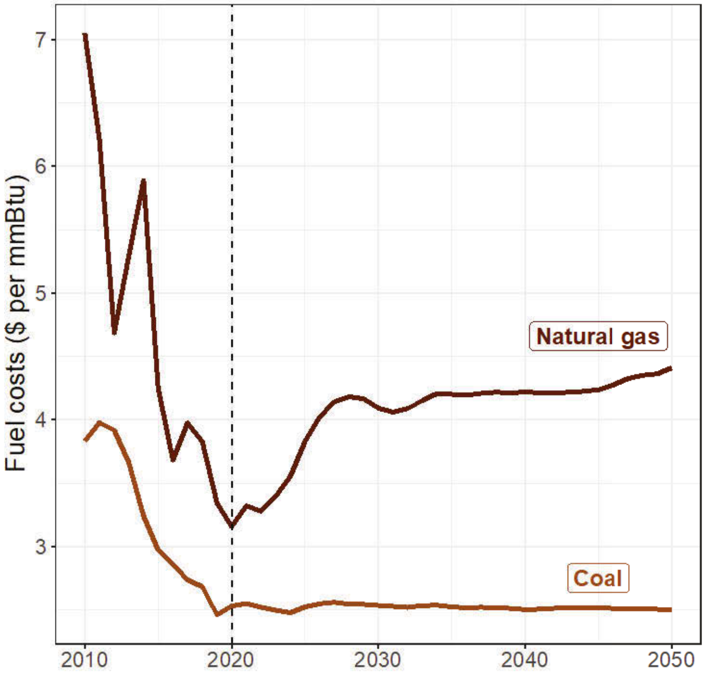
ReEDS approach to modeling the Carolinas



- 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

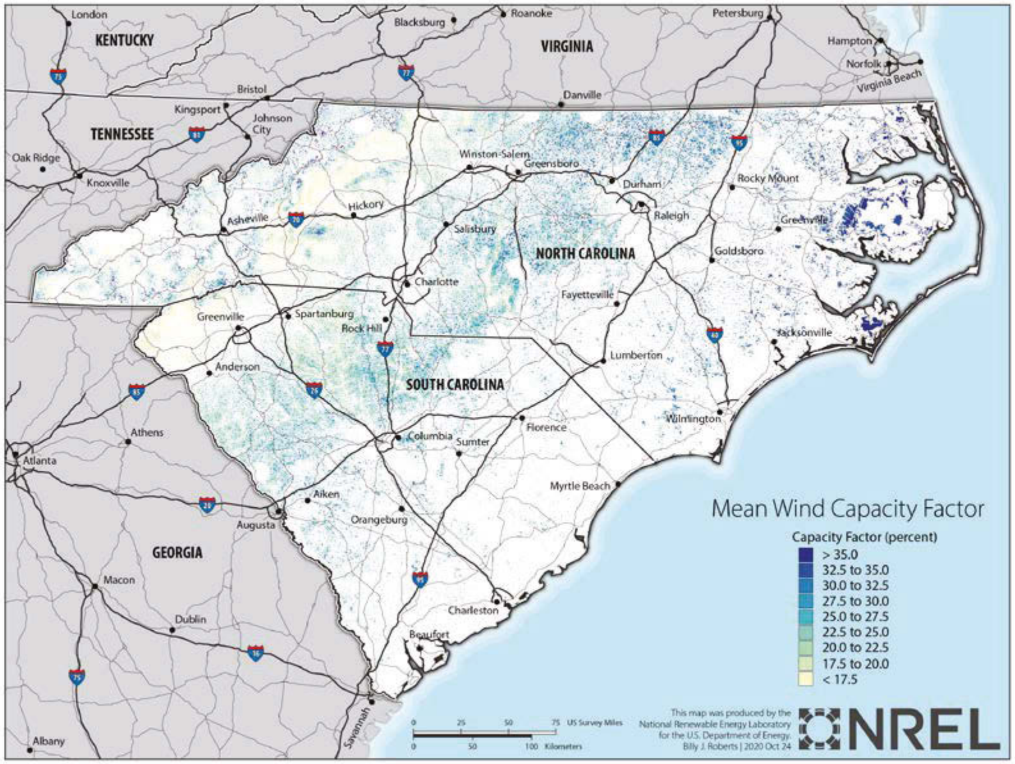
Technology cost assumptions





- Model assumes falling capital costs for solar, wind, and battery storage
- Coal prices stable, natural gas costs increase slightly over time
- Natural gas adder applied to any new NG-CC facilities built after 2020

Onshore wind exclusions



Basic exclusions include:

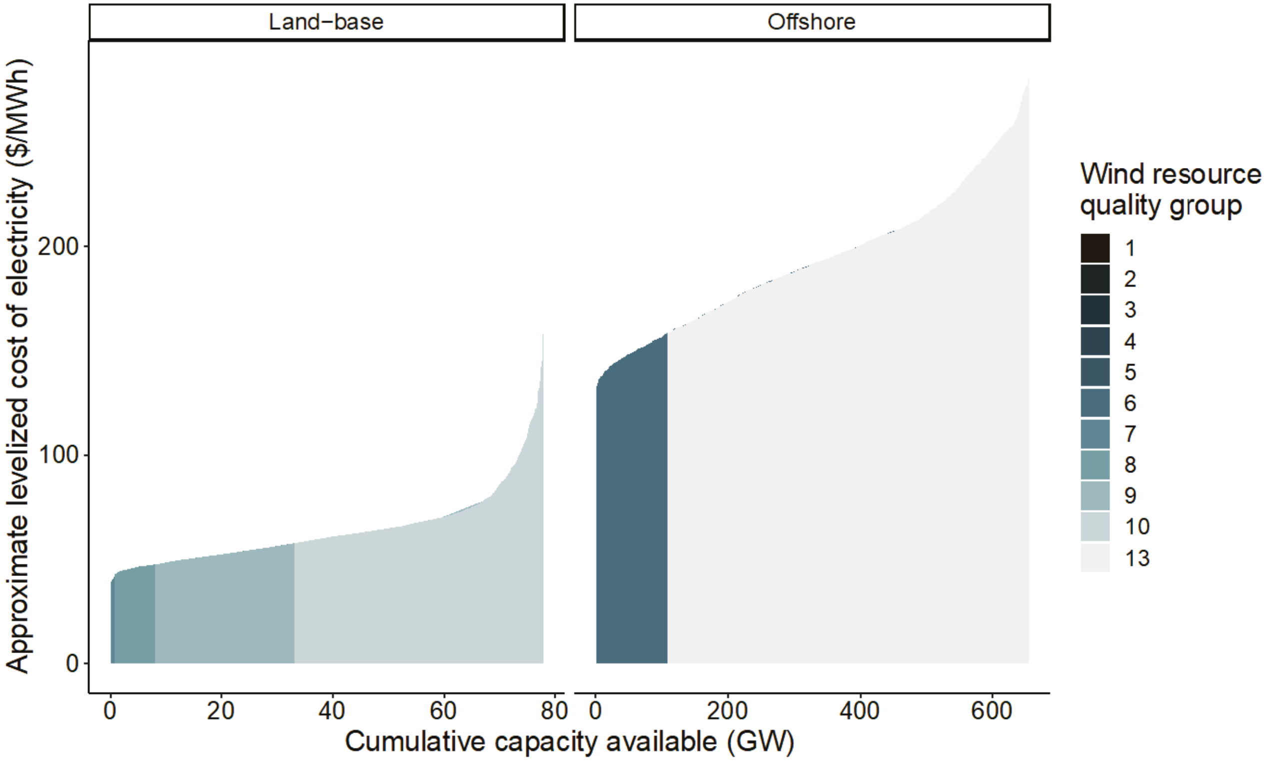
- Urban areas
- Bodies of water
- Protected lands
- Sloped lands
- Distance from structures

Exclusions added for this project:

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

Wind supply curves for the Carolinas

- Total available onshore capacity reduced from ~250 GW in previous estimates to ~80 GW

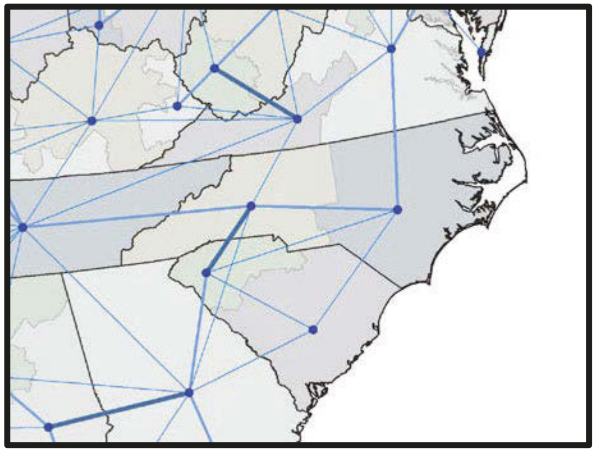


Scenario overview

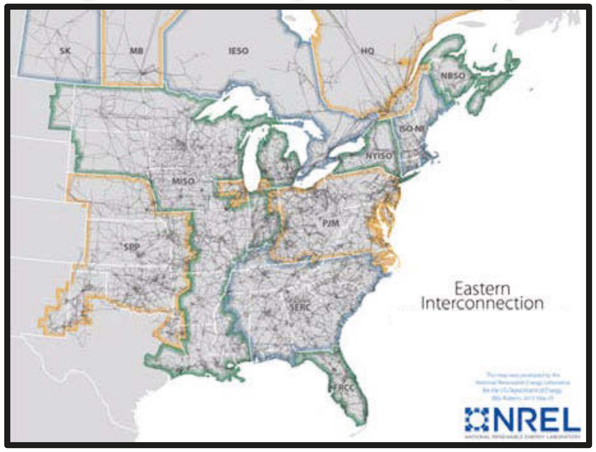
	Base (no emissions constraints)	**Policy** (70% CO_2 reduction in NC by 2030 + net-zero electricity in NC by 2050)
Main case	Standard modeling assumptions	
Cost sensitivities	Low cost wind	
	High cost solar/storage	
	High cost solar/storage + low cost natural gas	
Other sensitivities	Eastern Interconnect has similar CO_2 targets (70% in 2030, net-zero in 2050)	
	Duke able to secure firm capacity outside of the Carolinas	
	All fossil fuel must retire as part of net-zero 2050 target	

Putting the ReEDS results in context

- The portfolios built by ReEDS still need to be tested in PLEXOS for operational robustness
- Although we can gain insights from the ReEDS results, more work is needed to be done to ensure these system buildouts are feasible
- The production cost modeling may refine the conclusions from the ReEDS work
- Discussion on the plans for the production cost modeling phase later in the presentation



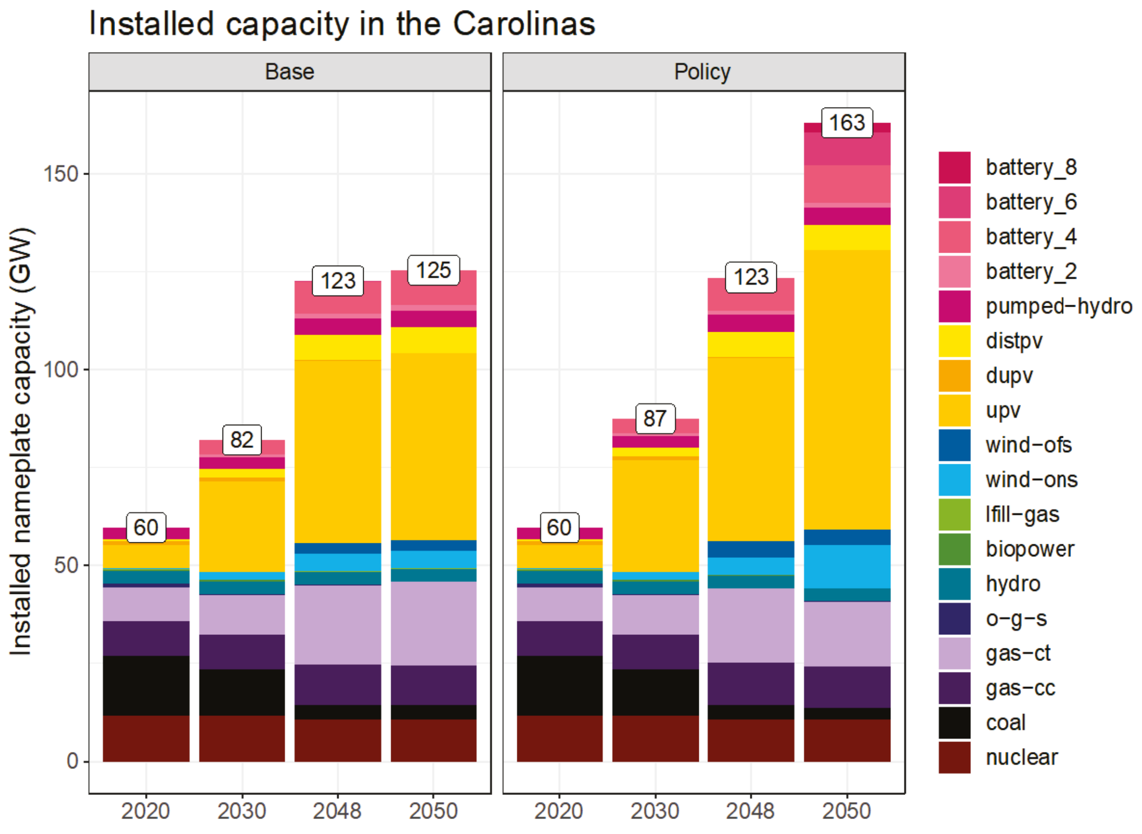
Capacity expansion in ReEDS



Production Cost Modeling in PLEXOS

Capacity and generation results

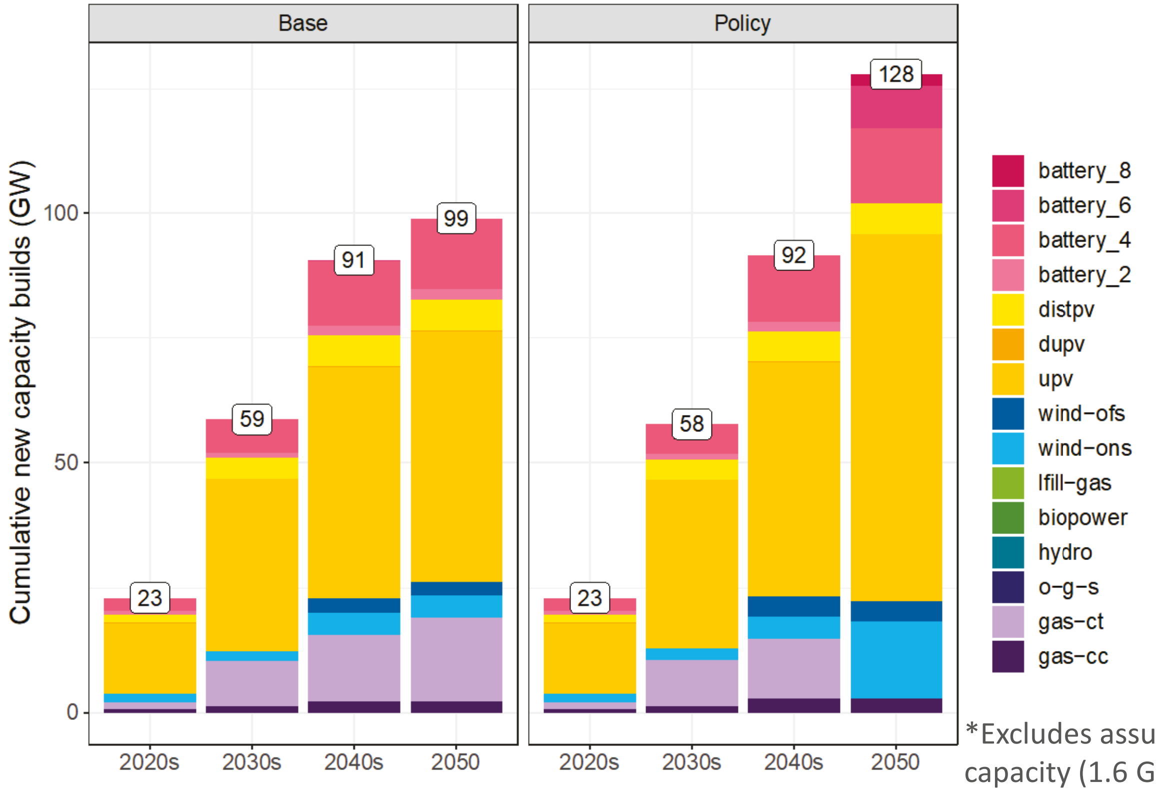
Installed capacity


Installed capacity in the Carolinas

	Base				Policy			
	2020	*2030*	*2048*	*2050*	*2020*	*2030*	*2048*	*2050*
Battery storage	0.03	4.5	9.5	10.3	0.03	4.5	9.5	21.5
Solar	7.6	26.5	53.1	54.3	7.6	31.9	53.5	77.8
Wind onshore)	0.2	1.9	4.4	4.4	0.2	1.9	4.5	11.0
Wind offshore)	-	-	2.8	2.8	-	-	4.0	4.0
atural gas	17.5	18.8	30.6	31.5	17.5	18.8	29.7	27.2

- Both scenarios rely on a mix of solar, gas, and nuclear through 2030
- Capacity mix in 2050 is similar across scenarios, with additional storage, solar, and wind in the net-zero 2050 case
- Note that the model allows fossil capacity to meet capacity planning requirements / reserves in the 2050 net-zero scenario
- First year of offshore wind build:
  - Base: 2042
  - Policy: 2040

New nameplate capacity builds*



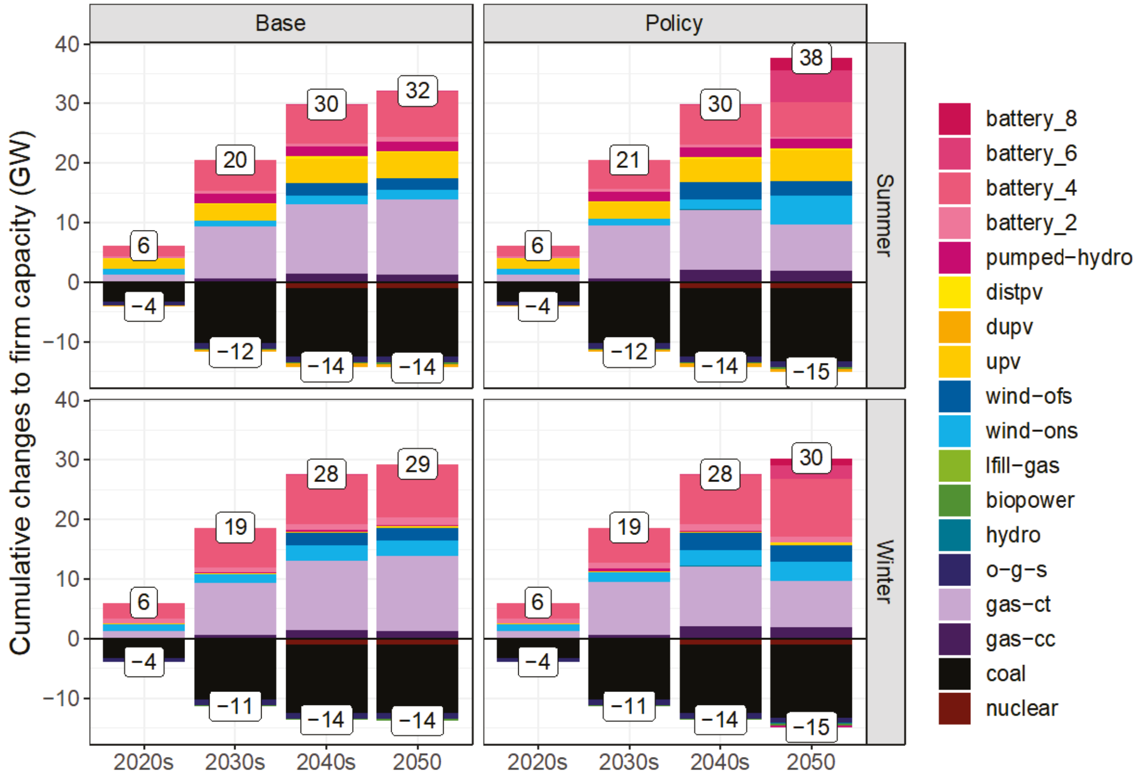
Cumulative new capacity in the Carolinas by decade

- Solar and storage are the primary builds through 2030 across both scenarios
  - 2030 target moves up some new capacity investments
- Achieving net-zero in 2050 acquires substantial additional capacity buildout
  - Model delays building this capacity to take advantage of declining costs
  - New gas capacity in the policy case reflects the model seeking dispatchable resources
    - Primarily used to meet reserve margins (Gas CTs have capacity factor < 1%)
    - Suggests the need for cheap, firm, zero-emissions technology
  - Reflects the operational challenge of getting to net-zero

*Excludes assumed expansion of pumped hydro storage capacity (1.6 GW in 2035) that occurs in both cases

Changes to firm capacity

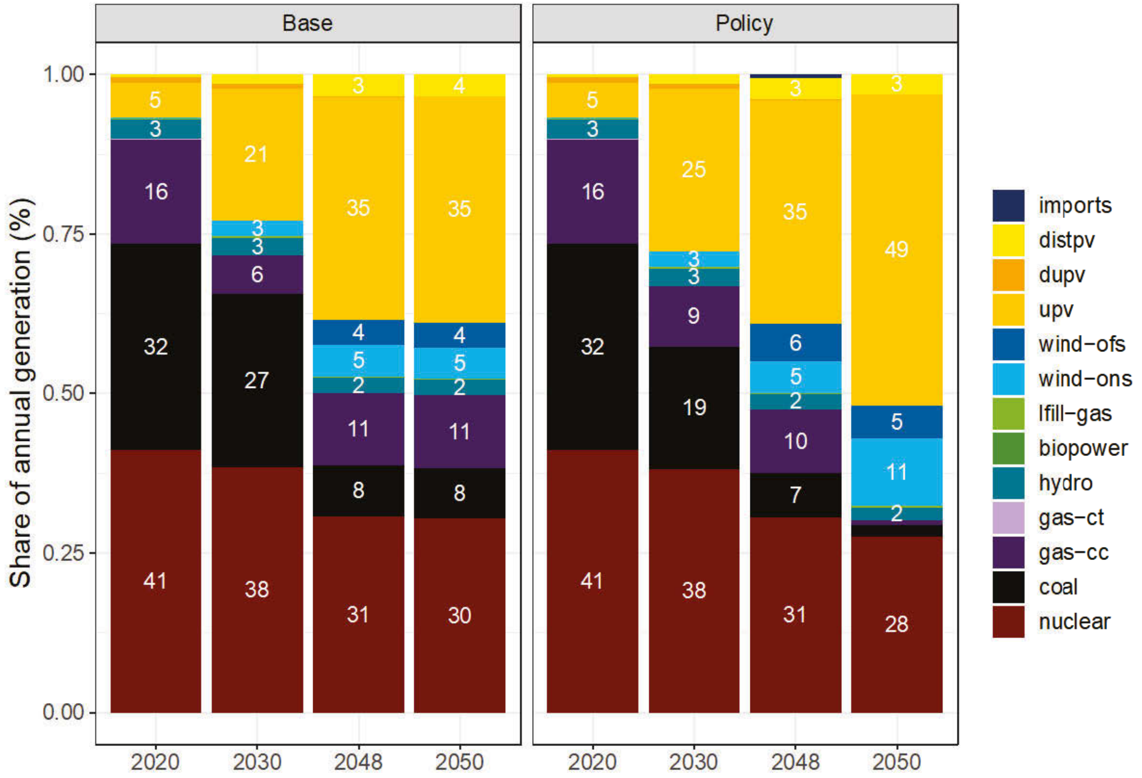
Cumulative firm capacity changes in the Carolinas



- Firm capacity credits determined by full 8760-hour analysis of net load
- Retiring firm capacity—primarily coal—is replaced by natural gas, solar, wind, and increasingly battery storage
  - Little solar available to meet winter peak; requires wind and battery storage
- As more firm capacity is retired, the amount of new capacity needed to replace it increases
  - Increasing need for the ability to shift energy across time using storage

Generation mix*

Generation mix in the Carolinas

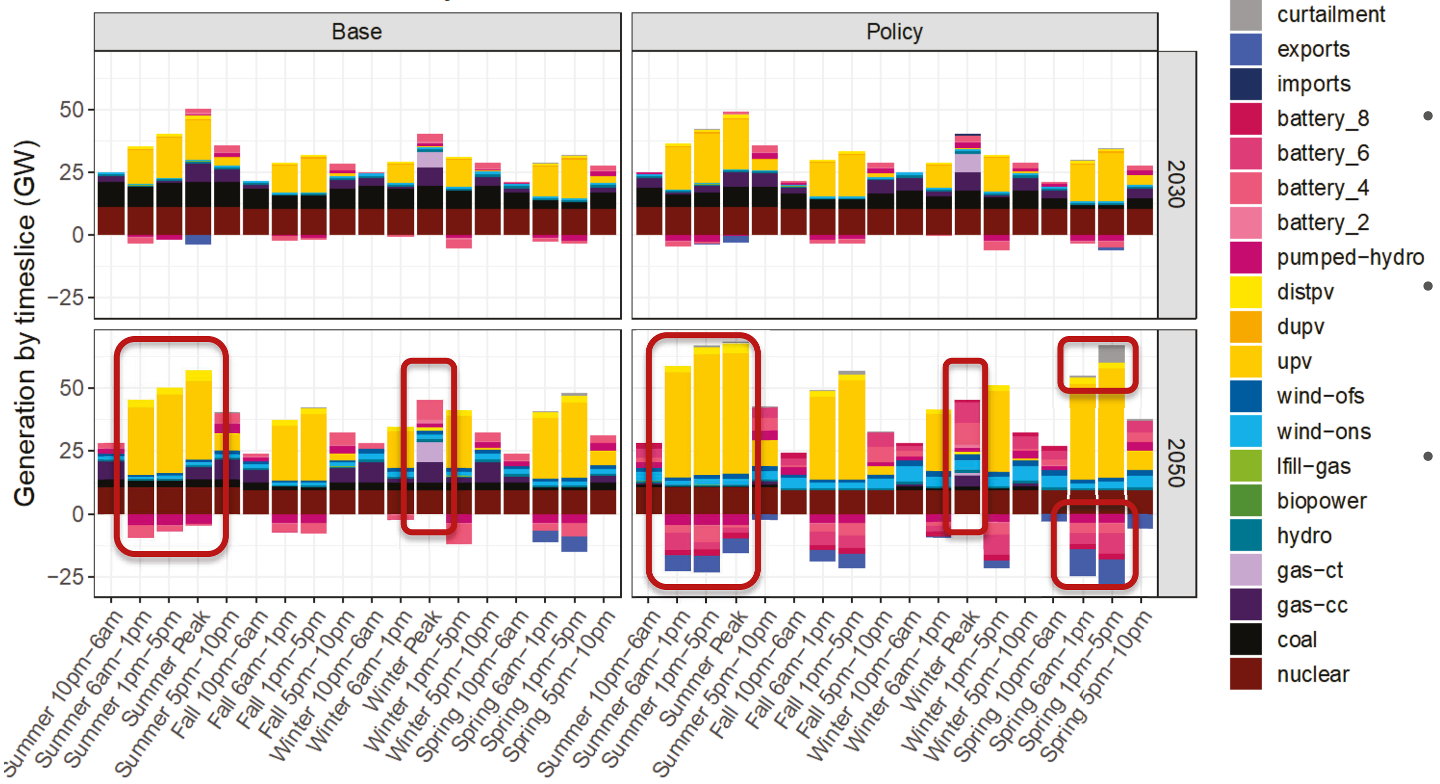


	Base 2020	Base 2030	Base 2048	Base 2050	Policy 2020	Policy 2030	Policy 2048	Policy 2050
distpv			3	4			3	3
upv	5	21	35	35	5	25	35	49
wind−ofs			4	4			6	5
wind−ons		3	5	5		3	5	11
hydro	3	3	2	2	3	3	2	2
gas−cc	16	6	11	11	16	9	10	
coal	32	27	8	8	32	19	7	
nuclear	41	38	31	30	41	38	31	28

- Existing nuclear supplies 28-30% of generation in 2050
  - assumed all licenses extended through 2050
- Very high penetrations of solar in the emissions constrained scenario
- Net-zero target relies on contributions from both onshore and offshore wind
- Note that remaining coal operates in SC outside of Duke's territory

Generation by ReEDS timeslice

Timeslices are representative dispatch periods used in ReEDS, representing each combination season and time of day (along with peaks)

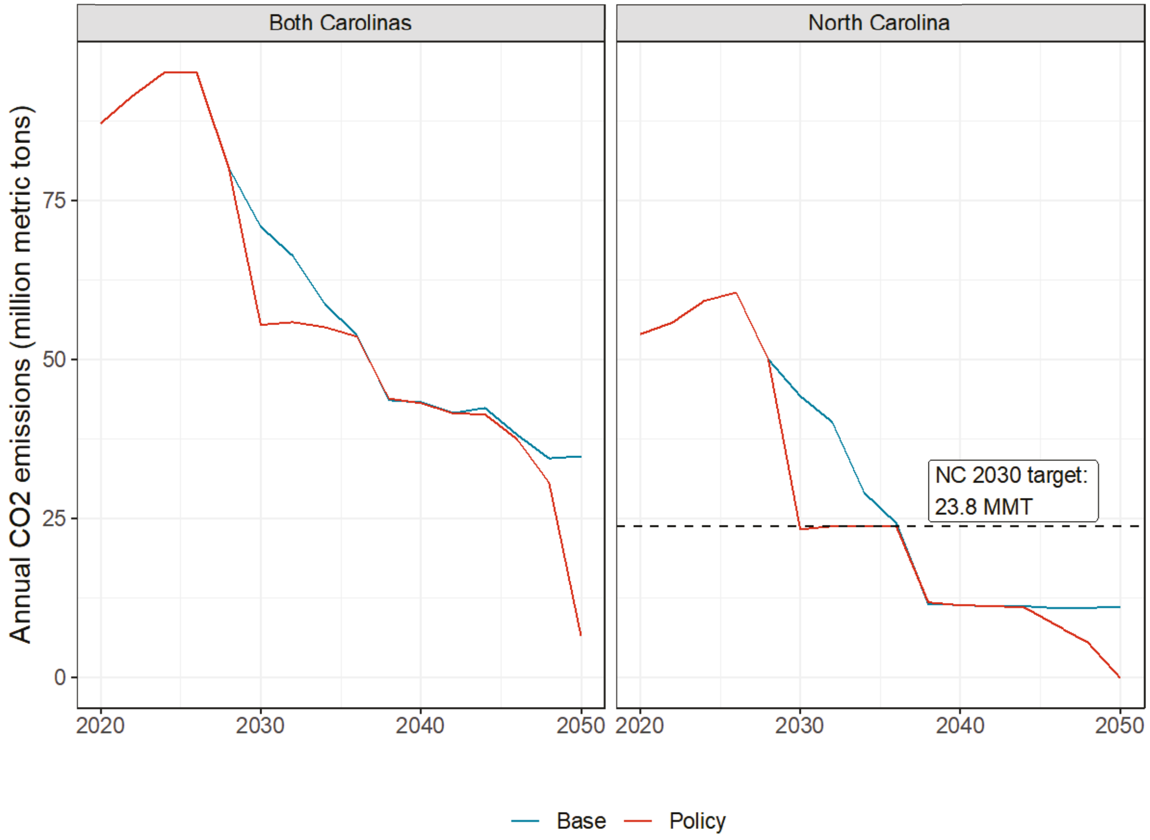


Carolinas Generation by ReEDS timeslice

- Nuclear generates consistently across timeslices in all cases
- Solar provides most of the mix in summer afternoon also fall and spring
- Large amount of storage dispatched to meet winter morning peak; wind also used
- Extensive storage charging and exports to handle solar overgeneration
  - Despite this, there is still solar curtailment

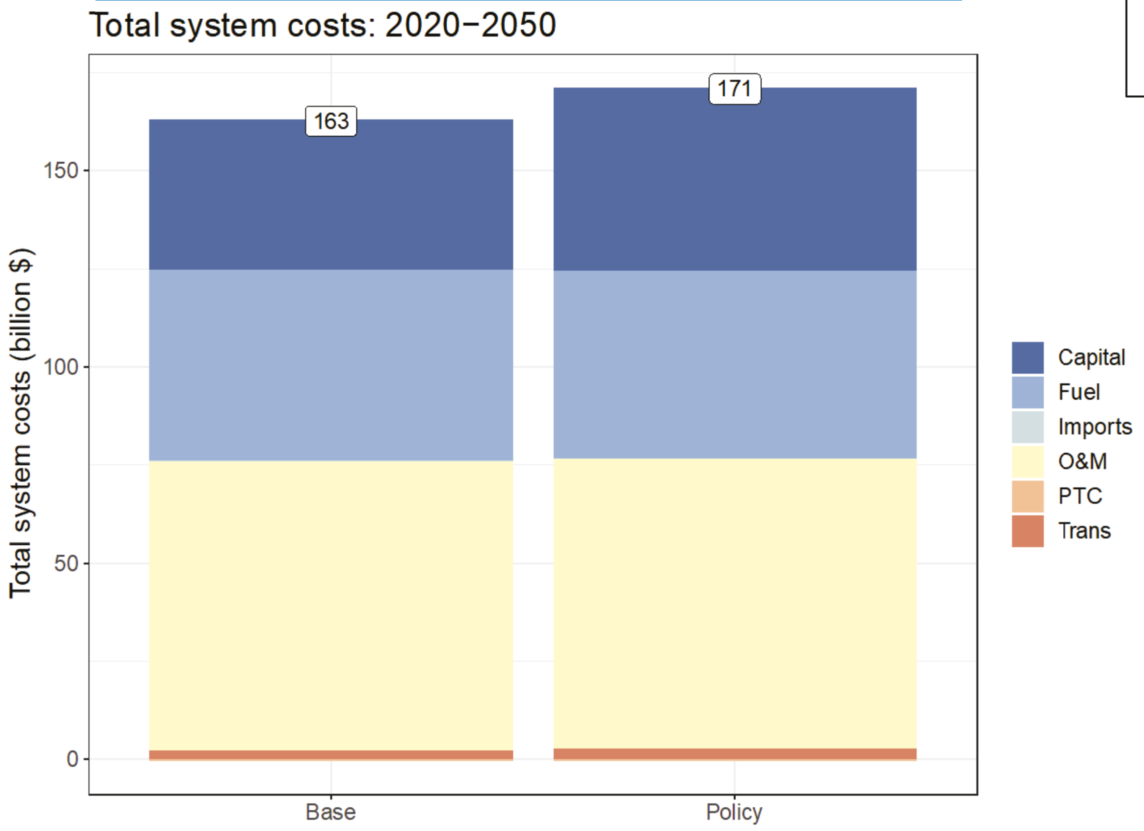
Emissions and system costs

CO_2 emissions



- Emissions decline without policy intervention, but 2030 NC target accelerates decline and reduces cumulative emissions
- Assuming base case emissions stabilize at 2050 levels, the policy yields **avoided annual emissions** 6.5 MMT in NC / 23 MMT in the Carolinas starting in 2050
- Some cumulative emissions reductions in NC from the 2030 target may be partially offset by dispatch changes in SC without any SC emissions policy

Total system costs



Cost assumptions

- Results in $2018
- Capital costs annualized over a 20-year period using a capital recovery factor that varies from 6.5-7%
  - Total costs includes full payments for any capital built through 2050
- Discounting using a 5% discount rate

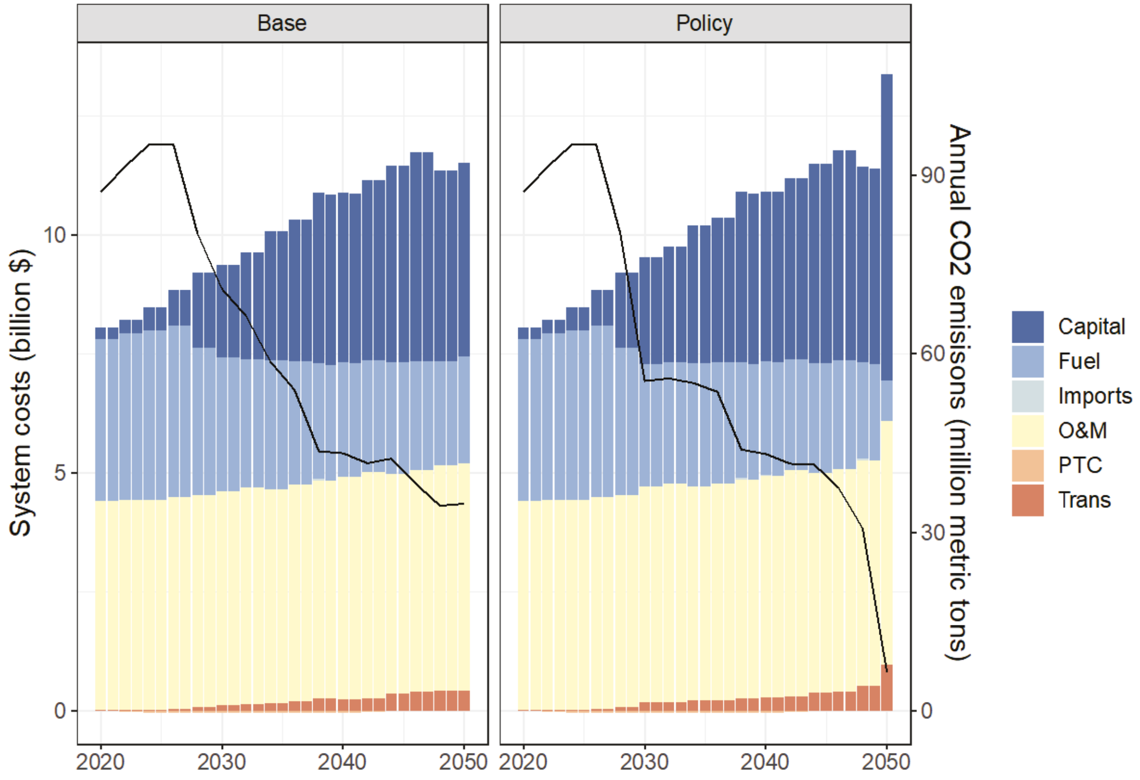
- Policy scenario associated with ~$8 billion above Base for the Carolinas
  - Without discounting, this difference is $52 billion
- Approximately 5% of total system costs over the time period
- Policy cost comes primarily from capital costs, along with increased transmission and O&M

Annualized system costs

Cost assumptions

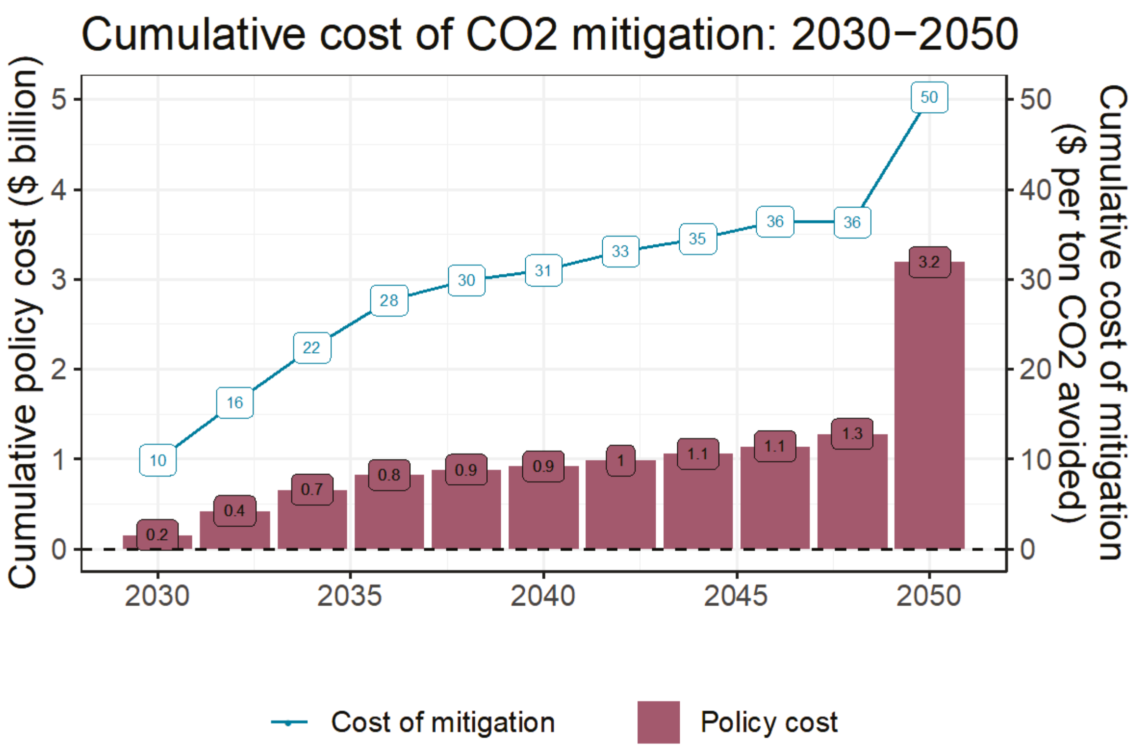
- Results in nominal dollars
- Capital costs annualized over a 20-year period using a capital recovery factor that varies from 6.5-7%

Undiscounted annualized system costs and emissions: 2020−2050



- Costs increasing over time for both scenarios
- Policy case incurs relatively large cost increases in 2050
  - Net-zero scenario requires more installed capacity and is harder than initial CO_2 reductions
  - Spike in costs reflects the increasing cost for eliminating the last bit of CO_2 in NC

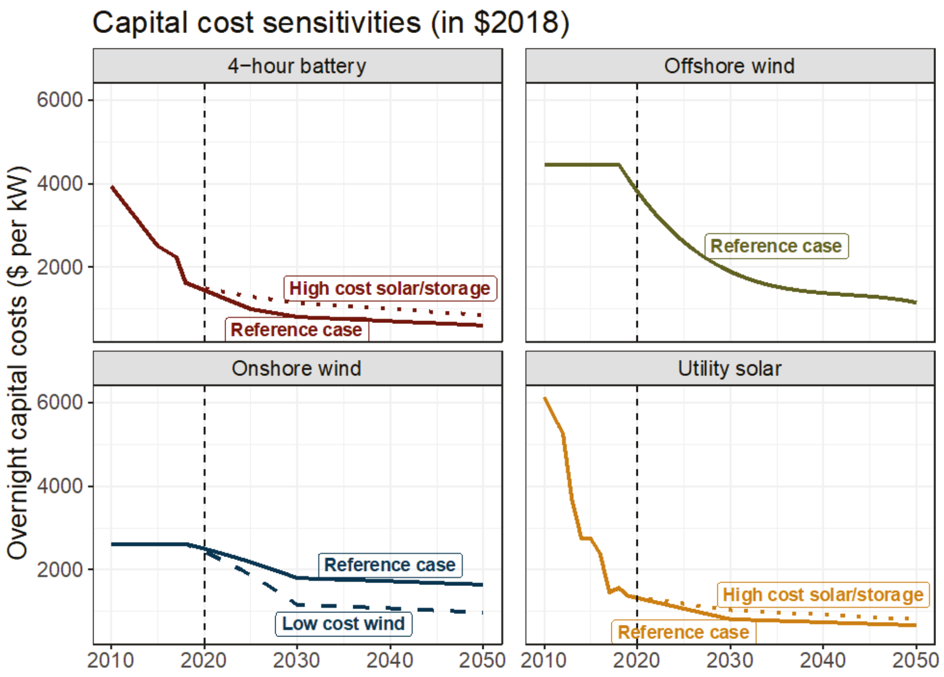
Cost of mitigation for both Carolinas

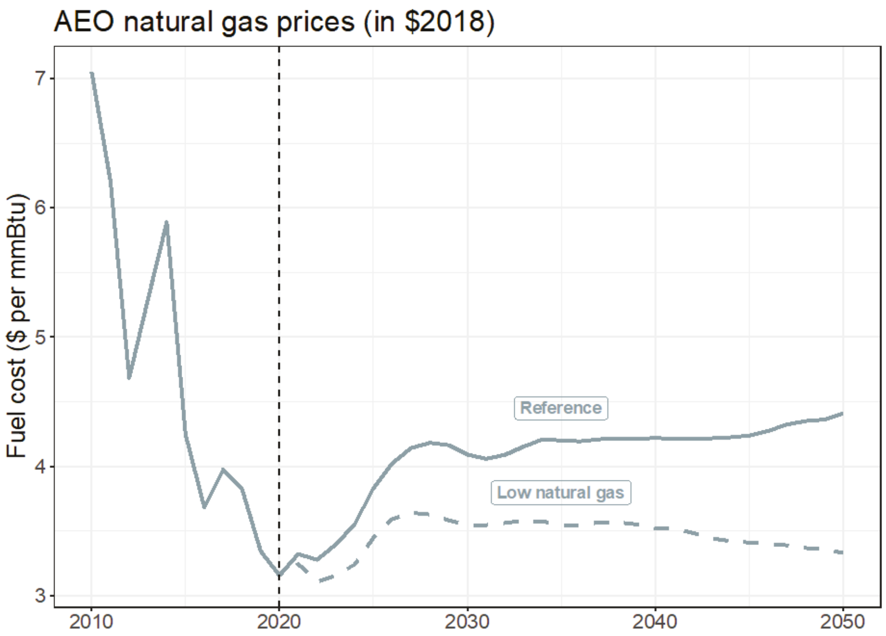


- Cost of mitigation calculation:
  - $COM^{T} = \frac{\sum_{t0}^{T}\left[Costs_{t}^{policy} - Costs_{t}^{base}\right]}{\sum_{t0}^{T}\left[Emit_{t}^{base} - Emit_{t}^{policy}\right]}$
  - Calculated using undiscounted annualized values
  - Starting year (t0) of 2030 (base and policy cases similar between 2020 and 2030)
- Cost of mitigation increases sharply as toward meeting 2050 net-zero target (increasing marginal cost of reductions)

Sensitivity analyses

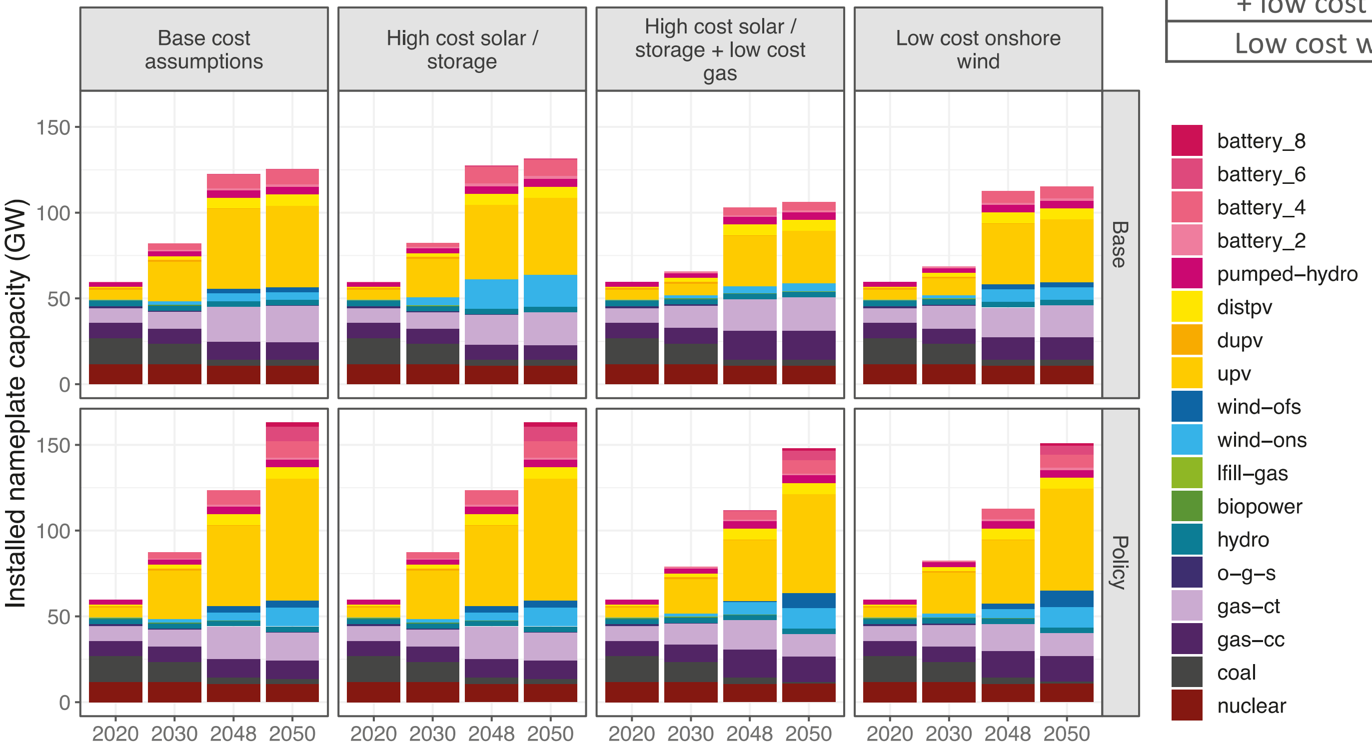
Cost sensitivities


Capital cost sensitivities (in $2018)


AEO natural gas prices (in $2018)

Cost sensitivities

Installed capacity in the Carolinas



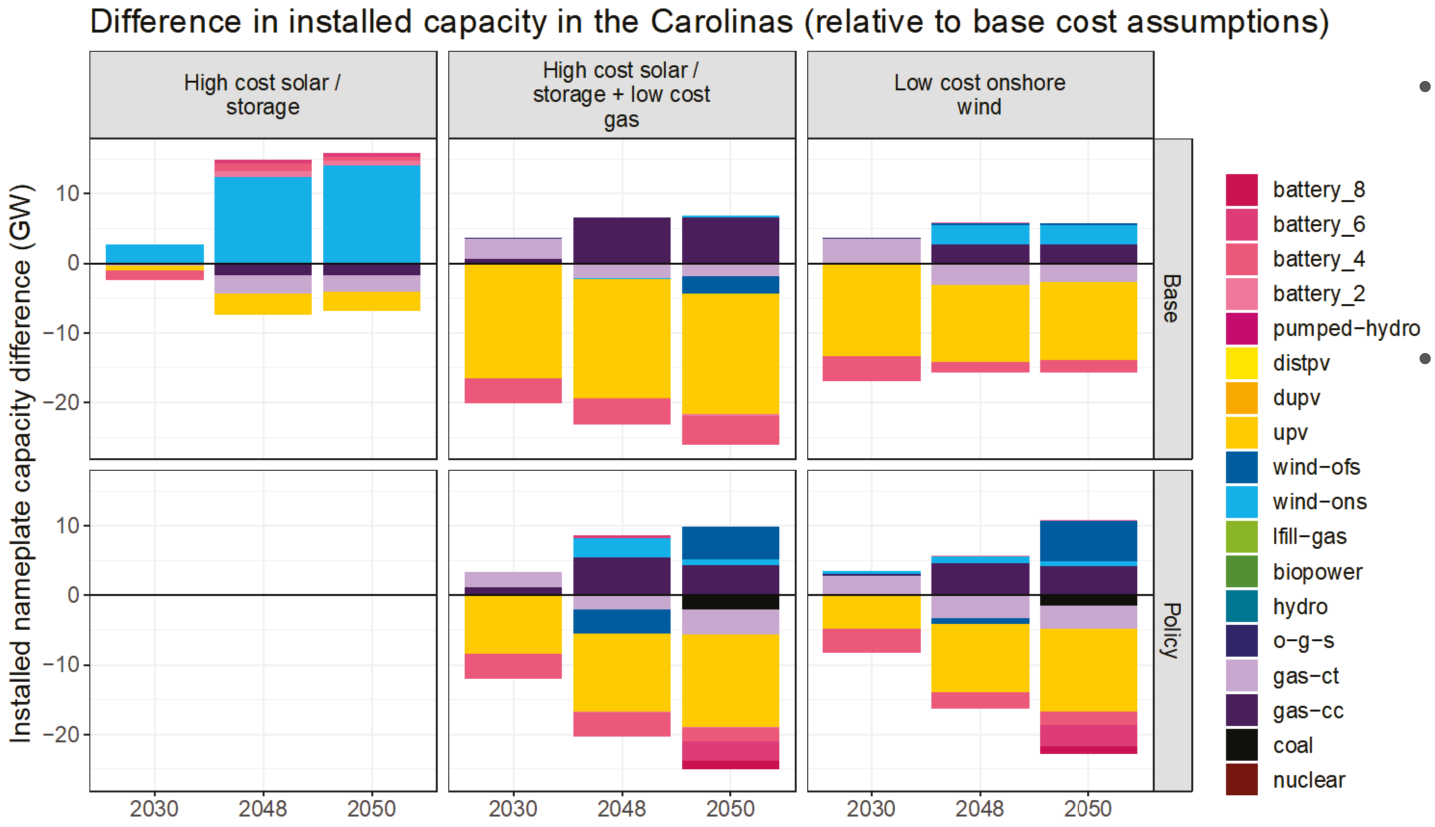
Cost difference relative to base cost assumptions ($ billion)

	Base	Policy
High cost solar/storage	$ 2.11	$ 4.05
High cost solar/storage + low cost gas	$ (2.60)	$ 1.35
Low cost wind	$ (1.76)	$

-

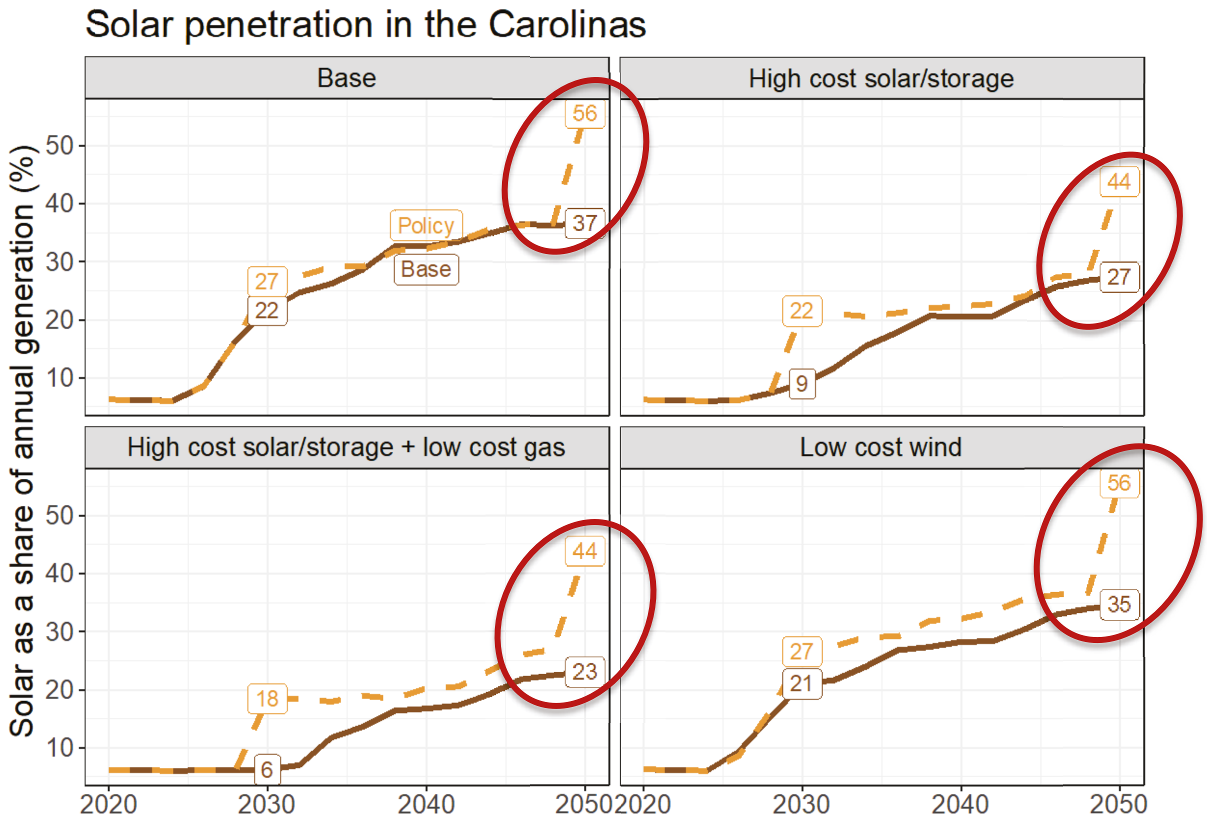
- Sensitivities to cost of onshore **shift investments slightly, but do not radically change** the technology mix
- First offshore wind builds:
  - Base cost assumptions, Base: 2042
  - Base cost assumptions, Policy: 2040
  - High cost solar / storage, Base: 2038
  - High cost solar / storage, Policy: 2034

Capacity differences



- **High solar/storage**: more wind in the base, no difference in the policy case
- **High solar/storage with low gas prices**: less solar/storage, more gas, later offshore wind builds in the policy case
- **Low onshore wind:** less solar/storage, more onshore wind in the base, more onshore/offshore wind in the policy case

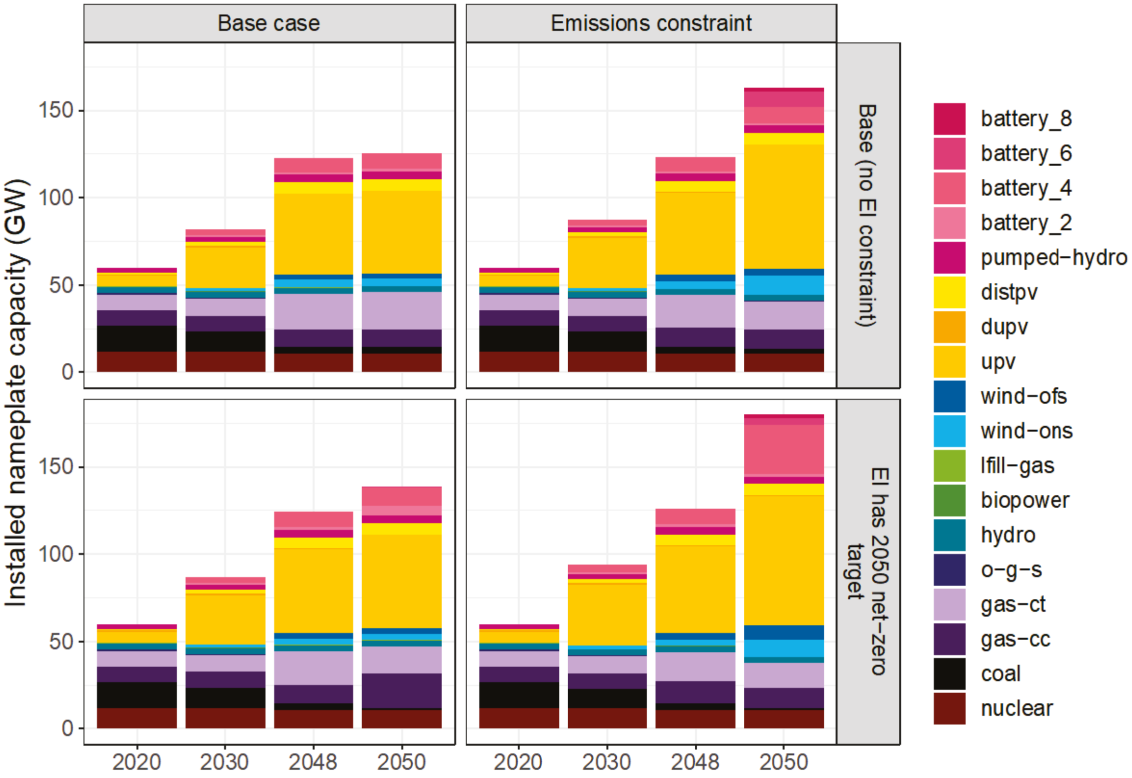
Solar penetration



- Under baseline cost assumption, policy accelerates solar adoption but base case “catches up” quickly
- Other cost assumptions yield lower solar adoption and more divergence between base and policy
- Large increase to meet 2050 net-zero target under all cost assumptions

What happens to the rest of the Eastern Interconnect?

Installed capacity in the Carolinas

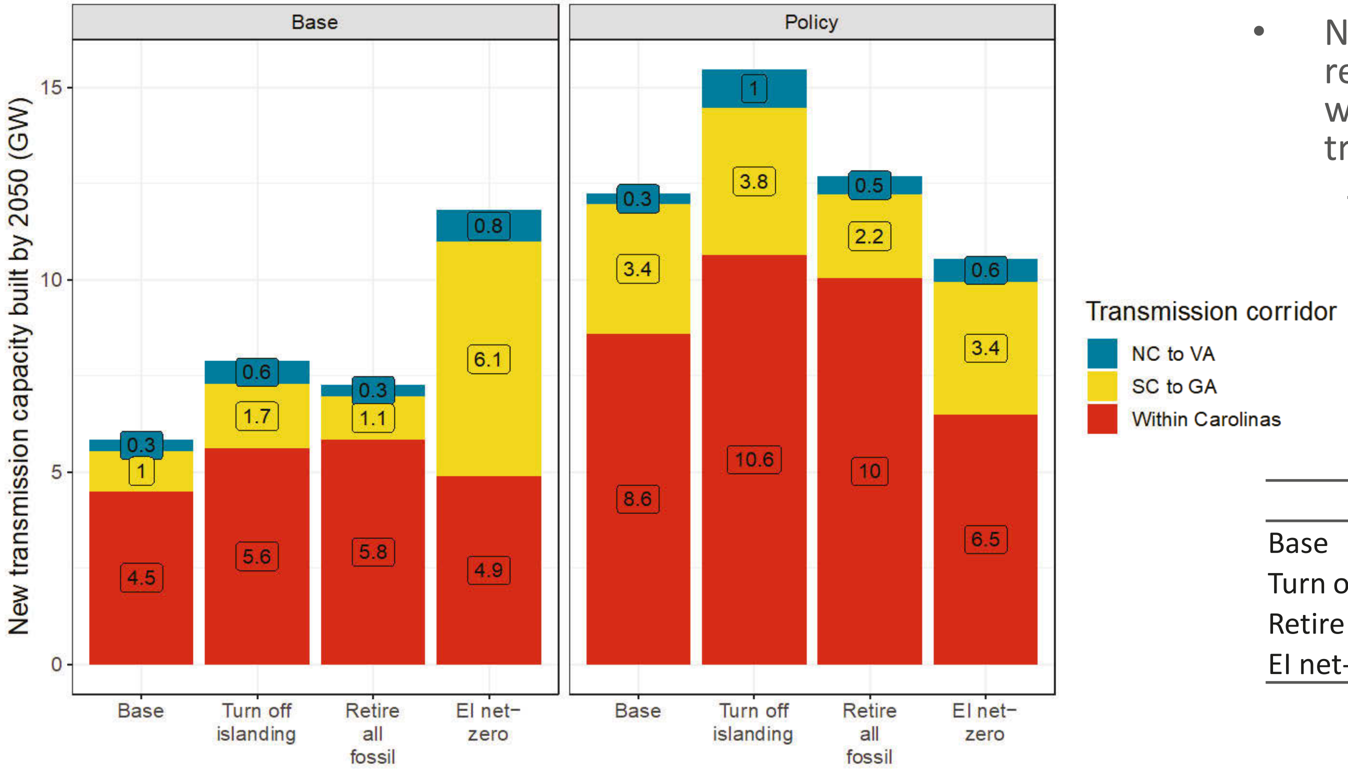


Cost difference relative to base cost assumptions ($ billion)

	Base	Policy
Constrained Eastern Interconnect	$ 4.94	$ 4.45

- An Eastern Interconnect (EI) wide net-zero target leads to more installed capacity in the Carolinas
  - Approximately 17 more GW capacity (10% increase)
  - Increase primarily in battery capacity
- EI constraint reduces the ability of the system to export excess solar generation when needed
  - Addressed with more storage, shift to more offshore wind

Interface transmission expansion



- Additional inter-BA transmission investments in all scenarios
- Policy cases rely on more transmission assets, both within Carolina balancing areas and with neighbors
- Note that these results do not reflect all the friction associating with building or using transmission
  - Production Cost Modeling will better simulate transmission system operations

Total capital expenditures on new transmission through 2050 ($ billion)

	Base	Policy
Base	2.27	2.71
Turn off islanding	2.70	3.15
Retire all fossil	2.34	2.82
EI net-zero	3.01	3.37

Summary of insights from the ReEDS modeling

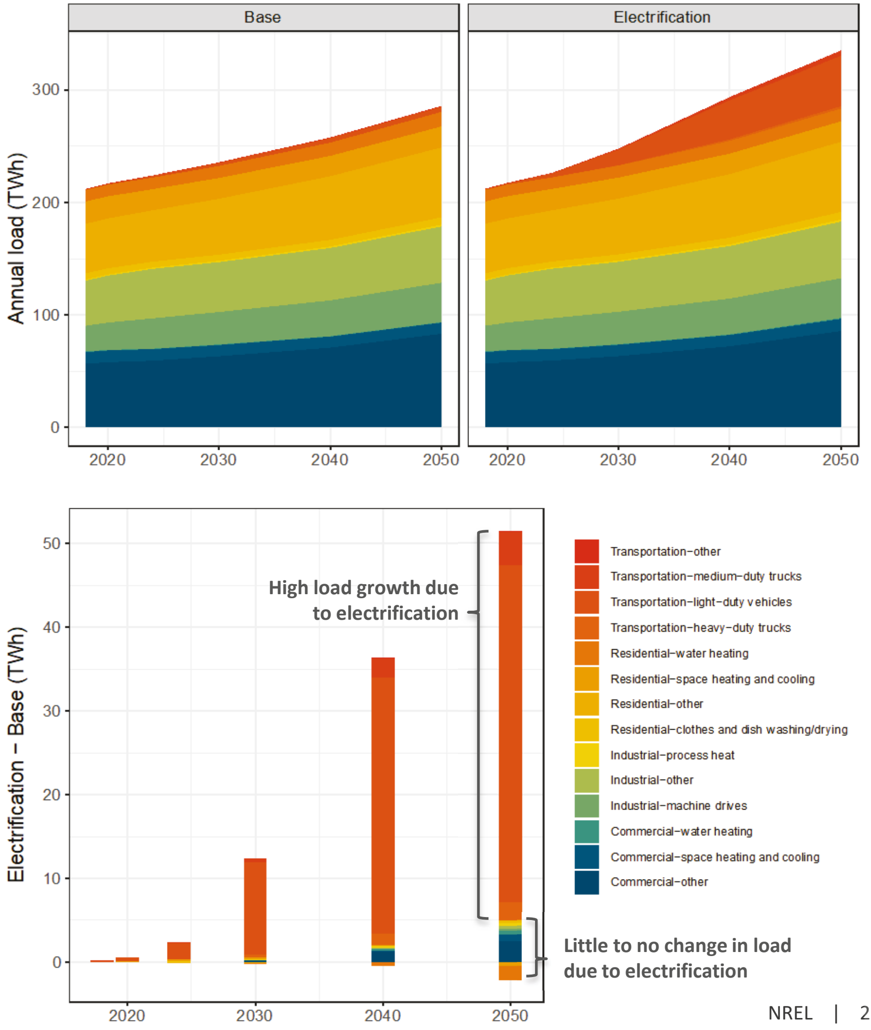
- 2030 targets can be achieved primarily with a buildout of solar and storage
  - Wind can also provide a valuable contribution, particularly if there are constraints on the ability to deploy new solar and storage
  - Resource mix is robust across sensitivities to costs of wind, solar, storage
  - Baseline also reduces emissions relative to 2020, but 2030 target results in faster decrease and more cumulative emissions avoided

- 2050 net-zero target more challenging to meet with existing technologies
  - Decreasing value of solar at high penetrations, increasing value of diversity (wind, additional storage) to achieve net-zero
  - Large capacity buildout required to eliminate last 5 million tons of CO2 in NC
  - Different resources needed to meet summer and winter peaks

- Sensitivities
  - Cost sensitivities tend shift from solar to other technologies, but generally the technology buildouts are similar, and none of the sensitivities impede getting to net-zero in 2050.
  - Increased value of storage, wind, and transmission if the entire Eastern Interconnect pursues a 2050 net-zero target

Additional analysis in ReEDS

- Will test sensitivity of ReEDS buildout to scenario with higher electrification
  - 1.5% annual load growth
  - 12.5% EV growth
  - Additional load flexibility, some efficiency gains from electrification
- Electrification scenario based on data from NREL's Electrification Futures Study and corroborated by Duke



High load growth due to electrification

Little to no change in load due to electrification

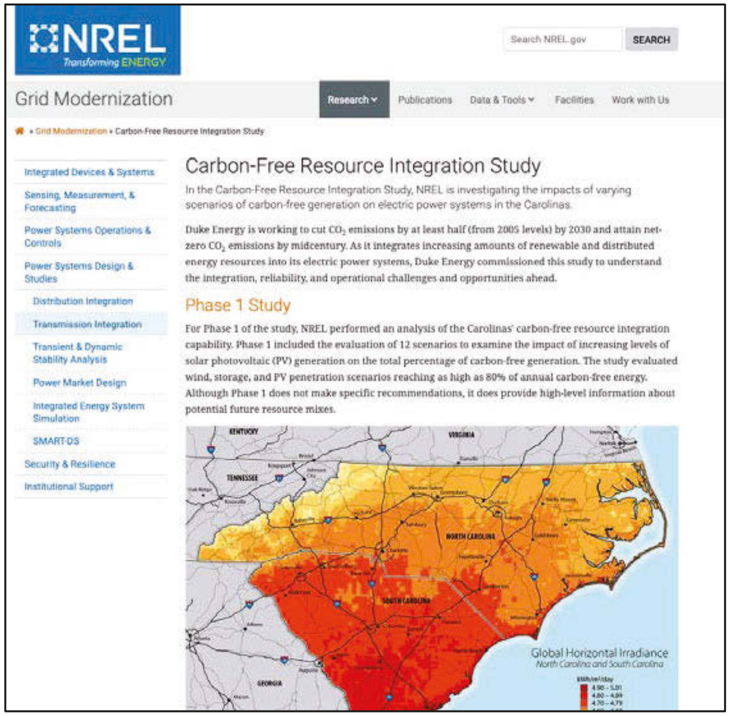
Caveats and challenges to consider

- ReEDS is not a full planning study – does not represent all the costs and challenges associated with siting new generation and transmission capacity
- Large amounts of new capacity required to achieve policy targets, particularly of solar and storage
  - Further work should investigate potential constraints on the ability to connect large amounts of new capacity
  - Larger and earlier investments in wind (on land or offshore) can provide additional benefits in terms of buildout diversification
- The capacity buildouts presented have not yet been tested for reliability in an operational model
  - **Production cost modeling in the next step will help determine the robustness of the portfolios built by ReEDS**
  - High-level findings presented here may change based on that analysis

Questions about the capacity expansion results?

For more information, see the NREL Carbon-Free Resource Integration Study website: https://www.nrel.gov/grid/carbon-free-integration-study.html

In the coming weeks, NREL will be posting details related to the capacity expansion results, including a "Frequently Asked Questions" document



Carbon-Free Resource Integration Study

In the Carbon-Free Resource Integration Study, NREL is investigating the impacts of varying scenarios of carbon-free generation on electric power systems in the Carolinas.

Duke Energy is working to cut CO_2 emissions by at least half (from 2005 levels) by 2030 and attain net-zero CO_2 emissions by midcentury. As it integrates increasing amounts of renewable and distributed energy resources into its electric power systems, Duke Energy commissioned this study to understand the integration, reliability, and operational challenges and opportunities ahead.

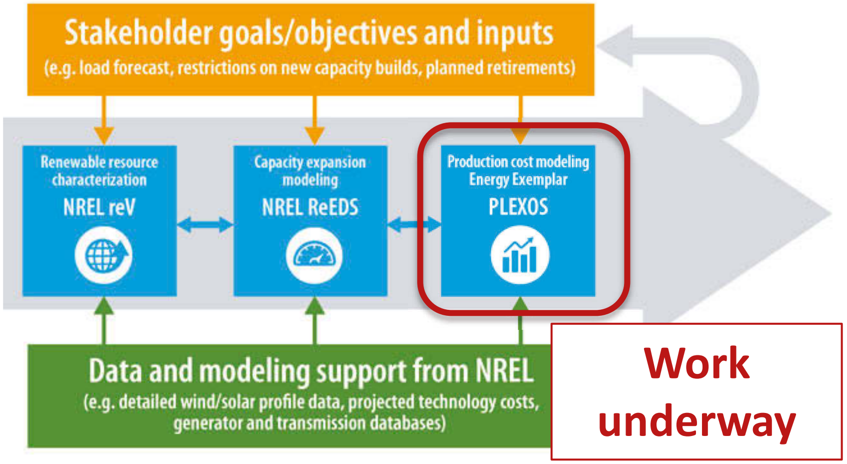
Phase 1 Study

For Phase 1 of the study, NREL performed an analysis of the Carolinas' carbon-free resource integration capability. Phase 1 included the evaluation of 12 scenarios to examine the impact of increasing levels of solar photovoltaic (PV) generation on the total percentage of carbon-free generation. The study evaluated wind, storage, and PV penetration scenarios reaching as high as 80% of annual carbon-free energy. Although Phase 1 does not make specific recommendations, it does provide high-level information about potential future resource mixes.

Plans for production cost modeling

Goals of the production cost modeling

- Test system built by ReEDS with production cost modeling using PLEXOS
  - Is the system able to serve load in all hours of the year?
  - Production cost model includes more detailed representation of key parameters (e.g. transmission network topology, generator characteristics, wind/solar availability)
- Evaluate system with more detailed representation of the Eastern Interconnection
- Production cost modeling may inform additional ReEDS modeling



Stakeholder goals/objectives and inputs

(e.g. load forecast, restrictions on new capacity builds, planned retirements)

Renewable resource characterization

NREL reV

Capacity expansion modeling

NREL ReEDS

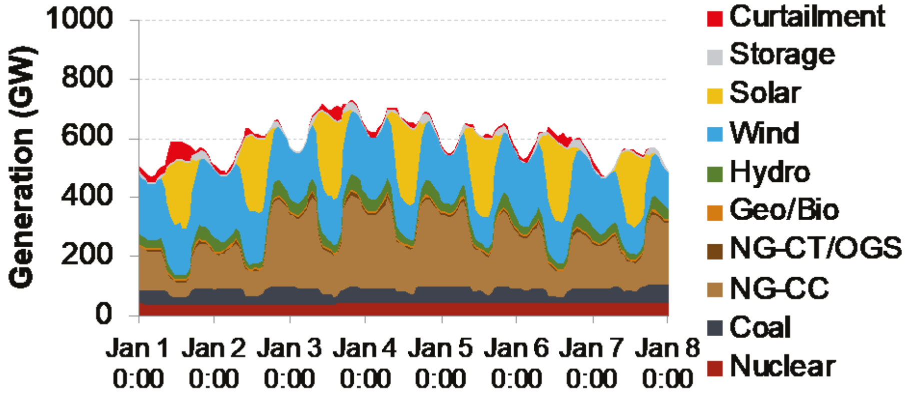
Production cost modeling Energy Exemplar

PLEXOS

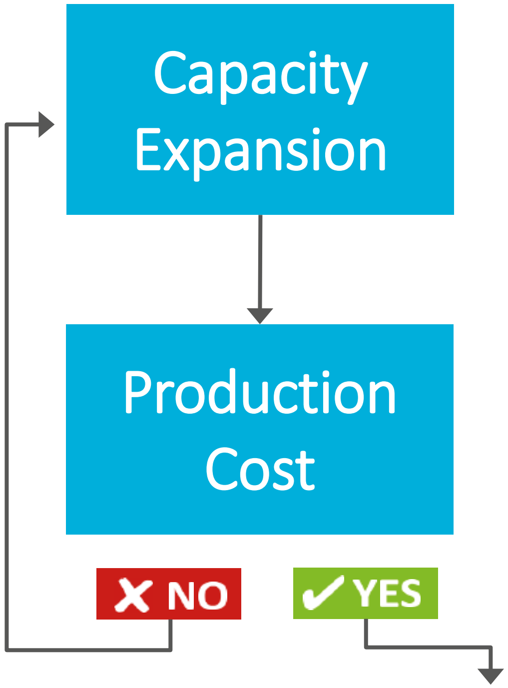
Data and modeling support from NREL

(e.g. detailed wind/solar profile data, projected technology costs, generator and transmission databases)

Work underway



From capacity expansion to production cost modeling



Capacity Expansion

Production Cost

❌ NO

✔ YES

BUILD

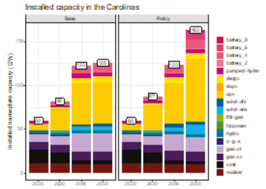
What do we build?
Where and when?

WORK?

Does it work?
(hourly operation)

ReEDS

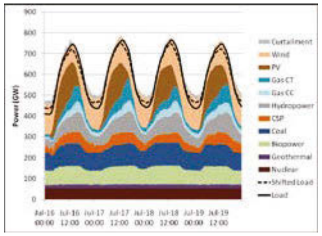
National policy, market technology analysis



Installed capacity in the Carolinas

PLEXOS ENERGY Exemplar

Security-constrained unit commitment & economic dispatch



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	Chronological hourly dispatch
Transmission	Between balancing areas	Full transmission system
Generator parameters	Average parameters assumed by generator type and vintage	Full heat rates, operational constraints (e.g. min gen levels, ramp rates) by plant
Dispatch	Dispatch according to time slices	Hourly unit commitment + economic dispatch

Capacity Model Scenario Zonal Translation

- Scenario translation (ReEDS to PLEXOS)
  - Planning to translate three cases:
    - *2024 Business-as-Usual case (nodal benchmark)*
    - *2030 70% emissions reduction*
    - *2050 Zero emissions target*
- PLEXOS will be used to validate hourly operational feasibility of buildouts from ReEDS for the three translated scenarios

Zonal Runs for Translated Cases

- **Objectives of zonal modeling**
  - Test translation workflow and used to understand how ReEDS intends power to flow across regions
  - Allows iteration with ReEDS as PCM encounters issues in results
- **PLEXOS zonal representation**: The transmission network is modeled to the zonal level with all resources within a zone connected to a single notional node
  - Only links between zones are modeled
  - Inter-zonal constraints are enforced
  - Zones are generally connected with adjacent zones for transferring electric energy

Eastern Interconnection (EI) 2024 Nodal Model

*Note: the following slides show a **preliminary characterization** of the EI model and do not represent final PLEXOS findings

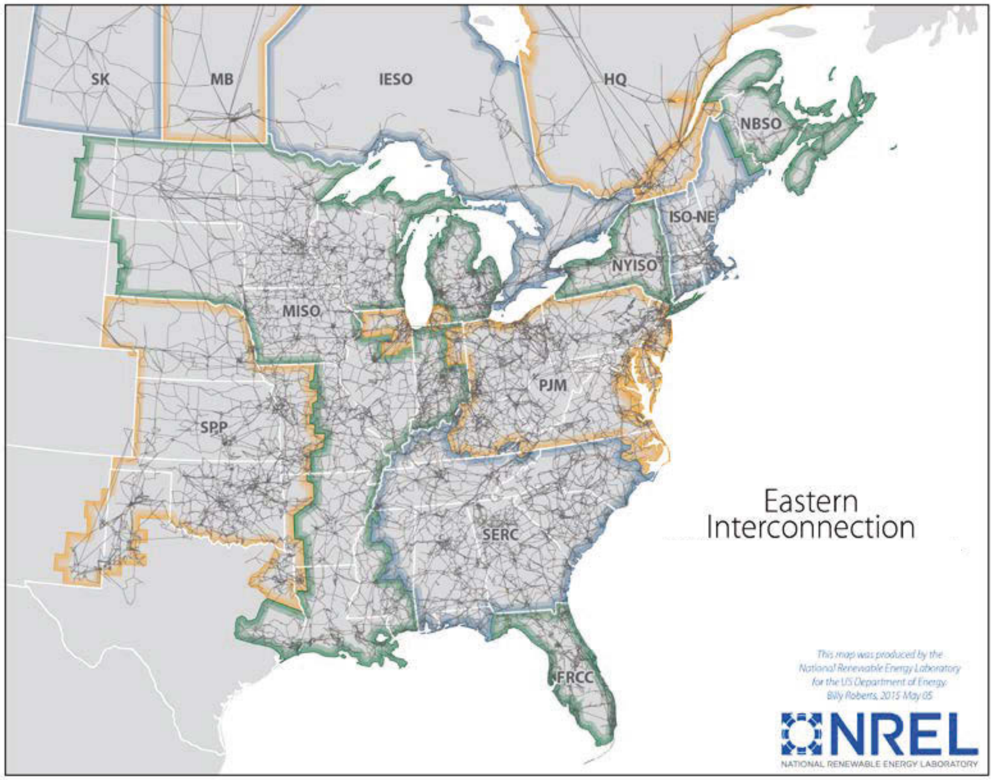
Eastern Interconnection Model Runs with PLEXOS

- **Eastern Interconnection (EI) 2024 Model**
  - 2024 nodal model with high resolution of the transmission network
    - Considers all transmission constraints such as thermal and interface limits
  - Computes optimal power flow – ensures generation dispatch and resulting DC power flow are at minimum cost and feasible with respect to transmission constraints
  - Model updated with current Duke's winter and summer capacities
    - Additional input planned from Duke on key parameters and constraints
  - For benchmarking and to represent Duke's existing power system

EI 2024 Base Transmission

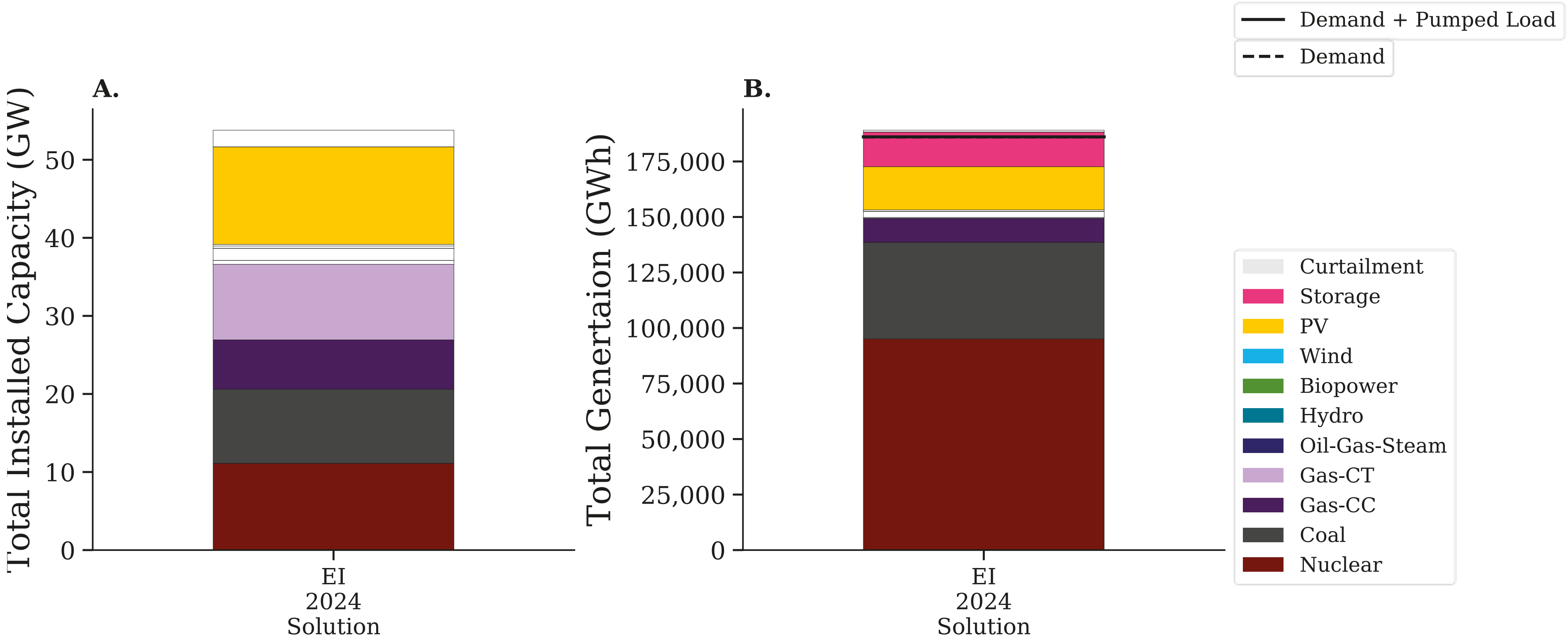
Base system data

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



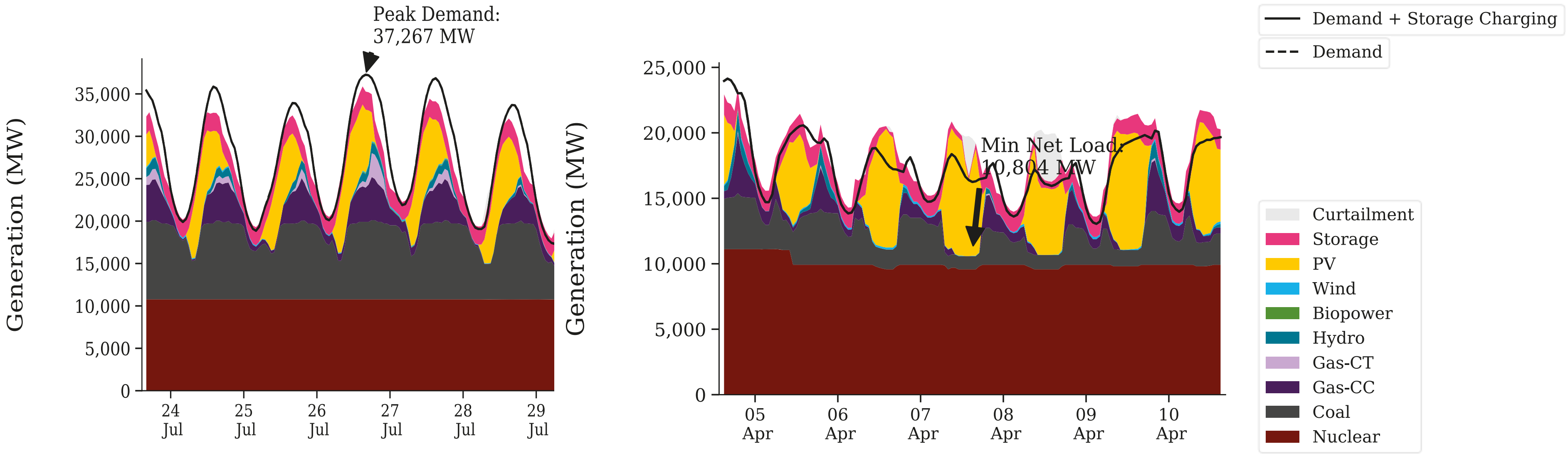
This map was produced by the National Renewable Energy Laboratory for the US Department of Energy. Billy Roberts, 2015 May 05

Duke's Total Installed Capacity and Generation



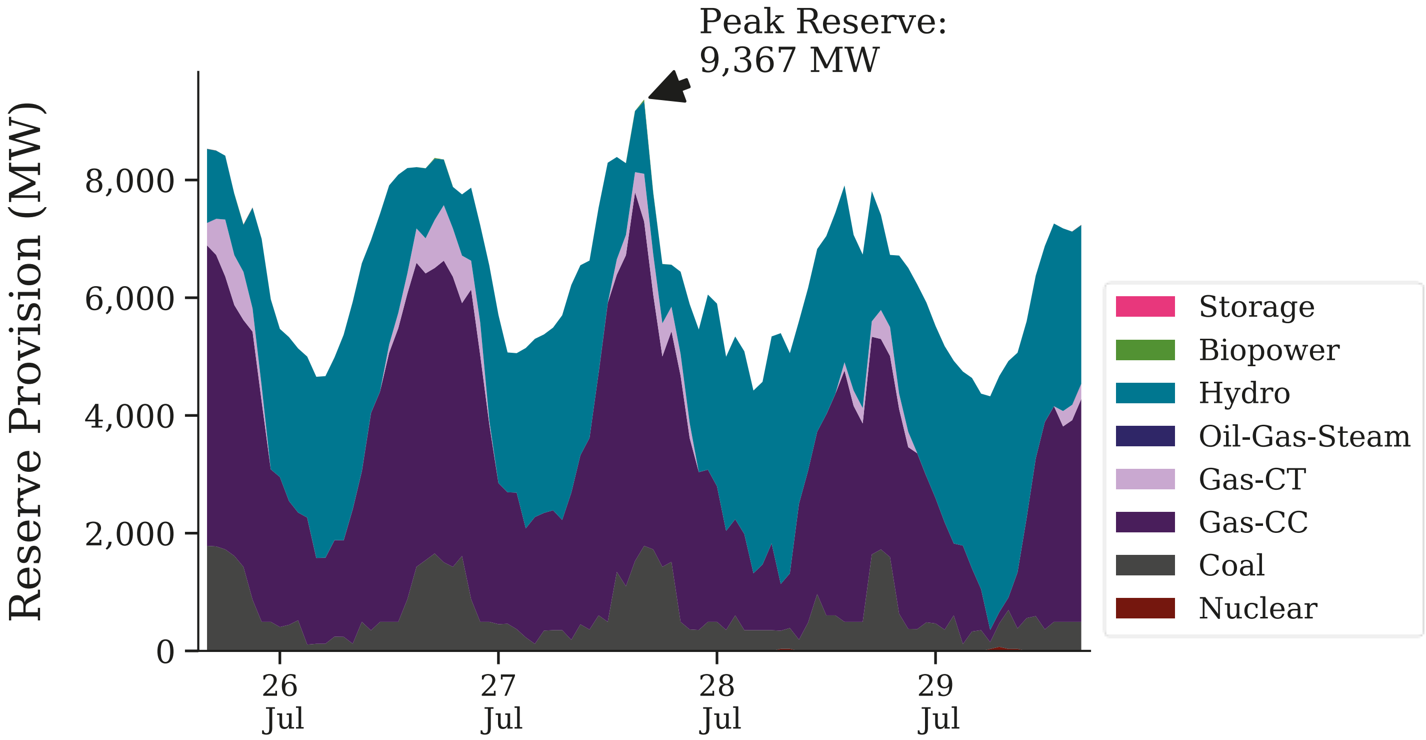
** Current model generates more with coal and less with gas than 2019 results

Duke’s Dispatch during peak demand and Min Net Load



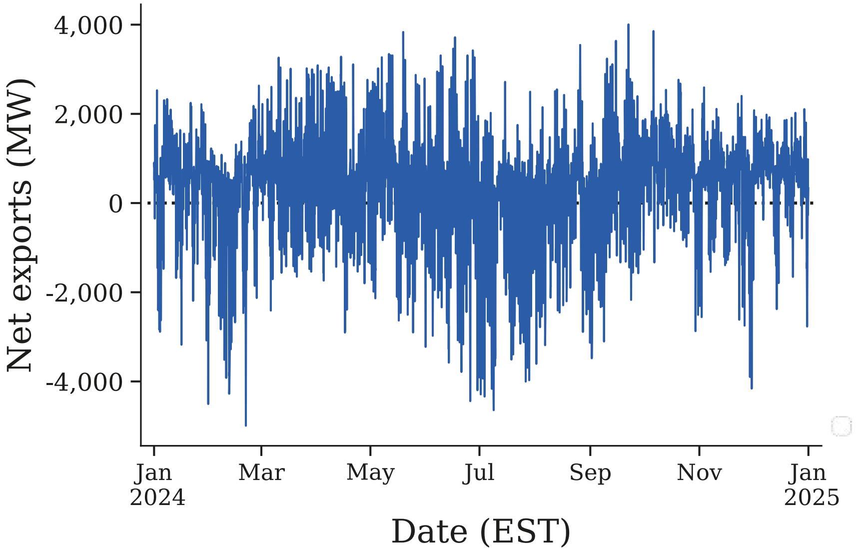
**Current model allows limited nuclear ramping; future runs to assume nuclear operates at 100% full capacity

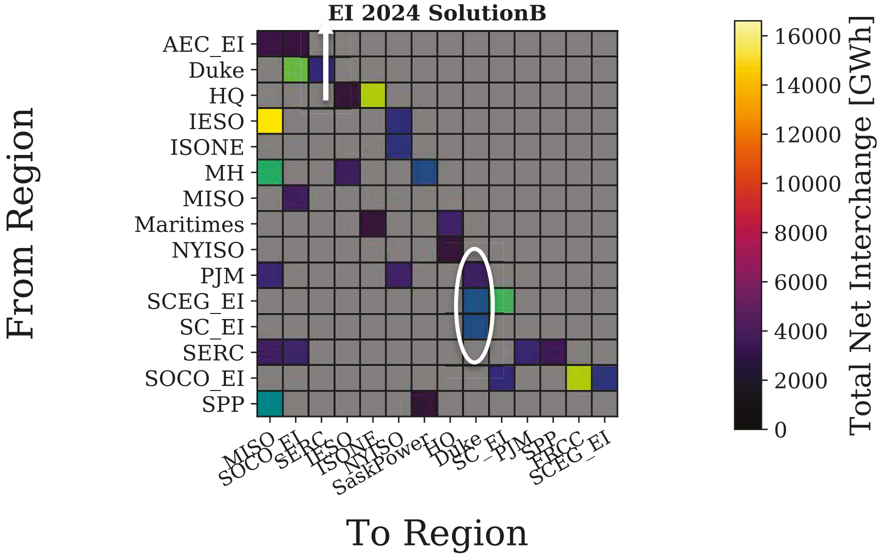
Reserve Provision



**Reserve provision for the entire SERC region

Duke’s Net Export (Export – Import)





SERC includes Duke, Southern Company (SOCO), South Carolina Electric & Gas Company (SCEG), Santee Cooper (SC), Aiken Electric Cooperative (AEC)

ReEDS-PLEXOS Comparison

- Production cost modeling more equipped to capture key operational issues:
  - large curtailment
  - dispatching of quick start units and ramping
  - periods of capacity shortages
- Comparison with of ReEDS and PLEXOS results can illustrate areas for refinement of planning results

ReEDS-PLEXOS Comparison Metrics

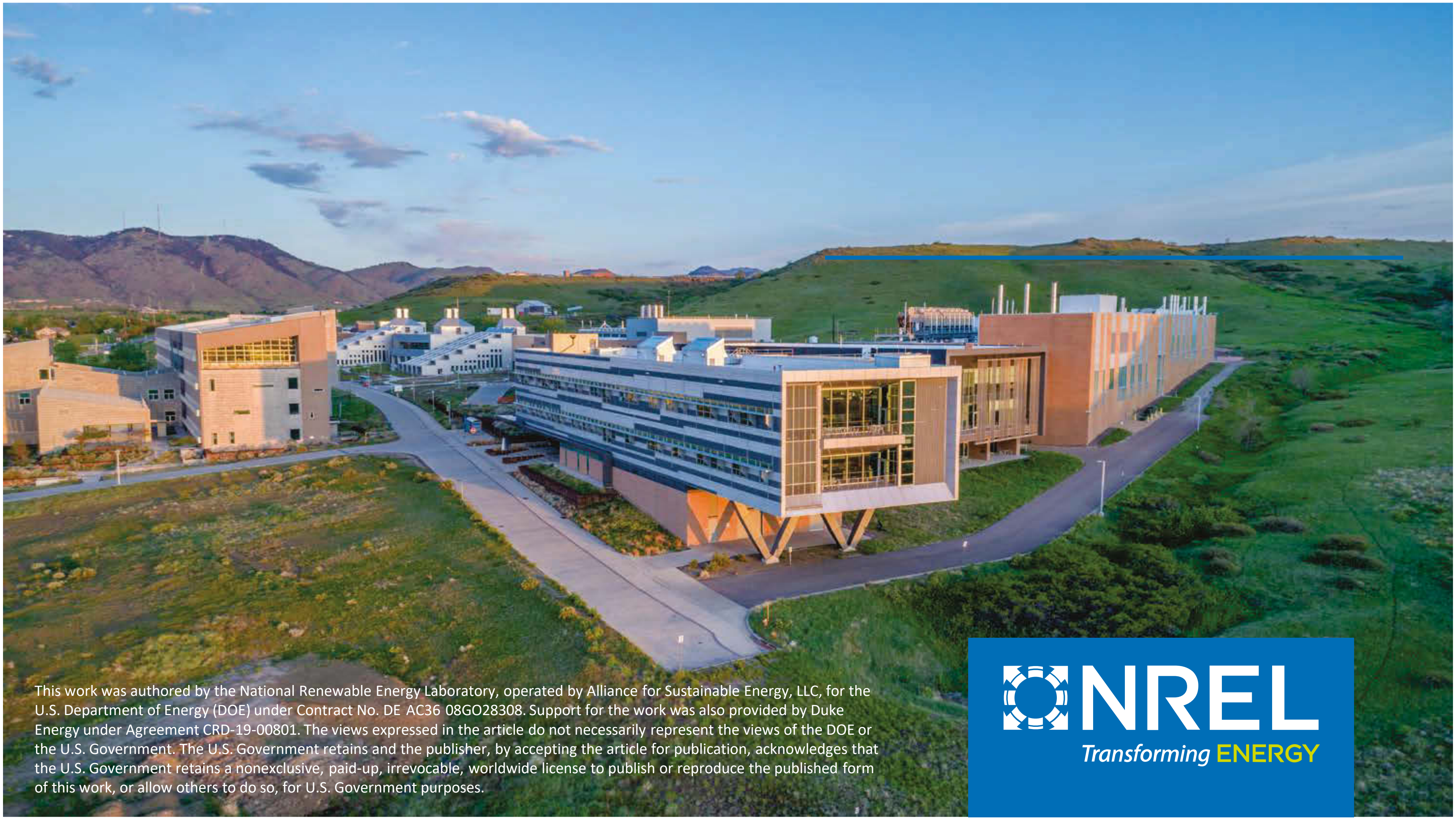
- Total generation by technology
- Are there hours of unserved load in the PLEXOS runs?
- VG Curtailment
- Transmission Utilization

ReEDS-PLEXOS Comparison Cases

- ReEDS BAU 2024 case vs. EI 2024 Nodal model (benchmarking)
- ReEDS 2030 70% emissions reduction
- ReEDS 2050 net zero

Summary and next steps

- Production cost modeling will provide detailed insight into operation of ReEDS buildouts with finer resolution than a capacity expansion model alone
- Next steps:
  - Refine the EI 2024 model
  - Translate ReEDS runs into zonal cases for running in PLEXOS



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