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Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina

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The following report was prepared by policy experts at the Duke University's Nicholas Institute for Environmental Policy Solutions and the University of North Carolina School of Law and reflects stakeholder input from members of the Carbon Policy and Technical Working Groups, a diverse group of over 40 stakeholders, who shared their time, insights, and expertise over the course of a year. We appreciate the work and dedication of the working groups and are grateful for their input. Working Group members are identified in **Appendix A** of this report. Members of a broader Clean Energy Plan Recommendation A1 Stakeholder Group are identified in **Appendix A** by organization. We thank UNC Law School student Alex Franklin for her research assistance. We also deeply appreciate Nicholas Institute Director Tim Profeta for his counsel throughout this project.

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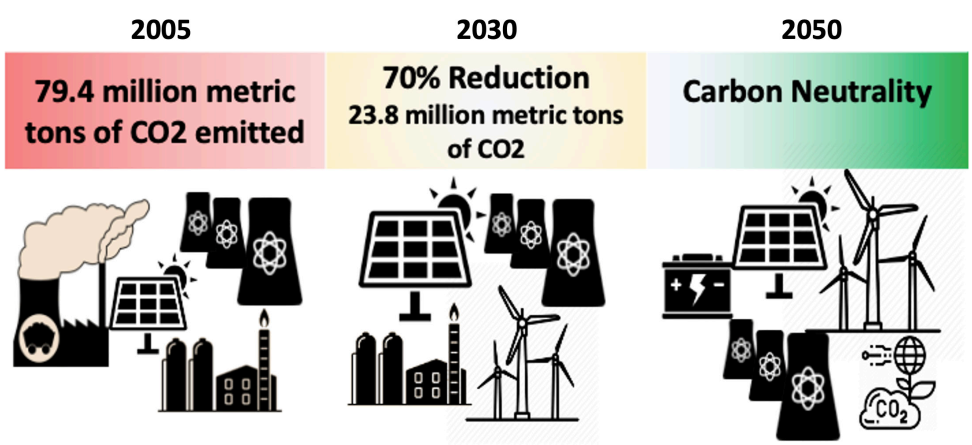
SECTION 1. EXECUTIVE SUMMARY

The North Carolina power sector is poised for transition. Economics have driven big changes on the grid, making cleaner options for electricity generation cost competitive with traditional resources. North Carolina clean energy policies have further enabled the shift into renewable resources. Building on this momentum, Duke Energy Corporation and our state's rural electric cooperatives have set ambitious climate goals, including "net zero" carbon emissions by 2050.

Well-designed policies can accelerate pollution reduction, make change more affordable for state residents and business, and stimulate job growth. For this reason, the North Carolina Clean Energy Plan (CEP)—developed pursuant to Governor Cooper's Executive Order No. 80—recommended the year-long study of carbon reduction policies for the power sector (Recommendation A1). The Duke University Nicholas Institute for Environmental Policy Solutions (Duke Nicholas Institute) and the University of North Carolina's Center for Climate, Energy, Environment, and Economics (UNC CE3) jointly conducted the study. This report reflects extensive modeling, policy and economic analysis, and stakeholder engagement. It does not make specific recommendations but evaluates different policies and offers options for decarbonizing the grid.

The CEP sets two emissions targets for the electricity used in North Carolina: a 70% reduction in 2005 CO_2 emissions levels by 2030, and carbon neutrality by 2050 (Fig. ES.1). These targets include emissions from in-state electricity generation and electricity imports.

Figure ES.1. Clean Energy Plan Power Sector Emissions Targets



A1 Policy Pathway Definitions

Starting with the CEP list, the A1 group refined options along four pathways or general reduction strategies. All specific policies analyzed in this report derive from these four pathways.

Accelerated coal retirements consider scenarios where different amounts of coal-fired capacity in North Carolina are retired by 2030, beyond any retirements likely to take place for economic reasons. In one scenario, all coal in the state is retired. In another, only less efficient so-called "subcritical" coal units are retired. In the case most often studied, subcritical units are retired and remaining coal units are limited to run just 10% of the year, in times of high electricity demand when other generating resources may not be available.

Carbon adders are a **market-based policy** that account for the costs to society imposed by a power plant that emits carbon dioxide (CO_2), including power plants run on coal, natural gas, oil, or biomass. These carbon adders are not actually paid by the utility but used in the decision-making process. If a utility could build a new natural gas plant or a solar photovoltaic (PV) farm, for instance, a carbon adder would make the natural gas plant look more expensive relative to a project that will not emit any pollution. Carbon adders can also be applied to decisions about which power plants to run to meet electricity demand at any given time. This can be an effective way to account for carbon pollution within a traditional rate-regulated state like North Carolina, where the Utilities Commission considers "least cost" to consumers when approving utility plans.

Another **market-based policy** studied in this report involves joining **a carbon market like the Regional Greenhouse Gas Initiative** (RGGI). Each state that participates in the RGGI market sets a budget of CO_2 allowances that shrink every year. For every ton of CO_2 that a power plant emits, it must hold one allowance. Generators may buy or sell allowances but must never emit more than the number of allowances they hold. The program works somewhat like a game of musical chairs—each year fewer tons of CO_2 may be emitted from all power generation across the participating states. RGGI scenarios studied in this report test different stringency levels and situations where North Carolina might raise revenues by selling CO_2 allowances. All variations feature an allowance budget that gets tighter each year from 2023–2030 and then remains level, reflecting that the RGGI states have not yet set budgets for the following years. However, it is widely expected that the allowance budget would continue to get more stringent after 2030.

The first three policy pathways may be characterized as "push" policies in that they seek to push carbon-intensive resources or CO_2 emissions out of the system. By contrast, the fourth pathway encompasses **clean energy standards** (CES), "pull" policies that work to draw in new clean resources. These standards can be technology neutral, allowing any non-emitting resource from solar and wind to nuclear and fossil with carbon capture to qualify, or require specific types of resources to meet part of the standard. (The report analyzes **offshore wind** and **energy efficiency** (EE).) The standard CES policies modeled in this report require an increasing percentage of electricity sales in North Carolina to be met with clean energy built in the state. Alternative cases set a declining rate of emissions from the entire North Carolina power generation fleet.

Push policies are less efficient at bringing in clean generation; pull policies are less efficient at reducing emitting generation. Combining them can bring advantages to the system. For this reason, the report also studies the effects of combining a CES with the other policies.

The CEP proposed several potential policy pathways for achieving these targets:

(1) Accelerated coal retirements;

(2) Market-based policies that put downward pressure on CO_2 emissions from the power sector;

(3) Clean energy policies; and

(4) Combinations of these policies.

Using these policies as a departure point, A1 stakeholders defined specific policies to analyze for possible application in North Carolina (Table ES.1). (Stakeholder organizations, and the individuals who served in A1 working groups, are identified in **Appendix A**.)

Key Findings

- The electricity system appears to be at a "tipping point" where small changes in gas prices or renewables costs can sway the balance between new capacity (i.e., gas turbines, renewables, and battery installations).
- CO_2 emissions from North Carolina's electric power sector will continue to decline as coal plants retire. However, new policies are necessary to achieve the CEP 2030 and midcentury emissions targets. If carefully designed, these policies can make emissions reductions more cost-effective and affordable, and drive positive economic development across the state.
- Coal retirement, carbon market, and carbon adder policies achieve reductions by lowering or "pushing out" in-state fossil generation, while CES policies increase in-state renewable generation, thus "pulling in" new resources to the grid. Combination policies can accomplish both outcomes more efficiently.
- Offshore wind requirements are projected to increase the cost of a CES but could drive economic development in supply chains and maritime trades.[1]
- Some policies can achieve relatively deep reductions in local air pollutants, including coal retirements or CES combined with RGGI and other "push" policies. This can improve health outcomes in fenceline communities and is important when considering equity in policy design.

Key Variables That Could Impact Emissions and Costs

- The level of electricity imports into North Carolina can have significant impacts on policy costs and in-state emissions.
- Amortizing the cost of renewable energy over a 30-year period rather than a 20-year period could lower cost estimates 21–64% across most policy scenarios.

1. This report did not study the economic opportunities of offshore wind. However, based on forecasts of East Coast offshore wind installed capacity, a recent study projects nearly $100 billion in economic value for North Carolina. See BVG Associates, Building North Carolina's Offshore Wind Supply Chain (2021), https://files.nc.gov/nccommerce/documents/Policymaker-Reports/Report_North-Carolina-OSW-Supply-Chain-Assessment_BVGAssociates_asPublished-Mar3-2021.pdf.

Electricity Capacity versus Generation

Electricity capacity refers to the maximum amount of electricity that a generator could produce, based on the size of the resource. Capacity is usually measured in megawatts—so for instance, Duke Energy has a 920-megawatt (MW) natural gas-fired power plant at the old H.F. Lee Facility in Wayne County.

Electricity generation refers to the amount of electricity that is actually produced by a generator. Generation turns on two factors—the availability of the generator, and the electricity demand on the system. A generator may not be available all the time, for instance if it needs to be taken off line for repairs, faces fuel supply shortages, or cannot run after the sun has set (in the case of a solar generator). Even if a generator could run, it may not run full-bore if other, less costly emitting resources are running at sufficient levels to meet demand for electricity.

When this report refers to capacity, it is referring to the total number and size of generating installations in North Carolina. When this report refers to generation, it is describing which of the generating installations are running and at what levels throughout a given year. Capacity and generation are important metrics to consider when comparing policies.

- Additional policy design choices can mitigate costs or allocation of costs. For example, the modeled CES required all qualifying renewable energy generation to occur within North Carolina. A more flexible policy could lower costs significantly but with possible emissions implications and a dampening of the economic development opportunities created by a "build it in North Carolina" approach.
- The absolute and relative costs of natural gas, renewable energy, and energy storage will continue to change. Even slight changes could impact costs and emissions.

The analysis in this report relies on two power sector capacity planning models—the consulting firm ICF's proprietary Integrated Planning Model (IPM) and the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at the Duke Nicholas Institute. IPM is familiar in the electric utility world and is relied on by regulators, utilities, and environmental organizations. RGGI states also rely on IPM for analysis of their carbon market. Meanwhile, as a robust in-house model at Duke University, DIEM could be used in a much more flexible way to test multiple policy variations and sensitivities. While the A1 Working Groups helped to coordinate the data and assumptions, differences remain in model structures and assumptions that—while leading to different outcomes—are nonetheless generally consistent. Modeling divergences, along with analyses to test the sensitivity to particular variables, underscore the uncertainties at play here and the role different assumptions play in policy outcomes.

This Executive Summary focuses on the stand-alone policies and clean energy standard (CES) combinations listed in Table ES.1. Section 6 of the report expands the analysis to the policy variations shown in the second part of the table, and **Appendix F** provides additional modeling and sensitivity analyses.

Table ES.1. Modeled Policy Cases and Variations

Category	Policy Cases	Model IPM	Model DIEM
	Baseline	x	x
Standalone	Accelerated Coal Retirement *(Option #2 below)*	x	x
	RGGI with 3% decline per year to 2030 *(steady after 2030)*	x	
	RGGI with 2030 CEP target *(steady after 2030)*	x	
	RGGI w/2030 CEP target & EE *(steady after 2030)*	x	
	CO2 Adder on New Capacity *($6/ton + 7%/year)*	x	x
	CO2 Adder on Generation *($6/ton + 7%/year)*		x
	CO2 Adder on Generation w/import border adjust *($6/ton + 7%)*		x
	CO2 Adder on Generation - USA wide *($6/ton + 7%)*		x
	CES on NC Retail Sales *(70% in 2030, 95% in 2050)*	x	x
	CES on USA-wide Retail Sales *(70% in 2030, 95% in 2050)*		x
CES Combinations *(NC Sales - 70% in 2030, 95% in 2050)*	CES + Coal Retirement	x	x
	CES + RGGI	x	
	CES + RGGI + Offshore Wind	x	
	CES + Carbon Adder on New Capacity	x	x
	CES + Carbon Adder on Generation	x	x
	CES + Offshore Wind	x	x
Category	**Policy Variations**	**IPM**	**DIEM**
Coal Retirement	Option #1 *(retire all subcritical by 2030)*		x
	Option #2 *(retire sub, limit supercrit to 10%, Rogers #6 on gas)*	x	x
	Option #3 *(retire all coal by 2030, Rogers #6 on gas)*		x
CO2 Adder on Generation	CEP Cap: "UK" approach		x
	$5/ton + $5/year		x
	$5/ton + $7/year		x
	Federal Social Cost of Carbon (SCC) in 2016 and 2017		x
	$13/ton + 7%/year		x
	$13/ton + 7%/year with import adjustment		x
	$13/ton + 7%/year - USA		x
Clean Energy Standards	Sales: 60% in 2030, 95% in 2050		x
	Sales: 65% in 2030, 95% in 2050		x
	Sales: 75% in 2030, 95% in 2050		x
	Sales: 65% in 2030, 90% in 2050		x
	Sales: 65% in 2030, 100% in 2050		x
	Generation: 70% in 2030, 95% in 2050		x
	USA Generation: 65% in 2030, 95% in 2050 – USA wide		x
	Emissions Rate Goal		x

Any policy or policy combination would be implemented in a system marked by unprecedented change. Since 2010, more than 100 gigawatts (GW) of coal capacity has retired in the United States. That number includes nearly 3 GW in North Carolina alone—enough to power 900,000 homes. Significant declines in natural gas prices and continuing reductions in the costs of new solar photovoltaic (PV), wind, and battery storage capacity have contributed to this shift. Given this, even modest market-based policies described in this report—a carbon adder that starts at \$6/ton of CO_2 and increases 7% each year, or a RGGI market price of \$5/ton—move the system. Moreover, results in this report do not reflect more recent developments such as the energy impacts of COVID-19, the December 2020 extensions for renewable energy tax credits, and a change in federal administration to one pledging ambitious climate policy action.

The policies cover a wide range of alternatives, but could be defined differently and would result in different emissions, costs, or influences on the resources built and run to supply electricity to North Carolina. For instance, the modeled coal retirement policies assume specific additional retirements of the state's coal units by 2030. Similarly, the modeled RGGI scenarios increase in stringency until 2030 and then level off, although it is expected that the RGGI states will agree to a further reduction of emissions after that time. By contrast, the modeled carbon adders and clean energy standards grow more stringent to 2050. After studying the comparative impacts of one type of policy versus another, North Carolina could choose to retire coal units sooner or later, set more stringent CO_2 reduction targets beyond 2030 in the RGGI program, or set carbon adders or CES at different levels of ambition. In addition, North Carolina might opt to rely more heavily on EE as a cost-effective component to any climate policy. This report incorporates discussions of EE but modeling was limited by the fact that North Carolina does not currently have an EE supply curve to predict the cost of deploying different types or levels of EE in this state.

Model results are projections about electricity system responses to various policy scenarios. As with any modeling exercise, the results are not meant to be relied upon for their absolute values, but serve as useful directional signals showing relative impacts of different policy approaches on NC's electricity system. Moreover, the impacts estimated and reported here are not comprehensive. For instance, policy cost estimates do not include the costs of inaction on climate change, or the health and economic benefits of reducing air pollution generally.

Results of Electricity Modeling

Outputs from the IPM and DIEM models allow comparisons of the relative emissions reductions (CO_2 and the local pollutants, NOx and SO_2) and systems costs of each modeled policy. These models also describe the policy's relative impacts on the electricity capacity and generation mix in North Carolina over time. Meanwhile, ICF conducted rate/bill impact analysis for a representative sampling of policies, and reported relative jobs and Gross State Product (GSP) numbers for that policy subset using the Regional Economic Models, Inc. (REMI) tool. An expert Technical Working Group helped to identify modeling inputs and assumptions.

The report also reflects regular discussions on policy design and concerns about affordability and equity among A1 stakeholders and a Policy Working Group representing utilities, environmental and environmental justice organizations, low-income consumers, industry, clean energy companies, government, and academia.[2] While interactions with these groups were extremely helpful, this is not a consensus document. Moreover, participation in the process does not

2. See Section 3 for more detail on the stakeholder process and analysis undertaken for this report.

imply endorsement of any of the report's findings. All final decisions regarding policy choices, assumptions, and report language are the responsibility of the authors.

Some of the key questions to pose when evaluating a carbon policy include:

- Will policies drive retirement of coal more quickly than under business as usual?
- What will replace retiring coal capacity—gas, renewables, battery storage, emerging technologies, or combinations of technologies to keep the system reliable?
- To what extent could a policy lead to increased reliance on electricity imports?
- Do some policies achieve or nearly achieve the near-term target but set a trajectory that could make it tougher to achieve a carbon neutral grid by midcentury?

In addition to these basic questions regarding the impact of different climate policies on the electric capacity and generation mix serving North Carolina, this report attempts to answer some next-order questions that follow on from potential changes in the industry such as:

- What do different policies cost and who bears these costs?
- What are the local air pollution implications of policies?
- Which policies may be net job creators?
- Which policies drive positive economic development in the state?
- How can any policy be designed to be more affordable, and more equitable?

Emissions and Systems Costs

Table ES.2 summarizes the CO_2 reductions associated with specific policy options. The four left-side columns of results focus on emissions from in-state electricity generation. The four right-side columns incorporate emissions estimates associated with imported electricity, since the CEP targets cover emissions associated with all electricity consumed in North Carolina.

By 2030, in-state power sector emissions under "business as usual" baseline forecasts are 32 million metric tons of CO_2 ($MMTCO_2$) in IPM and 28 $MMTCO_2$, in DIEM, representing a 56% or 62% reduction from 2005 in-state emissions respectively. IPM estimates another 5 $MMTCO_2$ from electricity imports, for a total of 37 $MMTCO_2$ in 2030, compared with 31 $MMTCO_2$ in DIEM. IPM, which selected more coal generation and fewer renewables in the baseline than DIEM, reports larger absolute reductions in emissions across policy cases that nonetheless remain further from CEP targets. Neither model suggests the system can meet the 2030 CEP target without additional policies.

Policies that achieve the 2030 CEP target in at least one of the models include:

- Carbon adders on generation (beginning at $6/ton and growing at 7% per year);
- A CES (with or without an offshore wind requirement); and
- Combination policies that start with a CES and also include either accelerated coal retirements, RGGI, or a carbon adder.

Among the stand-alone options, the **coal retirement** and **RGGI** policies drive some of the deepest in-state reductions by 2030, with RGGI providing the quickest reductions prior to 2030. However, these two policies increase system reliance on electricity imports. Moreover, emission reductions for these two options stagnate after 2030, again because of the policy definitions (i.e., assuming the CO_2 budget in RGGI will remain constant after 2030).

The modeled **carbon adder on new capacity** investment decisions has relatively small impacts on emissions by 2030 since it largely functions to preclude new investments in combustion turbines, but does not address emissions from existing fossil units. Reductions for the policy expand after 2030 as the adder becomes sufficiently robust to prevent construction of additional new turbines that would have appeared without the policy. Applying the same level of adder as a **carbon adder on generation** decisions achieves the 2030 CEP target.

A **CES** that aims for 70% clean generation in 2030 (and 95% clean by 2050) falls short of the 2030 CEP target in IPM, but meets it in DIEM (helped along by the additional renewables in that model's baseline). If a national CES were implemented, lower power sector emissions in North Carolina in DIEM suggests that the state would be better positioned to construct renewables than other states (and can then sell CES credits to a national market). Most policies that combine the 70% CES policy with other actions achieve CEP 2030 goals in IPM—and exceed them in DIEM. The greatest reductions are from the CES with the carbon adder on generation.

Looking further into the future, measures of cumulative reductions through 2050—in percentage terms compared to the baseline—vary across the two models, again because baseline emissions in DIEM are significantly lower than in IPM (see Section 6). As a result, policies such as a CES do less in DIEM to meet clean energy goals since baseline adoption of clean generation is higher. (Keep in mind when examining these 2050 results that the RGGI policies stop increasing in stringency in 2030, while the CES and carbon adders continue expanding through 2050.)

Table ES.2. Emissions in IPM and DIEM ($MMTCO_2$ and % Change)

IPM Model	In-State				Total (w/ Import Adjustment)			
Policy Cases	2030 (MMTCO2)	% Reduced from 2005	Cum to 2050	% Reduced from Baseline	2030 (MMTCO2)	% Reduced from 2005	Cum to 2050	% Reduced from Baseline
Baseline	32.4	56%	813		37.2	53%	946	
Accelerated Coal Retirement	23.7	68%	698	14.2%	30.0	62%	848	10.4%
RGGI - 3% decline/yr to 2030	26.6	64%	650	20.0%	32.5	59%	803	15.1%
RGGI with 2030 CEP target	24.6	66%	640	21.3%	30.9	61%	795	15.9%
RGGI w/2030 CEP target & EE	24.3	67%	636	21.8%	30.1	62%	785	17.0%
CO2 Adder on New Capacity	30.2	59%	734	9.8%	35.4	55%	893	5.6%
CES on NC Retail Sales	26.1	64%	633	22.1%	26.1	67%	678	28.3%
CES + Coal Retirement	18.2	75%	555	31.7%	21.8	**72%**	632	33.2%
CES + RGGI	20.4	72%	516	36.6%	23.5	**70%**	599	36.7%
CES + RGGI + Offshore Wind	19.8	73%	514	36.7%	23.1	**71%**	579	38.8%
CES + CO2 Adder on New Cap	26.3	64%	631	22.4%	26.3	67%	677	28.4%
CES + CO2 Adder on Gen	14.6	80%	342	58.0%	18.8	**76%**	474	49.9%
CES + Offshore Wind	25.8	65%	645	20.6%	25.8	68%	673	28.8%

DIEM Model	In-State				Total (w/ Import Adjustment)			
Policy Cases	2030 (MMTCO2)	% Reduced from 2005	Cum to 2050	% Reduced from Baseline	2030 (MMTCO2)	% Reduced from 2005	Cum to 2050	% Reduced from Baseline
Baseline	28.0	62%	626		30.9	61%	696	
Accelerated Coal Retirement	23.6	68%	571	8.8%	26.9	66%	644	7.4%
CO2 Adder on New Capacity	27.1	63%	577	7.7%	30.5	62%	646	7.1%
CO2 Adder on Generation	13.3	82%	312	50.1%	20.0	**75%**	460	34.0%
CO2 Adder on Gen w/imprt adj	14.2	81%	357	43.0%	19.5	**75%**	458	34.2%
CO2 Adder on Gen - USA wide	15.9	78%	391	37.4%	19.3	**76%**	448	35.6%
CES on NC Retail Sales	20.9	71%	537	14.1%	23.6	**70%**	603	13.3%
CES on USA-wide Retail Sales	12.2	83%	275	56.1%	13.7	**83%**	300	56.8%
CES + Coal Retirement	18.3	75%	497	20.6%	20.9	**74%**	564	19.0%
CES + CO2 Adder on New Cap	20.5	72%	516	17.6%	23.2	**71%**	579	16.9%
CES + CO2 Adder on Gen	11.1	85%	280	55.3%	15.9	**80%**	400	42.5%
CES + Offshore Wind	18.8	74%	525	16.1%	21.1	**73%**	579	16.8%

Note: Percentage reductions in bold are those that meet 2030 CEP targets for total emissions.

Table ES.3 presents the costs of providing electricity to the grid (e.g., capital costs of new construction, operating and fuel costs).[3] Costs are expressed in net present value (NPV) terms,

3. Costs include, for example, the costs of connecting new renewables to the grid. However, estimates of policy costs would not include general improvements to the grid that may be necessary regardless of any specific CEP policies.

compared to the costs of providing electricity under "business as usual."[4] Both models initially assume a 30-year book life for natural gas units and a 20-year book life for renewables,[5] which can make renewables appear more expensive by reducing the number of years over which payments for the capital investments are spread. Given the importance of this assumption in determining policy costs, DIEM results present alternative cases that assume a 30-year book life for renewables (similar to the default assumption in the NREL Annual Technology Base).

Policy cost highlights:

- **Accelerated coal retirements** raise NPV costs by less than 1% over baseline system costs through 2050 (most changes—in both costs and emissions reductions—occur by 2030). Costs per ton of emissions reduced, based on either in-state emissions or total emissions adjusted for imports, are on the lower end of the policy estimates.
- **RGGI** costs—either as a change in NPV or costs per ton—are among the lowest of the options (again bearing in mind that the policy is focusing on changes in the system up to 2030 and have more limited effects afterwards because of the assumption that RGGI budgets do not continue to tighten).
- Costs for a **carbon adder on new capacity** are low, but emissions reductions are also limited.
- The models have varying estimates of policy costs for a **CES over NC retail sales**. (These estimates will be very sensitive to assumptions about renewables' book life since they are focused on increasing renewables.)
- **Adding coal retirements to a CES** results in a minor cost increase, but costs per ton reduced are lower.
- Adding an **offshore wind requirement to a CES** raises costs (although these estimates are reduced by more than 30% in DIEM when using the assumption of a 30-year book life for renewables).
- How policy costs are calculated matters—the assumption of a 30-year book life for renewables lowers cost estimates for many policies in DIEM by 21–64%.

4. NPV metrics allow the annualization of capital payments over time, similar to how such costs would be experienced by firms that use either equity or debt to finance new construction. While expressing costs in this fashion is consistent with how electricity models solve for cost-effective methods of supplying electricity, they make it difficult to meaningfully express costs over a short time horizon—i.e., attempting to show NPV costs only through a year such as 2030 would miss most of the capital payments for units installed to meet any 2030 emissions goals.
5. Book life is essentially the number of years over which capital payments are annualized, thus, longer book life extends payments and lowers the estimated net present values of policy costs, especially for policies that involve high levels of renewables installations. Note that book life is largely an accounting technique and is not necessarily tied directly to the actual service life of a generating unit.

Table ES.3. Policy Costs

IPM Model	Renewables: 20-year booklife			
	NPV	NPV	$/ton Reduced	
Policy Cases	to 2050 ($ billion)	to 2050 (% change)	Based on In-State	Based on Total Emis
Accelerated Coal Retirement	$0.63	0.6%	$10	$11
RGGI with 3% decline/year to 2030	$0.51	0.5%	$5	$6
RGGI with 2030 CEP target	$0.56	0.6%	$5	$6
RGGI w/2030 CEP target & EE	($0.78)	-0.8%	($7)	($8)
CO2 Adder on New Capacity	$0.25	0.3%	$7	$10
CES on NC Retail Sales	$2.38	2.4%	$25	$17
CES + Coal Retirement	$2.51	2.6%	$18	$15
CES + RGGI	$2.62	2.7%	$15	$13
CES + RGGI + Offshore Wind	$10.10	10.4%	$57	$49
CES + CO2 Adder on New Capacity	$2.73	2.8%	$29	$20
CES + CO2 Adder on Generation	$4.08	4.2%	$15	$16
CES + Offshore Wind	$10.04	10.3%	$116	$72

DIEM Model	Renewables: 20-year booklife				Renewables: 30-year booklife			
	NPV	NPV	$/ton Reduced		NPV	NPV	$/ton Reduced	
Policy Cases	to 2050 ($ billion)	to 2050 (% change)	Based on In-State	Based on Total Emis	to 2050 ($ billion)	to 2050 (% change)	Based on In-State	Based on Total Emis
Accelerated Coal Retirement	$0.28	0.3%	$8	$9	$0.26	0.3%	$7	$8
CO2 Adder on New Capacity	$0.38	0.5%	$16	$17	$0.25	0.3%	$11	$11
CO2 Adder on Generation	$2.90	3.5%	$15	$20	$2.23	2.8%	$11	$15
CO2 Adder on Gen w/import adjust	$4.54	5.5%	$27	$32	$2.75	3.4%	$16	$19
CO2 Adder on Gen - USA wide	$4.49	5.5%	$34	$33	$3.32	4.1%	$25	$24
CES on NC Retail Sales	$3.81	4.6%	$65	$62	$2.18	2.7%	$37	$36
CES on USA-wide Retail Sales	$2.72	3.3%	$14	$12	$1.31	1.6%	$7	$6
CES + Coal Retirement	$4.10	5.0%	$49	$48	$2.45	3.1%	$29	$29
CES + CO2 Adder on New Capacity	$3.40	4.2%	$49	$47	$1.21	1.5%	$17	$17
CES + CO2 Adder on Generation	$6.11	7.5%	$28	$33	$4.16	5.2%	$19	$22
CES + Offshore Wind	$6.45	7.9%	$96	$85	$4.22	5.3%	$63	$56

Table ES.4 presents projected changes in two local air pollutants, nitrogen oxides (NOx) and sulfur dioxide (SO_2). These outcomes may be of particular importance to communities experiencing the health consequences of these emissions. The projected trends for these pollutants largely track projected reductions in CO_2. Once again, **accelerated coal retirements** drive some of the deepest reductions in 2030 in NOx and SO_2 of the stand-alone policies studied but by 2040 have more limited impact. Joining **RGGI** and setting the CO_2 budget at 22 million tons by 2030 ("RGGI with CEP 2030 target") reduces NOx and SO_2 more than a CES in 2030, but because the modeled RGGI policies did not increase in stringency beyond that year, by 2040 the CES outpaces RGGI in NOx reductions and matches RGGI in SO_2 performance.

There are also some notable differences between CO_2 and local pollutant outcomes. For instance, **carbon adder on new capacity** slightly increases NOx emissions over the baseline in 2030 in IPM (SO_2 emissions in IPM and both pollutants in DIEM fall slightly). The deepest reductions in local pollutants are achieved by policies that directly impact fossil fuel-fired generation: **carbon adders on generation** or **CES in combination with RGGI, coal retirement, or a generation adder**.

Table ES.4. NOx and SO_2 Emissions in North Carolina (1000 Metric Tons)

	IPM Model				DIEM Model			
	NOx		SO2		NOx		SO2	
Policy Cases	2030	2040	2030	2040	2030	2040	2030	2040
Baseline	15.6	5.8	4.6	0.7	13.9	4.4	4.1	0.3
Accelerated Coal Retirement	7.7	4.6	0.8	0.0	9.5	4.2	0.8	0.0
RGGI with 3% decline per year to 2030	12.1	4.7	3.4	0.3				
RGGI with 2030 CEP target	10.2	4.7	2.8	0.3				
RGGI w/2030 CEP target & EE	9.9	4.7	2.7	0.3				
CO2 Adder on New Capacity	15.7	5.5	4.7	0.7	13.3	2.5	4.2	0.3
CO2 Adder on Generation					3.4	0.8	0.0	0.0
CO2 Adder on Generation w/import adjust					4.0	0.9	0.0	0.0
CO2 Adder on Generation - USA wide					5.0	0.7	0.0	0.0
CES on NC Retail Sales	11.4	3.7	3.5	0.3	9.9	3.4	2.7	0.3
CES on USA-wide Retail Sales					3.1	0.1	0.1	0.0
CES + Coal Retirement	5.6	3.3	0.5	0.0	7.2	3.2	0.8	0.0
CES + RGGI	7.6	3.7	1.5	0.3				
CES + RGGI + Offshore Wind	7.1	3.6	1.3	0.2				
CES + Carbon Adder on New Capacity	11.7	3.9	3.5	0.3	9.2	2.4	2.5	0.2
CES + Carbon Adder on Generation	3.3	1.6	0.0	0.0	2.4	0.8	0.0	0.0
CES + Offshore Wind	11.4	4.4	3.3	0.3	8.0	2.8	2.0	0.2

Capacity Changes

Tables ES.5 and ES.6 show the changes in capacity for 2030 and 2050 under different policies, relative to 2023. The first row of each table shows capacity changes for the baseline forecasts (i.e., absent new climate policies). By 2030 in the baseline, IPM has retired 4.3 GW of coal and built 4.9 GW of new gas turbines, but has built no new renewables beyond the requirement of House Bill (HB) 589. DIEM's baseline retires less coal and builds gas turbines, solar PV, and a small amount of onshore wind. Although the models allow uneconomic nuclear plants to retire, this does not happen in the baseline or policy results.

Policy highlights for 2030:

- New gas turbines are used to meet **baseline** demand growth and reliability needs in IPM, while DIEM adds a mix of turbines, solar, and some onshore wind.
- **Accelerated coal retirements** are replaced by new turbines.
- **RGGI** policies lead to less construction of new gas turbines, but also have fewer coal retirements than in the baseline. RGGI does not lead to new renewables by 2030.
- A **carbon adder on new fossil investments** eliminates new turbines.
- **Carbon adders on generation** drive some additional solar and onshore wind.

- A 70% **CES** encourages a significant expansion of renewables, but has limited effect on existing coal plants.
- **CES combination policies** generally drive more coal retirements and higher renewables.
- IPM expanded battery storage in the CES policies. DIEM sees fewer battery installations because it assumed larger (and thus more expensive) batteries are tied to its paired solar/battery units than was the case in IPM (see the sensitivity analyses below to get a sense of how battery installations can vary across model assumptions).
- A **CES with an offshore wind** requirement reduces solar and expands turbines in IPM. In DIEM, offshore wind replaces a combination of solar and onshore wind.

Table ES.5. NC Capacity Changes by 2030 in IPM and DIEM (GW)

IPM Model						
Policy Cases	Coal	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-4.3	4.9	0.0	0.0	0.0	0.0
Accelerated Coal Retirement	-7.0	7.9	0.0	0.0	0.0	0.0
RGGI with 3% decline/year to 2030	-3.7	2.9	0.0	0.0	0.0	0.0
RGGI with 2030 CEP target	-3.7	2.5	0.0	0.0	0.0	0.0
RGGI w/2030 CEP target & EE	-3.7	2.6	0.0	0.0	0.0	0.0
CO2 Adder on New Capacity	-3.0	0.0	0.0	0.0	0.0	0.0
CES on NC Retail Sales	-4.9	0.4	13.2	1.2	0.0	2.8
CES + Coal Retirement	-5.8	0.9	12.9	1.4	0.0	2.9
CES + RGGI	-5.9	0.9	13.0	1.3	0.0	3.0
CES + RGGI + Offshore Wind	-5.3	1.3	9.0	0.5	2.8	2.0
CES + CO2 Adder on New Capacity	-4.5	0.0	13.2	1.2	0.0	2.7
CES + CO2 Adder on Generation	-6.7	0.5	12.9	1.5	0.0	3.1
CES + Offshore Wind	-5.0	1.5	9.0	0.5	2.8	1.9
DIEM Model						
Policy Cases	Coal**	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-2.4	1.7	3.9	0.3	0.0	0.0
Accelerated Coal Retirement	-5.6	4.2	3.9	0.3	0.0	0.0
CO2 Adder on New Capacity	-2.4	0.0	3.9	0.3	0.0	0.0
CO2 Adder on Generation	-2.9	0.0	3.9	1.8	0.0	0.0
CO2 Adder on Gen w/import adjust	-2.8	0.9	5.8	2.1	0.0	0.0
CO2 Adder on Gen - USA wide	-2.7	2.2	5.9	2.2	0.0	0.0
CES on NC Retail Sales	-2.5	0.8	11.2	2.5	0.0	0.0
CES on USA-wide Retail Sales	-2.7	1.5	9.8	2.9	0.0	0.0
CES + Coal Retirement	-5.6	3.5	10.9	2.7	0.0	0.0
CES + CO2 Adder on New Capacity	-2.5	0.0	12.8	1.7	0.0	0.9
CES + CO2 Adder on Generation	-2.9	0.2	11.1	2.6	0.0	0.0
CES + Offshore Wind	-2.5	0.7	8.0	1.2	2.8	0.0

* New solar capacity excludes required installations under HB589
** Change in coal summer capacity shown for DIEM.

Policy highlights for 2050:

- All coal units have reached the end of their depreciation lives and are forced out in the **baseline** forecast (and all policy cases).
- **Accelerated coal retirements** and **RGGI** have limited impacts on new turbines. RGGI shows some increases in solar PV by 2050.
- A **carbon adder on new capacity** prevents around 12 GW of new turbines by 2050. The turbines are replaced by a mix of solar and batteries.
- **Carbon adders on generation** don't prevent installation of gas turbines for reliability purposes, although utilization rates are lower. Adders on generation encourage a combination of solar and batteries.
- The **CES** policy—which reaches 95% in 2050—drives about 30 GW of in-state solar, along with some batteries; a **CES with an offshore wind** requirement shifts some of that solar capacity into wind.
- **CES combination policies** reduce construction of new turbines and shift the industry towards batteries.
- Generally, higher penetration of battery storage complements solar installations and displaces gas.

Table ES.6. NC Capacity Changes by 2050 in IPM and DIEM (GW)

	IPM Model					
Policy Cases	Coal	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-10.2	12.5	10.9	3.9	0.0	5.8
Accelerated Coal Retirement	-10.2	12.2	11.3	3.9	0.0	6.2
RGGI with 3% decline/year to 2030	-10.2	11.0	14.8	3.9	0.0	7.4
RGGI with 2030 CEP target	-10.2	11.0	14.8	3.9	0.0	7.4
RGGI w/2030 CEP target & EE	-10.2	11.4	13.9	3.9	0.0	7.0
CO2 Adder on New Capacity	-10.2	0.0	15.9	3.9	0.0	8.3
CES on NC Retail Sales	-10.2	4.2	32.2	3.9	0.0	11.5
CES + Coal Retirement	-10.2	4.5	32.2	3.9	0.0	11.6
CES + RGGI	-10.2	4.1	32.2	3.9	0.0	11.8
CES + RGGI + Offshore Wind	-10.2	7.2	21.5	1.4	8.0	7.5
CES + CO2 Adder on New Capacity	-10.2	0.0	32.2	3.9	0.0	12.5
CES + CO2 Adder on Generation	-10.2	3.7	33.6	3.9	0.0	13.8
CES + Offshore Wind	-10.2	7.3	20.9	1.8	8.0	7.5
	DIEM Model					
Policy Cases	Coal**	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-9.9	11.8	12.9	1.8	2.4	1.9
Accelerated Coal Retirement	-9.9	12.3	12.7	1.8	2.4	1.9
CO2 Adder on New Capacity	-9.9	0.0	30.3	1.2	1.9	10.3
CO2 Adder on Generation	-9.9	10.2	15.0	2.2	3.4	6.3
CO2 Adder on Gen w/import adjust	-9.9	5.7	30.3	2.4	3.4	9.5
CO2 Adder on Gen - USA wide	-9.9	7.4	22.3	2.2	2.0	7.6
CES on NC Retail Sales	-9.9	10.3	27.4	2.7	3.4	4.4
CES on USA-wide Retail Sales	-9.9	10.0	30.6	2.9	3.1	8.1
CES + Coal Retirement	-9.9	10.2	27.2	2.8	3.4	4.5
CES + CO2 Adder on New Capacity	-9.9	0.0	35.3	1.7	1.8	10.5
CES + CO2 Adder on Generation	-9.9	9.5	29.1	2.7	3.4	6.8
CES + Offshore Wind	-9.9	11.4	19.6	1.2	8.0	3.0

* New solar capacity excludes required installations under HB589.
** Change in coal summer capacity shown for DIEM.

Generation Changes

Table ES.7 categorizes in-state generation into three buckets: fossil; non-emitting sources such as nuclear, hydroelectric, and renewables; and net imports. Results are also shown for 2035 to examine the generation mix in the state at that juncture.

Policy Highlights

- By 2035, **baseline** in-state generation is 56% non-emitting in IPM and 71% non-emitting in DIEM. These responses affected the different emissions and cost outcomes shown previously between the two models.

- **Accelerated coal retirements** and **RGGI** do not lead to additional generation by renewables in the state. In IPM, most of the reduced coal generation from these policies is replaced by imports. Coal retirements have minor impacts on renewables in DIEM.
- The **CES stand-alone** and **CES combination** options lead to similar levels of in-state non-emitting generation. Differences across the CES options are largely in the mix of in-state fossil generation versus imported electricity.
- Even by 2050, **CES policies** have fairly limited effects on in-state fossil generation compared to "business as usual," except for options that combine the CES with a carbon adder on generation.[6] This is because fossil units can still generate power for export.
- **CES policies** lead to lower levels of net imports, or in later years net exports (shown as negative net imports), than other policies. A CES policy that enabled the use of out-of-state credits (not modeled in this report) would change this outcome.

Table ES.7. NC Generation in IPM and DIEM (TWh)

IPM Model	2030			2035			2040			2050		
	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import
Baseline	67	65	21	64	80	16	54	81	31	45	108	25
Accelerated Coal Retirement	56	65	33	51	80	28	50	81	34	45	109	25
RGGI with 3% decline/year to 2030	58	65	30	53	80	25	46	81	37	41	116	21
RGGI with 2030 CEP target	55	65	34	53	80	25	46	81	37	41	117	21
RGGI w/2030 CEP target & EE	54	65	31	52	80	22	46	81	34	41	115	21
CO2 Adder on New Capacity	63	65	25	60	80	19	46	81	38	39	120	20
CES on NC Retail Sales	57	99	-1	51	111	-3	40	125	2	35	154	-9
CES + Coal Retirement	46	99	9	42	111	6	38	125	4	35	154	-9
CES + RGGI	49	99	6	42	111	5	37	125	3	31	154	-6
CES + RGGI + Offshore Wind	48	99	7	42	111	5	38	132	-6	29	154	-5
CES + CO2 Adder on New Capacity	57	99	-2	51	111	-2	40	125	2	33	154	-7
CES + CO2 Adder on Generation	39	99	14	29	111	18	24	125	16	6	158	15
CES + Offshore Wind	56	99	-1	52	111	-4	41	132	-8	32	154	-8
DIEM Model	**2030**			**2035**			**2040**			**2050**		
	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import
Baseline	59	73	20	39	94	26	34	100	32	31	114	35
Accelerated Coal Retirement	56	73	23	34	96	29	33	100	33	31	114	35
CO2 Adder on New Capacity	57	73	22	35	101	24	30	119	19	26	142	16
CO2 Adder on Generation	35	78	40	25	97	38	14	104	50	3	121	57
CO2 Adder on Gen w/import adjust	36	83	33	26	110	23	19	129	21	7	155	21
CO2 Adder on Gen - USA wide	40	84	28	29	99	31	13	117	38	6	131	45
CES on NC Retail Sales	46	98	8	36	111	12	32	125	10	26	156	-2
CES on USA-wide Retail Sales	31	96	26	1	138	26	1	141	25	0	157	30
CES + Coal Retirement	43	98	10	33	111	15	30	125	11	26	156	-2
CES + CO2 Adder on New Capacity	46	98	9	34	111	14	29	129	10	24	156	2
CES + CO2 Adder on Generation	29	98	26	22	111	27	12	125	31	2	156	24
CES + Offshore Wind	43	98	10	36	111	11	29	136	6	27	156	-3

6. A similar outcome could be expected by combining the CES with a RGGI program that increased in stringency after 2030.

Sensitivities

Modeling results may be highly dependent on specific assumptions. Sensitivity analyses were conducted, largely in DIEM, to test for this using the following key variables: electricity demand, natural gas prices, renewables costs, and battery storage effectiveness. The analyses were conducted on one "push" policy—a carbon adder on generation—and one "pull" policy—a CES. Table ES.8 looks at how policy costs, emissions reductions in 2030, and capacity changes by 2040 can vary across assumptions in DIEM (looking at capacity differences in 2040 helps highlight how variables influence policy results better than those for 2030 when data differences may not have had enough time to alter the results). Policy cost results are shown under a 20-year and a 30-year payback schedule for renewables.

Assumptions about Electricity Demand Growth

The standard electricity growth assumption for most modeling came from the DEC/DEP 2020 IRP, which projects demand growth of around 0.6% per year, after accounting for EE and demand-side management ("**IRP**" in Table ES.8). Sensitivities were run using US Energy Information Administration forecasts that grow at around 1% and 1.3% per year in the Carolinas region ("**AEO Reference**" versus "**AEO High Macro**"). Another alternative looked at the potential for increased demand from electric vehicles, based on NREL's **Medium EV** forecast. Other demand projections are run as well (see **Appendix F**), assuming more ambitious uptake of EE measures (resulting in lower demand and the potential use of EE as a CES compliance mechanism). However, as noted in the EE call-out box, it is challenging to evaluate the full potential benefits of EE measures without the availability of a "supply curve" for EE that shows the quantity of EE savings available for a range of costs in the state of North Carolina.

Assumptions about Natural Gas Prices

Standard baseline assumptions about natural gas prices ("**ICF+AEO**") come from ICF gas modeling, transitioning to AEO forecasts after eight years (see **Appendix B** for a chart with these results). These prices start at around $2.50/MMBtu and rise to around $3.25/MMBtu after 2030. Sensitivity cases reported in Table ES.[8] assume gas prices that are around $1/MMBtu higher in all years ("**AEO Reference**"); there are also DIEM results assuming that gas prices remain flat at roughly today's levels in all future years ("**Flat at $2.50**"). Finally, it was assumed in most model runs that new combined cycle units face an additional $1.5/MMBtu fixed charge to secure access to firm gas contracts—this assumption is removed in the "**No +$1.50 on new CC**" results.

Assumptions about Renewables and Batteries

There was significant discussion among stakeholders about assumptions to use for renewables costs (and the related issue of battery effectiveness at meeting peak load). Standard modeling assumptions took a more conservative view of renewables. Then, sensitivities were run to demonstrate how more favorable—but still reasonable—outlooks could either enhance or decrease the cost-effectiveness of clean energy policies.[7]

While the "standard" runs in this report relied on **NREL's "Moderate"** forecasts for future solar PV, wind, and battery costs, other runs used **NREL's "Advanced"** forecast featuring more

7. In spite of the discussion, no consensus was reached regarding likely trends for renewables and batteries.

optimistic results for these cost trends. Also, standard assumptions about battery effectiveness and the amount that the DEC/DEP system can support come from an **Astrape Consulting** report that was part of the DEC/DEP 2020 IRP.[8] Given the uncertainty about the amount of battery storage that systems can support and the cost of batteries, these assumptions are contrasted to runs in which batteries are 100% effective at meeting peak demand needs in North Carolina (**"100% Credit"**) and runs in which an additional 15% cost adder is applied to the NREL Moderate Case battery cost assumptions to proxy additional costs associated with depth-of-discharge concerns for batteries that cycle on a daily basis (**"+15% DoD Cost"**).

Highlights of the sensitivity analyses:

- Across the sensitivities, policy costs using a 30-year book life are 20%–45% lower than for an assumption of a 20-year book life for renewables. (Recall that when all of the standard assumptions were used except for book life, some costs dropped 64%).
- Policy costs do not vary dramatically across assumptions about electricity demand (note that these are changes in costs relative to the baseline—total costs will be higher when there is additional electricity demand; adding the policies on top of a higher baseline demand is, however, not dramatically changing their costs).
- Higher gas prices in the "AEO Reference" runs lead to higher policy costs in the carbon adder case since the combination of the higher gas prices and price on the carbon content of gas mean that additional (and more costly) renewables are installed to avoid using gas.
- Conversely, higher gas prices under the CES policy are associated with lower policy costs since both the CES and the higher gas prices act to encourage renewables.
- The $1.50/MMBtu adder that proxies a premium for securing firm gas capacity for new combined cycle units makes these types of units uneconomic. If these additional costs are not incurred, combined cycles will be built—particularly under a CES.
- The lower renewable costs associated with the NREL Advanced forecasts lead to lower policy costs, regardless of the type of policy.
- Emissions in 2030 under the CES policy remain around the 70% reduction point across most sensitivities, with the exceptions of high gas prices (which cause coal units to run instead of gas units) and low renewables costs (where the CES and renewables costs move emissions in the same direction and lead to additional reductions).
- In either the carbon adder or CES cases, the Astrape battery assumptions limiting the contribution of batteries to peak demands lead to far lower battery installations than the assumption that batteries would contribute 100% of their capacity towards meeting peaks.
- Conversely, higher battery prices from an additional 15% cost to proxy depth-of-discharge concerns for daily cycling would lower battery installations by around 30–60%.

8. DIEM used data from Attachment IV to the IRP, while IPM used data from the body of the IRP.

Table ES.8. Sensitivity Analyses in DIEM

Policy Case	Variable	Sensitivity	Renewables booklife: 20-year NPV to 2050 ($ billion)	30-year NPV to 2050 ($ billion)	CO2 % reduced from 2005 in 2030 (w/imports)	Capacity Change by 2040 (GW) Combined Cycle	Gas Turbines	Solar PV	Wind	Battery Storage
CO2 Adder ($6/ton+7%/year)	Electricity Demand Growth	**IRP**	**$2.9**	**$2.2**	**75%**		**5.7**	**17.5**	**2.2**	**2.3**
		AEO Reference	$3.1	$2.1	73%		5.5	23.4	2.8	2.1
		AEO High Macro	$3.2	$1.9	72%		6.4	27.8	2.8	1.9
		NREL Medium EV	$3.7	$9.4	71%		0.9	33.5	2.9	1.6
	Natural Gas Prices	**ICF+AEO**	**$2.9**	**$2.2**	**75%**		**5.7**	**17.5**	**2.2**	**2.3**
		AEO Reference	$4.8	$3.3	85%		4.1	27.0	3.5	4.2
		Flat at $2.5	$2.5	$1.7	71%		7.3	15.0	0.3	
		No +$1.5 on new CC	$4.1	$3.2	75%	0.7	7.9	16.7	1.0	1.8
	Renewables Costs	**NREL Moderate**	**$2.9**	**$2.2**	**75%**		**5.7**	**17.5**	**2.2**	**2.3**
		NREL Advanced	$1.1	$0.8	95%		0.1	30.4	0.1	2.4
	Battery Storage Assumptions	**Astrape**	**$2.9**	**$2.2**	**75%**		**5.7**	**17.5**	**2.2**	**2.3**
		100% Credit	$4.1	$2.2	75%		0.8	21.8	1.8	9.9
		+15% DoD Cost	$2.4	$2.0	75%		7.4	14.9	2.2	0.7
CES (70% in 2030, 95% in 2050)	Electricity Demand Growth	**IRP**	**$3.8**	**$2.2**	**70%**		**7.9**	**24.6**	**2.7**	**0.6**
		AEO Reference	$3.9	$2.2	69%		8.2	26.2	2.8	0.6
		AEO High Macro	$4.1	$2.4	68%		9.9	29.9	2.9	1.4
		NREL Medium EV	$12.1	$9.5	68%		6.0	31.3	3.6	1.4
	Natural Gas Prices	**ICF+AEO**	**$3.8**	**$2.2**	**70%**		**7.9**	**24.6**	**2.7**	**0.6**
		AEO Reference	$1.4	$0.7	62%		4.4	27.3	2.8	3.2
		Flat at $2.5	$5.6	$3.2	71%		9.3	24.3	2.3	
		No +$1.5 on new CC	$5.7	$3.6	77%	5.7	6.3	25.1	1.7	0.2
	Renewables Costs	**NREL Moderate**	**$3.8**	**$2.2**	**70%**		**7.9**	**24.6**	**2.7**	**0.6**
		NREL Advanced	$1.0	$0.8	88%			29.1	0.3	3.1
	Battery Storage Assumptions	**Astrape**	**$3.8**	**$2.2**	**70%**		**7.9**	**24.6**	**2.7**	**0.6**
		100% Credit	$3.8	$2.1	70%		5.8	24.2	2.3	4.4
		+15% DoD Cost	$3.7	$2.2	70%		8.8	23.4	2.9	0.3

Note: Results for "standard" assumptions are shown in bold (and are the same across the bolded cases).

Incorporating Energy Efficiency into Modeling

Energy efficiency (EE) is widely considered a low-cost way to reduce energy use by upgrading technologies or encouraging behavioral changes behind the meter. EE investments can lower electricity demand over time, delaying or reducing the need for new, more costly, and possibly emitting units. However, different EE strategies vary in cost-effectiveness, and provide distinct non-energy benefits to the system.

North Carolina does not have state-specific cost performance data that could be used to evaluate the relative costs of EE programs or compare costs and system benefits of EE options.[1] Absent a so-called "EE cost curve," this report uses reductions in energy demand to approximate the impact of EE with reductions in energy demand. The report studies EE in three ways:

Standard Assumptions – This case uses electricity demand growth rates, energy efficiency, and demand-side management assumptions from the DEC/DEP IRPs.

"Medium" Energy Efficiency – This case assumes that EE measures result in a 1% decline in demand per year through 2030, taper to 0.5% by 2040, and persist at that level to 2050.

"High" Energy Efficiency – This case assumes that EE measures result in a 1–2% decline in demand per year through 2030, taper to 1.0% by 2040, and persist at that level to 2050.

In IPM, EE investments from RGGI auction revenue are analyzed for their ability to reduce load and moderate bill and rate impacts (Section 7, pages 120–123).

In IPM, the "Medium" and "High" EE cases are used for CES compliance to approximate the impact of an Energy Efficiency Resource Standard (EERS) (**Appendix F**, Figs. F.16 & F.17.).

In DIEM, three EE cases are used to study the impact of load assumptions on two policies: a carbon adder on generation and a CES (**Appendix F**, Figs. 48–53).

The approaches can be used to understand the directional impacts of EE investment. But to truly understand the costs and benefits of EE, analysis must be done with a state-specific cost curve.

1. For more on the use of EE cost curves, please see "The Cost of Saving Electricity: A Multi-Program Cost Curve for Programs Funded by U.S. Utility Customers," Goldman, C.A., et. al, Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA, USA, April 2020. https://eta-publications.lbl.gov/sites/default/files/manuscript.v9_nmf.pdf.

Rate/Bill Changes, and Macroeconomic Impacts

ICF studied some economic impacts of the following subset of carbon policies:

(1) A number of RGGI scenarios;

(2) The standard modeled CES (70% clean in 2030; 95% clean in 2050);

(3) The CES combined with the standard accelerated coal retirements policy; and

(4) The CES combined with different RGGI scenarios.

This part of the analysis considers how policy makers could use revenues generated from a RGGI CO_2 allowance auction to lower program costs to ratepayers. Table ES.9 presents the projected revenues from a RGGI auction—nearly $1 billion from 2023 to 2030.

Table ES.9. Projected RGGI Auction Revenues

Year	2023	2024	2025	2026	2027	2028	2029	2030	Cumulative, 2023–2030
Allowance Revenue (2012$)	140 m	139 m	139 m	139 m	113 m	113 m	90 m	90 m	963 m

ICF studied three possible outcomes of a RGGI auction—one where revenues are not recycled back into the power sector but used on other state budget priorities ("no revenue recycling"); another where proceeds are invested in EE; and finally, one where proceeds are given back to all residential ratepayers (or just low-income ratepayers) in a direct bill assistance program. If DEQ decided to freely allocate CO_2 allowances, the Utilities Commission would likely act to ensure that the value of the allowances flows through to the ratepayers. That suggests the direct bill assistance scenarios best approximate a free allocation regime, although the Utilities Commission might want to benefit all customer classes.

Across all four of the policy scenarios subjected to rate/bill analysis, ICF allocated costs to the three customer classes based on their current share of North Carolina electricity demand: 42% to residential; 38% to commercial; and 19% to industrial users. ICF then calculated the percentage change a policy caused to average monthly residential bills and retail rates for commercial and industrial customers. ICF did not translate commercial and industrial rate impacts into bills because an average bill would not tend to be representative for those sectors.

Table ES.10 presents the changes to electricity rates and bills in 2030 compared to projections under "business as usual." This is just a snapshot in time. ***By 2043, all climate policies result in lower monthly residential bills than the baseline***—in part because of a stronger shift into renewables which have no fuel costs. (The average residential household bill was projected to be $170.41 under business as usual in 2030.) By 2048, all climate policies result in lower rates than in the baseline for all customer classes.[9] Note that the standard policy modeling was used here; alternative scenarios for renewables costs would reduce all of these costs.

9. Section 7 of the report provides more detail on the cost impacts of the policies and their economic effect.

Table ES.10. Summary of Projected Bill and Rate Impacts in 2030, by Scenario (Expressed in Change over Baseline Cases)

Customer Class	RGGI No Revenue Recycling (RR)	RGGI Auction – direct bill assistance (DBA)*	RGGI Auction – EE invest-ment	CES	CES + Coal Retire-ment	CES + RGGI (no RR)	CES + RGGI (DBA)	CES + RGGI (EE)
Residential (per month)	$1.44 (0.8%)	-$0.65 (-0.4%)	$0.65 (0.4%)	$2.34 (1.4%)	$2.51 (1.5%)	$2.92 (1.7%)	$0.83 (0.5%)	$2.25 (1.3%)
Commercial (cents/kwh)	.13 (1.1%)	.13 (1.1%)	.06 (0.5%)	.21 (1.9%)	.22 (2.0%)	.26 (2.3%)	.26 (2.3%)	.20 (1.8%)
Industrial (cents/kwh)	.10 (1.5%)	.10 (1.5%)	.04 (0.7%)	.16 (2.4%)	.17 (2.6%)	.19 (3.0%)	.19 (3.0%)	.15 (2.3%)

* ICF also ran a scenario where direct bill assistance was only provided to low-income households (those earning up to the federal poverty level). In 2030, that policy would result in a $15.17 decrease in low-income monthly electricity bills (-8.9%), and an increase for other households of $1.44 per month (0.8%).

Table ES.11 summarizes the cumulative job and Gross State Product (GSP) impacts of the studied policies. The analyzed policies analyzed have a relatively small effect on North Carolina's economy, changing the jobs outlook -0.01% to +0.05% from "business as usual" job projections, and GSP levels -0.01% to +0.03%.

Table ES.11 Summary of Cumulative Job and GSP Impacts Across Scenarios

(2023–2050)	Cumulative Job Impacts		Cumulative GSP Impacts	
Scenario	**Job-years**	**% Change from baseline**	**GSP 2020$ (millions)**	**% Change from baseline**
1a: RGGI Load Adjusted Energy Efficiency	47,337	0.03%	4,868	0.02%
1b: RGGI Direct Bill Assistance (Using REMI allocation across income groups)	-11,228	-0.01%	-1,581	-0.01%
1c: RGGI Direct Bill Assistance (Focusing on low-income groups)	-10,901	-0.01%	-1,398	-0.01%
2: Stand-alone CES	37,275	0.02%	2,869	0.01%

(2023–2050)	Cumulative Job Impacts		Cumulative GSP Impacts	
Scenario	**Job-years**	**% Change from baseline**	**GSP 2020$ (millions)**	**% Change from baseline**
3: CES + Coal Retirement	25,376	0.01%	1,110	0.00%
4a: CES + RGGI (no revenue recycling)	17,777	0.01%	348	0.00%
4b: CES + RGGI (revenue recycling)	89,998	0.05%	7,885	0.03%

By 2033, a RGGI program with auction revenues invested in EE reduces rates/bills in all three customer classes below business as usual. This policy results in the lowest cost for commercial and industrial customers for any policy through lower demand projections. It also drives the most job creation of any of the stand-alone policies. Directing RGGI proceeds to bill assistance for residential households[10] results in the lowest residential bills of any policy but somewhat higher commercial and industrial rates (see Table ES.10) and lackluster jobs and GSP impacts. Targeting families earning up to the federal poverty level for bill assistance shifted the distribution of savings across residential bills but had no effect on the macroeconomic effect.

By the late 2020s, a **CES**, alone or combined with other policies, is increasing in compliance costs but also driving more clean energy job growth. The CES becomes relatively more expensive than other policies for ratepayers in the 2030s, but the higher percentage of fuel-free generation, coupled with electricity sales to other states, results in lower rates/bills for this policy starting in the 2040s than the other policies studied for rate and bills impacts.

A **CES combined with RGGI** leads to the largest cumulative increases in electric bills and rates. However, this upward rate pressure is moderated where RGGI proceeds are invested in EE. Moreover, this combination drives deep CO_2 reductions between now and 2050, resulting in a lower dollar-per-ton cost than a stand-alone CES (Table ES.4). This combination also creates the most jobs and positive economic activity across all studied policies—a cumulative 90,000 job-years, nearly twice that of a stand-alone RGGI program with EE investment.

10. If North Carolina were to freely allocate allowances, the Utilities Commission would likely require utilities to pass through the value of the allowances to customers. The residential “direct bill assistance” scenarios described here would be the most analogous to that situation, although the Utilities Commission might require the savings to flow to all customer classes. Similarly, if North Carolina were to require utilities to consign allowances to an auction, proceeds would also likely be required to pass through in the form of customer savings.

Conclusion

North Carolina has options for meeting the CO_2 reduction targets in the CEP. Given the rapid shifts occurring on the grid and the convergence of cost between types of electricity generation, even modest policies could drive large changes in the North Carolina power sector, with positive emissions and economic impacts.

The policy pathways described in this report could influence the state's installed capacity or the electricity generation mix that serves North Carolinians. They might also affect the cost of electricity, levels of air pollution, and the jobs and economic outlook for the state in different ways. This report does not recommend a single path forward but offers options for action and a number of ways to compare policies and policy combinations, to inform the design of effective, affordable, and equitable emissions reduction policies for this sector.

SECTION 2. BACKGROUND

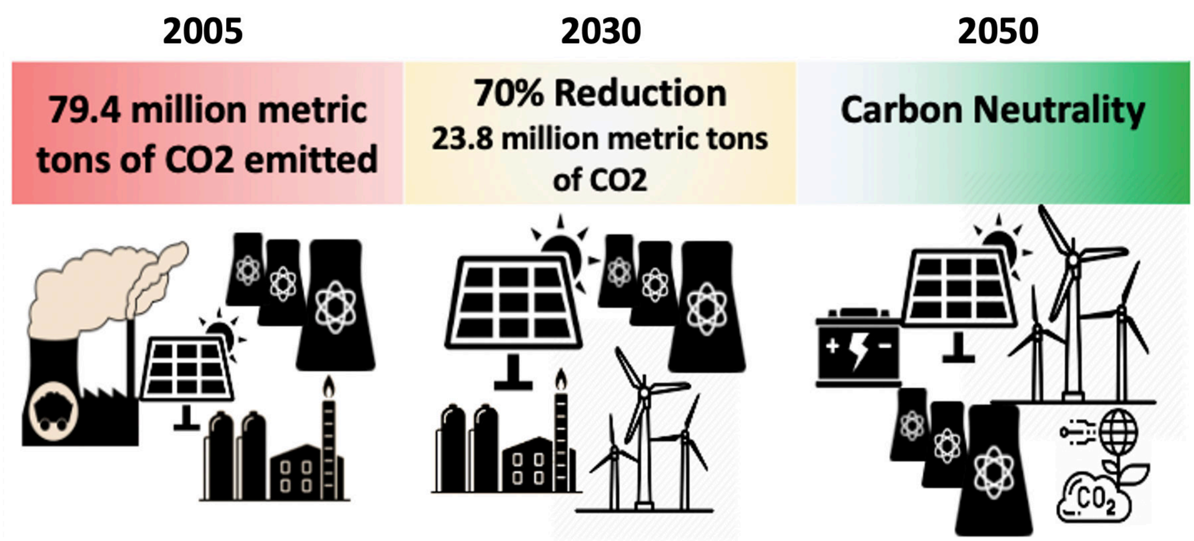
In October 2018, following Hurricanes Florence and Michael, Governor Roy Cooper issued Executive Order 80 (EO80) to "combat[ ] climate change while creating good jobs and a healthy environment." Through EO80, the governor set an economy-wide greenhouse gas (GHG) reduction goal of 40% below 2005 levels by 2025 and directed the NC Department of Environmental Quality (DEQ) to draft a Clean Energy Plan to implement this target.

DEQ released the North Carolina Clean Energy Plan (CEP) in October 2019. The document establishes three broad goals:[11]

- Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050 (see Fig. 2.1).
- Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes.
- Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

Figure 2.1 demonstrates the CO_2 reduction goals expressed in the Clean Energy Plan.[12]

Figure 2.1. Clean Energy Plan Electric Power Sector Emission Goals



11. North Carolina Clean Energy Plan (Oct. 2019), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf, at 12. The CEP set farther-reaching targets for the electric sector than EO80 had set for the economy, recognizing that (1) technologies exist to reduce emissions in the power sector today, and (2) over the longer term, a cleaner grid could electrify other sectors of the economy (i.e., transportation; building heating) and reduce emissions overall.
12. While the CEP uses the term "greenhouse gas," DEQ used carbon dioxide emissions (CO_2) reported in the state greenhouse gas inventory to define the 2005 emissions baseline for North Carolina electricity generation. Similarly, this report focuses on CO_2 emissions, as the primary greenhouse gas emitted by power plants. However, some stakeholders argued that North Carolina should consider upstream emissions from fuels used to generate electricity, including in particular the methane emissions associated with natural gas.

The CEP recommends 39 policy actions to achieve its emissions reductions, affordability, and economic opportunity goals. This report focuses on Recommendation A1, calling on DEQ to:

> enlist assistance from academic institutions to deliver a report to the Governor … that recommends carbon-reduction policies and the specific design of such policies that best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability.[13]

Recommendation A1 identified four broad policy pathways as a starting point:

(5) Accelerated coal retirements;

(6) Market-based policies that put downward pressure on CO_2 emissions from the power sector;

(7) Clean energy policies; and

(8) A combination of these policies[14]

In November 2019, DEQ and the Governor's Office asked the Duke Nicholas Institute and the UNC CE3 to lead this report. These institutions then launched a stakeholder process to inform the project.

The report authors and stakeholders decided that the final report would analyze the policies identified in A1 and offer bases of comparison without recommending a single path forward. Therefore, the stakeholder engagement did not seek to reach consensus. Instead, the report authors and stakeholders engaged in meaningful discussions for a year to refine, critique, and evaluate policy options. Participants were encouraged to discuss issues and express diverging viewpoints, which the report notes for key areas. The report's authors are indebted to the hard work of everyone who participated in these discussions, particularly those who contributed their time and expertise in the Policy and Technical Working Groups described in Section 3. Working Group members and other stakeholders are identified in **Appendix A**. ***Participation in a working group does not reflect endorsement of this report or of the CEP.***

The carbon reduction policy discussions did not occur in a vacuum, but were informed by:

- other CEP analyses and processes including most notably, the utility business model stakeholder process set into motion by Recommendation B-1 (known as the North Carolina Energy Regulatory Process, or "NERP");
- Integrated Resource Plan ("IRP") filings by Duke Energy Progress/Duke Energy Carolinas (DEP/DEC);
- Dominion Energy's net zero GHG emissions by 2050 goal, and Virginia's enactment of the Clean Economy Act;

13. Clean Energy Plan, *supra* n. 1, at 60, Table A-1.
14. Id., at 59.

- Duke Energy Corporation's climate goals, and the decarbonization study it commissioned from the National Renewable Energy Laboratory (NREL);[15]
- NC Electric Cooperative climate goals, which track Duke's goals (50% from 2005 levels by 2030 and net zero by 2050); and
- a regional proposal to increase the number of bilateral wholesale sales of electricity between utilities, perhaps paving the way to greater regional coordination and perhaps someday, centralized dispatch of electricity.

This report does not seek to cover these related subjects comprehensively. However, the report notes where other conversations informed our analysis or might have an impact on the implementation of one or more power sector carbon reduction policies.

15. NREL, "Carbon-Free Resource Integration Study," https://www.nrel.gov/grid/carbon-free-integration-study.html.

SECTION 3. A1 PROCESS

In December 2019, the Duke Nicholas Institute and UNC CE3 convened a stakeholder group, comprised of participants in the CEP stakeholder process and additional invitees to ensure representation of key state constituencies. The stakeholder group included utilities (IOUs, municipal utilities, and rural electric cooperatives); industrial utility consumers; low-income advocates; state agency and commission staff; North Carolina cities and towns; environmental justice representatives; environmental groups; the business community; agriculture; and clean energy companies. Through four stakeholder meetings held in person and virtually over the course of a year, the report's authors briefed, fielded questions, and solicited comments from this group of about 90 individuals to inform the analysis reflected in this report.

The Duke Nicholas Institute and UNC CE3 formed two working groups—one focused on policy, the other more technical in nature—from a subset of the larger stakeholder group. The Policy Working Group met at least monthly in 2020 to engage in detailed policy conversations, starting from the list of policy pathways in the CEP (accelerated coal retirements, market-based carbon reduction policies, clean energy policies, and a combination of these policies). Working Group members broke into teams to analyze each policy pathway, following templates to understand the mechanics of each approach, identify implementation steps,[16] describe policy design options, and study similar strategies already used in North Carolina (i.e., the Clean Smokestacks Act, NC REPS) and other states. These "homework teams" then reported back to the larger Policy Working Group for further discussion.

The Policy Working Group also discussed core values for the process and metrics for evaluating policies against one another. The report's authors had further conversations with an affordability working group and additional representatives of environmental justice communities, to provide more input on the core values of affordability and equity. The results of those discussions are summarized in Section 4.

Meanwhile, the Technical Working Group provided input on modeling analysis using two power sector capacity planning and dispatch models. These models can be run to project changes in electricity generation and capacity over time, by selecting the least-cost resources based on current assumptions (in a "business as usual" baseline case) and under different policy scenarios. The Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at the Duke Nicholas Institute, was used to screen policy scenarios and test the sensitivity of results to variables like fuel costs and electricity demand. Project consultants at ICF then modeled a subset of the DIEM policy scenarios with their Integrated Planning Model (IPM). The report's authors chose ICF to corroborate DIEM findings because the U.S. Environmental Protection Agency (EPA), North Carolina agencies, electric utilities, and environmental groups are familiar with IPM and often rely on it for their own policy analysis.[17] Both models report CO_2 and other air pollution reductions; the wholesale cost of electricity; and the power sector capacity and

16. The report does not provide detailed legal analysis although it does sometimes note where a policy may need legislative authorization.
17. In addition, the Regional Greenhouse Gas Initiative (RGGI), a regional carbon market relevant for the carbon market pathway explored in this report, has used IPM in support of analysis for its regular Program Reviews.

generation mix resulting from each policy scenario relative to the reference case. These results are not meant to be taken for their absolute values but as directional signals. The report notes where DIEM and IPM runs point to similar trends, and where results diverge.

Some of the modeled policies were further analyzed to illustrate the trade-offs policy makers might face in policy design. ICF was asked to assess the retail rate and bill impacts of specific policies, and to evaluate policies for their macroeconomic effects, changes in household expendable income, and state domestic product.

Finally, the Duke Nicholas Institute and UNC CE3 researchers held two public forums in September to inform a broader audience of the work underway.

SECTION 4. CORE VALUES

The Clean Energy Plan listed "core values" that stakeholders identified as important metrics by which pathways for power sector decarbonization can be compared. The Policy Working Group discussed many of these values, which are summarized in Table 4.1.

Table 4.1. Evaluating Carbon Reduction Pathways

Values for Analyzing Carbon Policies	Method for Evaluation
GHG reductions Non-GHG air pollution reductions Wholesale prices Expanded clean energy resources in NC Shifts in generation Some aspects of grid reliability	Outputs of modeling analysis (Section 6)
Retail prices Bill impacts Jobs	Outputs of economic analysis (Section 7)
Compliance flexibility Some aspects of grid reliability	Addressed in the policy design discussions for each policy pathway (Section 5)
Affordability Equity	Broader, less concrete concepts discussed by the Policy Working Group and with other impacted stakeholders, and then addressed in the policy design discussions for each policy pathway (discussed below and further on in the report)

Some of the values are readily available and quantifiable outputs of the analysis conducted for this report. For instance, the two power sector capacity planning and dispatch models used to support this report show levels of air pollution (CO_2 as well as health-based pollutants such as NOx and SO_2), electricity generation mix, and wholesale costs of policies as compared to a "business as usual" reference case. ICF also conducted retail rate and bill impact analyses of some of the policies, as well as their macroeconomic effects—for instance job creation, or changes in expendable income for households.

The Policy Working Group addressed some additional core values—such as compliance flexibility, cost containment, and equity—in the context of "policy design options." These are described in Section 5 for each policy pathway.

Grid reliability is more complex and dynamic concept to capture. That said, reliability is addressed in part by the capacity planning models, in that they constrain investment options based on the capacity of existing transmission lines or include the construction of new lines where necessary. Additional analysis would likely be necessary, with North Carolina's utilities, to study distribution system capacity. To further acknowledge possible reliability constraints, the policy pathways generally did not seek to reduce emissions entirely to zero by midcentury but provided a buffer of 5–10% of 2005 emissions, which could then be offset by reductions made elsewhere in the economy.[18]

The group discussed two of the core values, affordability and equity, at length in an attempt to define these values and articulate policy design options that could best achieve them. These discussions took place within the Policy Working Group and with other stakeholders, to daylight important issues and diversify the voices offering counsel to the process.

The rest of this section introduces the discussions around affordability and equity, and highlights the underlying concepts and questions associated with each. The purpose is to orient the reader and set up how these concepts can be used to compare outcomes described in Sections 6 and 7.

Affordability

The modeling results described in this report include information that is helpful in evaluating the financial impacts of a policy, such as wholesale electricity prices and retail rates. These results do not identify whether a policy option is affordable, however, as there is no uniform definition of affordability. Affordability depends on a ratepayer's circumstances.

Concerns about electricity affordability are not unique to climate policy. Electricity rates will increase over time as utilities manage aging infrastructure, invest in new infrastructure, and address inflation. Indeed, DEC and DEP recently requested a 6% and 12.3% rate increase, respectively.[19] Considerations about climate policy affordability should recognize these broader electricity sector trends, as well as the potential for clean energy and energy efficiency investments and avoided buildout of emitting infrastructure to mitigate factors that can drive future rate increases.

Moreover, there are mechanisms to address affordability concerns with each policy pathway. Securitization can reduce the financial impact of retiring undepreciated coal-fired power plants. Carbon markets can allocate allowances to utilities or use auction revenue to fund ratepayer assistance programs or help ratepayers reduce energy consumption. A CES can include a price cap, similar to the NC REPS program.[20] Examples of these mechanisms will be provided in Section 5 and are revisited in Sections 6 and 7 within the context of modeling cost results.

18. The A1 process did not identify the source of those offsets although as noted in Section 5, within the context of the declining cap/carbon market pathway the Policy Working Group expressed general for offsets investments in ecosystems and rural communities, drawing on the new state Climate Risk Assessment & Resiliency Plan.
19. Duke Energy, "Duke Energy Carolinas North Carolina Rate Case," https://www.duke-energy.com/home/billing/dec-nc-rate-case-2019. Rate increases for different customer classes would vary.
20. N.C. Gen Stat § 62-133.8(h)(3)&(4).

A subset of the Policy Working Group met during late summer and early fall to discuss options for comparing the affordability of specific decarbonization policy pathways. The group identified the following metrics:

(1) Near-term impacts on wholesale electricity costs, electricity rates, or customer bills, including:

  (a) Projected near-term impacts of clean energy policies compared to business as usual in 2030

  (b) The potential for immediate bill impacts versus impacts that could occur over time

  (c) Projected near-term impacts on different rate classes

  (d) Options for mitigating price shocks

  (e) Projected NC rate/bill impacts compared with those in other Southeastern states

(2) Longer-term impacts on wholesale electricity prices, electricity rates, or customer bills, including:

  (a) Projected impacts of clean energy policies in 2035 compared to reference cases

  (b) Projected impacts of clean energy policies in 2050 compared to reference cases

(3) Comparisons of the costs of the different clean energy policy scenarios

(4) The potential to mitigate risks that may cause future price increases (for example, fuel price risk, regulatory risk, technology risk)

In addition to identifying specific metrics for evaluating the affordability of specific decarbonization policies, the group also discussed the following cross-cutting considerations for any measures that may affect energy prices:

- **Impacts on electricity rates versus electricity bills**. There may be opportunities for customers to improve energy efficiency and lower demand. In that case, a ratepayer's monthly electricity bills may remain stable or decrease even if electricity *rates* increase.
- **Impacts on different types of ratepayers**. Electricity rate increases have different impacts for different types of ratepayers. Residential customers bear the full impact of a rate increase, while some commercial and industrial ratepayers may be able to pass along increased energy costs to their customers. For other commercial and industrial ratepayers, increased energy costs may undercut their ability to compete with businesses located in other states with lower electricity rates. Those commercial and industrial ratepayers, therefore, may focus more on their respective utility's rates compared to other Southeastern states rather than affordability.

- **Impacts on energy-burdened customers**. For some North Carolina ratepayers, electricity rates are currently unaffordable, and the number of energy-burdened customers has increased significantly due to the COVID-19 pandemic.[21]

Equity

The modeling results in this report can help to evaluate changes in air quality as the result of a policy, as well as a policy's impact on the electricity generation mix. However, these results do not tell a full story about how a policy's benefits and burdens are distributed across North Carolina households, communities, and businesses. Nor do they reflect how engaged these impacted groups were in shaping the policy in the first place.

The CEP makes six recommendations to address equity and environmental justice in the context of carbon and clean energy policy:

(1) Include non-energy equity-focused costs and benefits in decisions regarding resource needs, program design, cost-benefit analyses, and facility siting (CEP § I-1).

(2) Example the feasibility and proper design of a low-income rate class (CEP § I-2).

(3) Expand energy efficiency and clean energy programs specifically targeted to underserved markets and low-income communities (CEP § I-3).

(4) Ensure inclusion and meaningful involvement of historically marginalized communities, for instance in decision making around siting electricity generation assets (CEP § J-1).

(5) Launch an energy efficiency apprenticeship program within Apprenticeship NC (CEP § J-2).

(6) Create long term jobs with family sustaining wages and benefits in renewables and grid infrastructure industries for low-income communities and workers displaced by the transition to a clean energy economy (CEP § J-3).[22]

Additional recommendations in other sections of the CEP—development of a green bank, expansion of community solar projects, a call to use electrification (of transportation, buildings, industrial, and agricultural operations) to reduce energy burden—also support the principle of equity.[23] Each of these recommendations present meaningful ways for North Carolina to tackle power sector CO_2 emissions while addressing other disparities in health outcomes, economic opportunity, and access to clean energy.

The Policy Working Group met with individuals who work on environmental justice issues in North Carolina in late summer and early fall to discuss equity issues and identify options for

21. North Carolina Utilities Commission, "Report on Mandatory COVID-19 State of Emergency Monthly Reporting for the Month Ended September 30, 2020" (Dec. 2. 2020), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9304a0a7-4ba9-4d17-8a93-7d36c439443c.
22. NC Clean Energy Plan, https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf, at 112-124.
23. Id., at 97–99, 139–140.

comparing specific policy pathways along equity lines. A recurring theme in these discussions was that equity requires attention to the process as well as substantive policy design, ensuring that affected communities have a meaningful opportunity to participate. (Recommendation J-1 in the CEP also recognizes the need for an inclusive process.) Conversations centered around the need to build trust and engage impacted communities early in a policy process. In addition, principles of engagement with environmental justice communities were shared and could be used to guide stakeholder outreach during the policy making process.[24]

Stakeholders emphasized that equity considerations focus on:

- reducing the harms of energy production and transportation in overburdened communities, and
- ensuring that these communities will take part in the environmental and economic benefits of climate and clean energy policies.

In a similar way, policies can be designed to mitigate the economic impact of a fossil plant closure on a community reliant on that plant for employment and economic development, while ensuring that new clean energy investment and workforce development opportunities are made in those same communities.

One of the ten Principles of Climate Justice, published by the Environmental Justice Leadership Forum on Climate Change, is to ensure that carbon reduction strategies "do not further exacerbate existing health disparities among communities."

> This includes crafting strategies that prevent the creation of pollution hotspots, eliminate existing emissions hotspots in vulnerable communities, and reduce the emissions of greenhouse gas co-pollutants in and near communities-of-color, Indigenous, and low-income communities.[25]

Environmental justice groups and allies have raised concerns that some power sector carbon policies can sustain or even exacerbate pollution hotspots, because they enable source owners to decide where to make pollution reductions based on cost and not location. While these concerns have arisen most often in the context of discussions about a carbon market program, hotspots are important to consider for any of the policies described in this report. A policy that encourages the retirement of coal-fired power plants still leaves it to the generation owner to decide where to retire assets. A carbon adder on new capacity or generation could still enable the operation of coal and natural gas plants, or the construction of natural gas plants in North Carolina. Similarly, while a sales-based CES may direct the building of new clean power, it does not require a reduction in pollution at fossil-burning power plants. Therefore, an equitable path forward would consider the potential for hotspots and methods for reducing this possibility across all power sector carbon policies.

Through conversations in the Policy Working Group and with other stakeholders who work on environmental justice issues, the following considerations emerged:

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24. People of Color Environmental Justice, "Principles of Working Together" (October 27, 1991), https://www.ejnet.org/ej/workingtogether.pdf.
25. Environmental Justice Leadership Forum on Climate Change, "Principles of Climate Justice," https://www.ejnet.org/ej/ejlf.pdf, Principle 3.

(1) Geographic distribution of emitting and clean energy infrastructure, in Tier 1 counties and in environmental justice communities (identified through the EPA EJSCREEN tool), as compared to the state as a whole

(2) EJ reviews and community participation opportunities when issuing new permits for emitting power plants

(3) Timing of plant closures relative to conversations with communities that will be impacted by those closures, to determine local needs and incorporate policies and funding streams into retirement plans to meet those needs

(4) Local hiring requirements and workforce development training and opportunities for Tier 1 counties and census tracts with high levels of unemployment

(5) Investment of funds, particularly those generated by a power sector carbon policy, to attract clean energy development and improve health outcomes in overburdened communities and Tier 1 counties

(6) Over the long-term, a commitment to monitor the implementation of any power sector carbon policy to ensure that the policies do not create or exacerbate pollution hotspots in North Carolina

(7) Comparisons of the equity implications of the different clean energy policy scenarios, including whether a policy might enable additional buildout of emitting energy infrastructure in overburdened communities; and

Once these implications are made apparent, a climate policy may be designed in a more equitable way. For instance, a policy that encourages the shutdown of a coal plant might be designed to invest in economic development for the communities impacted by job loss (see **Appendix C** for a description of these types of investments). Moreover, with community input, the state could broker a wind-down agreement with the plant's operators to tighten air pollution controls or ensure that plant decommissioning address a legacy pollution issue that could affect nearby residents. A CES policy could provide "bonus" credit for projects sited in communities facing higher unemployment rates or health challenges from polluting industries nearby. A carbon market could generate revenues for substantial reinvestment in overburdened communities.

It may be necessary to implement companion policies in order to make any policy truly equitable in its application. A number of the CEP recommendations, including creation of a green bank and expansion of community solar programs, might be considered as complementary policies that decision makers could be implemented alongside any of the power sector carbon policies described in this report.

SECTION 5. POLICY ANALYSIS

This section introduces four possible policy pathways for achieving the CEP's electric power sector emissions reduction targets. Table 5.1 summarizes the pathways and compares them to the pathways identified in the CEP. In addition to detailing scenarios for the accelerated coal retirements, the Policy Working Group selected two types of market-based policies for further investigation: a carbon "adder" or shadow price on new proposed fossil capacity or emitting generation, when determining what is least cost to build or run; and a declining CO_2 emissions budget for North Carolina power plants, similar to the caps in the Clean Smokestacks Act, but in this case linked to an 11-state carbon market. The Policy Working Group also discussed different clean energy standard designs, including carveouts for offshore wind and allowing EE to count towards the requirement.

Table 5.1. Clean Energy Plan Policies and Pathways Analyzed in This Report

	CEP Policy Pathways	Pathways Analyzed in this Report
(1)	Accelerated coal retirements	Accelerated coal retirements
(2)	Market-based policies	Carbon adders; carbon market
(3)	Clean energy policies	Clean energy standard (with/without an offshore wind carveout); energy efficiency resource standard

As detailed in Section 6, the North Carolina electric power sector appears highly responsive to even relatively modest policy changes (or other changes in fuel prices and demand). Each policy pathway, however, could influence the electric power system differently. The following three points of comparison offer ways to think about the policy pathways and specific policy design options described below.

Policy focus: Targeting generation types versus CO_2 emissions. While all policy pathways analyzed in this report can reduce power sector CO_2 emissions, they do not all do so directly. Instead, two of the policy pathways—accelerated coal retirements and clean energy policies—focus on the type of electricity generation that operates in North Carolina or serves North Carolina load.

A coal retirement policy mandates or encourages retirement of the most carbon intensive electric generating units operating today. A clean energy standard (CES) seeks to encourage the buildout of clean energy resources, defined broadly or specified by type (i.e., an offshore wind carveout). Indirectly, coal retirements and new clean energy generation should reduce CO_2 emissions, but, total reductions will depend on what generation resources replace the retired coal capacity, or how "clean" energy is defined and whether it must be built in North Carolina.

In contrast, the market-based carbon policies studied in this report directly target CO_2 emissions. They may do so on a unit-by-unit basis, for instance by imposing a carbon adder on new fossil capacity or fossil generation that reflects each unit's CO_2 output, or by imposing an emissions cap across the generation fleet that grows more stringent over time. Both carbon pricing approaches may influence how a utility operates its system and what new capacity it builds but are more technology-neutral than generation-focused policies.

Measuring compliance: In-state power production versus in-state electricity consumption. The CEP decarbonization targets, presented in Figure 2.1, include emissions from in-state electricity generation as well as generation that is imported to meet North Carolina electricity demand. Therefore, it is important to consider the ways different policies could influence in-state *and* imported power.

Some policies focus on the emissions of in-state power generation, such as accelerated coal retirements or carbon adders on new fossil capacity or generation in North Carolina. Clean Energy Standards, on the other hand, have generally been implemented as a percentage of a state's retail sales and so are considered "consumption-based" policies.[26] (See **Appendix C** for examples of other state policies; see **Appendix F** for analysis of an alternative generation-based CES for North Carolina.) This distinction is important for two reasons. First, consumption-based policies are directly imposed on the electricity serving North Carolina even when that power originates in other states.[27] Therefore, utilities are less likely to increase reliance on out-of-state power as part of their compliance strategy, as they might if a policy only targets in-state power production or emissions. (As described in Section 6 and **Appendix F**, border adjustments can be added to generation-based policies, to impose similar obligations on out-of-state suppliers and reduce emissions "leakage.") Second, consumption-based policies could enable utilities to retain in-state fossil assets for export markets, which could soften in-state emissions reductions.

Policy design choices can influence these emissions and cost outcomes. For instance, the CES policies modeled for this report required all clean generation to be located in North Carolina. Under an alternative design and consistent with the NC REPS, utilities could meet a CES by importing clean generation from Virginia and South Carolina,[28] or buying clean energy credits from other more cost-effective locations. This could enhance compliance flexibility and reduce costs but would also shift clean generation out of state. Moreover, a "build it in North Carolina" CES policy ensures that North Carolina benefits from the air quality improvements and economic development that flow from the buildout of clean energy. Meanwhile, by combining a CES with a generation-based policy such as RGGI or coal retirements, policy makers can limit the amount of fossil that remains online in North Carolina in the coming decades.

By combining generation-based and consumption-based policies, a state may be able to build on the strengths of both approaches.

26. This report also explores CES designs that are based on the carbon intensity of in-state generation.
27. While North Carolina cannot dictate policies in other states, state policies can regulate an in-state company's electricity imports.
28. North Carolina's three investor-owned utilities—DEC, DEP, and Dominion—operate service territories across state borders. More discussion of the implications of this arrangement may be found in **Appendix E**.

Time scale: Short-term versus long-term impacts. The policies analyzed in this report would have different impacts on the power sector over time. Some might achieve significant emissions reductions in the short term, but then fail to achieve the net zero midcentury target. For instance, an accelerated coal retirements policy may help achieve the Clean Energy Plan's 2030 emissions target, but it does not limit the CO_2 emissions of the capacity that replaces the retiring coal units. Over time, then, the impact of an accelerated coal retirement policy may wane. However, pairing a coal retirements policy with one that drives construction of clean generation may achieve the near-term target while guiding the electricity sector toward a net zero future.

The remainder of Section 5 provides an overview of each policy pathway, including a discussion of North Carolina today; a description of the policies modeled for this report and similar policies to consider; and policy design options to address distributional impacts/equity, compliance flexibility/cost containment, and revenue generation.[29] The discussion of the modeling results in Section 6 provides directional information about the emissions, generation mix, and costs associated with these pathways.

Accelerated Coal Retirement Pathway

More than 100 gigawatts of coal-fired electric generation capacity have retired since 2010 in the United States. Several coal-fired units in North Carolina are slated for retirements in the 2020s based on economics alone. An accelerated coal retirements policy could mandate or encourage additional coal capacity to retire. Some states have implemented policies to facilitate or require coal retirement, and some of these states employ mechanisms that lower overall costs to ratepayers while generating revenue to support the communities that rely on coal plants for employment and economic activity. For example, Virginia's Clean Economy Act mandates most coal-fired units in that state to retire by 2024. Washington State requires state utilities to eliminate coal-fired power production and purchases by 2025. In addition, a growing number of states—including Colorado, Michigan, Montana, and New Mexico—have authorized securitization to facilitate coal retirement.

Types of Steam Generating Units

Supercritical steam generating units operate at higher pressures and therefore more efficiently than *subcritical units*, resulting in lower emissions for the same amount of electricity generation. North Carolina's subcritical units are generally older and smaller than the supercritical units.

29. These three topics address the qualitative core values of equity and affordability discussed in Section 4.

North Carolina Today

Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) own the remaining coal capacity in North Carolina. DEC operates 13 coal units at the Allen, Belews Creek, Cliffside/Rogers, and Marshall Steam Stations; DEP operates 5 coal units at the Mayo and Roxboro Plants.

Table 5.2. Currently Operating Coal-Fired Electric Generating Units in North Carolina

Subcritical Units		Supercritical Units	
Roxboro Unit 1	*369 MW*	Marshall Unit 3	658 MW
Roxboro Unit 2	*662 MW*	Marshall Unit 4	658 MW
Roxboro Unit 3	693 MW	Belews Creek Unit 1	1,110 MW
Roxboro Unit 4	698 MW	Belews Creek Unit 2	1,110 MW
Mayo Unit 1	727 MW	Rogers Unit 6	825 MW
Allen Unit 1	*162 MW*		
Allen Unit 2	162 MW		
Allen Unit 3	261 MW		
Allen Unit 4	276 MW		
Allen Unit 5	266 MW		
Rogers Unit 5	562 MW		
Marshall Unit 1	380 MW		
Marshall Unit 2	380 MW		

Note. Units in italics: assumed retirements in the 2020s.

Like many utilities across the country, DEC and DEP plan to retire a fair amount of their remaining coal-fired capacity over the next decade. According to a 2019 update to its Integrated Resource Plan (IRP), DEC anticipated retiring Allen units 1–3 by December 2024, and Allen units 4 and 5 by December 2028.[30] DEP's update to its 2019 IRP projected retiring Roxboro units 1 and 2 by 2028.[31] These retirements, which modeling for this report assumed in the "business as usual" reference cases, represent about 20% of North Carolina's remaining coal capacity.

The utilities may retire additional coal units by 2030 if the economic outlook for these units worsens. Indeed, the DEC and DEP 2020 IRPs identify two more retirements in the 2020s among the "most economical retirement dates" for existing units (Rogers 5 by December 2025 and Mayo 1 by December 2028). Similarly, the energy modeling for this report suggest that additional units may be uneconomic to operate by 2025. That modeling did not contemplate tighter federal emissions standards that could require pollution control upgrades at fossil plants.

30. Duke Energy Carolinas IRP 2019 Update Report, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de, at 88. The dates are expected retirement dates for planning purposes.
31. Duke Energy Progress IRP 2019 Update Report, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7f4b3176-95d8-425d-a36b-390e1e57a175, at 61.

Meanwhile, to increase operational flexibility and take advantage of low natural gas prices, DEC and DEP have retrofitted the following coal units to co-fire with natural gas (NG):

- Rogers 5 – 2018 (10%–40% NG)
- Rogers 6 – 2018 (100% NG)
- Belews Unit 1 – Jan 2020 (50% NG)
- Belews Unit 2 – Jan 2021 (50% NG)
- Marshall 1 & 2 – Dec 2021 (10%–40% NG)
- Marshall 3 & 4 – Dec 2020 (50% NG)

The utilities plan to use economic dispatch to shift between natural gas and coal. The units could blend in natural gas up to the percentage listed above; they could also revert to coal entirely should natural gas prices rise. DEC and DEP do not currently have plans to enable co-firing with natural gas at their remaining coal stations.

Description of Modeled Policy Scenarios

Based on Policy Working Group recommendations, the Duke Nicholas Institute modeled the following three coal retirement scenarios:

(1) **Retire all subcritical units by 2030**

(2) **Retire all subcritical units by 2030 and operate supercritical units seasonally** (i.e., to help meet winter peak events)

(3) **Retire all coal by 2030**

Scenario 2 retires all subcritical coal units by 2030 while keeping the more efficient super-critical units online for "seasonal operation." The modelers defined seasonal operation as operating for no more than approximately 10% of the hours in a year—about 20% in summer and winter months and up to 85% for short peaking periods. This allows the coal units to operate for shorter periods of time when electricity demand spikes.

Some members of the Policy Working Group discussed limiting supercritical during periods of low demand and excess system reserves rather than focusing on seasons where they might be needed to meet excess demand. The groups did not reach consensus about this alternative and so modeling focused on seasonal operation.

The Policy Working Group noted that the feasibility of any scenario, particularly Scenario 3, (retiring all coal by 2030), would depend upon DEP and DEC being able to build replacement generation or transmission by 2030, to address any reliability concerns that might arise.

Other Possible Scenarios

The modeled coal retirement policy scenarios do not reflect a particular policy mechanism. Instead, they are intended to demonstrate the reductions in CO_2 and other air quality benefits, as well as the possible costs, associated with early coal retirements. That said, the Policy Working

Group did summarily discuss policies targeting coal, as opposed to policies described in this report that might indirectly induce these retirements.

A rate-regulated, vertically integrated utility generally recovers costs associated with capital investments, including the cost of servicing debt and a reasonable rate-of-return for its investors. Early retirement may cause ratepayers to continue paying for a power plant that is no longer in operation or cause the utility to forego the undepreciated costs and prevent investors from earning their anticipated returns. Accelerated depreciation and securitization can address financial disincentives to early retirement. These mechanisms were discussed in detail during the NERP process[32] and are summarized here:

Accelerate or adjust the depreciation of coal assets. Accelerated depreciation shortens the time frame that the utility would have recovered costs on an asset, thereby frontloading costs to ratepayers and allowing the utility to recover its full anticipated rate of return on the asset despite its shortened functioning life. Accelerated depreciation does not require special action from the legislature—the North Carolina Utilities Commission (NCUC) can approve accelerated depreciation under its existing statutory authority.

Because accelerated depreciation shortens the cost recovery schedule for a facility, rates will increase during the shortened depreciation period. However, a utilities commission may want to approve a request for accelerated depreciation to move increasingly uneconomic coal units off the books and to induce the buildout of new, cleaner generation.

Convert coal assets into marketable securities. Securitization allows a utility to issue bonds to refinance a large expense, such as the undepreciated value of existing coal-fired power plants. Bondholders are compensated through a surcharge on customer bills. States have used securitization to pay for storm recovery,[33] nuclear power plant retirements,[34] and more recently, coal-fired power plant retirements.[35] Securitization can also allow a utility to reinvest in cleaner, more efficient resources. These bonds can result in ratepayer savings since lenders are willing to take a significantly lower rate of return than if utilities finance the costs themselves.[36]

Securitization typically requires legislative action to authorize a public utilities commission to offer securitization as a financing mechanism. Securitized bonds are backed by ratepayers and not the utility itself. Legislation authorizing securitization assures the lender that the bonds cannot be bypassed and that future legislatures will not disregard the financing arrangement.

32. See 2020 N.C. Energy Regulatory Process, Securitization for Generation Asset Retirement: Study Group Work Products (Dec. 2020), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/Securitization-Products-Final.pdf.
33. NC Gen. Stat. 62–172; La. Stat. § 45:1228.
34. Fla. Pub. Serv. Commission, PSC Approves Crystal River 3 Nuclear Plant Financing (Nov. 17, 2015).
35. See, e.g., S.B. 19-236, 2019 Reg. Sess. (Co. 2019), https://leg.colorado.gov/bills/sb19-236.
36. For example, Florida policy makers allowed Duke Energy to securitize its Florida Crystal River Nuclear Plant in 2016. According to the Florida Public Services Commission (PSC), securitization resulted in monthly surcharge of a $2.93 for a customer with a monthly 1,000 kWh, as compared to an increase of $4.96 per month using the traditional rate base recovery method. Securitization is expected to produce customer savings of $708 Million. Fla. Pub. Serv. Commission, PSC Approves Crystal River 3 Nuclear Plant Financing (Nov. 17, 2015).

Colorado, New Mexico, Montana, and Michigan have recently authorized securitized bonds to finance early retirement of coal-fired power plants and offer models for North Carolina policy makers to consider. **Appendix C** provides more detail on those state programs.

Policy Design Options

- **Flexibility/Cost containment strategies:** Securitization is a cost containment strategy for financing the remaining, undepreciated assets on a coal plant.[37] Accelerated depreciation increases near-term costs for ratepayers but reduces total costs by shrinking the utility's overall rate of return (in the same way paying a mortgage early achieves savings on interest for the homeowner). A utilities commission can take further steps to protect ratepayers in the short term, for instance by decreasing the allowed rate-of-return for the asset (known as adjusted depreciation). One thing to note, however, is that utilities may be constrained by the amount of total debt they can take on across their enterprise.

- **Distributional effects/Equity policy components:** Different communities in North Carolina could be affected in positively or negatively by the three coal retirement scenarios. Communities representing a large share of the coal plant workforce could face losses in jobs, tax revenues, and economic activity. Communities near the retiring units and further downwind of their air pollution could benefit from improved air quality. Discussions with these impacted communities could drive additional considerations for the selection and timing of coal plants to retire.

- **Revenue-raising potential/Key investments:** The General Assembly could authorize the financing of transition programs for coal communities, including workforce training to assist with plant decommissioning. Companion legislation could offer bonus credit under NC REPS or a new CES to site clean energy projects at or near former coal stations or in communities disproportionately impacted by the pollution generated from those plants.

Carbon Adder Pathway

A carbon adder could be used to reflect the costs of CO_2 pollution in the cost of generating electricity. Unlike a carbon tax, the emitter does not actually pay anything.[38] Instead, the adder is a planning tool. Under this policy pathway, the North Carolina Utilities Commission (NCUC) could require investor-owned utilities to incorporate an escalating carbon adder to the cost of building any power plant that emits CO_2 (coal, natural gas, biogas, or biomass). The NCUC could then determine what is least cost to build in North Carolina using these higher cost numbers for fossil generators. In addition, the North Carolina legislature could require application of these adders on fossil generation, which could shift the dispatch order of electricity generators in the state. While this policy mechanism might increase the cost of electricity in the near term, a

37. Rocky Mountain Institute modeled the financial impacts of securitizing some DEP units to inform the NERP Securitization Study Group. NERP Analysis Summary, Generation Asset Financial Analysis (Dec. 2020), available at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/Securitization-Products-Final.pdf. The RMI analysis "finds that securitization (with reinvestment) leads to greater ratepayer savings (in the short and long term) than using regulatory asset treatment as a method for early retirement. Furthermore, securitization with reinvestment provides the utility opportunity for earnings through additions to rate base and could fund transition assistance for impacted communities." *Id*.
38. The carbon adder modeling results provide insights into the effect of a carbon tax, as well. However, the Policy Working Group did not think a carbon tax was a likely policy option for the state at this time.

carbon adder could drive overall savings if it prevented utilities from building assets that could face higher costs due to future federal or state climate policies.

Voluntary adders currently in use can influence utility planning. However, a regulatory adder could more forcefully change decisions around operating and building power plants.

North Carolina Today

Since 2015 DEC and DEP have incorporated a price on CO_2 pollution in the development of their biennial IRP. This "shadow carbon price" or carbon adder does not require the utilities to actually pay these costs or to select the lower emitting options. Duke Energy Corporation members of the Policy Working Group explained that the carbon price was developed internally to help the utilities value existing coal assets, nuclear license renewal, and future capacity builds in what is likely to be a carbon-constrained future.

In the DEC 2020 IRP, for instance, the carbon adder begins at $5/ton in 2025 and increases annually at a rate of $5/ton (base CO_2 case) or $7/ton (high CO_2 case) for the IRP's planning horizon (i.e., through 2035).[39] Dominion Energy also uses shadow carbon pricing to manage regulatory risk, for instance to reflect possible compliance costs associated with the federal Clean Power Plan in its 2016 IRP ($10/ton starting in 2022, increasing to $19/ton in 2035). In its 2020 IRP, Dominion Energy incorporated a compliance cost associated with Virginia's upcoming entry into the Regional Greenhouse Gas Initiative (RGGI), as well as a possible federal climate policy beginning in the late 2020s.[40] The investor-owned utilities have included these carbon prices on a voluntary basis. To date there are no regulatory requirements that they do so.

Description of Modeled Policy Scenarios

The Policy Working Group explored different values of carbon adders. One category of values seeks to estimate the damages associated with each additional ton of CO_2 pollution emitted in a given year—a social cost of carbon. These costs can be quite high at the outset, making them politically challenging to impose. For another category of values, carbon adders can be set to reduce CO_2 emissions to a desired level (a "target-consistent approach"). Policy makers or utilities commissioners can identify these prices by running a series of forward-looking analyses to predict the changes different adders have on utility behavior, or by working backwards from an emissions reduction goal. The Duke Nicholas Institute modeling explored all three approaches.

The Duke Nicholas Institute initially modeled 13 carbon adder scenarios:

(1) **Applying six sets of carbon adder values** (see Table 5.3) **to new capacity** decisions

(2) Applying those same six sets of values **to new capacity *and* electricity generation**

(3) Back casting from the CEP's 2030 and 2050 CO_2 reduction targets to generate **a "target-consistent" adder for generation** (i.e., the adder necessary to bring down North Carolina power sector CO_2 emissions to 22 MMT by 2030 and zero by 2050)

39. Duke Energy Carolinas 2020 Integrated Resource Plan, NCUC Docket E-100 Sub 165, page 153.

40. Dominion Energy 2020 IRP, Appendix 4O starting on pdf page 184 (CO_2 on page 200).

How to Value Carbon Adders

There are generally two ways to set or value carbon adders:

Social Cost of Carbon: The social cost of carbon (SCC) is a metric designed to monetize climate damages. A federal Interagency Working Group on the Social Cost of Carbon identified these costs in a Technical Support Document in February 2010 and the 2016 updated report, for use in cost-benefit analyses for federal agency rulemaking. This accounting reflects the social costs of not acting on climate change. California, Colorado, and Minnesota have imposed a social cost of carbon into their utility decision-making processes.

Target-Consistent Approach: This approach works backward from an emissions goal. Economic models of the cost of meeting that target are then used to identify a carbon adder or price. The United Kingdom has used this approach.

As presented in Section 6 and **Appendix F**, the Duke Nicholas Institute also modeled variations on these scenarios to project how outcomes might change if North Carolina were to impose a border adjustment on power imported from other states, or if the federal government were to impose a carbon tax. Ultimately, ICF modeled application of the RGGI lower bound carbon adder values to capacity planning and generation, beginning in 2023.

Table 5.3. Carbon Adder Values Modeled in DIEM[41]

Year	2016 SCC ($2007)	2017 SCC ($2011)	RGGI Lower	RGGI Upper	Duke IRP $5/ton + $5/yr	Duke IRP $5/ton + $7/yr
2021	42	3.5	6	13		
2025	46	4	7.86	17.04	5	5
2030	50	4	11.03	23.90	30	40
2035	55	4.5	15.47	33.52	55	75
2040	60	5.5	21.70	47.01	80	110
2045	64	5.5	30.43	65.94	105	145
2050	69	6	42.69	92.49	130	180

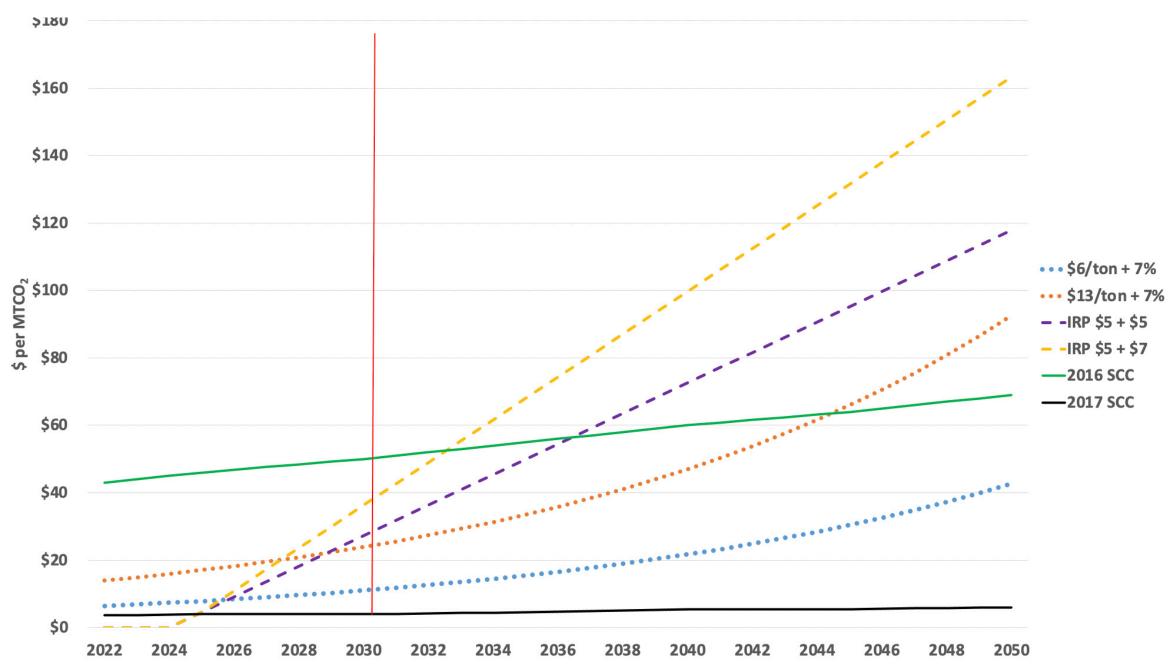
41. Table 5.3 presents the 2016 SCC in 2007 dollars, and the 2017 SCC in 2011 dollars, because these are the amounts most often used for these calculations. However, for modeling purposes, all values in the table were converted to $2019 dollars and metric tons.

Table 5.3 lists six sets of carbon adder values, based on the following sources:

- **2016 federal SCC — $42 in 2020 escalating to $69 in 2050**. The social cost of carbon developed by the Obama administration, updated in 2016, estimates the average global SCC in 2020 at $42 per metric ton with a 3% discount rate (p. 4).
- **2017 federal SCC — $3.50 in 2020 escalating to $6 in 2050.** The Trump EPA's revised cost-benefit analysis of the Clean Power Plan excluded global harms from the social cost of carbon and added a 7% discount rate. Numbers in Table 5.3 represent the midpoint between the 3% and the 7% average discount rates as found in the 2017 Regulatory Impact Analysis for the Review of the Clean Power Plan (Table 3.7, p. 44).
- **RGGI Upper and Lower Bounds — $6 and $13 in 2020.** To analyze prices that fell between the two federal SCCs and reflected more modest annual increases than the DEC/DEC IRPS, the Duke Nicholas Institute modeled carbon adder values that follow the upper and lower bounds of pricing in RGGI ($13 and $6 in 2020, increasing 7% each year thereafter). These bounds represent the points at which RGGI states release additional allowances or remove allowances from circulation, to keep rices from moving too high or falling too low.
- **DEC/DEP 2020 IRPs — $5 in 2025.** The IRPs present two carbon price paths. Both begin at $5/short ton in 2025; then the values increase by $5/short ton or $7/short ton each following year. While the IRP projection ended in 2035, modeling for this report continued to increase those prices along the same trajectories through 2050.

Figure 5.1 depicts the price trajectories for the six modeled carbon adder values.

Figure 5.1. Price Trajectories for Six Modeled Carbon Adder Values



As noted, the Duke Nicholas Institute modeled each carbon adder in two ways: imposed on capacity planning alone and imposed on capacity planning and electricity generation.

Carbon Adder for Planning

A carbon adder can help guide new capacity investments. Depending on the level of the carbon adder, it could incentivize earlier coal retirements, support nuclear relicensing decisions, induce or inhibit the construction of higher efficiency natural gas plants, and drive development of solar and wind resources, storage options, and additional demand-side management (DSM). They might be used to select among new capacity alternatives proposed by an investor-owned utility or incorporated in scoring for a competitive all-source procurement process.

However, if a carbon adder makes a particular resource appear less expensive to build than one that is more emissions intensive, that is not the final word even in a least-cost regulatory context. Utility planning includes other considerations as well, such as customer cost impacts, supply chain issues, interconnection lags, and impacts on system reliability. Modeling for this report provides some insights into customer cost impacts and system reliability (see Section 6).

Carbon Adder for Dispatch

Alternatively, a carbon adder may be built into the cost of producing a generator to produce electricity at any given moment in time. This may change which resources provide the next incremental unit of electricity demand. This may also change which fuel a generator chooses to burn at a particular power plant—a highly relevant point for units at Cliffside/Rogers, Belews Creek, and Marshall that can burn both coal and natural gas. In the short-term, so long as low natural gas prices persist and significant coal generation remains, the general impact of carbon pricing in system dispatch would be to incentivize the dispatch of more efficient and lower-emitting natural gas combustion turbine (CT) generation over coal. Longer term, as coal generation is retired, a carbon adder could have less impact on system dispatch, given that natural gas will be the only remaining carbon emitting resource. That fuel's persistence may at that point be more of a system reliability issue than any particular value of carbon adder.

Other Possible Scenarios

Consider other values. North Carolina might consider other carbon adder values, including the values modeled by the U.S. Energy Information Administration in early 2020. However, the values modeled for this report provide a reasonable range of options for the state to choose from.

Achieve similar results through a carbon pollution performance-based metric in rate making. Another way North Carolina might incorporate a carbon price into utility planning and generation decisions would be to design a CO_2 pollution performance-based metric. Such a metric, imposed or overseen by the NCUC, would reward investor-owned utilities for actions that reduced their CO_2 emissions below predetermined target levels. This policy mechanism was explored in the NERP process; details may be found in that report.

Policy Design Options

- **Flexibility/Cost containment strategies:** All of the modeled scenarios set a fixed acceleration schedule for the carbon adder values. However, the policy could establish a process to revisit the adder at set intervals and make necessary adjustments. For instance, a law could make clear that if an emission target is exceeded, the carbon adder must increase in ambition by 10% above preset levels in the following year. In addition, a carbon adder policy could include a consumer protection backstop, enabling a utility to dispatch or build emitting capacity when the carbon adder provides only a nominal advantage to the non-emitting option and the rate impact exceeds a *de minimis* threshold (both levels could be defined to avoid subjective application).

- **Distributional effects/Equity policy components:** A carbon adder does not require a utility to pay an actual price on carbon. However, depending on the amount of the adder, certain least-cost generators might not be selected in generation and/or dispatch decisions potentially resulting in higher rates or bills over the short term. One way to protect more vulnerable ratepayers would be to create a Percentage of Income Payment Program (PIPP), which caps the monthly electric utility payment of low-income participants at a specific percentage of a household income. In Virginia, for example, the PIPP would cap monthly electric utility payment of low-income participants at 6% (10% if household uses electric heat).[42]
- **Revenue raising potential/Key investments:** This policy pathway does not generate any additional revenues. However, policy makers might consider requiring utilities to contribute to a climate or clean air mitigation project whenever they have to deviate from a least-cost build decision under a carbon adder regime, for instance if a utility had to build a natural gas combustion turbine for reliability purposes.

Declining Carbon Cap/Carbon Market Pathway

Under the declining cap or carbon market approach, North Carolina would set an annual limit on the CO_2 emissions from all electricity generators in the state, a number that would decline over time. North Carolina DEQ would then distribute allowances to generators equal to the cap for a given compliance period. The state could freely allocate the allowances or sell allowances to utilities and use the proceeds for rate relief, investment in clean energy and energy efficiency, or other budgetary purposes.[43] Generators could transfer allowances between plants or buy and sell allowances between companies, so long as each generator held an allowance for every ton of CO_2 emitted by a plant by the end of the compliance period. This process would begin again for subsequent compliance periods, each time with a smaller cap and fewer allowances to distribute, driving down total emissions over time.

North Carolina Today

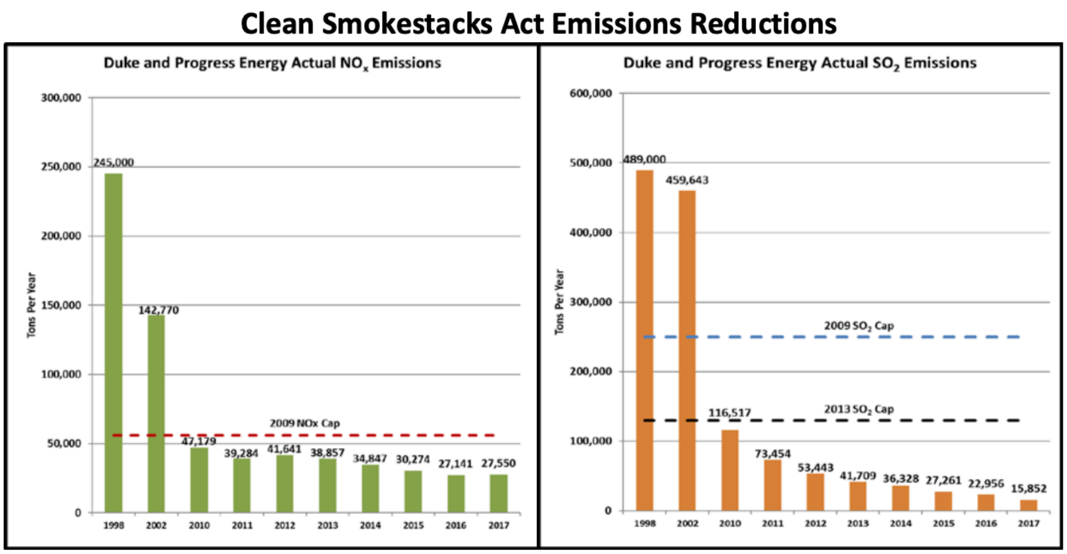
The United States has implemented a number of air pollution budget programs for the power sector. The first such program was the Acid Rain Program created by Congress in 1990 to cut power plant emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). The program balanced the need to make real, verifiable reductions of harmful air pollution with the flexibility for power plant owners to decide *where* to make the reductions. A declining budget with tradeable credits

42. Virginia General Assembly, House Bill No 1483, https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1483.
43. A third "consignment" approach is somewhat of a hybrid and is described in more detail in the "other policy scenarios" subsection.

thus ensured pollution reductions at least cost. Building on the success of the Acid Rain Program, the EPA launched several state-specific SO_2 and NOx cap programs to address downwind air quality issues. In large part due to these programs, EPA reports that since 1990, national annual power sector NOx and SO_2 emissions have dropped more than 86% and 93%, respectively.

In 2002, North Carolina's Clean Smokestacks Act also adopted this approach, setting declining SO_2 and NOx budgets for in-state power plants. Under this program, in-state power plants achieved an even steeper drop in pollution than the national electric power fleet, reducing NOx emissions by 89% and SO_2 emissions by 97% just since 1998 (see Fig. 5.2).[44]

Figure 5.2. Reductions in Sulfur Dioxide and Nitrogen Oxide Pollution from NC Power Plants, 1998–2014



Source: 2018 Air Quality Trends in North Carolina Report.

Description of Modeled Policy Scenarios

The Duke Nicholas Institute did not model any RGGI scenarios. Instead, ICF analyzed this policy pathway, given its expertise in modeling similar caps in other states and for RGGI. Each of the RGGI states sets its own carbon budget and enforces the program within its state boundaries. However, RGGI enables generators in participating states to access a regional carbon market, buying and selling allowances across state lines and so reducing the programs costs by having a wider geographic area over which to find CO_2 reductions.

44. N.C. Department of Environmental Quality, "Air Quality Trends in North Carolina" (Dec. 2018), https://files.nc.gov/ncdeq/Air%20Quality/Air_Quality_Trends_in_North_Carolina_122118.pdf, at 3.

ICF modeled a CO_2 budget program that began in 2023 with a budget equaling projected CO_2 emissions from North Carolina power generation for that year, about 36 million metric tons (MMT). Then, ICF modeled annual reductions in the budget in two ways:

(1) **Annual reductions** that matched the downward trajectory **used by the states participating in RGGI** (3% a year); and

(2) **Slightly steeper annual reductions** so that the 2030 NC budget is 22MMT of CO_2, **equivalent to the 2030 CEP in-state target**.

ICF modeling assumed that if North Carolina were to pursue an emissions budget or carbon market approach, it would do so by joining RGGI. Based on this assumption, ICF adopted some of the common program elements adopted by other RGGI states, including: the ability for companies to "bank" allowances for future years;[45] a prohibition on "borrowing" allowances from future years to exceed a cap; and price stability mechanisms in the form of a "cost containment reserve" and "emissions containment reserve" (more detail on these follow).

ICF modeled scenarios to capture the results of auctioning or freely allocating CO_2 allowances:

- First, ICF modeled the RGGI program described above in IPM. Outputs of that model included the tons of total air pollution reduced, the resulting generation mix, and the wholesale cost of electricity as compared to the reference case. ICF also analyzed the retail rate and bill impacts for each of the three customer classes in North Carolina.[46]
- The Policy Working Group selected investments to study under an auction scenario: auction proceeds are sent to the state treasury and not recycled back into the power sector; proceeds are given to residential ratepayers; and proceeds are invested in energy efficiency. The residential bill payment scenario also serves as a proxy for customer savings under a program that freely allocates allowances to North Carolina utilities.
- Then, ICF conducted a macroeconomic analysis to determine the effect of these investments. Output of that analysis included net money flows to North Carolina households and changes in electricity demand.
- Finally, ICF re-ran the capacity planning model using updated electricity demand assumptions for the RGGI scenario that invested auction proceeds into energy efficiency, which in turn changed emissions and cost outcomes for the carbon market.

Section 6 and 7 of this report detail the findings of this analysis. In the "revenue-raising potential/ key investments" discussion below, as well as in **Appendix C**, we present additional investment options. Beyond generating state revenues, allowance auctions play an important role in the functioning of the RGGI market. They enable price discovery, facilitating the market's ability to find the most cost-effective emissions reductions. As a related matter, price discovery signals

45. Recently, to tighten the regional RGGI cap, participating states agreed to a staged retirement of "vintage" banked allowances from 2021–2025; this was modeled but would not affect the design of a program in North Carolina.
46. The costs of allowances that must be purchased by utilities in an auction are directly passed onto to customers through electric rates as an environmental compliance cost of generating electricity. This would be similar to how utilities currently recover cost for other air emission programs such as Cross-State Air Pollution Rule (CSAPR) markets.

to states when to release additional allowances or remove allowances from circulation (within predetermined bounds), which ensures the stability of the market.

Other Possible Scenarios

Impose a state-only cap/Carolinas cap. Although ICF modeled North Carolina joining RGGI, the state might instead opt to set a budget and manage a declining CO_2 budget only within its borders. This could operate much in the way the Clean Smokestacks Act did in the 2000s for NOx and SO_2 pollution from power plants. Alternatively, North and South Carolina might create a carbon market, given that the service territories of DEC and DEP extend into both states.

Direct a consignment auction. As noted above, states may freely allocate allowances or auction them. If a state agency wishes to auction some or all allowances but has not received explicit authority to do so from the legislature, it might pursue the hybrid “consignment” approach. When Virginia first proposed to join RGGI, it designed a program in which the state would distribute allowances with conditional value to emitters free of charge. These allowances could not be turned in for compliance until they had been consigned to the RGGI auction platform for sale (this was the “condition”). RGGI was comfortable with this approach to enable universal price discovery. Virginia also allocated 5% of the allowances to the State Division of Mines, to generate revenue for state-led energy efficiency programs. The consignment auction approach went away in 2020, when the Virginia legislature authorized the direct auctioning of allowances and the creation of a state fund to spend the proceeds.

Carve out non-Investor-Owned Utilities. About 1 MMT of CO_2 are emitted from plants not owned by investor-owned utilities. ICF modeled an RGGI program covering all emitting generation in North Carolina, but the state could decide not to proceed in this manner.

Most of the non-investor-owned utility generation in North Carolina is produced by a natural gas plant owned by NTE. Participation in a declining cap and carbon market would not likely require renegotiation of NTE’s contracts in this state. Given that other pollution budget programs already exist for the power sector, NTE may have negotiated how to handle allowance revenue with purchasers of their electricity. Duke Energy Corporation reviewed standard power purchasing agreement (PPA) language and reported to the Policy Working Group that if the generator-seller under the PPA emits more than its allocated allowances then the buyer would owe the generator-seller the associated market value of the allowances needed to cover the obligation. The buyer could purchase the allowances themselves or pay the seller the dollar value.

Cover industrial sources. Grid-connected industrial boilers could be included in RGGI, although ICF did not include those sources in the modeled cap. The Southern Environmental Law Center proposed inclusion of industrial sources in the petition it filed with the North Carolina DEQ on January 11, 2021, seeking adoption of a rule limiting CO_2 pollution from the power sector.[47]

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47. Southern Environmental Law Center Petition for Rulemaking, Jan. 11, 2021, https://files.nc.gov/ncoah/documents/Rules/Petitions/2021-01-11-Environmental-Management-Commission-Petiton-for-Rulemaking-with-Attachments.PDF.

Key Definitions for a Carbon Market

Allowance banking allows firms to hold spare allowances and use them in a later compliance period. A broad range of stakeholders tend to support this mechanism.

Allowance borrowing allows companies to exceed early emission reduction caps in exchange for greater emission reductions in the future. Environmental groups such as EDF and SELC have not supported this mechanism because it effectively delays reductions.

Cost Containment Reserve – also known as a "soft cost cap," this mechanism enables states to add up to 10% additional allowances to a market to ease demand and lower prices. RGGI uses this mechanism; California used to but now has a hard price cap.

Emissions Containment Reserve – also known as a "soft cost floor," this mechanism enables states to remove up to 10% of their allowances from circulation, to tighten demand and raise prices. Nearly every state in RGGI uses this mechanism.

Offsets – a reduction of emissions outside of a sector targeted for regulation, to compensate for emissions from the targeted sector. In the context of this report, an offset would be a ton of CO_2 reduced outside the power system.

Policy Design Options

- **Flexibility/Cost containment strategies**: RGGI's power sector market and the economy-wide California market have incorporated cost containment measures. Each initially featured a "cost containment reserve" (CCR) in which a set number of allowances are not allocated or sold at the start of the compliance period. Then, for instance, RGGI states can release those reserve allowances (up to 10% of the allowances in circulation) if prices rise above a certain threshold, to slow the price increase. Over time, California's market has moved to a hard price ceiling to assuage industry concerns about future costs.

  Thus far, the more serious cost challenge for RGGI states has been keep allowance prices high enough to incentivize companies to reduce emissions. The simplest way to do this is to set a price floor. In addition, most RGGI states now authorize regulators to withhold up to 10% of total allowances from auctions when release of all allowances would result in prices that are too low. This mechanism refers to the withheld allowances as a state's "emissions containment reserve."[48] (Maine and New Hampshire opted not to implement this program.) Similarly, the European Union's Emissions Trading System has a market stability reserve that takes in allowances if there are too many allowances in circulation (the number of "excess" allowances triggers the reserve, rather than a price).

  Another way to potentially reduce costs is through offsets—enabling generation owners to purchase verified and additional CO_2 reductions outside of the power sector to "offset" any shortfall in the allowances they hold.[49] RGGI allows reliance on offsets for up to 3.3%

48. RGGI Revised Model Rule (2017), https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2017-Program-Review-Update/2017_Model_Rule_revised.pdf, at XX-1.2 and Table 2; XX-9.2(d).
49. Offsets might also be considered to achieve the CEP's "net" carbon neutral target for 2050.

of a plant's compliance obligation over each three-year compliance period. However, none of the generators covered by RGGI has used offsets thus far because allowance prices have remained so low.[50] By contrast, many covered entities have used offsets for compliance with the California program. There, offsets can be used to make up 8% of one's compliance obligation if the offsets follow state accounting protocols.

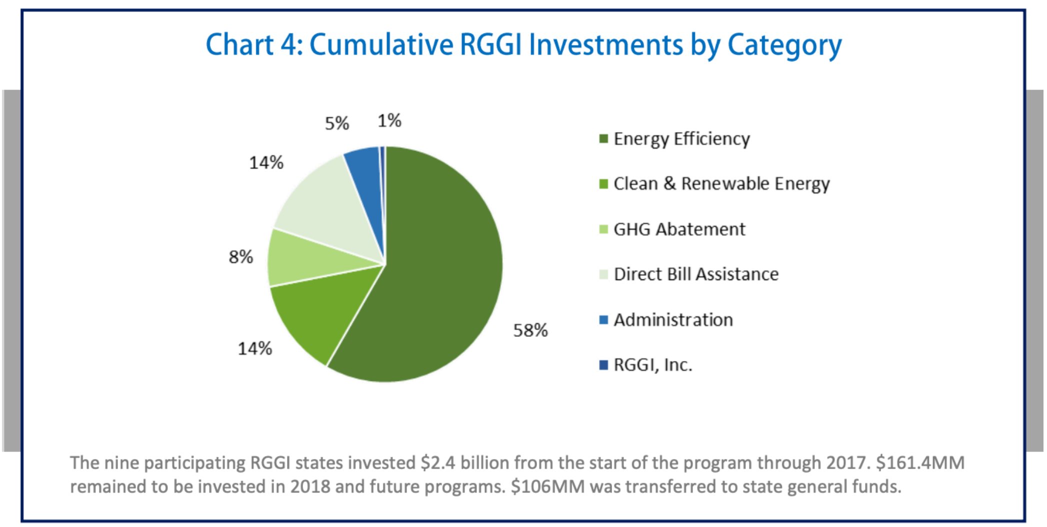
Some of the members of the Policy Working Group expressed concern that too many offsets, or offsets generated outside of the state, might undermine the climate and community benefits of North Carolina clean energy investments. This group called for limits on the number and geographic distribution of offsets. Other group members noted that carbon offsets should be verifiable, additional, and permanent. As for types of offsets, members of the Policy Working Group generally supported referencing the new state Climate Risk Assessment & Resiliency Plan, to identify ecosystems and rural communities where offsets investment would benefit North Carolina's conservation and economic development goals. Duke Energy Corporation representatives noted the company's investments in permanent conservation projects and expressed interest in similar projects qualify for any regulatory offsets program.

- **Distributional effects/Equity policy components:** The Policy Working Group discussed guardrails to protect disproportionately burdened communities from experiencing increased pollution from a carbon market, also known as "hotspots." As part of this discussion, the group considered actions taken by other states. For instance, while reauthorizing its carbon market, California also enacted legislation to enhance community air quality monitoring and create "a state-wide strategy to reduce emissions of toxic air contaminants and criteria pollutants in communities affected by a high cumulative exposure burden." Virginia's 2020 Clean Economy Act requires the state to conduct a triennial study "to determine whether implementation of the act imposes a disproportionate burden on historically economically disadvantaged communities." California, Virginia, and other RGGI states have also directed carbon market auction revenues to overburdened communities to increase access to clean energy and clean energy jobs, electrify transit, and make energy efficiency investments. One suggestion that went beyond these examples was to constrain the transfer of allowances to generating units located in Tier 1 counties, at least over their historic emissions levels.[51] While the RGGI program may not look favorably on policies that reduced the liquidity of the allowance market, North Carolina's Department of Environmental Quality (DEQ) could use its existing permitting authorities to limit pollution at those particular power plants. A power plant would not be able to purchase CO_2 allowances above the level of CO_2 emissions it was permitted to emit.

50. One project has been approved to provide offsets for RGGI, a landfill methane capture project in Maryland.
51. Tier 1 counties are the 40 most distressed counties in North Carolina, based on an economic assessment periodically undertaken by the state Department of Commerce. NC Department of Commerce, "County Distress Rankings (Tiers)," https://www.nccommerce.com/grants-incentives/county-distress-rankings-tiers.

- **Revenue-raising potential/key investments:** Of all of the policy pathways explored in this report, a carbon market with auctioned allowances would generate the most revenue for state programs and clean energy investments. As described in more detail in Sections 6 and 7, the modeling explored two investment scenarios: one focused on customer rebates and the other on energy efficiency. Members of the Policy Working Group concluded (although not unanimously) that these simplified "book end" scenarios could the best way to provide directional answers about how a particular type of investment might impact emissions, generation mix, electricity demand, and costs. However, California and most RGGI states take a portfolio approach, investing in a mix of consumer rebates, energy efficiency, clean energy, and clean transportation programs (see Figure 5.3).[52] Moreover, while ICF modeled residential rebates that were evenly distributed across households and energy efficiency programs that were evenly distributed across the economy, North Carolina might choose to target particular customer classes, income bracket, or census tracts.

Figure 5.3. RGGI Investments, by Category (Credit: Analysis Group)



Clean Energy Standards Pathway

A Clean Energy Standard (CES) is a technology-neutral electric portfolio standard that requires a minimum percentage of retail electricity sales to be met with "clean" (defined in this report as "zero emitting") sources. A CES is similar to, but broader than, a Renewable Portfolio Standard

52. Analysis Group, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States: Review of RGGI's Third Three-Year Compliance Period (2015–2017) (April 17, 2018), https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf, at pp. 31–32.

Key Definitions for a CES

Clean energy – for purposes of this report, the electricity that is produced by generating sources that do not emit greenhouse gases. The modeling performed in this analysis assumed wind, solar, battery storage charged by non-emitting sources, nuclear, hydro, and fossil with carbon capture and sequestration capacity were "clean."

Clean Energy Credits (CECs) – the mechanism through which utilities comply with the CES requirement, representing one unit of energy (e.g., 1 MWh) generated by a qualifying resource. Each year, a utility must turn in CECs equal to its compliance obligation. Utilities either accrue these credits from producing electricity via their owned clean generation, or via a contract to deliver electricity generated by a qualifying clean source. If allowed, CECs can be tradeable. A CEC could also represent energy saved through energy efficiency measures.

(RPS). Whereas an RPS is traditionally focused on setting targets for renewable generation such as wind and solar, a CES takes a wider lens, allowing for competition amongst all non-emitting generators including nuclear and fossil with carbon capture and sequestration capability. A CES can be designed to protect existing zero-emitting resources such as nuclear, encourage new clean resources, or both. While North Carolina is one of 29 states to have an RPS, just six states—Arizona, California, Massachusetts, New Mexico, New York and Washington—have a CES.

The rationale for a technology-neutral CES is that it allows the market rather than government to select technologies. The resulting competition should lower program costs. However, a CES may include carveouts to drive deployment of particular clean technologies, such as offshore wind.

North Carolina Today

In 2007, the NC General Assembly enacted the NC Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The law requires electric utilities in North Carolina to meet an increasing percentage of their annual retail sales through renewable energy resources or energy efficiency measures, reaching 12.5% by 2021 for investor-owned utilities, and 10% by 2021 for municipal utilities and rural electric cooperatives.

Description of Modeled Scenarios

The Duke Nicholas Institute modeled three different types of Clean Energy Standards:

(1) One where an increasing percentage of retail electric sales must come from clean generation sources. This is the type of CES that has been implemented in other states, and was the default form analyzed in this report;

(2) One where an increasing percentage of total in-state generation must be supplied by clean sources; and

(3) One that sets a declining average emission rate (expressed as metric tons of CO_2 per MWh of electricity produced) across the North Carolina generation fleet.

The first type of target is a consumption-based policy which—by covering all sales within North Carolina—implicitly covers electricity imports including those from Dominion Energy's territory in Virginia and DEC/DEP territory in South Carolina. In addition, a consumption-based CES could enable North Carolina fossil generation to remain online even in the 2040s and produce power for export.

By contrast, the second and third types of targets apply directly and exclusively to North Carolina generation. The Duke Nicholas Institute modeled the generation-based clean energy target to test whether that design could push fossil units offline more quickly than a sales-based CES of similar stringency (see Section 6). Finally, the average fleetwide emission rate requirement would force the North Carolina generating fleet to gradually become cleaner, but without setting minimum targets for zero-emitting power. Similarly, the Nicholas Institute modeled this type of CES for its effect on fossil plants and the timing of new solar and wind capacity (see **Appendix F**).

ICF modeled just the sales-based CES, in line with other state policies.

(4) ICF and the Duke Nicholas Institute also modeled a sales-based CES with a carveout for offshore wind, requiring part of the standard to be met with 2.8 gigawatts (GW) of offshore wind by 2030 and 8 GW of offshore wind by 2040.[53]

All modeling assumed that a CES policy would begin in 2023, but that the required level of "clean energy" would not increase beyond baseline levels for two years, giving utilities time to build new clean energy in North Carolina. The clean target for the default CES was set to 50% of retail sales in 2025—representing a small increase over baseline levels—and then increased linearly to 2030. By 2030, ICF modeled a CES that required clean energy to represent 70% of retail sales that—in their modeling—almost but did not quite hit the 2030 CEP emissions target (see Section 6). DIEM modeled a range of percentages for 2030 to test the sensitivity of the system. DIEM and IPM modeled a 95% clean energy standard in 2050, enabling some emitting resources to remain in the system for reliability purposes. In addition, DIEM modeled CES scenarios achieving a 90% and 100% clean target in 2050, to compare the outcomes associated with more or less compliance flexibility (i.e., credit for clean energy certificates, imports, or offsets).

The scenarios requiring specified levels of clean energy were modeled to assume the clean generation would be located exclusively in North Carolina. Compared to a policy that enabled a utility to use designated imports or clean energy credits from outside sources to meet the standard, this design requires a higher build-out of clean energy capacity within the state to meet the requirement. As time progresses and the requirement tightens, imported electricity—clean and dirty—would diminish. The "build it in North Carolina" approach is likely to put more upward pressure on wholesale electricity prices than other alternatives but would also likely generate greater numbers of clean energy jobs and spur economic development.

Other Possible Scenarios

Enable clean energy imports, or clean energy credits, for compliance with a CES. The modeled policies assumed that all required clean energy would have to be built in North Carolina.

53. The 2030 target was set to ensure that the power from the 2.4 GW Kitty Hawk project be delivered to North Carolina, while stimulating development of one other project. The 2040 target is intended to be ambitious, to study the cost and generation mix implications of introducing this much offshore wind to the grid. The three wind energy areas currently certified by the federal government off of the coast of North Carolina have an offshore wind potential of approximately 6 GW.

However, a CES could be designed to allow DEC, DEP, and Dominion Energy to use clean generation within their service territories in Virginia and South Carolina as credit towards the standard. CES compliance could also be met through the purchase of clean energy credits from out-of-state projects. Both types of compliance mechanisms are allowed under the NC REPS law, although DEC and DEP may only rely on out-of-state renewable energy credits (RECs) to meet 25% of their obligation. Allowing out-of-state power to count towards the CES requirement could lower compliance costs but at the expense of driving new clean energy development in North Carolina. Allowing clean energy credits to count towards the CES requirement could also reduce compliance costs but could also weaken the effectiveness of the standard, particularly if clean energy credits could be purchased from projects far away.

Build technology-specific carveouts into the CES. Some of the CES policy scenarios modeled for this report include a carveout for offshore wind. Stakeholders recommended making EE an eligible resource as well. **Appendix B** describes two more ambitious energy efficiency scenarios (representing a 1% and 2% further annual reduction in load from standard assumption by 2030). **Appendix F** presents ICF modeling results for a RGGI + CES policy combination (Figures F.14–F.17) and DIEM modeling results for the CES where EE implemented at these more ambitious levels counts towards the standard (Figures F.51–F.53).

Build a CES program around the existing NC REPs. Stakeholders also discussed how to implement a CES given the existing NC REPS program. From these discussions, it was determined that a CES could be implemented in North Carolina in a variety of ways: (1) policy makers could replace the REPS with a CES; (2) policy makers could renew and strengthen the REPS program by increasing the requirements and omitting emitting resources that are currently eligible to meet these standard, such that it becomes, in effect, a CES; and (3) REPS can remain unaltered at 12.5%, and a "pure" CES could be implemented as a supplementary program to strengthen requirements over time. **Appendix C** details how other states have approached implementing a CES given a pre-existing RPS.

Policy Design Options

- **Flexibility/Cost containment strategies:** There are several additional options for cost containment beyond the use of RECs and imports. Alternative compliance payments (ACPs) in lieu of clean energy credits, and cost off-ramp provisions, which can come in the form of a maximum percentage rate impact, can help to cap costs associated with CES compliance. Cost containment strategies need to be examined carefully such that they do not undermine the efficacy and targets of the CES.

- **Distributional effects/Equity policy components:** A CES can affect communities in North Carolina differently, depending on the pace and location of fossil plant retirements and the location of clean energy construction projects and related jobs. Frontline communities may raise additional concerns about air quality and pipeline infrastructure buildout if a CES allows any form of emitting generation, such as biogas or biomass. As with the coal retirements policy pathway, discussions with communities dependent on employment at North Carolina coal-fired power plants, and overburdened, underemployed communities would be important, to tackle issues such as siting and workforce development. Finally, a CES policy could draw from the examples of some RPS policies and offer bonus credits for clean energy projects built in Tier 1 counties, communities hit hard by a plant closure, or abandoned industrial sites.

- **Revenue-raising potential/Key investments:** If ACPs are built into the design of a CES, the revenues raised could be allocated to certain projects or goals, such as reducing the cost impacts of the CES to ratepayers, compensating for harms posed by excess emissions, or otherwise addressing equity concerns. In that case, some of the discussion in **Appendix C** about targeting investments could be highly relevant.

Policy Combination Pathways

As noted at the outset, policies may seek to shut down emitting sources, discourage emissions, or incentivize new clean generation. They may also target electricity generation or consumption. Strategic pairings of policies can target multiple goals and achieve greater or more cost-effective emissions reductions. On the other hand, some policy combinations could increase cost without making substantial emission reductions. By studying a few policy combinations, the report intends to seed discussion about the most promising hybrid paths forward. (Stakeholders also discussed that possible future federal policies or changes to the regulatory framework could have profound impacts on the costs and effectiveness of A1 policies.)

For instance, a coal retirement policy is a generation-based policy that focuses on the shutdown of particular emitting resources. The most targeted of the policies studied and the one most likely to deliver predictable near-term emissions benefits, a coal retirement policy alone does not determine what is built or used to replace that lost capacity. If large amounts of natural gas capacity are constructed to replace the coal, North Carolina could experience short-term emissions benefits but fail to forge a feasible trajectory to achieve carbon neutrality in 30 years. Similarly, if in-state coal capacity is replaced with large amounts of fossil imports, North Carolina may lose out on economic development opportunities to its neighbors while failing to drive overall greenhouse gas reductions in the region. Meanwhile, a CES may incentivize the buildout of more solar to increase the percentage of clean energy consumed by North Carolina without necessarily nudging North Carolina's existing fossil generation offline. By combining these policies, a state might improve near-term emissions with the shutdown of coal while laying the groundwork for a sustained clean energy buildout over the next few decades.

There may be similar benefits to combining a sales-based CES with a policy that puts downward pressure on North Carolina power sector emissions, such as a declining cap operating within a carbon market. The two policies could work in tandem to send a clear signal to the market to phase out emitting sources *and* build out clean capacity.

Policy combinations were selected for modeling based on preliminary outcomes of the single policy modeling runs. Therefore, a more detailed policy combination discussion follows the initial modeling results in Section 6.

SECTION 6. MODELING OF CEP A1 POLICIES

This section summarizes the modeling analysis of the four policy pathways described in Section 5. After briefly discussing the two models used, the section highlights the important assumptions driving the analysis, summarizes some baseline trends absent any new policies, and compares the changes in generation, capacity, emissions, and system costs of different decarbonization pathways. The section concludes with a comparison of emissions reductions in local air pollutants (nitrogen oxides, NOx, and sulfur dioxide, SO_2) from selected policies, a critical issue for communities leaving near fossil plants or downwind of their emissions.

Electricity Sector Modeling

Two long-term electricity capacity-planning and dispatch models were used to analyze climate policies: ICF's proprietary Integrated Planning Model (IPM), and the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at the Duke Nicholas Institute. The models have similar mathematical structures and have coordinated their assumptions about data and forecasts to the extent feasible. Both models are multiregional models that use linear optimization to solve for least-cost ways of providing electricity to the grid, while meeting all emissions policy objectives. Despite these similarities, enough differences remain in structures and assumptions that the models predict somewhat different—although generally consistent—outcomes. Modeling discrepancies, along with analyses to test the sensitivity to particular variables, underscore the uncertainties at play in the electricity system and the role different assumptions play in policy outcomes.

DIEM was run throughout the A1 process to stimulate discussion regarding the relevant data assumptions, forecasts, and policy definitions of interest. As DIEM is operated by the Nicholas Institute, the report's authors were able to use it to investigate a wide range of sensitivities about future market trends and policy options. The IPM modeling team participated less intensively in the A1 process and focused on a more limited array of policy options, based on discussions among Working Group members that were prompted by the DIEM findings.

Although using two models doesn't provide a simple set of policy recommendations as would be the case from a single model, the ability to compare differences between the two models helps to illustrate the sensitivity of the results to specific assumptions. This has proved to be particularly important in the analysis of the North Carolina power sector, since the model findings indicate that small changes in a few key variables can have relatively large impacts on future predictions. The most important modeling assumptions are summarized below; additional modeling details are provided in **Appendix B**. **Appendix F** contains additional results.

Important Assumptions in the Modeling

Throughout 2020, the report's authors coordinated with members of the Technical Working Group and other stakeholders to develop a common set of data assumptions and forecasts for the IPM and DIEM models to use in this analysis. Where feasible, the models have also attempted to integrate information from the DEC/DEP IRP 2020 filings.[54] All final decisions regarding the modeling and assumptions are the responsibility of the authors and should not be attributed to any of the Working Group members.

To conduct the modeling and interpret model results, it was first necessary to establish a default set of assumptions. The modelers then performed sensitivity analyses to evaluate how changes to the variables could alter baseline and policy findings. The most important assumptions for this analysis include:

- **Electricity demand**. Growth rates and peak demands are taken from the Duke Energy 2020 IRPs. These imply demand growth of around 0.6% per year (after factoring in Duke's projections of EE, demand-side management, distributed generation, and potential new sources of demand such as electric vehicles). Both models consider some alternative assumptions regarding EE and EV uptake; the DIEM model also considers larger baseline projections of demand growth (between 1% and 1.3% per year) from the U.S. Energy Information Administration's Annual Energy Outlook for 2020 (AEO 2020) forecasts.
- **Natural gas costs**.[55] Prices for the first eight years of the gas-price forecasts are based on ICF natural gas modeling and then transition after eight years to AEO 2020 forecasts. This approach tracks assumptions reflected in the DEC/DEP IRPs. As these gas prices do not include potential additional costs associated with providing firm gas capacity for potential new combined cycle units, an additional fixed cost of $1.50/MMBtu is added to the annual costs of new combined cycle units to approximate these firm capacity costs.
- **New technologies**. Costs of new conventional units are taken from the AEO 2020, while renewables and storage costs are based on the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) medium-cost forecasts. Both models combine NREL ATB assumptions about battery storage costs with data from the DEC/DEP 2020 IRPs. IPM relies on assumptions presented in the body of the IRPs regarding the effectiveness of solar-plus-battery installations at meeting peak demands; DIEM uses data from Attachment IV that assumes higher battery effectiveness. These findings are contrasted to results from alternative assumptions in IPM and DIEM.
- **Retirement of coal units**. Starting assumptions for the retirement schedule of coal units in North Carolina is taken from DEC/DEP's updated 2019 IRPs, which used an assumed depreciation life to determine retirement dates for coal plants. (By contrast, retirement schedules from the 2020 IRPs were based on economic modeling.) Both IPM and DIEM can retire any coal plants prior to the end of their depreciation life if the units become uneconomic in a particular model run.

The modeling does not assume any changes in electricity demand as the result of price changes associated with specific policy options or other factors such as changes in expected distributed generation, except for policy runs that are specifically studying the impacts of different EE

54. However, these analyses are not attempting an analysis of the DEC/DEP Integrated Resource Plans.
55. All prices and costs in this analysis are presented in $2019 dollars. All tons of CO_2 are in metric tons.

projections, RGGI investments, or electric vehicle demand. Additional details on assumptions are shown in **Appendix B**.

Highlights of the Baseline (or Business as Usual) Modeling

Prior to estimating potential impacts of different policy pathways, each model establishes a baseline forecast that presents business as usual trends. These baselines can then be contrasted to trends under different policies. The primary purpose of this—or any—modeling exercise is to estimate the differences between baseline trends and the outcomes of each policy.

In 2030, the IPM baseline retires 4.3 GW of coal units, and replaces most of that capacity with new combustion turbines (additional solar in 2030 is solely the result of HB589). DIEM retires only 2.4 GW of coal, relying on the remaining coal, rather than new turbines, to serve a reserve function for the solar PV entering the system in DIEM.[50] By 2040, all existing coal units have retired in both models, aside from Rogers unit 6. Between 2030 and 2040, IPM has constructed turbines and solar units; DIEM does the same along with some onshore wind. In 2050, IPM moves into stand-alone batteries and paired solar/battery units, while DIEM adds offshore wind. In part, IPM's greater emphasis on batteries result from different assumptions about the size (and thus cost and effectiveness) of the battery systems paired with solar PV—IPM assumes in most policy runs that batteries are one-quarter the size of the associated solar unit (based on the approach in the Duke Energy IRPs), while DIEM assumes that they are half the size of the solar unit (based on the Astrape Consulting analysis in Attachment IV of the IRPs).

As might be expected from the volatility seen in historical generation trends in North Carolina (see **Appendix F**), the future of the electricity industry is likely quite sensitive to evolving market conditions. Assuming that natural gas prices remain near today's levels (i.e., around $2.50/MMBtu delivered) over much of the next decade, the baseline forecasts of both models find the following broad trends:

- **Fossil capacity**—by 2030, IPM retires 4.3 GW of coal, which are replaced by new combustion turbines. DIEM retires less coal and adds a mix of turbines and solar PV. By 2040, all coal units are retired, aside from Rogers unit 6. Combustion turbines, particularly any new installations, run at higher utilization rates than historically, assuming existing combined-cycle units are already operating at high rates and if pipeline access (or policy choices) limit the availability or cost-competitiveness of new combined cycle plants. While battery costs continue to decline, they provide similar capacity services as turbines, leading to few battery installations over the next decade. Batteries then become more prevalent in baseline forecasts after 2030.
- **New renewables**—once near-term construction of solar PV units from HB589 is complete, additional solar PV has to compete with new turbines. DIEM forecasts new solar PV competing on a cost basis with turbines by 2030; IPM does not project new economic solar additions, beyond those required by HB589, before 2035.
- **Electricity demand growth**—the slower demand growth in the 2020 IRPs reduces incentives for new construction, particularly of renewables, compared to higher demand-growth scenarios.

- **Co-firing of natural gas at coal plants**—many of Duke Energy's coal plants have been retrofit to co-fire with natural gas (or exclusively fire with gas in the case of Rogers unit 6) (see Section 5 for a list). Low gas prices encourage co-firing, resulting in potentially significant reductions in CO_2 emissions over the next decade.
- **Coal plants without co-firing**—older and less efficient coal plants that have not been retrofit to co-fire with natural gas may retire or operate at significantly reduced levels over the next decade, also leading to CO_2 emissions reductions.
- **Coal plant retirements**—by 2048, all existing coal plants are assumed to retire (with most capacity gone by 2035). Estimates of replacement generation vary somewhat across the two models—IPM retains around 80% of the natural gas generation and meets new demand with solar PV and onshore wind, while DIEM reduces gas more and more somewhat more strongly into solar PV and onshore wind. DIEM also anticipates offshore wind beginning to compete on a cost basis (without subsidies) by 2045/2050 (similar to the NREL 2020 study).
- **Wind**—both models suggest that onshore wind can be cost effective, with the amount depending more on-site availability than on economics. DIEM sees offshore wind entering the mix by 2045 on a pure cost-basis. IPM does not select offshore wind in its baseline.

Baseline Emissions

Despite the expected trends in generation and CO_2 emissions, neither model forecasts that baseline trends will be sufficient to reach the 2030 CEP emissions target, particularly when estimated CO_2 emissions associated with imported electricity are considered. Achieving "net zero" emissions by 2050 will certainly require additional action.

This subsection summarizes the baseline emissions trends in each model; **Appendix F** provides more detail and describes additional baseline and policy sensitivity analyses.

Figure 6.1 shows estimated CO_2 emissions trends in the IPM and DIEM forecasts (similar figures depicting baseline generation and capacity in the two models are shown in **Appendix F**). Emissions are separated into those from in-state generation (solid lines) and import-adjusted emissions (dashed lines) which include an estimate of emissions from electricity imports into North Carolina. The 2030 CEP target, broken out into the in-state generation component (green) and import-adjusted (red), are shown as dotted horizontal lines.

The figure shows that emissions through 2028 are similar in the IPM and DIEM results. Starting in 2030, solar PV (and a small amount of onshore wind) in the DIEM baseline—which does not materialize so soon in the IPM baseline—lead to divergent CO_2 emissions estimates that continue through 2050. In 2030, DIEM's baseline reaches slightly more than a 60% reduction in emissions from 2005 levels whether calculated as in-state or import-adjusted emissions, IPM hovers around a 55% reduction. These differences occur largely because DIEM continues to shift out of coal generation between 2028 and 2030, which is partially replaced with solar, while IPM maintains coal generation in that time period (and increases coal generation in 2035 as gas prices rise and gas co-firing at coal plants becomes more costly).

Figure 6.1. Baseline Carbon Dioxide Emissions from Generation ($MMTCO_2$)

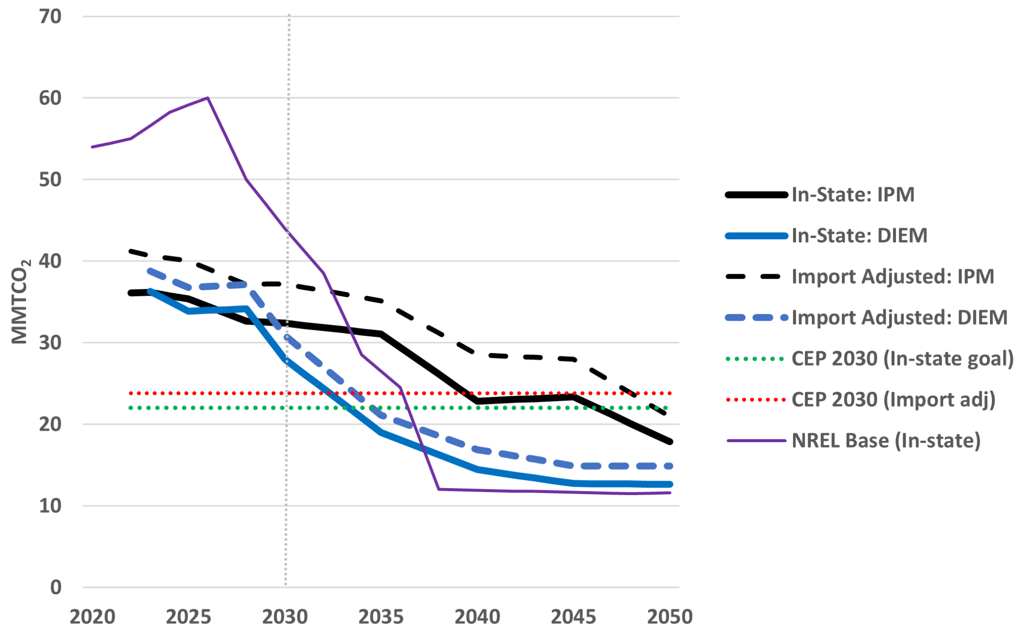


Figure 6.1 also compares the IPM and DIEM baseline CO_2 trends for North Carolina with baseline trends from the recent NREL analysis of the Duke Energy system.[56] NREL's emissions estimates are significantly higher than those reported by IPM and DIEM over the first decade, likely based on lower assumed coal prices and higher gas prices than in the IPM/DIEM analyses.[57] After 2030, while starting from a higher point, the overall renewables penetration—and so, emissions—trend lines in the NREL results largely track the trajectory reported from DIEM.

Highlights from the CEP A1 Policy Modeling

This part begins by presenting impacts of three basic CEP policy options that are run in both IPM and DIEM: accelerated coal retirements (option #2 described in Section 4), carbon adders on new capacity, and a sales-based CES that reaches 70% clean in 2030 and 95% clean by 2050. Then, they are compared against RGGI scenarios (run only in IPM). Following discussions of these basic options, a more detailed look at RGGI is provided, along with additional variations of the coal retirement, carbon adder and CES policy pathways, and finally, combination policy approaches. Sensitivity analyses of the findings to fuel prices, electricity demand growth, etc., are presented in **Appendix F**.

56. NREL presentation of Phase I results. 2020. "Duke Energy Carbon-Free Resource Integration Study: Capacity Expansion Findings and Production Cost Modeling Plan." https://www.nrel.gov/grid/carbon-free-integration-study.html. Phase II of this study, focusing on more detailed production-cost modeling, is ongoing.
57. *Id.*, slide 5.

Policy Cases and Labels (see Section 5 for more detail on the "Modeled Policies"):

- *Accelerated coal retirements ("Coal Retire")* – most results described here focus on the policy option that by 2030 eliminates subcritical coal plants, allows supercritical plants to operate seasonally on coal (i.e., about 10%) annually), and assumes that Rogers unit 6 thereafter only runs on natural gas. Results from DIEM are also shown for other policy variants.
- *Carbon adders ("Cap Adder" or "Gen Adder")* – this policy embodies two approaches: adders that affect only new capacity and adders that affect new capacity as well as the generation/dispatch of existing and new plants. Results focus on a carbon adder that starts at $6/ton and grows at 7% per year (i.e., $11/ton in 2030, $15/ton in 2035). A rough rule of thumb is that a $15/ton adder will increase coal-plant operating costs by $15/MWh (i.e., or about 50%). Other levels of adders on generation are considered later in this section.
- *Carbon Market (RGGI)* – IPM results focus on North Carolina joining the 11-state Regional Greenhouse Gas Initiative and capping CO_2 emissions either (1) to match the downward trajectory of other RGGI states or (2) to meet the 2030 CEP target.
- *Clean Energy Standards ("CES 70%+")* – For their primary CES policy case, the models ran a "clean energy" requirement (expressed as a percentage of retail sales) that began with 50% clean energy in 2025, increased in linear fashion to a 70% target in 2030, and then proceeded along a different linear trajectory to achieve a 95% "clean" energy target by 2050. In both models, "clean energy" was defined as a zero-emitting resource constructed in North Carolina. (Other CES levels are considered in this section and in **Appendix F**, including using EE measures as a way of meeting CES targets).
- *CES policy combinations* – The sales-based CES policy was combined with generation-based approaches to study the cost and emissions impact of implementing multiple polices in North Carolina.

All the policy cases shown in this section assume that North Carolina is pursuing climate goals in isolation from surrounding states, aside from the existing RGGI program and the Virginia's Clean Economy Act which are reflected in the baseline forecasts of both IPM and DIEM. (See **Appendix F** for a DIEM sensitivity analysis that assumes surrounding states engage in comparable climate policies to North Carolina.).

The following table summarizes the high-level impacts of these policy cases on CO_2 emissions, generation and capacity, and policy costs. The highlights attempt to focus on consistent findings across both of the models employed in the analysis. In some cases, ranges of costs and CO_2 emissions reductions are shown that cover estimates from both models. The changes discussed are in comparison to the baseline forecasts of IPM and DIEM.

Utility Treatment and Generator Coverage

The modeling assumed sales-based policies were applied evenly across all retail service providers in North Carolina. Similarly, generation-based policies covered all of the state's grid-connected electric generating units of at least 25 MW capacity,[1] regardless of ownership. This does not mean that policies would necessarily apply to all electric utilities. Other North Carolina policies have differentiated between utilities in their application.

Snapshot of North Carolina Power Sector

Generation. IOUs produce approximately 84% of the electricity in North Carolina; another 13% of in-state generation is produced by independent power producers (IPPs) that sell power to municipal and university customers.[2] Electric membership cooperatives (EMCs) and municipal utilities generate 1% of in-state power; they also have ownership stakes in South Carolina generating assets and purchase power from the IOUs or the Tennessee Valley Authority (TVA). The remaining 2% of power is generated in North Carolina by combined heat and power systems.

DEC and DEP own and operate most of the state's large fossil fuel-fired generation. About 1 mmt of CO_2 are emitted from plants not owned by DEC/DEP.

Distribution. In North Carolina, three IOUs—DEC, DEP, and Dominion Energy—serve about 67% of the state's retail customers (3.6 million), representing almost three-quarters of all retail sales. Of those customers, just 121,776 are served by Dominion Energy. The North Carolina Utilities Commission (NCUC) regulates the IOUs, as well as two small university-owned electric utility systems, New River Light and Power (Appalachian State) and Western Carolina University.

More than 100 EMCs or municipal utilities distribute 26% of the state's electricity and serve about one- third of North Carolina customers. The EMCs are independent, nonprofit corporations run by their boards. Seventy-two municipalities also run their own electric utilities, while receiving technical, administrative, and other support from the nonprofit organization Electricities.

Differential Treatment under Past Policies

In the past, North Carolina lawmakers have distinguished between electric utilities and other generation owners when crafting air quality or clean energy policies. For instance, in the Clean Smokestacks Act of 2002,[3] the General Assembly set pollution caps for coal-fired generation owned by IOUs. By contrast, the law amended general air pollution permitting provisions that applied to any "person." In 2007, the General Assembly required IOUs in North Carolina to meet an increasing percentage of their annual retail sales through renewable energy resources or EE measures, reaching 12.5% by 2021.[4] However, "an electric public utility with less than 150,000 North Carolina retail jurisdictional customers" of a certain date (i.e., Dominion Energy) could meet the requirement with renewable energy certificates (RECs).[5] The law set a less stringent target for EMCs and municipal utilities, requiring them to meet 10% of their retail sales by 2021 with renewable generation, EE, or RECs.[6]

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1. This is a standard threshold for air pollution regulation of the power sector, stemming from the U.S. EPA's definition of a regulated "electric utility steam-generating unit" as a unit that is capable of supplying more than 25 MW net-electrical output to the grid. 40 CFR §60.41Da.
2. Statistics in this call-out box may be found in EIA Detailed State Data, 1990–2019. (EIA-861, EIA-906, EIA-920, and EIA-923), https://www. eia.gov/electricity/data/state/.
3. S.B. 1078, 2001-2002 Sess. (N.C. 2002), https://www.ncleg.gov/Sessions/2001/Bills/Senate/PDF/S1078v5.pdf.
4. S.B. 3, 2007–2008 Sess. (N.C. 2007), https://www.ncleg.net/Sessions/2007/Bills/Senate/PDF/S3v6.pdf, at § 62-133.7(b)(1).
5. N.C. Gen. Stat. § 62-133.7(b)(2)(e). DEC and DEP are limited to covering 25% of their compliance obligations with RECs. *Id*.
6. N.C. Gen. Stat. § 62-133.7(c).

Table 6.1. Summary of Findings

Coal Retirement	Emissions	Retiring only subcritical coal units has little effect on emissions
		Retiring supercritical units or operating seasonally reduces 2030 in-state emissions to 68% below 2005 (not quite CEP target)
		Retirement policies provide only minor reductions after 2035
	Policy Costs	Costs per ton of emissions reduced are around $10 per ton and have cumulative in-state reductions of 10–15%
		Total present-value costs of retiring supercritical units or limiting their operation are between $280–$630 million
	Generation & Capacity	More turbines are added to offset declines in coal
		More electricity imports may also occur
Carbon Adders	Emissions	Adders on new capacity have some effect on emissions by eliminating new turbine installations
		Adders on generation have large and quick impacts on emissions from reducing fossil generation
		Adders on generation can achieve “net zero” emissions in 2050, but only if they are also applied to imports
	Policy Cost	Adders on new capacity cost $7–$16/ton per ton reduced and lower cumulative in-state emissions by 8–10%
		Adders on generation are among the most cost-effective ways of reducing emissions
		$6/ton adder on generation (growing at 7%/year) can reduce cumulative in-state emissions by 50% at a cost of $15/ton
	Generation & Capacity	Adders on new capacity prevent new turbine installations (and might lead to increased imports)
		Adders on generation allow existing and new turbines to continue helping meet peak demands
		Adders on generation that do not apply to imported electricity will shift generation out of the state
		Adders can lead to increases in solar capacity

RGGI	Emissions	Has large and quick impact on in-state emissions through 2030, but may not quite reach in-state CEP 2030 targets
		The specific allowance budget chosen by North Carolina may not affect allowance prices and reductions too much
		Combining RGGI with a CES policy reaches 2030 CEP targets (in-state and import-adjusted emissions)
	Policy Costs	Estimated 12-state RGGI allowance prices are between $2.50–$5/ton
		Is a cost-effective way of reducing emissions through 2030
		Can have negative costs per ton reduced (i.e., net benefits) if revenues are reinvested in energy efficiency
	Generation & Capacity	May reduce in-state generation and encourage imports of electricity
		May encourage coal units to remain in the system a bit longer as the policy discourages construction of new turbines

Sales-Based Clean Energy Standards	Emissions	Reductions may be lower than with other types of policies since CES do not directly address fossil generation
		For CES by itself, emissions won't reach "net zero" by 2050
		Ability of a specific CES level to reach 2030 CEP targets depend on market conditions (and modeling assumptions)
		For a CES that is 70% in 2030 and 95% in 2050, cumulative reductions range between 14% and 22%
	Policy Costs	Costs per ton of emissions reduced are higher than other policies since CES encourage renewables without limiting fossil
		Estimated costs per ton also depend on the level of renewables that are constructed in the model baselines
		System costs are largely from in-state capital construction
		Benefits are seen from increased electricity exports
	Generation & Capacity	Encourages in-state construction of new renewables
		By itself, does not explicitly target existing fossil generation
		By itself, may not eliminate fossil generation (even if the CES goal approaches 100%) since those units can be used to export
		May need to consider whether turbines can remain in the system for reliability purposes
		Doesn't offer mechanisms for dealing with imported electricity
		Defining a policy over retail sales does not account for transmission/distribution losses between wholesale and retail markets
		Defining a CES over generation (instead of sales) prevents in-state fossil generation for export, but can encourage imports

Combination Policies	Emissions	Combining CES with coal retirements leads to additional reductions in 2030 and 2035 since the polices are complementary
		Cumulative reductions through 2050 for most combinations tested are between 15%–30%
		Combining CES with an adder on generation ($6/ton growing at 7%/year) has cumulative reductions of around 55%
		Combining CES with an offshore wind requirement doesn't reduce overall emissions
	Policy Costs	Costs per ton reduced range from $15/ton to more than $100/ton, depending on the policy combinations
		DIEM finds some offshore wind cost-effective in the baseline, adding an offshore wind requirement to CES increases costs
		IPM doesn't add offshore wind in the baseline and suggests an offshore wind requirement is more costly
	Generation & Capacity	Onshore wind, if allowed, can play a role in meeting CES and combination policies
		Solar by itself, or paired with battery storage, represents the largest share of compliance with CES and combination policies
		The system will need either turbines or batteries for reliability and load smoothing

Modeling of Selected Basic CEP A1 Policy Options

The modeling of A1 policies begins with the three basic options run in both IPM and DIEM: accelerated coal retirements, a carbon adder applied to new capacity, and a CES that targets 70% clean generation in 2030 and 95% clean generation by 2050. For these options—and the subsequent policy variants—the subsections below compare CO_2 emissions, policy costs, generation, and capacity changes across these three policy pathways. Then, the IPM results of a fourth basic policy pathway, joining RGGI, are presented and compared.

Carbon Dioxide Emissions

Carbon dioxide emissions impacts of the three basic CEP policy pathways run in IPM and DIEM are compared with each model's baseline emissions in Figures 6.2a, 6.2b, 6.3a, and 6.3b. The results look at emissions from in-state generation (the in-state component of the 2030 CEP target is estimated at 22 $MMTCO_2$) and total emissions from in-state generation and electricity imports (2030 CEP target: 23.8 $MMTCO_2$). Next to each policy label in the figures are the percentage reductions from 2005 levels.

The models report different levels of CO_2 emissions since, as discussed above, the IPM baseline retains less coal capacity than DIEM and yet runs more fossil generation for a longer period of time. However, the models report similar emissions trends for policy cases. **Accelerated coal retirements** provide the largest CO_2 emissions reductions in 2030; in IPM, emissions under this scenario are reduced by 8.7 $MMTCO_2$, and in DIEM, by 4.3 $MMTCO_2$. However, by 2040, emissions under any of the accelerated retirements cases are similar to the baseline (because by then, most coal units would have retired for economic reasons). **RGGI** using the CEP target as the budget in 2030 has the largest initial reduction of in-state emissions in IPM (RGGI was not run in DIEM), however, many of these reductions are achieved by switching to electricity imports, which results in smaller declines in a total emissions metric that considers these emissions.

A **carbon adder on new fossil capacity** ("Cap Adder" – $6/ton growing at 7%/year) appears sufficient to prevent construction of the combustion turbines which both models build in the baseline.[58] IPM relies more on turbines in the baseline than DIEM; as a result, the carbon adder on new capacity reduces emissions by a greater amount (more than 2 $MMTCO_2$ lower than the baseline in 2030) in that model than in DIEM (0.9 $MMTCO_2$ lower). In neither model does this policy achieve the 2030 CEP target. After 2030, both models report additional reductions from this policy, still largely from avoiding combustion turbines that were built in the baseline.

A **sales-based CES** that targets 70% clean generation by 2030 (and 95% clean by 2050) increases in-state renewables in both models. Once again, absolute CO_2 emissions in IPM are higher, as that model chooses higher levels of coal generation alongside expanded clean energy generation, while DIEM favors generation from dedicated gas plants or co-fired coal/gas plants. As a result, DIEM estimates that a 70% CES will meet the 2030 CEP target, while the same level of CES stringency in IPM achieves 67% below 2005 levels, based on total emissions including imports. Still, the policy in IPM achieves more absolute CO_2 emissions reductions from the baseline than the policy in DIEM, because DIEM built more renewables in the baseline. This will contribute to IPM's lower cost per ton reported for the sales-based CES (next part).

58. Recall from the baseline discussion that combined cycle units are uneconomic in the base case based on the assumption that additional costs would be incurred to secure firm gas capacity for those baseload units.

Figure 6.2a. IPM Model Trends of NC In-State Emissions from Generation

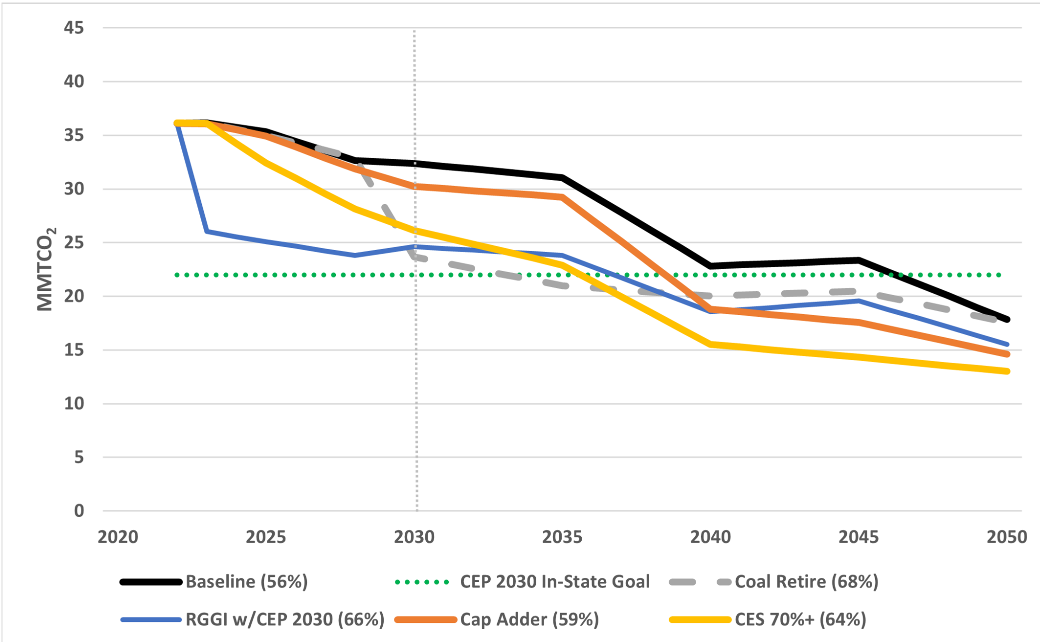


Figure 6.2b. IPM Model Trends of NC Total Emissions from Generation

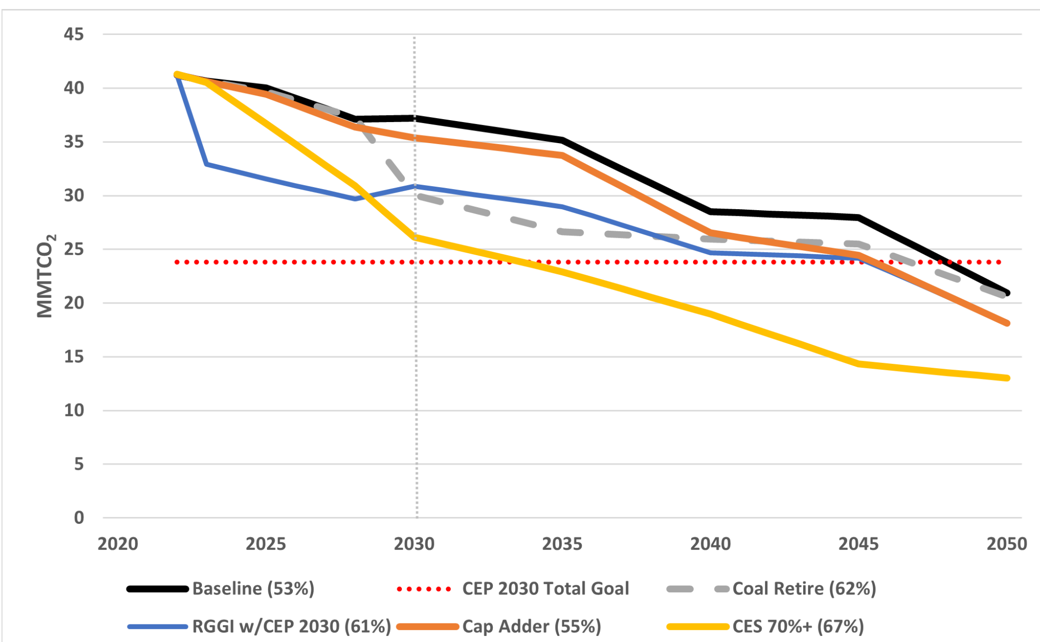


Figure 6.3a. DIEM Model Trends of NC In-State Emissions from Generation

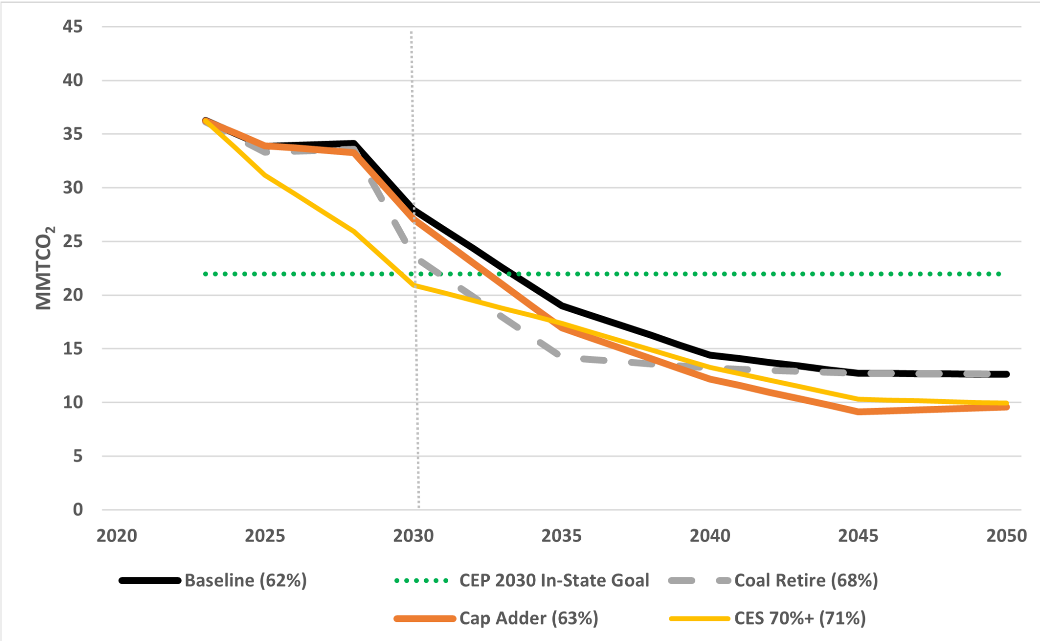
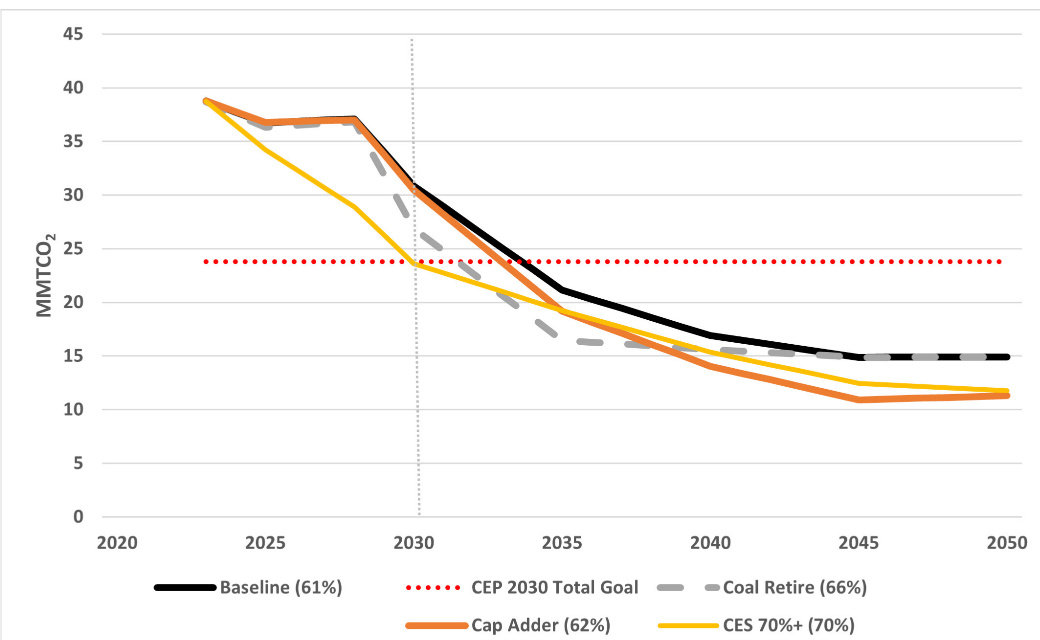


Figure 6.3b. DIEM Model Trends of NC Total Emissions from Generation



Policy Costs within the Electricity System

The policy costs associated with the CO_2 emissions reductions presented in Figures 6.2a,b and 6.3a,b encompass all the wholesale costs associated with delivering electricity to meet grid demands in North Carolina (see Section 7 for analysis of the retail costs and economy-wide macroeconomic impacts). The system costs include those directly related to generating electricity: capital costs of new construction or retrofits (typically annualized for cost-reporting purposes); fixed operations and maintenance (O&M) annual expenditures; variable O&M costs, which vary with the level of generation; and fuel costs.[59]

Notably, electricity dispatch models minimize policy costs over the entire model time horizon. This long-term approach to cost minimization can lead to short-term policy cost results that move counter to long-term trends. Estimating short-term policy costs can also be problematic because, for reporting purposes, capital payments are annualized (usually over 20 or 30 years) from the date of installation. Thus, over any particular reporting horizon, all the annualized capital payments may not have been fully realized.

Policy costs can be expressed in a number of ways; presenting costs in more than one way can overcome the challenges inherent in any one approach. The usual method is to compare the change in net present value (NPV) between the policy run and the baseline run in a model. This logic corresponds with the way the models attempt to minimize total costs of generating electricity, and the NPV calculation provides a simple metric that can be compared across policies. The NPV measurement can be shown as a total dollar cost to the system over a given period of time—usually, around 30 years—or as a cost per ton of CO_2 emissions reduced, which is an expression of the overall cost effectiveness of a policy at lowering emissions (both expenditures and emissions reductions are typically discounted to achieve a comparable metric).[60] The state of North Carolina often uses the NPV measurement to evaluate policies.

While NPV is the most accurate way of showing how a model is estimating policy costs, it can obscure the timing of different types of costs. By contrast, annual costs (for a model solution year) show how the system is responding to a policy over time. However, annual costs can be problematic to the extent they under-represent the full impact of capital expenditures. Thus, when interpreting annual results, it is important to remember that capital costs projected for a particular year in the future represent a portion of the total capital cost of a new unit. Both models base the number of payments for different types of units on IPM “book lives”—in the standard assumptions, 20 years for renewables and 30 years for turbines and combined cycle units (see **Appendix F** for policy cost comparisons in DIEM that assume a 30-year book life for renewables).[61]

59. Other types of “costs” such as proceeds from RGGI allowance auctions or carbon pricing (although the modeled carbon adder policies do not require payments to be made) may affect generation decisions in the model, but for cost-reporting purposes, are simply a transfer among agents in the economy and do not represent a net cost to society as a whole. Therefore, they are not reported here. Section 7 considers costs associated with a RGGI auction.

60. Net present values shown are calculated as the period 2022–2050 and are discounted to the year 2022. ICF used a discount rate of 4.1%. DIEM used NREL’s discount rates which fluctuate but hover around 4.2%.

61. See Chapter 10 in U.S. EPA “Documentation for EPA’s Power Sector Modeling Platform v6” for a discussion of the book lives of units—https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-november-2018-reference-case.

Figures 6.4a and 6.4b summarize costs and cumulative CO_2 emissions reductions for the three basic policy pathways shown in Figures 6.2a,b and 6.3a,b plus the RGGI option that sets the 2030 allowance budget to meet the in-state component of the 2030 CEP target. The figures use the metric of costs per ton reduced in present-value terms, compared to cumulative emissions reductions—with both variables calculated through 2050 to get a sense of the overall cost effectiveness of each option. Figure 6.4a focuses on costs compared to in-state emissions reductions, while Figure 6.4b includes CO_2 emissions associated with imported electricity to get a sense of the total emissions reductions from each policy.

As presented in Figure 6.4a, DIEM estimates that **accelerated coal retirements** lower in-state CO_2 emissions by a cumulative 9% from the baseline at a cost of $8/ton of CO_2 reduced, while in-state emissions fall 8% from a **carbon adder on new capacity** at a cost of $16/ton. IPM, meanwhile, estimates a 14% in-state reduction from baseline with **accelerated coal retirements** at a cost of $10/ton, and a 10% in-state reduction from a **carbon adder on new capacity** at $7/ton.

Figure 6.4b shows **total CO_2 reductions** in DIEM (so again, accounting for emissions) for **accelerated coal retirements** falling 7% compared to baseline, at a cost of $9/ton, and for the **adder on new capacity**, a 7% reduction at $17/ton. In IPM, reductions from accelerated coal retirements fall 14% below baseline at a cost of $10/ton; for the same cost the **adder on new capacity** reduces emissions just 6% below baseline. Therefore, when imports are considered, accelerated coal retirements are more cost-effective than capacity adders across both models. Meanwhile, RGGI reduces total emissions from the baseline by 16% for about $6/ton.

Both models suggest that the CES is a more capital-intensive strategy for achieving CO_2 emissions reductions (allowing EE measures to count towards the standard could mitigate this). However, DIEM and IPM estimates of CES cost effectiveness diverge more than results for other policies. This is for a number of reasons, starting with the higher amount of renewables and lower CO_2 emissions in the DIEM baseline, compared withthe higher emissions and lower renewables in the IPM baseline forecast.

Figure 6.4a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

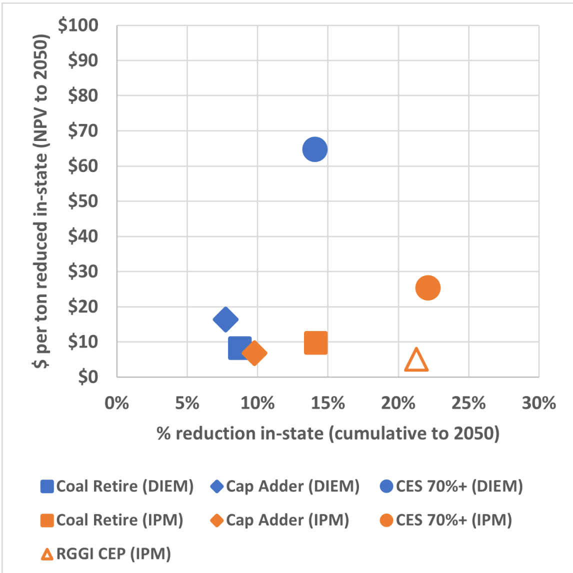
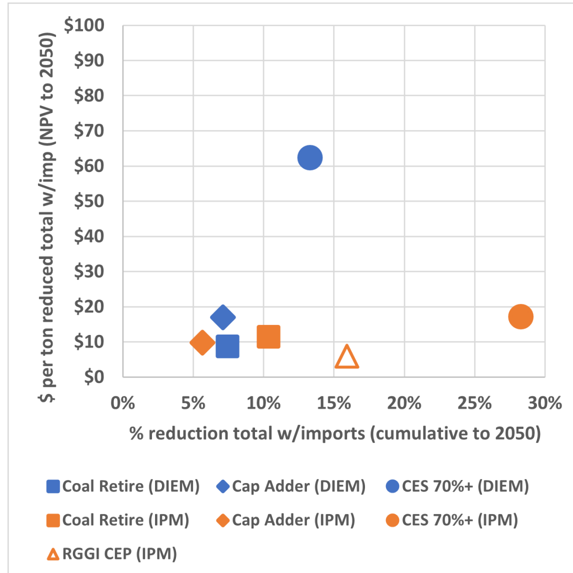


Figure 6.4b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions



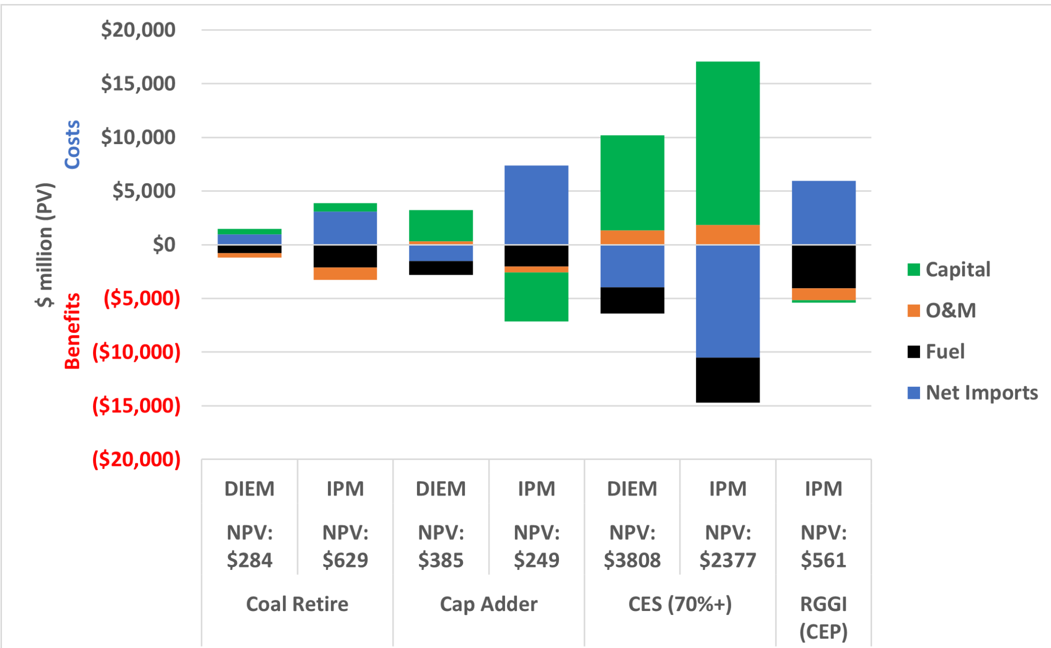
To further understand the differences in policy cost estimates, Figure 6.5 disaggregates the costs presented in Figure 6.4a into expenditure components. In the figures, the cost metric is again the change in the NPV of costs through the year 2050 compared with baseline costs. The types of costs (listed in the figure legends) are divided up into changes in capital, O&M, and fuel costs, along with North Carolina's estimated expenditures on net electricity imports. Increases in costs are shown above the zero line, while "benefits" or negative costs are shown below the zero line.[62] Below each model's name the total NPV cost of the policy in millions of dollars is provided, expressed as a change from the baseline system costs—e.g., DIEM estimates a $3.8 billion NPV cost for the sales-based CES, while IPM estimates a $2.4 billion cost. "Net imports" covers both electricity and capacity trade; "O&M" includes both fixed and variable operating and maintenance costs.

Disaggregated costs reveal important differences between models – and more importantly, different system responses to a policy. Costs in DIEM are driven by additional capital expenditures in North Carolina (largely in renewables—see Figure 6.9), while IPM is meeting policy goals by importing electricity and so is reducing capital investments compared to the baseline (where the model had built new turbine units—see Figure 6.8). Similarly, for RGGI, IPM's estimated costs are from imported electricity, which is offset by a reduction in fuel use within North Carolina.

62. After discussion with the Technical Working Group, both DIEM and IPM are assuming that for interstate electricity flows (or capacity payments), the trade price is the marginal cost of electricity in the importing region. Such decisions can have relatively large impacts on estimated policy costs since trade flows may represent a large share of estimated state responses to a policy (and the dispatch models are concerned with supplying electricity to the grid in the cheapest manner possible, not estimating or minimizing the costs of electricity imports to a state).

As seen in Figure 6.5, total estimated costs for the CES policy are 60% higher in DIEM than in IPM. The breakdown of these costs shows that DIEM has smaller increases in capital expenditures and O&M costs than the IPM model, but IPM offsets its higher capital costs with a significant increase in exports. Further detail on these reasons is provided in a discussion of annual cost components in **Appendix F**.

Figure 6.5. Cost Change in NPV through 2050 (Compared to Baseline)



Generation

Changes in CO_2 emissions, and the associated costs, are a function of the changes in the generation mix—what is run to generate electricity, and how often?—as a result of each policy. Table 6.2 summarizes how the two models respond to each policy over the next three decades. Where the responses are the same in the two models, the impacts are presented in the center of the table. Where there are differences, those differences are shown under each model's name. The details of these impacts are illustrated in Figures 6.6 and 6.7. Those figures also show the net energy for load (NEL) for each year, which is the amount of electricity needed to supply the grid in North Carolina. Any gap between this NEL and the generation column must be supplied by imports; conversely, if generation is greater than NEL, electricity produced in North Carolina is sold out of state.

Table 6.2. Generation Changes across Policy Options and Models

	Policy	IPM Model	DIEM Model
2030	Baseline	New turbines to meet demand Coal generation is maintained No new solar PV	New turbines to meet demand Coal generation decreases New solar PV is added
	Accelerated Coal Retirements	More turbines to offset coal More imports to offset coal	More turbines to offset coal
	RGGI with CEP 2030 targets	Reduction in fossil generation No new renewables Increased electricity imports	
	CO_2 Adder on New Capacity	No new turbines Increased coal generation	
	CES (70% in 2030, 95% in 2050)	Adds first new solar PV Adds a bit of wind Small decline in coal	Adds more solar PV Adds onshore wind Small decline in coal
2040	Baseline	More renewables as gas prices rise and coal plants retire	
	Accelerated Coal Retirements	Few changes over a baseline without the retirement policy	
	CO_2 Adder on New Capacity	Turbine generation mostly gone Increased imports to meet demand	Turbine generation mostly gone Increased generation from solar w/ battery backup to meet demand
	CES (70% in 2030, 95% in 2050)	Higher solar and battery use Generation from existing combined cycles remains	Higher solar and battery use Higher onshore wind
2050	Baseline	Solar w/battery enters on cost Onshore wind enters on cost	Offshore wind enters on cost
	Accelerated Coal Retirements	Few changes over a baseline without the retirement policy	
	CO_2 Adder on New Capacity	Solar w/battery increases over baseline to offset turbines	Solar w/battery increases
	CES (70% in 2030, 95% in 2050)	Renewables cover 95% of sales Total generation and exports rise, which allows fossil generation to remain in the system for reliability benefits Solar w/batteries increases	Renewables cover 95% of sales Total generation and exports rise, which allows fossil generation to remain in the system for reliability benefits Solar w/ and w/o batteries increases

Figure 6.6. IPM Forecast of NC Generation across Policies (2030–2050)

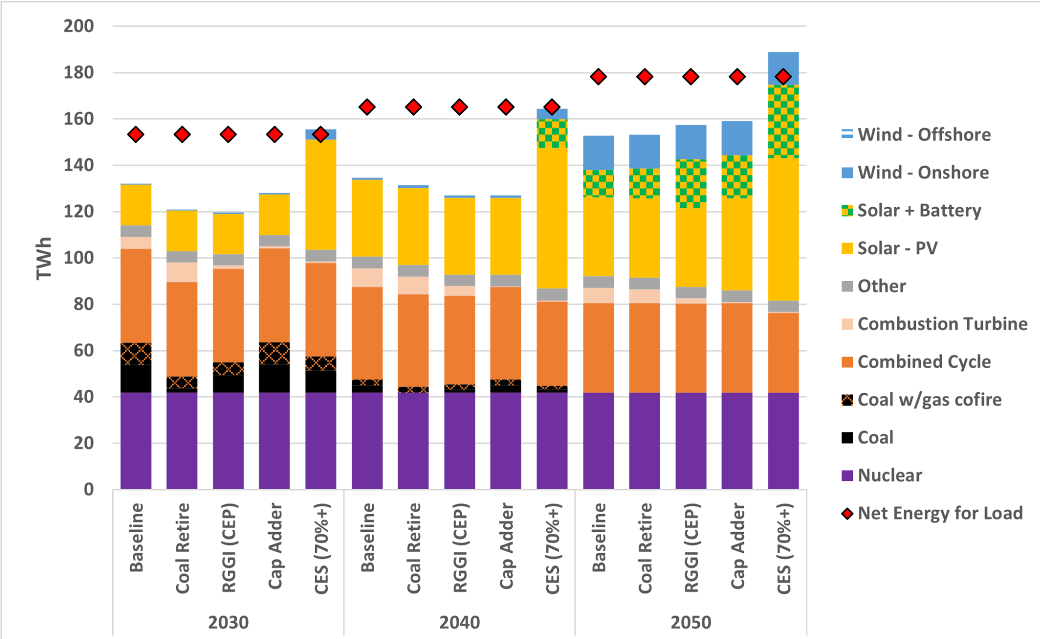
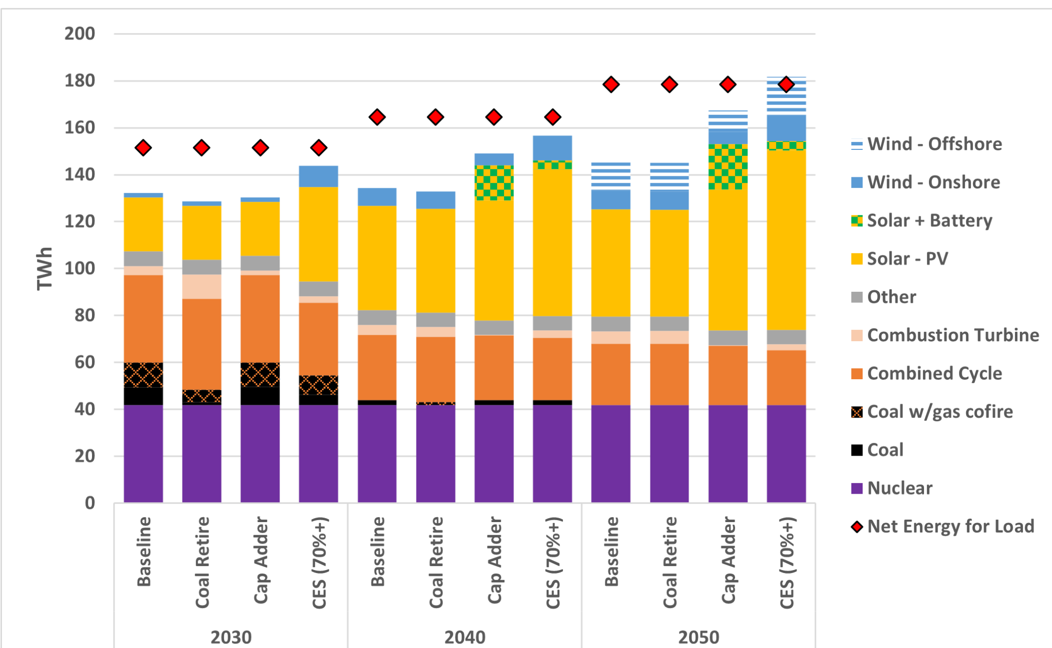


Figure 6.7. DIEM Forecast of NC Generation across Policies (2030–2050)



Capacity Changes

Figures 6.8 and 6.9 present capacity changes—what resources get built and retired in North Carolina. These trends relate closely to the generation changes. Retirement of existing units appear as negative numbers. Positive numbers represent increases in capacity over the system at the beginning of 2022 (including any renewables added in response to HB589). The graphs compare decadal changes in the baseline to those of the three policy options discussed previously.

In 2030, the IPM baseline retires 4.3 GW of coal units, and replaces most of that capacity with new combustion turbines (additional solar in 2030 is solely the result of HB589). DIEM retires only 2.4 GW of coal, relying on the remaining coal, rather than new turbines, to serve a reserve function for the new solar PV entering the system in DIEM.[63] By 2040, all existing coal units have retired in both models, aside from Rogers unit 6. Between 2030 and 2040, IPM has constructed turbines and solar units; DIEM does the same along with some onshore wind. In 2050, IPM moves into stand-alone batteries and paired solar/battery units, while DIEM adds offshore wind. In part, IPM's greater emphasis on batteries result from different assumptions about the size (and thus cost and effectiveness) of the battery systems paired with solar PV units—IPM assumes in most policy runs that batteries are one-quarter the size of the associated solar unit (based on the approach in the Duke Energy IRPs), while DIEM assumes that they are half the size of the solar unit (based on the Astrape Consulting analysis in Attachment IV of the IRPs).

By 2030, both models report similar reductions in coal plants under the **accelerated coal retirement** option (7 GW in IPM and 5.6 GW in DIEM), with that capacity replaced by turbines and solar PV. Applying a **carbon adder on new capacity** avoids new turbine construction, but also discourages retirement of coal units, which remain online to provide reliability for any increases in solar in the system (the coal units operate at low utilization rates, as many are today). A **sales-based CES** with a 70% clean requirement by 2030 drives new renewable generation in North Carolina: solar, wind, and batteries in IPM; solar and wind in DIEM.

In 2040, capacity changes for **accelerated coal retirements** track the baseline trends. For the **carbon adder on new capacity**, IPM relies on some new solar in 2040, and significantly greater imports. In DIEM, the model chooses to replace the turbines that appeared in the baseline with new solar (stand-alone and paired with batteries). Under a **sales-based CES** that approximates an 83% clean requirement in 2040 (on the way to 95% in 2050), IPM mixes solar with batteries to provide generation and reliability services, while DIEM emphasizes solar and turbines.

By 2050, the models had added a few more turbines in the baseline, but new capacity focused on renewables as capital costs continued to decrease over time. Despite some differences, both models add solar, balanced with batteries or turbines. **Accelerated coal retirements** have no discernible impact on capacity by this year. In response to a **carbon adder on new capacity**, DIEM tends to construct additional solar and batteries; IPM also builds new renewables but relies more heavily on imports. Capacity in 2050 under a **sales-based CES** is similar across models. Both IPM and DIEM choose to overbuild renewables in North Carolina while still maintaining fossil generation in the system for reliability purposes and for export.

63. Recall that IPM runs what coal exists a lot more than DIEM in the baseline, resulting in higher emissions.

Figure 6.8. IPM Forecast of NC Capacity Changes across Policies

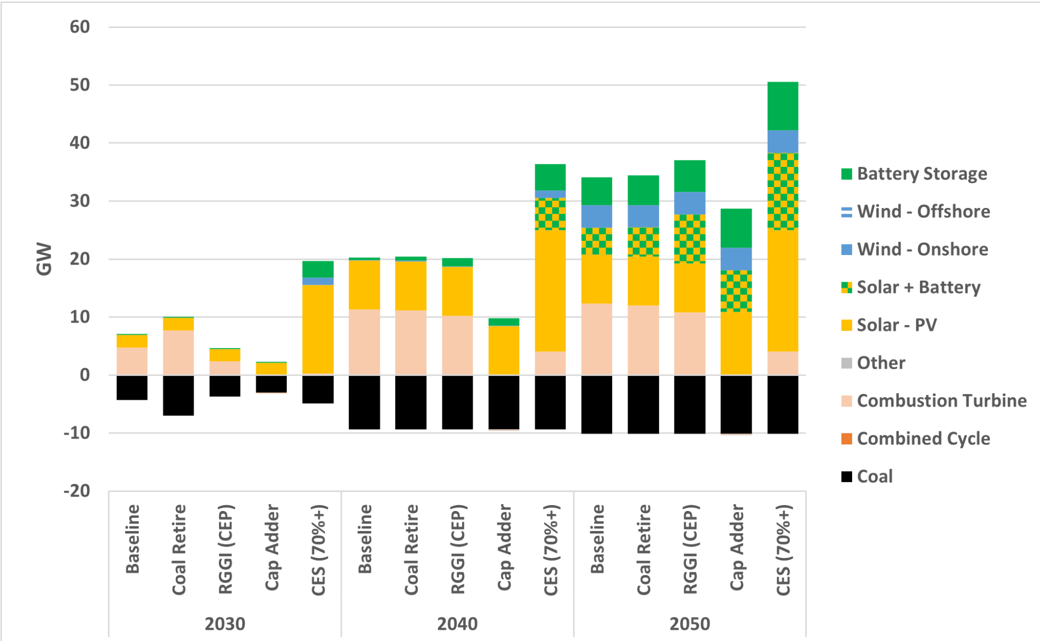
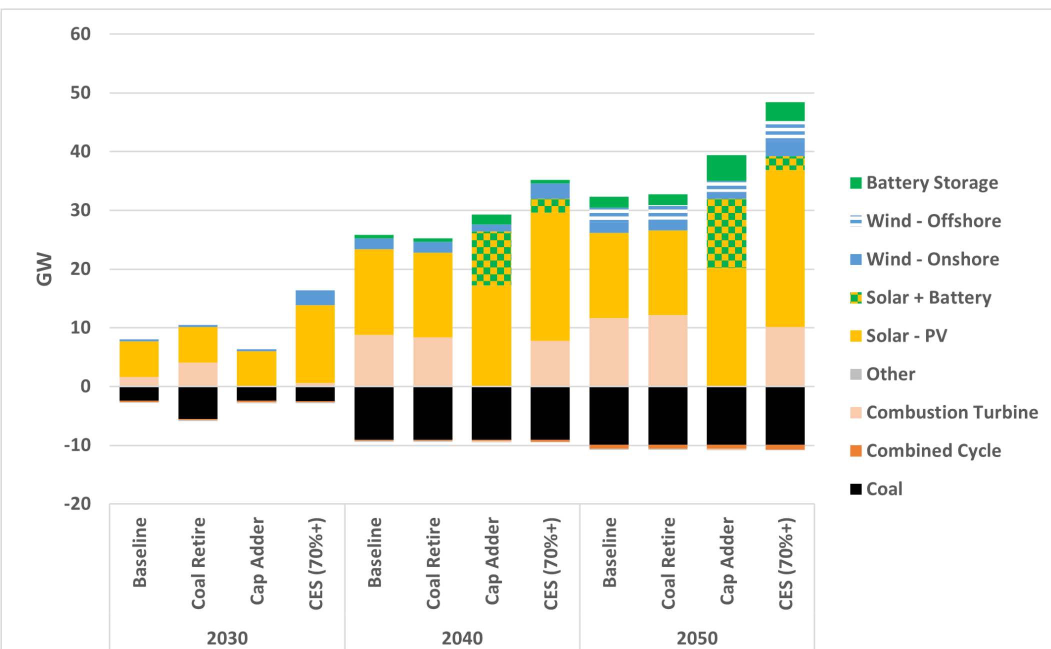


Figure 6.9. DIEM Forecast of NC Capacity Changes across Policies

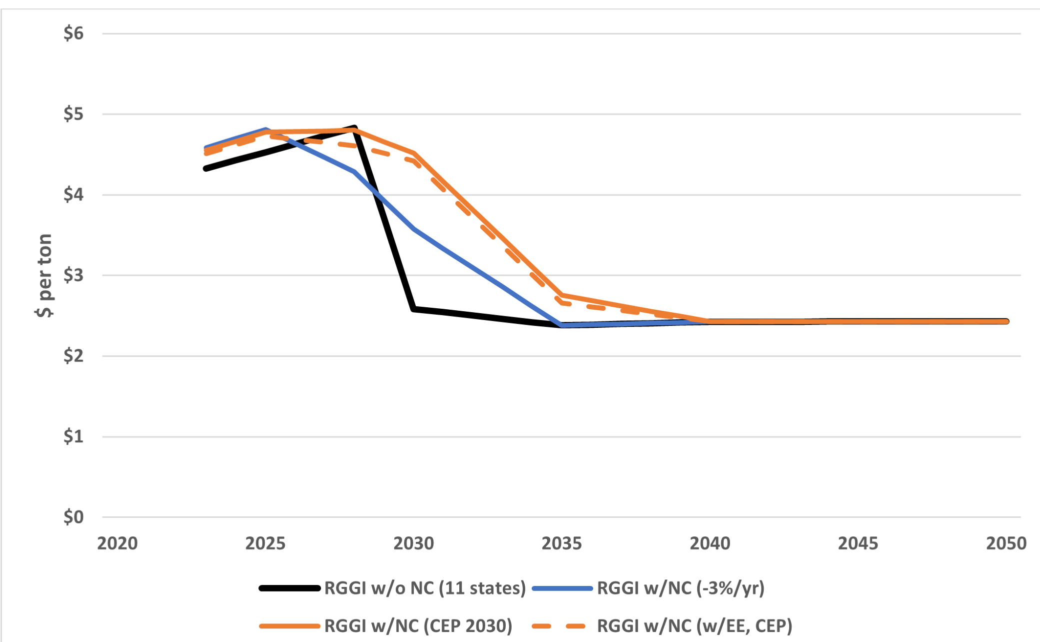


Declining Carbon Cap/Carbon Market (RGGI)

IPM has been relied on by RGGI, Inc. and participating states to conduct policy analyses; therefore, only IPM was used to explore the implications of North Carolina joining RGGI. Three options were studied, based on input from the Working Groups. In the first, North Carolina joins RGGI in 2023 and adopts a CO_2 emissions budget that would tighten by 3% each year through 2030. For the second option, North Carolina joins RGGI with a somewhat more aggressive reduction in CO_2 emissions, to match the in-state component of the 2030 CEP target (22 $MMTCO_2$). The third option considers a RGGI budget consistent with the 2030 CEP target and allowance revenues that are invested in EE.

Figure 6.10 reports the projected RGGI allowance price; the black line reflects the projected price in RGGI states if North Carolina does not join—"RGGI w/o NC (11 states)." Through 2028, the price rises but remains between $4/ton and $5/ton. The price declines towards the price floor of $2.05/ton starting in 2030. When North Carolina joins the other 11 states using a 3% decline in its budget per year through 2030, the allowance price for all members is higher in 2030 before declining to the price floor by 2035. If North Carolina joined using a smaller allowance budget (based on the in-state component of the 2030 CEP target, 22 $MMTCO_2$), the allowance price would remain above $4/ton in 2030, regardless of whether or not NC revenues are invested in EE.

Figure 6.10. IPM Forecast of RGGI Allowance Prices across Options



Figures 6.11 and 6.12 show the implications of the RGGI program for NC generation emissions. Consistent with DIEM's results for **carbon adders applied to generation** described later in this

section, in IPM the RGGI allowance price drives a significant drop in CO_2 emissions as soon as the state joins RGGI in 2023. The reduction holds fairly steady through 2030, after which emissions follow a similar pattern to baseline trends but at a lower level. Due to IPM's higher baseline, the RGGI policy by itself is not enough to meet the 2030 CEP target. (If assumptions reflected in DIEM's baseline proved to be correct, this policy might achieve the 2030 target.) However, RGGI results in lower CO_2 emissions in IPM by 2030 than any of the other basic policy cases discussed above—achieving a 64% to 67% reduction in in-state emissions from 2005 levels, depending on the stringency of the cap and the possibility of investing auction proceeds into EE.

Figure 6.11. IPM Forecast of NC In-State Emissions across RGGI Options

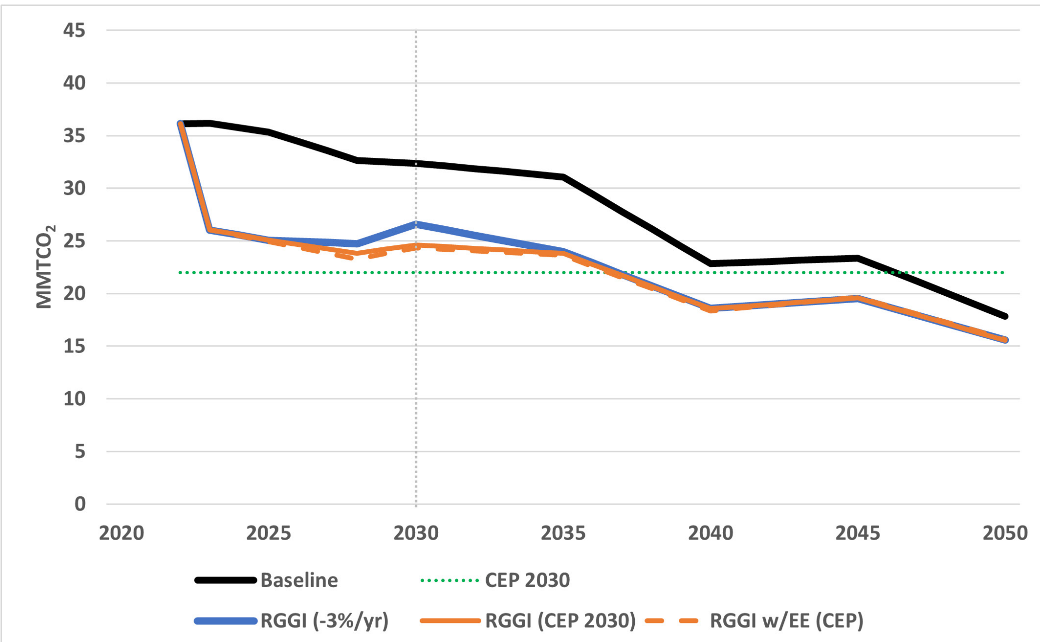


Figure 6.12. IPM Forecast of NC Import-Adjusted Emissions across RGGI

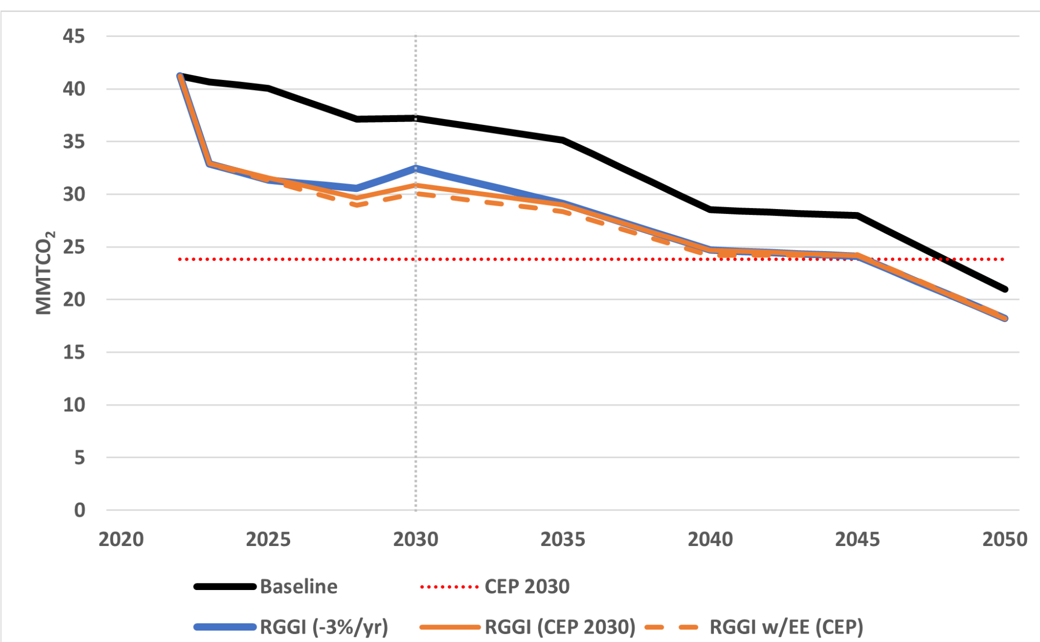


Figure 6.13a suggests that the RGGI options could drive a 20% reduction from baseline in cumulative (to 2050) in-state CO_2 emissions, with a NPV cost of around $5/ton for either level of stringency. This results in one of the more cost-effective of the four basic policy pathways, however, after accounting for emissions associated with import, the reductions achieved by RGGI fall by around one-quarter (Figure 6.13b). Investing in EE has similar emissions reductions but yields a negative cost per ton—indicating that the system saves money relative to the baseline by making these investments. As seen in the total NPV costs (Fig. 6.14) and subsequent figures on generation, a large part of IPM's response to this policy is a reliance on imported electricity. But when RGGI allowances are invested in EE, the amount of imported electricity purchases is smaller since EE has reduced demand in North Carolina, which leads the policy to have cost savings in aggregate.[64]

Figure 6.13a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

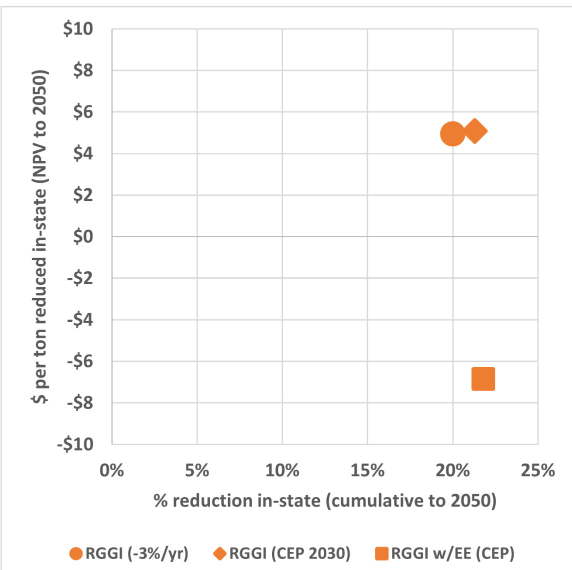


Figure 6.13b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions

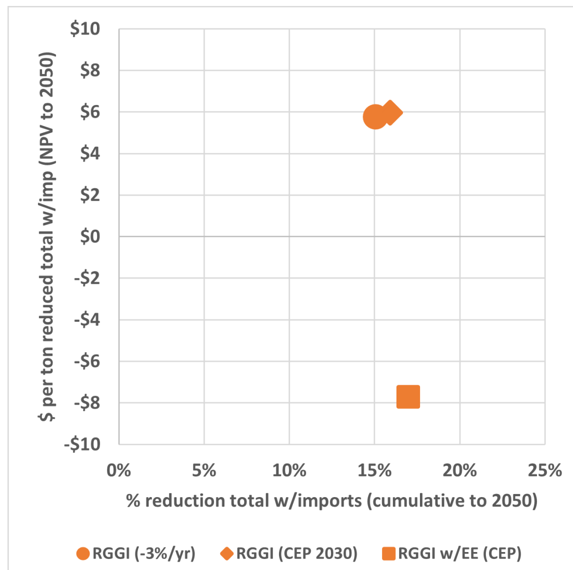


Figure 6.15 presents the generation and capacity changes in 2030 from the three RGGI options, as compared to the IPM baseline. In all cases, coal generation declines, but the reduction is—as would be expected—larger in 2030 for the cases where North Carolina joins using a tighter budget (based on the 2030 CEP target). The tighter budget also generates higher allowance prices across the RGGI states (around $4.50/ton in 2030, compared with $3.60/ton in the "-3%/year" case). On the capacity side, coal retirements are slightly less for the RGGI options than they were in the baseline. However, with coal in place to play a reliability role, new turbine construction is also lower for the RGGI runs. Renewable generation is not stimulated by joining RGGI, which is not necessarily the case in the other three basic policy options.

64. Note that the impacts of EE investment do not include the costs of the EE measures themselves.

Figure 6.14. Cost Change in NPV through 2050 (Compared to Baseline)

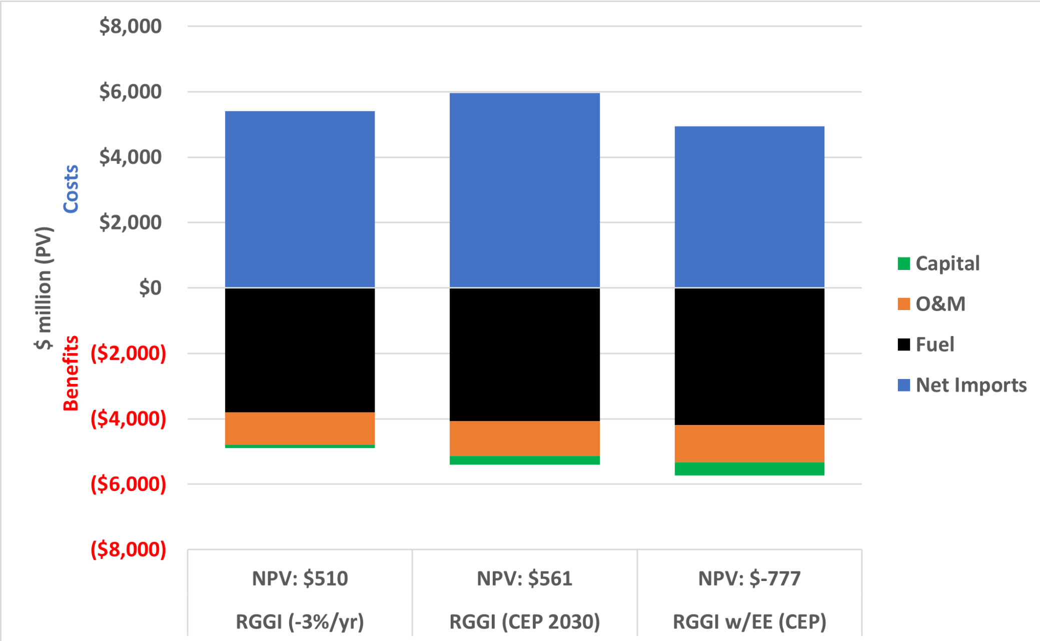
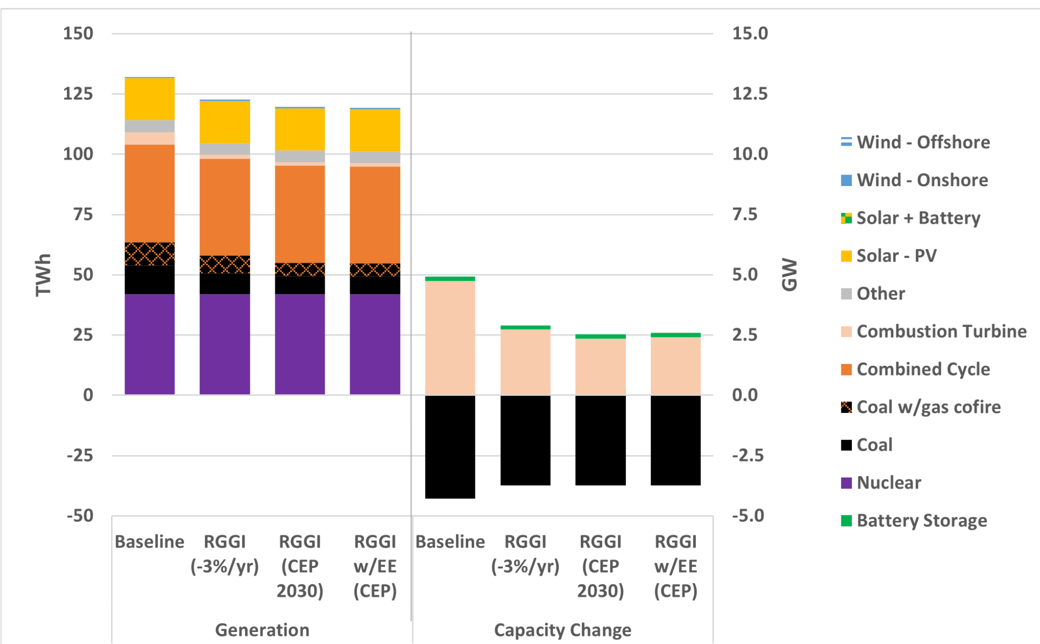


Figure 6.15. IPM RGGI Generation and Capacity Changes in 2030



This next part presents variations on the basic policy pathways for accelerated coal retirements, carbon adders, and clean energy standards.

Accelerated Coal Retirement Options

The accelerated coal retirement option presented above was one of three approaches discussed in Section 5. DIEM ran all three options to examine potential differences in emissions and cost:

(1) "Coal Retire #1" – retirement of subcritical units by 2030

(2) "Coal Retire #2" (shown previously) – retirement of subcritical units and seasonal operation of supercritical units, aside from Rogers unit 6 that can burn 100% gas.

(3) "Coal Retire #3" – full retirement of all coal plants by 2030, aside from Rogers unit 6 burning gas

Annual emissions for "Coal Retire #2" were shown in Figures 6.2 and 6.3. Figures 6.16a and 6.16b present the relative cost-effectiveness. Option #3 has similar CO_2 outcomes to Option #2, but at nearly double the cost per ton. Full retirement of the supercritical units (aside from Rogers unit 6) is more costly than allowing the units to operate at reduced loads during periods of high demand. Moreover, this prevents a more aggressive buildout of new gas capacity. Option #1, meanwhile, comes in only slightly below DIEM's baseline levels, also resulting in higher per-ton costs.

Figure 6.16a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

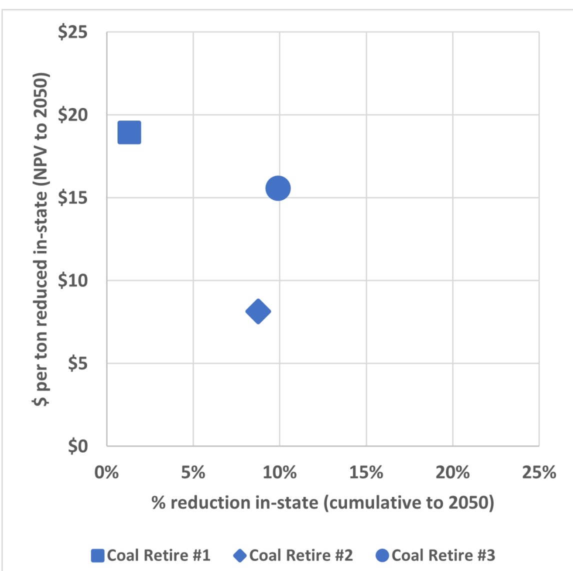
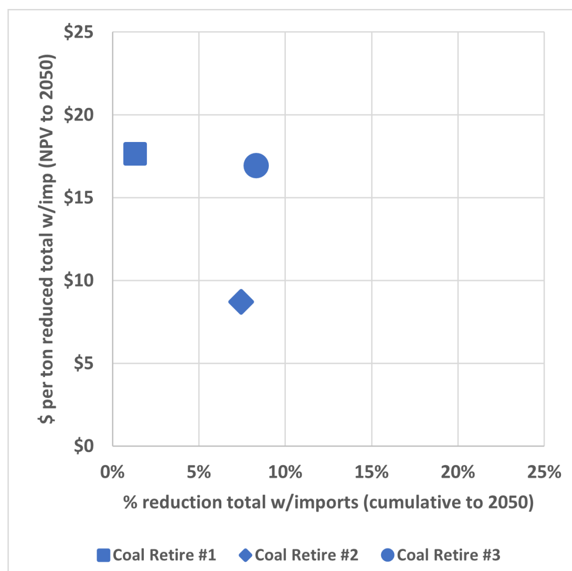
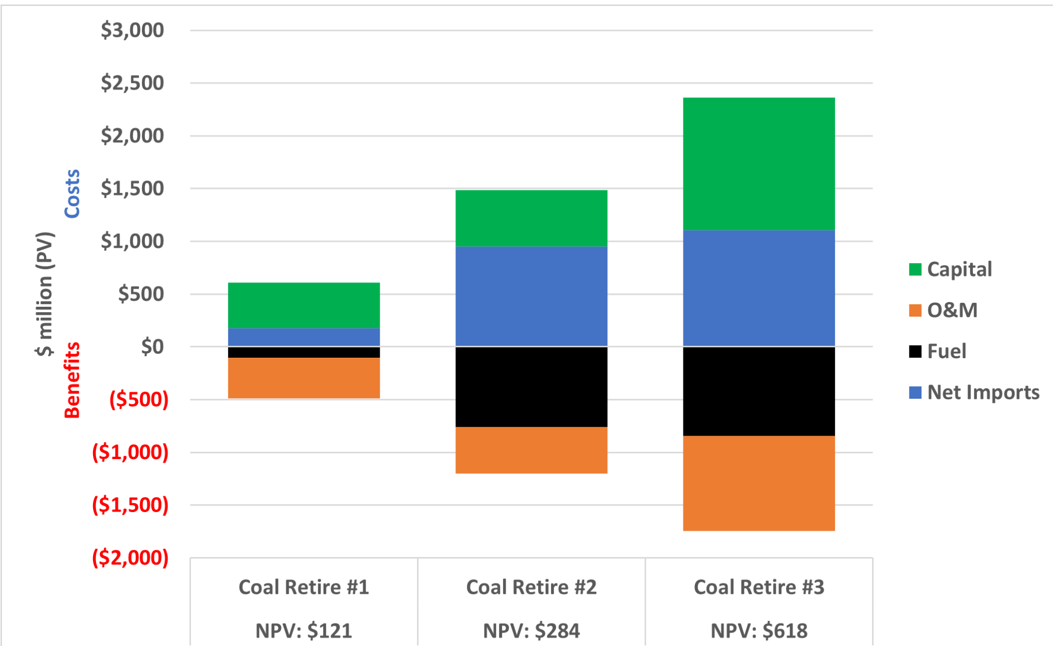


Figure 6.16b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions



These cost differences carry through in the cumulative cost analysis presented in Figure 6.17, which suggests that Option #2 is less than half the cost (at $284 million in NPV terms) of Option #3 (at $618 million). Option #1 has significantly lower costs but does not result in many CO_2 emissions reductions in DIEM (this story might be somewhat different in IPM since that model relies more on coal generation in the baseline). Policy costs are split between additional in-state capital expenditures and higher levels of electricity-import costs, which together outpace savings in fuel and O&M costs at the coal plants.[65]

Figure 6.17. Cost Change in NPV through 2050 (Compared to Baseline)



The generation and capacity changes (Figs. 6.18 and 6.19) describe why the first retirement option hews closely to baseline results. Emissions in 2030 are just 5% lower for Option #1 than baseline as some coal-fired generation has shifted into combustion turbines. There are some additional retirements of units by 2030 that would have otherwise stayed in the system (at low utilization rates) to provide reliability services. Retirement options #2 and #3 are similar—Option #3 retires more units than Option #2, but those units were not generating much electricity. By 2040, variation across the options shrinks even further. Minor generation differences can be seen between Options #1 and #2, where Rogers unit 6 unit can generate with coal in the first case and must use gas in the other two options.

65. Neither DIEM nor IPM considered any costs—or benefits—from factors such as coal ash disposal. The models also do not evaluate losses to utilities from the stranded assets represented by the existing coal fleet, since the value of existing units are a sunk cost in the modeling.

Figure 6.18. DIEM – NC Generation across Coal Retire Options

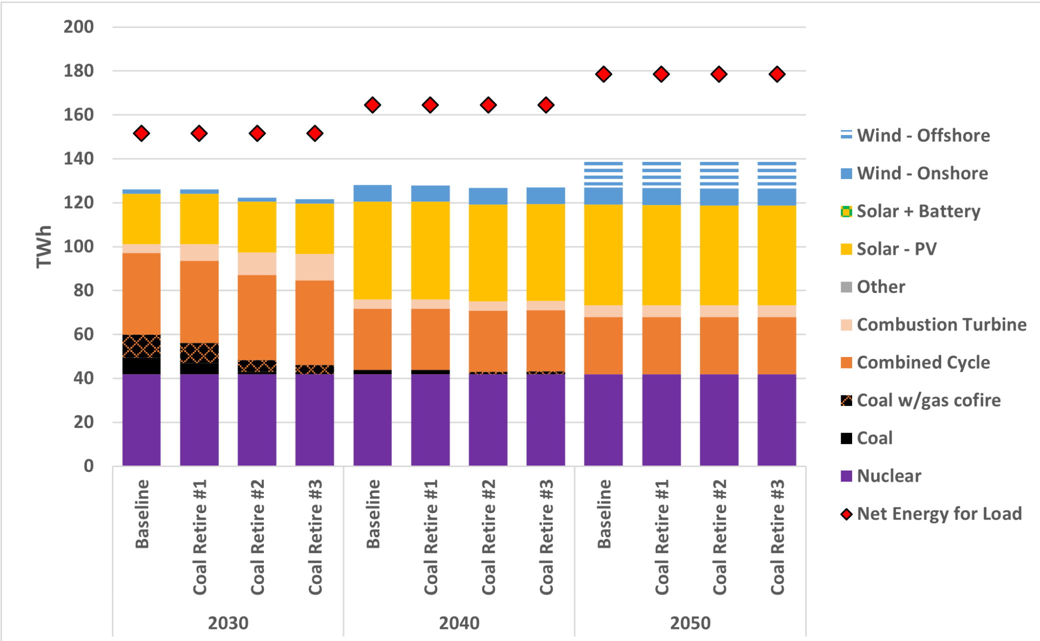
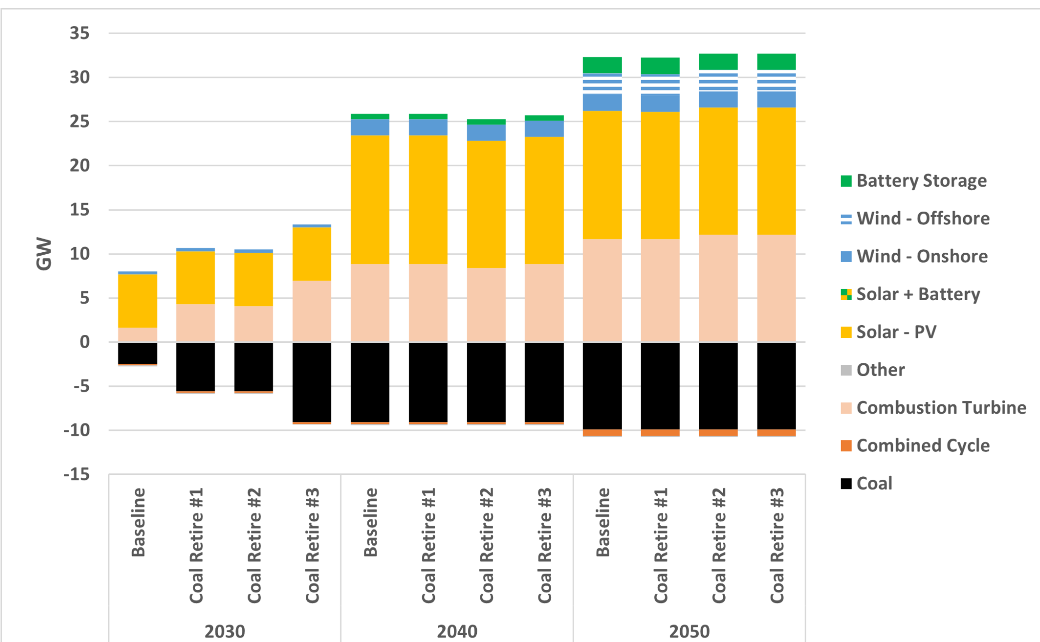


Figure 6.19. DIEM – NC Capacity Changes across Coal Retire Options



Carbon Adder Options

The Working Groups suggested a wide range of potential carbon adders to study how the system would respond to different price points and price applications. This part uses DIEM to consider the impact of different carbon adders applied to the generation of all fossil units, which has implications for order of dispatch. Model results are then compared for a variety of adders on new capacity, generation adders, and generation adders that also apply to electricity imports (i.e., border adjustments). Figure 6.20 shows CO_2 emissions from in-state generation; Figure 6.21 adds the import adjustment. Along with the baseline trends, each graph shows the relevant 2030 CEP target (in-state/import-adjusted).

Starting with Figure 6.20, CO_2 emissions under the "CEP Cap ('U.K.')" approach track a linear decline to 70% below 2005 levels by 2030 and 95% below 2005 levels by 2050.[66] By definition, then, this approach meets the 2030 CEP target. Using this dashed gray line as the basis for comparison, the results suggest that all other carbon adders on generation would also achieve the in-state component of the 2030 CEP target, 22 $MMTCO_2$ (i.e., if North Carolina did not consider emissions associated with imports). Several different versions of the adders that are around the $10–$15/ton mark in 2030 have roughly similar impacts on emissions (the orange and blue lines). The "$6 + 7%" and "$13 + 7" adders begin in 2023 and suggest the system responds quite quickly to adders applied to fossil dispatch decisions; the two "$5" adders don't begin until 2025 and thus cannot be used to assess their impact on emissions in 2023. Bookending these intermediate price points, the 2017 Social Cost of Carbon (SCC) reaches around $4/ton in 2030, while the 2016 SCC begins at more than $40/ton in 2023. In response to the most aggressive carbon adder, the model does everything feasible to shut down in-state fossil generation.

For most of the carbon adders, the total emissions associated with NC consumption of electricity (i.e., adjusted for imported electricity) rises by around 5 $MMTCO_2$ (Fig. 6.15). Even so, the system is responsive enough to meet the 2030 CEP target even considering imported electricity emissions. However, although import-adjusted emissions from the SCC 2016 adder are below the 2030 target, so much NC fossil generation is shut down that the system must import electricity representing 10–20 $MMTCO_2$ of emissions over the first decade of the policy. Across the adders, additional policy adjustments would be needed to address the emissions from imports to meet the 2050 net zero target.

Tracking results in the CO_2 emissions graphs, Figures 6.22a and 6.22b show a generally linear trend where higher carbon prices on generation lead to greater reductions at an increasing cost per ton as more emissions are removed from the North Carolina system. At the extreme, the 2016 SCC almost completely eliminates in-state fossil generation and emissions but looks less productive when considering the impacts of "imported" emissions, given the increase in electricity imports.

This effect of the "SCC 2016" adder is echoed in Figure 6.23, which shows that expenditures for imported electricity are the biggest share of the policy's large NPV of $15.5 billion dollars over

66. The run did not include options for banking or borrowing of carbon allowances, which would likely result in a "lumpier" distribution of emissions over the time period.

2023–2050. This is in contrast to—for example—the carbon adder on generation that starts in $6/ton and grows at 7% per year. While imported electricity is still the largest share of net expenditures, the much smaller absolute level of imports results in a cost per ton reduced that is less than half of the "SCC 2016" case. Across all price points, fuel expenditures decline and capital expenditures grow as the state shifts away from fossil and into renewables.

Figure 6.20. NC In-State Emissions across Carbon Adders on Dispatch

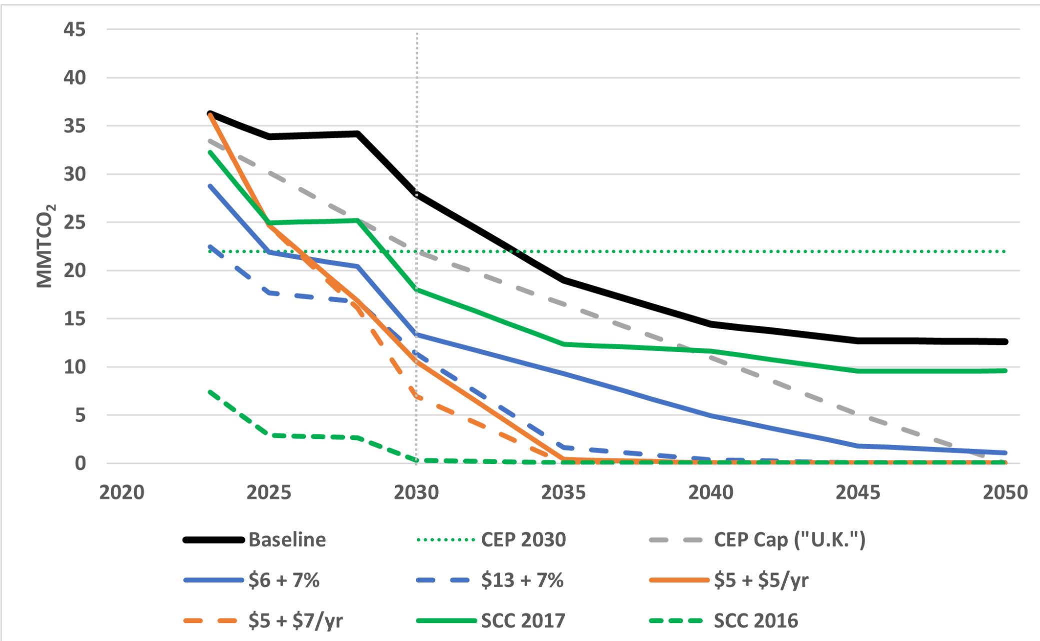


Figure 6.21. NC Import-Adjusted Emissions across Adders on Dispatch

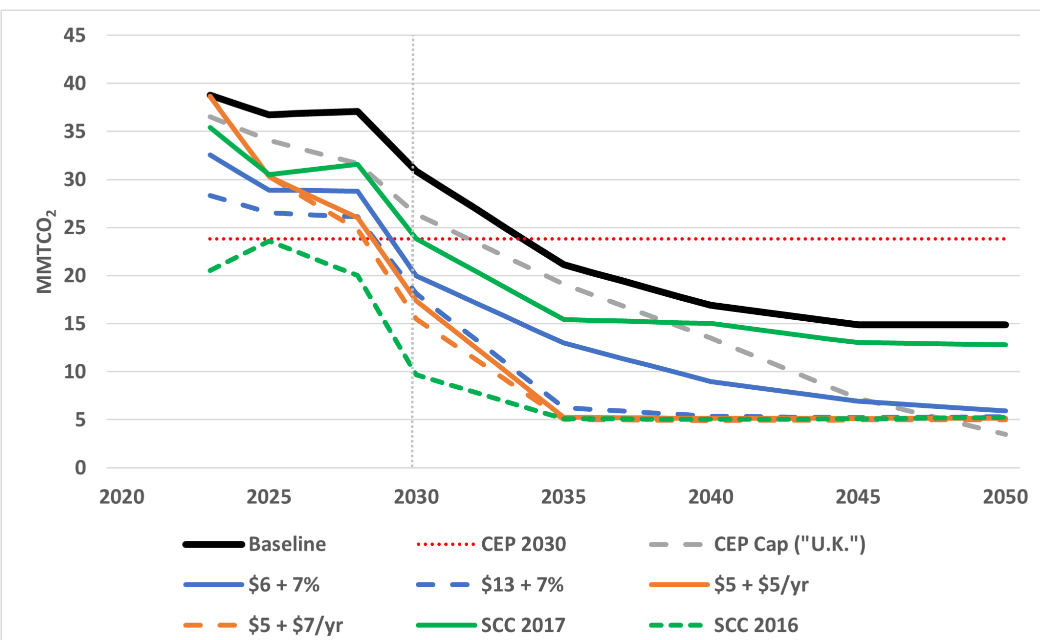


Figure 6.22a. Cost of In-State Reduction vs. % Reduction in Emissions

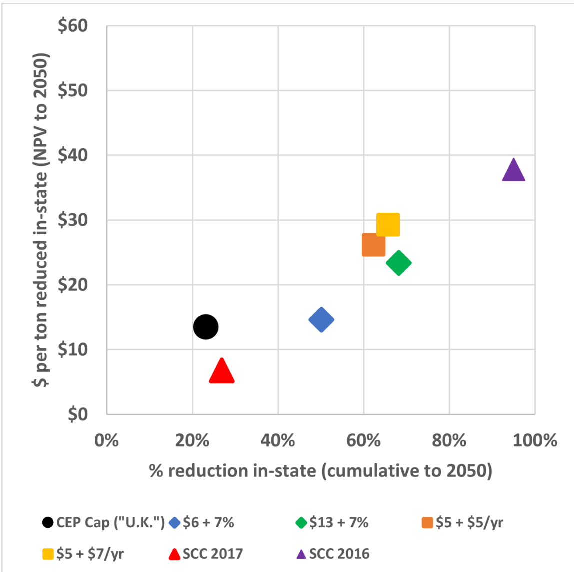


Figure 6.22b. Cost of Total Reduction vs. % Reduction in Emissions

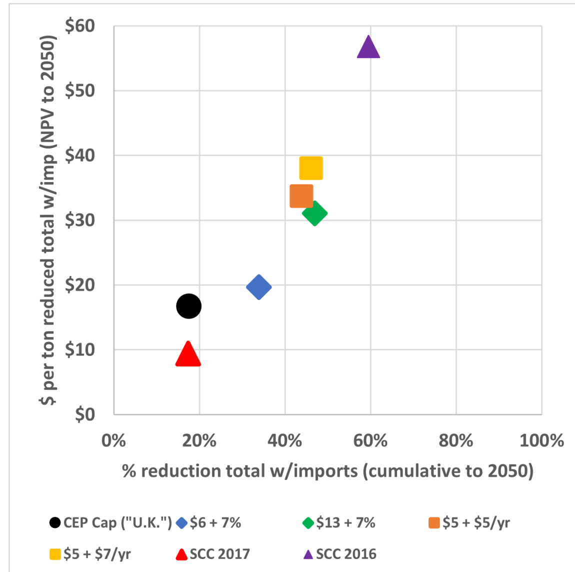


Figure 6.23. Cost Change in NPV through 2050 (Compared to Baseline)

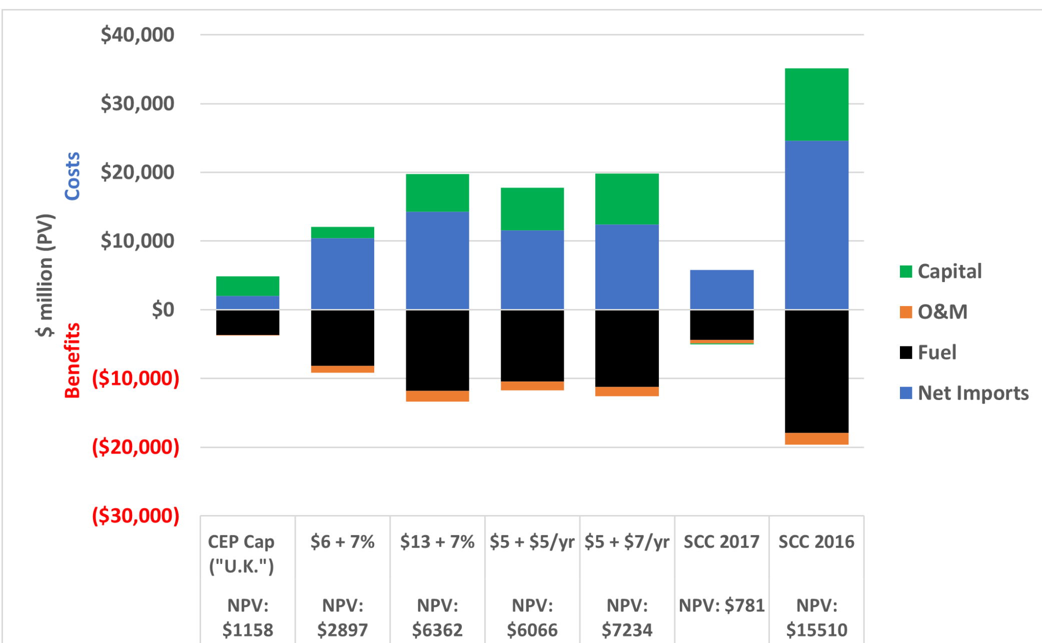


Figure 6.24 projects how North Carolina generation might respond in 2030 and 2050 to the range of modeled carbon adders applied to generation. Across most of the options, additional electricity is being imported (the difference between generation and NEL) in response to NC-only carbon

adders on generation. Changes in the generation mix track the level of the adder with small adders (such as SCC 2017: $4/ton in 2030) having a small impact on generation, and large adders (such as SCC 2016: $50/ton in 2030) more than doubling the cost of running a coal plant and so eliminating coal generation and potentially most of the gas generation. By 2050, the responses to carbon adders are fairly similar since coal units were retiring in the baseline anyway and the carbon prices have discouraged most gas generation (assuming border adjustments aren't being made to address imported CO_2 emissions).

In 2030, the total capacity mix varies less than the generation mix between policies (Fig. 6.25). The adders tend to accelerate the construction of onshore wind, but do not force all coal units to retire—even those not running much—since the system needs their reliability services to facilitate higher levels of renewables. In 2050, reaching net zero in-state emissions under the "CEP 2050 cap" (the U.K.-style approach) leads to higher in-state construction of renewables than the other policies, which are relatively similar in terms of their reliance on renewables combined with batteries and turbines for reliability.

Figure 6.24. NC Generation across Carbon Adders on Dispatch

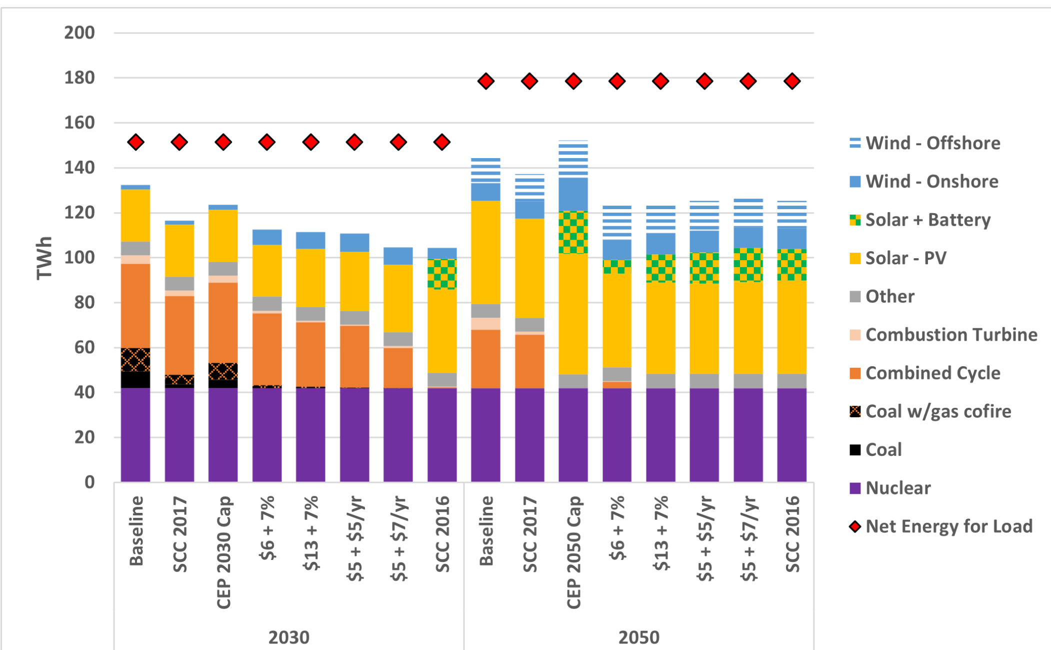
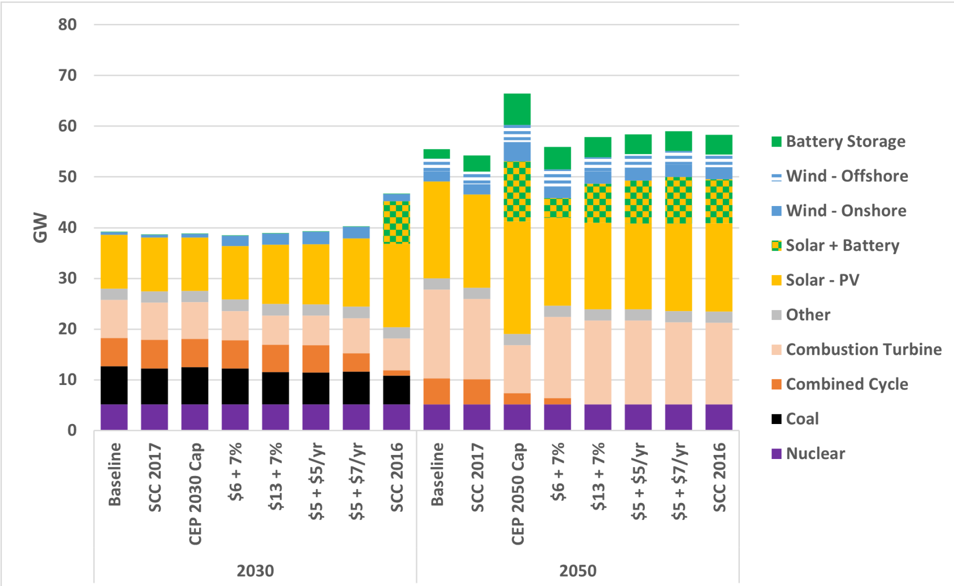


Figure 6.25. DIEM – NC Total Capacity across Carbon Adders on Dispatch



The next set of carbon adder runs in DIEM examine different applications for an adder on new capacity ("New Cap"); on capacity and fossil generation ("Gen"); and then also on generation with a border adjustment on imported electricity based on the import's carbon content, similar to the way California handles imports under its greenhouse gas program (note that in none of these cases are NC customers paying for these border adjustments, they are merely attempting to equalize the choices between in-state and imported generation). Figures 6.26a, 6.26b, and 6.27 show the cost impacts of these alternatives; Figure 6.28 shows the in-state and import-adjusted CO_2 emissions consequences.

A carbon adder on new capacity investments has relatively limited impacts on either in-state or total import-adjusted emissions, though it does provide some reductions compared to the baseline. There is no difference between the adder that starts at $6/ton and one that starts at $13/ton; the lower is sufficient to discourage new fossil generation within North Carolina. Carbon adders on in-state generation (in green) suggest that a $6/ton adder growing at 7%/year can reduce cumulative in-state emissions by around 50% between 2020 and 2050, at an average system cost of approximately $15/ton in present value terms. If the carbon adder also applies to "imported emissions" {$6/$13+ (import adj)"}, the system's cost per ton metric increases since imports are no longer a way to avoid the adder. The orange dots (with import-adjusted fees applied) reflect smaller in-state emissions reductions (and lower cost-effectiveness) as more generation remains within North Carolina. Figure 6.26b shows that considering total CO_2 emissions (in-state plus imports) reduces the effectiveness of the carbon adder policies as generation is shifted into surrounding states.

Applying a border adjustment leads to higher costs overall and shifts the mix from expenditures on imported electricity to capital construction within the state (Fig. 6.27). The difference between the two cost estimates represents the savings associated with importing electricity as a means of avoiding the carbon adder. (Electricity imports are valued on the assumption that North Carolina purchases electricity from other states at North Carolina's marginal wholesale price.)

Figure 6.28 considers the consequences of a carbon adder without versus with an import-adjustment fee. Broadly, results suggest that an import fee has the largest impact on CO_2 emissions between now and 2030, although in-state emissions remain higher throughout the model horizon to 2050 as the result of reduced imports.

Figure 6.26a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

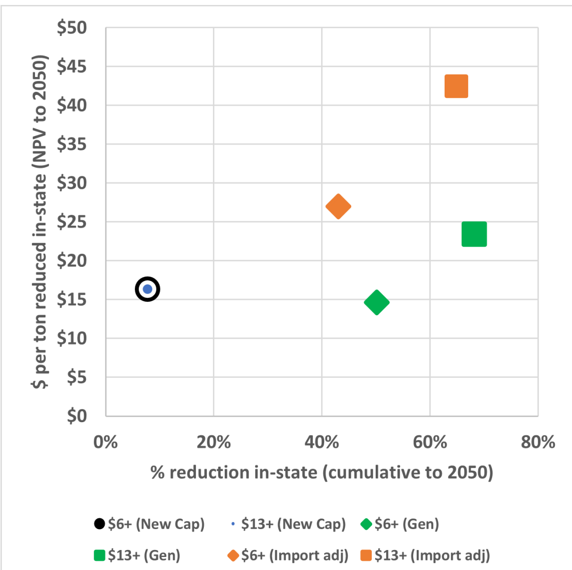


Figure 6.26b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions

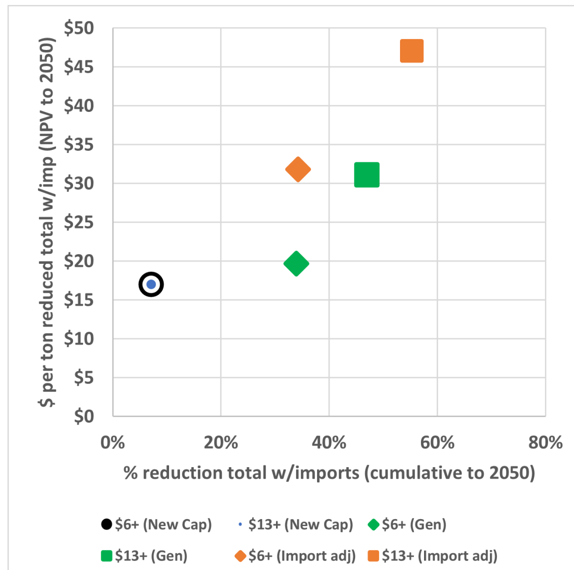


Figure 6.27. Cost Change in NPV through 2050 (Compared to Baseline)

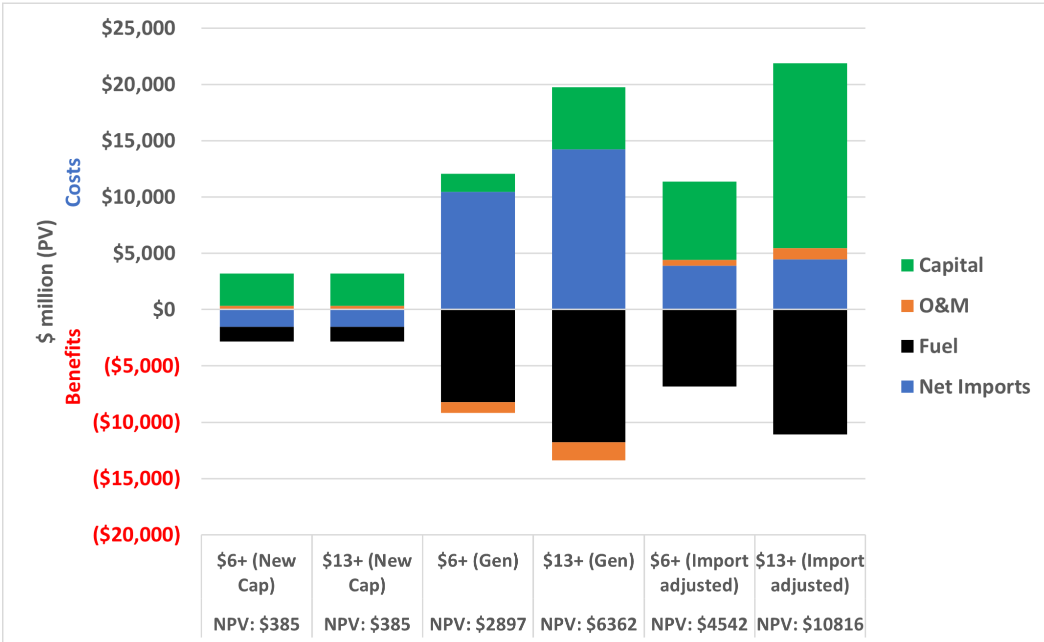


Figure 6.28. NC Emissions for a $6/ton+ Carbon Adder on Dispatch

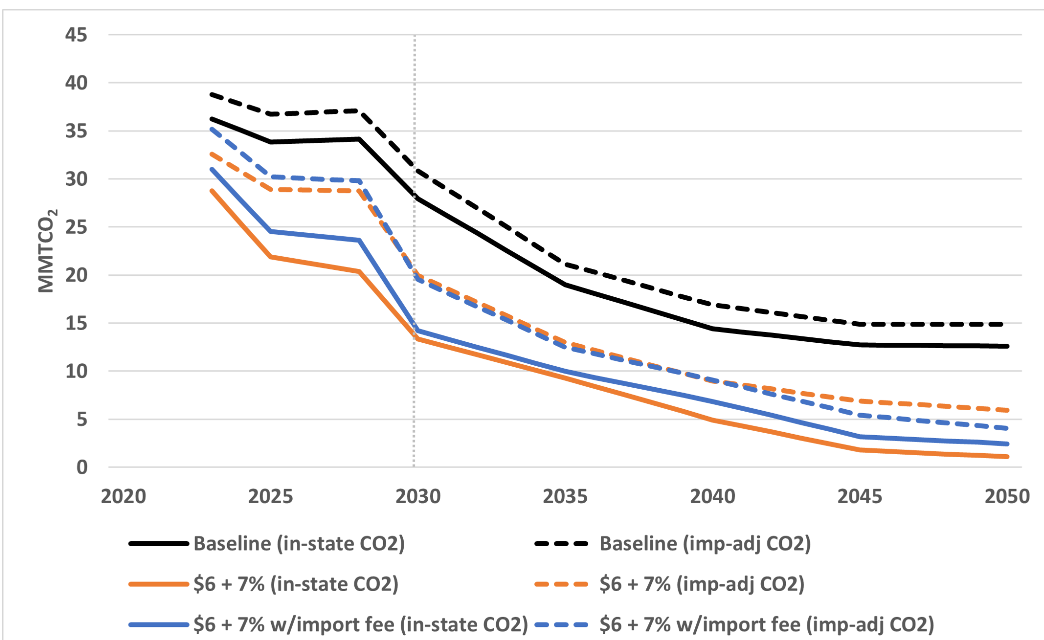
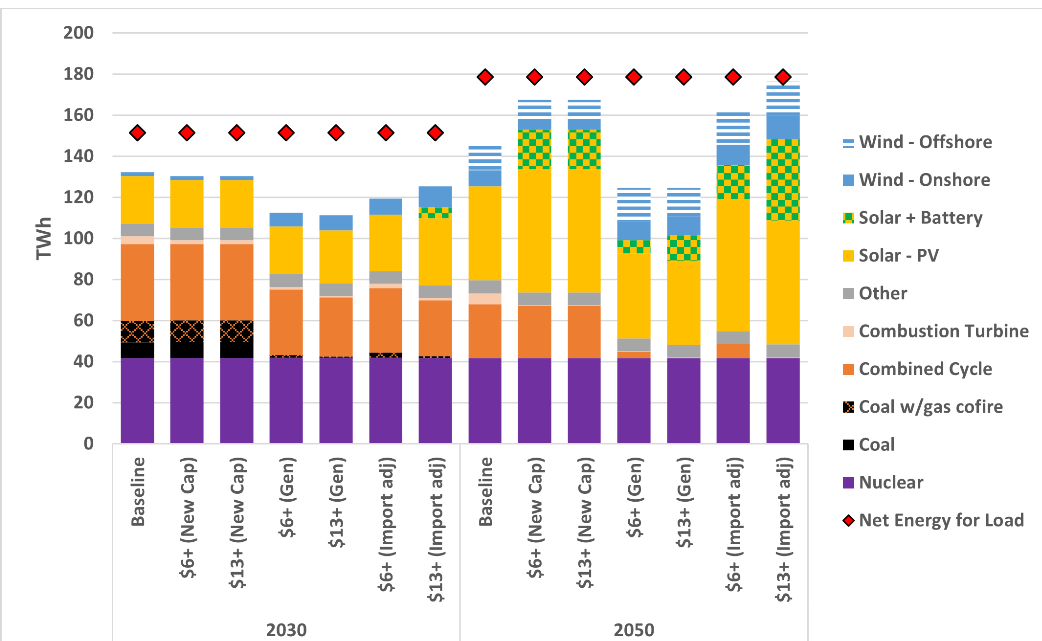


Figure 6.29 shows the generation mix associated with three applications of carbon adders: on new capacity ("New Cap"), on generation ("Gen"), and on generation with a border adjustment ("Import Adj"). This is done for two levels of adders: $6/ton and $13/ton, growing at 7% per year.

Again, since the $6/ton adder is sufficient to preclude new construction of turbines, DEIM shows no difference between that adder and a $13/ton adder. Similarly, the generation patterns of the $6/ton and $13/ton (plus 7% per year) adders applied to dispatch of all fossil units are quite close in the years 2030 and 2050 (the emissions results from Figure 6.28 above suggest more differences could be seen in the intervening years).

Larger impacts on both generation and total capacity can be seen for the "import adjusted" model runs, where the adder is applied to both dispatch and on imported electricity. These approaches can reduce—potentially significantly—the incentives to import electricity so as to avoid the adder. By 2050, most or all of NC retail sales are supplied by in-state non-fossil generation, although imports in the $6/ton case are used to reduce the need for the installation of paired solar/battery units seen in the $13/ton case. Since these adders apply to generation, the capacity results suggest that the system still finds it cost effective to maintain (and slightly expand) the combustion turbine fleet for reliability reasons.

Figure 6.29. NC Generation across Carbon Adder Implementations



Utility Business Model/Regulatory Context

DIEM and IPM select least-cost dispatch (generation) and capacity to meet electricity demand under different constraints—fuel prices, transmission capacity and other reliability considerations, the costs of building or running generating units, and of course, different climate policies. Least-cost dispatch is certainly employed in the real-world, particularly in competitive wholesale markets, while "least cost" procurement of new capacity is a bedrock principle in many public utility laws, including Chapter 62 of North Carolina's General Statutes. However, regulatory and market contexts can create different incentives for operators to build and run power plants, which may run counter at times to purely "least cost" principles. The contexts that create these incentives, moreover, are not fixed but may change over time. Given that the modeling for this report is projecting scenarios for the next thirty years, it is highly likely that the regulatory and market context may shift in that time period.

The CEP launched a parallel effort to the one culminating in this report, a stakeholder process to study the utility business model in North Carolina. That process has resulted in a set of recommendations such as multi-year rate plans; performance-based metrics for utility cost recovery in the ratemaking process; competitive procurement of new capacity, building on the successes of HB589 ("Competitive Energy Solutions for North Carolina"); and the entry of North Carolina's IOUs in competitive wholesale electricity markets.[1] Depending on their design, these proposals could create new incentives for the IOUs operating in North Carolina, or for independent power producers, to build new clean energy in the state. They could also accelerate the electrification of other sectors of North Carolina's economy, or stimulate energy efficiency measures, both of which could have profound effects on electricity demand in the state.

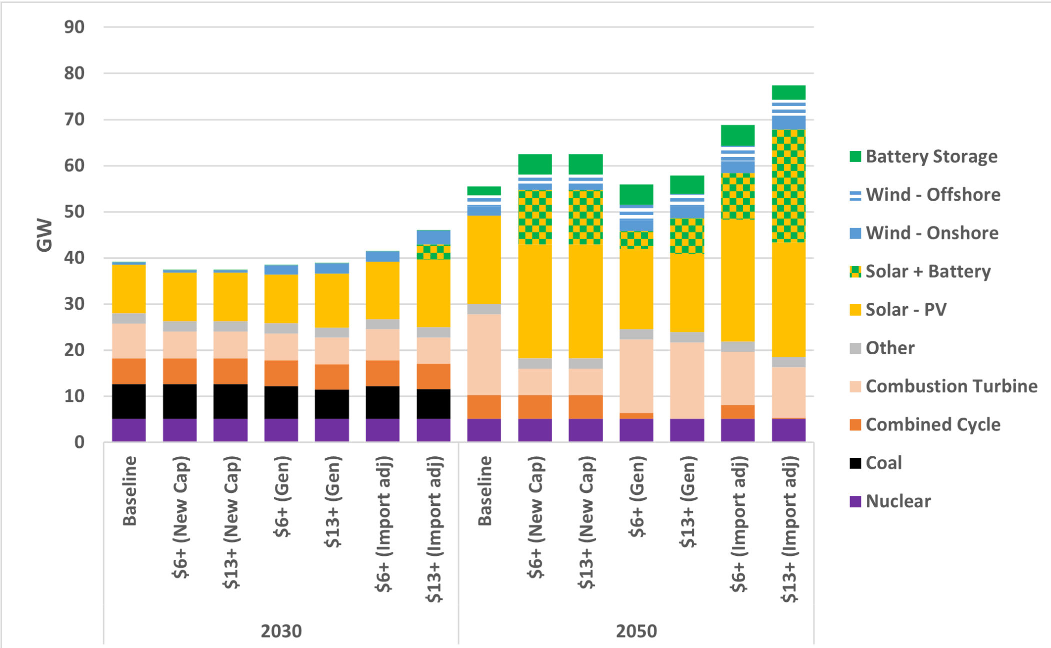
In addition, DEC and DEP gave notice to the NCUC on December 8, 2020, that they have negotiated an agreement with other Southeastern utilities to create a Southeast Energy Exchange Market. The "market" would be a platform where about 16 utilities could buy and sell electricity in 15-minute increments across the footprint of Alabama, Georgia, Kentucky, Mississippi, Missouri, Tennessee, and the Carolinas.[2] SEEM would not have any centralized dispatching authority, nor would it control the transmission of participating utilities. Moreover, SEEM transactions would likely represent a small share of total power sector activity; currently, 15-minute trades represent just 1–2% of total load in the region.[3] Some point to this as the possible beginning of a more open power market in the Southeast, with implications for electricity costs and the carbon intensity of regional generation, while others believe more competition is warranted. In any event, this filing, coupled with the broader set of NERP recommendations prepared by North Carolina stakeholders, suggest that the regulatory and market context for power sector generation and procurement could change in the coming years. These changes could impact the directional trends identified in this report's modeling.

1. See the NERP final report.

2. The covered utilities extend into Florida, Iowa, and Oklahoma as well.

3. See, e.g., R Street, Fact Sheet on Options for Enhancing Regional Competition in Wholesale Electricity (Sept. 29, 2020), https://www.rstreet.org/2020/09/29/fact-sheet-on-options-for-enhancing-regional-competition-in-wholesale-electricity/.

Figure 6.30. NC Capacity across Carbon Adder Implementations



Clean Energy Standard Options

In addition to the basic sales-based CES policy that required 70% clean generation in 2030 and 95% clean by 2050, DIEM was used to analyze different versions of this policy. Four of the additional cases vary the 2030 target between 60% and 75% clean generation. Another case considers scaling from 70% in 2030 to 100% in 2050 (instead of 95%). A final alternative case presented here applies the CES to in-state generation instead of sales to see how differently the system might respond to this policy definition.

Figure 6.31 shows the CO_2 consequences of the different definitions. Reducing the 2030 target from 70% clean to 60% shrinks the emissions reduction in 2030 by around 4 $MMTCO_2$ from baseline. However, moving modestly in the other direction (from 70% to 75%) yields an additional 4 $MMTCO_2$ reduction, suggesting that the system has made more significant adjustments to achieve that additional 5% clean generation in 2030. The largest reduction in in-state CO_2 emissions for 2030 for a CES policy, meanwhile, comes from a CES defined over in-state generation ("CES Gen"). A generation-based CES puts more pressure on in-state fossil, because under a sales-based CES, fossil in North Carolina can continue to produce for export markets. After 2030, the emissions paths tend to bunch together with the exceptions of the option that targets 100% clean generation in 2050 or the one that is generation-based.

Although the CO_2 emissions results in Figure 6.31 suggests that defining a CES over generation achieves deep in-state reductions, Figure 6.32 makes clear that most of these reductions are offset by emissions associated with electricity imports. Here, the generation-based CES performs only modestly better on emissions than the baseline. Similarly, after considering "imported" emissions, the CES that achieves 70% clean in 2030 has total CO_2 emissions similar to the CES targeting 75% in 2030.

As discussed, CES policies appear more costly relative to other modeled policies. In part this is due to the fact that CES doesn't specifically target fossil generation but relies on building renewables to indirectly drive out existing fossil units. (This buildout also creates jobs and stimulates economic development.) Additional reasons are tied to DIEM's particular results. The DIEM baseline already includes significant renewables construction, leaving fewer (and more expensive) opportunities to install additional renewables. For the same reason, the absolute level of CO_2 emissions reductions is small in DIEM, leading to an unfavorable comparison on a cost-per-ton basis.

Comparing policy costs across the sales-based CES levels (Figures 6.33a and 6.33b), it is notable that a CES requiring 90% clean in 2050 has a similar cost per ton as the CES that reaches 95% in 2050 (see also the NPV comparisons in Figure 6.34). The other notable result in Figure 6.33a is how much more cost-effective a CES policy that is defined over in-state generation ("CES Gen") appears in relation to CES based on in-state retail sales. As discussed above, shown by the results in Figure 6.33b, and explained in further detail in Figure 6.35, this is because in-state generation decreases significantly and the policy encourages electricity imports, which represent a large fraction of the total policy costs.

Figure 6.31. DIEM Forecast of NC In-State Emissions across CES Options

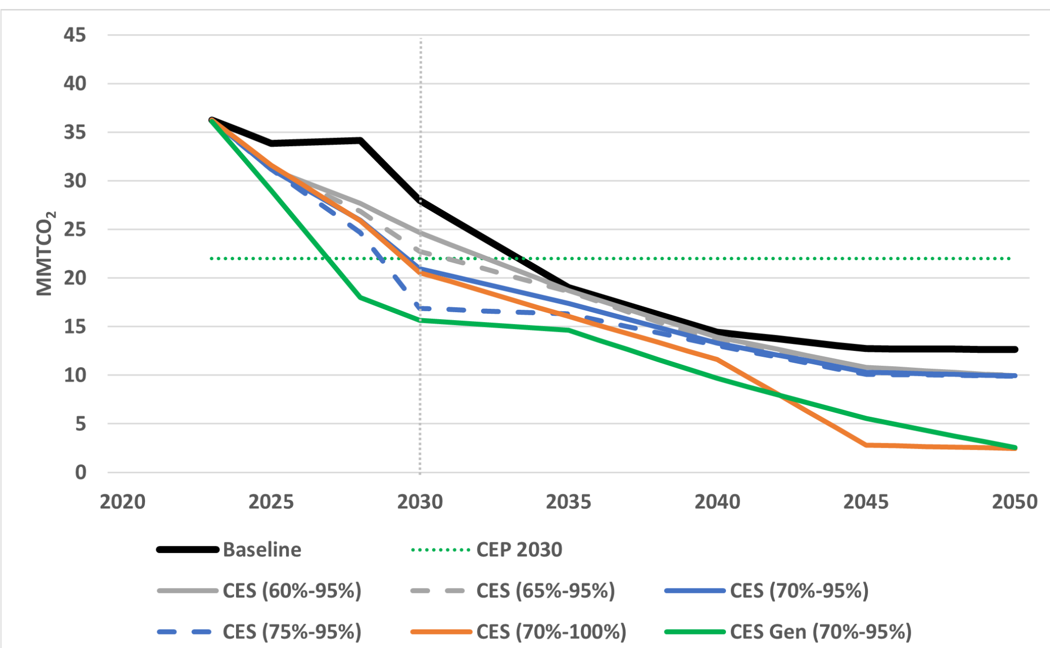


Figure 6.32. NC Import-Adjusted Emissions across CES Options

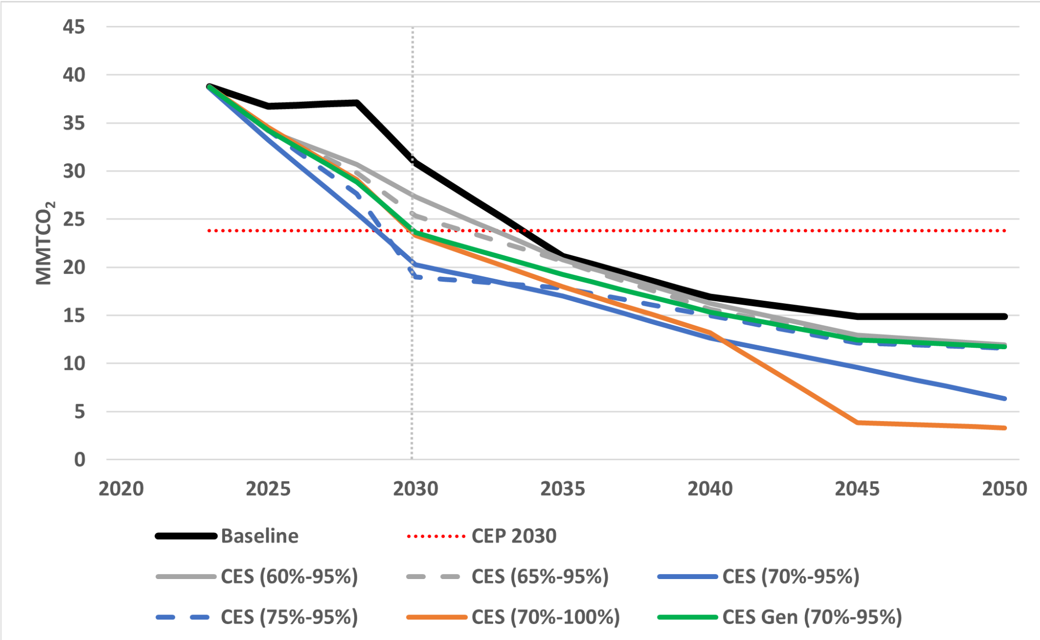


Figure 6.33a. Cost of In-State Reduction vs. % Reduction in Emissions

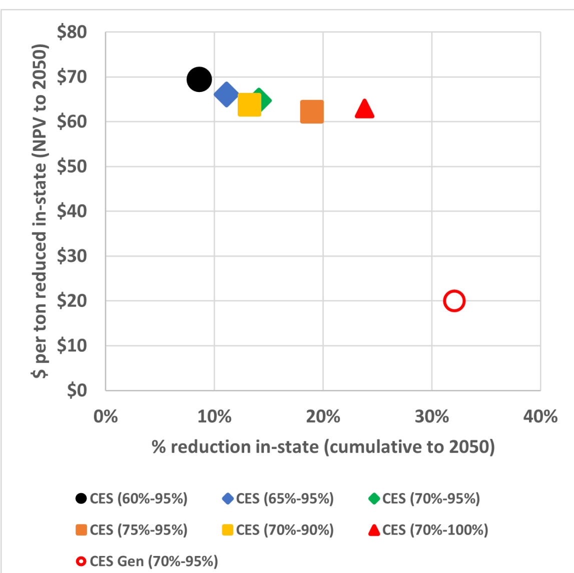


Figure 6.33b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions

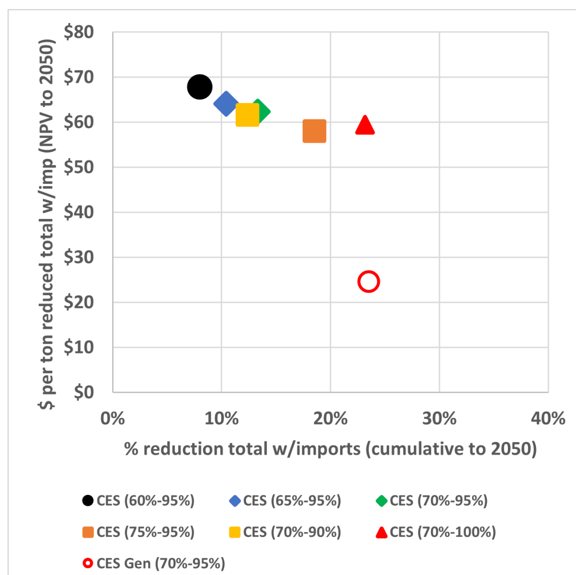


Figure 6.34. Cost Change in NPV through 2050 (Compared to Baseline)

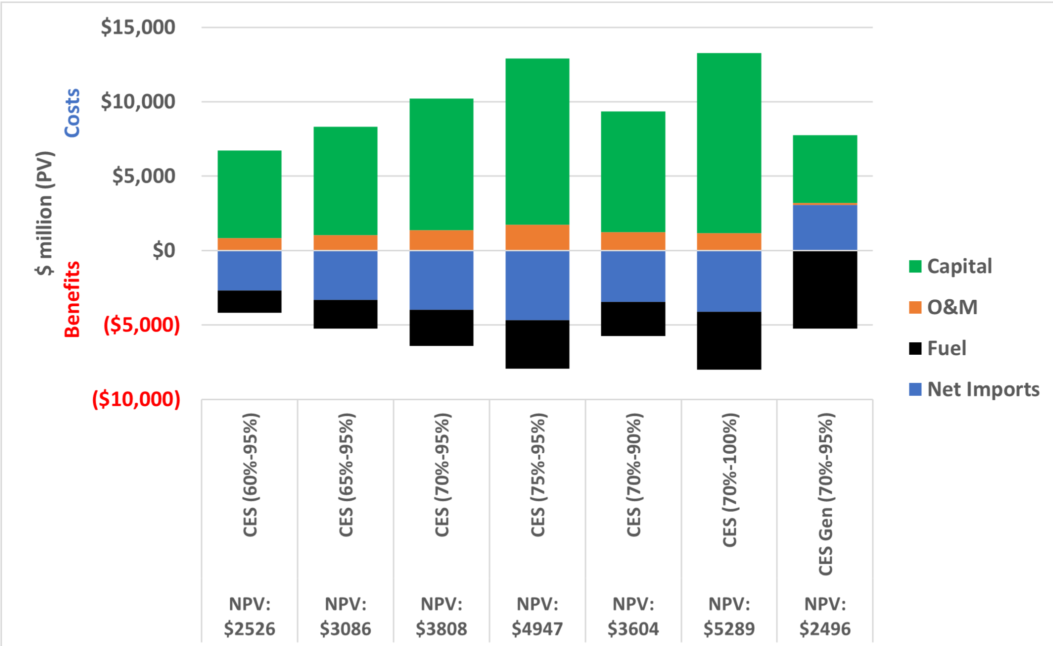
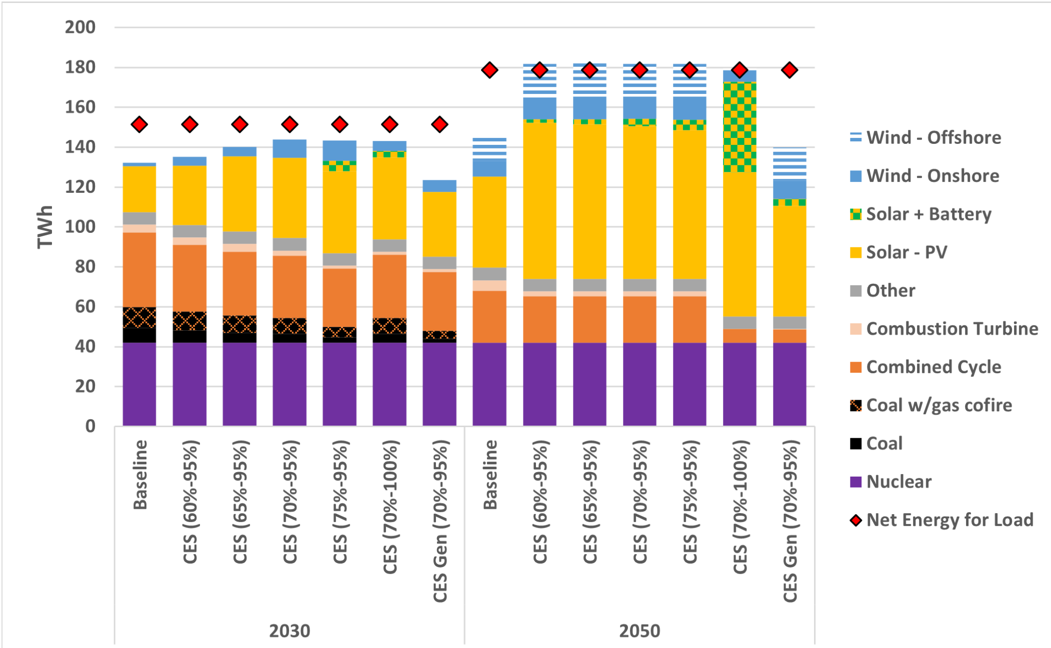


Figure 6.35 shows the generation patterns that drive the CES emissions trends across the options. The model results show a modest decline in fossil generation as the 2030 target increases from 60% to 70%. Those changes are driven largely by the amount of in-state renewables since a CES policy does not target fossil generation directly. As in-state renewables expand in 2030 to meet the target, imports decline under a sales-based CES. Once the 2030 goal reaches 75%, in-state renewables have already replaced the baseline imports and consequently in-state fossil generation feels more of an impact, even though the CES does not explicitly target fossil generation. A similar trend in 2030 is seen for the CES that is heading towards 100% clean by 2050. Once again, the notable outlier in 2030 is the CES policy targeting generation—here, the system meets the generation goal by reducing in-state generation so that fewer renewables (in TWh) are needed to supply 70% of in-state generation.

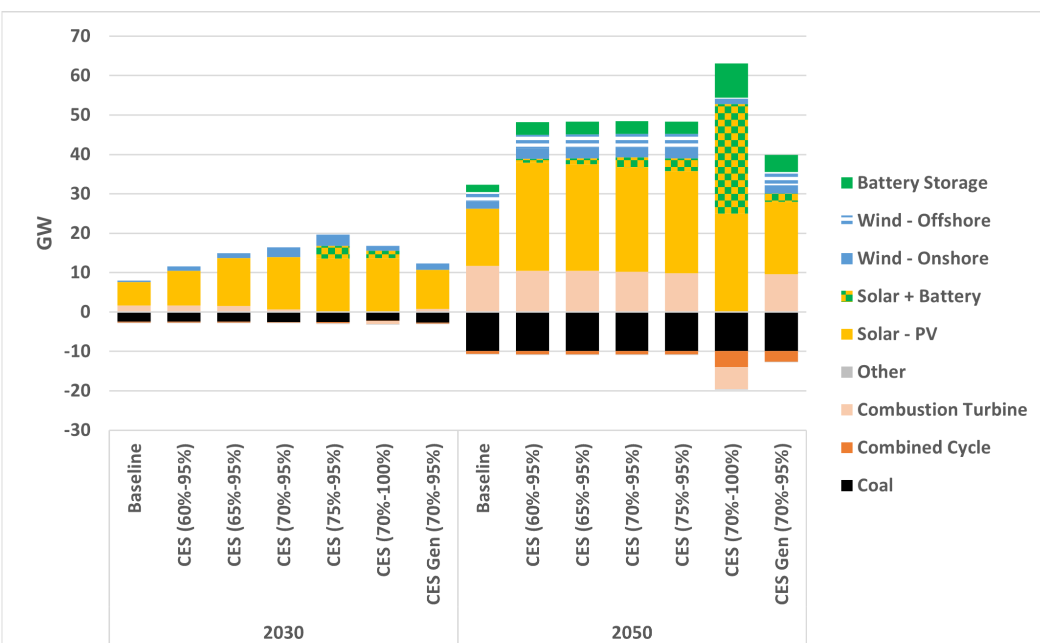
By 2050, there are few differences across the “95% clean” policies. Alongside an overall expansion in renewables, North Carolina shifts from being an electricity importer to exporting electricity under the CES. These exports, along with the fact that a sales-based CES does not consider transmission and distribution losses that lead retail sales to be smaller than generation, allow the system to reduce costs and maintain more flexibility by keeping in-state fossil generation active. Targeting 100% clean in 2050, meanwhile, shifts the mix out of most fossil generation, which then requires more reliance on paired solar/battery installations to provide reliability services that would have been supplied by fossil units. If the CES instead targets generation, the mix is quite a bit different—and generation is lower—by 2050 as imports are an easier way of meeting the generation goal.

Figure 6.35. DIEM Forecast of NC Generation across CES Targets



The capacity changes presented in Figure 6.36 support the generation shifts seen across the options. There is a steady increase in new solar capacity in 2030 as the target in that year tightens. By 2050, the options achieving 95% clean have similar expansions in renewables—along with new turbines to provide reliability services (even if they are not generating much, or at all). Reaching 100% clean in 2050, however, has much bigger changes in capacity than reaching 95%. Additional batteries are needed to offset a lack of turbines and other fossil generation. Alternatively, capacity changes for a CES defined over generation are not much different from changes in the baseline.

Figure 6.36. DIEM Forecast of NC Capacity Changes across CES Targets



CES Combination Options

Finally, the models analyzed policy combinations for their relative effectiveness and cost. In particular, combining a sales-based CES with "push" policies may be a way to maximize the best of both types of strategies: one incentivizes the construction of clean capacity, while the other puts downward pressure on emitting generation and CO_2 emissions.[67] In addition, as in the Virginia Clean Economy Act, there may be a desire to target specific types of generation such as offshore wind to enhance system flexibility to enhance system flexibility and drive shoreline economic development. IPM and DIEM ran a set of comparable policy options to explore these possible combinations: CES with accelerated coal retirements, CES with an offshore wind goal of 2.8 GW in 2030 and 8 GW by 2040, CES with a carbon adder on new capacity, and CES with a carbon adder on dispatch/generation. In addition, IPM ran a number of CES-RGGI combinations.

Figures 6.37 and 6.38 present the CO_2 emissions consequences of four sales-based CES policy combinations, compared to baseline trends and a stand-alone CES. As discussed, there are differences in baseline trends across the models and, thus, in each model's response to a stand-alone CES policy. Despite these differences, the addition of specific "push" policies has relatively similar impacts on emissions in 2030. Combining **accelerated coal retirements with the CES** reduces 2030 emissions by an additional 17% in IPM and 13% in DIEM over a stand-alone CES. This makes sense given that a CES doesn't squarely address coal emissions (although as discussed above, once the target reaches particularly high levels of clean energy, fossil generation may be forced out of the mix). The IPM findings suggest that combining an accelerated coal retirements policy with CES is enough to nearly achieve the 2030 CEP target, while the DIEM model with higher estimates of renewables had reached the target with the CES alone.

An **offshore wind requirement** in 2030 provides even more emissions reductions in the DIEM results, but none in IPM. Both models suggest that a **carbon adder on new capacity** investments —"CES + Adder (Cap)"—does not enhance the emissions reductions of a stand-alone CES.

Figure 6.39a shows that both IPM and DIEM are expecting the percentage change in cumulative in-state emissions (to 2050) for the CES combination options over a stand-alone sales-based CES to be around 20%. Factoring in the impacts of changes in imported electricity under a CES, Figure 6.39b shows similar percentage reductions in total emissions, but at a lower cost than the in-state estimates in Figure 6.39a. Absolute reductions in tons of emissions in the DIEM model are smaller, however, leading to a higher cost per ton measure. In both models, the offshore wind requirement raises the cost of the policy without much corresponding impact on total emissions, resulting in higher costs per tons reduced. However, total costs for the offshore wind addition (Fig. 6.40) are much lower in DIEM.

Combining a carbon adder on new capacity with a CES has lower overall costs in DIEM than other CES combination policies (suggesting that estimation of electricity export—or capacity import—values using prices in importing regions is high), while it leads to a moderate cost

67. See, e.g., Dallas Burtraw, Karen Palmer, Anthony Paul, and Paul Picciano, State Policy Options to Price Carbon from Electricity. Resources for the Future: Report 19-04 (May 2019) (suggesting that a combination of generation-based policy with a clean energy policy can enhance the outcomes of each type of policy on its own).

increase in IPM. In DIEM, a carbon adder on generation leads to a mix of in-state renewables generation and higher imports, while IPM costs mostly come from the increase in in-state renewables.

Figure 6.37. IPM Forecast of NC In-State Emissions across CES Combination Options

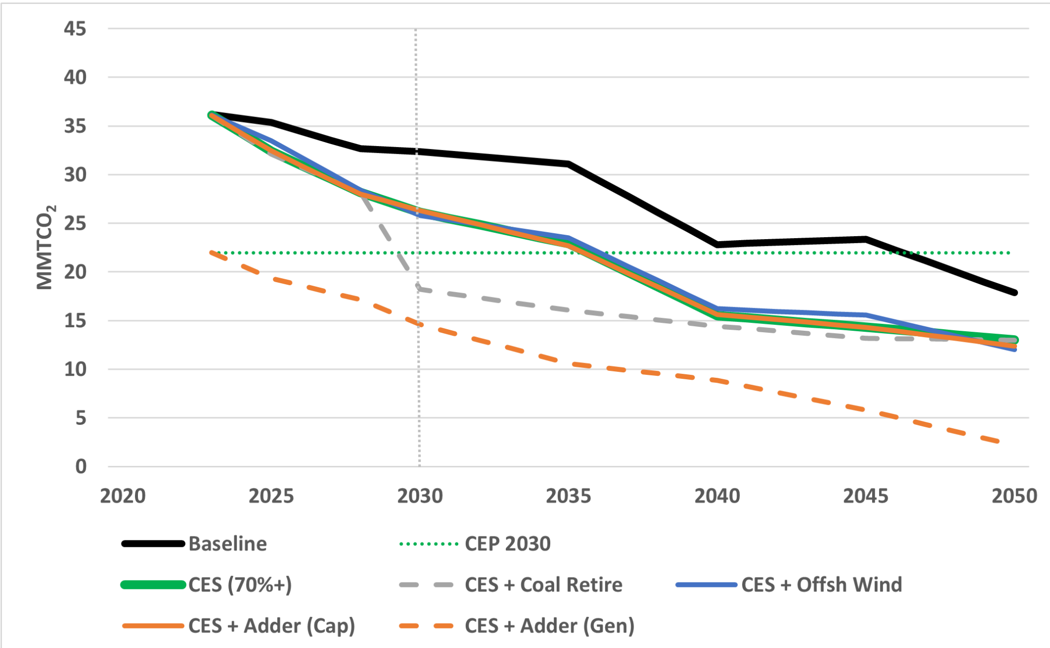


Figure 6.38. DIEM Forecast of NC In-State Emissions across CES Combination Options

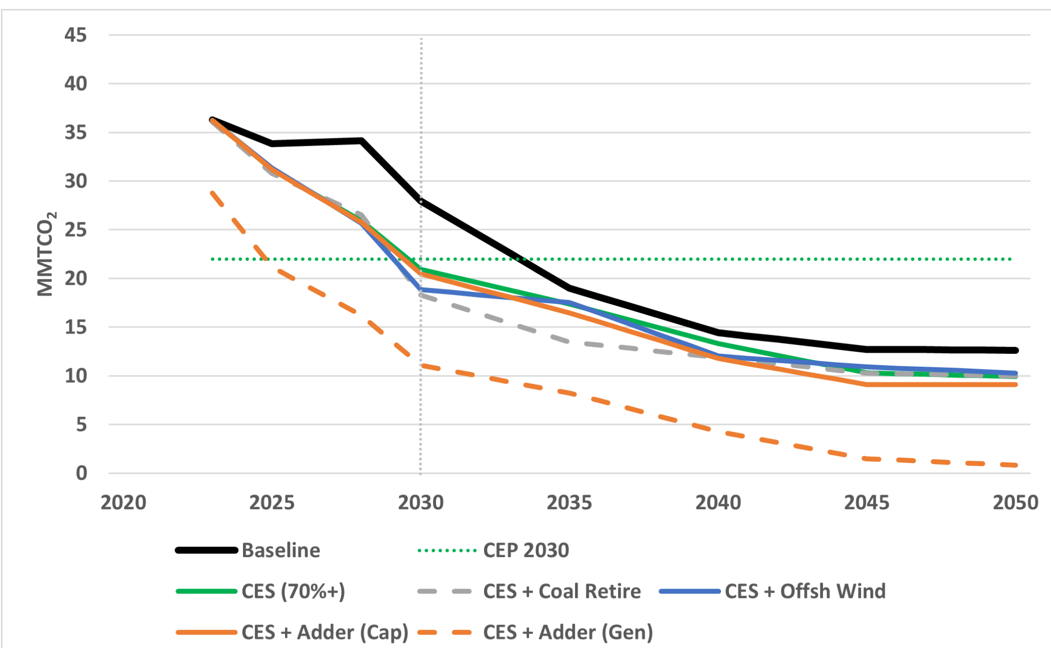


Figure 6.39a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

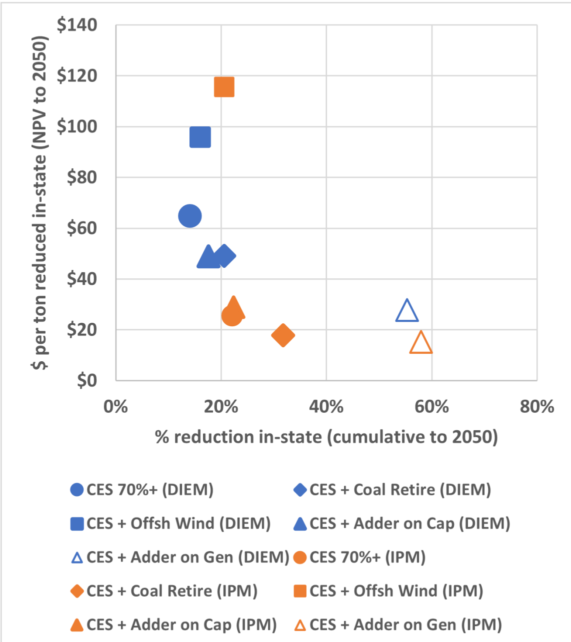


Figure 6.39b. Cost of Total CO_2 Reduction vs. % Reduction in CO_2 Emissions

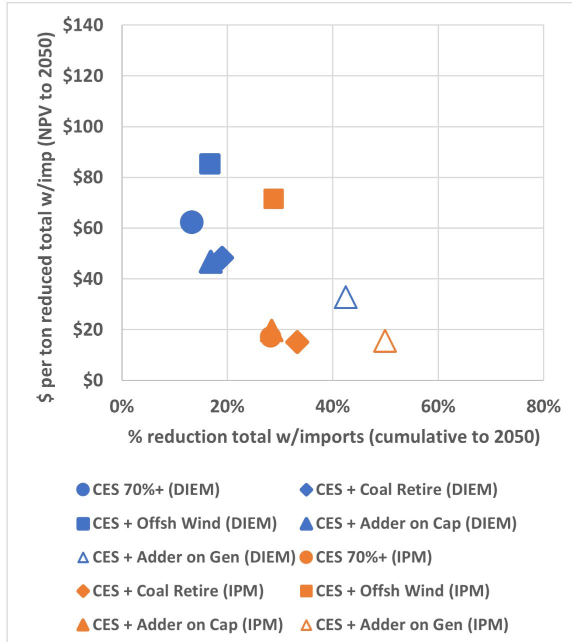
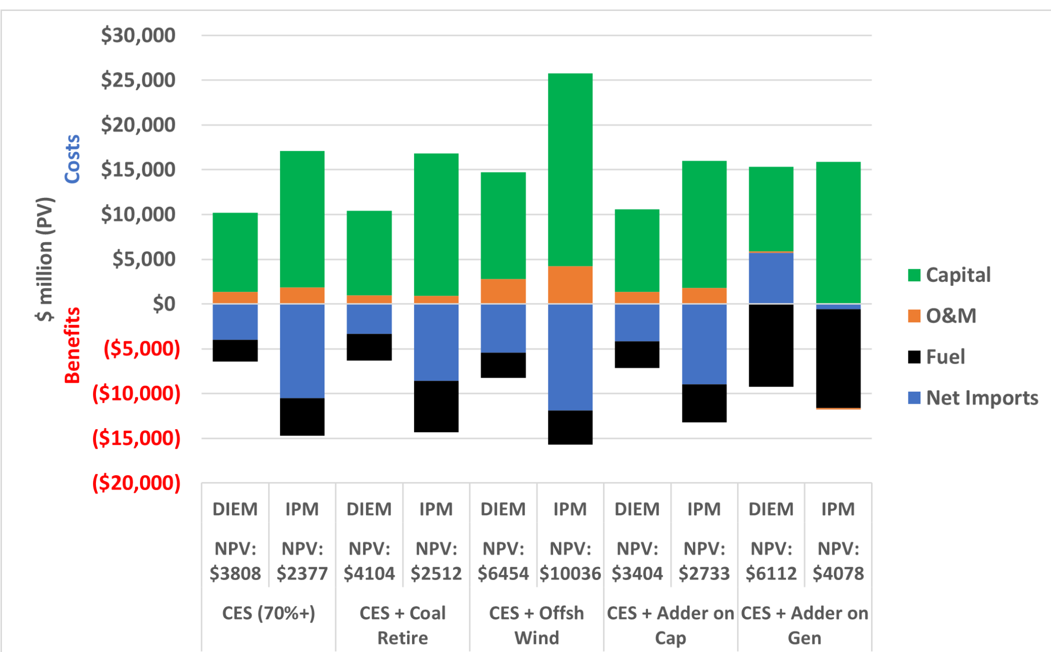


Figure 6.40. Cost Change in NPV through 2050 (Compared to Baseline)



The next two graphs (Figs. 6.41 and 6.42) consider the effects of the CES combinations on generation. In 2030, across the options IPM is inclined to switch North Carolina from importing to exporting electricity to enable the system to meet the 70% CES requirement while still meeting reliability requirements with fossil generation (this partially explains the higher levels of CO_2 emissions in the IPM results). DIEM, by contrast, adds more onshore wind as a way of contributing to the CES while offsetting the solar PV incentivized by the policy. DIEM also increases new turbines in the coal retirement option to help with reliability. By 2050, the largest sensitivities across the two models are in the choice between offshore wind and paired solar/ battery installations, where both approaches help with reliability.

Figure 6.41. IPM Forecast of Generation across CES Combination Policies

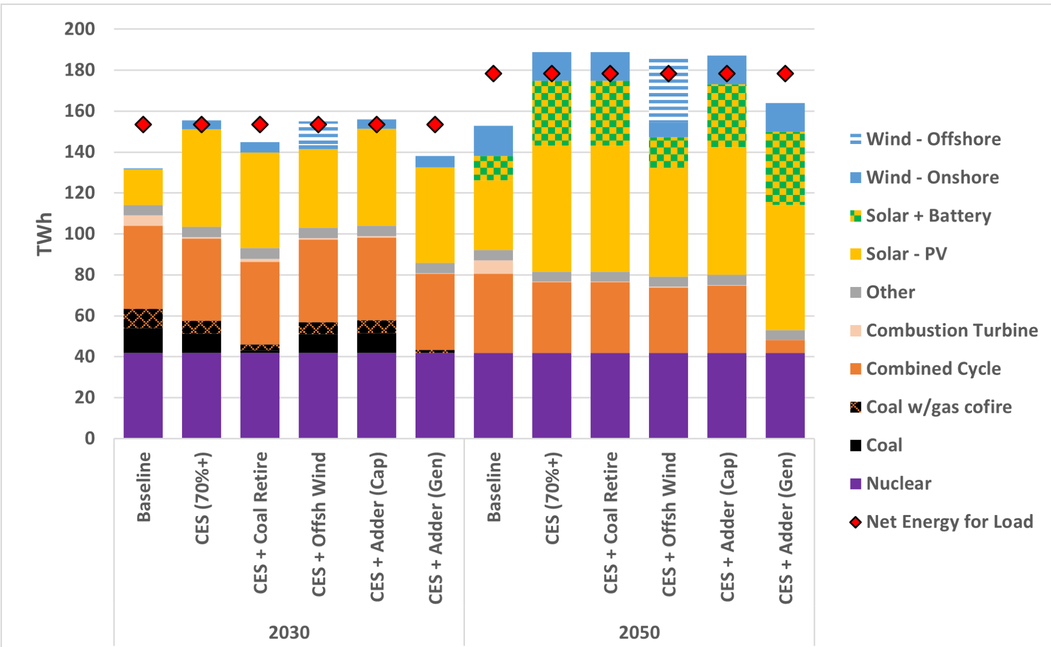
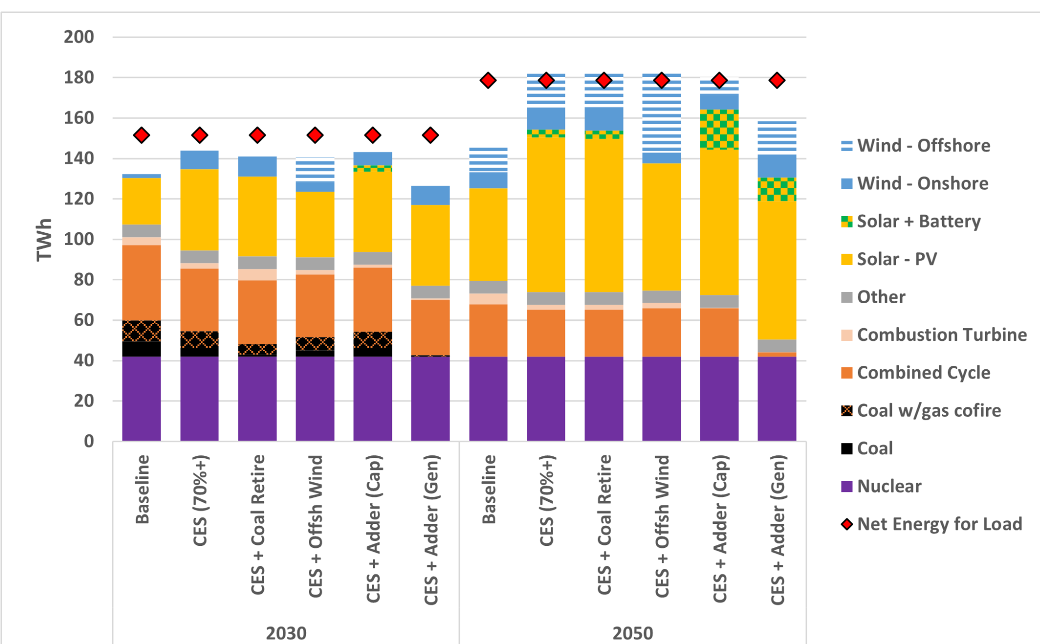


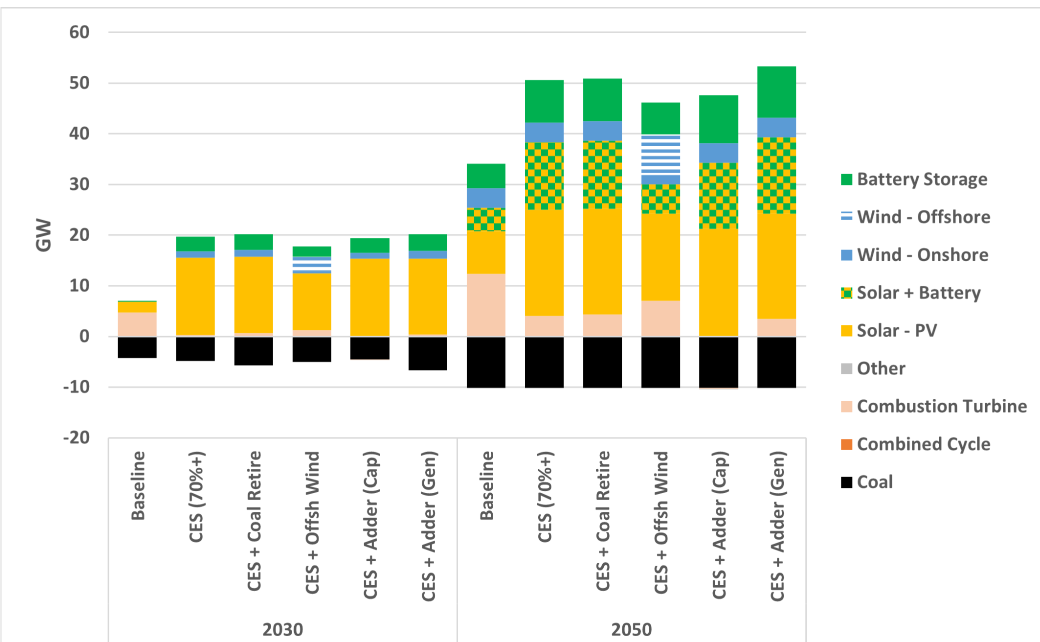
Figure 6.42. DIEM Forecast of Generation across CES Combination Policies



A carbon adder on new capacity in conjunction with a CES has a modest impact on the generation patterns over the stand-alone CES. By contrast, the **carbon adder on generation** removes most of the coal generation for both models in 2030 and provides large reductions to in-state combined cycle generation by 2050. In 2050, reduced generation from combined-cycle units is offset largely by imports in both models (the carbon adder in this case is not applied to imported electricity).

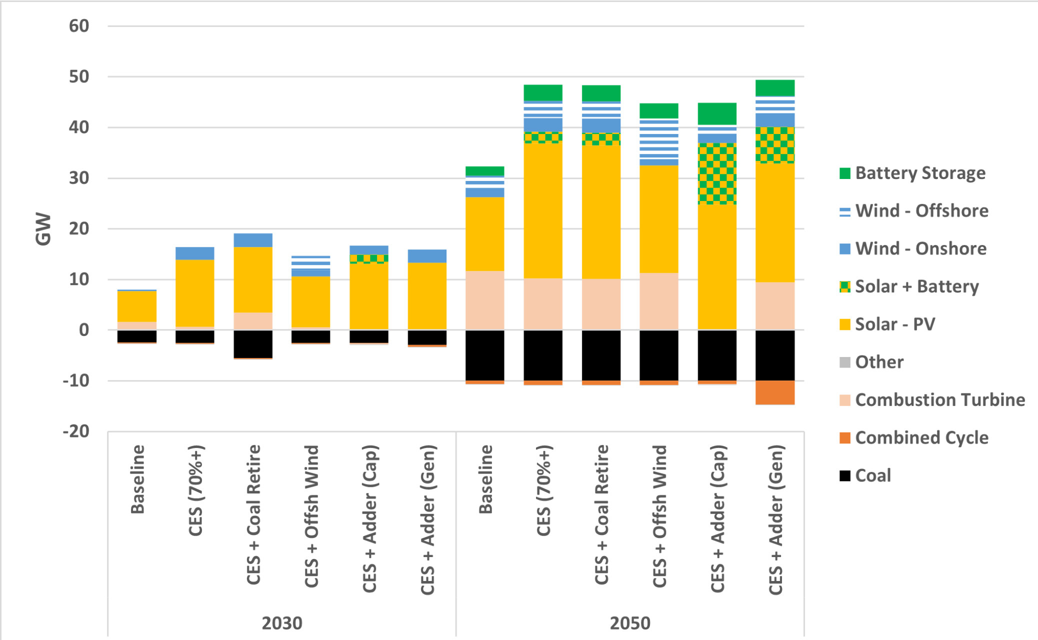
The capacity changes shown in Figures 6.43 and 6.44 track the generation impacts. Note that outcomes may be sensitive to specific realized trends in installation costs between turbines and paired solar/battery facilities. Across many of the combinations, IPM (which assumed lower battery sizes—and hence costs—for the paired solar/battery technology) tends to move into this option, while DIEM is more inclined towards new turbines as a method for providing reliability services.[68] Altering these assumptions in either model could easily reverse the pattern of installations for these two technologies.

Figure 6.43. IPM Forecast of Capacity Changes across CES Combinations



68. Recall in the baseline discussion that DIEM assumes batteries that are 50% of the paired solar PV size, while IPM assumes a 25% battery size. **Appendix B** includes more discussion of the battery assumptions.

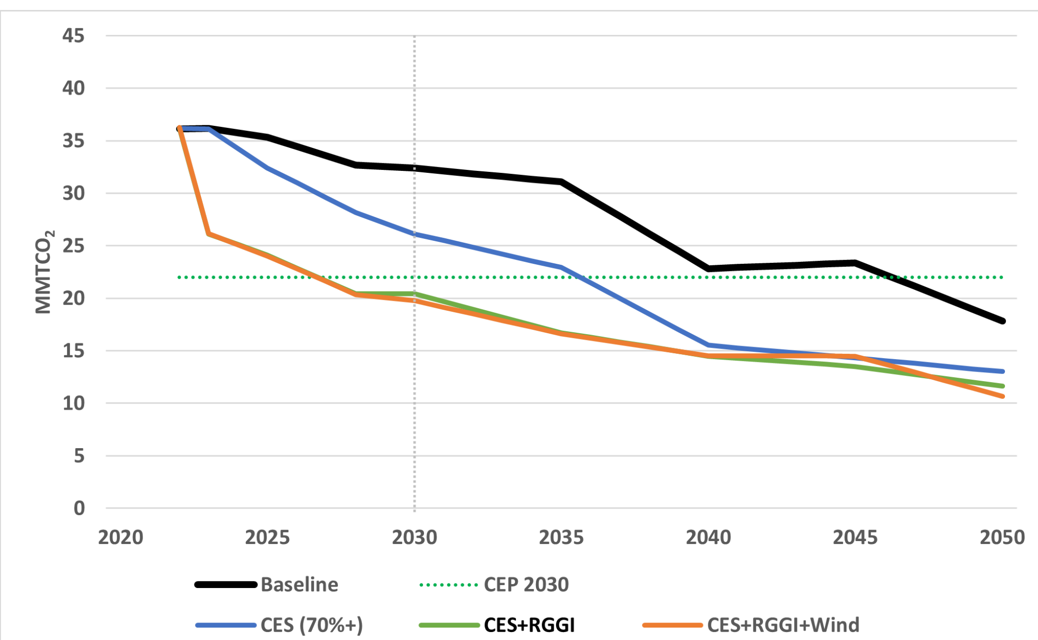
Figure 6.44. DIEM Forecast of Capacity Changes across CES Combination



RGGI and CES Combinations

IPM also considered the implications of combining RGGI with the basic sales-based CES, as well as with a CES containing an offshore wind requirement (2.8 GW in 2030, and 8 GW by 2040). Although neither policy met the 2030 CEP target on its own in IPM, combining RGGI and the CES does achieve the target (Fig. 6.45).

Figure 6.45. IPM – NC In-State Emissions across RGGI Combinations



According to the IPM results shown in Figure 6.46a, adding RGGI to a CES almost doubles the cumulative in-state CO_2 emissions reductions, while lowering the costs per ton reduced. These benefits are moderated but still deep enough to meet the 2030 CEP target when considering the emissions associated with imported electricity in Figure 6.46b. Adding an offshore wind requirement significantly raises policy costs without providing additional reductions, implying that the increase in offshore wind is offset by reductions in onshore renewables. The large increase in NPV costs can also been seen in Figure 6.47 that has increased capital expenditures for the offshore wind policy variant, but fewer electricity exports to defray those costs.

Figure 6.46a. Cost of In-State CO_2 Reduction vs. % Reduction in Emissions

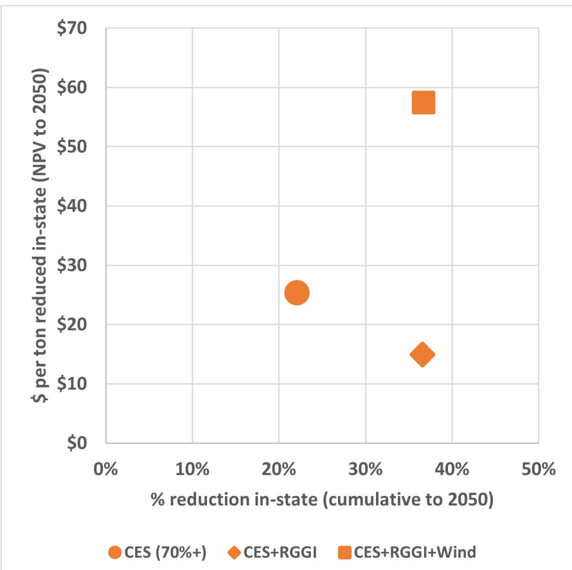


Figure 6.46b. Cost of Total CO_2 Reduction vs. % Reduction in Emissions

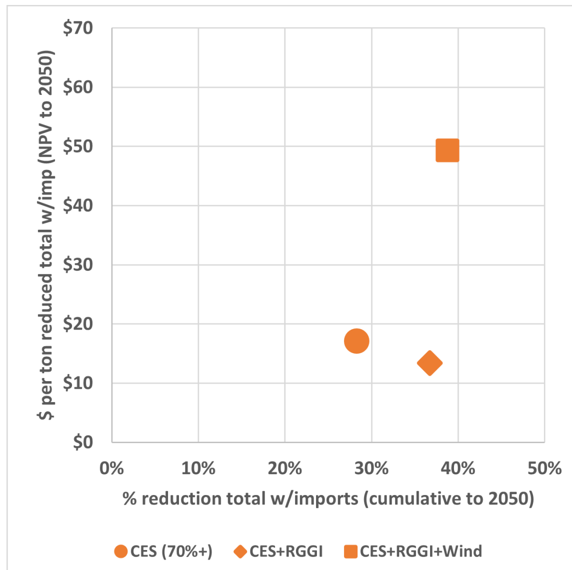
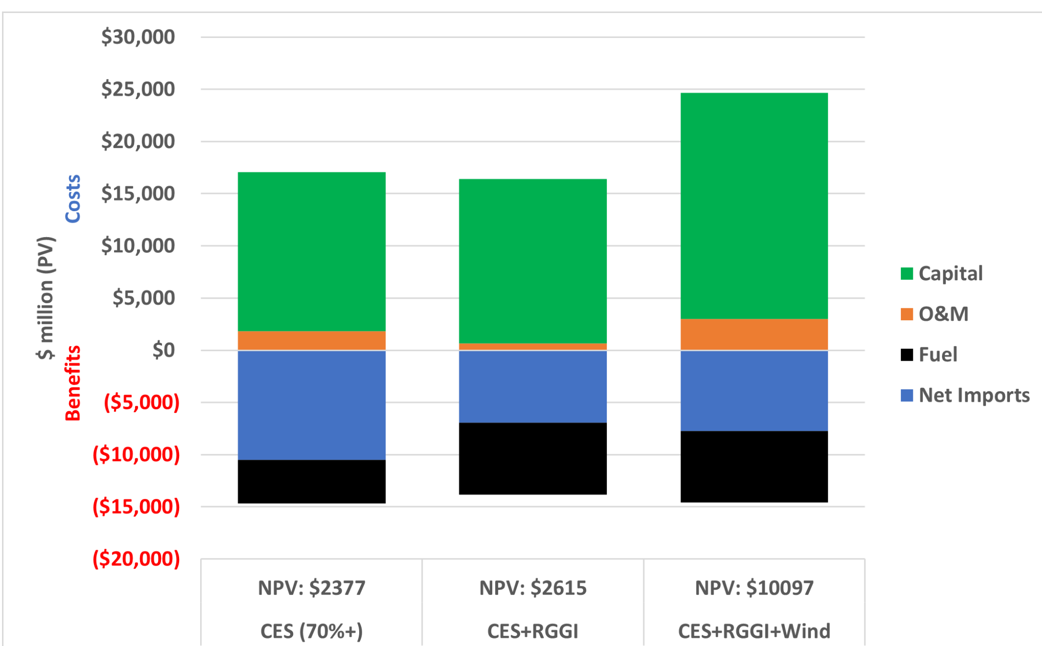


Figure 6.47. Cost Change in NPV through 2050 (Compared to Baseline)



The final two figures for this section present the generation and capacity changes that lead to the emissions reductions under a combined RGGI-CES policy. As defined in this report, RGGI has the most impact before 2030 since the program's stringency does not increase after that point. Compared to a stand-alone CES, adding RGGI provides a larger decline in coal generation, even if coal capacity is relatively unaffected. After 2030, the CES and CES with RGGI are fairly similar. Again, adding an offshore wind requirement tends to shift the mix among renewables and batteries, rather than having significant impacts on fossil generation. Impacts on new turbine capacity are somewhat larger than other types.

Figure 6.48. IPM Forecast of Generation across CES+RGGI Options

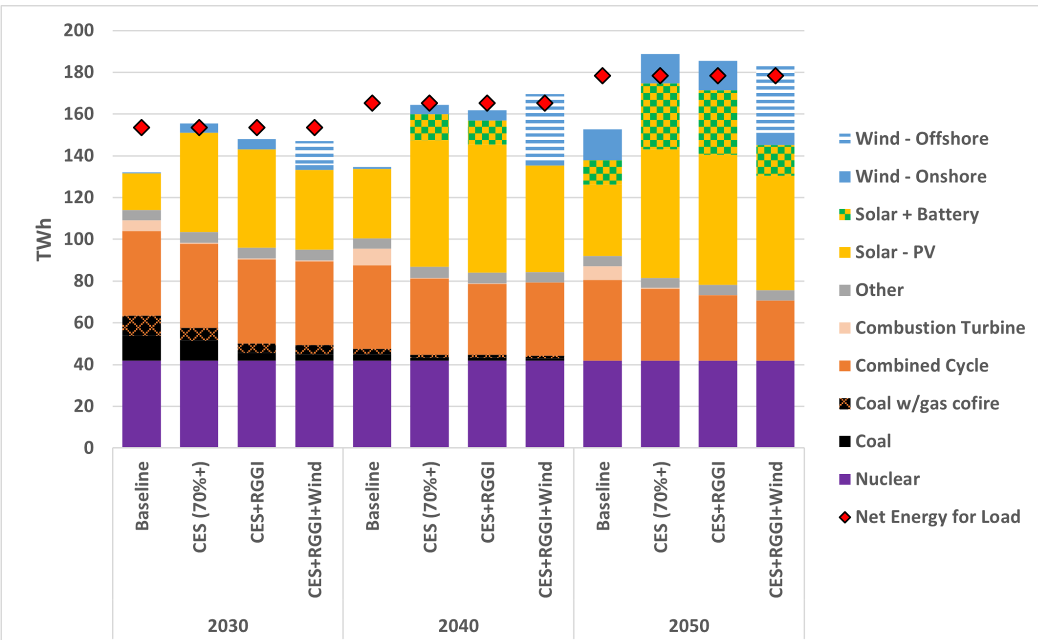
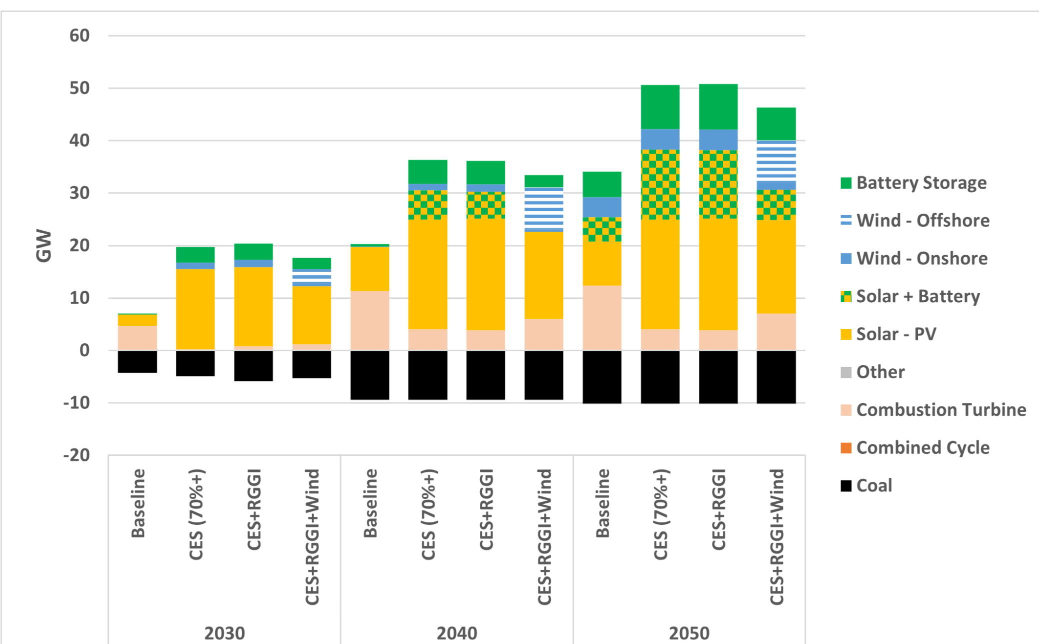


Figure 6.49. IPM Forecast of Capacity Changes across CES+RGGI



Local Air Pollution (Emissions of SO_2 and NOx)

The 2030 and 2050 CEP emissions targets are focused on CO_2 emissions. However, the same electricity generating resources that emit CO_2 also emit other air pollution. During the CEP stakeholder process and in conversations during the A1 process, a number of people raised public health concerns and asked that power sector carbon policies be evaluated for their ability to reduce local air pollution, too. Table 6.3 presents reductions in two local air pollutants across a number of studied carbon policies, for 2030 and 2040. While fossil-fired power plants emit a range of pollutants that can pose public health risks, modeling focused on sulfur dioxide (SO_2) and nitrogen oxides (NOx) Both SO_2 and NOx can cause respiratory damage and exacerbate asthma and other breathing conditions. NOx is also a precursor pollutant to smog. Natural gas plants do not emit SO_2; therefore, this pollutant drops more quickly as coal leaves the mix. Both coal and gas plants emit NOx, leading to the persistence of that pollutant to 2040.

The projected trends for these pollutants largely track projected reductions in CO_2. Once again, **accelerated coal retirements** drive some of deepest reductions in 2030 in NOx and SO_2 of the stand-alone policies studied, but by 2040, has more limited impact. No more coal is retiring at this point relative to the baseline, and NOx persists from natural gas plants in the system. Joining **RGGI** and setting the CO_2 budget at 22 million tons by 2030 ("RGGI with CEP 2030 target") reduces NOx and SO_2 more than a CES in 2030, but because the modeled RGGI policies did not increase in stringency beyond that year, by 2040 the CES outpaces RGGI in NOx reductions and matches RGGI in SO_2 performance. (If the RGGI program did increase in stringency past 2030 as is expected, these relative results might change.) However, there are notable differences between CO_2 and local pollutant outcomes. For instance, **carbon adder on new capacity** slightly *increases* NOx emissions over the baseline in 2030 in IPM (SO_2 emissions in IPM and both pollutants in DIEM fall slightly). The deepest reductions in local pollutants are achieved by policies that directly impact fossil fuel-fired generation: **carbon adders on generation** or **CES in combination with RGGI, coal retirement, or a generation adder**.

Table 6.3. NOx and SO_2 Emissions (1000 Metric Tons)

	IPM Model				DIEM Model			
	NOx		SO2		NOx		SO2	
Policy Cases	2030	2040	2030	2040	2030	2040	2030	2040
Baseline	15.6	5.8	4.6	0.7	13.9	4.4	4.1	0.3
Accelerated Coal Retirement	7.7	4.6	0.8	0.0	9.5	4.2	0.8	0.0
RGGI with 3% decline per year to 2030	12.1	4.7	3.4	0.3				
RGGI with 2030 CEP target	10.2	4.7	2.8	0.3				
RGGI w/2030 CEP target & EE	9.9	4.7	2.7	0.3				
CO2 Adder on New Capacity	15.7	5.5	4.7	0.7	13.3	2.5	4.2	0.3
CO2 Adder on Generation					3.4	0.8	0.0	0.0
CO2 Adder on Generation w/import adjust					4.0	0.9	0.0	0.0
CO2 Adder on Generation - USA wide					5.0	0.7	0.0	0.0
CES on NC Retail Sales	11.4	3.7	3.5	0.3	9.9	3.4	2.7	0.3
CES on USA-wide Retail Sales					3.1	0.1	0.1	0.0
CES + Coal Retirement	5.6	3.3	0.5	0.0	7.2	3.2	0.8	0.0
CES + RGGI	7.6	3.7	1.5	0.3				
CES + RGGI + Offshore Wind	7.1	3.6	1.3	0.2				
CES + Carbon Adder on New Capacity	11.7	3.9	3.5	0.3	9.2	2.4	2.5	0.2
CES + Carbon Adder on Generation	3.3	1.6	0.0	0.0	2.4	0.8	0.0	0.0
CES + Offshore Wind	11.4	4.4	3.3	0.3	8.0	2.8	2.0	0.2

SECTION 7. ECONOMIC IMPACT ANALYSIS

Introduction

Section 6 summarized the outputs of two capacity models for baseline cases and a range of carbon reduction policies. Using the systems cost outputs from these models as the departure point, this section presents additional information about the economic impacts of a subset of policies relative to the IPM baseline.[69] The policies were chosen to illustrate the rate, bill, and macroeconomic effects of different policy pathways and do not reflect stakeholder or author preference for a particular set of policies. The policies and policy combinations described in this section include:

(1) A number of RGGI scenarios;

(2) The standard modeled CES (70% clean in 2030; 95% clean in 2050);

(3) The CES combined with the standard modeled accelerated coal retirements; and

(4) The CES combined with different RGGI scenarios.

To assess the economic impacts of RGGI, this section considers how policy makers could use revenues generated from a RGGI CO_2 allowance auction to lower program costs. Every state that currently participates in RGGI sells allowances to generators through an auction mechanism. Table 7.1 presents the revenues that IPM projects from a RGGI auction—nearly $1 billion from 2023 to 2030.

Table 7.1. Projected RGGI Auction Revenues

Year	2023	2024	2025	2026	2027	2028	2029	2030	Cumulative, 2023–2030
Allowance Revenue (2012$)	140 m	139 m	139 m	139 m	113 m	113 m	90 m	90 m	963 m

ICF studied three possible outcomes of a RGGI auction—(1) revenues are not recycled back into the power sector but used on other state budget priorities ("no revenue recycling"); (2) proceeds are invested in EE; and (3) proceeds are given back to all residential ratepayers (or just low-income ratepayers) in a direct bill assistance program. If DEQ decided to freely allocate CO_2 allowances, the NCUC would likely act to ensure that the value of those allowances flowed through to ratepayers. Therefore, the direct bill assistance scenarios best approximate a free allocation regime, although the NCUC might want to benefit all customer classes and not just residential customers.

69. Funding constraints limited the number of policies that could be analyzed.

This section is divided into two parts. The first part presents ICF's work to convert wholesale system costs into monthly bill impacts for residential customers in North Carolina, as well as retail rate impacts for commercial and industrial electricity customers. The second part describes changes in job numbers and Gross State Product (GSP) under each policy scenario, generated by ICF using the Regional Economic Models, Inc. (REMI) model.[70] All results are presented in terms of changes from the IPM baseline case. ICF's method for calculating rate and bill impacts was unable to reflect the specific retail bill structures of North Carolina utilities. Moreover, REMI is a proprietary model with confidential inputs, limiting the ability of the authors to fully unpack this analysis. Within these limitations, the authors have worked with ICF to understand these results in order to present this summary. As with all results in this report, the numbers reported in this section should be relied on for directional and comparative purposes only.

Across both measures of economic impact, a few highlights emerge:

- These policies have a relatively small effect on North Carolina's economy. The climate policies modeled in REMI changed the cumulative job-years outlook -0.01% to +0.05% from job projections in the baseline and GSP levels -0.01% to +0.03% from the baseline.
- All climate policies by 2048 have rates/bills that are lower than the baseline; by 2043, all policies but RGGI without revenue recycling produce savings for residential customers.
- The analyzed policies highlight trade-offs that policy makers and stakeholders can weigh.
    - By 2033 and for the rest of the studied period, **a RGGI program with EE** investments reduces rates/bills in all three customer classes below business as usual, and results in the lowest cost for commercial and industrial customers for any policy. It also drives the most job creation of any of the stand-alone policies.
    - **A RGGI program with direct residential bill assistance** results in the lowest residential bills for all time periods, but with limited macroeconomic effect. (Providing bill assistance only to low-income customers does not notably change the jobs or GSP numbers; it does however change the distribution of program costs and savings among residential customers.) Under this scenario, commercial and industrial rates remain higher than business as usual until 2048.
    - **A CES combined with RGGI** leads to the largest increases in electric bills and rates. However, this upward rate pressure is moderated where RGGI auction allowances are invested in EE. Moreover, this policy combination achieves the largest CO_2 emissions from 2020–2050 (nearly 40% from baseline) of all studied policies, as well as the most positive economic activity—90,000 job-years, nearly twice that of a stand-alone RGGI program with EE investment.
    - **A CES combined with accelerated coal retirement** shows strong job growth in the early years as more solar is built to replace the retiring coal capacity. (These results are state-wide; communities near retiring coal units still may experience job losses.)

70. REMI is further described below in this section.

It is also only nominally more expensive to ratepayers than a stand-alone CES, while achieving relatively greater CO_2 reductions.

- A CES is more expensive than a RGGI policy, particularly in the 2030s. However, alone or in combination with other policies, it drives significant clean energy job growth.[71] A CES also drives higher generator revenues in the 2040s through electricity sales to other states. Combining a CES with other policies can accentuate these positive economic outcomes.

As noted in these highlights, some of the policies that appear to have greater rate or bill impacts may also drive deeper CO_2 reductions. To provide this context, this section periodically refers back to the dollar-per-ton-of-CO_2-reduced metric from Section 6 and presented in Table 7.7.

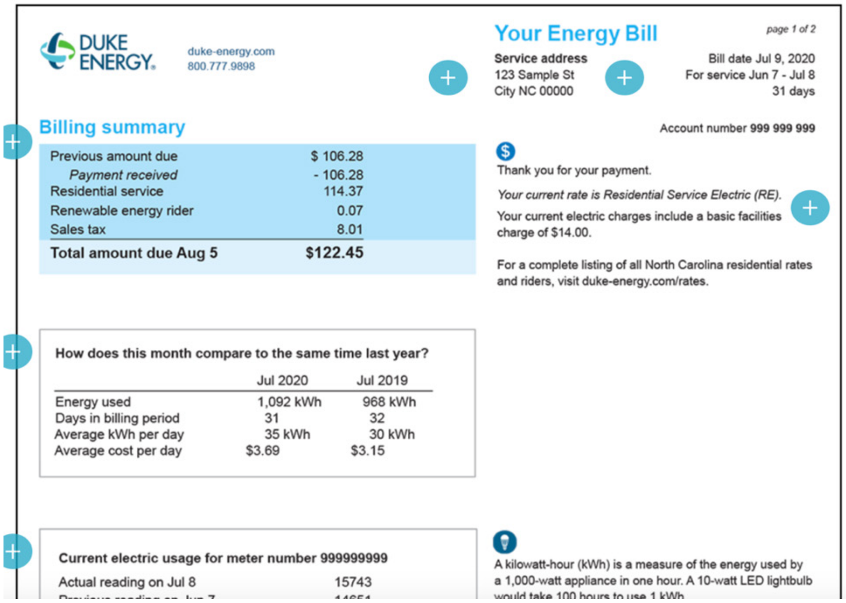
Retail Rate and Bill Impacts

Wholesale electricity costs are the costs a utility incurs producing or purchasing electricity. These costs may not be visible to an electricity customer; on Duke Energy bills, for instance, there is no line item on the bill identified as "wholesale costs." Instead, those costs are embedded in the price of electricity supplied to a home or business. Other costs embedded in the per kwh cost include the costs of delivering the electricity to the end-use customer, and rider costs for fuel and EE. In Figure 7.1, these combined costs are reflected in the "RS-Residential Service" line item. As indicated, additional costs may be added to the electricity bill, such as a renewable energy rider to pay for REPS compliance.

Retail rates of electricity differ among the three customer classes in North Carolina: residential, commercial, and industrial. Moreover, there may be different charges associated with the three types of bills. This part of Section 7 presents possible changes to residential bills and retail rates for commercial and industrial customers, flowing from some of the policy pathways.

71. Although this report does not analyze the jobs or economic impact of an offshore wind carveout in the CES, a recent North Carolina Department of Commerce study projects nearly $100 billion in economic value to North Carolina from East Coast offshore wind projects. See BVG Associates, Building North Carolina's Offshore Wind Supply Chain (2021), https://files.nc.gov/nccommerce/documents/Policymaker-Reports/Report_North-Carolina-OSW-Supply-Chain-Assessment_BVGAssociates_asPublished-Mar3-2021.pdf.

Figure 7.1. Sample Bill from Duke Energy[72]



Methodology

ICF began the retail rate calculations with systems costs reported by IPM in the baseline. Then, they compared baseline projections with the system costs reported by IPM under four policy pathways (RGGI; CES; CES + coal retirements; CES + RGGI), as well as a load-adjusted RGGI run representing lower electricity demand after investing RGGI proceeds in EE.

Next, ICF pulled AEO 2020 data on projected retail rates in two Southeast regions.[73] The AEO forecasts suggest that retail electricity rates could decrease slightly between now and 2050, for all three customer classes (Table 7.2). This may be explained in part by shifts in capacity—as greater amounts of renewable energy come online, a utility's fuel costs are expected to go down. However, the ICF baseline was projecting an increase in rates over time, under business as usual. To address this discrepancy, ICF pegged projected retail rates to AEO's 2023 projections, and then increased the rates by the same proportion as IPM's projected system cost increases under the business as usual scenario (Table 7.3). Table 7.3 presents the baseline retail rates used to compare the CEP policies costs. Given AEO projections rates, it is possible that ICF overstates all ratepayer costs, in the baseline and across policy cases.

72. Duke Energy, "Billing & Payment," https://www.duke-energy.com/home/billing/reading-your-bill/new.
73. ICF used projections for the Carolinas (Table 54.14) and Georgia/Alabama (Table 54.15), https://www.eia.gov/outlooks/aeo/tables_ref.php.

Table 7.2. AEO 2020 Projections for Retail Rates in the Southeast

Customer Class	2020 rates (cents/ kwh)	2023 rates (cents/ kwh)	2025 rates (cents/ kwh)	2030 rates (cents/ kwh)	2035 rates (cents/ kwh)	2040 rates (cents/ kwh)	2045 rates (cents/ kwh)	2050 rates (cents/ kwh)
Residential	12	11.8	11.9	11.7	11.5	11.1	10.8	10.4
Commercial	10.4	9.9	9.9	9.5	9.1	8.8	8.3	8.0
Industrial	6.2	5.7	5.8	5.7	5.5	5.3	5.1	5.0

Table 7.3. AEO 2020 Projections for Retail Rates, Adjusted by IPM Baseline Projections

Customer Class	2020 rates (cents/ kwh)	2023 rates (cents/ kwh)	2025 rates (cents/ kwh)	2030 rates (cents/ kwh)	2035 rates (cents/ kwh)	2040 rates (cents/ kwh)	2045 rates (cents/ kwh)	2050 rates (cents/ kwh)
Residential	12	11.8	12.3	13.2	13.3	14.2	15.0	15.8
Commercial	10.4	9.9	10.3	11.06	11.2	11.91	12.6	13.29
Industrial	6.2	5.7	6.0	6.41	6.5	6.91	7.3	7.7

ICF assumed that all of the changes in wholesale system costs between the IPM baseline and a particular policy case were passed through to retail customers. Therefore, all of the costs or savings were allocated to retail rates and bills, divided among the customer classes based on EIA sales data. Those data indicate that residential customers consume 42%, commercial customers consume 38%, and industrial customers consume 19% of the electricity in the Carolinas. Then:

- For residential customers, ICF calculated household-level bill impacts, using EIA data on average monthly electricity consumption by North Carolina households.
- For commercial and industrial customer classes, ICF calculated the incremental impact and percentage increase/decrease of each of the four analyzed policy pathways and compared those changes to projected changes in retail rates reported in Table 7.3.
- ICF did not calculate bill impacts for commercial or industrial customers because of the large variation in energy usage across these customer classes.

A number of factors caution over-reliance on these results, particularly as the analysis moves into the 2040s. First, as noted, ICF's methodology for calculating rate and bill impacts could not incorporate the specific retail bill structures of North Carolina utilities. Instead, ICF's approach was consistent with the U.S. EPA's retail price model which the agency uses to generally estimate rates under different policies. Second, rates will ultimately turn on the availability and cost of different generation technologies, fuel prices, the regulatory and market context, and the implementation of national or other state climate policies—and these variables grow more uncertain in the out years of this analysis. Third, ICF uses costs from the IPM model through 2050; therefore, capital costs from construction in the 2040s may not be fully reflected within the analysis time horizon. Bill and rate amounts, therefore, should not be taken to reflect actual costs in particular years but as a basis for comparison between policies.

Results

The ICF analysis suggests that the retail price impacts of the studied policies are modest. For instance, for the commercial sector in 2030 (Table 7.4), policies change the retail electricity rate from 0.5% (RGGI with EE investment) to 2.3% above baseline (CES + RGGI with no revenue recycling or direct bill assistance—note these scenarios have the same impact on commercial and industrial rates because bill assistance is only provided to residential customers).[74] Similarly, for the industrial sector in 2040 (Table 7.5), policies change the retail rate from 0.3% below baseline (RGGI with EE investment) to 2.5% above baseline (CES + RGGI with no revenue recycling or direct bill assistance). All three customer classes are projected to experience lower rates/bills by 2040 under the RGGI policy case that invests auction proceeds into EE than under business as usual. Moreover, as presented in later tables, ICF projects that every studied policy reduces rates/bills in all three customer classes by 2048 relative to the baseline. Based on the system costs breakdown in Section 6, lower fuel costs and growing electricity exports may outweigh the increased capital costs associated with construction of new renewables.

74. While 2–3% increases are not small, these scenarios can be avoided by allocating allowance value to all customer bills or investing allowance revenue in EE.

Table 7.4. Projected Bill and Rate Impacts in 2030 (Expressed in Change over Baseline Cases)

Customer Class	RGGI No Revenue Recycling (RR)	RGGI Auction – direct bill assistance (DBA)*	RGGI Auction – EE investment	CES	CES + Coal Retirement	CES + RGGI (no RR)	CES + RGGI (DBA)	CES + RGGI (EE)
Residential (per month)	$1.44 (0.8%)	-$0.65 (-0.4%)	$0.65 (0.4%)	$2.34 (1.4%)	$2.51 (1.5%)	$2.92 (1.7%)	$0.83 (0.5%)	$2.25 (1.3%)
Commercial (cents/kwh)	.13 (1.1%)	.13 (1.1%)	.06 (0.5%)	.21 (1.9%)	.22 (2.0%)	.26 (2.3%)	.26 (2.3%)	.20 (1.8%)
Industrial (cents/kwh)	.10 (1.5%)	.10 (1.5%)	.04 (0.7%)	.16 (2.4%)	.17 (2.6%)	.19 (3.0%)	.19 (3.0%)	.15 (2.3%)

Monthly Bill Change

Change in Retail Rate

*ICF also ran a scenario where direct bill assistance was only provided to low-income households, defined as households making less than the federal poverty level. In 2030, that policy would result in a $15.17 *decrease* in low-income monthly electricity bills, and an increase for other households of $1.44 per month.

Table 7.5. Projected Bill and Rate Impacts in 2040 (Expressed in Change over Baseline Cases)

Customer Class	RGGI No Revenue Recycling (RR)	RGGI Auction – direct bill assistance (DBA)*	RGGI Auction – EE investment	CES	CES + Coal Retirement	CES + RGGI (no RR)	CES + RGGI (DBA)	CES + RGGI (EE)
Residential (per month)	$0.75 (0.4%)	-$0.15 (-0.1%)	-$0.30 (-0.2%)	$2.14 (1.2%)	$2.27 (1.2%)	$2.61 (1.7%)	$1.71 (1%)	$1.85 (0.9%)
Commercial (cents/kwh)	.07 (0.6%)	.07 (0.6%)	-.03 (-0.2%)	.19 (1.6%)	.20 (1.7%)	.23 (1.9%)	.23 (1.9%)	.16 (1.4%)
Industrial (cents/kwh)	.05 (0.7%)	.05 (0.7%)	-.02 (-0.3%)	.14 (2.1%)	.15 (2.2%)	.18 (2.5%)	.18 (2.5%)	.12 (1.8%)

Monthly Bill Change

Change in Retail Rate

*In 2040, a scenario where direct bill assistance is provided only to low-income households would result in a $6.44 *decrease* in their monthly electricity bills, and an increase for other households of 75 cents per month.

Tables 7.4 and 7.5 provide snapshot comparisons of rate and bill impacts in 2030 and 2040. As discussed in Section 6, comparing costs in any single year can be misleading, particularly if that year is not representative of total costs. To provide more context, Table 7.6 presents the net present value (NPV) of the cumulative costs of each studied policy on residential bills in North Carolina, using a 4.1% discount rate. The column labeled "DBA-LI (Avg HH/LI HH)" presents two values for the scenario in which RGGI auction proceeds are used for low-income direct bill assistance: the cost to the average household and the savings to low-income households. For the average household, universal direct bill assistance yields the lowest bills (and under a stand-alone RGGI policy, deep customer savings). A stand-alone RGGI program investing in EE is the next least cost policy. The most expensive policy for the average household is a combination of a sales-based CES plus RGGI where auction proceeds are not recycled into the power sector. Even here, the average cost to residential households is less than $400 over thirty years. These findings are consistent with the single-year results in Tables 7.4 and 7.5.

Table 7.6 Net Present Value of Total Household Bill Impact, 2020–2050, by Scenario

RGGI				CES + RGGI			CES	CES + Coal Retirement
No RR	EE	DBA	DBA-LI (Avg HH/LI HH)	No RR	EE	DBA		
$199.29	$75.99	-$120.05	$204.33/ -$2,461.46	$391.55	$290.74	$72.21	$256.60	$273.06

Of course, each studied policy achieves a different level of CO_2 reductions. Understanding how much work each policy is doing to make progress towards the CEP's targets, then, is important for cost context. The final summary table, Table 7.7, presents the NPV in dollars per ton of CO_2 reduced for each studied policy. (These metrics were introduced in Section 6 and are re-stated here for quick reference.) Note that the system costs for a RGGI program with no revenue recycling and with direct bill assistance are the same. A stand-alone RGGI policy presents as the least expensive policy, reducing CO_2 at a cost of $5.1/ton; when RGGI auction revenues are invested in EE policy, the models predict cost *savings* over business as usual.

Table 7.7 Net Present Value of System Costs in Dollars per Ton (and Percentage of CO_2 Reduction from the Baseline, 2020–2050), by Scenario Analyzed in Section 7

RGGI[75]		CES + RGGI		CES	CES + Coal Retirement
No RR/DBA	EE	No RR/DBA	EE		
$5.10/ton (21.3%)	-$6.90/ton (21.8%)	$11.20/ton (39.6%)	Not run in IPM	$25.30/ton (22.1%)	$14.70/ton (31.5%)

The remainder of the rate and bill impacts discussion is divided by policy type.

RGGI

As discussed above, ICF analyzed several RGGI scenarios, reflecting decisions to freely distribute or sell CO_2 allowances, and then how to spend any resulting revenues collected. As detailed in **Appendix C**, RGGI states use a small percentage of auction revenue to administer the program (approximately 5%) and invest the remainder in EE, clean energy, and bill assistance programs. The Policy Working Group discussed these and other investment options. For this report, however, the group recommended studying the impacts of investing in residential bill assistance or EE. ICF also analyzed the impacts of using auction proceeds for general state needs rather than power system investments (the "no Revenue Recycling" analysis) (Table 7.8).

Table 7.8 RGGI Auction Proceeds Investment Assumptions

Scenarios	Efficiency	Bill Assistance	General Revenue	Admin
1 – No Revenue Recycling	-----	-----	95%	5%
2 – Energy Efficiency	95%	-----	-----	5%
3 – Direct Bill Assistance	-----	95%	-----	5%

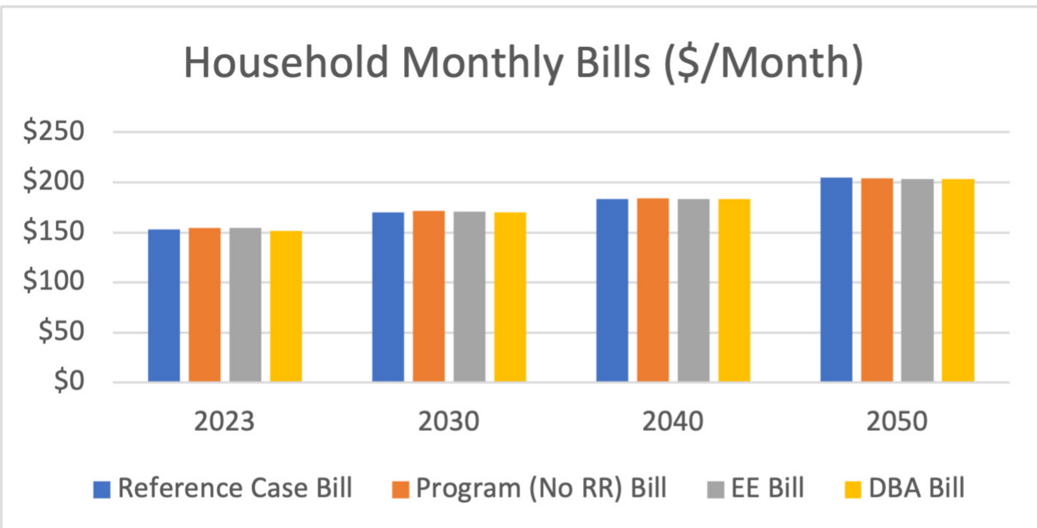
For EE, ICF used the REMI model to predict the impact of EE investments on the North Carolina economy. More discussion of those results is presented in the next part. However, a REMI output relevant here is the projection of lower energy demand due to specified levels of EE investment. Those lower demand projections were then run through IPM for a "load-adjusted RGGI run." Results from that second IPM run were used to project new rate and bill impacts.

While REMI assumed that some of the EE improvements occurred in the commercial and industrial sectors, the analysis did not require that these improvements take place under a utility-run EE program. Therefore, the results do not assume any change to the current opt-out program for large electricity customers.

75. These costs are associated with the RGGI scenario that sets a budget consistent with the 2030 CEP target.

For direct bill assistance, ICF assumed that the available funds would be distributed as savings on each residential kilowatt hour of demand. ICF then calculated impacts based on an **average household bill** (projected to be $170.41 under business as usual in 2030). Figure 7.2 presents the changes in monthly residential bills under three RGGI scenarios as compared to baseline (i.e., "reference case bills"). Table 7.9 presents the same data as the incremental change from the baseline to each RGGI case. A RGGI program with direct residential bill assistance results in lower bills than in the baseline. In other words, residential customers might expect to see their electricity bills go down. (This scenario also serves as a proxy for a free allocation or consignment auction scenario (see Section 4), if the utilities were then directed to pass savings onto to residential bills.)[76] A RGGI program investing in EE sees some upward movement in monthly bills, moderated by lower electricity demand. A RGGI program that does not invest auction proceeds into the power sector predictably results in the highest bill increases.

Figure 7.2 Projected Monthly Residential Electricity Bills under 3 RGGI Scenarios



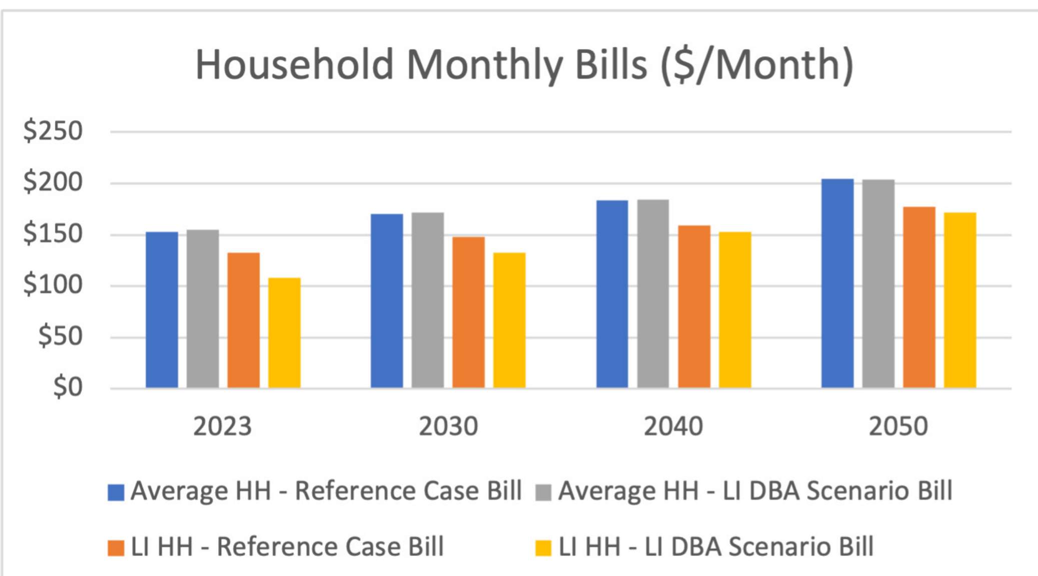
76. North Carolina might require the proceeds to flow to all customer classes—residential, commercial, and industrial.

Table 7.9 Projected Changes in Monthly Residential Electricity Bills under 3 RGGI Scenarios

Year	Bill with no Climate Policy	Difference – No Revenue Recycling	Difference – 95% EE investment	Difference – 95% Direct Bill Assistance
2023	$152.73	$1.92	$1.86	-$1.41
2030	$170.39	$1.44	$0.65	-$0.65
2040	$183.50	$0.75	-$0.30	-$0.15
2050	$204.66	-$0.87	-$1.26	-$1.53

ICF also studied the impact of providing direct bill assistance only to low-income households.[77] When RGGI allowance proceeds are credited to bills of households earning less than the federal poverty level, those bills drop significantly relative to low-income bills in the baseline (in 2023, almost $25 less per month; in 2030, about $15 less per month) (Fig. 7.3). Over time, these discounts shrink as North Carolina's generating fleet grows cleaner and RGGI auction revenue declines. Meanwhile, other residential households see a small increase in their monthly bills (in 2023, almost $2 per month over baseline; in 2030, between $1–2 a month).

Figure 7.3 Projected Monthly Residential Electricity Bills under RGGI with Low-Income Bill Assistance



77. For this analysis, two "average" household electricity bills were used, for low-income and other households. ICF projected an average low-income bill as $148.95 in 2030, and for other households, $171.83.

Tables 7.10 and 7.11 present the incremental changes in commercial and industrial retail rates under each RGGI scenario. For these classes, the direct residential bill assistance scenario has no impact; the results are the same as if auction revenues were directed to the state treasury (i.e., columns 3 and 5 are identical). The EE scenario reduces the costs of this program for commercial and industrial customers relative to the other two scenarios, due to the resulting lower electricity demand in North Carolina.

Table 7.10 Projected Commercial Retail Rate Impacts under 3 RGGI Scenarios

Year	Rate with no Climate Policy (cents/ kwh)	Difference – No Revenue Recycling (cents/kwh and % change)	Difference – 95% EE investment (cents/ kwh and % change)	Difference – 95% Direct Bill Assistance (cents/ kwh and % change)
2023	9.92	.17 (1.7%)	.16 (1.6%)	.17 (1.7%)
2030	11.06	.13 (1.1%)	.06 (0.5%)	.13 (1.1%)
2040	11.91	.07 (0.6%)	-.03 (-0.2%)	.07 (0.6%)
2050	13.29	-.08 (-0.6%)	-.11 (-0.8%)	-.08 (-0.6%)

Table 7.11 Projected Industrial Retail Rate Impacts under 3 RGGI Scenarios

Year	Rate with no Climate Policy (cents/ kwh)	Difference – No Revenue Recycling (cents/kwh and % change)	Difference – 95% EE investment (cents/ kwh and % change)	Difference – 95% Direct Bill Assistance (cents/ kwh and % change)
2023	5.75	.13 (2.2%)	.12 (2.1%)	.13 (2.2%)
2030	6.41	.10 (1.5%)	.04 (0.7%)	.10 (1.5%)
2040	6.91	.05 (0.7%)	-.02 (-0.3%)	.05 (0.7%)
2050	7.70	-.06 (-0.8%)	-.09 (-1.1%)	-.06 (-0.8%)

CES

ICF analyzed the retail rate and bill impacts of a CES requiring utilities to procure an increasing amount of “clean” energy as a percentage of retail sales: 70% by 2030, and 95% by 2050.

As indicated by the results in Figure 7.4 and Table 7.12, residential customers do not see an impact from the modeled CES program as soon as they do under the RGGI scenarios (although RGGI costs are masked by direct bill assistance). That is because, as described in Section 4, the modeled CES policy gave utilities two years to construct new clean energy before increasing the “clean” target above baseline projections. By 2030, CES residential costs are projected to exceed all stand-alone RGGI scenarios (Table 7.9). CES costs remain relatively higher than costs posed by any

CES Affordability

The ICF analysis did not include CES cost containment policies such as:

• Banking & Borrowing. A credit banking provision in a CES can lower the cost without impacting the ability to meet the long-term target. Borrowing is more controversial because it enables underperformance in the early years of a program in exchange for overcompliance later. However, this mechanism can also help to lower costs.

• Alternative Compliance Payments (ACP). An ACP allows a utility to pay a fee rather than fully comply with clean energy requirements. The value of an ACP can be fixed, increase at the rate of inflation, or increase in real terms over time as the CES target becomes more ambitious.[1] Revenue raised through an ACP can be used for bill assistance or investment in clean energy or EE, just as revenue from RGGI might be used.

• Cost Off-Ramp. A cost off-ramp is a ceiling on the rate impact that can be imposed by CES compliance. If a utility demonstrates that full compliance with the CES requirement would exceed the acceptable rate impact, then the utility's compliance obligation may be lowered.

RGGI scenario in 2040. (Recall that the RGGI budget as modeled does not increase in stringency after 2030.) These trends reverse in the 2040s, such that by 2050, household electricity bills under a CES are projected to be lower than the baseline case or any of the RGGI policies including direct bill assistance. This is likely due to the higher percentage of fuel-free generation, coupled with ICF's projections of the CES driving robust electricity sales to other states (see Section 6). Recall that the modeled CES requires all of the clean generation to be built in North Carolina; if the policy were to allow out-of-state power to qualify, CES compliance costs might be lower—but utilities might also generate less revenue from electricity exports.

Figure 7.4 Projected Monthly Residential Electricity Bills under CES Scenario

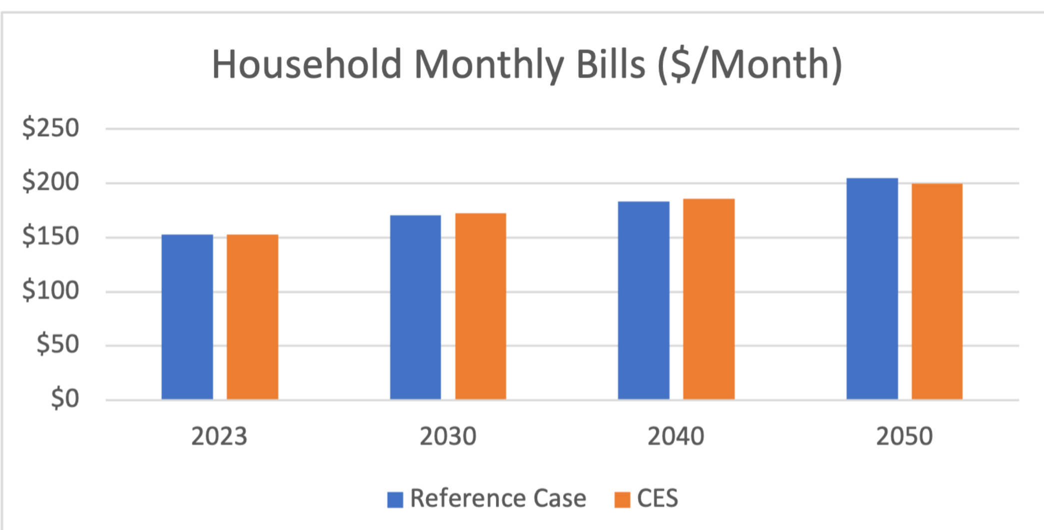


Table 7.12 Projected Changes in Monthly Residential Electricity Bills under CES Scenario

Year	Bill with no Climate Policy	Bill with CES Policy	Difference in Monthly Bills
2023	$152.73	$152.74	$0.01
2030	$170.39	$172.74	$2.34
2040	$183.50	$185.64	$2.14
2050	$204.66	$199.73	-$4.93

Tables 7.13 and 7.14 present the incremental changes in commercial and industrial retail rates under the CES scenario. Like the bill impact results for residential customers, the modeled CES policy pathway does not raise commercial or industrial rates right away. But by 2030, commercial rates increase 1.86% under a CES policy, versus 1.1% under a RGGI policy with no revenue recycling or residential bill assistance, and 0.5% under a RGGI policy investing in EE. Industrial rates under a CES are up 2.45% by 2030, as compared to 1.5% under a RGGI policy with no revenue recycling or residential bill assistance, and 0.7% under a RGGI policy with EE. By 2050, as with the residential class, commercial and industrial customers are seeing deeper discounts in their rates under a CES than any RGGI policy. (In addition, after facing bigger rate impacts in percentage terms than the commercial class in 2030 and 2040, industrial customers are projected to enjoy deeper reductions in 2050.)

Table 7.13 Projected Commercial Retail Rate Impacts under CES Scenario

Year	Rate with no Climate Policy (cents/kwh)	Rate with a CES Policy (cents/kwh and % change)
2023	9.92	.001 (.01%)
2030	11.06	.21 (1.86%)
2040	11.91	.19 (1.58%)
2050	13.29	-.43 (-3.27%)

Table 7.14 Projected Industrial Retail Rate Impacts under CES Scenario

Year	Rate with no Climate Policy (cents/kwh)	Rate with a CES Policy (cents/kwh and % change)
2023	5.75	.001 (.01%)
2030	6.41	.16 (2.45%)
2040	6.91	.14 (2.08%)
2050	7.70	-.33 (-4.29%)

CES + Coal Retirement

ICF also analyzed the retail rate and bill impacts of the same CES policy in combination with accelerated coal retirements. The selected coal retirement policy was Option #2, as the DIEM results suggested this was the most cost-effective coal retirement option modeled (see Section 6). That option induced all subcritical coal units in North Carolina to retire by 2030, and limited operation of supercritical units to "seasonal" operation, defined as running approximately 10% in any given year to meet peak load. ICF ran this combination policy through IPM and then used those system cost outputs for this rate and bill analysis.

As presented in Figure 7.5 and Table 7.15, monthly residential bills climb slightly higher in the 2020s for a CES + coal retirements policy over a stand-alone CES, because the effects of the accelerated retirements are felt sooner than CES compliance costs. The difference in bill impact between these two scenarios shrinks over time, as costs associated with coal retirements decline.

This combination policy has a small incremental impact on household bills over a stand-alone CES. Moreover, there may be equity reasons for selecting this policy over a stand-alone CES policy, if nearby communities benefit from improved air quality after a coal unit is shut down. Indeed, when emissions reductions are considered, this combination policy achieves more environmental benefit at a smaller per-unit cost. A stand-alone CES achieves a 22.1% reduction in CO_2 emissions from the baseline, 2020–2050, at a cost of $25.30/ton, while a combination CES + coal retirements policy achieves a 31.5% reduction in CO_2 emissions over the same time period at a cost of $14.71/ton (Table 7.7). This is because, as discussed in Sections 5 and 6, a CES does not require the shut-down of fossil in North Carolina so long as there is sufficient clean energy to meet increasing percentages of in-state electricity demand. Yet additional coal can be induced to retire at relatively small cost.

Coal Retirement Affordability

ICF's economic analysis did not consider the price mitigation effects of securitization, a mechanism described in Section 4 and Appendix C, which could reduce the rate impacts of retiring some coal-fired power plants. The North Carolina Energy Regulatory Process (NERP) report, "Securitization for Generation Asset Retirement" includes financial analysis of securitization and regulatory asset treatment of coal-fired power plants. See https://deq.nc.gov/cep-nerp.

Figure 7.5 Projected Monthly Residential Electricity Bills under CES + Coal Retirement Scenario

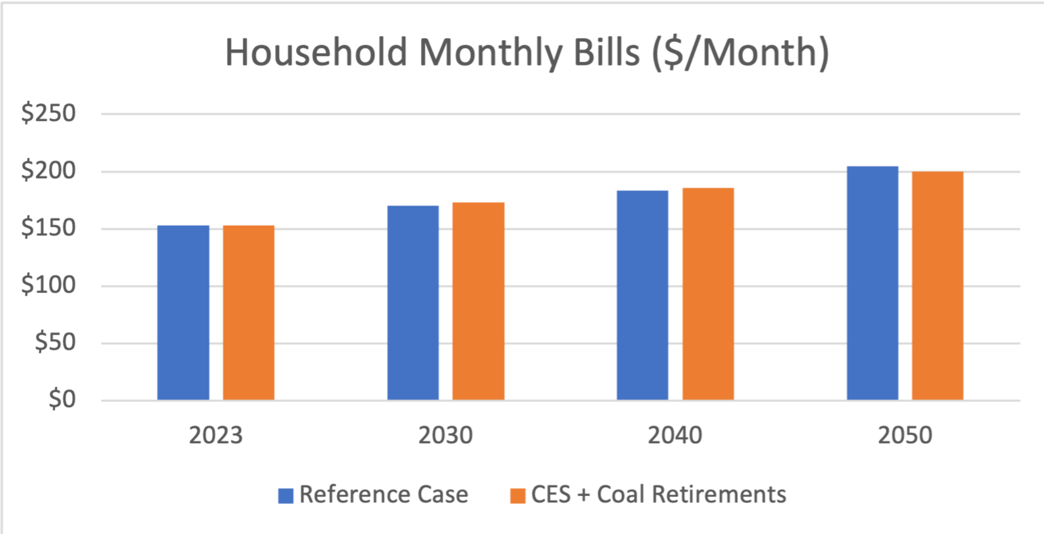


Table 7.15 Projected Changes in Monthly Residential Electricity Bills under CES + Coal Retirement Scenario (Compared to the Stand-alone CES policy)

Year	Bill with no Climate Policy	Difference in Monthly Bills with CES Policy (from Table 7.11)	Difference in Monthly Bills with CES + Coal Retirement Policy
2023	$152.73	$0.01	$0.13
2030	$170.39	$2.34	$2.51
2040	$183.50	$2.14	$2.27
2050	$204.66	-$4.93	-$4.81

Tables 7.16 and 7.17 present the incremental changes in commercial and industrial retail rates under the CES + coal retirement scenario. The changes in commercial and industrial retail rates under a CES and accelerated coal retirement combination policy are virtually the same as under a stand-alone CES. Moreover, again, securitizing the coal retirement costs may further reduce the projected rate impacts. In light of the significantly higher percentage of CO_2 reductions that the combination policy achieves over the stand-alone CES, and at lower per-ton cost, one could conclude that the combination policy is more cost-effective.

Table 7.16 Projected Commercial Retail Rate Impacts under CES + Coal Retirement Scenario (Compared to the Stand-alone CES policy)

Year	Rate with no Climate Policy (cents/kwh)	Rate with a CES Policy (cents/kwh and % change)	Rate with a CES + Coal Retirement Policy (cents/kwh and % change)
2023	9.92	.001 (.01%)	.01 (.1%)
2030	11.06	.21 (1.86%)	.22 (2.0%)
2040	11.91	.19 (1.58%)	.20 (1.7%)
2050	13.29	-.43 (-3.27%)	-.42 (-3.2%)

Table 7.17 Projected Industrial Retail Rate Impacts under CES + Coal Retirement Scenario (Compared to the Stand-alone CES policy)

Year	Rate with no Climate Policy (cents/kwh)	Rate with a CES Policy (cents/kwh and % change)	Rate with a CES + Coal Retirement Policy (cents/kwh and % change)
2023	5.75	.001 (.01%)	.01 (.2%)
2030	6.41	.16 (2.45%)	.17 (2.6%)
2040	6.91	.14 (2.08%)	.15 (2.2%)
2050	7.70	-.33 (-4.29%)	-.32 (-4.2%)

CES + RGGI

Finally, ICF analyzed the retail rate and bill impacts of the CES in combination with a RGGI policy. Once again, the rate and bill impacts of a RGGI policy depend on whether North Carolina auctions CO_2 allowances, and how the state invests any resulting auction proceeds. ICF analyzed three CES + RGGI combination policies to compare the effect of different RGGI investment scenarios on the overall cost. As in the stand-alone RGGI policy case, the highest cost CES + RGGI combination is one where auction proceeds are not invested in the power sector. The lowest cost CES + RGGI scenario for residential customers is when RGGI auction proceeds are used for direct bill assistance.[78]

As presented in Figure 7.6 and Table 7.18, across all three CES + RGGI variations, the cost in 2023 to residential customers is projected to track the stand-alone RGGI scenarios (Table 7.8). This is consistent with the projections for the stand-alone CES which did not incur costs until 2025. The 2030 and 2040 projections are higher for this combination policy than for a stand-alone RGGI (Table 7.9) or a stand-alone CES (Table 7.12). However, because of the deeper CO_2 reductions (Table 7.7), this policy combination merits a second look. In 2030, a stand-alone RGGI policy with no revenue recycling adds $1.44 to the average residential customer's monthly bill; a stand-alone

78. ICF did not study the low-income household bill assistance scenario for this combination policy.

sales-based CES adds $2.34; and a CES + RGGI with no revenue recycling adds $2.92. Yet this CES + RGGI combination policy yields nearly twice the cumulative CO_2 reductions to 2050 than either policy acting alone (39.6% from baseline, versus 21.3% for the stand-alone RGGI policy and 22.1% for the stand-alone CES).

Moreover, by the 2040s, residential bills are lowest—and lower than business as usual—under a combination CES + RGGI policy with direct bill assistance than under any other policy studied by ICF. The next least expensive policy in the 2040s is a combination CES + RGGI policy that invests in EE, followed by a stand-alone CES. These findings are consistent with the relative costs of the different RGGI scenarios, the fact that the modeled RGGI scenarios did not increase in stringency after 2030, and the long-term benefits of a CES (higher penetration of fuel-free generation and robust electricity exports).

Figure 7.6 Projected Monthly Residential Electricity Bills under CES + RGGI Scenarios

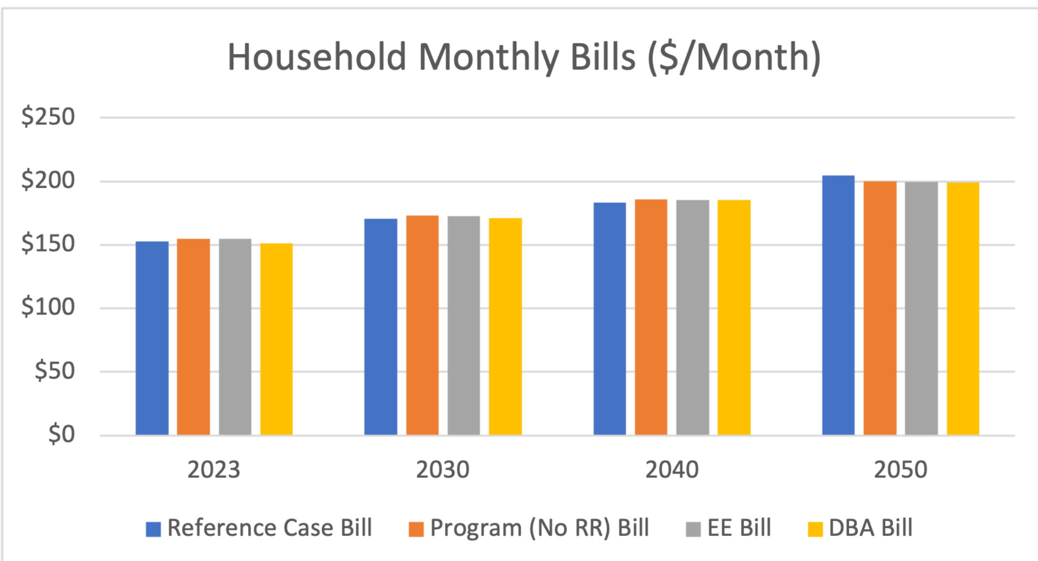


Table 7.18 Projected Changes in Monthly Residential Electricity Bills under CES + RGGI Scenarios

Year	Bill with no Climate Policy	Difference – CES + RGGI with No Revenue Recycling	Difference – CES + RGGI with 95% EE investment	Difference – CES + RGGI with 95% Direct Bill Assistance
2023	$152.73	$1.99	$1.92	-$1.34
2030	$170.39	$2.92	$2.25	$0.83
2040	$183.50	$2.61	$1.85	$1.71
2050	$204.66	-$4.66	-$5.04	-$5.32

Tables 7.19 and 7.20 present the incremental changes in *commercial and industrial retail rates* under the CES + RGGI scenarios. Again, RGGI programs with no revenue recycling or direct bill assistance for residential customers have the same effect on the other two customer classes. For commercial and industrial customers, the lowest cost CES + RGGI scenario is one where RGGI auction proceeds are invested in EE. The CES + RGGI policy combinations drive larger increases in commercial and industrial retail rates than either a RGGI (Tables 7.7 and 7.8) or a CES (Tables 7.10 and 7.11) policy, but again, result in nearly twice the CO_2 reductions.

Table 7.19 Projected Commercial Retail Rate Impacts under CES + RGGI Scenarios

Year	Rate with no Climate Policy (cents/ kwh)	Difference – CES + RGGI with No Revenue Recycling (cents/kwh and % change)	Difference – CES + RGGI with 95% EE investment (cents/ kwh and % change)	Difference – CES + RGGI with 95% Direct Bill Assistance (cents/ kwh and % change)
2023	9.92	.17 (1.8%)	.17 (1.7%)	.17 (1.8%)
2030	11.06	.26 (2.3%)	.20 (1.8%)	.26 (2.3%)
2040	11.91	.23 (1.9%)	.16 (1.4%)	.23 (1.9%)
2050	13.29	-.41 (-3.1%)	-.44 (-3.3%)	-.41 (-3.1%)

Table 7.20 Projected Industrial Retail Rate Impacts under CES + RGGI Scenarios

Year	Rate with no Climate Policy (cents/ kwh)	Difference – No Revenue Recycling (cents/kwh and % change)	Difference – 95% EE investment (cents/ kwh and % change)	Difference – 95% Direct Bill Assistance (cents/ kwh and % change)
2023	5.75	.13 (2.3%)	.13 (2.2%)	.13 (2.3%)
2030	6.41	.19 (3.0%)	.15 (2.3%)	.19 (3.0%)
2040	6.91	.18 (2.5%)	.12 (1.8%)	.18 (2.5%)
2050	7.70	-.32 (-4.1%)	-.34 (-4.4%)	-.32 (-4.1%)

Macroeconomic Effects

Electricity rates and bill impacts are critical economic metrics for evaluating the affordability and cost-effectiveness of climate policies. However, they only tell part of the economic story. How many jobs will be created or lost in the North Carolina economy under a policy, and is the economy expanding or contracting? Knowing these economic indicators will provide a more complete picture of the economic health of the state. Therefore, to complement the rate and bill impact analysis described above, ICF also ran a macroeconomic analysis to estimate jobs and GSP outputs for each of the studied policies.

Methodology

ICF relied on the REMI software to conduct its macroeconomic analysis. REMI is used by consulting firms, government,[79] and public utilities for research and analysis of policies relating to economic development, energy, infrastructure, natural resources, transportation, and taxation.

REMI estimates economic impact by tabulating the cumulative cascade of transactions that occur across and within sectors in a jurisdiction (here, North Carolina). Model outputs estimate the policy's impact on jobs, income, and GSP into the future. For this report, ICF modeled the impacts to the workforce and GSP through 2050 using 70 NAICS-based sectors[80] across North Carolina for the policy pathways described above: RGGI; a CES; a CES in combination with accelerated coal retirements; and a CES in combination with RGGI.

Results

This section summarizes the results from the REMI modeling outputs of the policy scenarios. Table 7.21 portrays the high-level cumulative impacts to North Carolina jobs and GSP compared to a baseline case for labor and GSP through 2050.

For the RGGI scenarios, spending allowance revenues on EE investments yields the most favorable impacts in terms of both jobs and GSP. Combining that RGGI scenario with a CES drives the largest job and GSP growth of any policy or policy combination. Meanwhile, there is no meaningful macroeconomic difference between a universal bill assistance program or one targeting low-income customers; in both cases, revenue recycling toward bill-assistance yields nominal macroeconomic benefits. That said, all of the macroeconomic impacts are small relative to North Carolina's entire labor force and economy, ranging from -0.01% to +0.05% of a change from job projections without a climate policy and -0.01% to +0.03% of a change from GSP levels without a climate policy. (Note: A "job-year" is one year of work for one person; the metric captures all employment whether it lasts for six months or multiple years.)

79. See, e.g., Scott Nystrom, REMI, A Contrast: Modeling the Macroeconomic Impact of 'Medicaid Expansion' in North Carolina, Prepared for the North Carolina Department of Health and Human Services (Jan 7, 2013).
80. The North American Industry Classification System is the standard used by the federal and most state governments to collect industry information across the economy.

Table 7.21 Summary of Cumulative Job and GSP Impacts Across Scenarios

(2023–2050)	Cumulative Job Impacts		Cumulative GSP Impacts	
Scenario	Job-years	% Change from baseline	GSP 2020$ (millions)	% Change from baseline
1a: RGGI Load Adjusted Energy Efficiency	47,337	0.03%	4,868	0.02%
1b: RGGI Direct Bill Assistance (Using REMI allocation across income groups)	-11,228	-0.01%	-1,581	-0.01%
1c: RGGI Direct Bill Assistance (Focusing on low-income groups)	-10,901	-0.01%	-1,398	-0.01%
2: Stand-alone sales-based CES	37,275	0.02%	2,869	0.01%
3: CES + Coal Retirement	25,376	0.01%	1,110	0.00%
4a: CES + RGGI (no revenue recycling)	17,777	0.01%	348	0.00%
4b: CES + RGGI (revenue recycling)	89,998	0.05%	7,885	0.03%

While investing in clean energy and EE has net positive impacts in terms of cumulative job-years and cumulative contribution to GSP, the annualized REMI outputs reveal more nuanced insights. Consistent across all scenarios is a small decline in jobs and GSP relative to the baseline until around 2030, from a reduction in employment at fossil fuel-fired power plants. (In the 2020s, scenarios featuring a CES or EE investment post net job growth despite a loss in fossil employment.) From this point forward, the policies follow different paths. In 2035, the RGGI scenario with EE investment shows the greatest job growth. By 2040, CES policies are creating more jobs, related to the construction of new clean energy in North Carolina.

The remainder of this section provides jobs and GSP projections for each studied policy.

RGGI Scenarios

Figures 7.7 and 7.8 show the annualized job-year and GSP impacts of the stand-alone RGGI scenarios. Positive employment numbers over time are driven by investment in EE, bill savings for customers, and investments in solar and battery storage (Fig. 7.7). Job losses from the retirement of fossil-fueled generation plants are most prevalent in the 2020s but diminish substantially by the 2030s. Meanwhile, the strain on job-years resulting from the out-of-pocket costs of EE and the allowance price impacts is outweighed by bill savings from reduced energy consumption as early as 2033.

Figure 7.7. RGGI Energy Efficiency Revenue Recycling – Jobs Impacts

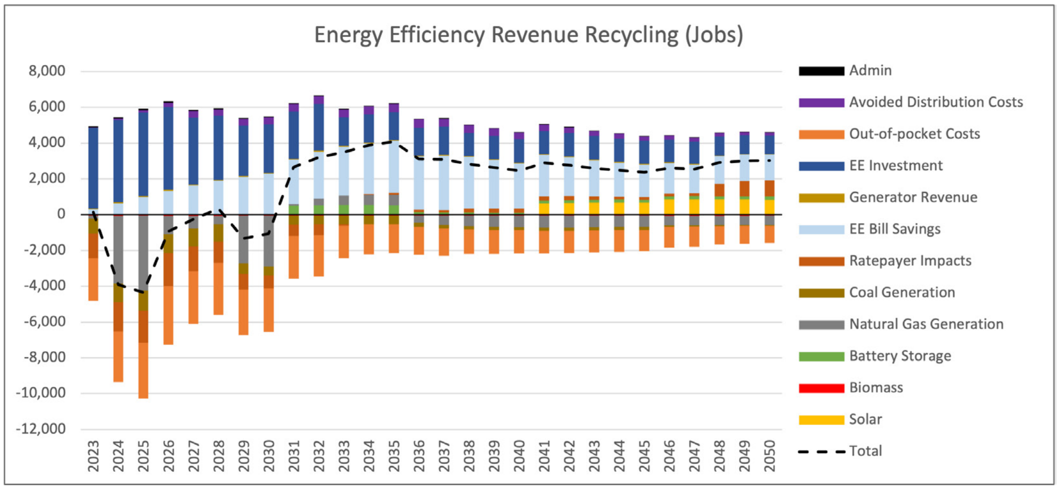
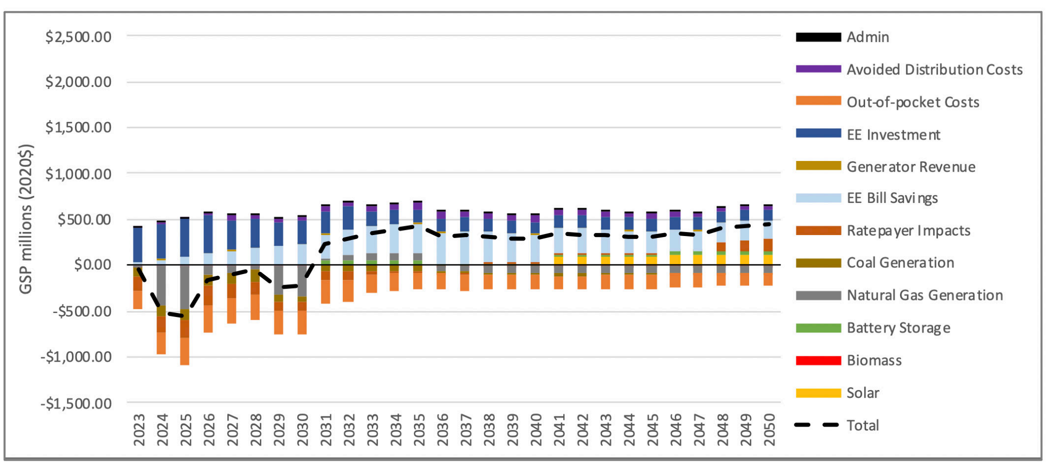


Figure 7.8 shows the impacts of a RGGI program with EE investment on GSP, depicting a similar top-line trend as the jobs picture. Again, positive impacts are driven almost entirely by bill savings and investments in EE, and to a lesser extent, avoided distribution costs and out-year solar development. The savings from EE bills cancel out the combined negative GSP impacts of the allowance prices and out-of-pocket costs as soon as the policy is implemented. Meanwhile, near-term negative impacts on GSP are due to a downturn in coal and natural gas generation.

Figure 7.8. RGGI Energy Efficiency Revenue Recycling – GSP



Definitions for Select REMI Impact Categories

Generator revenue changes: net changes to NC generators resulting from changing rates associated with recovering incremental system costs from each policy including reduced demand from EE and reduced need for energy imports.

Avoided distribution costs: reduced load from EE results in less costs (i.e., cost savings) associated with electricity distribution that are passed on to ratepayers

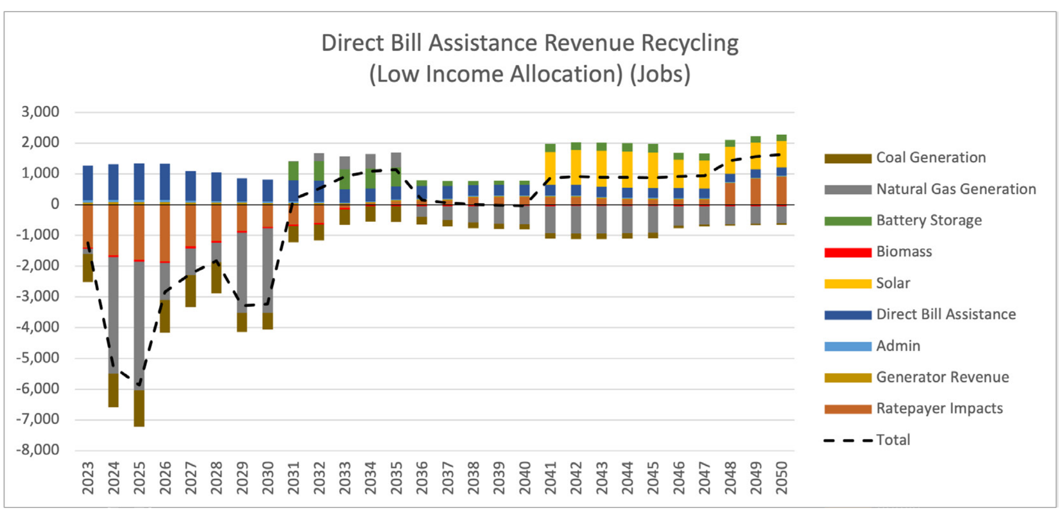
Out-of-pocket costs: investments in EE by NC residents resulting in budgetary impacts, assuming constant budget. For instance, RGGI auction proceeds might fund a rebate program for an energy-efficient refrigerator. To take advantage of this program, a family would need to pay for the remaining costs of a new refrigerator after the rebate was applied.

Ratepayer impacts: impacts to ratepayers from passing on all system costs associated with a policy to retail customers, including the cost of allowance purchases under RGGI scenarios.

By contrast, investing RGGI revenues into direct bill assistance does not generate the same level of economic development. Because of the negligible difference between bill assistance recycling to all ratepayers and low-income allocation, Figures 7.9 and 7.10 demonstrate, and the following paragraphs discuss, the impacts of a low-income bill assistance program.

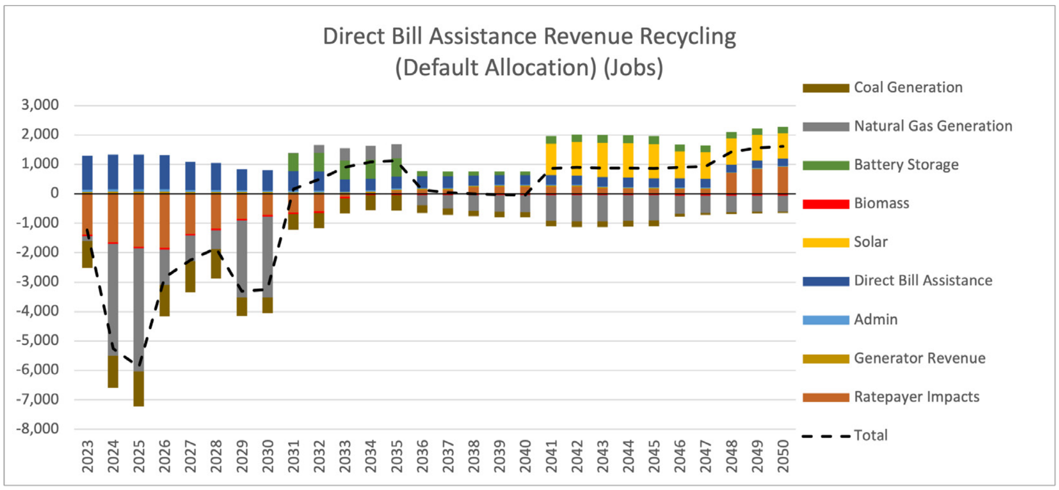
Negative job impacts are driven again by reduced utilization and closure of fossil plants, as well as ratepayer impacts from the allowance price. By 2030, these negative impacts are largely diminished, and positive job impacts from solar and battery storage offset those losses. In 2034, ratepayer impacts switch from being a drag on job-years to a positive driver of job-years, which grows more positive as time progresses. Even sooner, direct bill assistance is netting out rate impacts, resulting in lower bills for recipients of the assistance than under baseline cases with no climate policy. In addition, direct bill assistance is the primary driver of jobs in the 2020s, although these impacts diminish overtime. It is not until the 2040s that this scenario drives job creation in the clean energy industry and moves the jobs picture consistently positive.

Figure 7.9. RGGI with Direct Bill Assistance for Low-Income Families – Jobs



The GSP reflects a similar story: allowance price impacts, and changes to fossil fuel generation are a drag on GSP in the near-term, while increased spending power from direct bill assistance offsets rate impacts but cannot turn the GSP positive relative to the baseline until after 2030. Once the bulk of impacts from fossil fuel retirements have occurred, solar and battery storage pull the jobs impacts into the net positive.

Figure 7.10. RGGI with Direct Bill Assistance for Low-Income Families – GSP



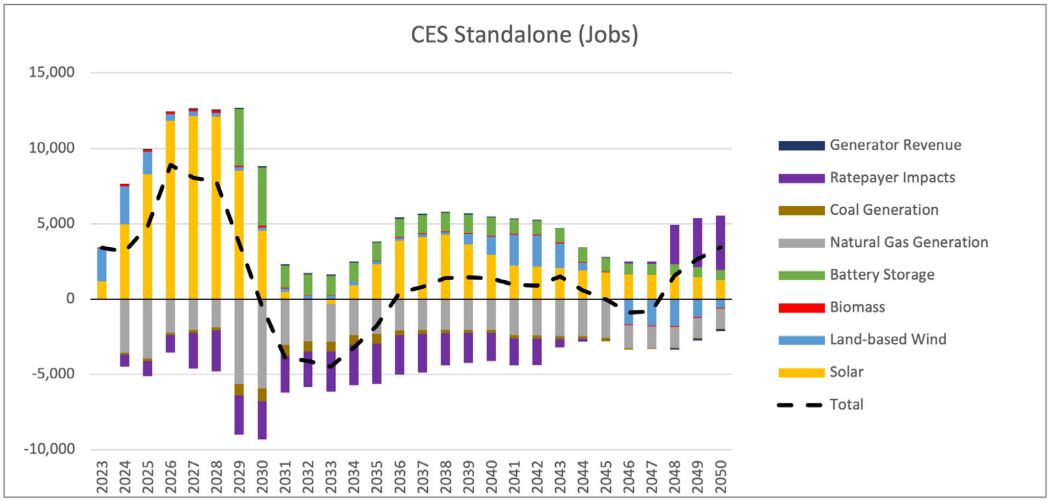
The positive macroeconomic effects of direct bill assistance are not nearly as beneficial as recycling through EE investments. However, these results do not indicate what is happening at a community level. The positive economic and employment impacts of low-income bill assistance could have a tangible, positive impact on low-wealth communities, where families already find it difficult to pay their utility bills. In addition, while not studied here, the state might split RGGI auction revenues between low-income bill assistance and EE investments, to make energy bills more affordable while stimulating the economy with EE jobs and efficient appliance purchases. In light of the economic downturn caused by COVID-19, and mounting utility arrearages, such a split might be particularly helpful in the near-term.

Stand-alone CES

In a scenario where a sales-based CES is implemented on its own, model results (Fig. 7.11) indicate a strong uptick in jobs in the late 2020s, driven by expansion of solar, battery storage, and to a lesser extent, land-based wind and biomass. As with the RGGI scenarios, the near-term loss of natural gas and coal generation, and ratepayer impacts, are the predominant negative forces on job-years. These drivers of job loss are significantly overshadowed by the expansion of solar, wind, and battery storage until 2029, when incremental additions of solar job-years take a 5-year pause (solar continues to be built but at the rate projected in the baseline). REMI predicts that this interlude of stalled addition of solar jobs will rebound, augmented by wind additions in the early 2040s. In the intermediate-term, ratepayer impacts are a sizeable drag on employment, through about 2042. This tracks the interim period where higher retail rate and bill impacts were projected for the stand-alone CES.

In the late 2040s, land-based wind job-years decline, reflecting the projected shift in generation away from these sources to solar, battery storage and offshore wind.

Figure 7.11. CES Impacts – Jobs



The GSP impacts of a stand-alone CES follow a similar trend, with the same positive (solar, land-based wind and biomass until the 2040s) and negative (loss of employment in fossil generation, ratepayer impacts) drivers (Table 7.22). While Table 7.22 indicates no economic development from offshore wind, a CES with a wind carveout is expected to drive fairly significant economic development.[81]

81. See BVG Associates, Building North Carolina's Offshore Wind Supply Chain (2021), https://files.nc.gov/nccommerce/documents/Policymaker-Reports/Report_North-Carolina-OSW-Supply-Chain-Assessment_BVGAssociates_asPublished-Mar3-2021.pdf.

Table 7.22. CES Impacts – GSP

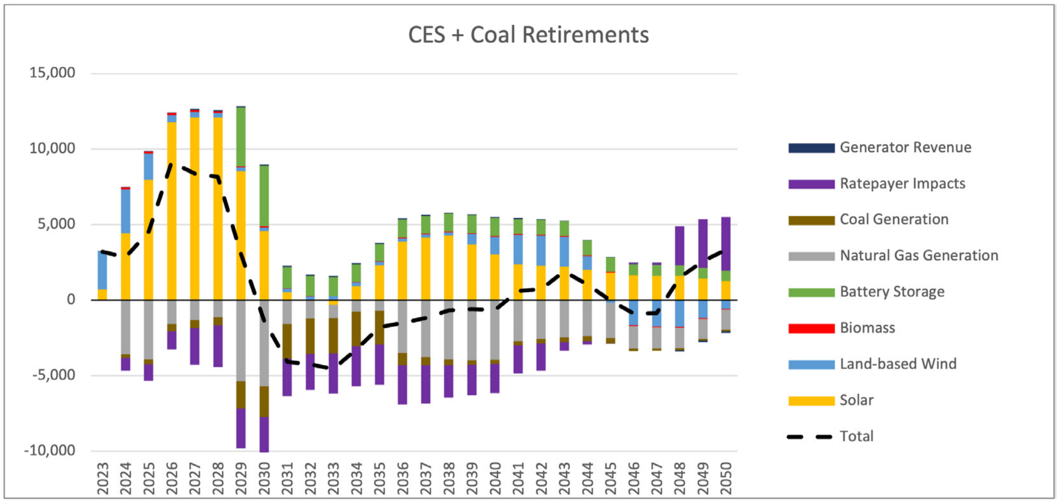
GSP (Million 2020$)

Component	2023	2028	2030	2035	2040	2045	2050	Cumulative
Solar	$123.16	$1,328.09	$519.46	$305.12	$392.71	$267.08	$213.89	**$12,594.73**
Land-based Wind	$204.45	$27.61	$24.34	$25.40	$139.94	-$11.55	-$66.22	**$1,075.57**
Offshore Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biomass	$3.28	$14.43	$9.69	$2.44	$6.56	$6.59	-$6.45	**$141.93**
Battery Storage	$0.00	$0.00	$385.43	$140.20	$153.52	$128.49	$103.83	**$3,417.68**
Nuclear	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biogas	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Natural Gas Generation	-$0.90	-$214.79	-$699.46	-$288.48	-$258.97	-$319.65	-$184.53	**-$8,259.14**
Coal Generation	-$0.41	-$21.40	-$116.42	-$85.14	-$28.58	-$31.54	-$5.84	**-$1,105.84**
Retrofits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Ratepayer Impacts	-$0.70	-$318.04	-$315.83	-$391.97	-$345.44	-$98.49	$509.11	**-$5,148.37**
Generator Revenue	$0.03	$12.65	$11.98	$14.68	$11.23	$0.54	-$25.89	**$146.94**
Total	**$328.91**	**$828.38**	**-$180.76**	**-$277.73**	**$70.94**	**-$57.98**	**$538.54**	**$2,869.28**

CES + Coal Retirement

A CES combined with accelerated coal retirements yields similar results to the stand-alone CES (Fig. 7.12), resulting from most of the same drivers. (Recall that the rate/bill impacts of a stand-alone CES and this policy combination were also quite similar.) The primary difference in terms of employment and economic impacts is intuitive; the negative changes related to coal generation are more concentrated in the late 2020s and the first half of the 2030s, when implementing a policy that accelerates the market trend of coal retirement. A CES + coal retirement requirement is projected to have more substantially negative impacts on jobs related to coal changes in that time period than a stand-alone CES, resulting in lower net job growth.

Figure 7.12. CES + Coal Retirement Impacts – Jobs



In most years, the negative ratepayer impact on GSP under the CES + coal retirement scenario (Table 7.23) is only about 2% larger than for the stand-alone CES scenario (Table 7.22). The economic losses associated with coal retirements are, as would be expected, earlier and more pronounced here than with a stand-alone CES and are the largest driver of change in GSP. By contrast, the negative impacts on gas generation are smaller under the combined policy, as gas units are run—and built—to provide some of the capacity services that the retiring coal would have met. Meanwhile, the positive impacts of solar, land-based wind, biomass, and battery storage construction and operation are similar to those seen under the CES. Overall, the positive GSP impacts of the CES + coal retirements are less than half those for the CES on its own.

Table 7.23. CES + Coal Retirement Impacts – GSP

GSP (Million 2020$)

Component	2023	2028	2030	2035	2040	2045	2050	Cumulative
Solar	$72.85	$1,324.51	$518.55	$303.83	$402.59	$273.27	$212.68	**$12,509.22**
Land-based Wind	$236.48	$31.93	$28.14	$30.18	$136.54	-$12.52	-$64.87	**$1,301.16**
Offshore Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biomass	$0.39	$11.70	$7.22	$1.85	$6.40	$6.41	-$6.62	**$114.47**
Battery Storage	$0.00	$0.00	$399.71	$133.47	$149.36	$133.85	$105.58	**$3,428.72**
Nuclear	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biogas	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Natural Gas Generation	$0.01	-$124.86	-$677.29	-$87.71	-$508.63	-$310.66	-$185.78	**-$8,157.47**
Coal Generation	-$0.70	-$66.87	-$270.87	-$312.04	-$43.03	-$53.55	-$15.74	**-$2,984.23**
Retrofits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Ratepayer Impacts	-$4.46	-$323.68	-$322.21	-$389.87	-$351.23	-$100.65	$503.28	**-$5,258.94**
Generator Revenue	$0.48	$13.09	$12.06	$13.56	$11.73	$0.67	-$25.26	**$150.86**
Total	**$305.04**	**$865.63**	**-$304.60**	**-$306.68**	**-$196.25**	**-$62.65**	**$523.88**	**$1,109.80**

CES + RGGI

The CES + RGGI scenario was modeled with EE investments—the scenario likely to drive the most positive economic change based on the stand-alone RGGI analysis—and without revenue recycling. Not surprisingly, the scenario featuring EE investment drives larger positive impacts on jobs and GSP. However, the two RGGI designs follow similar trend lines across employment and GSP impacts. For instance, there is virtually no difference between the two scenarios when it comes to jobs constructing or operating solar, wind, biomass, battery storage, coal, and natural gas generation—because both scenarios result in much the same generation mix over time. The jobs impact category with the most notable difference between the scenarios with/without revenue recycling was "generator revenue"—EE investments create more job-years under this category than when RGGI auction revenues are deposited in the state treasury. For the GSP impacts, economic productivity is driven higher by the categories that only exist as a function of revenue recycling in EE, including bill savings from EE investments, reduced electricity demand, out-of-pocket costs, avoided distribution costs, and program administration. Other categories remain quite similar.

Only the CES + RGGI with EE scenario is presented here (Figs. 7.13 and Table 7.23). Based on these results, a CES + RGGI combination produces more employment in the renewables and biomass categories than a stand-alone RGGI policy investing in EE. The combination also produces more job-year losses in the fossil categories than a stand-alone RGGI policy. The net result is more robust growth in job-years over baseline (89,998) than either a stand-alone RGGI (47,337) or CES (37,275)—or the sum of the job-year growth of those two stand-alone policies.

Similarly, the combination of these policies is more than additive when it comes to generating GSP. While a stand-alone RGGI with EE investment generates about $4.87 billion, and a stand-alone CES about $2.87 billion, above baseline over the lifetime of the policies, the combination drives more than $7.88 billion in economic growth.

Figure 7.13. CES + RGGI with Revenue Recycling – Jobs

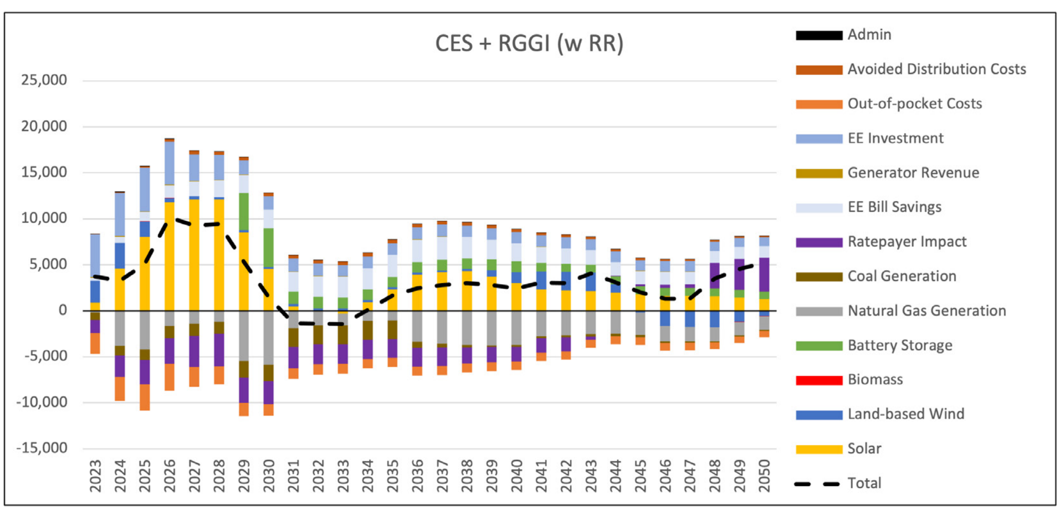


Table 7.24 CES + RGGI with Revenue Recycling – GSP

GSP (Million 2020$)

Component	2023	2028	2030	2035	2040	2045	2050	Cumulative
Solar	$88.39	$1,325.62	$517.30	$307.43	$400.83	$269.21	$212.45	**$12,535.65**
Land-based Wind	$226.58	$30.60	$26.97	$28.70	$137.59	-$11.50	-$65.31	**$1,266.46**
Offshore Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biomass	$0.32	$0.73	$0.50	$0.01	$0.06	$0.15	-$2.92	**-$8.23**
Battery Storage	$0.00	$0.00	$415.12	$128.75	$148.16	$122.15	$124.01	**$3,463.69**
Nuclear	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Biogas	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Natural Gas Generation	-$16.95	-$131.43	-$692.68	-$130.42	-$478.18	-$326.03	-$204.90	**-$8,506.28**
Coal Generation	-$103.39	-$161.67	-$240.22	-$277.51	-$31.58	-$41.81	-$16.09	**-$3,218.22**
Retrofits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Ratepayer Impact	-$151.31	-$422.19	-$329.86	-$330.21	-$305.35	-$60.33	$527.80	**-5,351**
EE Bill Savings	$27.99	$179.09	$208.27	$265.56	$237.77	$189.01	$174.86	**5,505**
Generator Revenue	$9.78	$7.26	$6.25	$2.23	$2.04	$4.02	$0.41	**125**
EE Investment	$388.67	$241.61	$130.61	$122.74	$124.09	$122.98	$106.12	**4,788**
Out-of-pocket Costs	-$206.96	-$208.50	-$139.00	-$118.78	-$116.17	-$112.95	-$100.15	**-4,037**
Avoided Distribution Costs	$2.37	$38.97	$43.53	$56.04	$51.37	$42.24	$39.66	**1,175**
Admin	$6.27	$3.90	$2.15	$2.10	$2.16	$2.18	$1.91	**80**
Total	**$270.76**	**$913.67**	**-$48.27**	**$56.71**	**$174.02**	**$203.67**	**$794.94**	**$7,884.94**

APPENDICES

APPENDIX A – PARTICIPANTS IN THE A1 CARBON POLICY STAKEHOLDER PROCESS

The Policy Working Group met at least once monthly throughout the project on the following dates. Dates where the Policy and Technical working groups met together to discuss matters that would impact the modeling are indicated by an asterisk.

12/11/2019*	8/5/2020*
2/3/2020	8/12/2020*
3/10/2020	9/15/2020
4/7/2020	10/15/2020*
5/5/2020	10/19/2020
6/26/2020	10/29/2020
7/28/2020	11/13/2020

Table A.1. Policy Working Group Members

Organization	Name(s) of Participants
Audubon NC	Greg Andeck Zach Wallace
Dominion Energy	Sarah Cosby Jeff Matzen Gina Pisoni
Duke Energy	Diane Denton Mark McIntire Dawn Santoianni
Duke University, Sanford School	Billy Pizer
Environmental Defense Fund	Dionne Delli-Gatti Michelle Allen
Litz Consulting	Franz Litz
NC Clean Energy Business Alliance	Brian O’Hara Tyler Norris
NC Clean Energy Technology Center	Steve Kalland

Organization	Name(s) of Participants
NC Dept. of Environmental Quality	Matthew Davis Paula Hemmer Sushma Masemore Jennifer Mundt Bradley Nelson
NC Electric Membership Corporation	Michael Youth
NC Governor's Office	Jeremy Tarr
NC Justice Center	Al Ripley Claire Williamson
NC Manufacturers Association	Preston Howard
NC Sustainable Energy Association	Ivan Urlaub
NC Utilities Commission - Public Staff	Jack Floyd Nadia Luhr Jeff Thomas
SolNation	Nakisa Glover
Southern Environmental Law Center	Nick Jimenez
Vote Solar	Tyler Fitch

Table A.2. Technical Working Group Members

Organization	Name(s) of Participants
Duke Energy	Nate Finucane Bobby McMurray
Duke University, Energy Initiative	Brian Murray
Environmental Defense Fund	Drew Stilson
Natural Resources Defense Council	Amanda Levin
NC Electric Membership Corporation	Charlie Bayless
NC State University	Joseph DeCarolis
NC Utilities Commission	Steve McDowell
NC Utilities Commission – Public Staff	Bob Hinton Jay Lucas
Resources for the Future	Dallas Burtraw

The Policy and Technical Working Groups were drawn from a larger Stakeholder Group representing additional organizations and interests. The Stakeholder Group met on the following dates:

12/9/2019 (In person)

2/19/2020 (In person)

5/28/2020 (Virtual)

8/26/2020 (Virtual)

Organizations Represented at Stakeholder Meetings

Abundant Power

Advanced Energy

AARP

Appalachian State University

Appalachian Voices

Audubon Society NC

Bailey & Dixon (CIFGUR)

Carolina Solar Energy

Carolina Utility Customers Association

CERES

Chambers for Innovation

City of Charleston

Clean Air Carolina

Climate Reality Project

Cypress Creek Renewables

Dominion Energy

Duke Energy

Duke University, Energy Initiative

Duke University, Environmental Law & Policy Clinic

Duke University, Nicholas School

Durham County

ElectriCities

Environmental Defense Fund

Fayetteville Public Works

Google

Litz Consulting

Natural Resources Defense Council

NC Business Council

NC Clean Energy Technology Center

NC Conservation Network

NC Dept. of Environmental Quality

NC Department of Justice

NC Electric Membership Corporation

NC Farm Bureau

NC Governor's Office

NC Justice Center

NC League of Conservation Voters

NC Manufacturers Alliance

NC Pork Council

NC Retail Merchants Association

NC State University

NC Sustainable Energy Association

NC Utilities Commission

NC Utilities Commission - Public Staff

NC WARN

Research Triangle Clean Tech Center

Roanoke Electric Cooperative

Robinson Consulting

SAS

Sierra Club

Southeast Wind Coalition

Southern Alliance for Clean Energy

Southern Environmental Law Center

Trane Technologies

UNC Chapel Hill

UNC Charlotte

Vote Solar

Wal-Mart

Weyerhaeuser

Two public forums were also held in 2020 on September 9 and 16 to provide input and allow for feedback from the broader public. The first forum was recorded and made publicly available via YouTube. An information sheet was made available in advance of the public forums, in both English and Spanish to increase accessibility.

APPENDIX B – DETAILED TECHNICAL ASSUMPTIONS

The results of power sector modeling are strongly influenced by the assumptions the modeler makes about electricity demand patterns, fuel prices, and new generation technology costs. The purpose of this appendix is to provide a transparent overview of the assumptions that were made by modelers using IPM and DIEM to compare carbon policy outcomes such as emissions reductions, wholesale costs, and generation mix. Many more policy scenarios and sensitivities were run using DIEM; a subset of scenarios and sensitivities were run in the more familiar IPM to corroborate the directional signals produced by DIEM.

The first section summarizes the assumptions that have the most influence on the modeling. Details of forecasts, sensitivities, and data assumptions that are specific to the Carolinas region are described in the next subsection. More general model descriptions and data sources used in IPM and DIEM are described in the remaining two subsections respectively. Where there is overlap between these CEP-specific assumptions and the more general assumptions typically used in the two models, the CEP-specific data override any general assumptions.

Summary of Key Assumptions in the Main CEP-A1 Model Runs in IPM and DIEM

To conduct modeling, as well as to interpret the results, it is necessary to establish a central set of assumptions and forecasts that cover the variables with the most influence on the models' policy results. From this standard starting point, it is then possible to evaluate how sensitivity analyses around these forecasts would alter baseline and policy findings. The list below summarizes the most important assumptions in the modeling analyses:

- Electricity demand growth – Growth rates are taken from the DEC/DEP 2020 IRPs and imply demand growth of around 0.6% per year. Alternative cases are run based on the AEO 2020 forecasts, which assume growth rates between 1% and 1.3% per year.
- Peak capacity needs – Winter and summer peaking needs are also taken from the DEC/DEP 2020 IRPs. The data imply that DEP remains a winter-peaking system throughout the forecast, while DEC switches from a winter-peaking to a summer-peaking system around 2030. Alternatives are modeled using historical FERC Form 714 data on hourly demands that represent a range of possible peak-demand patterns.
- Natural gas prices – Prices for the first eight years of the forecasts are based on ICF natural gas modeling and then transition after eight years to AEO 2020 forecasts. This tracks DEC/DEP assumptions as reflected in their IRPs.
- Cost of securing firm gas capacity – Fixed costs are added to potential new combined cycle units to proxy costs associated with securing firm gas capacity ($1.50/MMBtu applied as a fixed annual cost). These costs are not added to existing capacity or new combustion turbines since existing capacity already has gas capacity available and turbines that operate for limited periods require much less gas.

- Renewables costs – Capital and operating costs are based on the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) forecasts. The medium-cost forecasts underlie the main CEP cases; the more advanced, lower cost forecasts are used as alternatives.
- Battery storage – Costs are from the NREL ATB. Quantities that can be added to the DEC/DEP systems and their effectiveness at meeting peak needs are taken from Attachment IV to the DEC/DEP 2020 IRPs (note that the quantities in Attachment IV are higher than those used in the main sections of the IRPs). These assumptions are contrasted with assumptions on battery effectiveness across the Southeast from an NREL report (Denholm et al. 2018). The main CEP cases use NREL ATB assumptions about depth-of-discharge and costs. Alternative cases assume an additional 15% cost to approximate potential concerns about the impact of daily cycling of batteries over time.
- Solar plus battery storage options – New technologies have been added to the IPM and DIEM models in order to represent potential benefits of joint installations for meeting peak demands and possible cost savings.

Details of Modeling Forecasts and Data Specific to the Carolinas Region

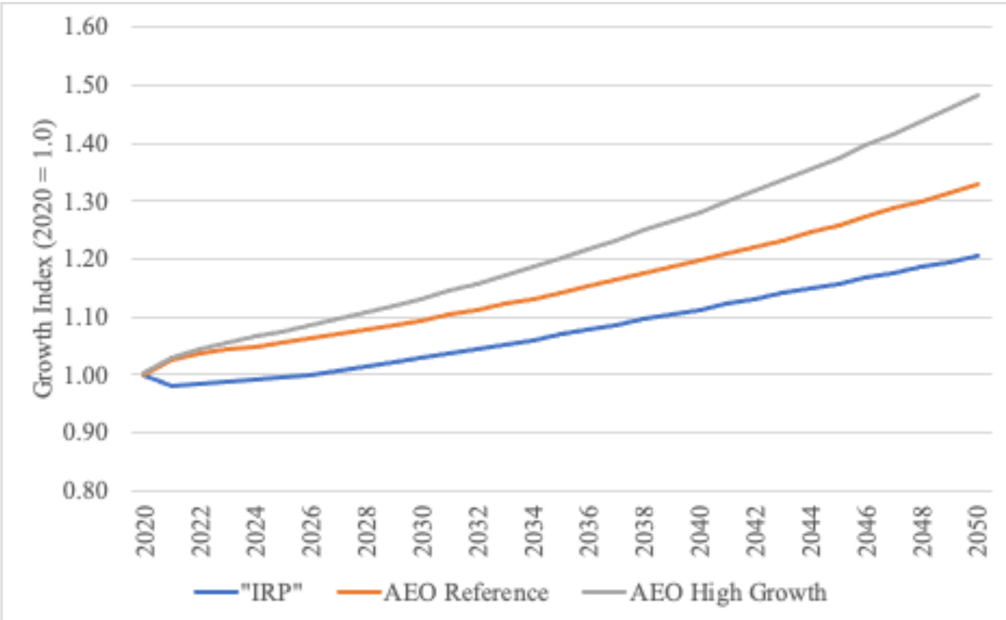
This subsection discusses details of the main data and forecasts that have been used in the IPM and DIEM modeling. Sensitivities around critical forecasts are also shown. The data in this subsection focus on the Carolinas region; broader regional assumptions and more general data and assumptions in the IPM and DIEM models are described in the following subsections on the two models.

Electricity Demand Growth

One of the most critical factors in determining policy costs is the growth rate of electricity demand. The starting point in this analysis is the DEC/DEP IRP projections of demand for net energy. These estimates, along with those from the other South Carolina utilities (Santee Cooper, SCE&G), are scaled up to match the regional demand as presented in the AEO 2020 (EIA 2020b). From this starting point, the growth rates in the various IRPs are used to estimate net energy demands through 2035. Similar logic is used to scale up the IRP data on winter and summer peak demands for capacity. After 2035, the end of the planning window discussed in the most recent DEC/DEP IRPs, the growth rates in the various IRP forecasts are extended through 2050 to cover the CEP policy forecast horizon.

In sensitivity analyses, the growth rates forecasted in regional IRPs can then be contrasted with growth rates from the AEO 2020 Reference Case and AEO 2020 High Macroeconomic Growth Case. Figure B.1 shows these three growth paths as trends starting from an index of 1.0 in 2020. The main assumption ("IRP"-related growth) grows at 0.62% per year on average over the 2020–2050 time frame, while the AEO 2020 Reference Case grows at 0.96% per year and the AEO High Macroeconomic Growth Case grows at 1.32% per year. The IRP net energy demand data already include estimates of energy efficiency and demand-side management, as do the AEO forecasts. There is a discussion of additional options for calculating energy efficiency below.

Figure B.1. Electricity Growth Indices for the Carolinas



Usually, long-term dispatch models assume that peak demands grow at the same rate as total demand. For any sensitivity cases using the AEO Reference and High Growth forecasts, this assumption is maintained for the CEP A1 analysis. For the main model runs, the estimates of winter and summer peak demands are based on the trends shown in the IRPs for utilities in the Carolinas. In the DEC region (DEC 2020), the winter peak is assumed to grow at 0.56% per year over 2020–2050 and the summer peak grows at 0.80% per year. In the DEP region (DEP 2020), the winter peak is assumed to grow at 0.79% per year and the summer peak at 0.88% per year.

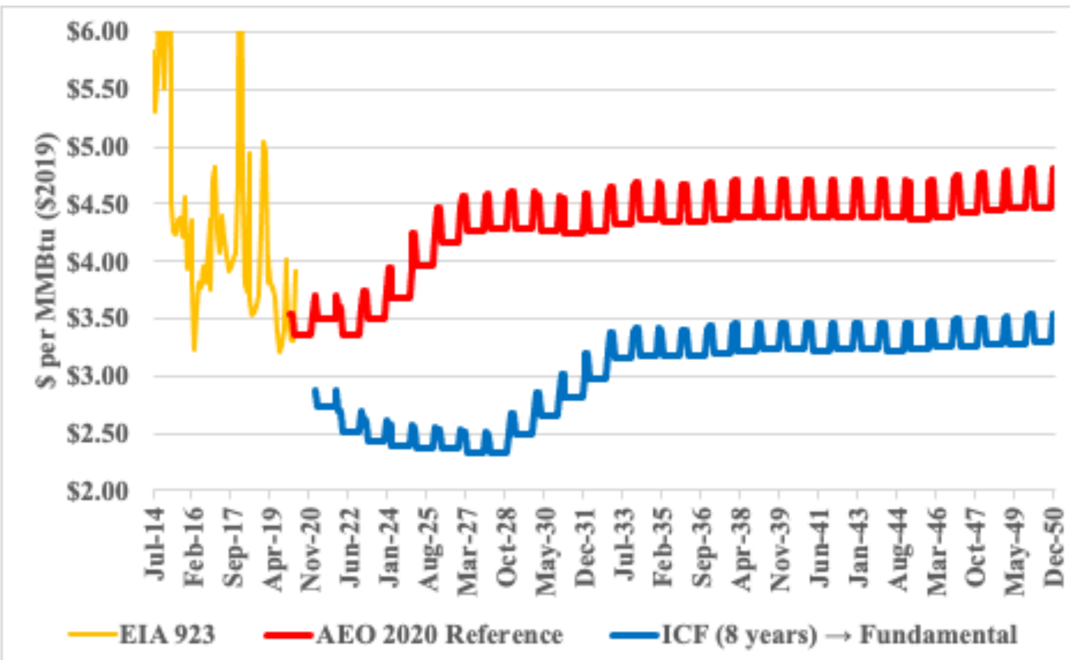
Fuel Prices

The two natural gas price forecasts used in this analysis are from ICF's Gas Market Model (GMM) (EPA 2018, Chapter 8) and the AEO 2020 Reference Case. In the main model runs, delivered gas prices in the Carolinas follow the blue line in Figure B.2. In these trends, the first eight years of wholesale prices are forecast by the GMM model, plus the transportation costs associated with reaching Transco Zones 4 and 5 (natural gas delivery points along the transmission system). Following the approach used in the Duke IRPs, after the first few years the GMM gas price forecast transitions to a fundamental forecast using Henry Hub prices from the AEO 2020 Reference Case, with transport costs again added for delivery to the Carolinas. This shift in forecast sources accounts for the increase in gas prices around 2030.

It is assumed that existing combined cycle units in the Carolinas pay Zone 4 prices (as shown in Fig. B.2), while combustion turbines pay Zone 5 prices (which are around \$0.20/MMBtu higher). In addition, to approximate the additional costs of securing firm gas deliveries, any potential new combined cycle units are assumed to pay an additional \$1.50/MMBtu as a fixed annual cost. In the figure below, this additional cost for new gas supplies can be roughly seen by the difference between the EIA Form 923 historical data on average delivered gas prices (shown in yellow in Fig. B.2; these prices include any costs for securing non-firm gas supplies) and the marginal gas prices that are forecast by ICF's GMM model (shown in blue). Sensitivities are conducted in some DIEM model runs that remove this assumption of additional gas costs for new combined cycle units. Additional sensitivities are also conducted using the AEO 2020 Reference Case forecast for delivered gas prices to the Carolinas (shown in red).

As for delivered coal prices for the Carolinas, both models used assumptions forecast by ICF (see Chapter 7 of EPA 2018 for a discussion of this methodology). For the Carolinas, coal prices remain generally flat in these forecasts at around \$2.95–\$3.00/MMBtu over the 2020–2050 time frame (in \$2019).

Figure B.2. Natural Gas Price Forecasts for North Carolina



Characterization of Existing Units

The IPM and DIEM models normally start characterizing existing units with the U.S. EPA's National Electric Energy Data System (NEEDS) v6[1] database (EPA 2020) and adjust these data as needed to best represent ongoing changes in the industry. Table B.1 presents NEEDS data on the characteristics of coal plants in North Carolina (shown in black) and contrasts these data to information from the DEP/DEC IRP filings (in red). The subcritical/supercritical designation (shown in blue) is used in some coal-retirement policy modeling runs.

1. DIEM is using version 6 from March 2020 and IPM is using version 6 from June 2020.

The NEEDS data and the DIEM and IPM models (and other models) focus on summer capacity when representing the size of generating units, while the DEC/DEP IRP data include both summer and winter capacity. For this modeling, since both DEC and DEP project being winter-peaking systems through at least 2030, the NEEDS capacity data for Duke Energy units have been replaced with the data from the IRPs. The DIEM modeling also separates winter capacity data from summer capacity for units in the Carolinas, again given that North Carolina can be a winter-peaking system.

The NEEDS data only include planned retirement dates for the Allen coal plants, while the 2019 IRPs have expected retirement dates for all coal plants in North Carolina, based on their depreciation life. The data in the modeling have been adjusted to match the IRP data when it differs from the NEEDS data (similar adjustments are made to capacity and retirement dates for non-coal units also).

There was discussion among members of the Technical Working Group regarding the appropriate heat rate data to use for the Duke Energy units. After consideration of heat rate data provided in the DEQ supporting documentation for a rule intended to implement the U.S. EPA's Clean Power Plan (DEQ 2015), it was decided that the NEEDS heat rate data was a more appropriate characterization of current operations at existing coal plants.

Table B.1. DEP/DEC Coal Units

Plant Name	Unit ID	County	NEEDS Summer Capacity (MW)	DEC/DEP IRP Winter Capacity (MW)	DEC/DEP IRP Summer Capacity (MW)	Heat Rate (Btu/kWh)	On-Line Year	NEEDS Retirement Year	DEC/DEP IRP Retirement Date	Boiler Type	DEC/DEP IRP Resource Type	Scrubber Online Year	NOx Post-Comb Control	NOx Online Year	ACI Online Year	Coal-to-Gas Convert
Marshall (NC)	1	Catawba	370	380	370	9520	1965		12/2034	subcritical	intermediate	2007	SNCR	2006		
Marshall (NC)	2	Catawba	370	380	370	9523	1966		12/2034	subcritical	intermediate	2007	SNCR	2007		
Marshall (NC)	3	Catawba	658	658	658	9426	1969		12/2034	supercritical	base	2007	SCR	2009		
Marshall (NC)	4	Catawba	660	660	660	9361	1970		12/2034	supercritical	base	2006	SNCR	2008	2016	
James E. Rogers	5	Cleveland	544	546	544	9605	1972		12/2032	subcritical	peaking	2010	SCR	2002		2019
James E. Rogers	6	Cleveland	844	849	844	9167	2012		12/2048	supercritical	intermediate	2012	SCR	2012		2019
G G Allen	1	Gaston	162	167	162	10739	1957	2024	12/2024	subcritical	peaking	2009	SNCR	2003		
G G Allen	2	Gaston	162	167	162	10800	1957	2024	12/2024	subcritical	peaking	2009	SNCR	2008		
G G Allen	3	Gaston	258	270	261	10401	1959	2024	12/2024	subcritical	peaking	2009	SNCR	2005		
G G Allen	4	Gaston	257	267	257	10430	1960	2029	12/2028	subcritical	intermediate	2009	SNCR	2006	2016	
G G Allen	5	Gaston	259	259	259	10422	1961	2029	12/2028	subcritical	peaking	2009	SNCR	2008	2016	
Mayo	1A	Person	364	746	727	11235	1983		12/2035	subcritical	intermediate	2009	SCR	2004		
Mayo	1B	Person	364			11235	1983			subcritical	intermediate	2009	SCR	2004		
Roxboro	1	Person	379	380	379	10316	1966		12/2028	subcritical	intermediate	2008	SCR	2002		
Roxboro	2	Person	671	673	668	10423	1968		12/2028	subcritical	intermediate	2007	SCR	2002		
Roxboro	3A	Person	346	698	694	10429	1973		12/2033	subcritical	intermediate	2008	SCR	2003		
Roxboro	3B	Person	346			10429	1973			subcritical	intermediate	2008	SCR	2003		
Roxboro	4A	Person	349	711	698	10453	1980		12/2033	subcritical	intermediate	2007	SCR	2001		
Roxboro	4B	Person	349			10453	1980			subcritical	intermediate	2007	SCR	2001		
Belews Creek	1	Stokes	1110	1110	1110	9174	1974		12/2038	supercritical	base	2008	SCR	2003		
Belews Creek	2	Stokes	1110	1110	1110	9170	1975		12/2038	supercritical	base	2008	SCR	2004		

The NEEDS data show that the Rogers units 5 and 6 (formerly Cliffside) were converted to co-fire gas in 2019. Based on discussions with the Technical Working Group, it is assumed that unit 5 is able to co-fire with 10%–40% gas, and unit 6 can burn 100% gas. The NEEDS data don't list coal-to-gas options for Belews Creek 1 and 2 or Marshall 1 to 4, however, these data have been updated to reflect the following ongoing improvements at these plants. The Belews Creek units 1 and 2 are assumed to be converted to dual fuel by January of 2020 and 2021, respectively, and will be able to burn up to 50% natural gas. The Marshall units 3 and 4 are assumed to retrofit by December of 2020 and able to burn up to 50% gas, while the Marshall units 1 and 2 will be retrofit in December of 2021 and able to burn 10%–40% gas.

The NEEDS database includes the Asheville combined cycle unit shown in the DEP IRP. The IRP states a winter capacity of 560 MW and a summer capacity of 495 MW, starting in November 2019. The NEEDS data do not include the possible new combined cycle unit at the Reidsville Energy Center. Given uncertainty regarding completion of this project, this potential unit was not added to the models.

Operation of Existing Plants

Assumptions about operating costs of existing units come from the EPA version of the IPM model (EPA 2018, Chapter 4, Table 4-8 and 4-9), which has publicly available documentation and data (unlike the proprietary version of IPM from ICF that is used in this analysis). These data give fixed and variable operations and maintenance (O&M) costs by type of unit, installed equipment and age. Depending on the type of unit, the data distinguish operating costs by SO_2, NOx, and mercury control equipment. Based on recommendations from the Technical Working Group the fixed and variable costs for coal plants were set to the lower end of the range from the EPA data for units with scrubbers. Variable operating costs for combined cycle and combustion turbine units were also set to the lower end of the ranges shown in the EPA data. In addition, variable operating costs for combined cycle units—which are related to ongoing maintenance—were converted to a fixed annual charge that does not affect dispatch of these units.

Other assumptions include:

- nuclear plants will receive a second 20-year life extension at a cost of $495/kW;
- aside from coal plants, the models do not force fossil generators to retire based on age (wind, solar, and battery storage have lifetimes defined in the EPA IPM documentation); and
- the availability of combined cycle units will track operational data for these units in 2019 (i.e., NGCC units are able to run up to 96% of the time during peak winter and summer periods, instead of the 81.2% used in EPA modeling).[2]

New Generation

Table B.2 shows the AEO 2020 assumptions for new plant costs and efficiency (EIA 2020a). These data are used by most modelers as a starting point for their cost assumptions, particularly for conventional generation. The data shown for capital costs (expressed as overnight costs) are the current costs for units—these costs typically decline somewhat over time in the AEO modeling as learning-by-doing leads to additional cost declines and, in some cases, improvements in heat rates.

EIA's cost estimates for small modular nuclear (SMR) plants are shown at the bottom of Table B.2. These costs were not initially included in the AEO 2020 assumptions but were added to EIA's modeling during an analysis of carbon policies released in March 2020. However, for this CEP A1

2. Total annual availability across seasons remains at 87%, based on EPA (2018).

analysis, SMR capital cost estimates from Duke Energy's Climate Report (Duke 2020) were used. This report assumed capital costs of $5,500/kW.

The overnight capital costs shown are U.S. national averages. These data are then combined with regional cost multipliers that reflect market conditions affecting construction costs at a regional level. Members of the Technical Working Group suggested that taking an average of the regional multipliers from the AEO 2020 and the EPA IPM models for the Carolinas region would provide the best reflection of local construction costs.

Table B.2. AEO 2020 New Unit Assumptions

Technology	First Available Year	Size (MW)	Lead time (years)	Total overnight cost ($2019/kW)	Variable O&M ($2019/MWh)	Fixed O&M ($2019/kW-yr)	Heat rate (Btu/kWh)
Ultra-supercritical coal (USC)	2023	650	4	3,661	4.48	40.41	8,638
USC with 30% carbon capture and sequestration (CCS)	2023	650	4	4,652	7.05	54.07	9,751
USC with 90% CCS	2023	650	4	5,997	10.93	59.29	12,507
Combined cycle - single shaft	2022	418	3	1,079	2.54	14.04	6,431
Combined cycle - multi shaft	2022	1,083	3	954	1.86	12.15	6,370
Combined cycle with 90% CCS	2022	377	3	2,569	5.82	27.48	7,124
Internal combustion engine	2021	21	2	1,802	5.67	35.01	8,295
Combustion turbine - aeroderivative	2021	105	2	1,170	4.68	16.23	9,124
Combustion turbine - industrial frame	2021	237	2	710	4.48	6.97	9,905
Fuel cells	2022	10	3	7,339	0.59	30.65	6,469
Advanced nuclear	2025	2,156	6	6,317	2.36	121.13	10,461
Distributed generation - base	2022	2	3	1,555	8.57	19.28	8,946
Distributed generation - peak	2021	1	2	1,868	8.57	19.28	9,934
Battery storage	2020	50	1	1,383	0.00	24.70	NA
Biomass	2023	50	4	4,104	4.81	125.19	13,500
Geothermal	2023	50	4	2,680	1.16	113.29	9,156
Municipal solid waste - landfill gas	2022	36	3	1,557	6.17	20.02	8,513
Conventional hydropower	2023	100	4	2,752	1.39	41.63	NA
Wind	2022	200	3	1,319	0.00	26.22	NA
Wind offshore	2023	400	4	5,446	0.00	109.54	NA
Solar thermal	2022	115	3	7,191	0.00	85.03	NA
Solar photovoltaic - tracking	2021	150	2	1,331	0.00	15.19	NA
Small modular nuclear (EIA, Sargent & Lundy, 2020)		600		6,191	3.00	95.00	10,046

Table B.2 shows average installation costs reported by AEO 2020 for wind and solar units as constructed in the baseline forecast from the NEMS model. However, significantly more detail is required to evaluate specific options (considering site locations and costs) for new renewable generation that may be installed in response to policies targeting carbon emissions (particularly at a state level). In the models, these data are based on the NREL Annual Technology Baseline (NREL 2019a, 2020a), which provides cost and effectiveness trends for renewable generation used in the NREL ReEDS model and the EPA IPM model (these data also help form the basis of costs used in EIA's NEMS model).

Figure B.3 illustrates NREL cost trends from the ATB 2019 for overall renewables costs for selected classes of wind and solar PV units (technological resource groups, TRG), along with battery storage. These costs exclude grid connection costs and regional capital-cost multipliers.

The costs are given for NREL's midrange and a low-cost forecast from the ATB 2019. Similar forecasts with updated data from the ATB 2020 are characterized as either a "Conservative," "Moderate," or "Advanced" scenario. For this modeling, the main cases are based on the "Mid" or "Moderate" cost trends with some sensitivity analyses using the "Low" or "Advanced" cost trends.

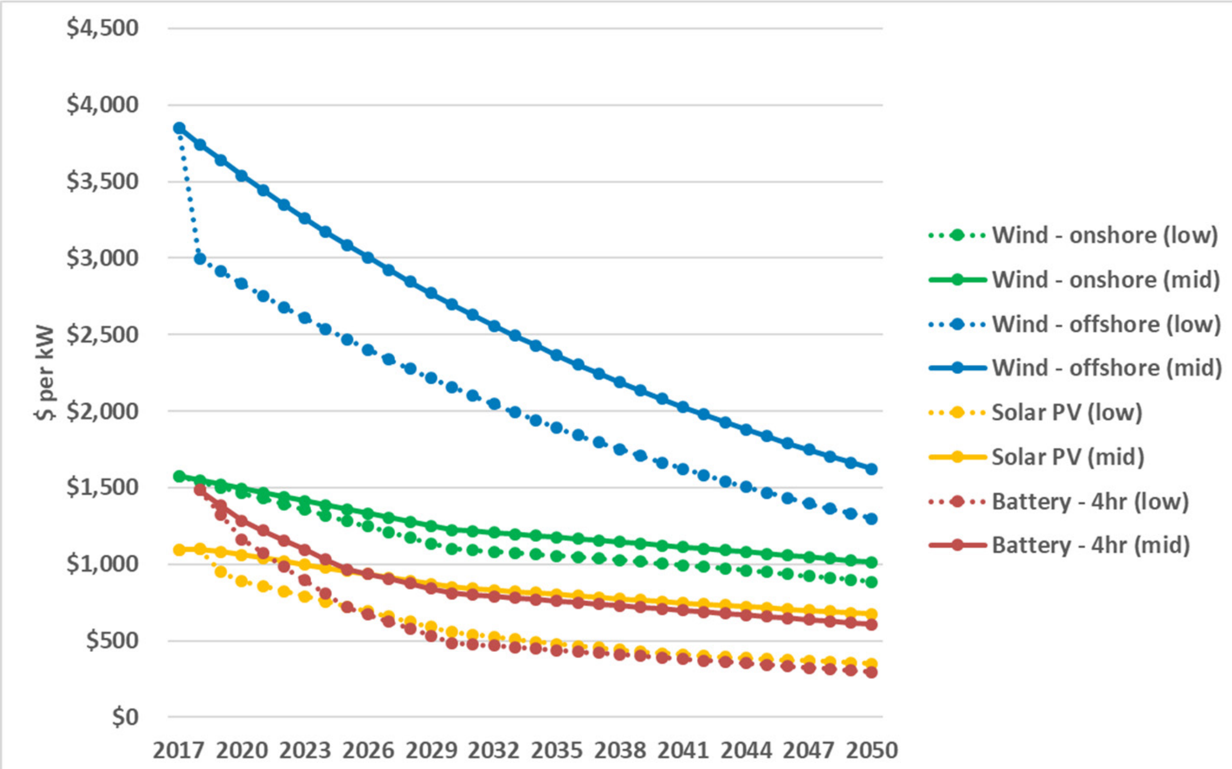
In the policy modeling, overall NREL trends for the costs of renewables units from Figure B.3 are combined with data on the costs of connecting new wind and solar units to the grid. These costs are added to the DIEM modeling using data from the NREL ReEDS model (data for the IPM model are shown in Chapter 4 of EPA [2018]). These cost/transmission data define several classes of utility-scale solar PV and onshore wind in North Carolina for IPM and DIEM (where the different classes consider location sites, available resources, and connection costs). Distributed solar PV is assumed to be included in the electricity-demand forecasts discussed previously.

DIEM uses detailed wind data from the ATB 2019 instead of the ATB 2020 because wind resource groups were reclassified in the latest ATB in ways that do not match up with the resource and connection costs available in the ReEDS model data (NREL 2019b). Average solar PV capital costs in IPM and DIEM have been updated using ATB 2020 trends when contrasted with ATB 2019 trends. NREL data also provide details on potential resource and cost categories of wind off of the coast of North Carolina. The offshore wind trend (Fig. B.3) is TRG3 of fifteen possibilities and includes average offshore spur line costs (the onshore wind is TRG8 of ten possibilities).

The starting point for battery storage costs is also the NREL ATB 2020. These data provide trends for battery energy costs by kilowatt-hour (kWh) and balance-of-system costs, which can be used to define several different size battery systems ranging from four to eight hours. There can be uncertainty surrounding additional potential costs, particularly with regards to daily depth-of-discharge issues, and the effectiveness of batteries at contributing to peak demands as more batteries are installed in the Carolinas.

Attachment IV of the DEC/DEP IRPs (DEC 2020) includes information from an Astrape Consulting report on the effective load carrying capacity of batteries within the Duke Energy systems. The IPM and DIEM models include estimates of this effectiveness based on Tables 7–8 of Attachment IV, which show how increasing penetration of 4-hour and 6-hour batteries may reduce their capacity values as quantities increase. These assumptions are contrasted in some of the DIEM modeling runs (as a sensitivity) with assumptions from an NREL report (Denholm et al. 2019) that finds higher levels of 4-hour batteries are able to fully contribute to meeting peak demands.

Figure B.3. NREL ATB 2019 Renewables Capital Cost Assumptions ($ per kW)



Hourly Load Shapes

The IPM model uses Federal Energy Regulatory Commission (FERC) hourly load data (FERC 2020) for the year 2012 as the basis for creating load blocks of demand by season and level of demand across all regions. For the Carolinas, the DIEM model also uses FERC data to represent load blocks for seasons and times of day. These are developed using FERC data for 2018 to represent a winter-peaking system and the data for 2016 to represent a summer-peaking system. For regions outside of the Carolinas, the DIEM model uses hourly load data from the EPA IPM model (EPA 2018).

Financial Assumptions

The IPM model typically uses financial assumptions, such as the cost of capital or investment hurdle rates, that are used in the EPA IPM model (EPA 2018, Chapter 10). The DIEM model, meanwhile, typically uses financial assumptions from the NREL ATB (NREL 2020a). For the CEP A1 modeling, both models have replaced some of the financial data with information from the Duke Energy system. These data include: return on equity (9.9% [DEC 2020a, DEP 2020a]), debt-to-equity ratio (48.38% to 51.62% from DEC [2020a], 48.49% to 51.51% from DEP [2020a]), and cost of debt (4.46% from DEC [2020a], 3.98% from DEP [2020a]).

The IPM model uses "book lives" (the depreciation schedule) for units that vary by type of unit when calculating capital charge rates, which are used to convert capital costs into streams of levelized capital payments (EPA 2018, Chapter 10, Table 10–12). IPM assumes a 30-year book life for new gas units, a 40-year book life for coal and nuclear units, and a 20-year book life for solar and wind units. The DIEM model uses the IPM book life assumptions for some results, but as a sensitivity contrasts the implications of these assumptions for policy-cost estimates with those from the NREL ATB which uses a 30-year book life. For additional reference, the EIA NEMS model that generates the AEO 2020 forecasts uses a 30-year book life for all types of units; the NREL ReEDS model uses a 20-year life.

Energy Efficiency

The "business as usual" reference case scenarios use demand-side EE savings estimates based on DEC and DEP's 2020 IRPs. In turn, the IRP estimates are informed by Duke Energy Corporation's 2020 Market Potential Study.[3] To understand how alternative EE estimates might affect total electricity demand, the team ran sensitivities in IPM and DIEM assuming higher EE savings (Fig. B.4). The "Medium EE" estimate (approximately 1% reduction in load by 2030; 1.2% thereafter) is based on a recommended level for an Energy Efficiency Resource Standard (EERS) in the 2019 North Carolina Energy Efficiency Roadmap[4] and tracks the stringency of existing EE programs in Arkansas and Virginia.[5] The "High EE" estimate (approximately 2% reduction in load by 2030) is based on existing EE targets in states including Colorado, Illinois, Maryland, and Massachusetts.[6] Both scenarios illustrate possible reductions to load based on additional EE/DSM investment during the modeled time period. **Appendix F** models a CES where these enhanced levels of EE can be credited towards the standard.

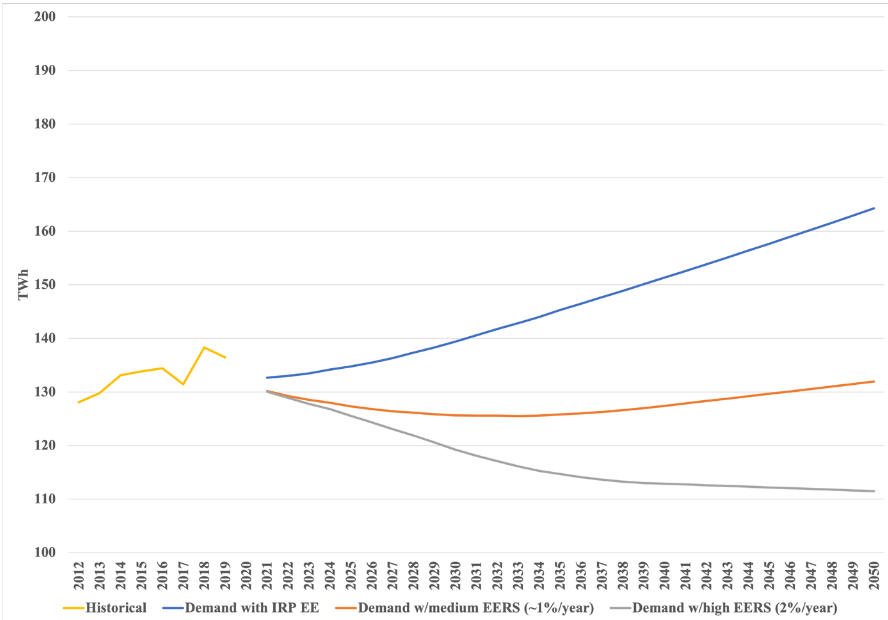
3. For their 2020 IRPs, DEC and DEP prepared a Base EE Portfolio savings projection that was based on each company's five-year program plan for 2020–2024. For periods beyond 2029, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Base Achievable Portfolio presented in Nexant's Market Potential Study. For the period of 2025 through 2029, the Company employed an interpolation methodology to blend together the projection from the EE/DSM program plan and the Market Potential Study Achievable Potential.

4. Duke Nicholas Institute, "North Carolina Energy Efficiency Roadmap" (August 2019), https://nicholasinstitute.duke.edu/sites/default/files/publications/North-Carolina-Energy-Efficiency-Roadmap-Final.pdf, Recommendation 25, at 53–54.

5. Arkansas Public Service Commission, In the Matter of Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas, Docket No. 13-002-U, Order No. 43, http://www.apscservices.info/pdf/13/13-002-U_293_1.pdf; Virginia Clean Economy Act (2020), https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER, § 56-596.2. Virginia's annual energy savings appear high in the text of the statute but include sustained savings from previous years.

6. Colorado Public Utilities Commission, Proceeding No. 17A-0462EG, Decision No. C18-0417 (Apr. 11, 2018), https://www.swenergy.org/Data/Sites/1/media/documents/news/co-xcel-dsm-puc-decision-6-6-18.pdf, at ¶ 78; 220 Illinois Compiled Statutes 5/8-103(b), https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K8-103; Maryland Public Service Commission, Order No. 87082 (July 16, 2015), https://www.psc.state.md.us/wp-content/uploads/Order-No.-87082-Case-Nos.-9153-9157-9362-EmPOWER-MD-Energy-Efficiency-Goal-Allocating-and-Cost-Effectiveness.pdf, at 21-22; Massachusetts Department of Public Utilities, D.P.U. 18-110 to 18-119 (January 29, 2019), Three Year Plans Order, 2019-2021, https://www.mass.gov/doc/2019-2021-three-year-plans-order/download.

Figure B.4. NC Electricity Demand with IRP, "Medium," and "High" Levels of Energy Efficiency



Electric Vehicles

By 2050, electric vehicles (EV) may represent a significant source of new demand in the economy. In the AEO 2020 Reference Case forecasts, EVs are only a few percent of total electricity demand by 2050. However, in sensitivity runs these main-case assumptions are contrasted with the NREL Medium scenario from their Electrification Futures Study, EFS (NREL 2018a)—in which EVs are around 15% of total demand by 2050. The Nicholas Institute has already done DIEM modeling of the implications of EVs for electricity generation (Ross 2019) and runs some similar scenarios for this CEP A1 analysis using state-level data from EFS for North Carolina and surrounding states.

Reserve Margins

Reserve margins refer to the buffer of electricity generating capacity needed above peak demand, to ensure reliability of the system when some of the units become unavailable through forced outages or scheduled maintenance. The DEC and DEP IRPs (2019) use a 17% minimum winter reserve margin target, although the IRPs also examine a 16% reserve margin at the request of NCUC. The EPA IPM model normally uses a 15% reserve margin for the "S_VACA" reliability region that includes most of the Carolinas (Table 3-9 of the November 2018 Reference Case). The NREL ReEDS model uses a 15% reserve margin for North Carolina (and South Carolina).

For the CEP modeling, the IPM and DIEM models are using 17%, based on the DEP/DEC approach. There is some discussion in the analysis of the implications of using 16% in DIEM.

Years Included in the Modeling

IPM includes the years 2022, 2023, 2025, 2028, 2030, 2035, 2040, 2045, and 2050. The year 2022 represents the electricity industry prior to any CEP policy implementation in 2023. The DIEM model uses the years 2023, 2025, 2028, 2030, 2035, 2040, 2045, and 2050, where both the baseline forecasts and any CEP policies begin in the year 2023. Given that runs do not report outputs for every year, the results will be "lumpy"—for instance, if the results indicate a lot of new solar capacity in 2035, that might reflect a more modest increase in capacity over the previous five years.

Model Structure and Data in the IPM Model

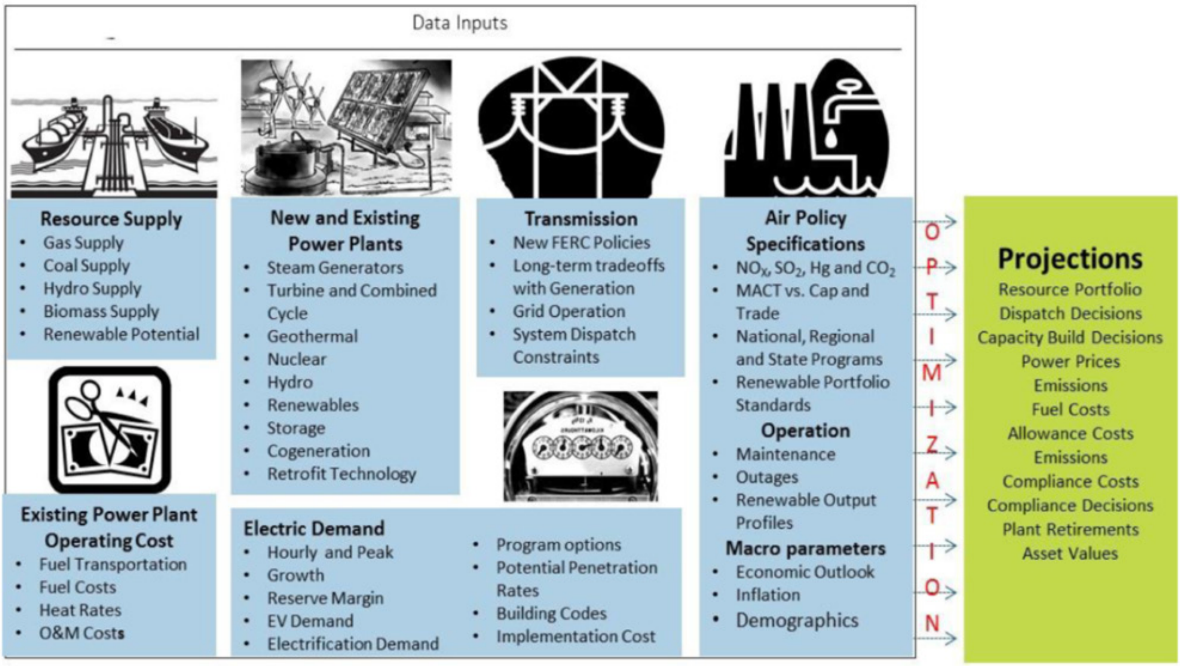
IPM® is a well-established modeling platform with a long history of utilization for power sector resource planning and environmental compliance. ICF has relied on IPM to provide long-term system studies to public and private sector clients for more than 40 years.

IPM provides a detailed engineering/economic capacity expansion and production costing model of the power sector supported by an extensive database of every boiler and generator in the nation. It is a proven, multi-region model which uses linear optimization to simultaneously solve for unit-by-unit dispatch (or generation), fuel use, regional capacity expansion, environmental retrofitting, air emission changes, modernization/re-powering, inter-regional transmission, regional electric energy and capacity prices, renewable energy credit (REC) prices, allowance prices for controlled pollutants, fuel prices, and electric power system costs.

IPM explicitly and simultaneously considers gas and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. The model captures the unique performance characteristics and limitations of conventional and unconventional generation technologies including gas and steam turbines, combined cycle, co-generation, and nuclear, as well as hydro, wind, solar, and other renewables. As a multi-year model, IPM optimizes capacity decisions over the entire planning period simultaneously. Results can be directly reported at the national or regional level. ICF can develop regional impacts as well as unit level impacts.

Outputs of IPM include regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs—capital, fixed operations and maintenance (FOM), and variable operations and maintenance (VOM)—allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Figure B.5 illustrates the key inputs and outputs of IPM.

Figure B.5. Key Inputs, Outputs of Integrated Planning Model (IPM)®



Model Structure and Data in the DIEM Model

Parts of the CEP analysis are conducted with an updated version of the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at Duke University's Nicholas Institute. Broadly, DIEM is a dynamic linear-programming model of U.S. wholesale electricity markets with intertemporal foresight regarding future market conditions and electricity policies. Similar to models such as EPA IPM (EPA 2018) and NREL ReEDS (2019), it represents intermediate- to long-run decisions about generation, transmission, capacity planning, and the dispatch or retirement of units. The model has participated in several collaborative peer-reviewed studies through the Stanford Energy Modeling Forum (EMF)—see, for example, Ross and Murray (2016). DIEM was also used throughout the EPA Clean Power Plan process to help Southern states understand the implications of alternative choices for meeting emissions goals (see, for example, Ross, Hoppock, and Murray 2016).

The model minimizes the present value of electricity generation costs (capital, fixed operating and maintenance or O&M, variable O&M, and fuel costs) subject to meeting electricity demands, planning and operating reserve margins, and any pre-existing policy constraints such as North Carolina HB589. The initial set of data inputs and assumptions about market trends discussed above are used by the DIEM model to estimate a baseline forecast for the industry in the absence of any new policies. This long-run baseline forecast can then be compared to model outcomes for the various CEP policy options to see how each may affect the industry.

Details of IPM Model Assumptions about Offshore Wind

IPM sourced offshore wind assumptions from NREL's 2020 Annual Technology Baseline as well as EPA documentation from their Base Case modeling with their version of IPM.

NREL Cost and Performance Assumptions

For offshore wind cost assumptions, ICF relied on NREL's 2020 ATB for shallow offshore wind resources (specifically, the Class 3 Moderate Capex $/kW costs included in in row 342 of the Offshore wind tab). These costs per kW decline from $3,840 in 2020 to $2,310 in 2040 and $2,048 in 2050. For mid-depth offshore wind resources, costs were modeled in accordance with NREL's TRG 6. Capital costs were regionalized using the same approach as for other renewable resources, which reduced costs 6% given the average regionalization factor of 0.94. FO&M assumptions were adopted from the same source document, utilizing the same Class 3 moderate forecast provided in row 474, declining from $114/kW in 2020 to $61/kW in 2040. Capacity factor assumptions were implemented consistent with NREL ATB 2020 data as well (47% for offshore wind units). (All $ values are listed as $2018).

Resource Classes Modeled

Resource classes of offshore wind were modeled in accordance with EPA IPM v6 documentation, which includes resources in the shallow classes 2 and 3 (mapping to NREL TRG 2 and 3), as well as mid-depth resources of class 6, which maps to the NREL TRG 6. TRG 6 however includes higher capital costs and lower capacity factors, as evident in the NREL 2020 ATB documentation. As an example, costs for a class 6 offshore wind unit in 2040 is $194/kW higher, whereas the capacity factor is 8% lower. Given the lower output per MW and the higher costs per MW, the offshore wind resources chosen in all runs are of the Shallow Class 2 and 3.

Capacity Credit

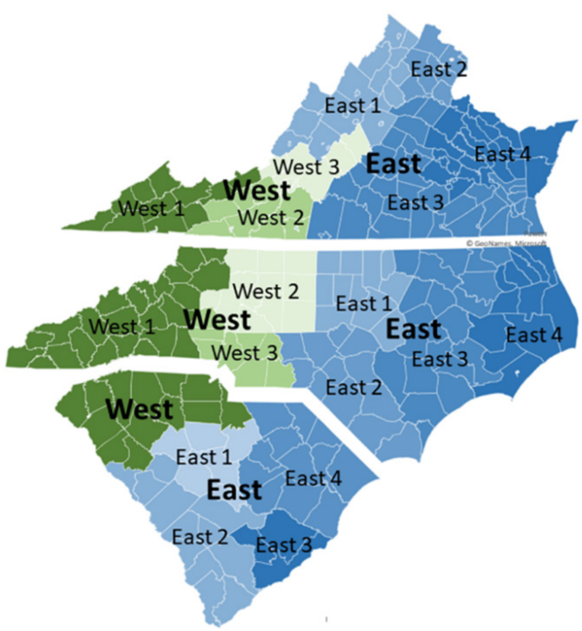
EPA base case documentation served as another source for capacity credit assumptions. In addition, ICF reviewed capacity credit assumptions from neighboring ISOs to confirm treatment of offshore wind in capacity planning. The closest ISO to the Carolina's region – PJM – assumes 26% capacity contribution for offshore wind under resource procurement rules. 26% was also the EPA assumption for capacity credit of class 2 shallow offshore wind. Given overlap between these two sources, the capacity credit for offshore wind was set at 26%.

The structure of DIEM begins with a characterization of existing units based on the IPM NEEDS database v6 (Mar 2020). As discussed, where there are differences between NEEDS and the DEC/DEP IRP data on existing units, the IRP data are used in the modeling, including information on the winter capacity of units since the NEEDS data focus on summer capacity. Retirement dates for units from the IRPs, based on depreciation lifetimes, are used in the modeling (see the 2019 IRPs). Economic retirement of units is also possible in the model's baseline and policy forecasts, if units are not cost effective. Co-firing options for several existing coal plants are also modeled, based on discussions with technical advisors. Planning reserve margins are taken from the DEC/DEP IRPs. Characterization of operating reserve requirements (spinning, regulation, and flexibility) are based on NREL (2018b). Minimum load assumptions by type of unit are from NREL ReEDS 2019 (e.g., nuclear runs full out, coal has to run at least 40% of the maximum gigawatts used in a season).

As shown in Table B.2 above, construction of new conventional generation is based on the AEO 2020 Assumptions (EIA 2020a). Assumptions about existing and new renewable generation are based on capacity and cost data from the NREL ReEDS model (NREL 2019b) and the NREL ATB (NREL 2020a). These data define trends in costs for onshore and offshore wind, utility-scale solar PV, and battery storage. These technology costs are combined with detailed ReEDS data on the availability and grid-connection costs of wind and solar resources in the Carolinas.

Plants in the model are dispatched on a cost basis to meet demand within each region through 2050 and beyond. The version of DIEM-Electricity used in this analysis focuses on the Eastern Interconnection and defines some regions along continental U.S. state lines. In the Carolinas and Virginia, each state is subdivided into two regions—East and West—using NREL ReEDS model data on sub-state electricity demand shares and transmission limits among the regions (Figure B.6). Based on discussions with technical advisors, the ReEDS transmission limits between North Carolina and Tennessee and Virginia, along with between South Carolina and Georgia, are replaced with EPA IPM data on energy and capacity trade limits (EPA 2018).

Figure B.6. Model Regions around the Carolinas



As shown in Figure B.6, there are two balancing areas within each of the three states. In some model runs, it is assumed that reserve margins are met in part through trade with surrounding regions. In other runs, it assumed that the Carolinas act as an island system and don't trade capacity with other regions in order to meet peak margins.

The subregions within each of these states are also used to define solar and wind resources using data from the NREL Renewable Energy Potential (reV) model (NREL 2020c). Utility-scale solar PV, whether centralized or distributed, are defined by the two east-west subregions within each of the three states. There are up to seven efficiency categories within each region in the model, each of which can have up to five different levels of grid connection costs. There are estimates of available solar resources for each of the 35 potential efficiency-cost combinations. Onshore wind resources are defined for each of the four areas within the east or west subregions of the states (East 1-4, West 1-4). Each of these four regions can have up to 10 different efficiency categories and five grid connection costs. There are also three coastal regions for each state representing offshore wind potential, with up to 14 efficiency groups and five grid-connection costs.

It is our understanding, based on discussions with technical advisors, that NREL is in the process of re-examining their assumptions about the availability of onshore wind resources in the Carolinas. The quantity of the resources is likely to be revised downwards significantly from the data in NREL ReEDS (2019) once additional factors are taken into consideration such as siting restrictions, locations near military bases, etc. The outcome of this ongoing process is approximated in the A1 analysis by scaling down the ReEDS 2019 data by three quarters to get an onshore wind resource that is a closer proxy of the outcome of these revisions.

Within each region, hourly load data from FERC (2020) are aggregated to show the amount of electricity demand in a number of load "blocks." These blocks convert annual electricity demands from the IRP demand forecasts in Figure B.7 into subcomponents in order to capture the nonstorable nature of electricity within a year. For this analysis, three seasons are defined after an examination of the FERC 714 data across the year, shown in Figures B.7 and B.8.

Figure B.7. Combined DEC/DEP Hourly Load Data from FERC Form 714

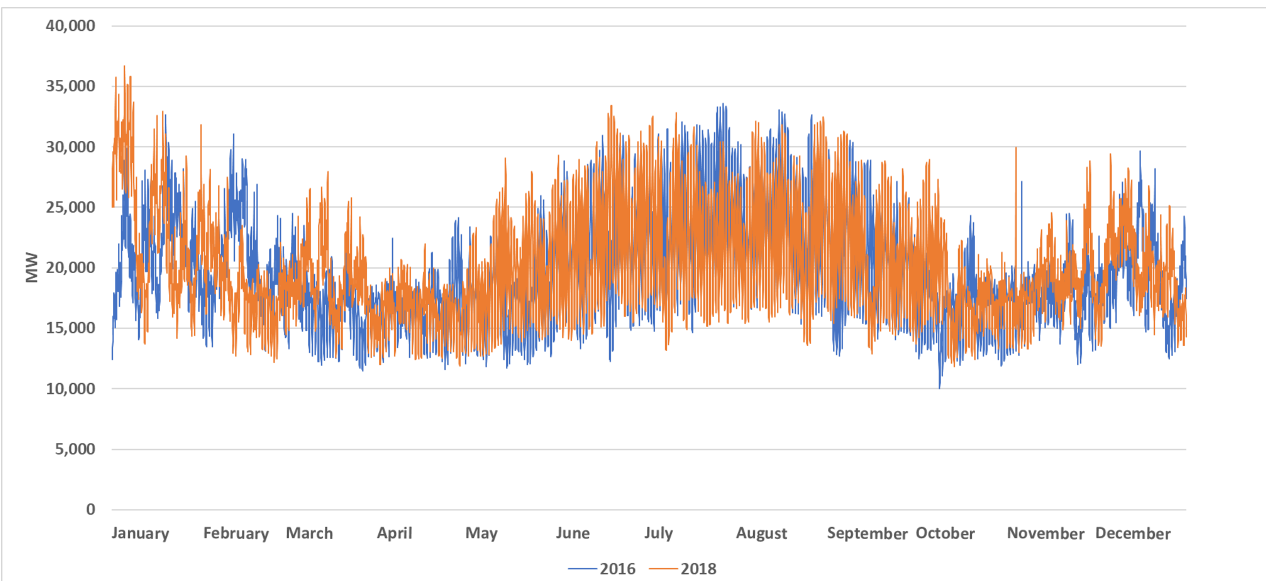
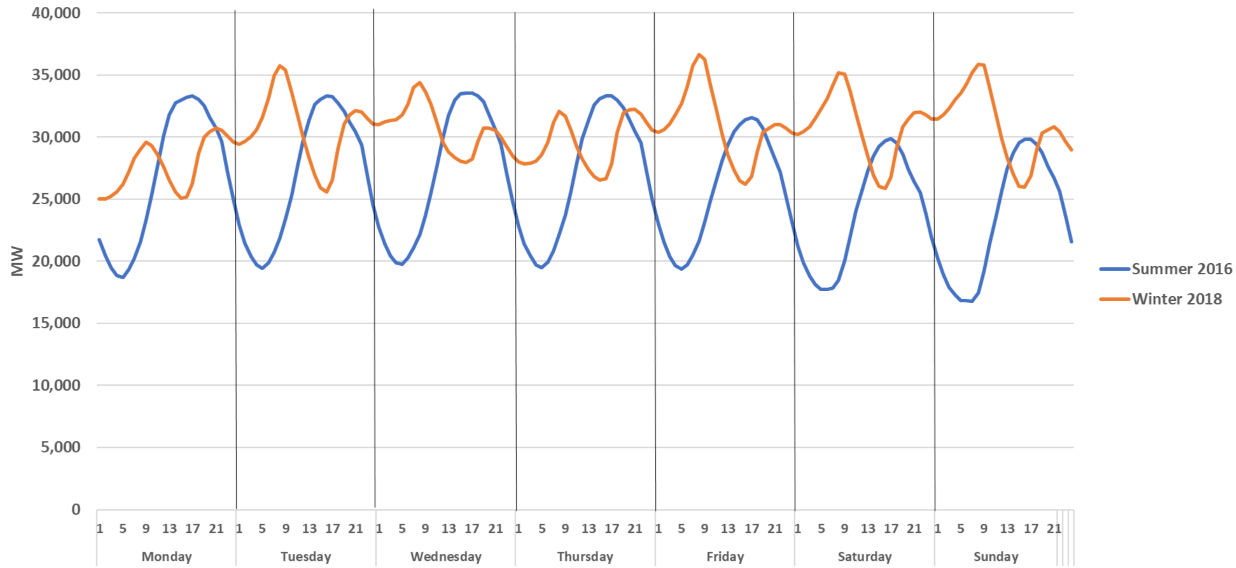


Figure B.8. DEC/DEP Load Data for Last Week of July 2016 versus First Week of January 2018



The goal in selecting a representation of load blocks was to separate the months of the year and the times of day in which the Carolinas system is likely to experience high levels of demand from those periods of lower stress on the system. Two sets of data are shown: the 2018 data have a slightly winter-peaking pattern and are used for years in which the IRP forecasts suggest that DEC or DEP will be winter-peaking systems; and the 2016 data, which are slightly summer-peaking pattern, are used for the years in which the IRP data show a summer-peaking system.

From FERC Form 714 data, hourly load patterns are used to define the following seasons and times-of-day that capture broad patterns in DEC/DEP demand for three seasons (summer, winter, fall/spring):

- Summer: June through August
    - Morning: 6 a.m. to 12 p.m.
    - Afternoon: 12 p.m. to 6 p.m.
    - Peak Afternoon: highest 66 hours of afternoon
    - Evening: 6 p.m. to 10 p.m.
    - Night: 10 p.m. to 6 a.m.
- Fall/Spring: September through November, March to May
    - Morning: 6 a.m. to 11 a.m.
    - Afternoon: 11 a.m. to 5 p.m.

    - Evening: 5 p.m. to 10 p.m.
    - Night: 10 p.m. to 5 a.m.
- Winter: December through February
    - Morning: 6 a.m. to 10 a.m.
    - Peak Morning: highest 22 hours of morning
    - Afternoon: 10 a.m. to 5 p.m.
    - Evening: 5 p.m. to 10 p.m.
    - Night: 10 p.m. to 6 a.m.

Additional data sources and assumptions typically used in the DIEM model (excluding revised assumptions specific to the Carolinas region for this analysis) are shown in Tables B.3 and B.4.

Table B.3. Supply-Side Assumptions in DIEM

Categories		Variables	Data Description	Source / Links	Additional Comments and Sources
Supply Side	Existing Units	Capacity by location	NEEDS data by unit	EPA NEEDS v6 - March 2020	NEEDS data on ~19,000 units by county and state
		Efficiency (heat rates)	NEEDS data by unit	EPA NEEDS v6 - March 2020	NEEDS data on ~19,000 units by county and state
		Control equipment and emissions rates	NEEDS data on unit-level equipment and effectiveness	EPA NEEDS v6 - March 2020	FGD, SCR, ACI and associated emissions rates
		Operating costs	Fixed and variable O&M costs by type of unit, age, and equipment	EPA Power Sector Modeling v6 - IPM Chapter 4	Tables 4-8 and 4-9 for variable and fixed O&M costs
		Lifespan extension costs	Lifetimes and capital costs for extending units	EPA Power Sector Modeling v6 - IPM Chapter 4	Table 4-10
		Availability	NEEDS data on unit-level availability by season	EPA Power Sector Modeling v6 - Nov 2018	Table 3-27
		ACE Rule	Heat rate improvements for coal plants to comply with ACE	EPA Power Sector Modeling v6 - Jan 2020	Table 3-32, Affordable Clean Energy Rule assumptions by plant size and efficiency
		Coal-to-gas conversion	Capital costs, changes in fixed and variable O&M costs	Assumptions to AEO 2020	Page 13 (capital cost ~$150/kW for 500 MW, fixed O&M reduced by 33%, variable O&M reduced by 25%)
		Biomass co-firing at coal plants	Up to 15% of total output	Assumptions to AEO 2020	Page 18 ($565/kW of capital investments)
		Retrofits and emissions for NOx, SO2, and Hg	Coal plants from AEO Assumptions (Table 8), other from EPA v6	EPA Power Sector Modeling v6 - Nov 2018 Reference Case and updates to Jan 2020	
		Mercury (Hg) emissions modification factors	EMF by type of equipment and coal type	Assumptions to AEO 2020	Table 11
	New Units	Capacity, construction times, costs, heat rates	Table 3 on costs and performance of non-renewable generation	Assumptions to AEO 2020	Additional data from EIA on changes in overnight capital costs ($/kW) over time
		Regional capital cost multipliers	AEO data from Table 4, EPA IPM data from Table 4-15	Assumptions to AEO 2020	EPA Power Sector Modeling v6 - IPM Chapter 4
		Lifespan extension costs	Lifetimes and capital costs for extending units	EPA Power Sector Modeling v6 - IPM Chapter 4	Table 4-10
		Availability	EPA data on availability assumptions	EPA Power Sector Modeling v6 - IPM Chapter 3	Table 3-7
		Degradation	New (and existing) solar PV degrades at 0.5% per year	NREL (Jordan and Kurtz, 2013) - Photovoltaic Degradation Rates	
		Ongoing construction	EIA data on planned new units	EIA Electric Power Monthly	Tables 6.3 and 6.5
		Construction limits and cost adders	Short-term capital cost additions for rapid construction	EPA Power Sector Modeling v6 - IPM Chapter 4	Table 4-14
		Grid connection costs	Costs of connecting non-renewable new generation to the grid	EPA Power Sector Modeling v6 - Nov 2018 Reference Case	Page 4-21. Cost of $97/kW for the eastern interconnection
		Financing	Assumptions on debt, inflation, interest rates, ROE, depreciation, and construction	NREL ATB 2020	Calculations of CAPEX,WACC, and fixed charge rates (interest rate from AEO 2020)
	Fuel Markets	Coal supply curves	Data on increases in coal costs as production increases	EPA Power Sector Modeling v6 - IPM Chapter 7	Table 7-26
		Coal transportation costs	Data on coal transport costs from minemouth to utility state	EPA Power Sector Modeling v6 - IPM Chapter 7	Table 7-25
		Coal characteristics	20 coal ranks based on AEO data on heat, SO2, Hg, and CO2 content	Assumptions to AEO 2020	Table 5
		Natural gas supply prices	Henry hub price for wholesale gas	AEO 2020	Table 1
		Natural gas delivery costs	Difference between henry hub price and delivered price by region	AEO 2020	Tables 54.1-54.25
		Nuclear fuel costs	Uranium prices by EIA Census Region	AEO 2020	Tables 2.1-2.9
		Biomass fuel supply curves	Biomass supply curves (quantities and prices) by state	EPA Power Sector Modeling v6 - Nov 2018	Chapter 9, Table 9-4
		Petroleum fuel costs	Distillate and residual prices	AEO 2020	
	Renewables and Storage	Wind (onshore) - new construction costs and capacity fact	10 resource groups that vary by cost, capacity factors from NREL ATB	NREL ATB 2020 and NREL ReEDS Model	Chapter 3.1.1 in ReEDS documentation
		Wind (onshore) - generation profiles	Historical hourly generation by state	NREL Systems Advisory Model	
		Wind (offshore) - new construction costs and availability	15 resource groups that vary by cost	NREL ATB 2020 and NREL ReEDS Model	Chapter 3.1.2 in ReEDS documentation
		Wind (offshore) - generation profiles	Availability for 17 load blocks and up to four subregions per model region	NREL ReEDS 2019	Chapter 3.1.2 in ReEDS documentation
		Solar PV - new construction costs and average availability	7 resource groups that vary by capacity availability, and connection costs	NREL ATB 2020 and NREL ReEDS Model	Can be either centralized or distributed utility-scale PV (distributed has higher cost w/o distribution losses)
		Solar PV - generation profiles	Historical hourly generation by state	NREL Systems Advisory Model	
		Solar CSP	5 resource groups that vary by cost, capacity availability, and connection costs	NREL ATB 2020 and NREL ReEDS Model	Chapter 3.1.4 in ReEDS documentation
		Hydroelectric	Dispatchable/nondispatchable existing, upgrades, nondispatchable new	NREL ReEDS 2019	Chapter 3.1.6 in ReEDS documentation
		Geothermal	10 types of geothermal by region (hydro, binary, flash)	NREL ReEDS 2019	Chapter 3.1.5 in ReEDS documentation
		Landfill gas	3 types of landfill gas by state	EPA Power Sector Modeling v6 - IPM Chapter 4	Table 4.16 (cost) and Table 4.48 (MW of resource)
		CCS	Carbon transport and storage costs	EPA Power Sector Modeling v6 - IPM Chapter 6	Tables 6.4 and 6.5
		Battery storage & efficiency	2-hour, 4-hour, 6-hour, 8-hour storage with 15 year life and 85% round-trip efficiency	NREL ATB 2020	
	Transmission	Existing transmission	Up to 134 balancing areas	NREL ReEDS 2019	Chapter 6 in ReEDS documentation
		New transmission	$2,333/MW-mile (345-kV), $1,347/MW-mile (500 kV), $1,400/MW-mile (765 kV)	NREL ReEDS 2019	Chapter 6. Plus regional cost multipliers. EIPC (2012) "Phase 2 Report: Interregional Transmission Developmen
		Wheeling charges	Transmission tariffs for trading electricity across RTO regions	EPA Power Sector Modeling v6 - Nov 2018 Reference Case	Table 3-21
		Capacity trading	Trading less than capacity limit of transmission lines		
		Losses	1% per 100 miles	NREL ReEDS 2019	Chapter 6 in ReEDS documentation

Table B.4. Demand-Side Assumptions in DIEM

Categories		Variables	Data Description	Source / Links	Additional Comments and Sources
Demand Side	Load	Historical Electricity Sales by End-Use and State	Data for 2019 (through end of December 2019)	EIA Electric Power Monthly	Table 5.4.B in February 2020 for sales through December 2019 YTD
		Electricity demand - LDC blocks	Hourly demands to aggregate into seasonal/time-of-day load blocks	EPA Power Sector Modeling v6 - Nov 2018	Table 2-2
		Electricity demand growth	Forecasts by EIA Census Region and consumer type	AEO 2020	Tables 2.1-2.9
		Peak demands	Typically assumed to grow with demand (excluding EV demand sensitivities)		
		International trade	Imports and exports by EIA NEMS model region	AEO 2020	Tables 54.1-54.25
		Purchases from CHP	Purchases from combined heat-and-power by EIA NEMS model region	AEO 2020	Tables 54.1-54.25
		Demand elasticities	Not applied, at least initially		Percent change in electricity demand for percent change in price
	Reserve Margins	Planning reserves	NERC M-1 Planning Reserve Margins by region	NERC data	Capacity reserves to meet demand plus reserve margin
		Operating reserves	Three types of operating reserves supplied within 18 "RTO" regions	NREL - "Operating Reserves in Long-term Planning Models" (Cole et al., 2018)	
		Spinning	3% of load		Approximation of short-term reliability reserves in long-term model:
		Regulation	1% of load, 0.5% of wind generation, 0.3% of PV capacity		Reserves to maintain flexibility with variable renewables
		Flexibility	10% of wind generation, 4% of PV capacity		Approximate ability of different units to supply reserves
		Ramp rates	Ramping time scale to provide reserves		Ramp rates (% per minute) by different types of units
		Spinning	10 minutes		Costs of providing regulation reserves by type of unit
		Regulation	5 minutes		Only "committed capacity" that is operating in a load block provides reserves
		Flexibility	60 minutes		Generation plus reserves is less than or equal to available capacity
	Electrif-ication	Electric vehicle forecasts	AEO 2020 and NREL Electrification Futures Study	NREL EFS data	See Ross (2020) for details of modeling
		EV charging patterns	NREL Electrification Futures Study	NREL EFS data	See Ross (2020) for details of modeling
		Other sectors of the economy	AEO 2020 and NREL Electrification Futures Study	NREL EFS data	See Ross (2020) for details of modeling
	Existing Regulations	RGGI	State caps on emissions with trading and ECR/CCR	RGGI	
		State RPS and CES	NREL data and assumptions on current state RPS	NREL ReEDS documentation	Table 20 (pg. 78)
		Virginia Clean Economy Act	RPS to 100% by 2045/2050, coal retires by 2025, all carbon retires by 2045	Virginia HB 1526	Additional requirements for storage, onshore wind, solar PV, and offshore wind (5.2 GW by 2035)
		Criteria pollutants	NOx SIP Call, BART, MATS, state policies, ACE, etc	EPA Power Sector Modeling v6 - IPM Chapter 3 and Jan 2020 update	

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APPENDIX C – ADDITIONAL POLICY PATHWAY INFORMATION

This appendix provides additional information about other states' experiences with these policies and in some cases, more detail on design alternatives for each pathway. Much of this section was informed the Policy Working Group process. This information is meant to further assist North Carolina's policy makers and stakeholders as they evaluate options to decarbonize the state's electricity sector.

A. Pathway 1: Coal Retirement

Colorado

The Colorado legislature authorized securitization for coal-fired power plants in 2019.[7] The law allows the state Public Utilities Commission (PUC) to approve a utility's securitization proposal to compensate that utility for unrecovered capitalized costs of a retiring electric generating plant. Utilities proposing accelerated retirement of a coal unit must also include a transition assistance plan. The law allows utilities to assume debt to support transition assistance as well.

Prior to the 2019 law, the Colorado PUC had permitted accelerated depreciation on uneconomic coal plants. In 2018 Xcel Energy requested an accelerated depreciation schedule in order to close its Comanche 1 and 2 coal plants, which was approved.[8] To offset rate increases, the PUC reduced an existing renewable energy fee included in ratepayers' bills. Low costs for new renewable resources were also expected to mitigate the rate impacts of early depreciation.[9]

Michigan

The Michigan legislature authorized securitization in the 2000 Customer Choice and Electricity Reliability Act.[10] Under the law, the Michigan Public Service Commission may approve a bond "if the commission finds that the net present value of the revenues to be collected under the financing order is less than the amount that would be recovered over the remaining life of the qualified costs using conventional financing methods."[11] The law restricts the use of bonds to "refinancing or retirement of debt or equity."[12]

Montana

A 2019 Montana law allows securitized bonds when a utility retires or replaces electric generating infrastructure or facilities located in Montana, as well as costs a utility previously incurred related to the closure or replacement or electric generating infrastructure or facilities.[13] Utilities issuing a bond must reduce the balance owed on the retired electric generating facility. The utility may

7. S.B. 19-236, 2019 Reg. Sess. (Co. 2019), https://leg.colorado.gov/bills/sb19-236.
8. In the Matter of the Application of Pub. Serv. Co. of Colorado to Modify the Depreciation Schedules for the Early Ret. of Comanche 1 & Comanche 2 Generating Units, Establish A Regulatory Asset to Collect Incremental Depreciation, Reduce the Renewable Energy Standard Adjustment Collection to One Percent, & Implement A Gen. Rate Schedule Adjustment, Contingent on the Approval of the Colorado Energy Plan Portfolio in Proceeding No. 16a-0396e., No. 17A-0797E, 2018 WL 4385358, (Sept. 10, 2018). https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=25588.
9. David Roberts, "In Colorado, A Glimpse of Renewable Energy's Insanely Cheap Feature," Vox (Jan. 16, 2018) https://www.vox.com/energy-and-environment/2018/1/16/16895594/colorado-renewable-energy-future.
10. Customer Choice and Electricity Reliability Act, Mich. Comp. Laws §460.10i&j (2000), http://www.legislature.mi.gov/(S(3fbhbg2lg0lxlsp5f23vaqxw))/mileg.aspx?page=getobject&objectname=mcl-460-10i.
11. *Id*., at 460.10i(1).
12. *Id*., at 460.10i(2)(a).
13. HB467, 2019 Reg. Sess. (Mont. 2019), https://legiscan.com/MT/text/HB467/2019.

invest bond funds in new generation, electric storage, network modernization, or to replace any damaged or destroyed electric transmission facilities.

New Mexico

The New Mexico legislature adopted the Energy Transition Act in 2019.[14] In addition to establishing new renewable energy standards and carbon reduction goals, the law permits utilities to request a securitization financing order from the PUC to retire any "qualifying generation facility."[15] Utilities must use competitive procurement to select replacement generation. Selection criteria include "cost, economic development opportunity and ability to provide jobs with comparable pay and benefits to those lost due to the abandonment of a qualifying generating facility."[16] The law also requires the PUC to prioritize replacement resources with least environmental impacts and those with a higher ratio of capital costs to fuel costs.[17] The law establishes three funds to provide transition assistance for communities and workers affected by a plant closure. In April 2020 regulators approved PNM's request to decommission its San Juan coal plant via securitization to meet the utility's 2020 clean energy requirements under the Act.[18]

B. Pathway 2: Carbon Adder

This section focuses on policies in other states that apply carbon adder cost values to some aspect of the state's decision-making process. The section includes information about the levels of carbon adders used in California, Colorado, Illinois, Minnesota, Nevada, and Washington and the role these adders play in power-sector planning. The section concludes with a description of the "target-consistent" carbon adder approach adopted by the U.K.

States Incorporating the Social Cost of Carbon

As summarized in Table C.1, each of the following states' utilities commissions use one or more carbon values in at least one—and in some cases, several—areas of decision making.

14. S.B. 489, 2019 Reg. Sess. (N. Mex. 2019), https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf.
15. *Id.,* at Sec. 4.
16. *Id.*, at Sec. 3(A).
17. *Id.*, at Sec. 3(B).
18. Kendra Chamberlain, *PRC OKs PNM's San Juan Generating Station Exit*, New Mexico Political Report (April 1, 2020) https://nmpoliticalreport.com/2020/04/01/prc-oks-pnms-san-juan-generating-station-exit/.

Table C.1. Summary of State Use of Carbon Adders

State	Use of the Carbon Adder Value	Enacted via
CA	Three values, used for different purposes: 1) a "GHG planning price" for utilization in IRP development, 2) a "GHG adder price" for proceedings related to DERs, and 3) IWG Social Cost of Carbon (IWG SCC) values for use in a three-element Societal Cost Test.	CA PUC Rulemakings
CO	The PUC requires utilities to use a carbon adder in sensitivity analysis for resource acquisition in 2022 and beyond; the IWG SCC is used as 3rd sensitivity.	Regulatory decisions by the CO PUC
MN	All commission proceedings, including resource planning, other resource acquisition, and diversification proceedings.	Updated values established via MN PUC Order
NV	Utilities must submit IRPs that account for CO_2 emissions using the SCC	Statute; then, regulation drafted and enacted by NV PUC
WA	Utilities must use the SCC in utility resource planning	Statute & Dept of Commerce rulemaking

Of the states examined, all but Minnesota reference and rely in some part on the Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis report published by the federal Interagency Working Group (IWG) in August 2016. Some states use the IGW Social Cost of Carbon (IGW SCC) directly, applying one or more of the discount rates presented in the 2016 document; others modify it for instance by adopting a different escalation rate. Nevada states a preference for the IGW SCC but does not require utilities to use it.

Table C.2. Comparison of IWG Social Cost of Carbon and State Carbon Adder Values

	IWG SCC Values (2007$/metric ton CO_2)				California ($/metric ton CO_2)		Colorado (nominal $/short ton)		Minnesota (2015$/net short ton)		Washington (2018$/metric ton)
Col. #	1	2	3	4	5	6	7	8	9	10	11
Year	5.0% Avg.	3.0% Avg.	2.5% Avg.	3.0% 95th Percentile	GHG Planning Price - IRPs	GHG Adder - DER	Low-case	High-case	Low Cost	High Cost	2.5% SCC adjusted
2010	10	31	50	86							60
2011	11	32	51	90							
2012	11	33	53	93							
2013	11	34	54	97							
2014	11	35	55	101							
2015	11	36	56	105							67
2016	11	38	57	108							
2017	11	39	59	112					8.44	39.76	
2018	12	40	60	116	15.17	66.37			8.64	40.66	
2019	12	41	61	120	16.05	73.34			8.85	41.56	
2020	12	42	62	123	16.94	80.31			9.05	42.46	74
2021	12	42	63	126	17.88	87.28			9.25	43.36	
2022	13	43	64	129	18.86	94.25	1.86	20.00	9.46	44.26	
2023	13	44	65	132	19.91	101.22	2.79	20.49	9.66	45.16	
2024	13	45	66	135	21.02	108.19	4.21	20.99	9.87	46.06	
2025	13	46	68	138	22.19	115.15	4.63	21.50	10.07	46.96	81
2026	14	47	69	141	23.44	122.12	6.65	22.02	10.28	47.86	
2027	15	48	70	143	55.08	129.09	8.69	22.56	10.48	48.77	
2028	15	49	71	146	86.72	136.06	10.79	23.11	10.69	49.67	
2029	15	49	72	149	118.36	143.03	12.97	23.68	10.89	50.57	
2030	16	50	73	152	150.00	150.00	15.06	24.25	11.10	51.47	87

	IWG SCC Values (2007$/metric ton CO_2)				California ($/metric ton CO_2)		Colorado (nominal $/short ton)		Minnesota (2015$/net short ton)		Washington (2018$/metric ton)
Col. #	1	2	3	4	5	6	7	8	9	10	11
2031	16	51	74	155			15.43	24.85	11.30	52.37	
2032	17	52	75	158			15.81	25.45	11.51	53.27	
2033	17	53	76	161			16.19	26.07	11.71	54.17	
2034	18	54	77	164			16.59	26.71	11.92	55.07	
2035	18	55	78	168			16.99	27.36	12.12	55.97	93
2036	19	56	79	171			17.41	28.03	12.33	56.87	
2037	19	57	81	174			17.83	28.71	12.53	57.77	
2038	20	58	82	177			18.27	29.41	12.74	58.67	
2039	20	59	83	180			18.71	30.13	12.94	59.58	
2040	21	60	84	183			19.17	30.87	13.15	60.48	100
2041	21	61	85	186			19.64	31.62	13.35	61.38	
2042	22	61	86	189			20.12	32.39	13.56	62.28	
2043	22	62	87	192			20.61	33.18	13.76	63.18	
2044	23	63	88	194			21.11	33.99	13.97	64.08	
2045	23	64	89	197			21.63	34.82	14.17	64.98	106
2046	24	65	90	200			22.15	35.67	14.38	65.88	
2047	24	66	92	203			22.69	36.54	14.58	66.78	
2048	25	67	93	206			23.25	37.43	14.79	67.68	
2049	25	68	94	209			23.81	38.34	14.99	68.58	
2050	26	69	95	212			24.40	39.28	15.20	69.48	113
2051							24.99	40.24			
2052							25.60	41.22			
2053							26.23	42.23			
2054							26.86	43.26			

California

In February 2018, the California PUC adopted a GHG Planning Price (Table C.2, column 5) and directed load serving entities to use these values for IRP development and planning purposes.[19] These values are up for re-evaluation at each IRP cycle; the Commission can update them based on whether realized GHG emission reductions are adequate to achieve the state's goals.

In the same decision, the PUC instituted a separate GHG adder trajectory for integrated distributed energy resource proceedings. Table C.2, column 6 outlines the values for use in any proceedings that rely on assumptions about the GHG benefits associated with DERs. As presently calculated, both the GHG Planning Price and the DER GHG adder reach $150 per metric ton of CO_2e by 2030. However, the utility planning price starts more modestly and accelerates in the out years, while the DER adder begins at a more robust level. The rationale for a different approach to valuing the GHG adder for DERs was to give market certainty to DER providers. The PUC highlighted the difficulty of deploying DERs at scale compared to utility-scale supply, which in part justified a higher, smoother GHG adder curve for DER cost-effectiveness analyses. The CPUC indicated that it would revisit these assumptions in the next round of IRP proceedings but expects that under any scenario the GHG Planning Price and the DER GHG adder will eventually converge.

In a subsequent Decision (19-05-019) the PUC adopted a new framework for analyzing the cost-effectiveness of distributed energy resources.[20] The Commission updated the Total Resource Cost (TRC), Program Administration Costs (PAC), and Ratepayer Impact Measure (RIM) cost-effectiveness tests to include the new DER GHG adder values.

The PUC also created a Societal Cost Test (SCT) beta-test for the 2020 IRP. The Commission is using the SCT for informational purposes only, to test whether it could facilitate California's carbon reduction objectives. The SCT incorporates two of the IWG SCC calculations—the high impact values (95th percentile) and the values using a 3% discount rate (Table C.2, columns 2 and 4); an air quality adder of $6.00/MWh; and a societal discount rate using a discount rate of 3% and a value representing the utilities' weighted average cost of capital.

The Commission's Energy Division will review and evaluated the results of an application of the SCT in the IRP proceeding and propose refinements after the conclusion of the beta-testing period on December 31, 2020.

Colorado

Under Colorado law, the state PUC "may give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire

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19. Cal. Public Utilities Commission, *Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans*, D.18-02-018, Rulemaking 16-02-007 (Feb. 8, 2018), http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=209771632.

20. Cal. Public Utilities Commission, *Decision Adopting Cost-Effectiveness Analysis Framework Policies for All Distributed Energy Resources*, D.19-05-019, R.14-10-003 (May 16, 2019), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF.

resources."[21] In granting approval for Excel Energy's 2016 Electric Resource Plan,[22] the Colorado PUC agreed to allow the utility to continue to use a $0 value for carbon in base-case modeling, but then required sensitivity analyses that accounted for the costs of carbon pollution. The PUC allowed the utility to use its own suggested low carbon cost case and high carbon cost case values (Table C.2, columns 7 and 8) for two of the sensitivity analyses.[23] However, noting that the full costs of externalities were not reflected in the utility's values, the PUC also directed Xcel to run a third carbon price sensitivity: the IWG SCC calculated using a 3% discount rate (Table C.2, column 2). The results of these analyses were required to be included in Xcel's 120-Day Report. For carbon values extending beyond 2050 (when the IWG SCC calculations end)—and specifically for the period between 2051–2054—the PUC directed Xcel to assume the escalation rate it proposed for its high carbon cost case (~2.4%) across all three sensitivities.

Minnesota

The Minnesota PUC is statutorily mandated to consider externalities for all proceedings.[24] Under this authority, the PUC set rules that requires it to use the values shown in Table C.2, columns 8 and 9. Both sets of values were established by Minnesota and are to be used by utilities when planning for new projects. The PUC uses updated SCC values in evaluating and selecting resource options in all commission proceedings, including resource planning and other resource acquisition or diversification proceedings.[25]

Nevada

In 2017, the Nevada legislature amended the statute governing electric utility IRPs.[26] One provision required that IRPs include information related to reducing customer exposure to potential costs of carbon. The PUC then revised its regulations[27] to include the following directives:

(1) The summary of the preferred plan in a utility's IRP must now explain how the preferred plan reduces consumer exposure to the price volatility of fossil fuels and the potential social cost of carbon in accordance with applicable regulations. Those regulations[28] allow the utility to conduct its own calculation of the social cost of carbon but stipulates it must be calculated using the "best available science and economics," and cites the analysis published by the IWG in August 2016.

21. Colo. Rev. Stat. § 40-2-123(1)(b).

22. Col. Public Utilities Commission, *Phase I Decision Granting, With Modifications, Application For Approval of 2016 Electric Resource Plan*, D.C17-031 for proceeding 16A-0396E, https://cossa.co/wp-content/uploads/2017/05/erp-decision-c17-0316_16a-0396e-1.pdf

23. Public Service Company of Colorado (May 27, 2016), 2016 Electric Resource Plan Vol. 2 (Mar. 23, 2017), https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-2.pdf, at 2-265.

24. 2016 Minn. Stat. § 216B.2422 Subd. 3, https://www.revisor.mn.gov/statutes/cite/216B.2422.

25. Minn. Public Utilities Commission, *Order Updating Environmental Cost Values*, D. E-999/CI-14-643 (Jan. 3, 2018), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5066BD60-0000-C71B-9B5B-305CF65BCAE1}&documentTitle=20181-138585-01.

26. S.B. 65, 79th Sess. (Nev. 2017), https://www.leg.state.nv.us/App/NELIS/REL/79th2017/Bill/4712/Overview.

27. Nev. Public Utilities Commission, *Investigation and Rulemaking to Implement Senate Bill 65*, Docket No. 17-07020, Attachment 1 (August 15, 2018), http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-7/32153.pdf.

28. Nev. Admin. Code 704.937, https://www.leg.state.nv.us/nac/nac-704.html.

(2) Electric utilities must quantify the environmental costs to the state associated with operating and maintaining the supply or demand side plan using the same calculation of the social cost of carbon as described above.

(3) Utilities must include the social cost of carbon in the calculation of the present value of annual societal and environmental costs associated with each alternative plan for the supply of power. Once again, an electric utility may use its own calculation of the SCC in lieu of the IWG social cost of carbon values *if* the utility provides information to support the alternative method and that method uses best available science and economics and is equivalent in quality to the IWG's method.

(4) Resource plans must include a table showing the projected mix of generation by fuel type and the projected total emissions of CO_2 for each supply plan analyzed. The utility must also include a graph for each supply plan that shows the percentage change in the preferred plan's projected total emissions of CO_2 that result from that plan, for each year of the plan.

Washington

In 2019, Washington's Department of Commerce established the rulemaking on the social cost of GHG emissions for consumer-owned electric utilities.[29] The rulemaking specifies that the social cost of GHG emissions is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5% discount rate as listed in the technical support document published by the IWG (Table C.2, column 3). The SCC values must be adjusted for inflation, using the implicit price deflator for GDP as published by the US Department of Commerce, from the 2007 dollars to the base year used for other cost and benefit values in the utility's analysis.

The SCC values for intermediate years are calculated by linear interpolation as provided by IWG. Beyond 2050, SCC values must be determined by applying an escalation factor of 1.3%. Utilities are directed to use these values in resource planning, evaluation, and selection.

United Kingdom: Target-Consistent Approach

The Carbon Adder homework team identified a "target-consistent" approach as an alternative approach to calculating a value for carbon using some variation of the social cost of carbon. Under this approach, the carbon value is priced at a level to achieve a specific CO_2 or GHG reduction goal. As described in Section 5 of the report, a target-consistent carbon adder on generation was modeled in DIEM. The results of that policy, compared to results from a harms-based "social cost of carbon" accounting, are presented in Sections 6 and 7 of the report.

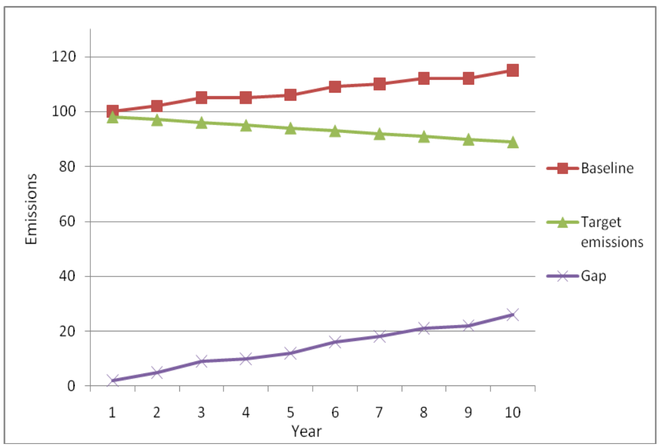
The United Kingdom (UK) has adopted this method of carbon adder accounting. In 2009, the UK switched from estimating societal costs of GHG emissions using SCC calculations to a target-consistent approach. Their carbon adder estimates the marginal abatement costs (MAC), using a "non-traded price of carbon," necessary to meet specific emissions reduction targets. The

29. Wash. Admin. Code 194-40-100 Social Cost of Greenhouse Gas Emissions, https://app.leg.wa.gov/WAC/default.aspx?cite=194-40&full=true&pdf=true.

benefit of this approach is that it provides greater confidence in the feasibility of achieving carbon reduction goals.[30]

Calculating the carbon adder using a target-based approach first requires comparing baseline emissions projections and emissions reductions targets. As shown in Figure C.1, the difference between baseline and target emission levels represents the emission reductions necessary to meet the target goals in any given year. In Year 10, for instance, the gap is approximately 26 tons. This gap value is then fed into a marginal abatement cost curve to produce a price on carbon.

Figure C.1. Example of the Difference between Projected and Target-Consistent Emissions



There are two basic methods for defining an abatement cost curve: a "by policy" MAC curve; and a "feasible technical" MAC curve.

- A "by policy" MAC curve collates all the appraisals of abatement that different policies (actual and potential) are projected to deliver, by date and cost.
- A "feasible technical" MAC assesses the level of abatement that could be realized by the actions and behaviors of individuals and firms. Under this approach, technical potential from measures could be adjusted to reflect limitations on feasibility such as supply-side constraints, and the cost of the abatement adjusted to reflect the average anticipated policy costs of delivering the measures.

In the U.K., these analyses are reviewed every five years.

30. UK Department of Energy & Climate Change, Carbon Valuation in UK Policy Appraisal: A Revised Approach (2009), https://www.gov.uk/government/publications/carbon-valuation-in-uk-policy-appraisal-a-revised-approach.

C. Pathway 3: Declining Carbon Cap/Carbon Market

Section 5 of this report explained that the carbon market scenario modeled by ICF tracks the policy design of the 11-state regional carbon market, known as the Regional Greenhouse Gas Initiative, or RGGI. Those 11 states, extending from Maine to Virginia's border with North Carolina, participate in the country's only power sector carbon market. (In addition, California operates an economy-wide carbon market.) On January 8, 2019, Governor Wolf of Pennsylvania signed an executive order also directing his environmental agency to pursue joining RGGI.[31]

While most RGGI states have adopted similar regulations for most elements of the carbon market program to ensure a fluid market, they have struck out on somewhat different paths when it comes to investing funds raised by auctioning carbon allowances. The Carbon Markets homework team discussed potential uses of revenue generated by allowance auctions. The discussions were informed by a report by The Analysis Group examining how RGGI states invest their respective portions of the auction revenue.[32] The first seven categories below were identified in the Analysis Group RGGI Report, whereas categories 8–10 are additional options for North Carolina to consider.

(1) Energy Efficiency and Other Utility Programs
RGGI states spend much of the auction revenue on EE measures, including funding for residential and commercial retrofits and new construction. EE programs offer numerous benefits, including reducing electrical demand, lowering wholesale power prices, and lowering electricity bills for all consumers (particularly for consumers who participate in the program). The Analysis Group report noted that "expenditures include payments for engineering services for energy audits, sales of energy-efficient equipment, dollars spent to train those installers, and state taxes collected on all of these activities. Together, these dollar flows have direct and indirect multiplier effects locally and regionally."[33] The NC CEP also noted that EE could help alleviate NC's substantial energy burden problem.[34]

(2) Renewable Energy Investment
RGGI states support renewable energy investments through grants and investments "focused on the development, distribution, and installation of renewable or advanced energy technologies."[35] Like EE, renewable energy investments can help offset the impact on customer electricity prices resulting from CO_2 allowance costs.

31. Pa. Exec. Order No. 2019-01 (Jan. 8, 2019), https://www.governor.pa.gov/newsroom/executive-order-2019-01-commonwealth-leadership-in-addressing-climate-change-and-promoting-energy-conservation-and-sustainable-governance/.
32. Paul J. Hibbard, *et al.*, The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States, The Analysis Group (Apr. 17, 2018) ("Analysis Group RGGI Report"). See pages 31–32 for the seven categories of investments.
33. *Id.* at p. 5.
34. N.C. Dep't of Envt'l Quality, North Carolina Clean Energy Plan: Supporting Document: Part 3: Electricity Rates & Energy Burden 14, Table 4-1 (2019), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/3.-Electricity-Rates-and-Energy-Burden-FINAL.pdf.
35. Analysis Group RGGI Report, at p. 32.

(3) **Education and Job Training**
States also use RGGI auction revenue to "(i) [ ] educate business and residential consumers about energy consumption and the availability of programs to reduce consumption, and (ii) train workers with new skills and knowledge in industries and activities that contribute to lowering energy use (e.g., installation of EE measures) or the production and distribution of renewable or other advanced energy technologies."[36] Training workers for clean energy jobs can help fulfill a need identified by NC Commerce Department in its Clean Energy Workforce Assessment.

(4) **Clean Technology Research/Development**
Some RGGI states use a portion of auction revenue to "support research or other public/private groups focused on the furthering R&D related to GHG emissions (e.g., clean technologies, alternative transportation, carbon sequestration)."[37]

(5) **Direct Energy Bill Assistance**
Some RGGI funds "provide payment credits or other means to reduce bills paid by consumers for electricity and heating/cooling. In some cases, investments in this category are targeted to low-income households."38

(6) **GHG Reduction Programs**
This category may include R&D funding for CO_2 emission abatement technologies, similar to the fourth category above, as well as numerous other expenditures aimed at reducing GHG programs. According to the Analysis Group RGGI Report, these programs may include "direct investment in 'green' start-up companies, efforts to reduce vehicle miles traveled, climate change adaption measures, investments in existing fossil-fuel fired power plants to make them cleaner and/or more efficient."[39]

(7) **Program Administration**
RGGI states spend a portion of the RGGI proceeds on administrative support so as not to draw down on appropriated funds for this purpose.

(8) **Environmental Justice and Resilience Investments**
North Carolina could use some auction revenue to invest in overburdened communities to improve health and economic opportunity, and to prepare for climate change impacts. For instance, California requires that 35% of all carbon market revenues be directed to "disadvantaged communities and low-income communities and households."[40] California's carbon market auction proceeds support projects such as low-income weatherization, coastal resilience planning, renewable energy for agriculture programs, urban greening, transit, and low carbon economy workforce development.[41]

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36. *Id*.
37. *Id*.
38. *Id*.
39. *Id*.
40. California Climate Investments, Cap-and-Trade Dollars at Work, https://www.caclimateinvestments.ca.gov/ (last visited Dec. 9, 2020).
41. California Climate Investments, 2020 Annual Report, at pp. iv and v.

(9) Health Care Investments
Health care investments might include medical monitoring for illnesses or conditions related to or exacerbated by air pollution, as well as interventions to reduce exposure to harmful air pollutants (including indoor air pollution). The homework team noted that health investments in communities of color could provide an important policy bridge between North Carolina's Clean Energy Plan and E.O. 143 (Addressing the Disproportionate Impact of COVID-19 on Communities of Color).

(10) General Budget Needs
In addition to the categories described above, North Carolina could also use auction proceeds to support general budgetary needs.

D. Pathway 4: Clean Energy Standard

At the time of writing, six states had enacted a sales-based CES, as shown in Table C.3. There is wide variability among these enacted CES policies, and even more potential variation when additional design alternatives not reflected in these policies are considered.

Table C.3. Existing CES Policies

State	Arizona	California	Massachusetts	New Mexico	New York	Washington
CES Target	Carbon emissions must be reduced by 50% by 2032, 75% by 2040, and 100% by 2050 compared to average emissions created to meet a utility's retail sales during the 3-year 2016–2018 period	100% of total retail sales to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045.	80% of retail electricity sold to MA end-use customers by 2050, and each year thereafter must be met by clean generation attributes and clean existing generation attributes.	Renewables must supply 20% of retail sales by 2020, 40% by 2025, 50% by 2030, 80% by 2040, and by 2045 100% shall be supplied by zero-carbon resources	50% of electricity consumed in New York by 2030 will be generated by renewable and zero emitting sources; the electricity system will be carbon free by 2040	All retail sales of electricity must be GHG neutral by January 1, 2030; non-emitting electric generation and renewables must supply 100% of retail sales by January 1, 2045
Established	2020	2018	2017	2019	2019	2019
Enacted via	Corporation Commission – *Proposed* Clean Energy Rules[42]	Legislation – The 100 Percent Clean Energy Act[43]	Agency Regulation – 310 CMR 7.75 Clean Energy Standard[44]	Legislation – Energy Transition Act[45]	Public Service Commission CES Order[46] + Climate Leadership and Community Protection Act of 2019[47]	Legislation – Clean Energy Transformation Act[48]
Compliance mechanism	Annual reporting and independent 3rd party verification of utility carbon emissions	Non-compliance penalties	Clean generation attributes	RECs	RECs and ZECs and alternative compliance payments	RECs, and credits for alternative compliance options
Cost-containment provisions		Cost-offramps	Credit banking allowed with limits; alternative compliance payments	"Reasonable cost threshold"[49]	Credit banking; alternative compliance payments	Shut-down credits; cost-offramp; alternative compliance options

42. Ariz. Corporation Commission, *In the Matter of Possible Modifications to The Arizona Corporation Commission's Energy Rules*, Docket RU-00000A-18-0284 (November 23, 2020), https://docket.images.azcc.gov/0000202570.pdf.
43. S.B. 100, Chapter 312 (Cal. 2018), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.
44. Clean Energy Standard, Mass. Admin. Code 310 § 7.75 (2020), https://www.mass.gov/guides/clean-energy-standard-310-cmr-775.
45. Energy Transition Act, S.B. 489, 54th legislature (N. Mex. 2019), https://www.nmlegis.gov/Sessions/19%20Regular/bills/senate/SB0489.html.
46. N.Y. Public Service Commission, *Order Adopting A Clean Energy Standard*, Case 15-E-0302 (Aug. 1, 2016), http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=15-E-0302.
47. Climate Leadership and Community Protection Act of 2019, State of New York, 2019-2020 Reg. Sess. (June 18, 2019), https://legislation.nysenate.gov/pdf/bills/2019/S6599.
48 Clean Energy Transformation Act (CETA), State of Washington, 66th Leg. Sess. (E2SSB 5116, 2019) (May 13, 2019), https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf.
49. The "reasonable cost threshold" outlined in statute is $60/MWh, adjusted for inflation beyond 2020. If a public utility determines that the average annual levelized cost of procuring

Among these states, not all refer to their policy as a Clean Energy Standard officially, though their policy meets the minimum requirements to classify as such.

Additional CES Policy Design Options

Clean Energy Standards are highly customizable. This section summarizes some CES design alternatives identified by the Policy Working Group.

Partial credit for lower-emitting sources. The CES scenarios modeled for this report defined "clean energy" as generating sources that do not emit greenhouse gases. However, it is possible to design a CES that provides partial credit for other types of generation. For example, the Clean Energy Standard Act of 2019, introduced in the U.S. Senate, would allow partial credit for natural gas generation.[50]

Interim timetables. Some state CES include a timetable with intermediate year requirements that define electric utilities' annual compliance obligations. The timetable can either increase stringency at a constant rate to the nominal target (well-suited to banking and borrowing flexibility) or increase stringency slowly at first and then at an accelerated pace in later years. The latter approach allows utilities time to ramp up investments and allows flexibility for longer-lead time projects.[51] However, accelerating stringency over time also postpones the most significant emission reduction requirements, thus increasing the uncertainty of whether the longer-term target is attainable.

Massachusetts is the only state with a CES that sets a target for every intervening year between now and 2050. New Mexico has intermittent year targets in five-year increments for renewable energy generation but only introduces a zero-emission generation target in the final year, 2045. Arizona has intermittent year targets for emissions reductions (as opposed to a percent of sales requirement): carbon emissions must be cut in half by 2032 and 75% by 2040 relative to average utility emissions between 2016–2018. Interim timetables may be more important for policies that require Alternative Compliance Payments when targets are not achieved.

Carveouts

The North Carolina REPS includes carveouts for specific technologies.[52] Similarly, a CES can include carveouts to facilitate deployment of specific clean energy technologies. For example, the Arizona Corporation Commission's proposed clean energy rules include carveouts for energy efficiency and battery storage.[53]

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renewable energy needed to comply with the standard, the public utility is not required to incur this excess cost.

50. S. 1359, 116th Cong. §610(b)(1) (2019). The bill provides partial clean energy credit for generation from a facility with a carbon intensity lower than 0.4 metric tons of CO_2-per megawatt-hour (with an adjustment for upstream emissions from natural gas). *Id*.

51. Center for Climate and Energy Solutions, Clean Energy Standards: State and Federal Policy Options and Consideration, p. 32 (2019), https://www.c2es.org/site/assets/uploads/2019/11/clean-energy-standards-state-and-federal-policy-options-and-considerations.pdf.

52. The NC REPS includes carve-outs for solar energy, swine waste resources, and poultry waste resources. N.C. Gen. Stat. § 62-133.8(d)-(f).

53. Ariz. Corporation Commission, *In the Matter of Possible Modifications to The Arizona Corporation Commission's Energy Rules*, Docket RU-00000A-18-0284, *Notice of Proposed Rulemaking* (Dec. 1, 2020), https://docket.images.azcc.gov/E000010319.pdf?i=1608137357350. According to the proposal, each utility must include demand-side resources equal to at least 35% of its 2020 peak demand by 2030, and energy storage systems must have an aggregate capacity equal to 5% of the utility's 2020 peak demand by 2035, 40% of which must be customer-owned or -leased distributed storage.

APPENDIX D – CARBON NEUTRALITY TARGETS AND GOALS IN OTHER STATES

The North Carolina CEP recommends a 2050 carbon-neutrality goal for the state's electric power sector.[54] Carbon neutrality refers to a balance between anthropogenic GHG emissions and activities that remove carbon from the atmosphere, such that there is no difference between the quantity emitted and the quantity removed.[55] Neutrality can either be achieved via a complete reduction of emitting activities, or by undertaking activities which remove and sequester carbon from the atmosphere at a rate that matches continued emissions. The states discussed in this section have established economy-wide carbon-neutrality targets, in contrast to the electricity sector target recommended by the CEP, but the concept is the same.

Table D.1. Terminology Used by Other States

State	Term Used
California	Carbon neutral
Hawaii	Zero-emission
Louisiana	Net-zero
Maine	Carbon neutral
Massachusetts	Net-zero
Michigan	Carbon neutral
Montana	Net greenhouse gas neutral
Nevada	Zero or near-zero
New York	Net-zero
Washington	Both net-zero and carbon neutral

Though straightforward in concept, there is a high degree of variability in terms of the implications of net-zero commitments depending on the context. Some of the different ways states articulate their net-zero commitments include applicability (economy-wide versus application to specific sectors), content (all GHGs or just CO_2), offset acceptability (local, domestic or international, and of certain types), and offset caps (limiting the percentage of emissions which can be offset).

54. CEP, p. 58.
55. The terms "net-zero and "carbon neutral" often include all greenhouse gas emissions. *See, for example*, Anne C. Mulkern, "California: State can Be Carbon Neutral in 25 Years with Drastic Action,' E&E News (Jan. 31, 2020), https://www.eenews.net/energywire/stories/1062222789 ("California can hit its goal of going carbon neutral by 2045 if it pulls emissions out of the air and slashes greenhouse gases from farming, landfills and other sources.").

Eight U.S. states have enacted net-zero or carbon neutrality targets at the time of writing: California, Hawaii, Louisiana, Maine, Michigan, Nevada, New York, and Washington.[56] Table D.2 compares these states' net-zero targets and provides hyperlinks to their policy. These state targets are economy-wide, in contrast to the electricity sector target in the CEP.[57]

California, Louisiana, Maine, and Michigan established economy-wide net-zero targets via executive order, while state legislatures established the targets in the other states. None of these policies provide a definition of carbon neutrality or net zero. Further, each of these orders requires a state agency or newly established task force to develop an implementation strategy.

Massachusetts has proposed a carbon neutrality target. A letter of determination signed by the Governor of Massachusetts established a target "level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level."[58] In August 2020, the Massachusetts House of Representatives passed a bill which would codify the net-zero goals set forth by the governor.[59]

Table D.2. Attributes of State Net-Zero Targets

State	Target Year	Target Status & Year Implemented	All GHGs	% Reduction	Enabling Policy
California	2045	Implemented 2018	Yes	80%	Executive Order B-55-18
Hawaii	2045	Implemented 2018	Yes	Unclear or Undecided	HB2182
Louisiana	2050	Implemented 2020	Yes	Unclear or Undecided	Executive Order JBE 2020-18
Maine	2045	Implemented 2019	Yes	80%	Executive Order 10 FY 19/20
Michigan	2050	Implemented 2020	Yes	Unclear or Undecided	Executive Directive 2020 - 10

56. Nevada's legislation does not explicitly state economy-wide applicability; instead, the statute lists a broad selection of sectors individually, which together appear to be quasi-economy-wide.
57. Montana Governor Bullock issued an executive order in 2019 establishing an interim goal of net greenhouse gas neutrality for average annual electric load by 2035, in addition to an economy-wide neutrality goal with the target date to be determined by a new Montana Climate Solutions Council. *See* Montana Climate Solutions Plan, August 2020, http://deq.mt.gov/Portals/112/DEQAdmin/Climate/2020-09-09_MontanaClimateSolutions_Final.pdf.
58. Mass. Executive Office of Energy and Environmental Affairs, Determination Of Statewide Emissions Limit For 2050 (Apr. 22, 2020), https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download. For more information on the Massachusetts decarbonization roadmap, see https://www.mass.gov/info-details/ma-decarbonization-roadmap.
59. H.4912 (Mass. 2020), https://malegislature.gov/Bills/191/H4912.

State	Target Year	Target Status & Year Implemented	All GHGs	% Reduction	Enabling Policy
Nevada	2050	Implemented 2019	Yes	Unclear or Undecided	Senate Bill 254
New York	2050	Implemented 2019	Yes	85%	Senate Bill S6599
Washington	2050	Implemented 2020	Yes	95%	HB2311

APPENDIX E – ELECTRICITY IMPORTS

I. Background on Electricity Imports

The electricity that serves North Carolina's load is generated by sources located in North Carolina, South Carolina, Virginia, and to a lesser extent, Tennessee. Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy operate their respective systems across state borders. Because each of the utilities operate their territories as single balancing areas, they do not consider electricity that they generate beyond NC's borders to meet NC's load as "imported." However, this power does cross state lines and may originate from a state that has set rather aggressive carbon reduction policies—such as Virginia—or no climate policy at all.

Each of the carbon policies analyzed in this report has the potential to change the degree to which NC continues to be a net-importer, as well as the times of year, hours of the day, and source of those imports. For instance, if a North Carolina policy encouraged the retirement of a coal plant or increased the wholesale cost of coal or natural gas-fired electricity generated in North Carolina, utilities might import more power from fossil plants that are not subject to these new rules. As imports increase, a larger share of North Carolina's 2030 emissions budget might come from imported power.

By contrast, some carbon policies might result in North Carolina becoming a net power exporter. For instance, a clean energy standard with a percentage of retail sales requirement may be agnostic regarding the location of the clean energy generation.[60] Such a requirement could result in the growth of clean capacity in neighboring states while generating electricity from NC's emitting plants to export for consumption elsewhere. This could change the amount of clean energy consumed in North Carolina without changing generation patterns—or regional emissions trends.

II. Calculating Emissions for Imported Electricity

For the purposes of GHG emission accounting, there are two types of imported electricity: specified and unspecified. Specified electricity is when a utility has entered into a bilateral agreement for power from an identified generating unit with a known emissions profile. Most power on the grid is "unspecified"—meaning that it may not be clear which generators in a given region have ultimately served the load of a particular state.

Washington and California have enacted rules to account for emissions from imported electricity. In Washington, all electric utilities must report the emissions from electricity delivered to consumers. Unspecified electricity is accounted for using an emission rate established and periodically updated by the state's Department of Ecology, which must be consistent with other markets in the western interconnect. Washington's laws also stipulates that in the absence of a Department-established emission rate, a rate of 0.437 metric tons of CO_2/MWh is to be used for unspecified electricity imported to the state.[61] Similarly, in California, electric power entities must

60. As discussed in Section 5 of the report, the team modeled a CES that required the clean generation to be located in North Carolina.

61. Wash. Rev. Code § 19.405.070. Greenhouse gas content calculation. https://app.leg.wa.gov/RCW/default.

calculate the annual CO_2 equivalent mass emissions from unspecified electricity using a default emission factor of 0.428 metric tons of CO_2e/MWh, adjusted for transmission loss factor of 1.02 to account for losses associated with generation outside of a California balancing authority.[62]

NC DEQ already accounts for emissions from imported electricity in the North Carolina Greenhouse Gas Inventory. DEQ uses historical imported electricity levels from the US Energy Information Administration and applies the EPA's eGRID emission factors for the subregion to which North Carolina belongs. Because imported electricity levels have generally remained constant over time, DEQ projects no change to the ratio of imported electricity to retail sales. However, the grid emission factors are projected to change, as new generation comes online to replace retiring units. For the Greenhouse Gas Inventory, DEQ did not project changes to the grid emission factors for future years. However, for other modeling work, DEQ has developed projected grid emissions using the projected fossil fuel generation and CO_2 emissions from the ERTAC model base case and adding the current level of nuclear generation from the rest of the sub-region to the fossil fuel generation value from ERTAC.[63] This method does not consider smaller emitting and non-emitting resources and is less accurate than the California and Washington approaches, which require utility-level accounting and reporting.

As presented in Section 2 of the report, the CEP establishes the goal of reducing electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030. DEQ calculated 2005 emissions based on reported emissions from in-state generation, and an upwards "import adjustment" using the methodology described above. Similarly, the resulting 2030 target of 23.8 million metric tons (mmt) includes an estimated 22 mmt of CO_2 from in-state generation, and another 1.8 mmt from imported electricity.

Both DIEM and IPM modelers identified the emissions intensity of different exporting regions that deliver power to North Carolina: the states of Virginia (or, the Dominion Energy service territory), North Carolina, Tennessee (or, the Tennessee Valley Authority service territory), and subregions of the nearby competitive wholesale market, PJM. The outputs for the reference case and each policy case identify the exporting regions and the quantity of estimated imports into North Carolina. The modelers were able to estimate emissions associated with those imports, by weighting the emissions intensity of each exporting region based on what share of imports were delivered to North Carolina from that region.[64] In case and years where North Carolina is a net exporter of electricity, the modelers do not calculate any emissions associated with imports.

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aspx?cite=19.405.070.

62. Cal. Code Regs. tit. 17 § 95111. Data Requirements and Calculation Methods for Electric Power Entities. https://govt.westlaw.com/calregs/Document/I87F5540BAF1A4547AE87EC17C57032CC?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

63. ERTAC is the name of a model developed by the Eastern Regional Technical Advisory Committee. For more on this committee and its work, please see https://marama.org/technical-center/ertac-egu-projection-tool/#:~:text=The%20Eastern%20Regional%20Technical%20Advisory,planning%20organization%20(MJO)%20representatives.

64. These import adjustments treat all power coming from an export region—for instance, Virginia—as originating in that region/state. That may not be accurate; some of this power may have been generated elsewhere and "wheeled" or transmitted through Virginia before serving North Carolina load.

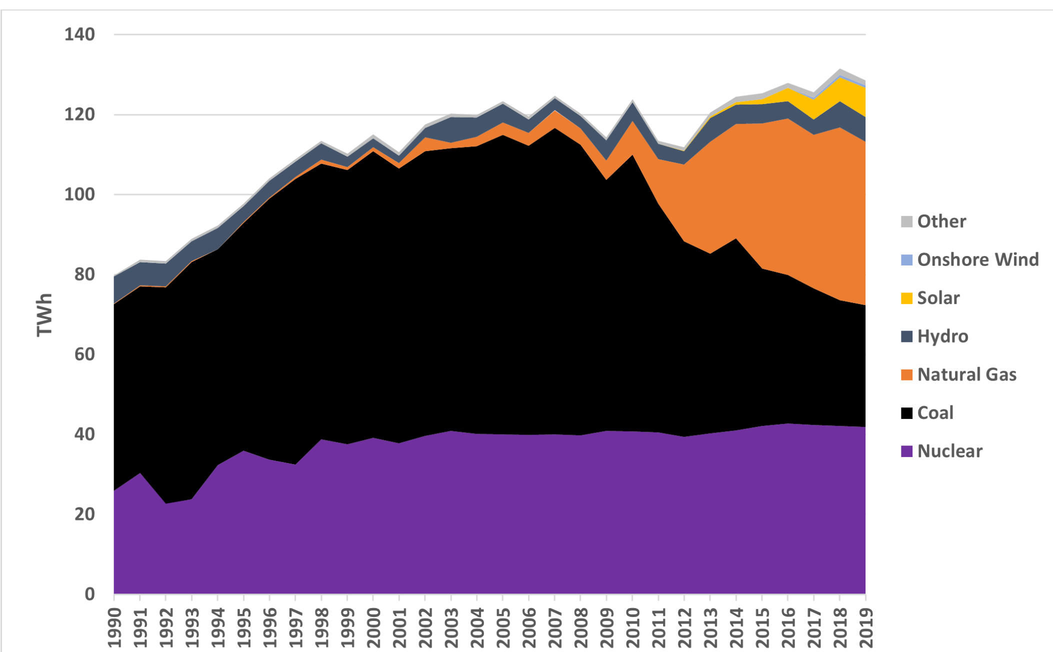
APPENDIX F – SENSITIVITY MODELING

This appendix presents historical trends in North Carolina generation and contrasts them to baseline estimates from IPM and DIEM going forward to 2050, in the absence of new climate policies. The following subsections then look at some additional policy variants and then illustrate how changes in model assumptions may impact both baseline trends and policy impacts.

Historical Trends in North Carolina

The starting point for the CEP A1 analysis is a generation mix in North Carolina that has evolved significantly over the last several decades, illustrating how sensitive the electricity industry has been to trends in fuel prices, technology costs, and state policies—even in a cost-of-service state relatively shielded from competition. Figure F.1 shows significant growth occurred in nuclear and coal generation in the 1990s as electricity demand rose, nuclear plants increased generation, and coal prices remained low compared to natural gas prices.[65] Natural gas started appearing in the 2000s, and in 2009 natural gas prices began a decline that has largely continued to the present day. Meanwhile, in 2007, North Carolina passed a Renewable Energy Portfolio Standard (REPS). These changes, along with reductions in solar PV and combined-cycle unit costs, have resulted in dramatic shifts in generation over the 2010–2020 decade, with gas and solar increasing at the expense of coal generation.

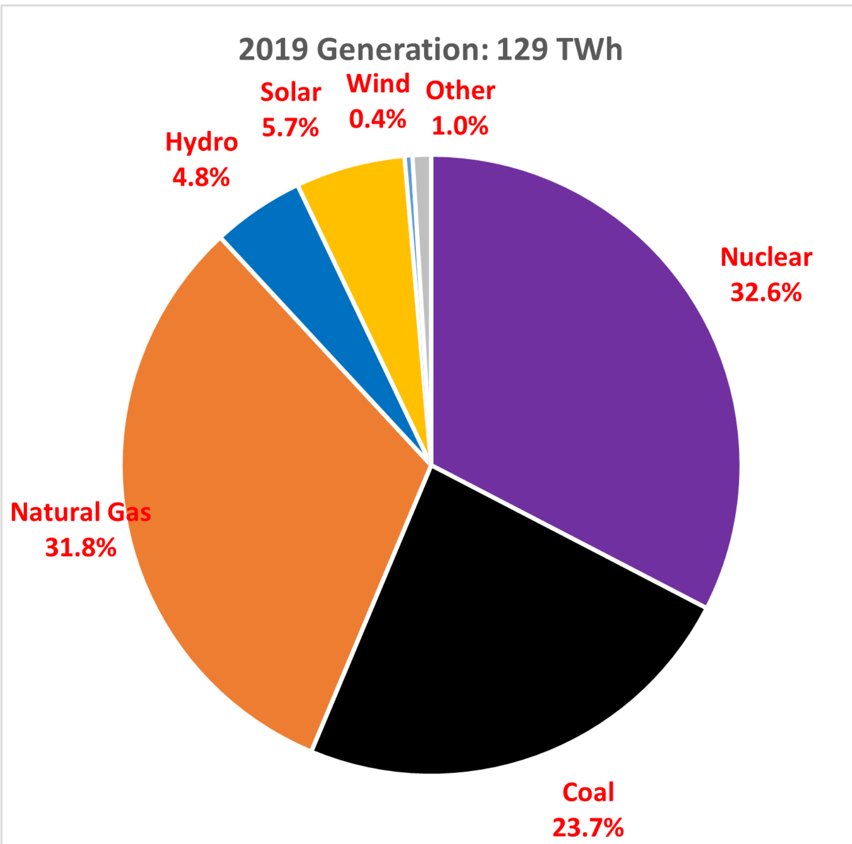
Figure F.1. Generation Trends in North Carolina Since 1990 (TWh)



65. EIA Electric Power Monthly, https://www.eia.gov/electricity/monthly/#four.

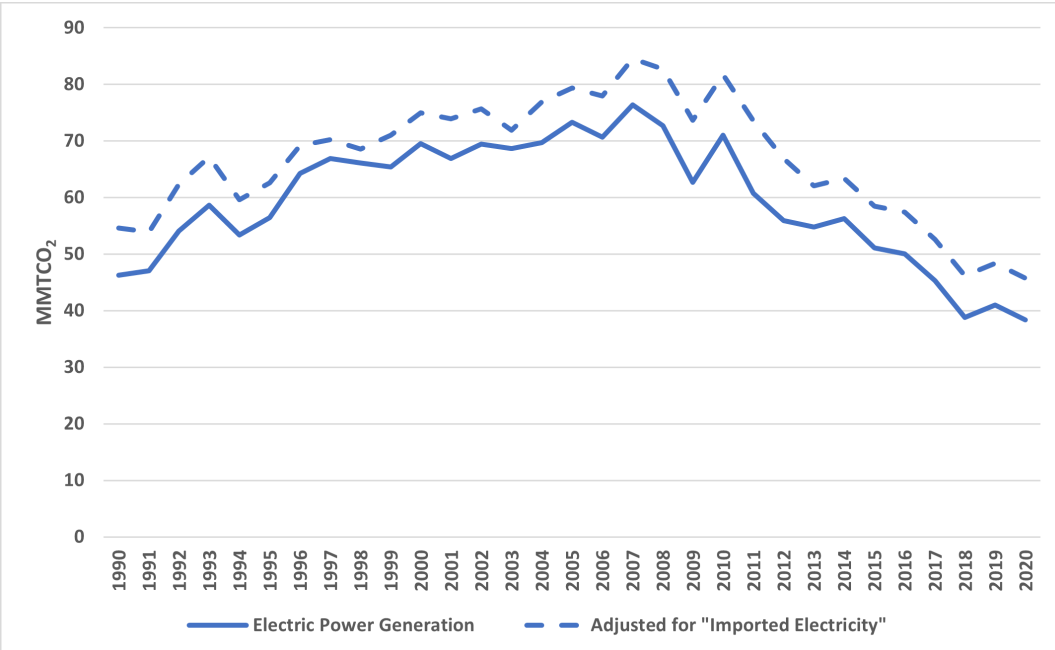
Figure F.2 shows that as of 2019, roughly one-third of NC generation is produced from nuclear units, another third from natural gas, and the final third was split between coal, hydroelectric, and solar units (with small contributions from other sources). This shift into natural gas and solar, and away from coal generation has had similar implications for emissions trends in the state, as shown in Figure F.3. That figure distinguishes between emissions from in-state fossil generation and an estimate of emissions associated with generating the electricity that is imported into North Carolina. This adjustment for "imported emissions" is also shown in some of the IPM and DIEM modeling results.

Figure F.2. North Carolina Generation Shares in 2019 (%)[66]



66. EIA Electric Power Monthly, https://www.eia.gov/electricity/monthly/#four.

Figure F.3. Emissions Trends in North Carolina Since 1990 (Metric Tons of Carbon Dioxide)[67]



Baseline Generation

As shown in Figures F.4 and F.5, both models expect the historical trend away from coal generation to continue in North Carolina. The generation mix across the two models is quite similar in 2030 with both expecting a shift into gas co-firing at coal plants that have been retrofitted to accommodate it. IPM retires more coal capacity than DIEM but runs the remaining coal units more often, which—though a small difference overall—will be sufficient to cause some divergence in the emissions projections across models. DIEM moves into new solar PV by 2030 in place of the existing coal, while IPM does not add new solar based on economics until after 2030. The greater expansion of turbines in IPM also increases its gas share and worsens the relative economics for solar.

Patterns by 2050 have shifted in both models away from coal—and to a lesser extent gas—and into renewables. Solar PV has quite similar shares by 2050 as IPM catches up with the DIEM installations between 2035 and 2050. DIEM moves into offshore wind, based on the economics, which allows it to reduce the remaining gas generation, while IPM maintains more gas with consequences for emissions.

67. North Carolina Department of Environmental Quality (DEQ). 2019. "North Carolina Greenhouse Gas Inventory (1990–2030). https://files.nc.gov/ncdeq/climate-change/ghg-inventory/GHG-Inventory-Report-FINAL.pdf. Data after 2015 include short-term projections to 2017, followed by longer-term estimates based on U.S. EPA's "State Inventory and Projection Tool (SIT)," as discussed in the GHG inventory report.

Baseline Total Capacity

Figure F.6 contrasts the total capacity of selected types of generation in the two models underlying the generation patterns in the previous figures, focusing on the types of capacity that might diverge between the two models in response to the CEP A1 policies (nuclear, hydroelectric, and other types of capacity show few changes over time and across the two models in the baseline forecasts). Although IPM has higher coal generation in 2030, DIEM estimates a higher remaining coal capacity. This low-utilization coal capacity is used to provide for reserve capacity needs and offset higher solar and lower turbine construction in DIEM, compared to IPM. By 2050, capacity is quite similar across the models with the exception that DIEM adds offshore wind that has different time-of-day generation patterns than solar, while IPM adds more batteries to help balance the solar generation.

Figure F.4. IPM Baseline Forecast of NC Generation in 2030 and 2050 (TWh and % Shares)

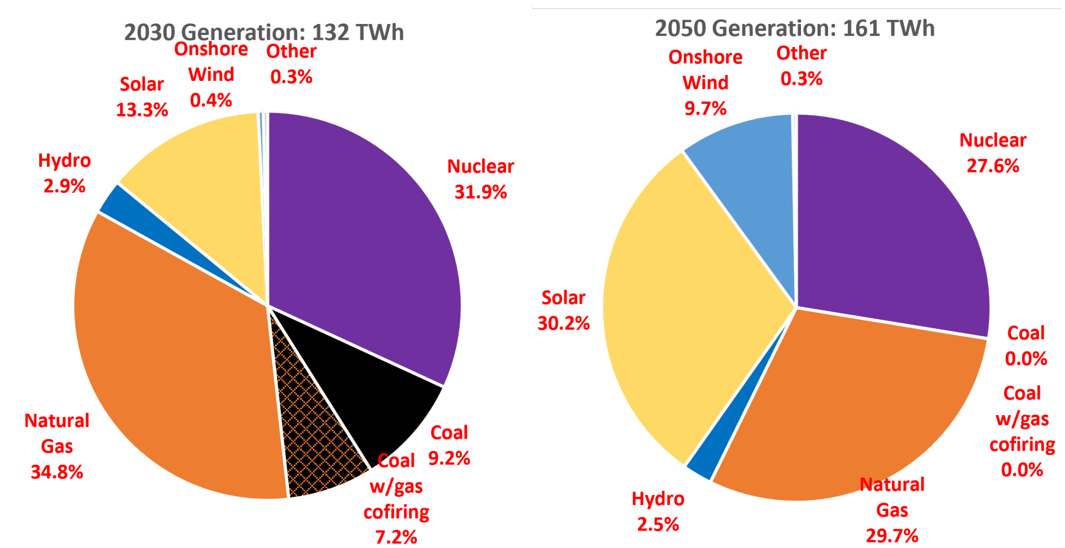


Figure F.5. DIEM Baseline Forecast of NC Generation in 2030 and 2050 (TWh and % Shares)

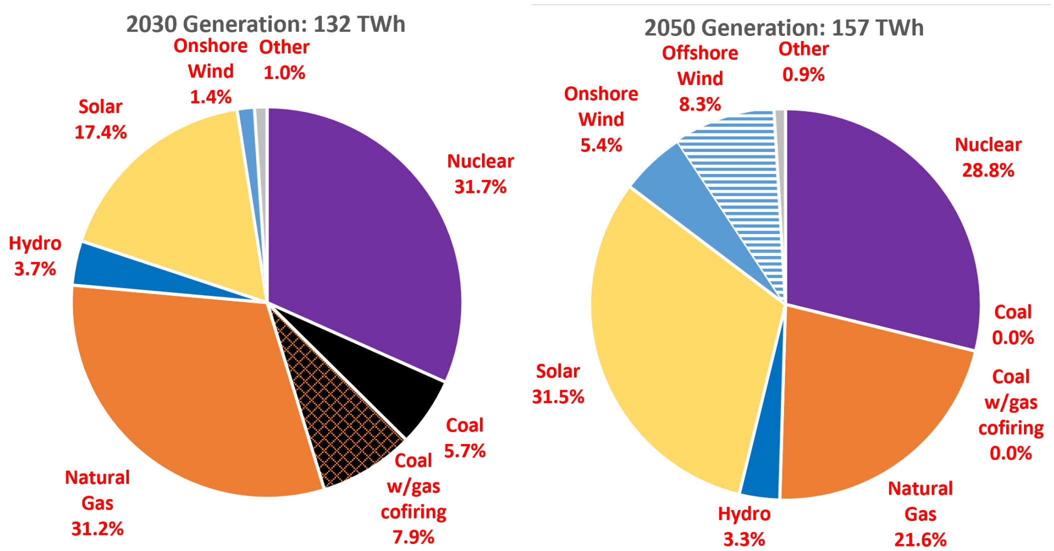
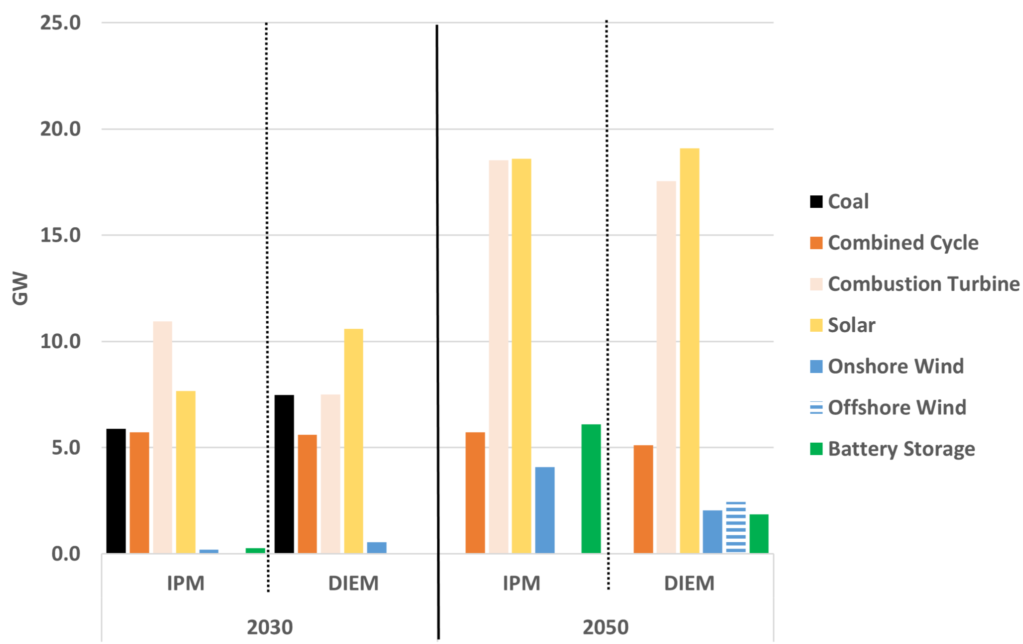


Figure F.6. Baseline Capacity in North Carolina – Selected Types (GW)

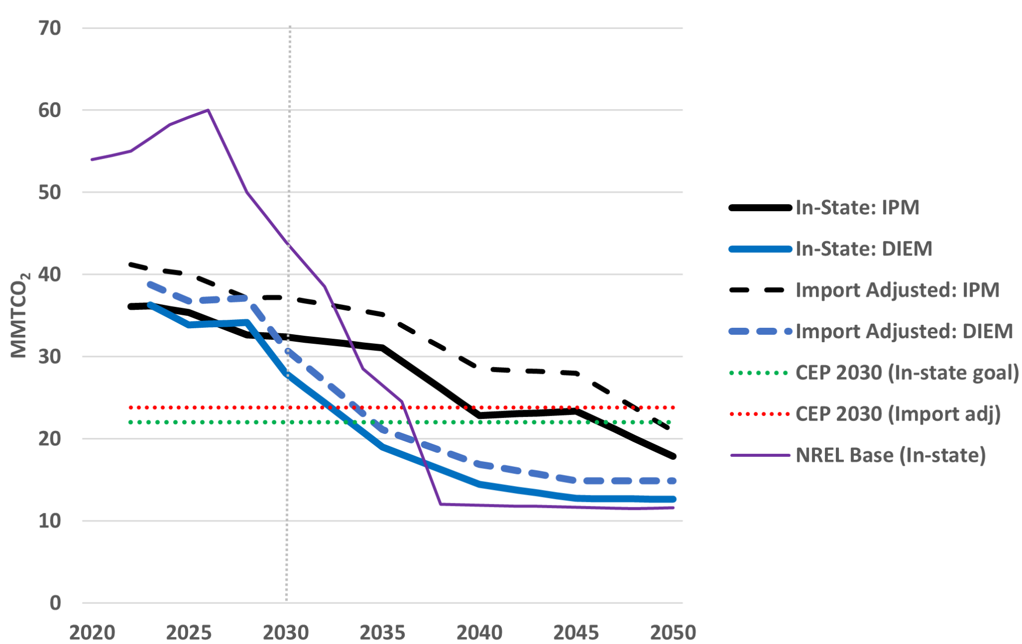


Baseline Emissions

As discussed in Section 6, Figure F.7 shows estimated emissions trends in IPM and DIEM forecasts, based on the estimates of generation and capacity in the two models. Emissions are separated into those from in-state generation (solid lines) and import-adjusted emissions (dashed lines) which include an estimate of emissions associated with generation of electricity elsewhere that is imported into North Carolina. CEP goals for 2030, whether based on in-state generation (in green) or import adjusted (in red), are shown as dotted horizontal lines.

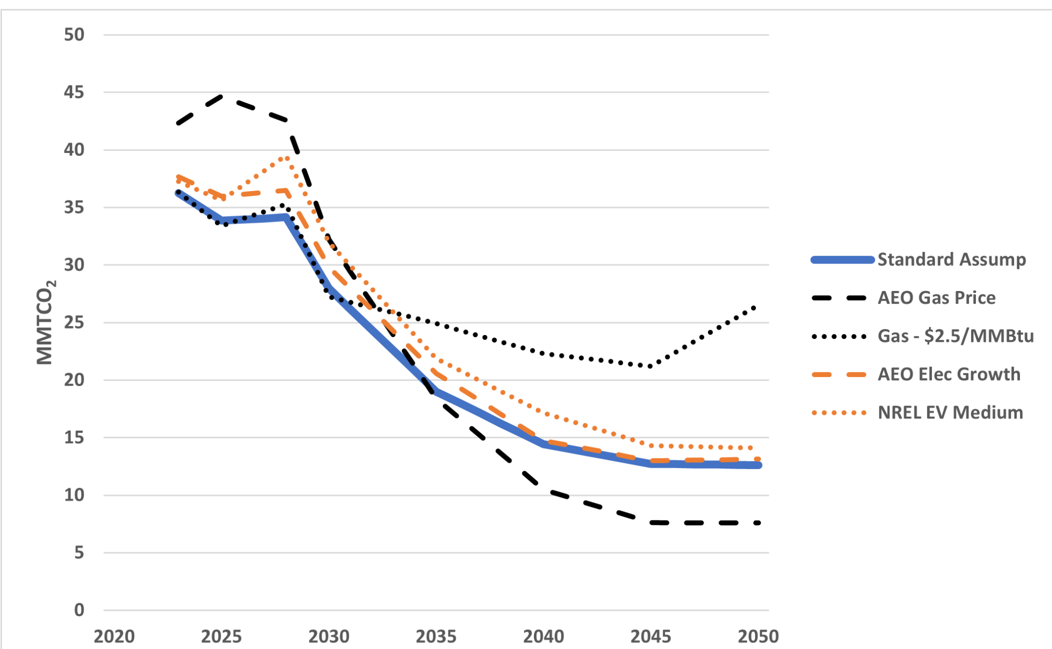
The figure shows that emissions through 2028 are very similar in IPM and DIEM. Starting in 2030, penetration of solar PV (and a small amount of onshore wind) in the DIEM baseline—versus a lack of new renewables through 2030 in the IPM baseline—lead to divergences in emissions estimates that continue through 2050. These differences occur largely because DIEM continues to shift out of coal between 2028 and 2030 (and into renewables), and IPM maintains coal generation between 2028 and 2030 (and increases coal generation in 2035 as gas prices rise and gas co-firing at coal plants becomes less cost effective). Figure F.7 also overlays emissions from a recent NREL analysis of the Duke Energy system and its ability to integrate carbon-free resources. The NREL estimated emissions are significantly higher than in IPM and DIEM over the first decade. After 2030, the overall trend in the NREL results, although starting from a higher point, follows a similar trend to DIEM for pace of renewables entering the system in the baseline forecast.

Figure F.7. Baseline Carbon Dioxide Emissions from Electricity Generation ($MMTCO_2$)



Although IPM and DIEM have relatively similar emissions in 2030, the contrast in the early years with the NREL results (and the difference between IPM and NREL in the later years) raises the question of how sensitive baseline trends may be to assumptions made during the CEP or the NREL analysis. Using the DIEM model, Figure F.8 looks at two sensitivities that have the most impact on emissions—gas prices and electricity demand (other sensitivities are shown later in this appendix). Compared with the "standard assumption" that gas prices start around $2.50/MMBtu and increase to around $3.20/MMBtu over the next dozen years, the use of AEO 2020 gas prices for the SERC-East region, which are around $1–$1.50/MMBtu higher than the "standard" assumptions (see **Appendix B**, Figure B-2), leads to baseline emissions that are significantly higher and more in line with the NREL ReEDS baseline trends.[68] In the near term, higher gas prices encourage coal plants to operate more and to use coal instead of gas. In the longer term, these higher gas prices lead to additional renewables, resulting in emissions below those in the "standard" baseline. In contrast, gas prices that remain low at $2.50/MMBtu through 2050 would eventually lead to additional gas generation and more limited construction of new renewables. Higher electricity demand, whether from overall higher growth rates or through increased penetration of electric vehicles ("NREL EV Medium" forecast from the NREL EFS study), increases total generation and thus emissions.

Figure F.8. DIEM Baseline Emissions from NC In-State Generation across Selected Sensitivities



68. This occurs even though coal prices in the IPM/DIEM modeling are relatively flat at around $2.95/MMBtu over time, compared with lower AEO 2020 forecasts for the South Atlantic region of around $2.50/MMBtu for coal.

Policy Cost Estimates

As discussed in Section 6 and expanded upon in this appendix, the policy costs in this report focus on wholesale costs associated with delivering electricity to meet grid demands in North Carolina. To recap, these costs include only those directly related to generating electricity: capital costs of new construction or retrofits or transmission (typically annualized for cost-reporting purposes); fixed operations and maintenance (O&M) annual expenditures; variable O&M costs, which are a function of the level of generation; and fuel costs. Within this overall framework, there are a number of important aspects to consider when evaluating policy cost estimates.

First, electricity dispatch models minimize policy costs over the entire model time horizon. This long-term approach to cost minimization can lead to short-term policy cost results that move counter to long-term results. Estimating shorter-term costs within the longer-term horizon of the modeling can be problematic because, for reporting purposes, capital payments are annualized (usually over 20 or 30 years) from the date of installation. Thus, over any particular reporting horizon, all the annualized capital payments may not have been fully realized. As these costs move farther into the future, the costs become less important in current discounted terms.

Second, costs can be expressed in a number of ways. The usual method is to compare the change in net present value (referred throughout this report as "NPV") between the policy and baseline cases. As noted in Section 6, NPV provides a simple metric that can be compared across policies, and best reflects how the models seek to minimize total costs of generating electricity. North Carolina often uses the NPV measurement to evaluate proposed regulatory policies.

The NPV measurement is often shown as a total dollar cost to the system over a given period of time—usually around 30 years and in these results, to 2050. Alternatively, NPV can be expressed as a cost per ton of emissions reduced, which also helps to assess the overall cost effectiveness of a policy at lowering emissions. Both expenditures and emissions reductions are typically discounted to achieve a comparable metric.

While total NPV costs are the most accurate way of showing how a model is estimating policy costs, they can obscure the timing of different types of costs. By contrast, annual costs show how the system is responding to a policy over time. Annual costs can be problematic, however, since at any specific point in time they under-represent the full impact of capital expenditures. Thus, when interpreting annual results, it is important to remember that capital costs projected for a particular year in the future represent a portion of the total capital cost of a new unit, which are spread over the next 20–30 years. In these results, for both models the number of payments for different types of units are based on IPM book lives—mainly 20 years for renewables and 30 years for turbines and combined cycle units.[69] (This is then contrasted in Figures F.12 and F.13 to an assumption in the DIEM modeling that capital costs for all units are annualized over 30 years, as is done in the EIA modeling underlying the AEO 2020).

69. See Chapter 10 in U.S. EPA "Documentation for EPA's Power Sector Modeling Platform v6" for a discussion of the book lives of units—https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-november-2018-reference-case.

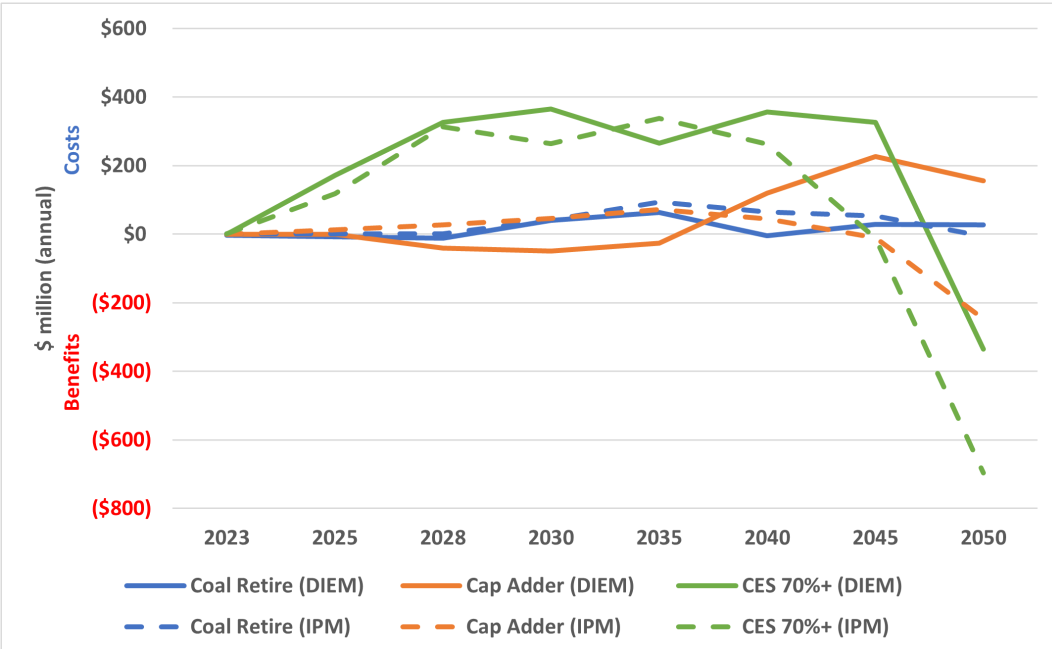
Figure F.9 presents the annual costs in IPM and DIEM that were used to calculate the NPV costs shown in Section 6 (Figs. 6.4 and 6.5) for the basic CEP policy options. Figure 6.5 showed DIEM's NPV cost estimates for the coal retirement policy as lower than IPM. The annual costs for this policy suggest that the two models have relatively similar estimates for most periods in the modeling, with the exception of 2040. This variation, along with a difference in cost estimates of $10–$15 million per year prior to 2030 (which are discounted less than future years when presenting NPV results), leads to the more substantial differences that were shown in Figure 6.5.

NPV costs for the carbon adder on new capacity were relatively close between the two models. As seen in Figure F.9, however, the annual costs behind this are less similar. DIEM suggests initial cost savings as new turbines, which would have been built in the baseline forecast, are not constructed in the policy case. Costs then increase over time as in-state renewables expand to counterbalance the lack of new turbines (see Figure 6.9). IPM, on the other hand, replaces what would have been turbines in the baseline forecast with imports of electricity and capacity, leading to higher costs in the early years, followed by a decline in annual costs in 2050.

Previous results in Section 6 indicated that estimated CES policy costs in DIEM were significantly higher than in IPM, in NPV terms. As seen in the figure below, however, through 2040 the annual costs behind these NPV are relatively comparable. Starting in 2045, IPM begins exporting increasing amounts of electricity as in-state renewables expand in response to the CES policy. A similar effect doesn't occur in DIEM until 2050, leading to the different estimates of NPV costs. Capital costs in both models also decline in 2050, compared to baselines that saw expansion of renewables delayed farther into the future than under the CES policy.

Given the patterns of annual costs and NPV costs in the two models for the CES policy, it is educational to look at a breakdown of annual costs into its components—see Figures F.10 and F.11 (keeping in mind the caveats about interpretation of capital costs when the payments shown in the reporting are spread out 20–30 years past the installation date). Both models show an initial increase in capital expenditures in 2028 as the sales-based CES requirement moves from 50% in 2025 to about 60% in 2028 (and then 70% in 2030 before heading to 95% in 2050).

Figure F.9. Annual Cost Changes for the Selected Basic CEP Policies (Compared to Baseline)



Post 2028, additional capital costs in the DIEM results are generally steady at a level that is 40%–50% lower than in IPM. This occurs because, as was shown in Section 6, the baseline in DIEM already constructs comparatively high levels of renewables, and thus it requires fewer additional installations to meet CES targets, compared to IPM. The other big driver of differences in annual costs is the changes in the estimated values of electricity exports.[70] Both models export electricity as a mechanism for meeting the CES goals, but export values are much higher in IPM, which offsets its higher capital cost—to the point that overall CES policy is cheaper in dollar terms in IPM than in DIEM. (Variations in fuel costs are comparatively less important, and differences are largely a function of additional expenditures on fossil fuels in the IPM baseline.)

Finally, Figures F.12a, F.12b, and F.13 use DIEM to look at how changing the assumption about annualizing capital costs over 30 years for turbines/combined-cycle units and 20 years for renewables ("20/30 yr") to the assumption that all capital costs are annualized over 30 years would affect policy cost results. The figures focus on the coal-retirement, CES (with and without an offshore wind requirement), and carbon adder on generation of $6 per ton growing at 7% per year (which for illustration purposes has larger changes than a carbon adder just on new capacity). As Figures F.12a and F12b show, switching to 30 years leads cost estimates to be lower across all three policies. However, the biggest change is in the CES policy that involves the largest investments in renewables. On a per-ton basis, the cost per ton reduced of the CES drops around

70. After discussions with the Technical Working Group, and the NREL and IPM modelers, it was decided to follow the standard practice in other models and value electricity trade at the marginal cost of providing electricity—where the importing state pays a price based on the cost within that state (i.e., a wholesale competitive price).

43% measured on in-state reductions and 35% measured on import-adjusted emissions. These changes can also be seen in total dollar terms in Figure F.13, which also shows how cost estimates for O&M, fuel, and net imports are unaffected.

Figure F.10. Annual Cost Changes in DIEM for the CES Policy (Compared to Baseline)

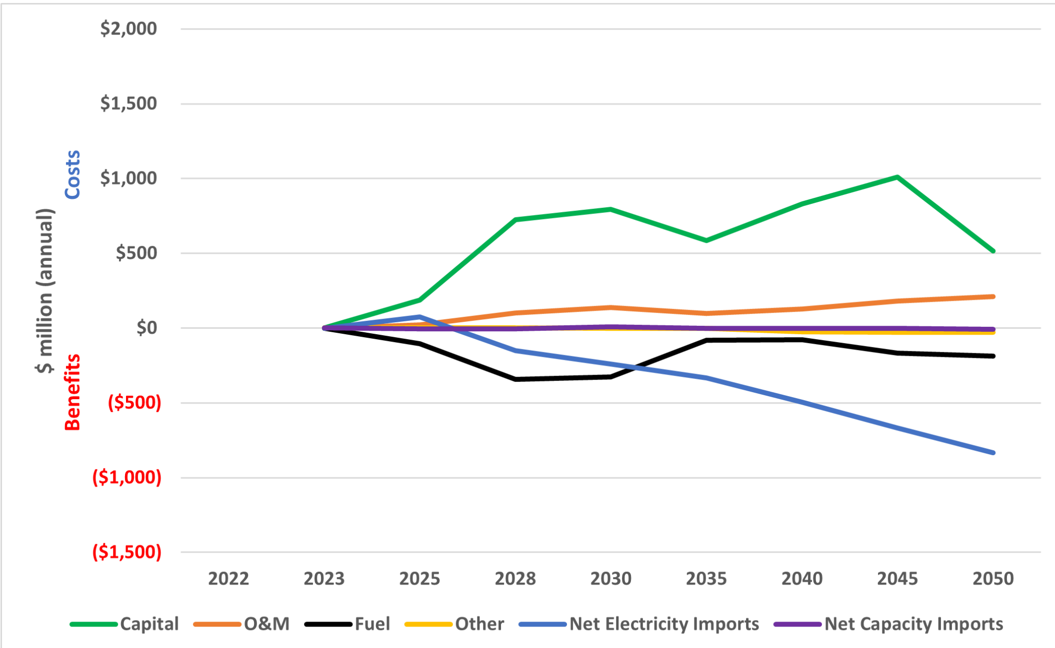


Figure F.11. Annual Cost Changes in IPM for the CES Policy (Compared to Baseline)

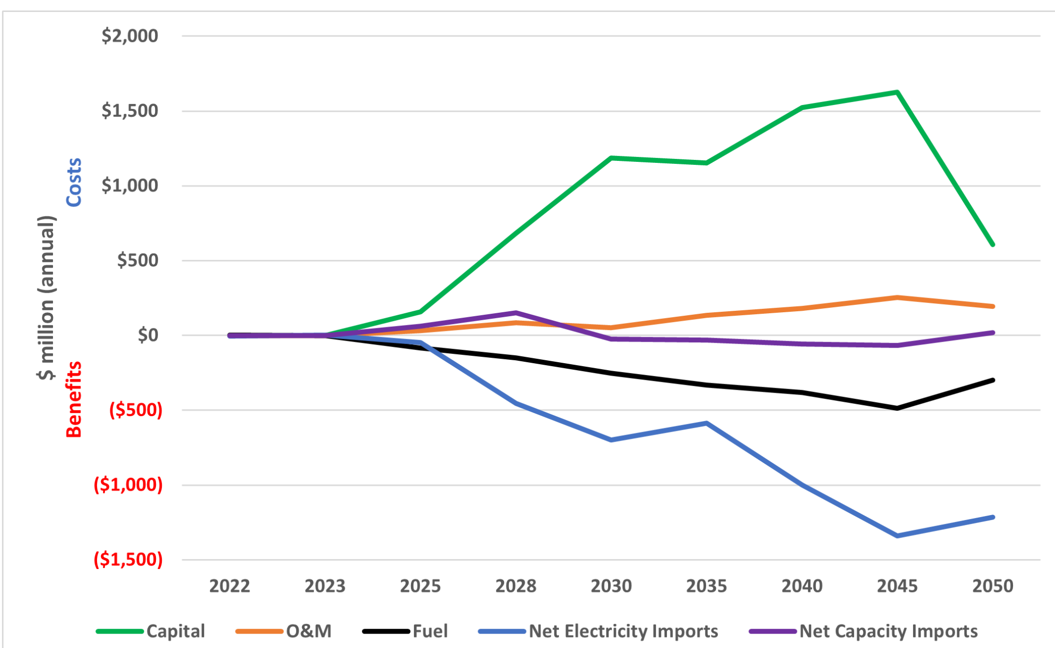


Figure F.12a. DIEM Costs of In-State CO_2 Reduction vs. Percent Reduction in CO_2 Emissions

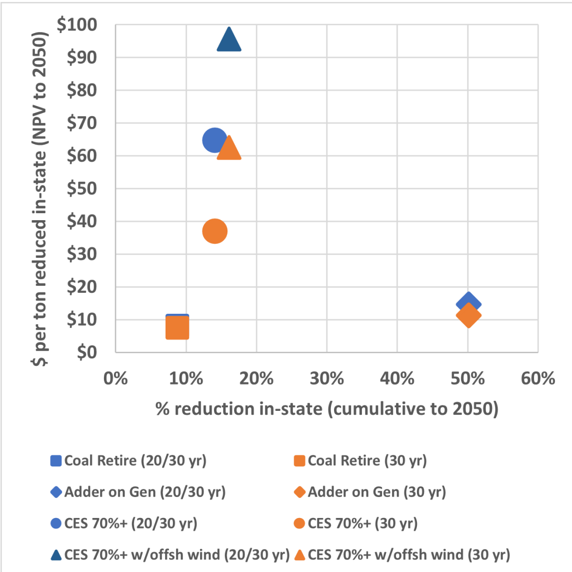


Figure F.12b. DIEM Costs of Total CO_2 Reduction vs. Percent Reduction in CO_2 Emissions

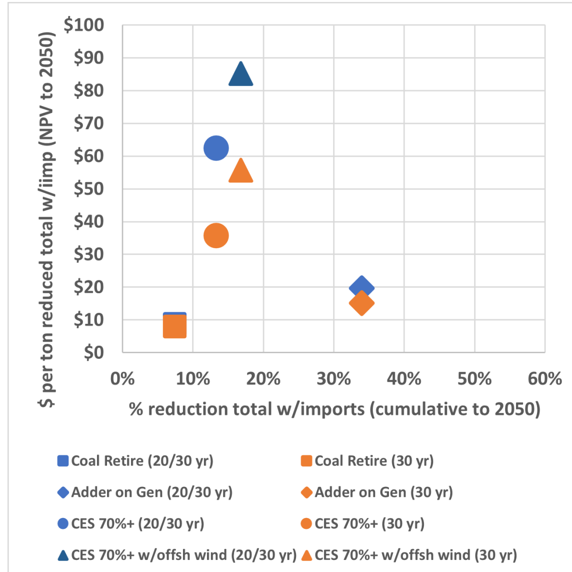
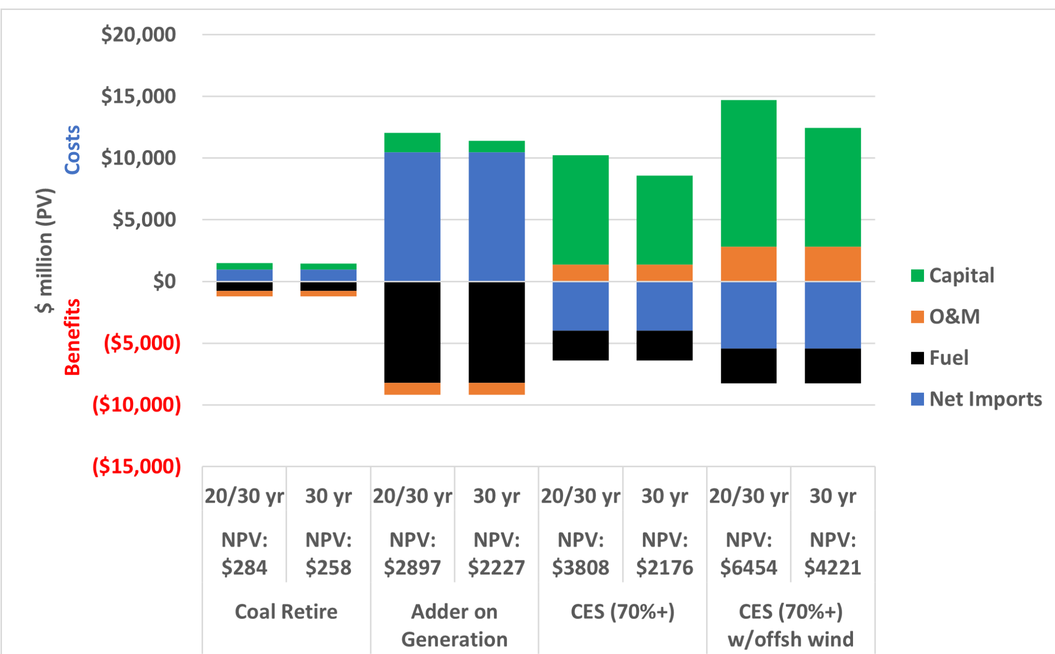


Figure F.13. DIEM System Cost Change in NPV through 2050 (Compared to Baseline)



Sensitivity Analysis of Policy Definitions and Market Trends

The rest of **Appendix F** examines how sensitive estimates of generation, capacity, and costs are to a range of policy outcomes and potential future market trends. First, results are given for IPM findings regarding a RGGI-plus-CES policy would be affected across energy efficiency and electric-vehicle assumptions. Then, DIEM results look at how policy responses may differ for an alternative generation-based approach to a CES, and also how participation by surrounding states in carbon adder and CES policies may affect how North Carolina's system responds.

IPM Sensitivities (CES + RGGI + EE, CES + RGGI + EV)

This part starts with some illustrative cost results for IPM runs looking at a CES combined with a RGGI policy—across different levels of electricity demand from either energy efficiency measures or higher electric-vehicle growth than in the standard assumptions. Neither the EE measures nor the electric-vehicle adoption have costs (or benefits) attached to them in these estimated IPM policy costs, which focus on costs to the electric system of providing electricity, as has been done previously. Therefore, normally cost results would not be presented for such scenarios, as they do not capture all relevant costs and benefits. However, for these cases the cost results are provided with the caveat that they must be interpreted with caution.

With this caveat in mind, Figures F.14a and F.14b contrast results from the basic CES+RGGI option shown in Section 6 (the black circle) with the same policy combination assuming the medium and high EE scenarios described in **Appendix B**. These CES+RGGI scenarios are being compared against a baseline that does not assume medium or high uptake of EE; therefore, the policies are presumed to be the reason for the additional EE. As a result, EE measures are counting towards the CES requirement and are displacing renewable generation that would have entered in place of the EE measures. Given this, the medium and high EE assumptions are not resulting in notably deeper emissions reductions.

Although cumulative emissions reductions in the EE cases are slightly less than for the CES+RGGI policy without the EE measures (see the generation results in Figure F.16), policy costs per ton reduced (within the electricity system) are significantly negative. Total costs shown in Figure F.15 are also significantly negative due to the lower electricity demand in the face of the EE measures. Costs are also lowered through meeting CES targets using EE measures (for free) that otherwise would have been met through construction of new in-state renewables. (Again, recall that the systems costs do not include the costs of the energy efficiency investments, which would offset some of these savings.)

The generation and capacity impacts of the CES+RGGI policy are shown in Figures F.16 and F.17. IPM suggest that, whether without or with the EE measures (beyond baseline levels from the IRPs), the model constructs large amounts of new renewables, which are used—in part—to allow the export of electricity as a way of meeting CES targets. Across the EE options, the CES combined with the EE measures still allows similar levels of operation by fossil units within the state. The capacity results show how EE has displaced construction of renewables.

Figures F.18a and F.18b show the costs per ton and cumulative CO_2 reductions to 2050 reported by IPM for the CES+RGGI scenario assuming NREL's "Medium" EV projection.[71] Unlike the EE sensitivities, where EE was only included in the policy run and not the baseline since it was assumed the EE measures were instituted in conjunction with the climate policy, the extra demand from EVs is assumed to be included in both the baseline and the policy runs. As a result, the cost per ton and percentage emissions reductions, compared to the baselines without and with EVs, are fairly similar. As shown in Figure F.19, additional capital expenditures are needed to meet the CES+RGGI goals, but present value costs are similar when compared to the respective baselines.

Figures F.20 and F.21 show the two baselines without and with demand from EVs, and compare them to the policy case runs. In broad terms, the results suggest that the extra demand from EVs is met through additional renewable generation in the CES+RGGI policy cases but would have led to an expansion of new combustion turbine generation without the climate policy.

Figure F.14a. IPM Costs of In-State CO_2 Reduction vs. Percent Reduction in CO_2 Emissions

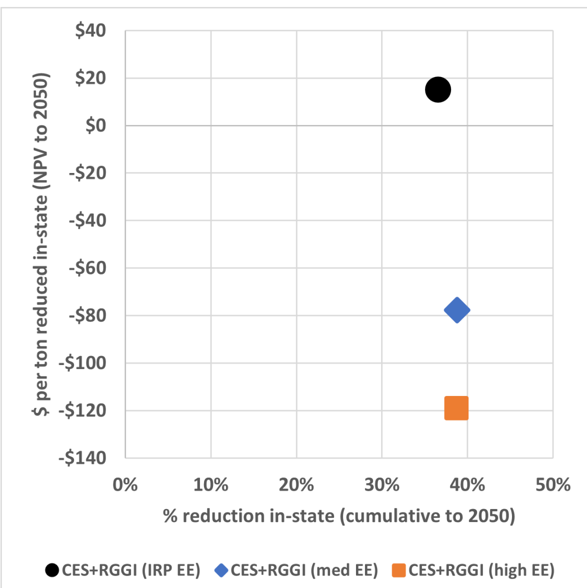
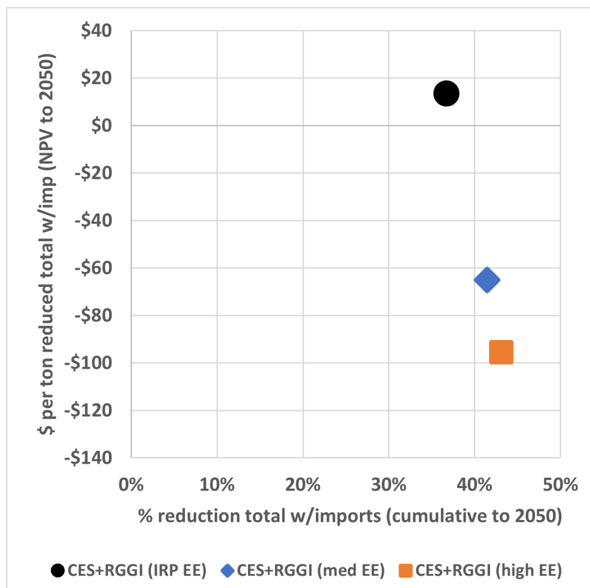


Figure F.14b. IPM Costs of Total CO_2 Reduction vs. Percent Reduction in CO_2 Emissions



71. Total demand in NC after including the EV forecast is 4.7% higher in 2030, 11.8% higher in 2040, and 13.9% higher in 2050, compared to baseline demand.

Figure F.15. IPM System Cost Change in NPV through 2050 (Compared to Baseline)

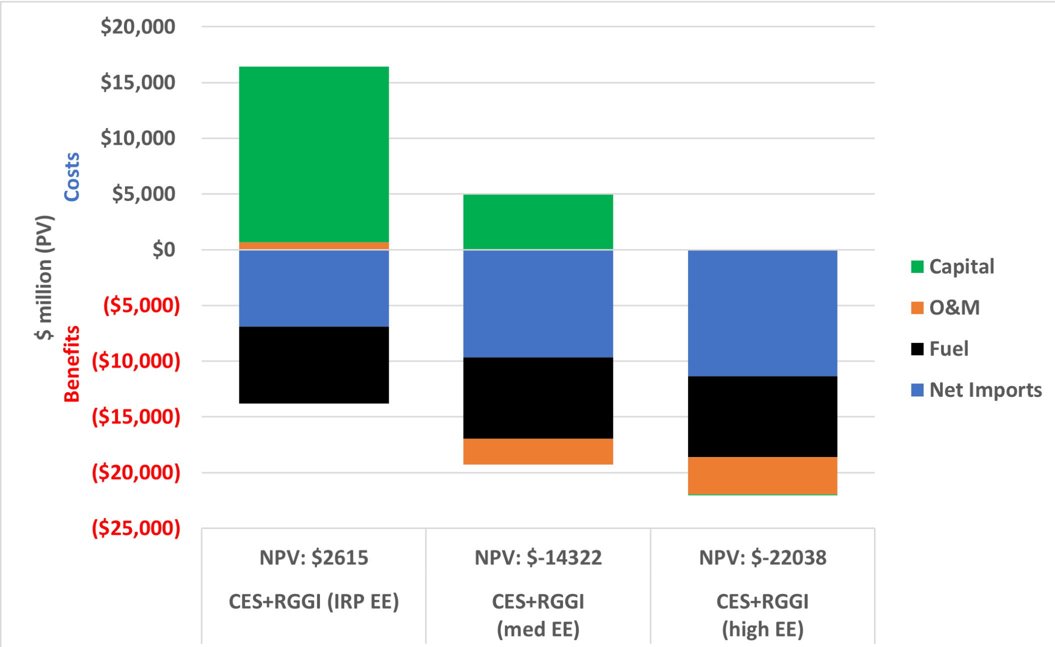


Figure F.16. IPM Combinations: NC Generation across CES+RGGI without/with Additional EE

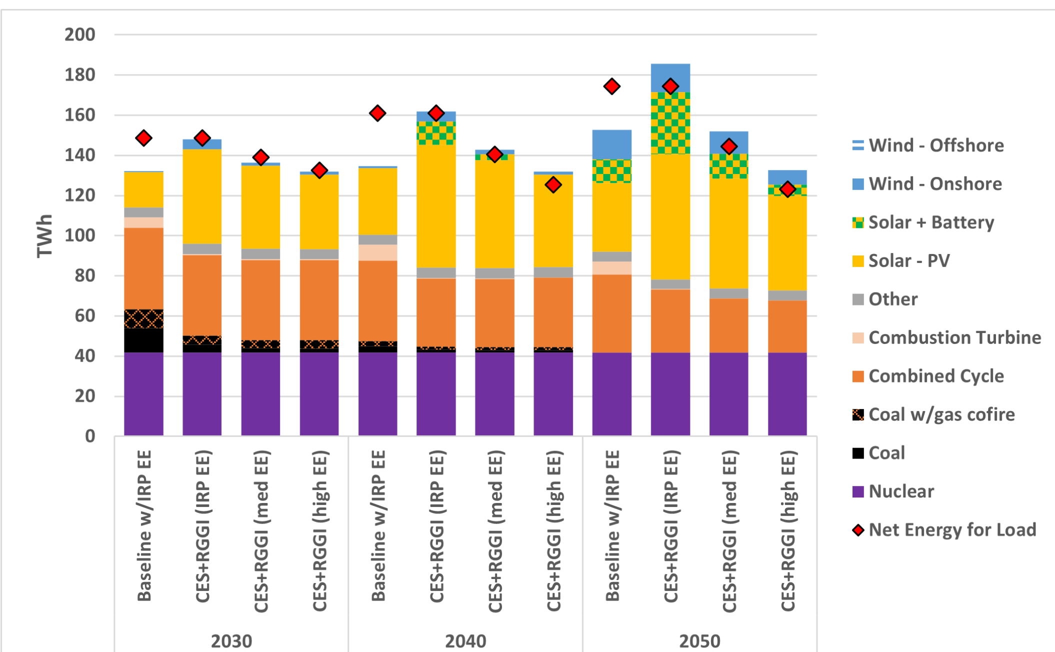


Figure F.17. IPM Combinations: NC Capacity Changes across CES+RGGI wo/w Additional EE

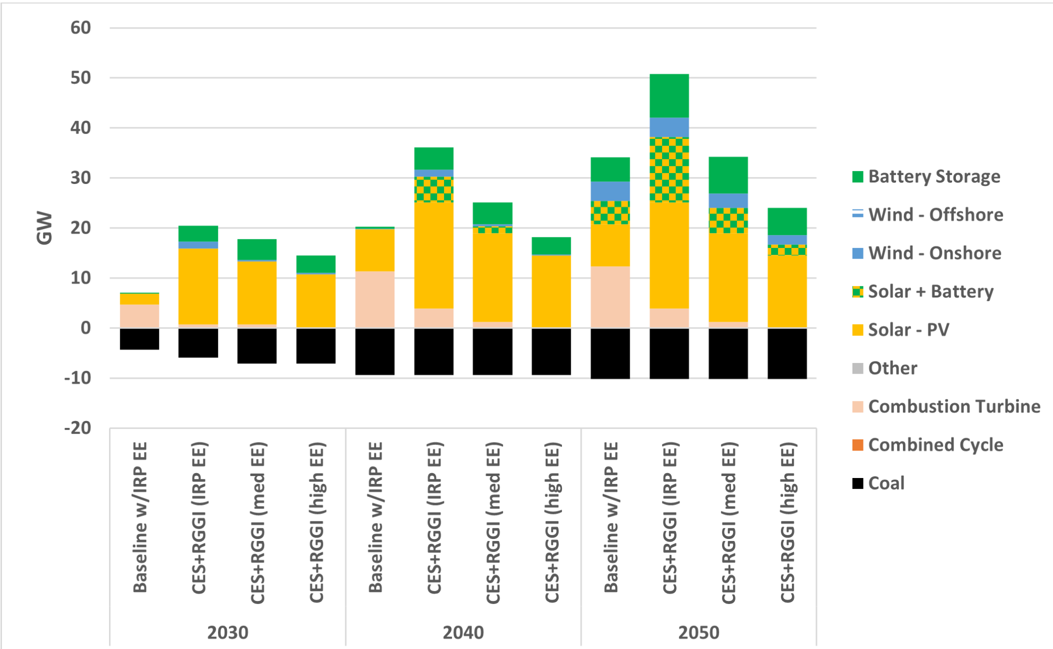


Figure F.18a. IPM Costs of In-State CO_2 Reduction vs. Percent Reduction in CO_2 Emissions

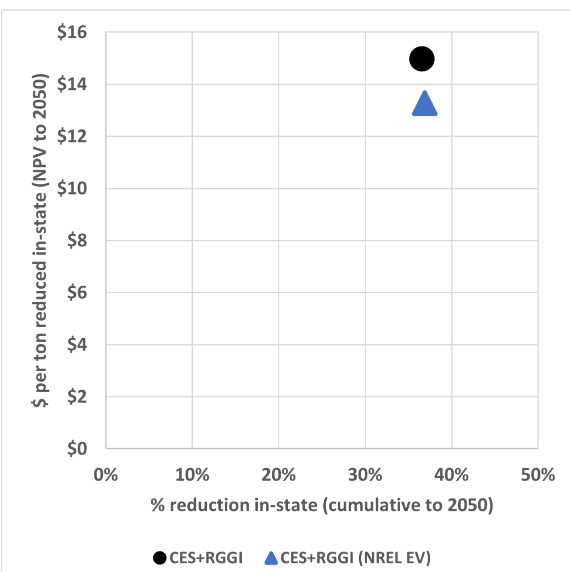


Figure F.18b. IPM Costs of Total CO_2 Reduction vs. Percent Reduction in CO_2 Emissions

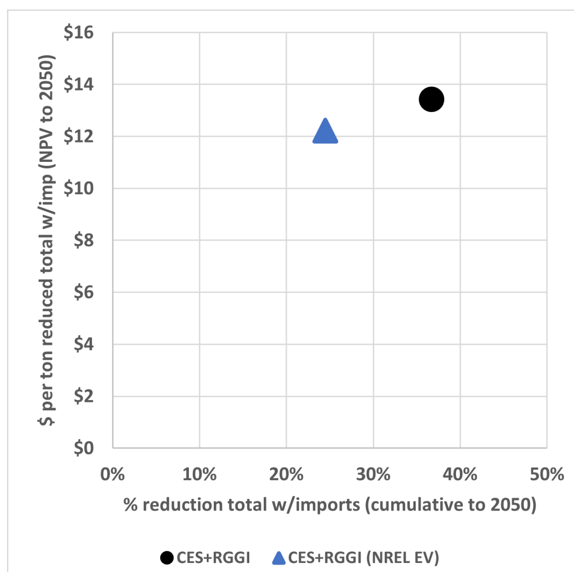


Figure F.19. IPM System Cost Change in NPV through 2050 (Compared to Baseline)

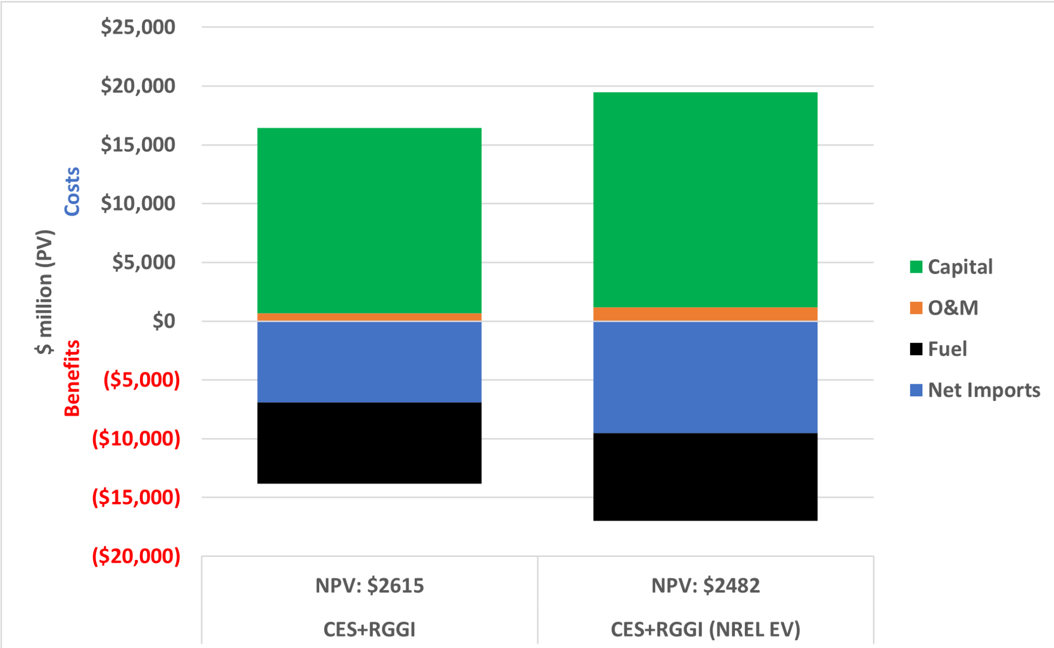


Figure F.20. IPM Combinations: NC Generation across CES+RGGI without/with NREL EVs

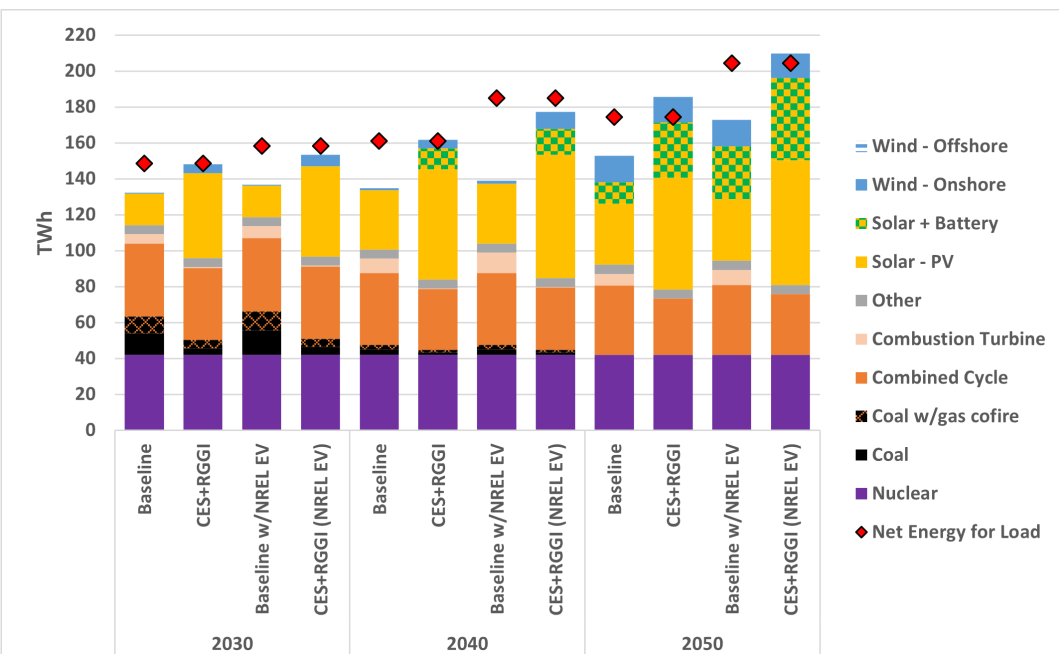
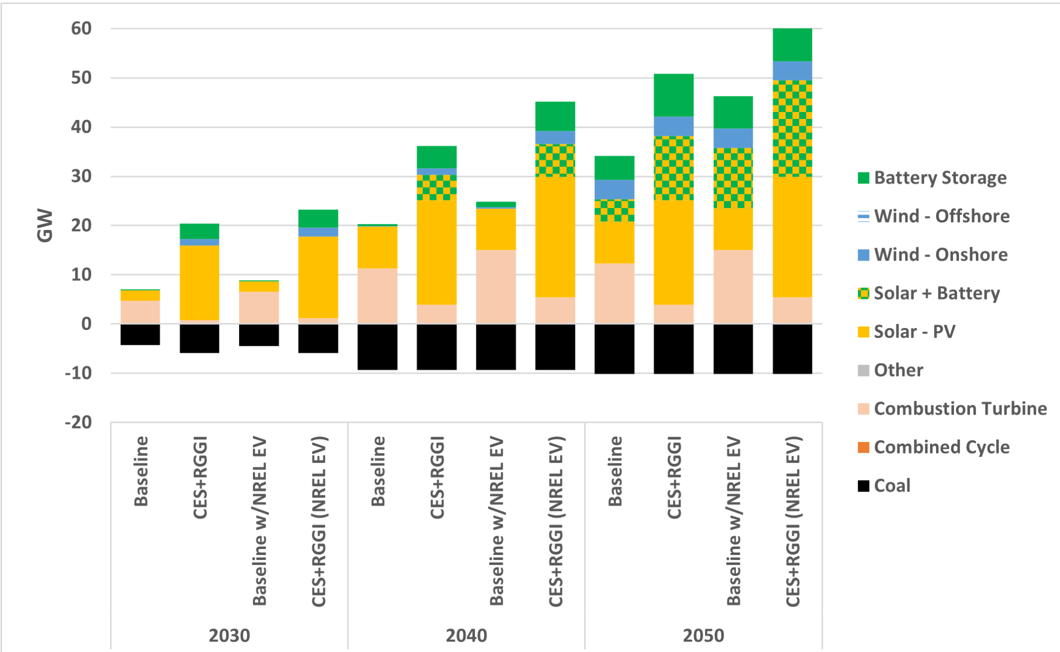


Figure F.21. IPM Combinations: NC Capacity Changes across CES+RGGI without/with NREL EV



Alternative Definitions of Policies and Geographic Scopes

Aside from the 12-state RGGI policy investigated in Section 6, the rest of the modeling assumed that North Carolina enacts climate policies without similar actions in other states (apart from existing policies such as Virginia's Clean Economy Act that are in the baseline of all model runs). Using DIEM, this part chooses two policy options that could potentially be instituted across all states to see how impacts on North Carolina might differ from those under a NC-only approach. It also looks at an alternative way of encouraging clean energy by using a NC emissions-rate goal across all generation.

The figures compare two NC-only policies from Section 6 with national policy alternatives:

(1) *Carbon Adder on Generation of $6/ton plus 7%/year* ***("$6+ (Gen) - NC")*** – for comparison to the alternatives, this is the basic carbon adder from Section 6 that affects generation decisions, starts at $6/ton in 2021 and grows at 7% per year thereafter. It applies only in North Carolina. The figures below report the outputs for this policy without and with a border adjustment for imported electricity based on its carbon content ***("$6+ (Gen) – NC imp adj").***

(a) NOW. The first carbon adder is run in DIEM but on the assumption that the carbon adder on generation is also adopted in states surrounding North Carolina ***("$6+ (Gen) – USA")***. Note that since the carbon adder is not part of a market-based "trading" approach, North Carolina cannot sell or purchase allowances from other states to enhance the flexibility of the policy and lower costs. This run is therefore testing the effect of a less flexible policy being imposed nationally.

(2) *Clean Energy Standard of 65% in 2030 growing to 95% in 2050* ***("CES (65%+) - NC")*** – this is a "clean energy" target (expressed as a percentage of retail sales) that begins with 50% clean energy in 2025, increases in linear fashion to a 65% target in 2030, and then proceeds along a different linear trajectory to achieve a 95% "clean" energy target by 2050. It is applied only in North Carolina. The 65% target for 2030 is used in these runs since, in the DIEM results, it is more equivalent to achieving the CEP 2030 emissions goal than the 70% used in Section 6 (because that was the level of "clean" necessary to achieve the CEP 2030 target in IPM).

   (a) NOW. The 65% by 2030 Clean Energy Standard is run in DIEM but on the assumption that all states adopt the same CES policy as North Carolina, starting in 2025. This case assumes each state has the flexibility to buy or sell CES credits, therefore testing the effect of a more flexible national policy ***("CES (65%+) - USA")***.

   (b) *Emissions Rate that Targets CEP 2030 and 2050 Goals* ***("Emis Rate (CEP)")*** – this is a North Carolina specific approach to meeting CEP emissions targets, similar to a CES, but it attempts to define an emissions rate that will reach 22 $MMTCO_2$ from in-state generation in 2030 and "net zero" emissions from in-state generation in 2050. The modeling iterates towards a rate, defined over in-state retail sales, that generally meets these goals. The policy is not applied in other states.

Figures F.22 and F.23 show in-state generation and import-adjusted emissions for North Carolina. As seen previously, a carbon adder on generation in the state results in a quick decline in in-state emissions (through a reduction in generation and increase in imports). However, adjusting for the emissions content of imports results in higher in-state emissions as imported electricity becomes less attractive as a method of avoiding the NC-only carbon adder. These two emissions trends can be compared to those from the carbon adder applied to all states ("*$6+ (Gen) – USA*"). In this case, NC emissions do not show the initial drop as all states now face the same increase in generation costs, meaning that prices of imported electricity will rise by an amount comparable to the rise in in-state prices.

While trends across the three carbon-adder alternatives are similar regardless of other state action, the emissions outcomes between the NC-only and USA-wide CES differ widely. The 65% clean target in 2030 was defined based on what would roughly be needed to achieve CEP 2030 targets in DIEM. This led to modest declines in emissions over the first decade and then generally tracks the DIEM baseline that focuses on new renewables, rather than fossil generation. Extending the geographic scope of the CES policy to surrounding states, however, results in significant changes within North Carolina. The sharp decline in in-state generation emissions suggests that the state is better positioned to add renewables that at least some other states in the country. This leads to quicker reductions locally and, as will be seen in the cost results, the selling of CES credits to other states based on overcompliance with policy targets in North Carolina. This level of in-state reductions depends on the national policy being coordinated and efficient so that the state can realize the benefits of exceeding the targets locally.

Finally, the emissions rate policy reaches CEP targets for emissions from in-state generation. The emissions rate approach does not, however, provide an easy way of addressing emissions associated with imported electricity and, as seen in Figure F.23, these trends may not meet CEP 2030 or 2050 goals without additional ways of handling "imported" emissions.

Figure F.22. NC In-State Generation Emissions across Alternative Policy Definitions

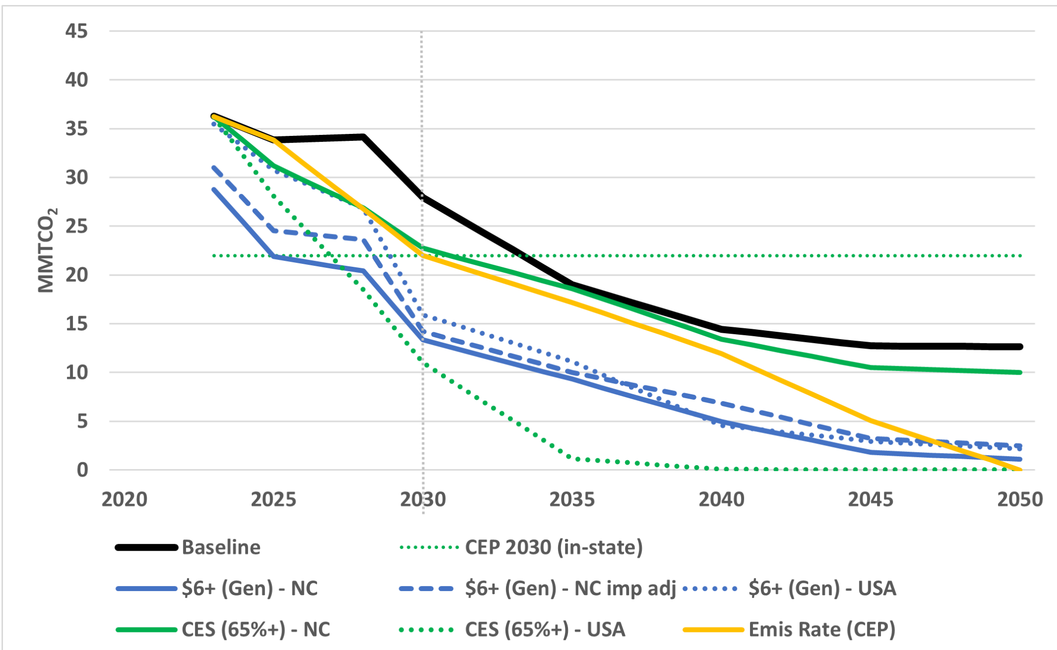
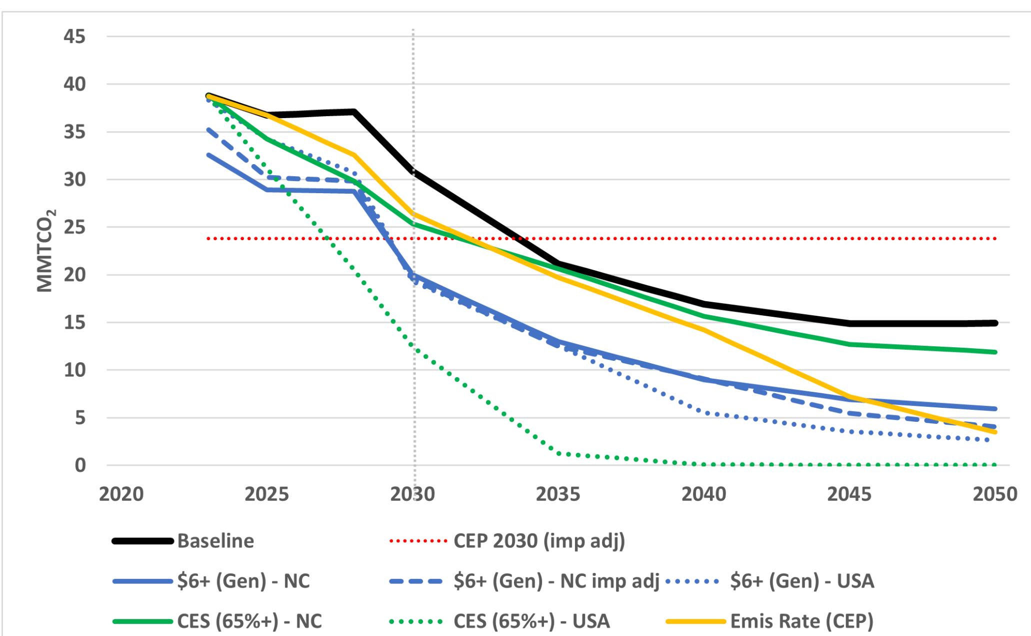


Figure F.23. NC Import-Adjusted Emissions across Alternative Policy Definitions



As was discussed in Section 6 and seen in Figures F.24a and F.24b, a carbon adder on generation is a cost-effective way of achieving potentially significant emissions reductions, although accounting for emissions associated with imported electricity (Figure F.24b) lowers the benefits. Adjusting the policy definition so that it accounts for imports ("NC imp adj" in both Figure F.24a and F.24b) raises the costs per ton and lowers cumulative emissions reductions. If the carbon adder is adopted nationally, costs per ton within North Carolina are higher than in either of the NC-only approaches and emissions reductions are lower. This implies that North Carolina has less flexibility to reduce the costs of a carbon adder by relying on generation in other states, if those states are also adopting the carbon adder.

A CES policy adopted within the state, as seen previously, can potentially have limited emissions reductions at a relatively high cost per ton.[72] Implications are different for a national CES, which has a lower cost per ton of reductions as the result of spreading costs across a larger quantity of emissions reductions. The emissions rate policy has a cost around $16/ton reduced in present-value terms and cumulative reductions of 19% over 2023–2050, where there are reductions in the first decade of the policy and then again towards 2050.

Figure F.24a. Cost of In-State CO_2 Reduction vs. Percent Reduction in CO_2 . Emissions

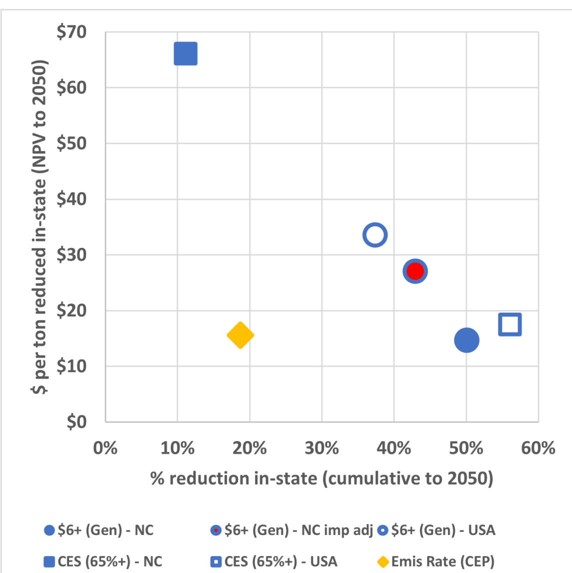
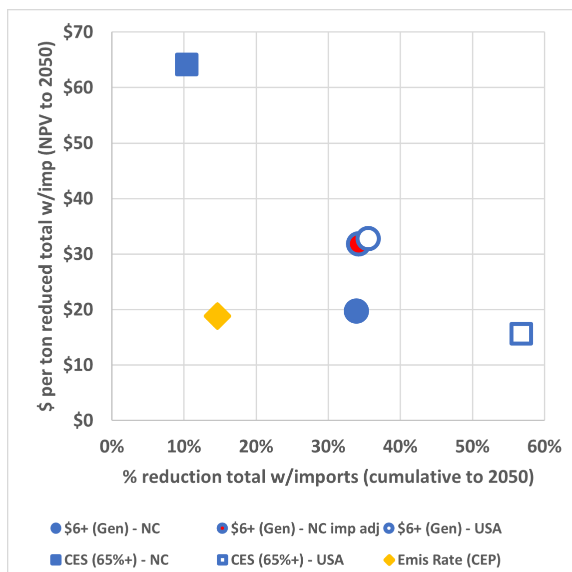


Figure F.24b. Cost of Total CO_2 Reduction vs. Percent Reduction in CO_2 Emissions



The first two columns in Figure F.25 were seen in Section 6 and illustrate how in the first case, an NC-only adder without any accounting for imports, the costs are largely those related to imported electricity as in-state generation declines. The adder with the import adjustment encourages investment in more low- or zero-carbon generation in North Carolina and shifts

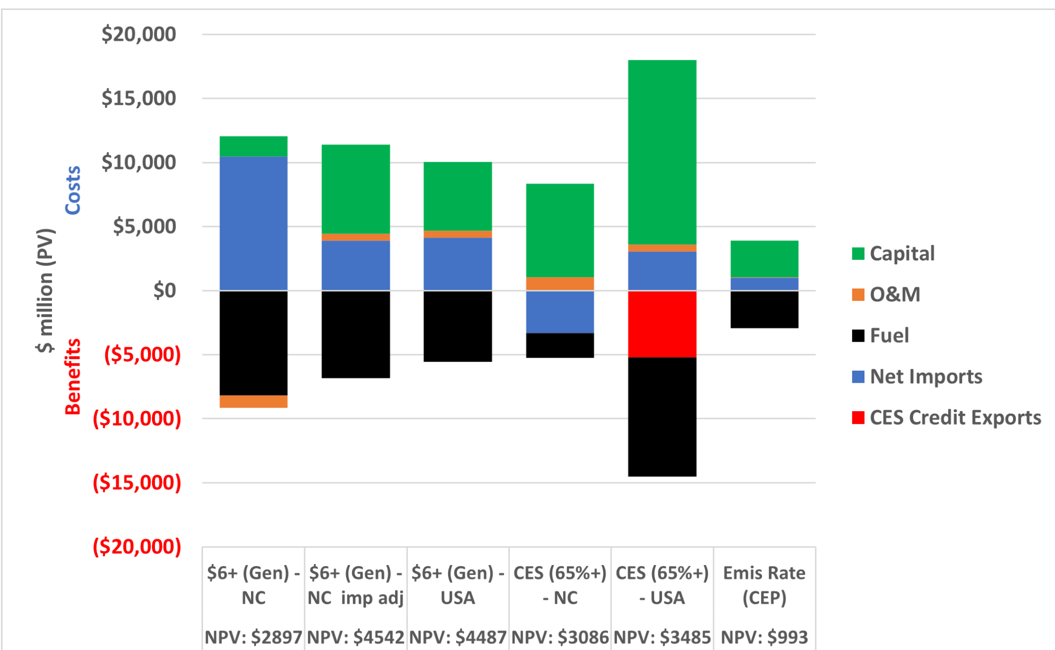
72. As described in Section 7, however, in-state clean energy directives drive job creation and economic activity, which can offset some of the rate impacts.

the cost mix towards the capital associated with these investments and away from imported electricity. A national carbon adder has similar implications for in-state investments at a roughly similar total cost.

The CES costs for the NC-only policy are also concentrated in in-state capital expenditures (the 65% target in 2030 results in few electricity exports than the 70% CES option shown in Section 6). The costs to the North Carolina system of a national CES are somewhat higher in total than the state-only approach, and the mix of costs shifts significantly. The additional in-state investments in clean generation lead to higher capital expenditures, which are partially offset through the selling of CES credits to other states ("CES Credit Exports").

Finally, the NC-only emissions rate policy has lower total NPV costs than the other options. In part, this is because it achieves fewer emissions reductions and, in part, it is due to the timing of the costs. As was seen in Figure F.22, there are some initial emissions reductions in the first decade, followed by a decade in which the emissions trend is similar to that seen in the baseline forecast. Then, as in-state generation moves towards zero emissions in 2050, the policy costs increase as a result. However, as these future costs to the system from 20–30 years in the future are discounted back to the present, total costs over the entire policy horizon appear relatively modest, regardless of any more substantial increase towards 2050.

Figure F.25. System Cost Change in NPV through 2050 (Compared to Baseline)



Fossil generation declines the most for the NC-only carbon adder on generation. In 2030, pricing imports based on carbon content shifts some of this generation back to North Carolina, as does a nation-wide adder. The shift into imports is even larger in 2050 for the NC-only adder, but by this point the import adjustment to the adder results in more in-state generation than the nation-wide policy does. Across all three adder alternatives, gas generation is largely gone by 2050 (coal has already retired by this year as all units have reached the end of their depreciation lives).

The NC-only CES has small increases in renewable generation by 2030 without much effect on fossil generation. A national CES has more substantially reduced fossil generation in 2030 as North Carolina begins to transition towards increased in-state renewables and the selling of CES credits discussed previously. By 2050, an NC-only CES still has gas generation comparable to the baseline forecast (with additional renewables used to meet policy goals while maintaining the fossil units). A national CES, however, has eliminated in-state gas generation by 2050 and increased in-state renewables even more as other states have also moved to high levels of in-state renewable generation and are less likely to purchase extra electricity from North Carolina, as seen under the NC-only CES alternative.

The emissions rate approach to encouraging clean generation does not have much effect on renewables in 2030 but reduces in-state fossil generation as a way of reducing the state system's emission rate. By 2050, the policy has shifted the in-state gas generation seen in the baseline forecast into solar and batteries.

Figure F.26. NC Generation across Alternative Policy Definitions (2030–2050)

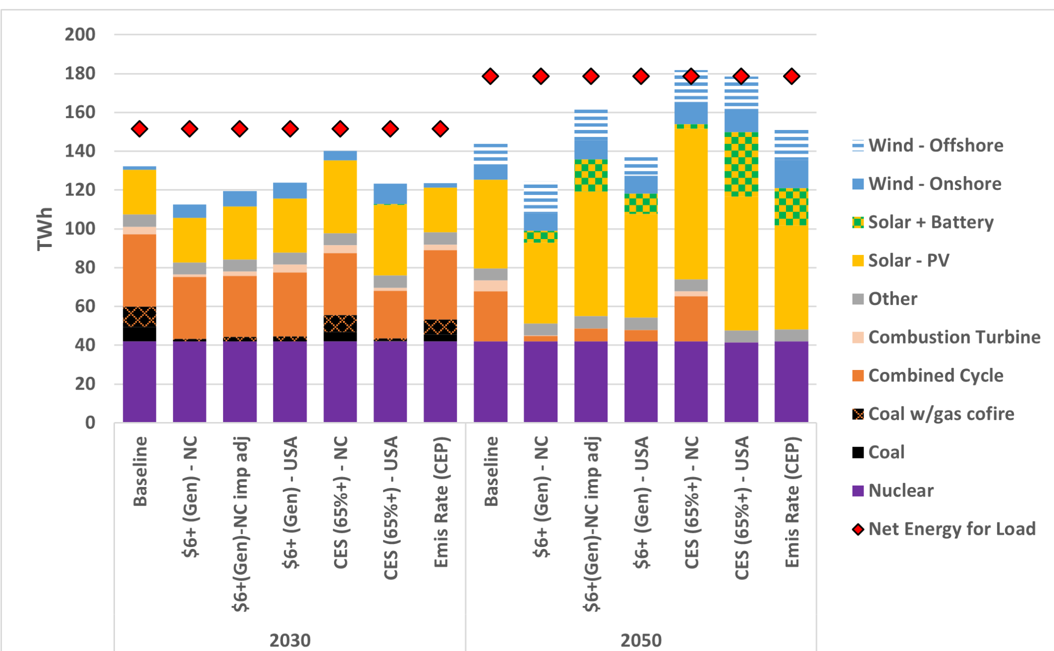
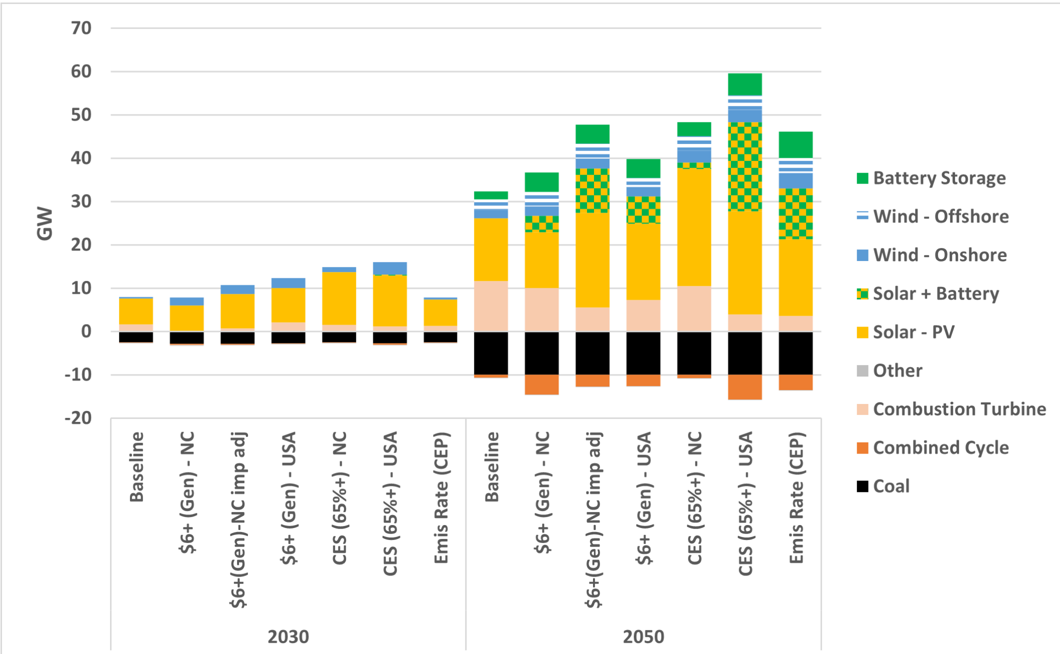


Figure F.27. NC Capacity Changes across Alternative Policy Definitions (2030–2050)



Sensitivity Analysis on the Market Trends

Next, DIEM was used to examine how sensitive estimates of generation, capacity, and costs are to possible changes in assumptions about future market trends, using the two different ways of approaching emissions reductions: a carbon adder on generation—which targets fossil generation, ***"$6+ Adder (Gen)"*** versus a Clean Energy Standard—which targets renewable generation, ***"CES (65%+)."*** The sensitivities investigated include natural gas prices, electricity demand growth, energy efficiency alternatives, trends in the costs of renewables, and battery storage assumptions.

One thing to keep in mind when interpreting sensitivity results is that—unlike the EE results shown in the IPM policy runs above where EE only enters the system as a consequence of a climate policy—the market trends occur in both a policy run, and the baseline that the policy is compared against (i.e., the policy does not determine the market trends). For example, high gas prices will make both the baseline and a policy cost more in total. However, the relative difference in cost between a baseline and a policy with lower gas prices may be larger than the difference in cost between a baseline and a policy when gas prices are higher. While this will not always be the case, it is possible for policy impacts in the sensitivity cases below to move in what might appear to be counterintuitive directions.

Note that the carbon adder runs are once again for policies in which North Carolina adopts a generation adder on its own, without the surrounding states following suit. In general, this leads to reductions in in-state fossil generation and increased reliance on imported electricity.

Gas Price Sensitivities

The gas price alternatives compare the following four alternatives:

(1) *Standard Assumptions* ***("Std Assump")*** – This is the "standard" assumption used in the previous analyses, for contrasting with the policy variants. The gas prices are shown in Figure B.2.

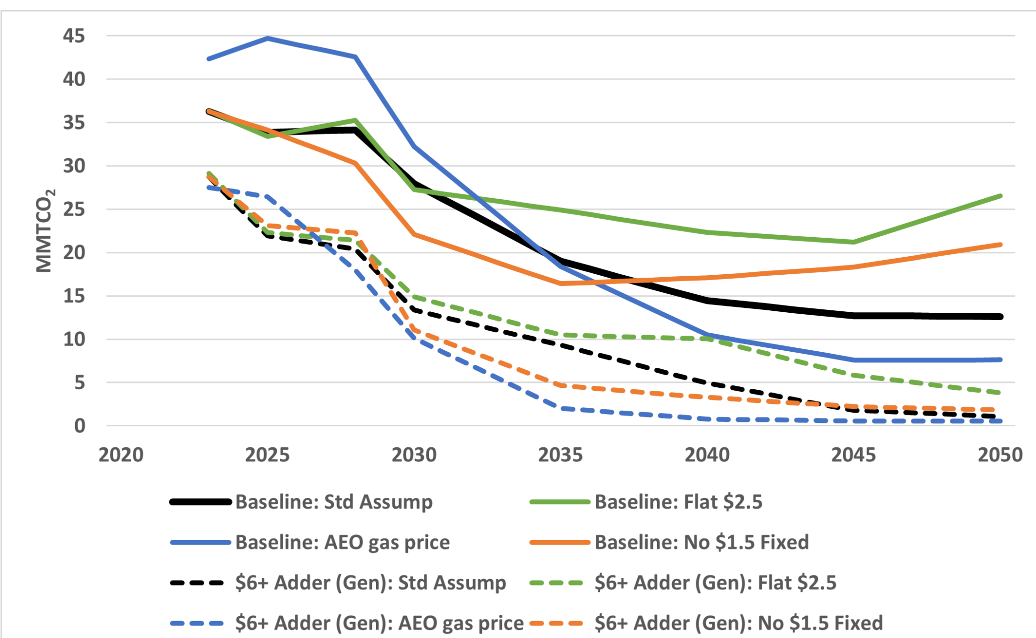
(2) *Flat Gas Price at $2.5/MMBtu* ***("Flat $2.50")*** – The case holds gas prices flat at $2.50/MMBtu through 2050.

(3) *AEO 2020 Reference Gas Price* ***("AEO Gas Price")*** – This case uses the AEO Reference Case gas prices from the Carolinas region (see Appendix B, Figure B.2) that start at around $3.50/MMBtu in the next few years and grow to around $4.50/MMBtu by 2028.

(4) *No Fixed $1.50/MMBtu Charge for New CC* ***("No $1.50 Fixed")*** – This case removes the assumption that new combined cycle units would face an additional fixed charge of $1.50/MMBtu (applied as an annual charge) in order to secure firm gas capacity.

The first figure shows how the alternatives affect baseline emissions and emissions under a carbon adder on generation. The highest emissions are for the alternative where gas prices remain at $2.50/MMBtu in perpetuity. In comparisons, while high gas prices (represented by the "AEO gas price" case) initially lead to higher emissions as coal plants run more in the near term, eventually the higher prices discourage existing combine-cycle generation and the construction of new turbines.

Figure F.28. Adder on Generation: Emissions from NC In-State Generation across Gas Prices



Policy costs (Figs. F.29a, F.29b, and F.30) show some variation in costs per ton reduced, with costs ranging between $12/ton and $20/ton in net present value terms for in-state reductions (with cumulative emissions reductions between 50% and 64%)—and $17–$36/ton for total import-adjusted reductions with cumulative effects of 27%–56%. However, there is more variation looking at the total NPV costs of the carbon adder across the gas price alternatives (Figure F.30). For example, the "AEO gas prices" lead to larger capital expenditures in the state, compared to the other alternatives that have higher import expenditures.

In Figures F.31 and F.32, the results show that higher imports are a policy response across the gas price alternatives (the differences between the "net energy for load" point and the generation bar in Figure F.25). Removing the assumption that there are additional costs associated with securing firm gas capacity for new combined cycle units ("No $1.50 Fixed") leads to construction of 7 GW of new CC units in the baseline that are not needed if the carbon adder policy were instituted. Lower gas prices discourage renewables in both the baselines and policy runs.

Figure F.29a. Adder on Generation: Cost per In-State Tons Reduced vs. % Reduction across Gas Prices

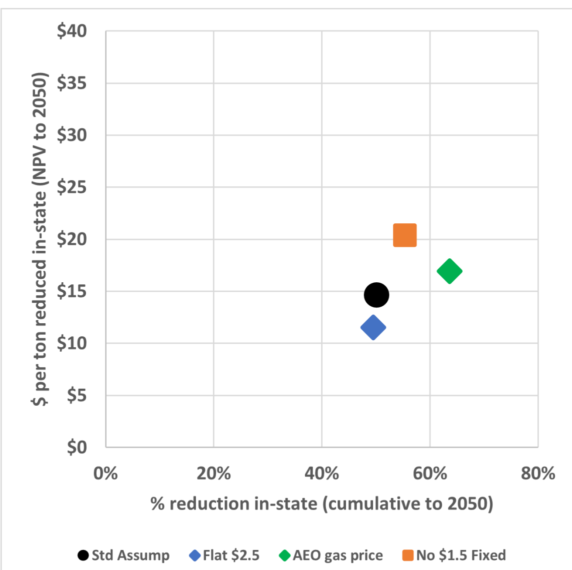


Figure F.29b. Adder on Generation: Cost per Total Tons Reduced vs. % Reduction across Gas Prices

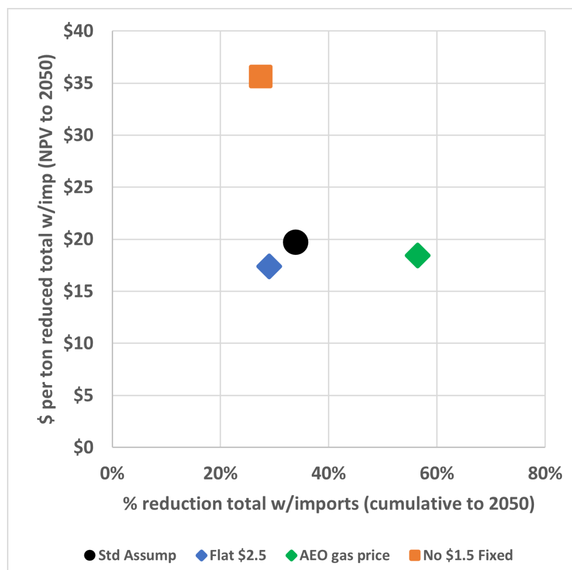


Figure F.30. Adder on Generation: Cost Change in NPV through 2050 across Gas Prices

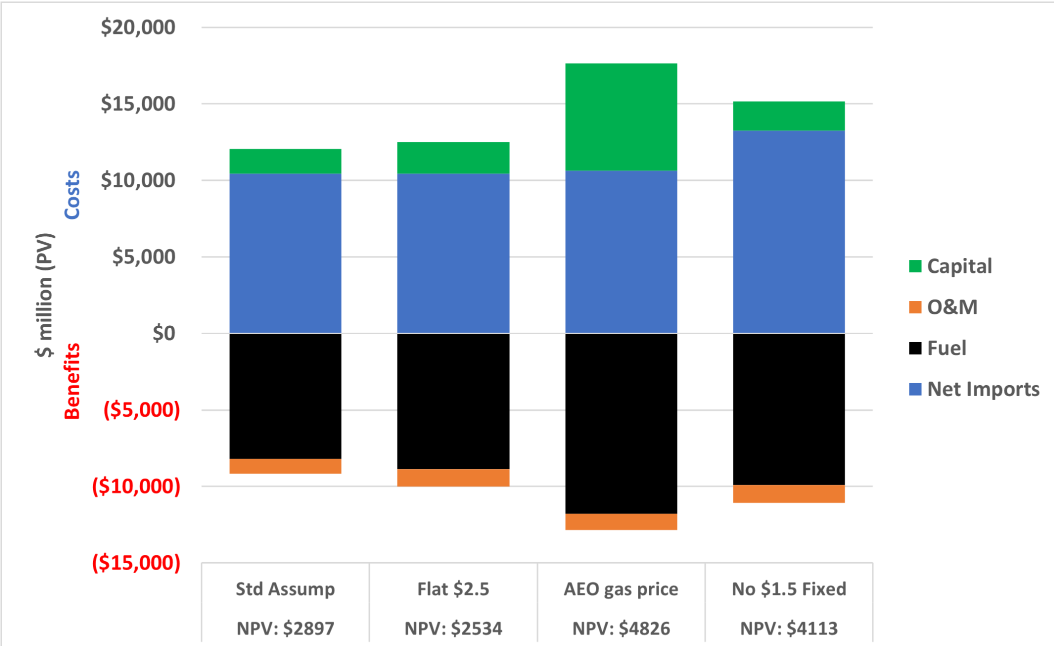


Figure F.31 Adder on Generation: NC Generation across Gas Prices

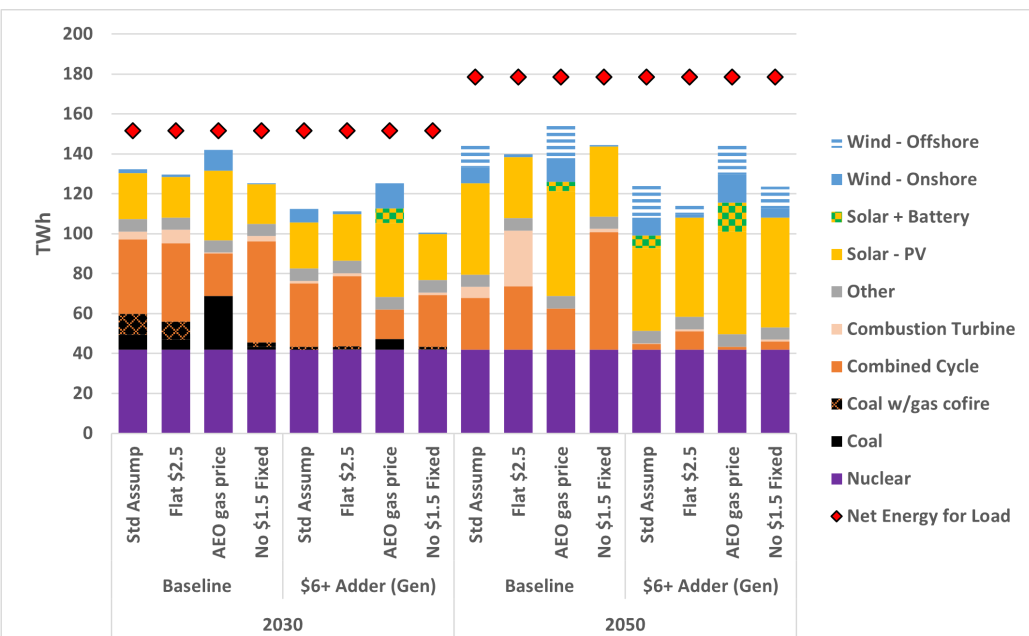


Figure F.32 Adder on Generation: NC Capacity Changes across Gas Prices

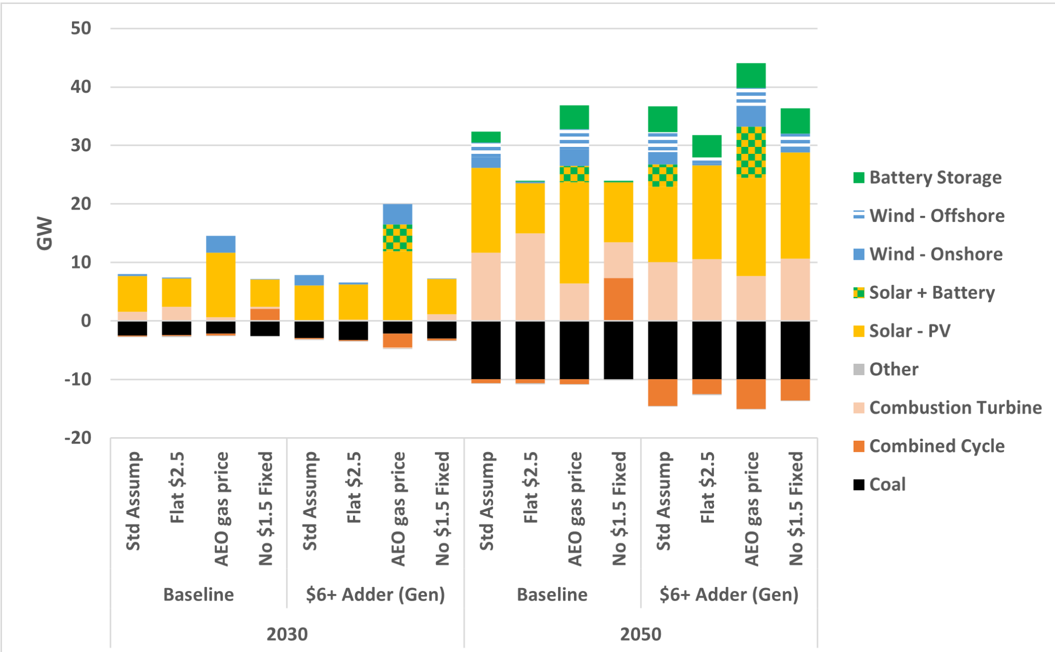
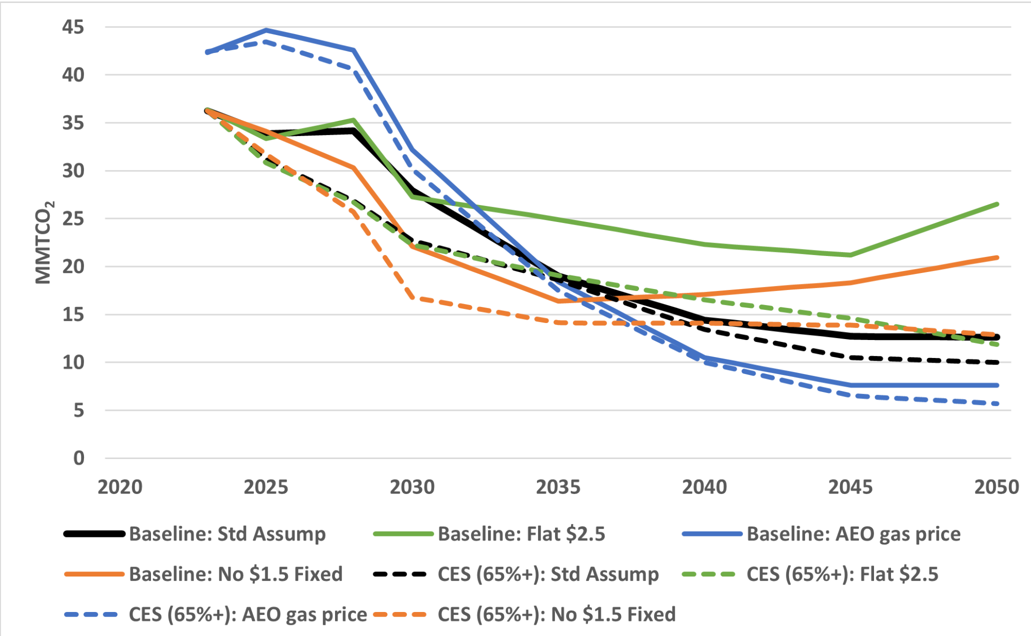


Figure F.33 shows baseline and sales-based CES policy emissions trends for the gas alternatives. Across all the gas prices, the CES policy has a somewhat limited impact on emissions since construction of renewables is fairly high in the baseline without the policy. The biggest take-away from the emissions results, however, is that meeting a CEP 2030 goal of a 70% reduction is not guaranteed if gas prices are higher than $2.50/MMBtu. Higher gas prices lead the coal units to generate more (somewhat like what is seen in the IPM baseline), leading to higher emissions, which are not directly affected by the CES policy. Even towards 2050, higher gas prices have already limited fossil generation by gas units, implying that the addition of the CES policy has very limited effects on emissions.

Figure F.33. CES (65% in 2030): Emissions from NC In-State Generation across Gas Prices



On a cost per ton reduced metric, CES costs once again present as comparatively high for the reasons discussed previously (Figs. F.34a and F.34b). Total policy costs (Fig. F.35), interestingly, move in almost the opposite direction of the carbon adder policy for similar gas price trajectories. Low gas prices—whether the flat prices or the removal of the fixed cost for new combined-cycle units—lead to high CES policy costs since they make gas generation more desirable and, thus, the renewable generation favored by the CES costs more in relative terms to build instead of gas. High gas prices would have the opposite impact over the full-time horizon to 2050 since they have already made renewables a desirable option in the baseline.

The generation and capacity results in Figures F.36 and F.37 reflect these market impacts from the gas price alternatives. While the CES mandates similar levels of renewables regardless of the gas price (setting aside minor differences in exports), the baseline choices are quite different, depending on the gas price. Assuming a flat gas price at $2.50/MMBtu (effectively for new turbines since the fixed adder on gas for new CC units) results in 15 GW of turbines being built by 2050, compared to 6 GW if gas prices follow the "AEO gas price" trends. Removing the fixed charge for gas to new CC units shifts the mix from turbines to combined cycle in the baseline, which is less likely to occur under the CES policy.

Figure F.34a. CES (65% in 2030): Cost per In-State Tons Reduced vs. % Reduction across Gas Prices

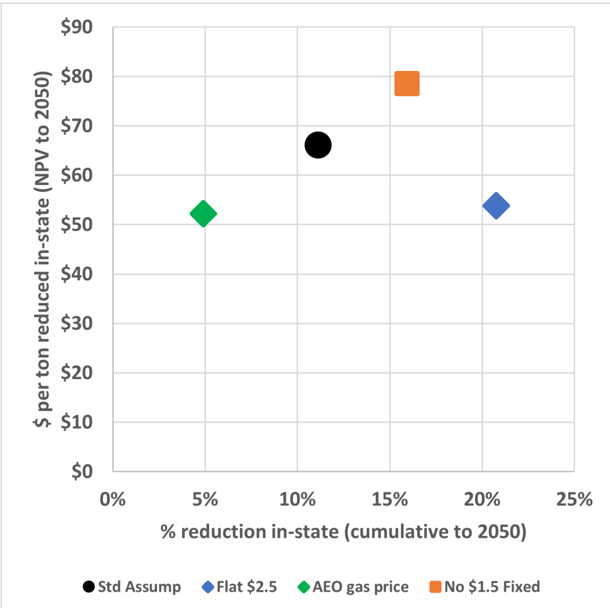


Figure F.34b. CES (65% in 2030): Cost per Total Tons Reduced vs. % Reduction across Gas Prices

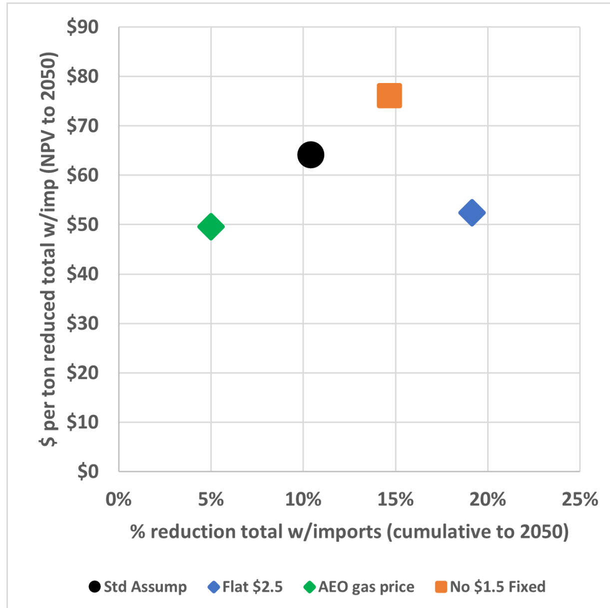


Figure F.35. CES (65% in 2030): Cost Change in NPV through 2050 across Gas Prices

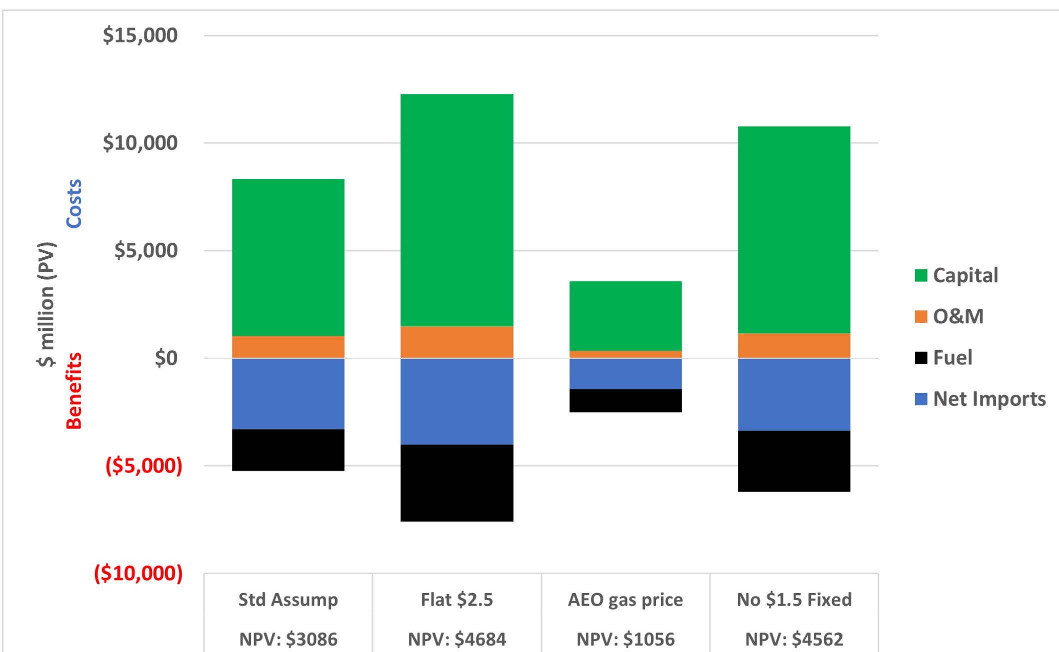


Figure F.36. CES (65% in 2030): NC Generation across Gas Prices

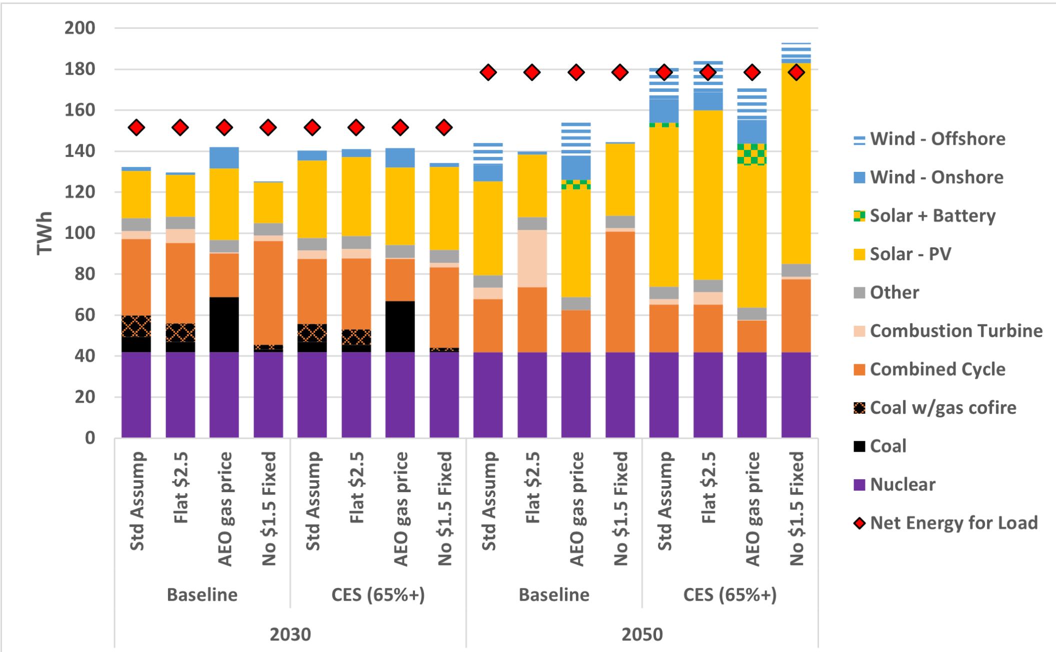
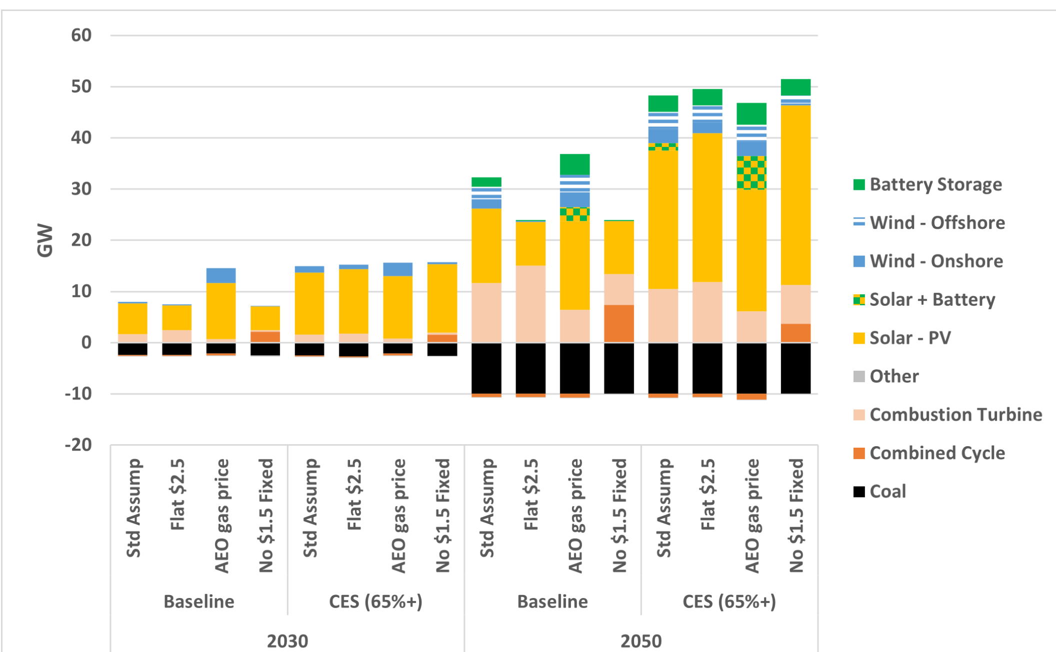


Figure F.37. CES (65% in 2030): NC Capacity Changes across Gas Prices



Electricity Demand Growth Sensitivities

The electricity demand growth trends are compared across four alternatives for the two policy options:

1. *Standard Assumptions **("Std Assump")*** – This is the assumption used in the analyses in Section 6, based on DEC/DEP IRP growth rates of around 0.6% per year.
2. *AEO 2020 Reference Case **("AEO Ref")*** – This case assumes demand growth rates based on the AEO Reference Case for the Carolinas region of around 1% per year.
3. *AEO 2020 High Macroeconomic Growth Case **("AEO High")*** – This case uses growth rates based on the AEO High Macroeconomic Growth Case, which are around 1.3% per year.
4. *NREL EFS Medium EV Forecast **("NREL Med EV")*** – This case starts with the DEC/DEP IRP electricity growth rates and then adds demand from electric vehicles (EV), based on the NREL Electrification Futures Study (EFS) for the Medium forecast.[73]

Baseline emissions show some variation across demand growth forecasts (Fig. F.38), although less than would be the case if DIEM wasn't installing mainly renewables to supply baseline growth. Emissions are insensitive to assumed growth in the presence of the carbon adder on generation. This can also be seen in the costs from Figures F.39a and F.39b on dollars-per-ton basis. Total dollars expended in the policy case (Fig. F.40) have more variation with greater growth in electricity demand leading to higher policy costs. Providing additional electricity to vehicles has the highest capital costs as it requires a larger shift in the generation mix (towards charging in evening hours)[74] than the other types of growth that merely scale demand up uniformly across the hours of a day.

73. NREL (2018). "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States." https://www.nrel.gov/analysis/electrification-futures.html.
74. See the "Home" charging pattern in Ross (2019). "Emissions Benefits of Electric Vehicles: Influencing Electricity Generation Choices." Nicholas Institute Working Paper, https://nicholasinstitute.duke.edu/publications/emissions-benefits-electric-vehicles-influencing-electricity-generation-choices.

Figure F.38. Adder on Gen: Emissions from NC In-State Generation across Electricity Growth

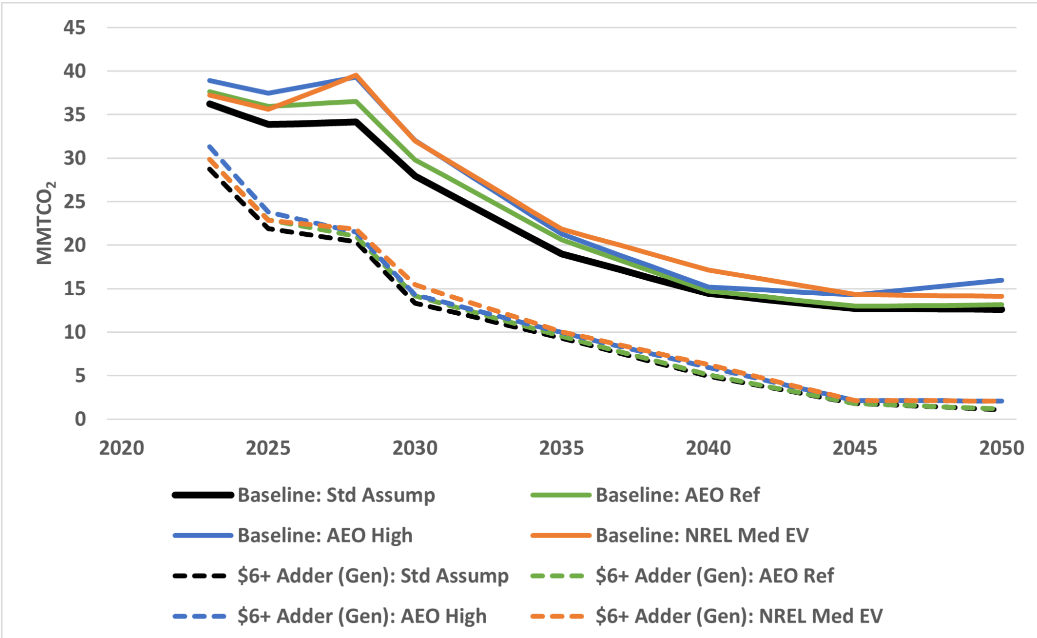


Figure F.39a. Adder on Generation: Cost per In-State Tons Reduced vs. % Reduction across Electric Growth

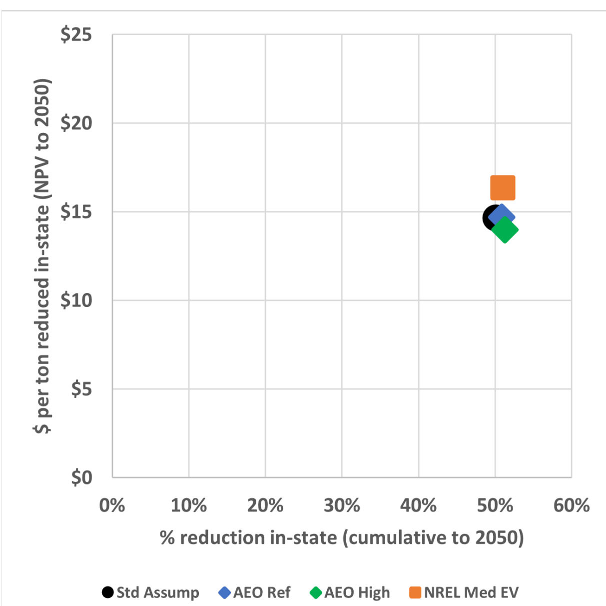


Figure F.39b. Adder on Generation: Cost per Total Tons Reduced vs. % Reduction across Electric Growth

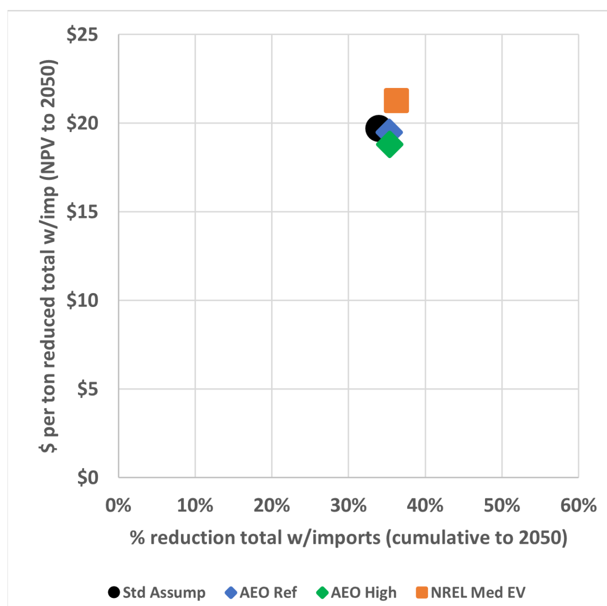
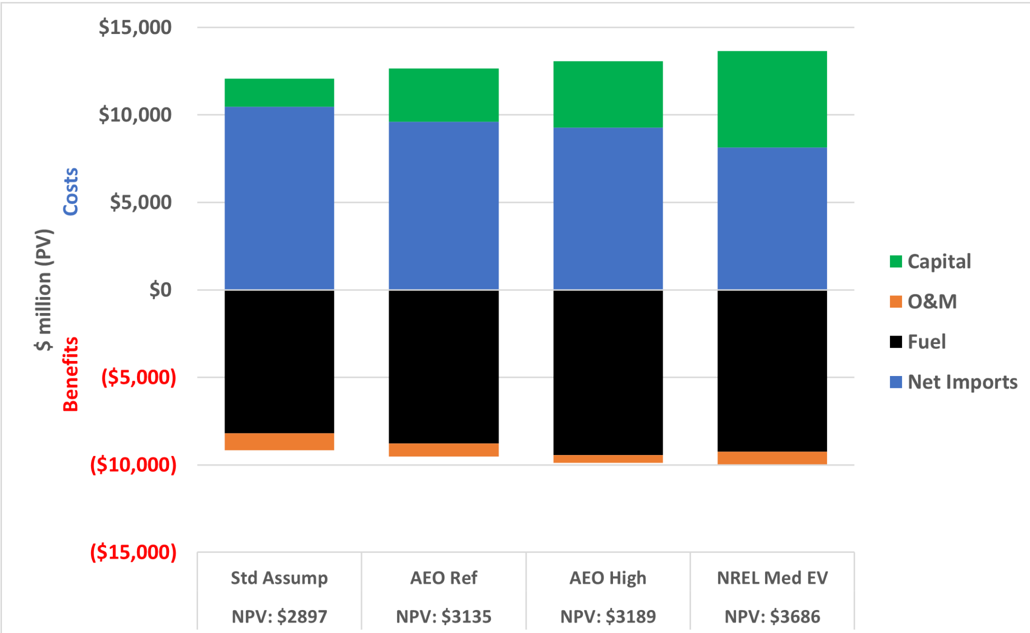


Figure F.40. Adder on Generation: Cost Change in NPV through 2050 across Electricity Growth



As seen in Figures F.41 and F.42, higher demand growth in the baseline is met using a mix of turbines and renewables, with the electric-vehicle case also moving into some additional wind generation. Across all the growth alternatives, the carbon adder in North Carolina leads to an increase in imports. With fewer combustion turbines available, the model also shifts into more solar paired with batteries for reliability reasons, particularly in the NREL EV case.

Figure F.41. Adder on Generation: NC Generation across Electricity Demand Growth

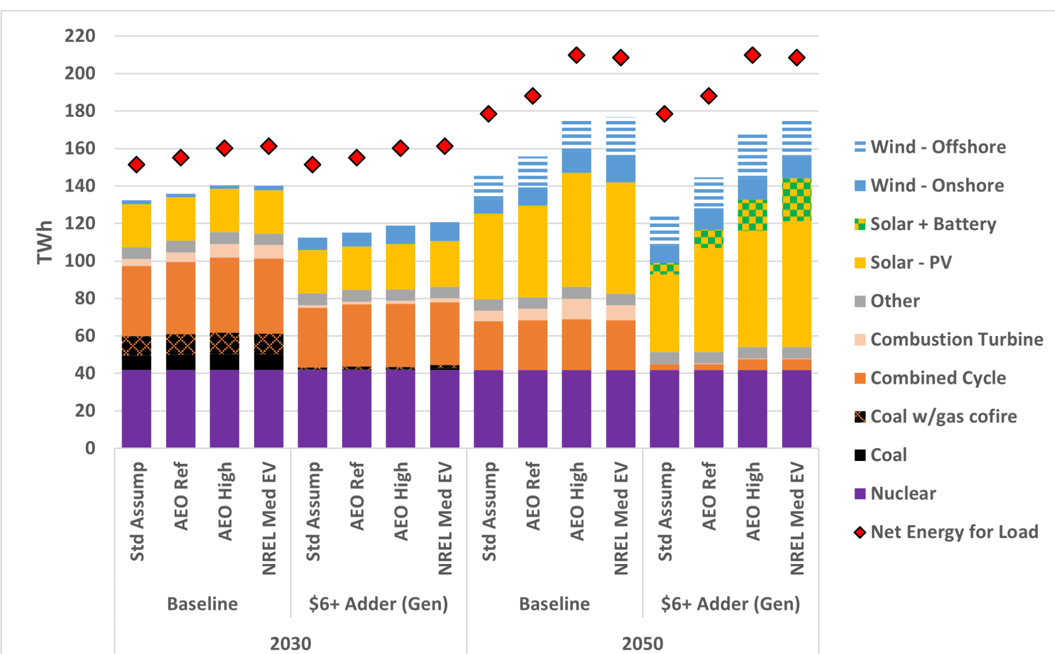
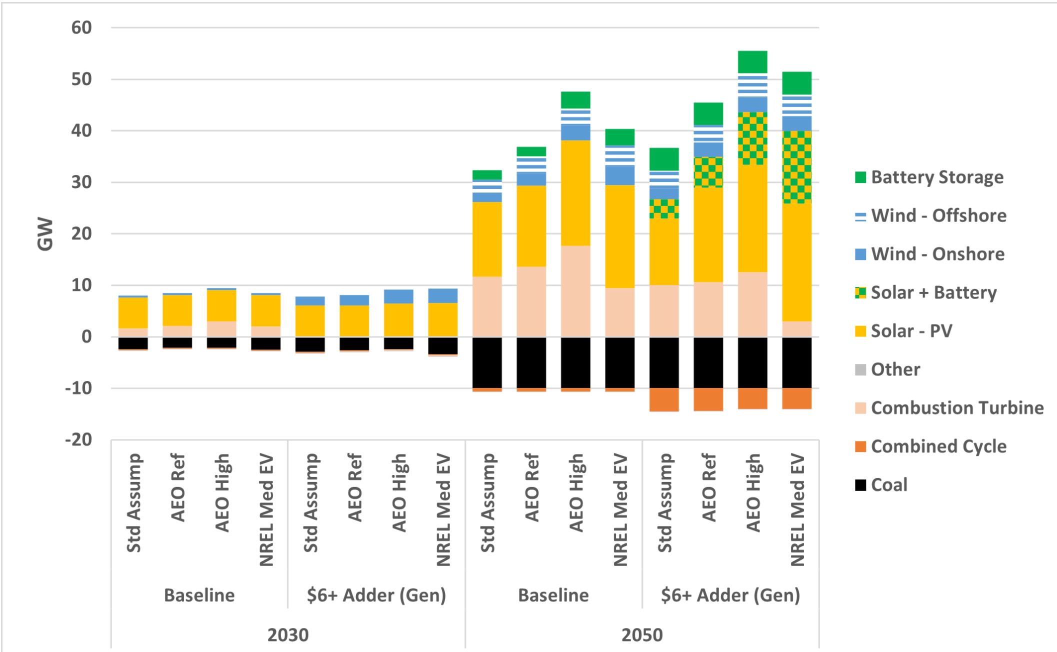


Figure F.42. Adder on Generation: NC Capacity Changes across Electricity Demand Growth



As with the carbon adder policy, emissions for the CES across demand growth alternatives are relatively consistent—higher demand leads to higher baseline emissions and higher policy emissions since the CES doesn't discourage fossil generation directly. For the CES policy, however, additional growth makes it less likely that the policy will be able to achieve the CEP 70% reduction goal in 2030. By 2050, differences in emissions trends have narrowed across the alternatives.

Policy costs, whether on a dollars-per-ton or total dollars basis, are somewhat less closely grouped than under the carbon adder. Higher growth leads to a lower $/ton cost across the alternatives, largely because baseline emissions are higher which leaves more for the CES policy to accomplish. Total costs are also lower in some of the cases (Fig. F.45), which is a function of the types of generation installed in the baselines in order to meet the higher demand growth.

Figure F.43. CES (65% in 2030): Emissions NC In-State Generation across Electricity Growth

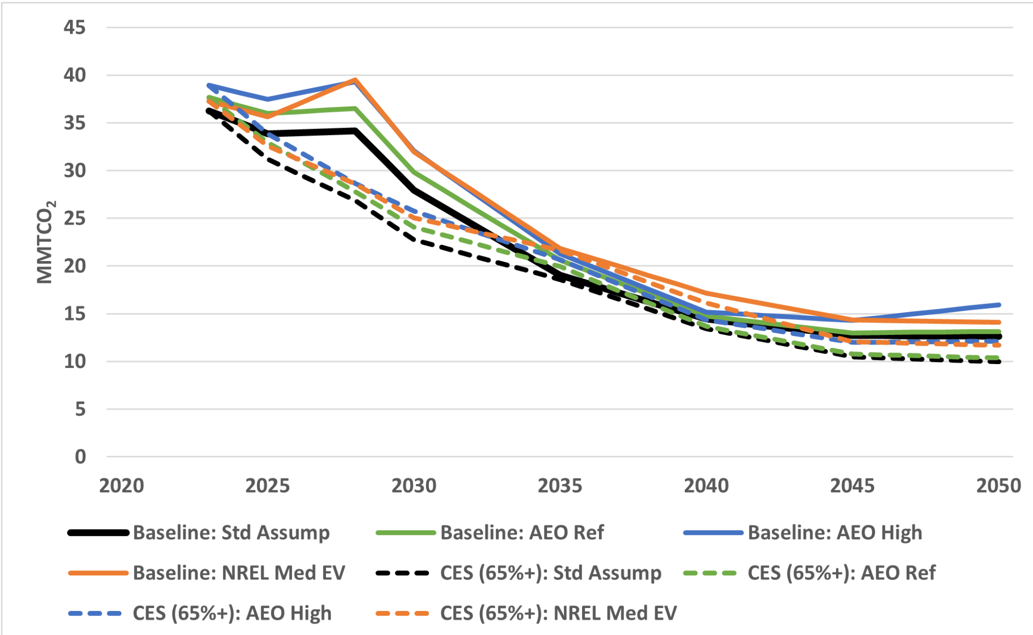


Figure F.44a. CES (65% in 2030): Cost per In-State Tons Reduced vs. % Reduction across Electricity Growth

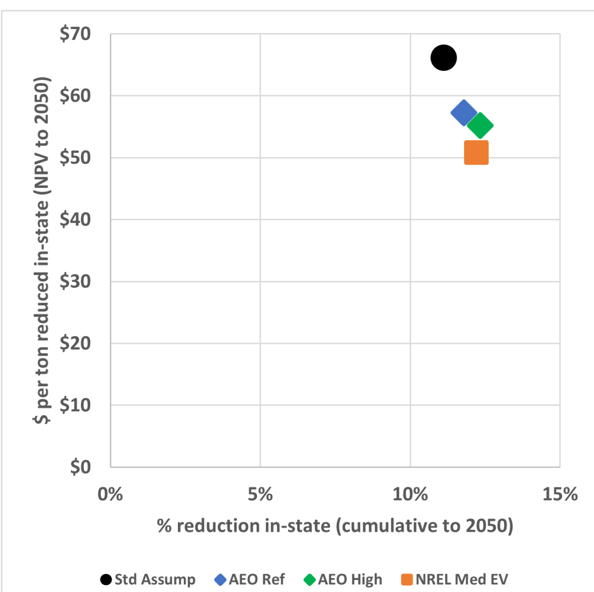


Figure F.44b. CES (65% in 2030): Cost per Total Tons Reduced vs. % Reduction across Electricity Growth

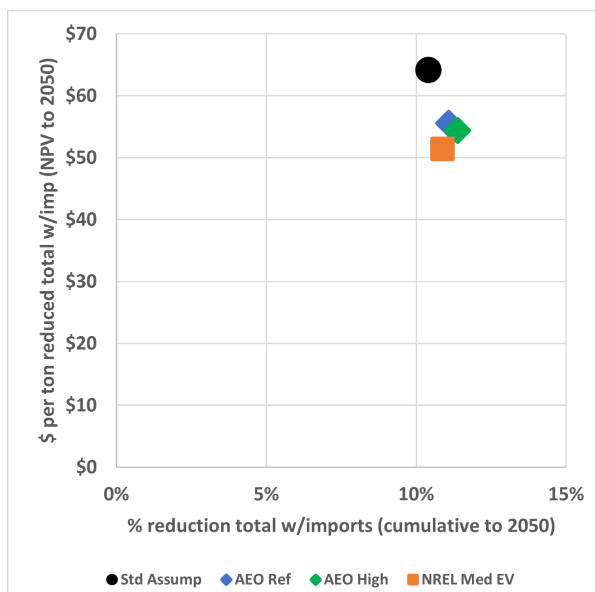
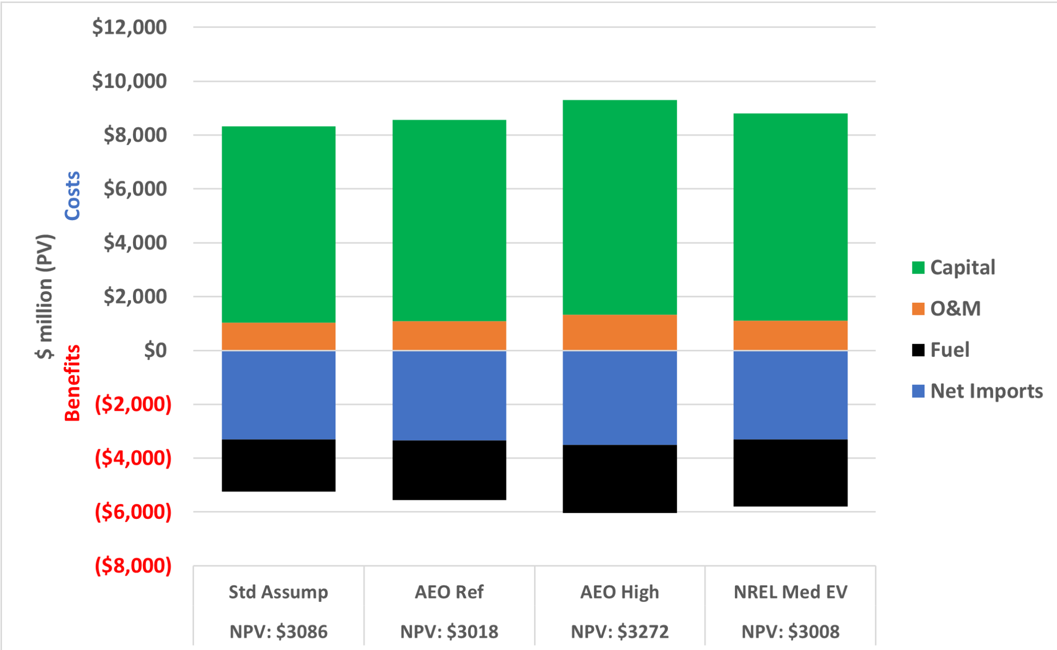


Figure F.45. CES (65% in 2030): Cost Change in NPV through 2050 across Electricity Growth



Baseline generation initially shows higher levels of fossil generation to meet demand, but by 2050 more of the demand is being supplied by new renewables than an increase in fossil. The CES policy accelerates the construction of some onshore wind in 2030, particularly as demand grows, but fossil generation also supplies part of the higher demand even in the CES cases. By 2050 under the CES, there are few differences in combined cycle and turbine generation across the demand alternatives, and higher demand is supplied by renewables—a combination of solar, offshore wind, and paired solar/battery installations.

For capacity, the biggest differences across the baselines and CES policy results are in the number of in-state turbines used for generation and reliability, with the electric-vehicle cases having the fewest turbines and comparatively higher levels of capacity imports. In the baselines and CES cases, solar installations tend to follow the demand growth patterns across the alternatives.

Figure F.46. CES (65% in 2030): NC Generation across Electricity Demand Growth

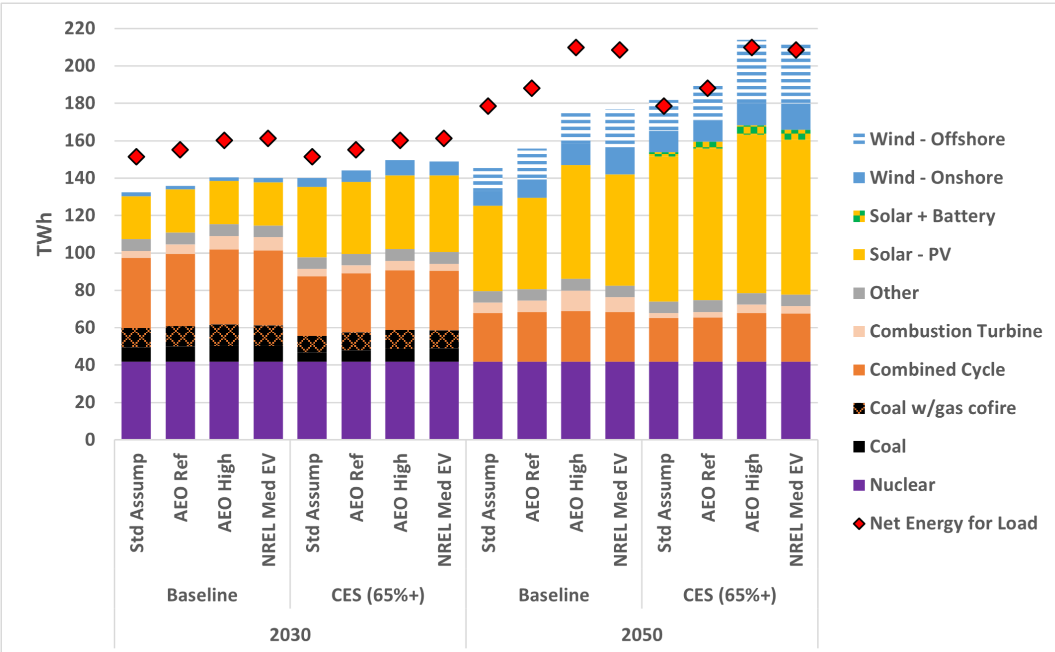
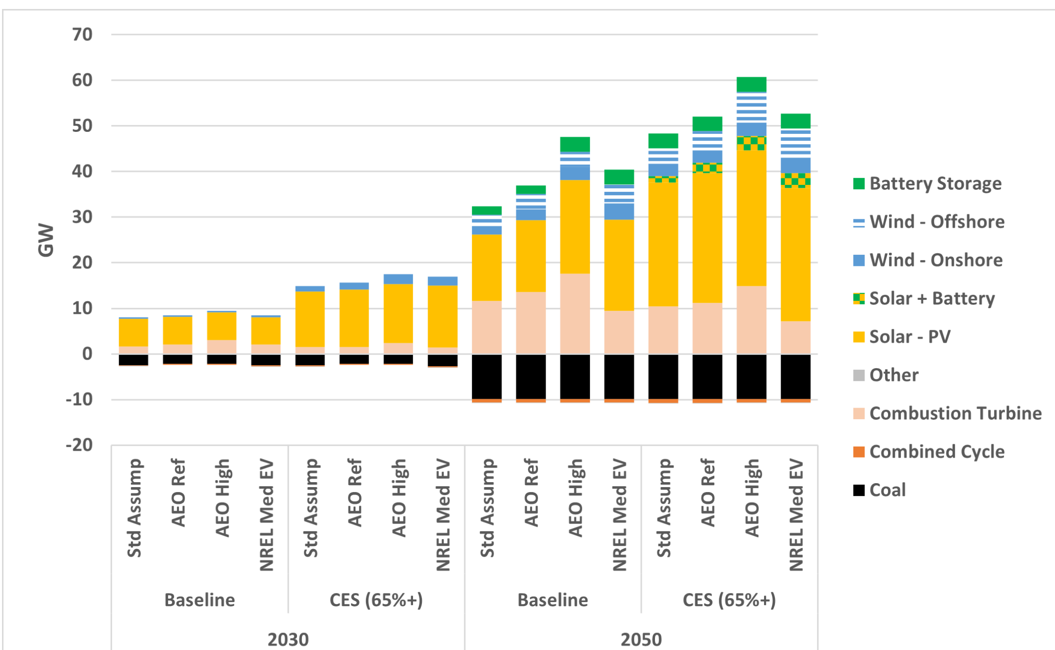


Figure F.47. CES (65% in 2030): NC Capacity Changes across Electricity Demand Growth



Energy Efficiency Sensitivities

To test the sensitivity of the system to enhanced energy efficiency investment, two policies (a generation-based adder and the sales-based CES) are compared across three EE forecasts discussed in Section 6 and **Appendix B**:

(1) *Standard Assumptions* ***("Std Assump")*** – This standard case from Section 6 uses electricity demand growth rates, energy efficiency and demand-side management assumptions from the DEC/DEP IRPs.

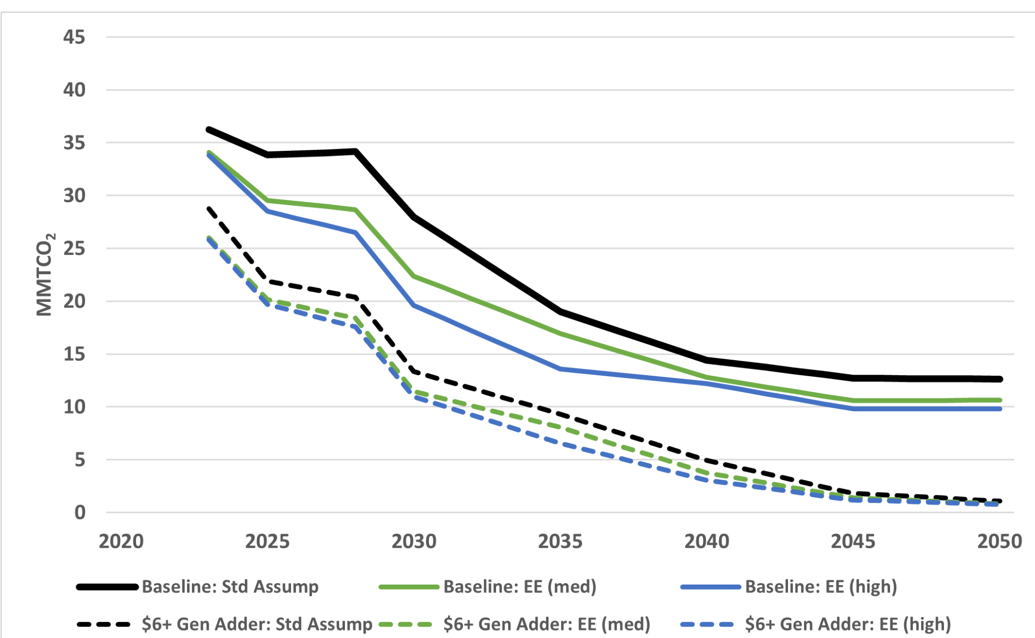
(2) *Energy Efficiency* ***("EE (med)")*** – This case assumes that EE measures result in a 1% decline in demand per year through 2030 and 1.2% per year after 2030.

(3) *Energy Efficiency* ***("EE (high)")*** – This case assumes that EE measures result in a 1–2% decline in demand per year through 2030 and 2.0% per year after 2030.

Baseline emissions across the two EE alternatives are initially lower than the forecast based on the EE levels in the IRP. However, by 2035 the forecasts are starting to converge, in spite of the significantly lower electricity demand for the two alternatives. This suggests that, while the EE measures in the near term are displacing existing fossil generation (and reducing the need for new fossil units), in the longer-term energy efficiency is largely displacing new renewable units that otherwise would have been constructed to meet increasing demand.

A carbon adder on generation, since it addresses fossil generation irrespective of any effects of EE on renewables, still results in large declines in emissions (in part from an increased reliance on imports) that are maintained throughout the forecast horizon.

Figure F.48. Adder on Generation: Emissions from NC In-State Generation across Energy Efficiency



Generation and capacity (Figs. F.49 and F.50) follow these emissions trends. The carbon adder removes coal generation more quickly in the near term, regardless of the level of EE available. By 2050, the pattern of EE displacing renewables in the baseline and policy cases.

Figure F.49. Adder on Generation: NC Generation across Energy Efficiency

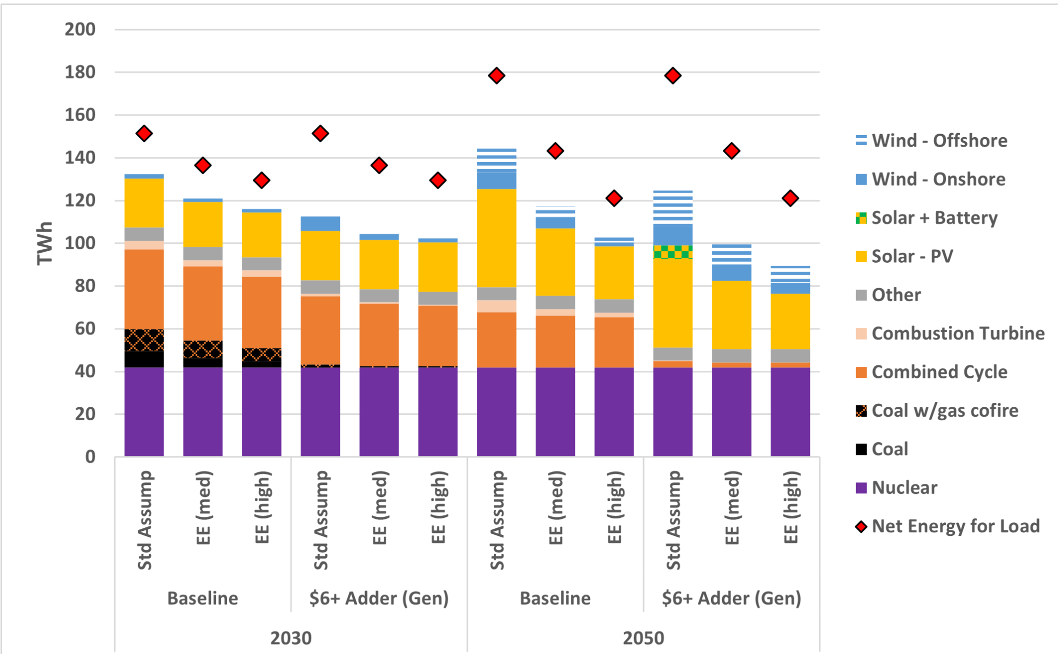


Figure F.50. Adder on Generation: NC Capacity Changes across Energy Efficiency

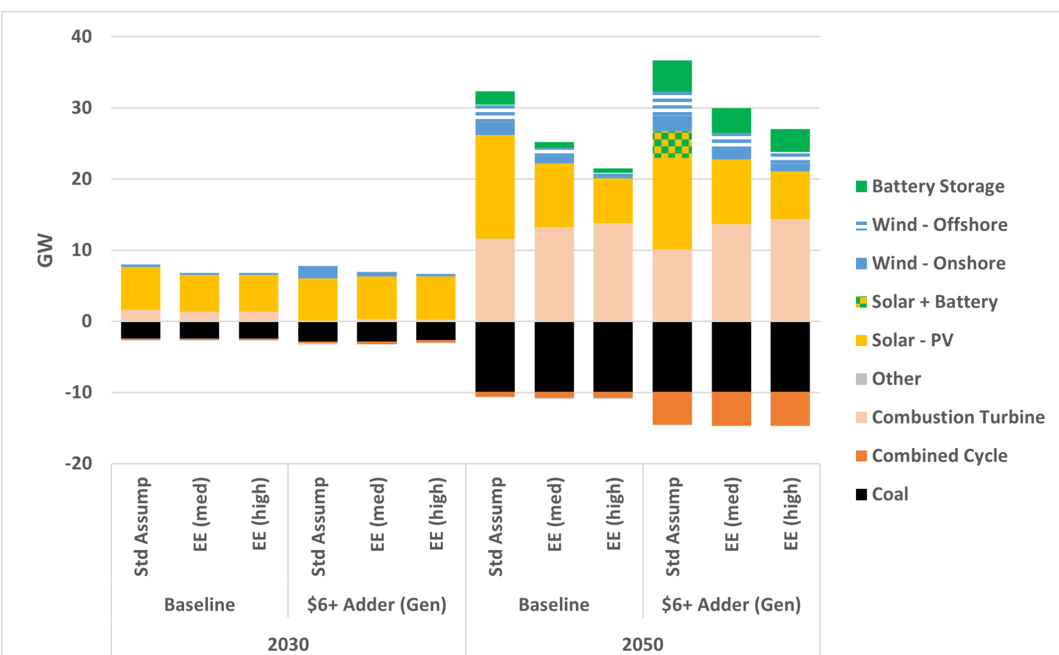
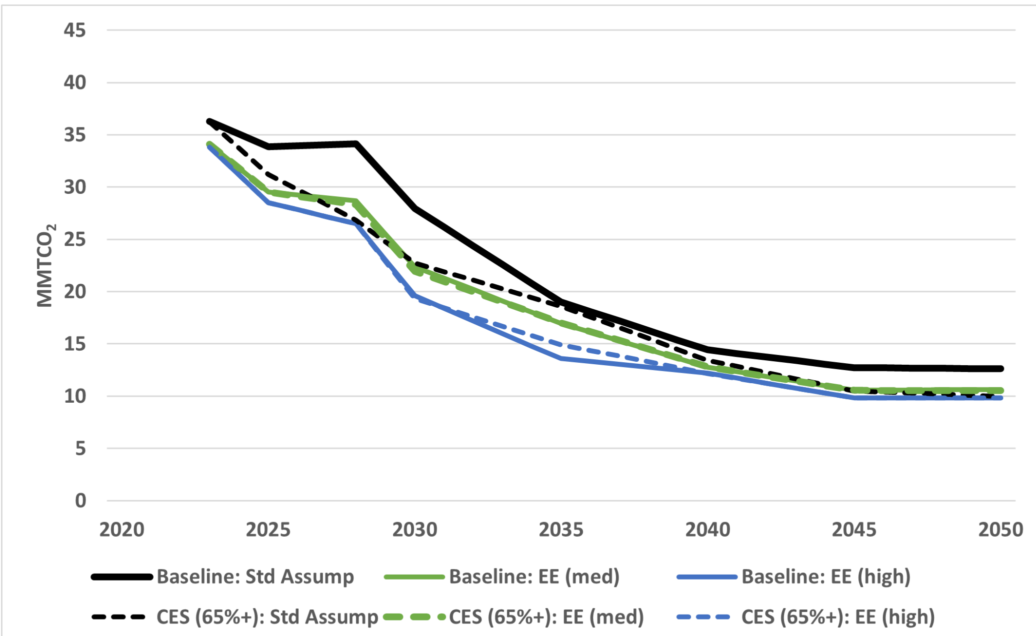


Figure F.51 initially shows the 65% clean goal in 2030 having an impact on emissions (black lines). However, under either of the two alternatives with higher levels of EE, CES emissions are essentially the same as the baseline trends (assuming that EE counts towards the requirements of the CES goals). This suggests two things: (1) as seen previously, a CES is not by itself an effective way to address fossil generation, and (2) the CES policy is not doing anything to encourage new renewable construction in North Carolina—compared to the baseline trends that would have occurred without the policy.

Figure F.51. CES (65% in 2030): Emissions from NC In-State Generation across Energy Efficiency



Generation and capacity (Figs. F.52 and F.53) highlight these impacts. Neither EE nor the CES policy have much effect on fossil generation by 2050—although there are some minor differences in baseline generation in 2030. The CES credits provided by the EE, particularly for the "high EE" case, are sufficient to cover any demand growth that would have occurred by 2050, leaving renewables in both the baseline and policy cases near the levels seen in 2030. New turbine capacity is largely unaffected, aside from in the CES policy with IRP levels of EE, where some turbines in 2050 are replaced by batteries or paired solar/battery installations.

Figure F.52. CES (65% in 2030): NC Generation across Energy Efficiency

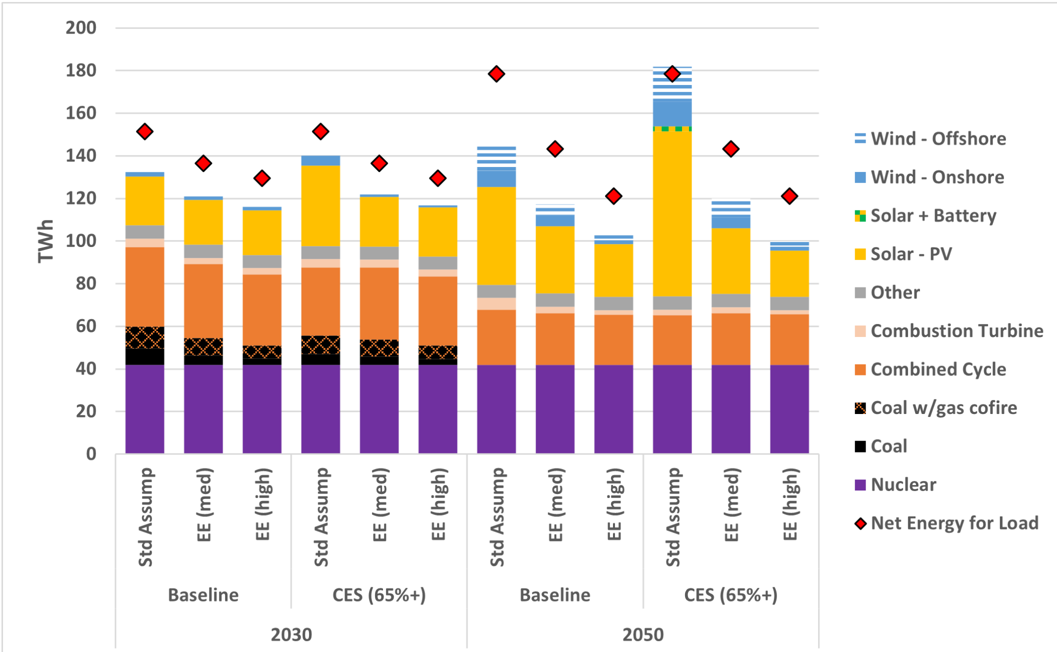
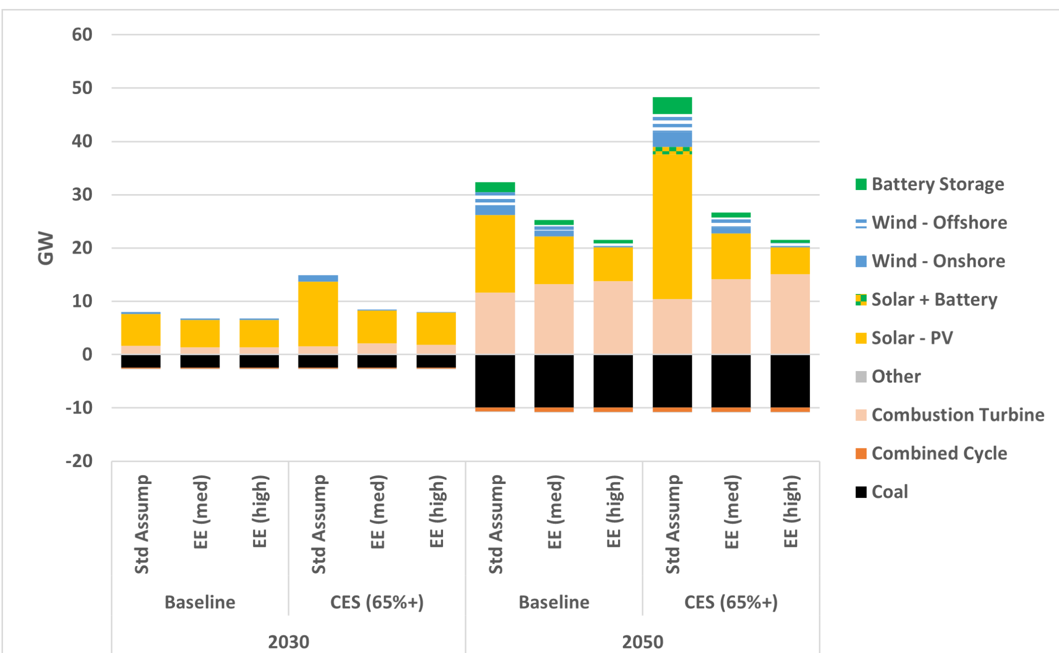


Figure F.53. CES (65% in 2030): NC Capacity Changes across Energy Efficiency



Renewables Costs Sensitivities

Trends in renewables costs are compared across three alternatives:

(1) *Standard Assumptions* ***("Std Assump")*** – As discussed in Appendix B, the standard assumption about renewables costs and effectiveness is based on the NREL ATB Moderate Case cost trends.

(2) *NREL Advanced Renewables Costs* ***("NREL Adv Renew")*** – This case uses the more optimistic NREL ATB Advanced Case cost trends.

(3) *NREL Advanced Renewables Costs plus a 15% Depth-of-Discharge Cost Adder* ***("Adv Rnw + 15% DoD")*** – This case combines the NREL Advanced Case trends with an additional 15% cost on battery units to proxy potential depth-of-discharge issues.

Renewables installations are very dependent on assumed capital costs for new units. As is implied by the decline in baseline emissions using the NREL ATB Moderate Case costs, renewables are very close to being cost-competitive with fossil generation, even if gas prices are low. As shown in Figure F.54, using the lower-cost assumptions from the Advanced Case has important implications for emissions trends, even without climate policies. Adding a carbon adder on fossil generation on top of these lower renewables costs accelerates the transformation of the industry very rapidly. Of course, this outcome is assisted by the assumption that North Carolina is pursuing the carbon adder in isolation from surrounding states, but all states are experiencing the low-cost renewables from the NREL Advanced forecasts.

Figure F.54. Adder on Generation: Emissions of NC In-State Generation across Renewables Costs

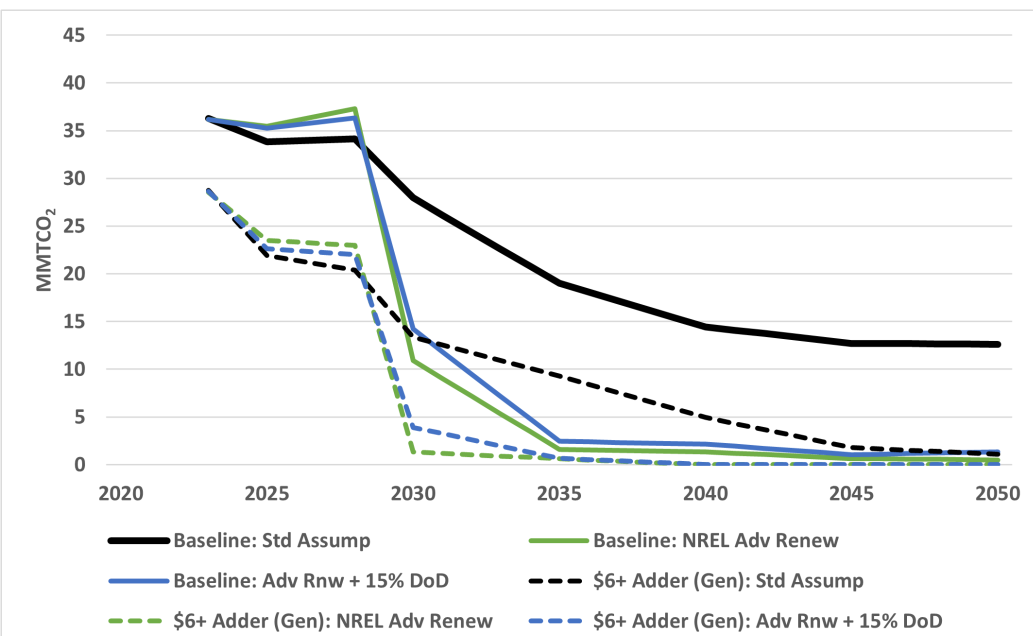


Figure F.56 shows that the cost of the Advanced Case is reduced by around one-third, compared to results using the standard assumptions. The assumption that batteries are more costly, however, appears to have a fairly detrimental impact on this result. As Figure F.56 shows, cheaper renewables reduce the carbon-adder policy cost by more than 60%, but also that the assumption that batteries may be more expensive than shown in the NREL Advanced case could almost double these policy costs.

Figure F.55a. Adder on Gen: Cost per In-State Tons Reduced vs. % Reduction across Renewables Costs

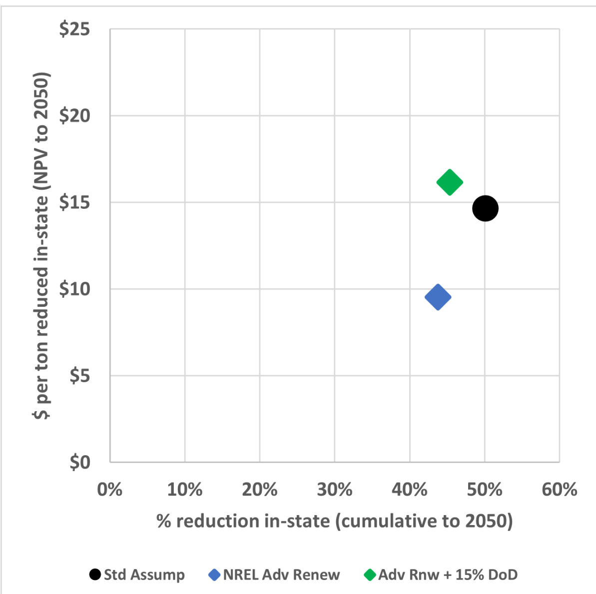


Figure F.55b. Adder on Gen: Cost per Total Tons Reduced vs. % Reduction across Renewables Costs

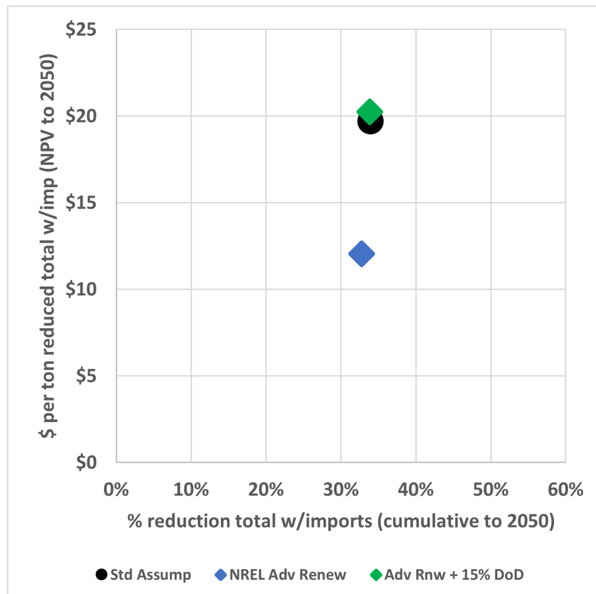
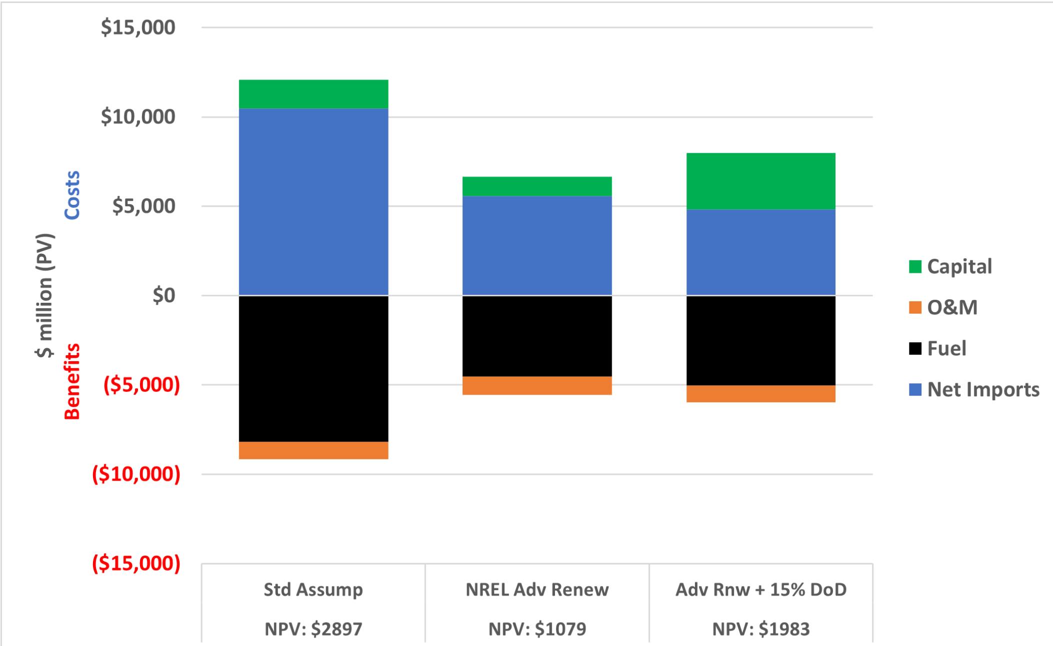


Figure F.56. Adder on Gen: Cost Change in NPV through 2050 across Renewables Costs



Across the generation and capacity decisions, the Advanced Case shift choices away from turbines and into paired solar/battery installations. This shift is large enough that the carbon adder doesn't lead to the significant increase in imports seen in the other carbon adder cases. The more expensive batteries in the "15% DoD" alternative do shift the choice back somewhat more towards imports, however. Without the carbon adder, generation in the state is almost decarbonized by 2050 and in-state generation is completely decarbonized with the carbon-adder policy (although existing turbines remain in the mix for reliability reasons).

Figure F.57. Adder on Generation: NC Generation across Renewables Costs

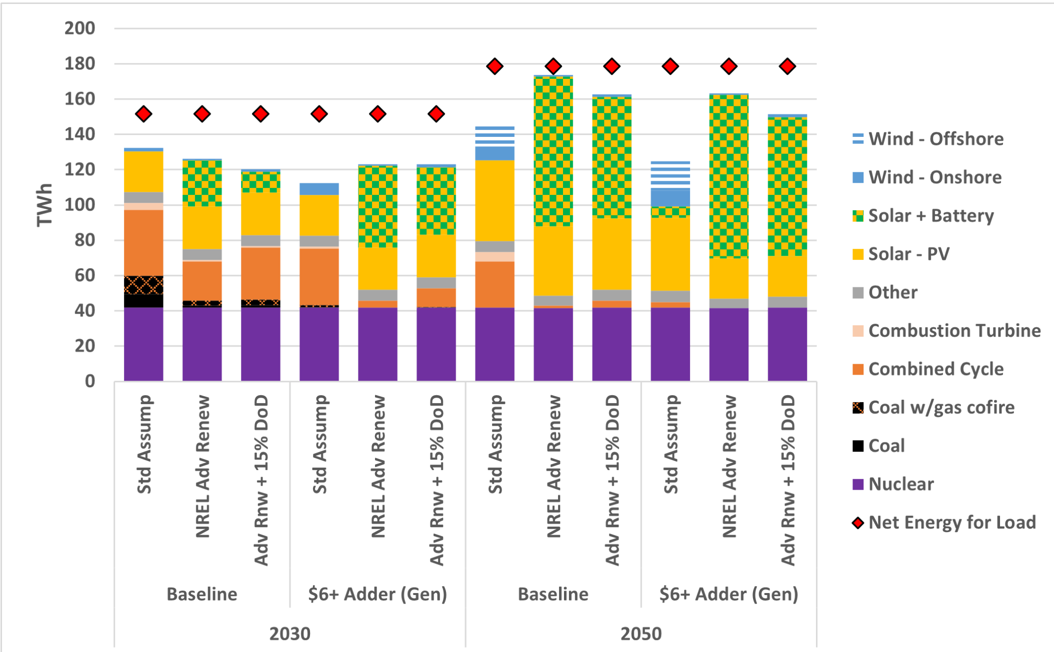
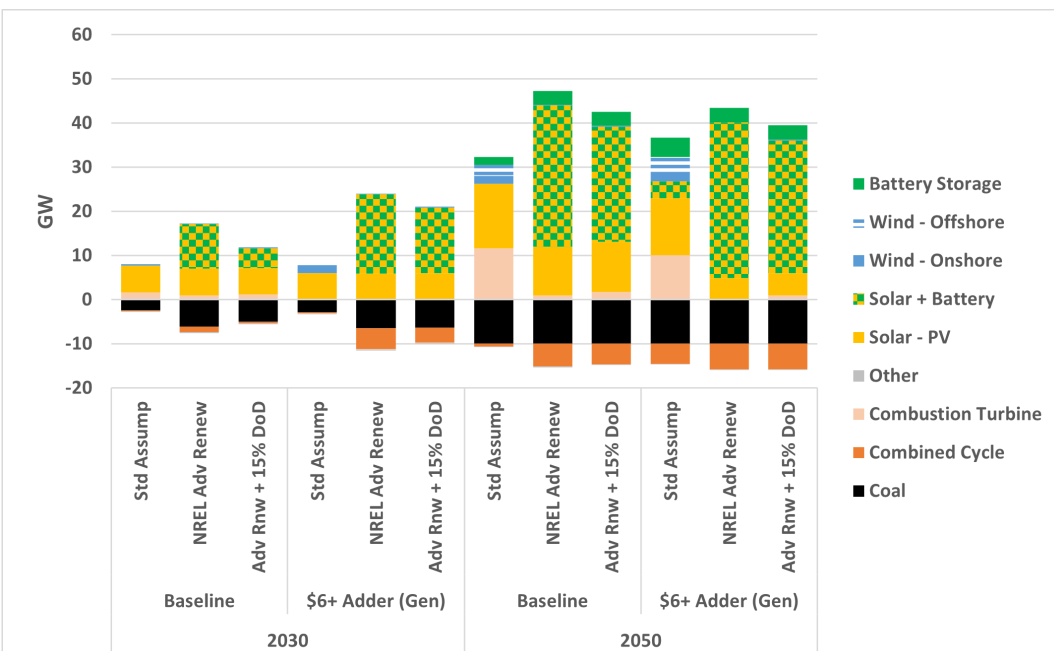
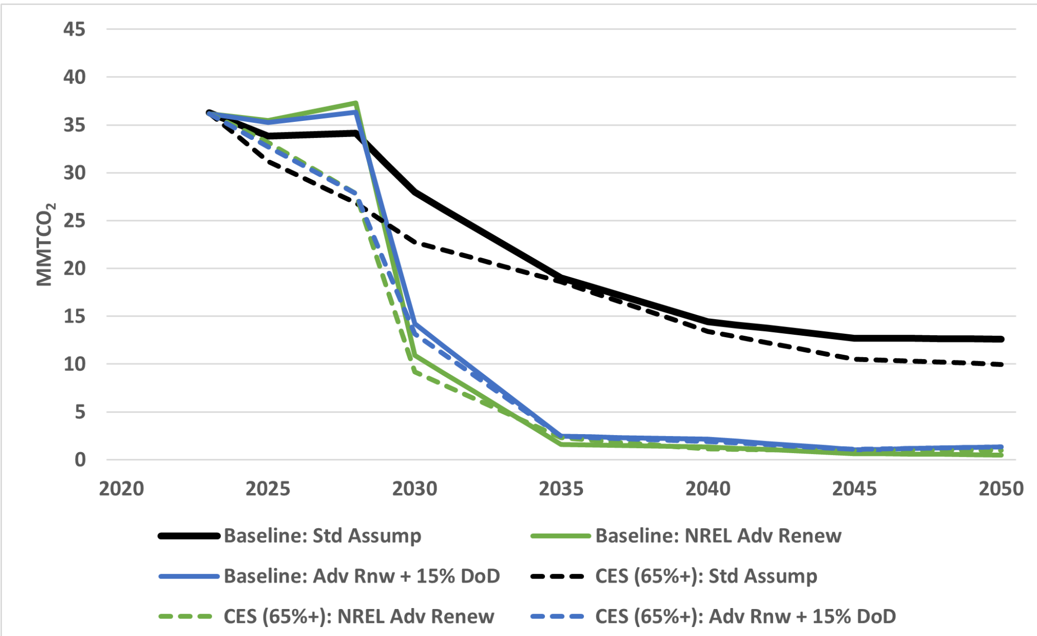


Figure F.58. Adder on Generation: NC Capacity Changes across Renewables Costs



The sales-based CES policy doesn't have the dramatic effect on emissions in the near term that is seen when carbon adders are imposed on generation decisions (Figure F.59). Across the alternatives, aside from the standard assumption based on the NREL Moderate Case renewables, the CES policy is only binding in the year 2028. As renewables costs continue to decrease, there are few differences in emissions between the baseline alternatives and the CES policy trends.

Figure F.59. CES (65% in 2030): Emissions from NC In-State Generation across Renewables Costs



As there are few reductions for the CES policy left to realize, costs per ton reduced remain higher than seen for other types of policies such as the carbon adder on generation. However, total policy costs (Figure F.61) are significantly lower since the CES policy targets renewable generation and the NREL Advanced cost trends have reduced the costs of installing those renewables. In relative terms, the "15% DoD" additional cost assumption does lead to larger capital expenditures, compared to the alternative without that assumption, but costs are still much less than for the standard set of assumptions.

Generation and capacity results for the CES policy (Figures F.62 and F.63) are similar to those in the carbon-adder policy. There are large installations of paired solar/battery units, instead of separate turbine and solar PV that was preferred under the standard-assumption alternative. As before, existing turbines remain in the system for reliability purposes since the CES policy does not specifically preclude them.

Figure F.60a. CES (65% in 2030): Cost per In-State Tons Reduced vs. % Reduction across Renewables Costs

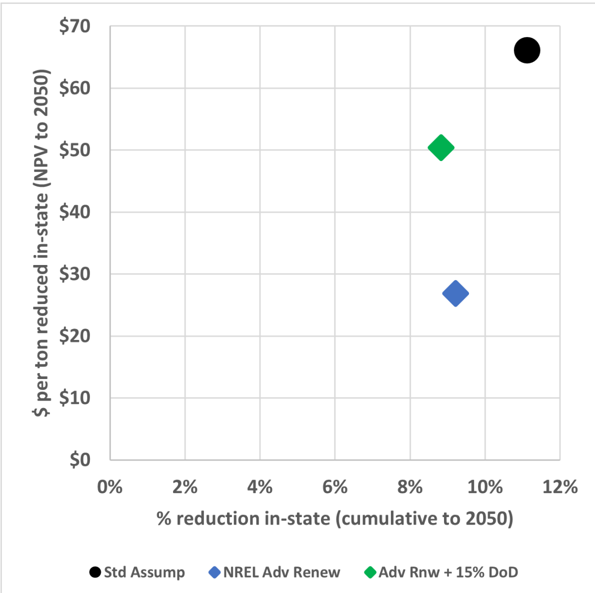


Figure F.60b. CES (65% in 2030): Cost per Total Tons Reduced vs. % Reduction across Renewables Costs

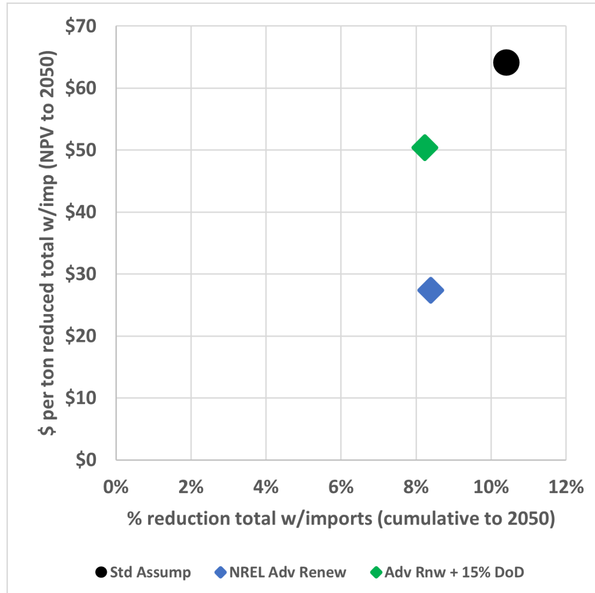


Figure F.61. CES (65% in 2030): Cost Change in NPV through 2050 across Renewables Costs

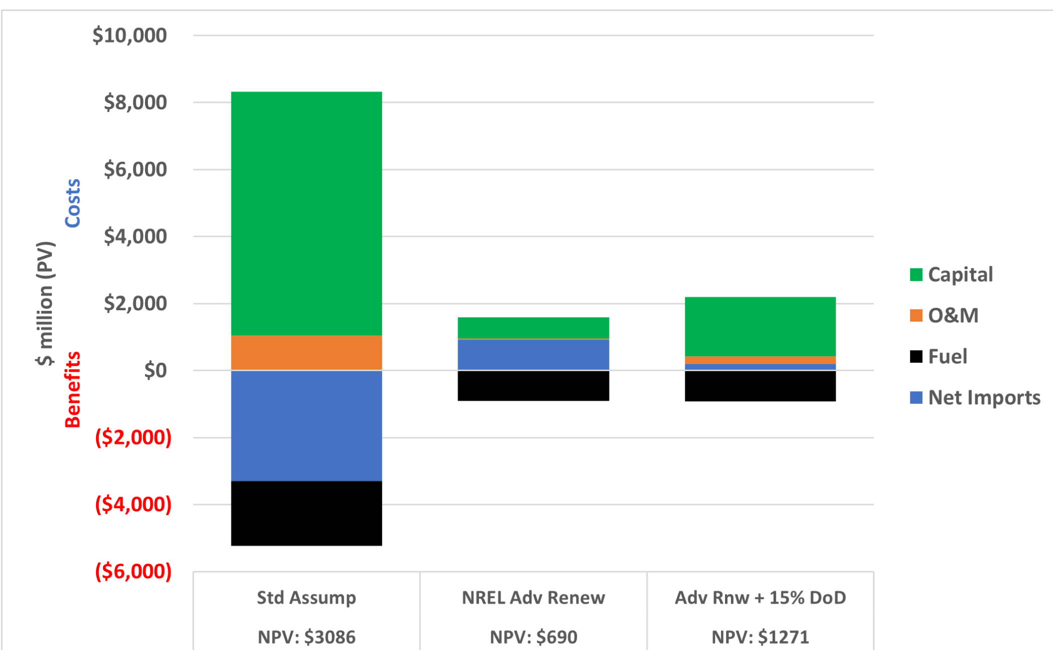


Figure F.62. CES (65% in 2030): NC Generation across Renewables Costs

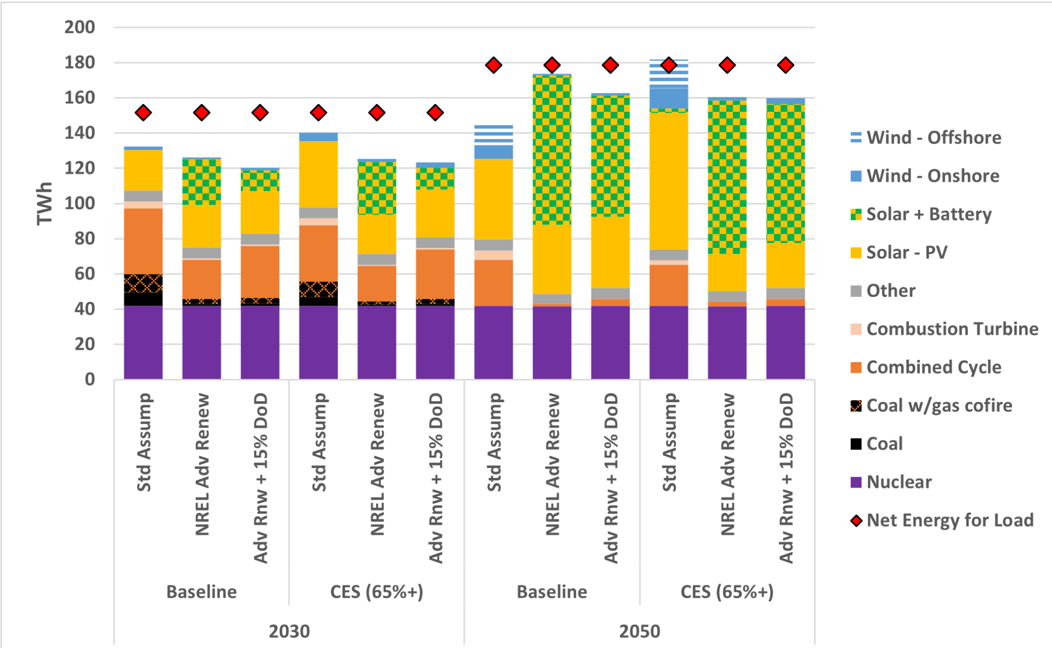
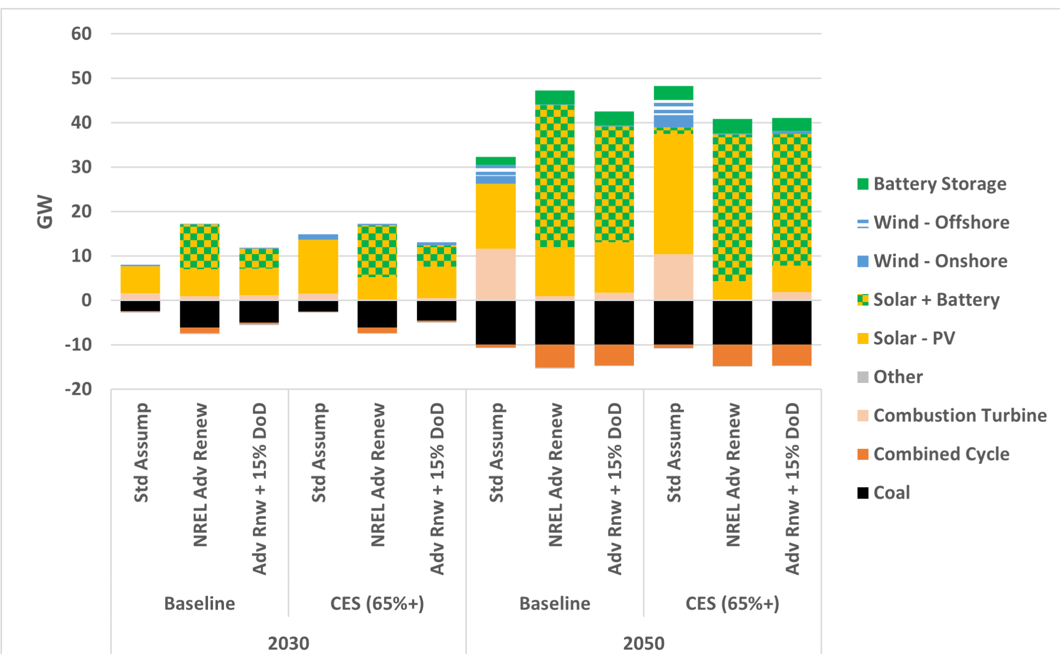


Figure F.63. CES (65% in 2030): NC Capacity Changes across Renewables Costs



Battery Storage Sensitivities

Two alternative sets of assumptions about battery storage effectiveness and cost are compared in the baseline and carbon adder or CES policy options:

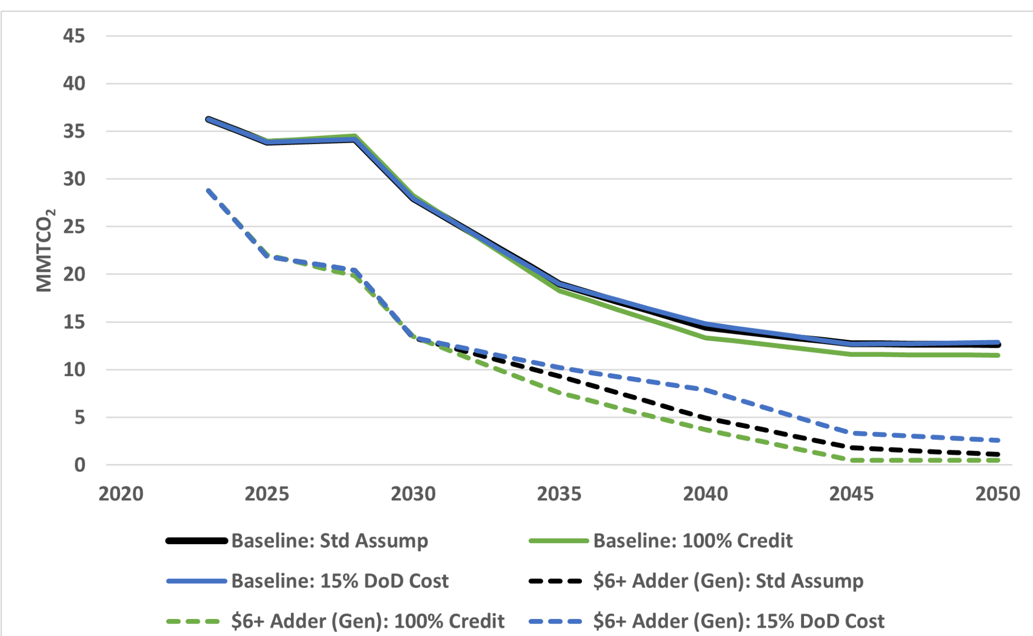
(1) *Standard Assumptions* ***("Std Assump")*** – These are the assumptions used in the DIEM model for the policy runs in Section 6. Battery effectiveness at meeting peak capacity is reduced as battery installations increase, based on Attachment IV of the DEC/DEP IRPs. Costs are based on the NREL ATB 2020, as discussed in Appendix B. Paired solar/battery installations have batteries that are half the MW of the solar unit and 50% of the capacity counts towards meeting summer and winter peaks.

(2) *Full Credit for Batteries Meeting Peaks* ***("100% Credit")*** – This case removes the assumption that batteries contribution to meeting peaks is reduced as installation levels rise, thus batteries receive full credit towards the summer and winter peaks.

(3) *Battery Depth-of-Discharge Cost Adder* ***("15% DoD Cost")*** – This case adds an additional 15% cost to the batteries to proxy the possibility that batteries which cycle on a daily basis may need to be oversized to avoid depth-of-discharge issues.

Figure F.64 suggests that battery assumptions are not playing a big role in the baseline forecast and have minor impacts on emissions. For the carbon adder on generation, batteries are having some impact with the assumption of more effective batteries leading to slightly lower emissions in the policy case, and conversely more costly batteries resulting in higher emissions.

Figure F.64. Adder on Gen: Emissions from NC In-State Generation across Battery Assumptions



Policy costs move in what might be somewhat counterintuitive directions, where more effective batteries are associated with higher policy costs and more costly batteries have lower policy costs. However, these trends are occurring in the results only because all states are seeing the impacts of the two battery sensitivities, while only North Carolina is adopting the carbon-adder policy. If all states had cheaper (more expensive) batteries and all states had a carbon adder, then overall policy costs would be lower (higher), as would be intuitively expected.

The cost results in Figure F.66 show that capital expenditures have increased if batteries are more effective ("100% Credit") and the reverse if batteries are more costly. What has counterbalanced these cost trends for the NC-only carbon adder are the differences in net expenditures on imported electricity.

Figure F.65a. Adder on Gen: Cost per In-State Tons Reduced vs. % Reduction across Battery Assumptions

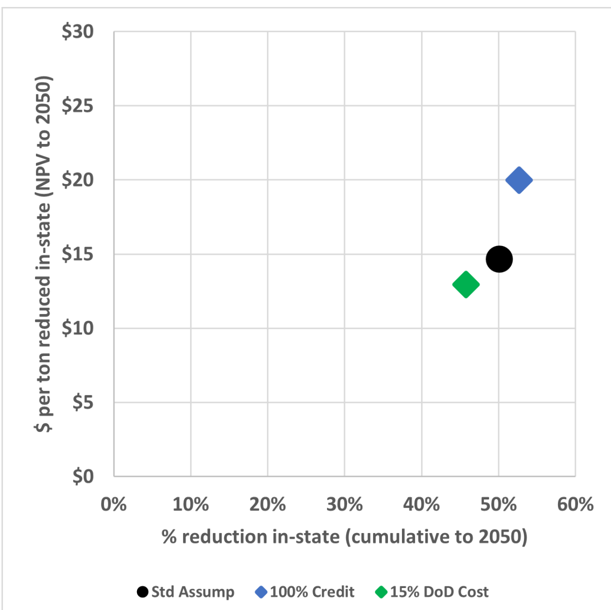


Figure F.65b. Adder on Gen: Cost per Total Tons Reduced vs. % Reduction across Battery Assumptions

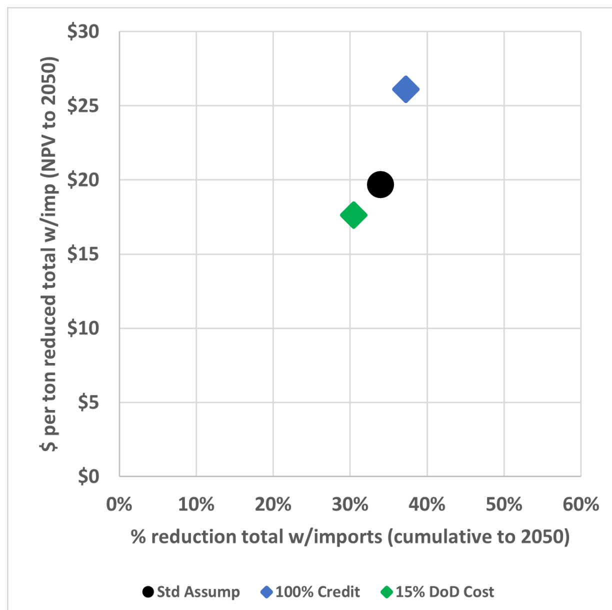
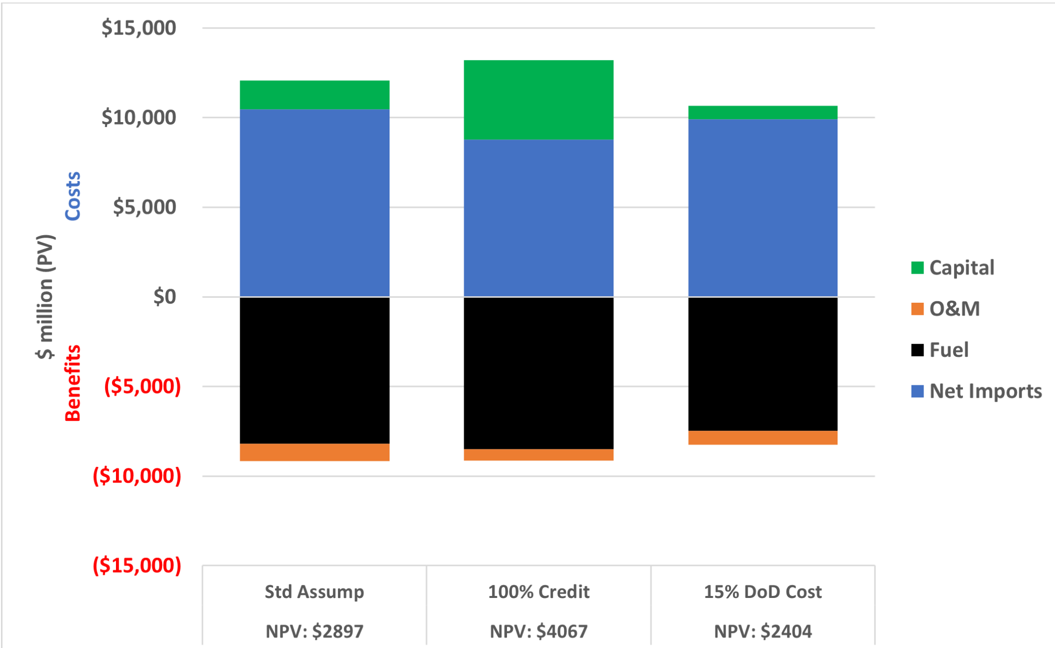


Figure F.66. Adder on Gen: Cost Change in NPV through 2050 across Battery Assumptions



The next two figures on generation and capacity show changes in trends in line with the two battery alternatives. There are few impacts in 2030 as batteries have not yet achieved significant penetration in the market—and the assumption of 100% credit towards peak demands is not yet sufficient to alter this. By 2050, the assumption of full credit for batteries has more than doubled storage capacity in the baseline and has even larger effects in the carbon-adder where batteries have completely supplanted turbines by 2050—and renewable generation is correspondingly higher. Conversely, a 15% increase in battery cost is large enough to disincentive the paired solar/battery installations that were seen in the carbon-adder policy without the depth-of-discharge cost on batteries.

Figure F.67. Adder on Generation: NC Generation across Battery Assumptions

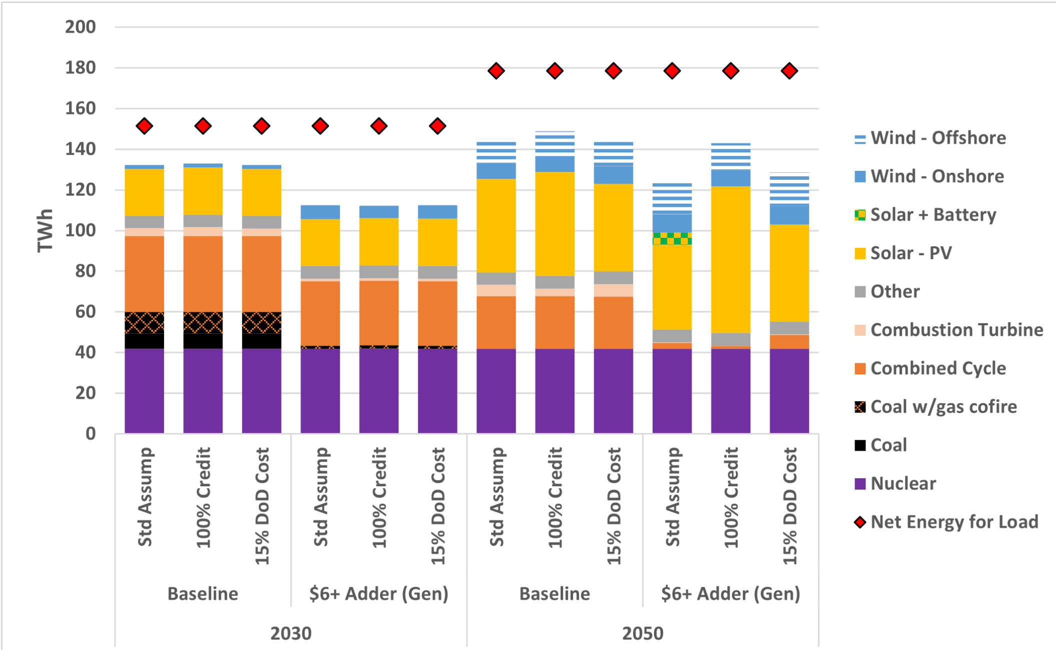
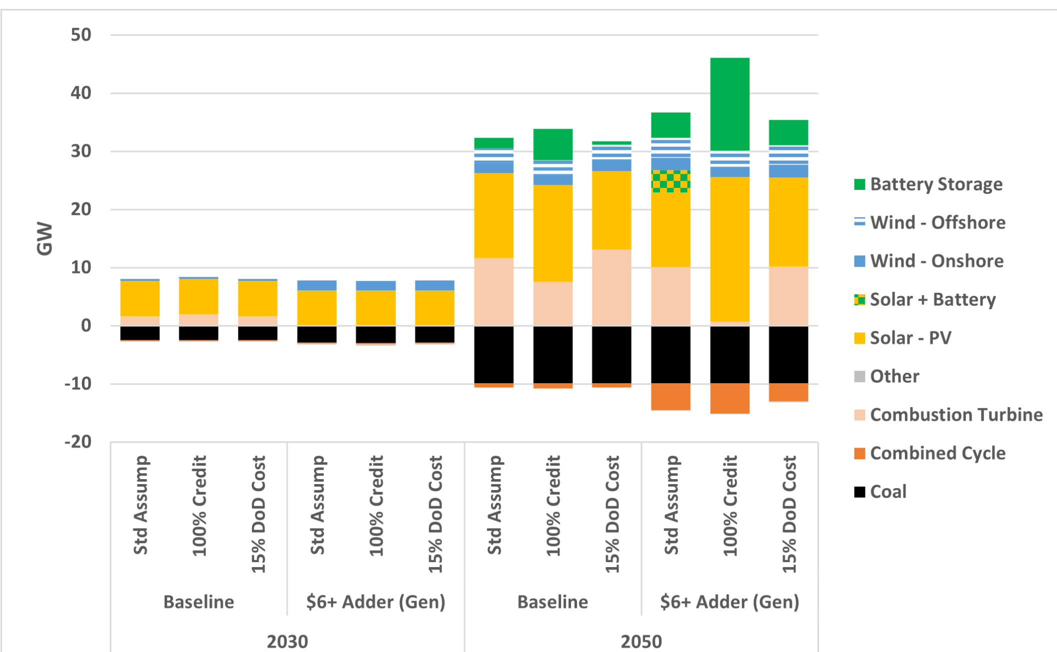


Figure F.68. Adder on Generation: NC Capacity Changes across Battery Assumptions



The two battery alternative assumptions have only limited impacts on emissions trends under the CES policy case. Impacts on policy cost estimates (Figs. F.70a, F.70b, and F.71) are also limited, aside from minor shifts in capital versus import expenditures. These effects tend to hold for the generation and capacity results as well (Figs. F.72 and F.73). The assumption of more effective batteries does lead to additional renewable capacity in the CES policy, supported by more batteries and fewer turbines. The assumption of more costly batteries has the opposite effects.

Figure F.69. CES (65% in 2030): Emissions of NC In-State Generation across Battery Assumptions

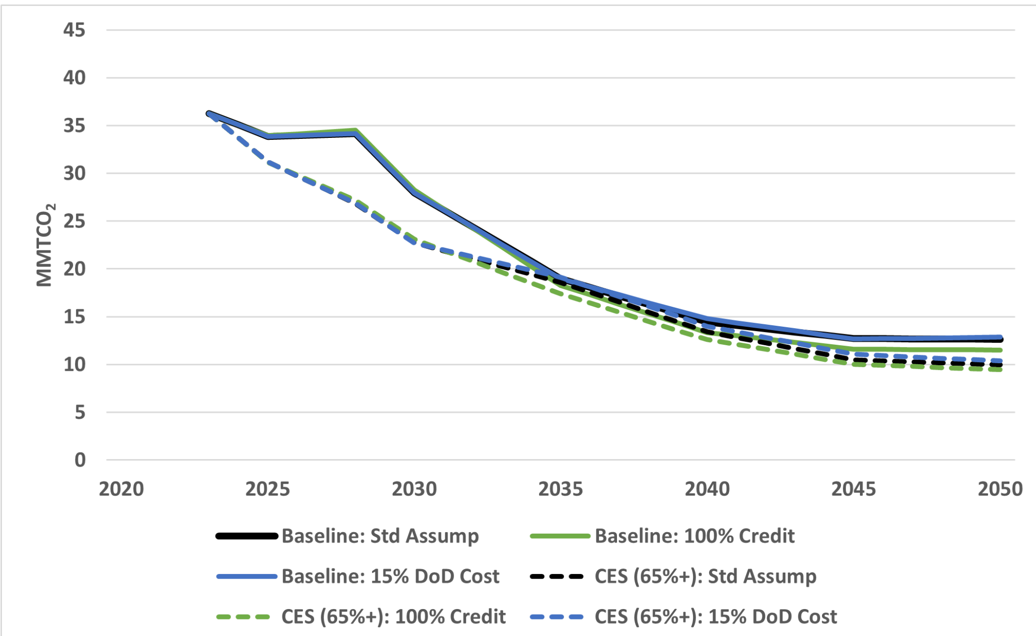


Figure F.70a. CES (65% in 2030): Cost per In-State Tons Reduced vs. % Reduction across Battery Assumptions

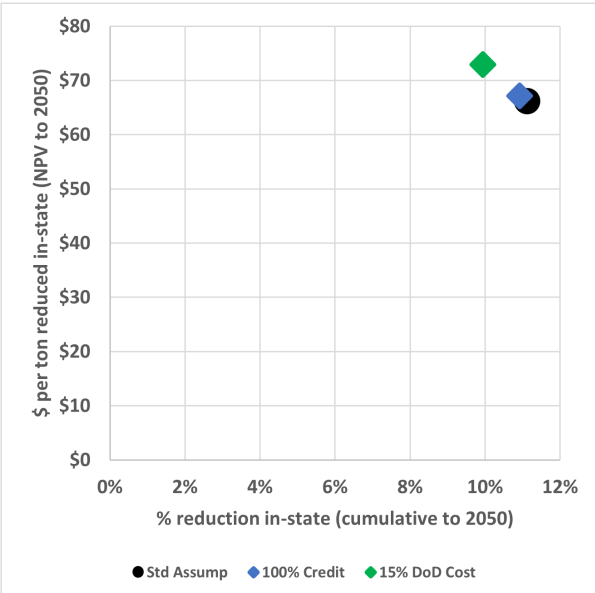


Figure F.70b. CES (65% in 2030): Cost per Total Tons Reduced vs. % Reduction across Battery Assumptions

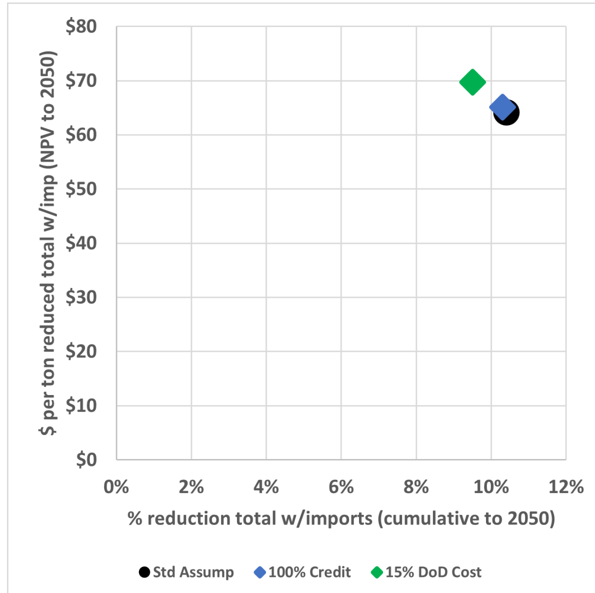


Figure F.71. CES (65% in 2030): Cost Change in NPV through 2050 across Battery Assumptions

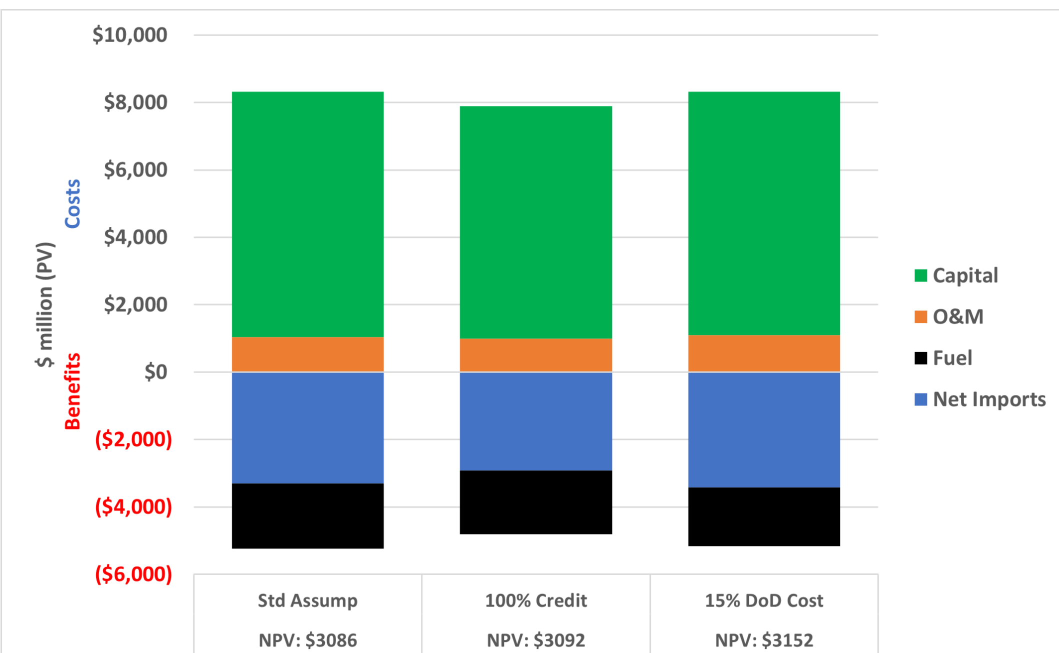


Figure F.72. CES (65% in 2030): NC Generation across Battery Assumptions

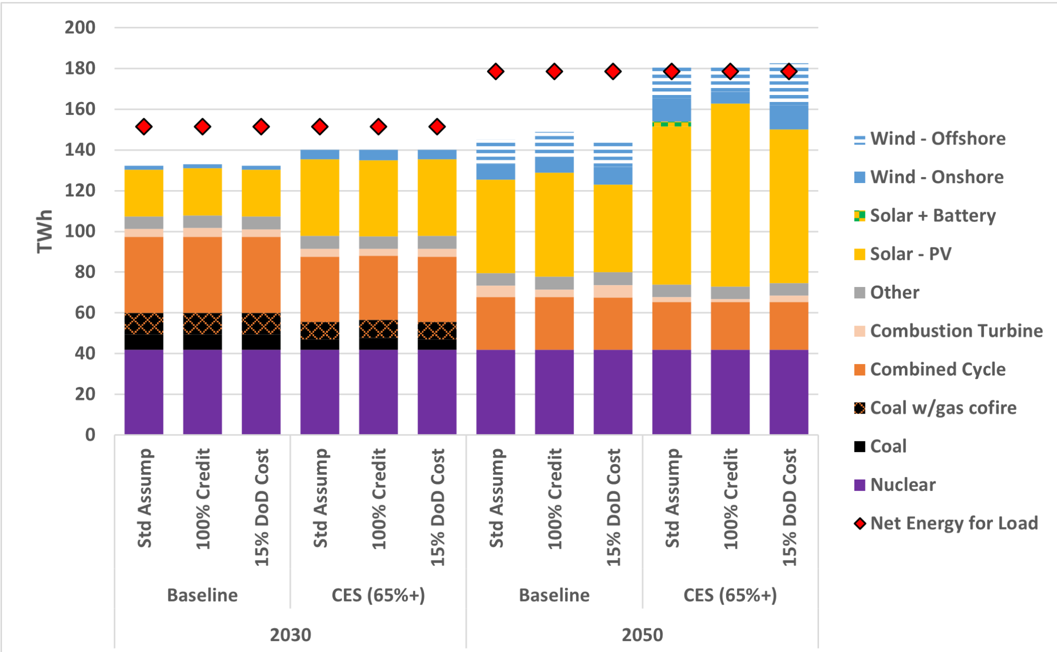
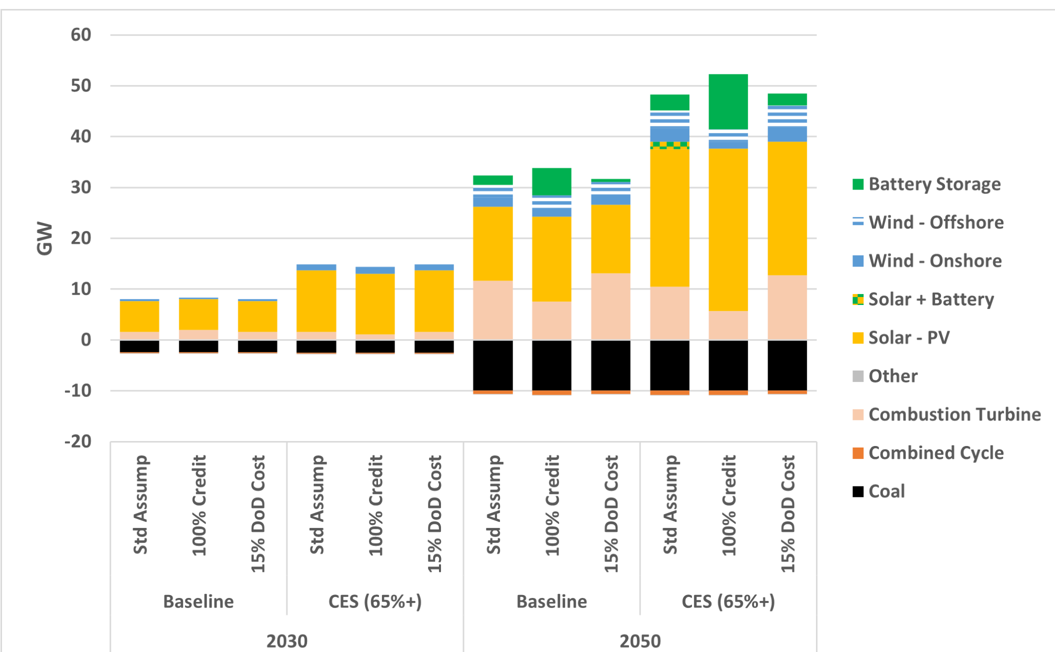


Figure F.73. CES (65% in 2030): NC Capacity Changes across Battery Assumptions



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