A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation

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Executive Summary

Duke Energy could achieve over 70% GHG emissions reductions by 2030 while lowering ratepayer costs by building on the framework of H951 and shifting its resource mix from coal and gas resources to renewable energy and battery storage

- **GHG Emissions:** Duke Energy could **reduce 2030 GHG emissions to 20.4 MMT**, a 74% reduction relative to 2005, by increasing adoption of renewable energy and battery storage, accelerating coal plant retirements, and avoiding new gas capacity
- **Generation Costs**: Greater GHG emissions reductions could be achieved while **decreasing generation costs by $590 million in 2030 and $1,200 million in 2035** under the set of assumptions described in this study
- **System Upgrades**: Up to $5.2 billion of additional T&D upgrades could be built in the case with higher renewable energy and storage such that total ratepayer costs through 2035 decrease in present value terms compared to a case with greater reliance on gas and coal resources

Introduction

Objective: Analyze generation cost and emissions impacts of a future resource mix that achieves the H951 mandates (as passed by the House) and avoids additional development of natural gas capacity

Scope: Generation-specific impacts of H951 in the combined Duke Energy system; does not estimate impacts of transmission and distribution (T&D) investments or changes in regulatory approach (PBR/MYRP)

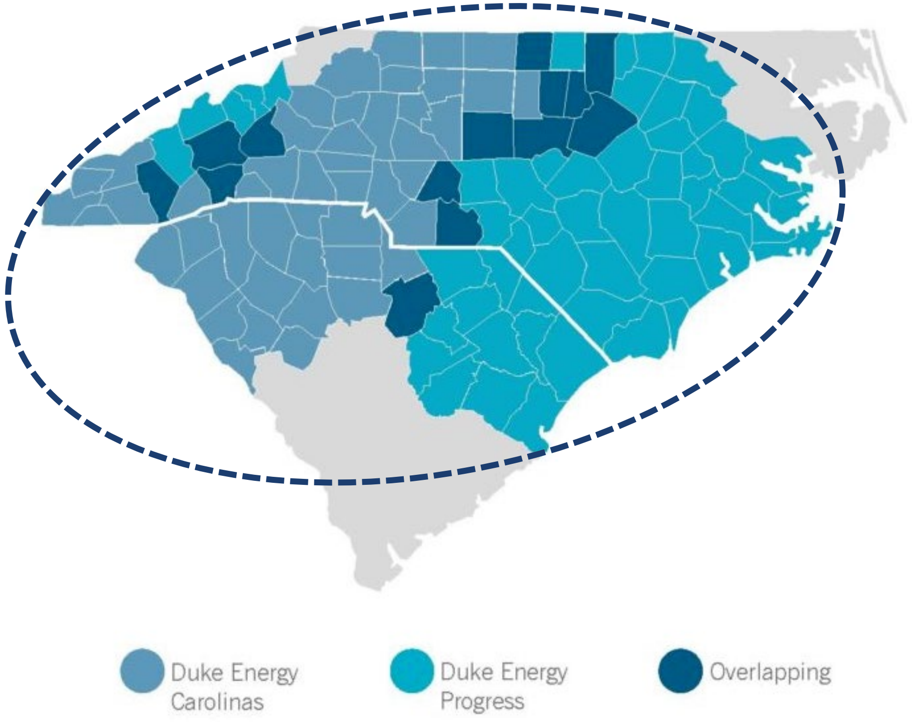
Approach:

- Simulate the operation of the combined Duke Energy system through 2035 under two scenarios:
  - *Base Case*: Resource additions based on Duke's 2020 IRP Base Case with Carbon Policy
  - *Policy Case*: Resource additions based on H951 mandates (*see slide 18 for details*) with Roxboro replaced by cost-effective renewable and storage capacity; no additional gas capacity built
- Calculate difference in generation-related costs, including production costs (fuel and variable O&M costs), capital and fixed O&M costs, and securitization of the net book value (NBV) of retiring coal plants
- Calculate difference in emissions of air pollutants, including CO_2, SO_2, NOx, and Mercury

Modeling Approach

- Analyzed the combined Duke Energy system using Brattle's internal capacity expansion model gridSIM
  - Simulates dispatch of generation and storage resources to meet demand and cost-effective resource expansion
  - Captures chronological dynamics of a future power system that relies more heavily on renewable resources by analyzing 49 representative days (4 days in each month plus the peak demand day)
- Modeled the Duke service territory as an island with limited transactions with neighboring markets, similar to the approach in Duke 2020 IRP
  - Coal units modeled separately based on unit-specific heat rate, operating costs, and fuel costs
  - Other resource types modeled in aggregate based on average operating characteristics

Duke Service Territory Modeled



Source: https://www.hannonlaw.com/wp-content/uploads/2017/12/Duke-Energy-Carolinas-Territory-Map-768x768.jpg

Key Modeling Assumptions

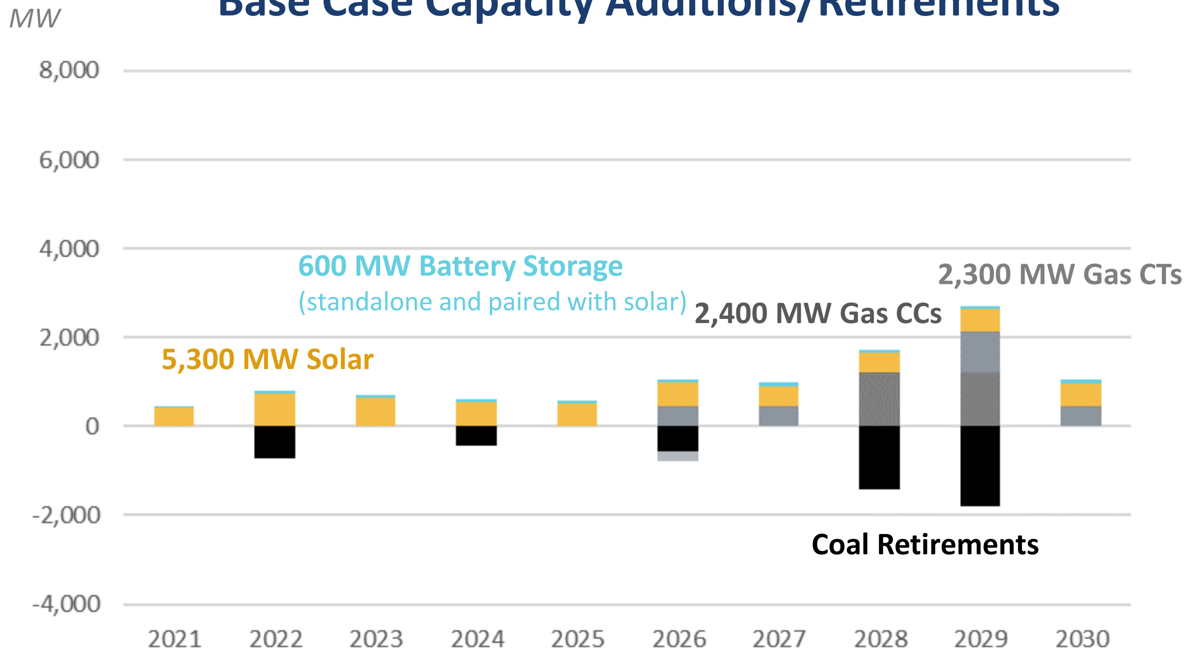
- **New Resources:** New resources in the Policy Case (beyond H951 mandates) limited to solar, onshore wind and battery storage; onshore wind capped at 3,000 MW based on max capacity in Duke 2020 IRP
- **Capacity Expansion:** gridSIM identified mix of economic resources to minimize costs and achieve reserve requirements; ELCCs based on Duke IRP (1% for solar, 33% for wind, 100% for 4-hour battery storage)
- **Generation and Storage Capital Costs**: Based on 2020 ATB Aggressive case with EIA regional adjustments and NC-specific cost data where available, including:
  - Gas CC: Based on the reported costs of the Asheville CC (about $1,500/kW in 2019)
  - Gas Pipeline: Based on EPA study of the costs of converting NC coal plants to gas
  - IPP-Owned Solar: Based on most recent CPRE prices of $37/MWh, trending with ATB projections
- **Federal Tax Credits**: Full value extended to plants under construction by Jan 1, 2027 for ITC and PTC, then reduced by 20% per year thereafter; standalone storage can receive the ITC
- **Delivered Fuel Prices**: Unit-specific coal prices based on 2020 delivered prices, escalated by AEO2021 forecast for SCRA region; annual delivered gas prices based on AEO2021 forecast for SCRA region and shaped by monthly 2018 – 2020 prices (no carbon price modeled)
- **Emissions Rates**: Based on historical CO_2, SO_2, NO_X and Hg emissions rates of Duke's coal and gas plants

Projected Generation and Storage Resource Mix

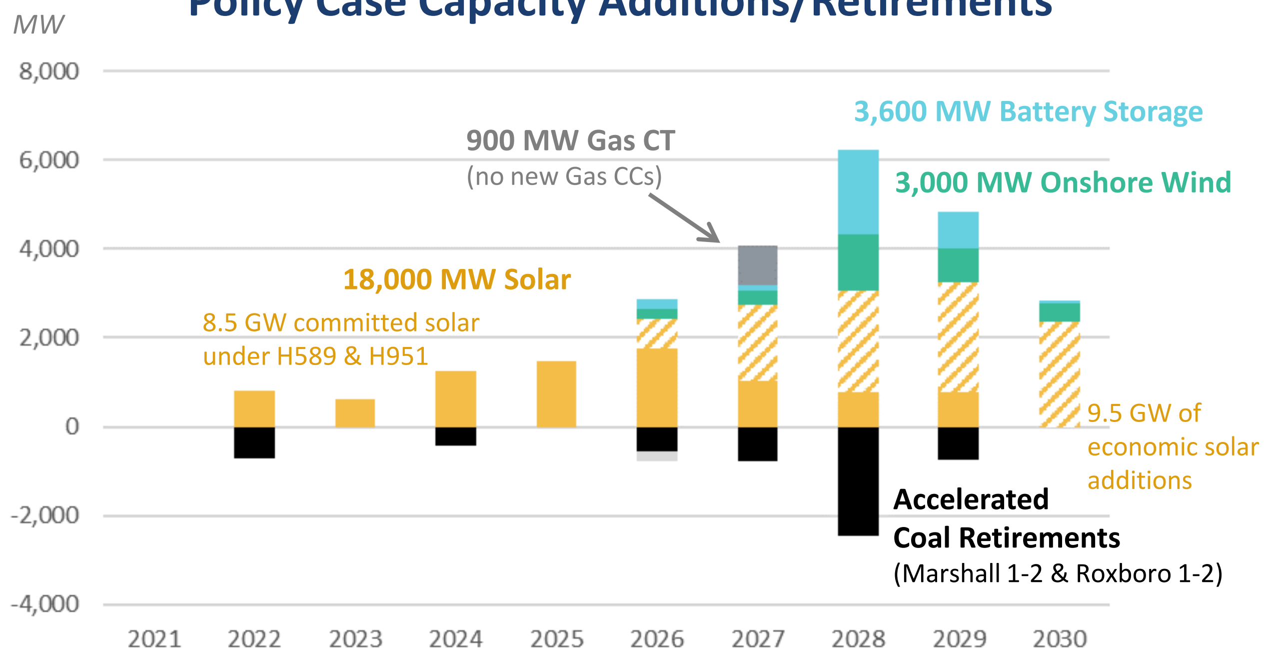
Meeting H951 mandates and limiting new gas significantly alters the 2030 resource mix:

- Adds 18,000 MW of solar, 3,000 MW of onshore wind, and 3,600 MW of battery storage
- Accelerates 1,800 MW of coal retirements (Marshall 1-2 by 8 years; Roxboro 1-2 by 1 year)
- Avoids 3,800 MW of natural gas capacity

Base Case Capacity Additions/Retirements



Policy Case Capacity Additions/Retirements



Note: Assume that the maximum potential solar additions per year will increase from 1,000 MW in 2021 to 3,700 MW in 2030 (or 300 MW per year); assume all economic solar additions beyond H951 are utility-owned.

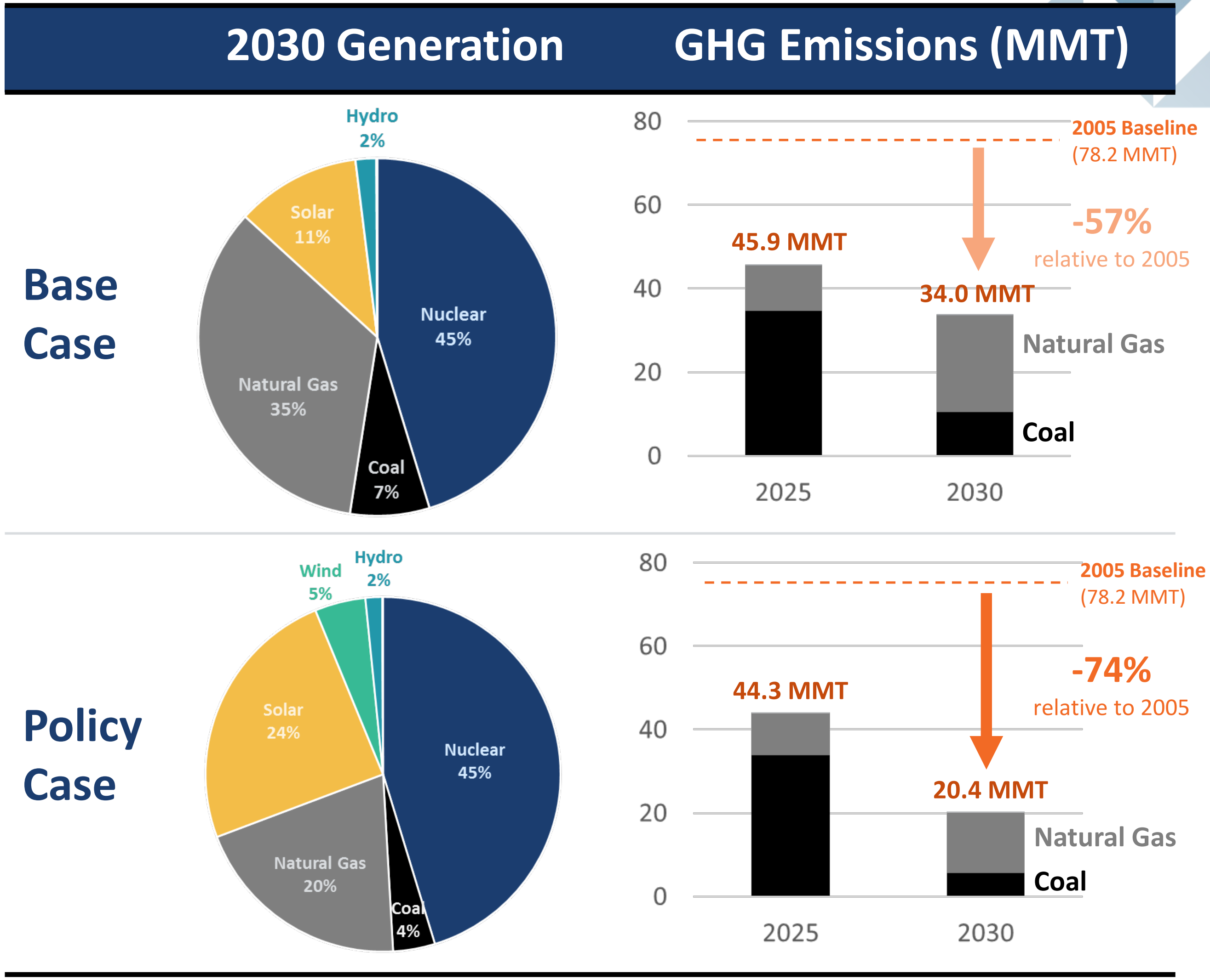
Projected 2030 Energy Generation and GHG Emissions

In 2030, solar and wind generation increase from 11% of total generation in the Base Case to 29% in the Policy Case

- Total coal and natural gas generation decrease by 42% relative to the Base Case
- Total non-emitting resources (i.e., solar, wind, hydro and nuclear) in the Policy Case account for 76% of total 2030 generation

Combined Duke Energy system GHG emissions decrease to 20.4 MMT in 2030 in the Policy Case, a 74% reduction relative to the 2005 baseline

- 2030 GHG emissions are 13.6 MMT lower in the Policy Case than the Base Case
- NC 2030 GHG emissions in Duke's territory decrease to 15.8 MMT in the Policy Case

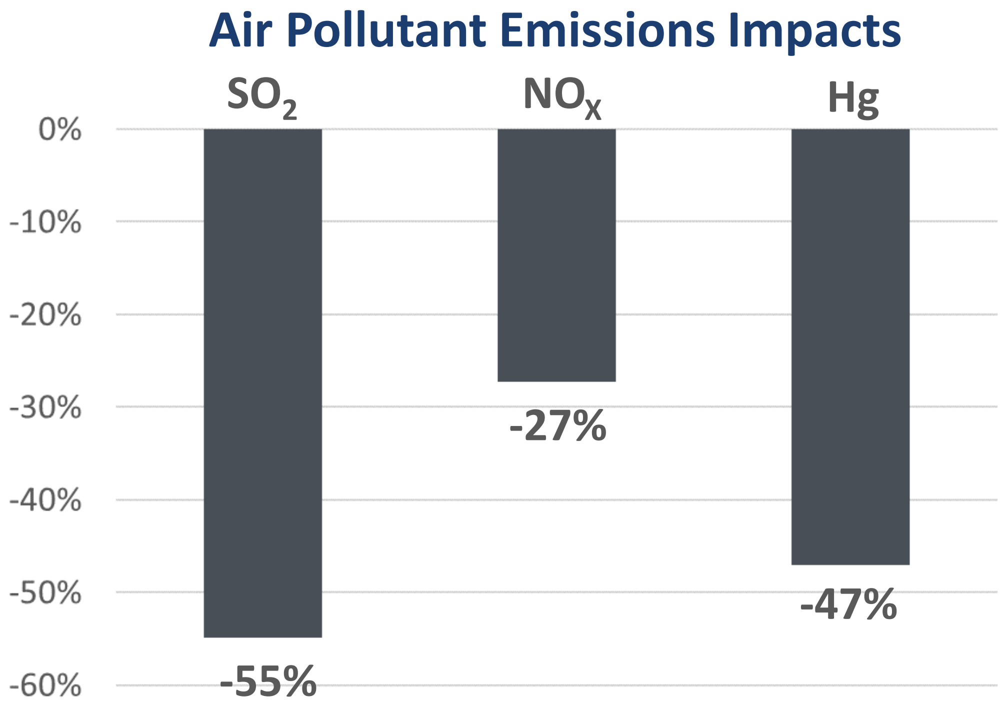


Note: If the carbon price assumed in Duke's IRP is included in the dispatch, Base Case emissions align with Base Case with Carbon Policy emissions (59% reduction relative to 2005).

Reduced Air Pollutant Emissions

Reduced coal and gas generation air pollutant emissions in 2030 compared to Base Case:

- Sulfur dioxide (SO_2) emissions decrease by 3,400 tons
- Nitrogen oxides (NO_X) emissions decrease by 15,800 tons
- Mercury (Hg) emissions decrease by 42 lbs



Generation Cost Impacts

Shifting Duke's resources away from coal & gas and towards renewables & storage results in:

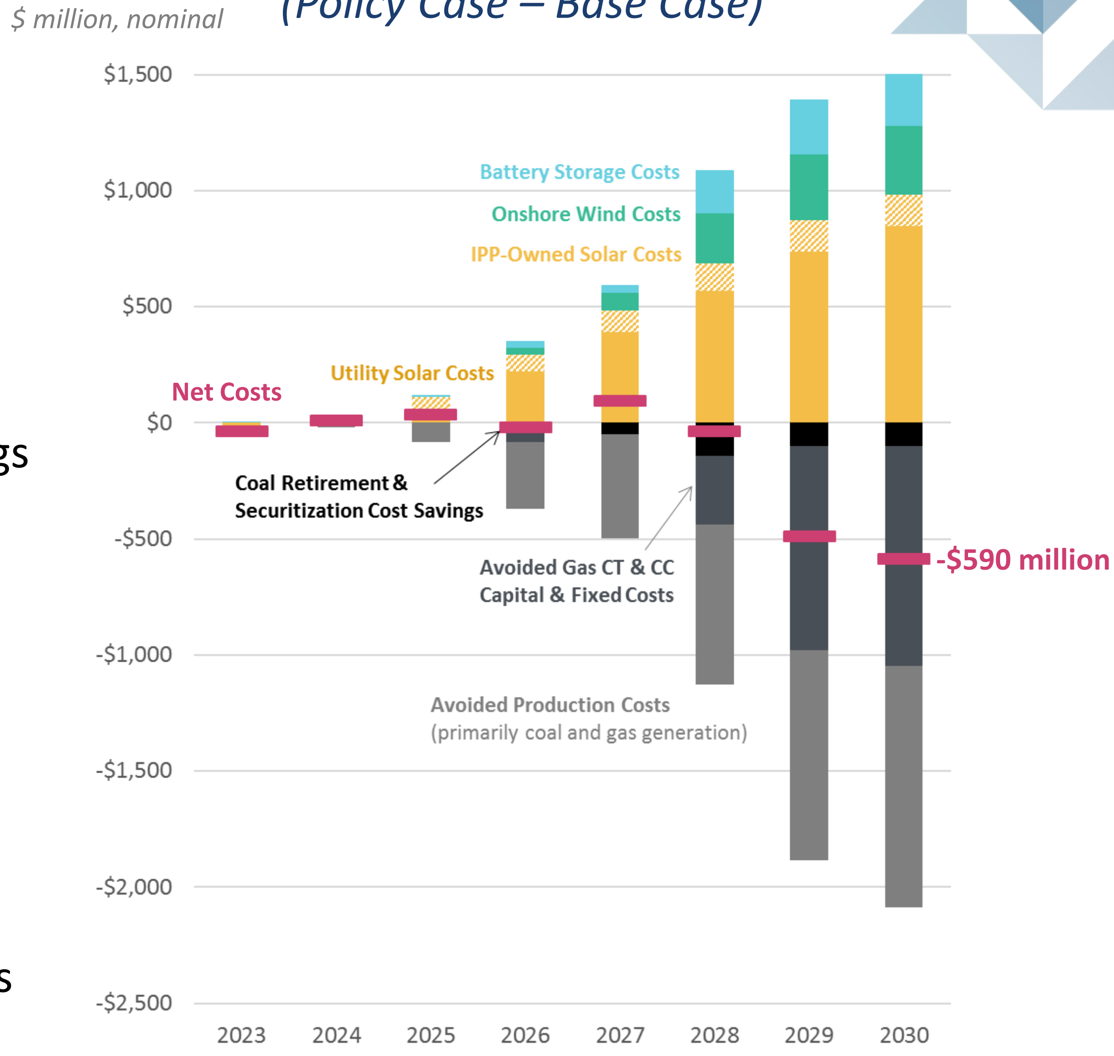
- Low near-term cost impacts with annual net costs fluctuating from $50 million cost savings to $93 million cost increase
- Annual generation cost savings in 2030 of $590 million
- Greater cost savings in later years ($1.2 billion in 2035) due to declining revenue requirements and rising production cost savings

New renewable and storage resources (net of federal tax credits) are lower costs to build than operating existing gas and coal resources and building new gas resources

This analysis does not account for two potential factors:

- Additional non-generation costs, such as transmission and distribution system upgrades, caused by the shift in resources
- Rising costs and declining performance of resources added in less ideal locations and other limitations to increasing solar capacity

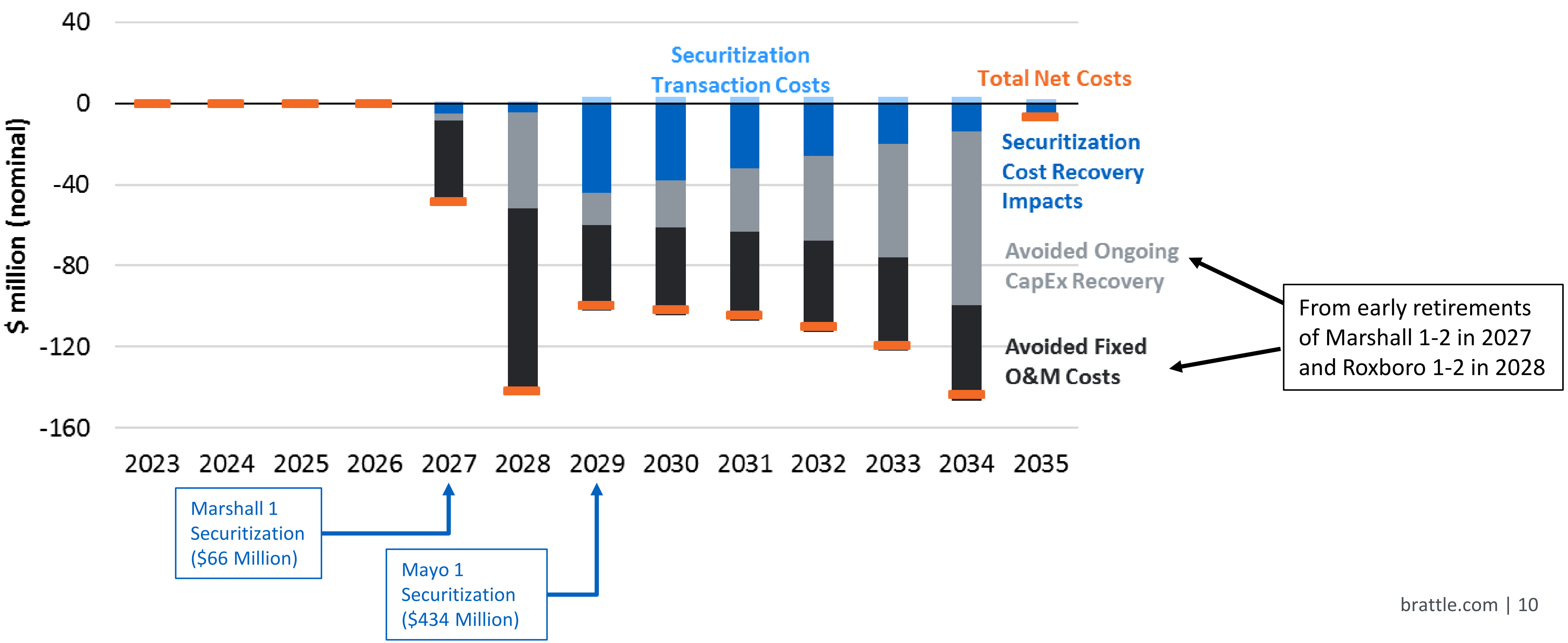
Annual Generation Net Costs
(Policy Case – Base Case)



Coal Plant Cost Savings under Policy Case

Accelerated coal plant retirements and $500 million of securitization of the remaining Net Book Value of coal plants (amortized over 8 years from retirement in alignment with H951) results in significant cost savings to ratepayers (*see slides 25-28 for more details*)

Cost Savings from Accelerated Coal Plant Retirements and Securitization



Transmission and Distribution Upgrades

The differences in the resource mix between the Base Case and Policy Case will lead to differences in T&D system investment needs and associated ratepayer costs

- Analyzing the differences in T&D system is beyond the scope of our study as it would require a detailed analysis of the future power system under each case, including assumptions about the location of each resource and the utilization of existing interconnection capacity
- H951 does not prescribe any specific transmission system investments
- Similar studies of the future resource mix took a similar approach (Synapse and NC Public Staff); Duke IRP included a high-level estimate of transmission investment

Given the potential for higher T&D investments with a greater reliance on renewable energy, we estimate that up to $5.2 billion of additional T&D investments could be built in the Policy Case such that the present value of the revenue requirement (PVRR) for generation and T&D upgrades through 2035 would remain lower than the Base Case

2030 Generation Cost Impact Sensitivities

- **Solar and Storage Costs**: Assuming slower capital cost declines based on NREL ATB Moderate case (instead of Aggressive case) reduces 2030 cost savings by $190 million
- **Solar Ownership**: Shifting 50% of economic solar additions (beyond current designated additions and H951 mandates) from utility-owned to IPP-owned increases 2030 cost savings by $100 million
- **Coal Plant Securitization:** Raising the coal plant securitization cap from $500 million to $859 million increases cost savings by $14 million in 2030
- **Gas Pipeline Costs**: Avoided gas pipeline costs contribute $190 million of 2030 net cost savings
- **Federal Policy**: There is significant uncertainty in the scale and type of federal incentives for renewable energy and storage that will be available through 2030 with the potential for greater incentives than those modeled in our analysis (ITC/PTC extension and PTC optionality for solar) or lower incentives if legislation does not pass

Conclusions

- **GHG Emissions:** Duke could **reduce 2030 GHG emissions to 20.4 MMT**, a 74% reduction relative to 2005 by shifting its resource mix away from existing coal plants and new gas plants and towards renewable energy and storage
- **Generation Costs**: Greater GHG emissions reductions could be achieved while **decreasing 2030 generation costs by $590 million and 2035 costs by $1,200 million** under the set of assumptions described in this study
- **T&D System Upgrades**: Up to $5.2 billion of additional T&D upgrades could be built in the Policy Case such that total generation and T&D system costs through 2035 decrease in present value terms compared to the Base Case

Appendix:
Study Assumptions

GridSIM Overview

INPUTS

Supply
- Existing resources
- Planned builds and retirements
- Fuel prices
- Investment/fixed costs
- Variable costs

Demand
- Representative day hourly demand
- Forecasts of annual and peak demand
- Planning reserve margins

Transmission
- Zonal limits
- Intertie limits

Regulations and Policies
- State energy policies and procurement mandates

GridSIM OPTIMIZATION ENGINE

Objective Function
- Minimize NPV of Investment & Operational Costs

gridSIM

Constraints
- Planning Reserve Margin
- Hourly Energy Balance
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

OUTPUTS

Generator Revenues

Carbon Emissions

Market Prices (Energy, Capacity, REC)

Builds/Retirements

Customer Costs

Total Resource Costs

Projected Energy Demand

DEP Projected Demand

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,885	14,161	63,731
2022	12,909	14,221	64,117
2023	12,913	14,240	64,525
2024	13,063	14,431	65,097
2025	13,207	14,566	65,600
2026	13,381	14,670	66,192
2027	13,461	14,867	66,824
2028	13,589	14,998	67,538
2029	13,833	15,248	68,159
2030	13,917	15,310	68,781
2031	14,075	15,506	69,412
2032	14,241	15,672	70,070
2033	14,361	15,792	70,655
2034	14,499	15,920	71,276
2035	14,757	16,210	71,925
Avg. Annual Growth Rate	1.0%	1.0%	0.9%

Source: DEP IRP (2020), Table C-11.

DEC Projected Demand

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,198	17,795	91,609
2022	18,284	17,933	92,162
2023	18,498	18,042	92,863
2024	18,670	18,195	93,622
2025	18,787	18,334	94,022
2026	18,976	18,493	94,702
2027	19,181	18,607	95,411
2028	19,358	18,790	96,167
2029	19,501	18,933	96,872
2030	19,738	19,074	97,533
2031	19,907	19,226	98,236
2032	20,124	19,393	98,869
2033	20,237	19,502	99,370
2034	20,420	19,605	99,875
2035	20,533	19,752	100,409
Avg. Annual Growth Rate	0.9%	0.7%	0.7%

Source: DEC IRP (2020), Table C-11.

2030 Resource Mix Assumptions

Base Case: Based on Duke 2020 IRP Base with Carbon Policy scenario

- Coal: 4,900 MW of retirements
- Gas: 2,400 MW of new Gas CCs and 2,300 MW of new Gas CTs
- Solar: 5,300 MW of new capacity
- Storage: 600 MW of new 4-hr capacity

Policy Case:

- Coal: Accelerate retirements based on H951
- Gas: Remove Gas CT and Gas CC new builds identified in 2020 IRP, but add 900 MW CT built at Marshall in 2027 based on H951
- Solar Capacity:
  - Remove 2,646 MW of Undesignated Solar included in the IRP
  - Add 5,817 MW of new solar resources mandated by H951
- Battery Storage: 20 MW/80 MWh unit built at Allen in 2024
- GridSIM identifies additional solar, wind, and battery storage capacity necessary to meet capacity shortfall and reduce total ratepayer costs

H951 Solar Additions

- CPRE: 4,667 MW (55% Utility, 45% IPP)
- Shared Solar Program: 750 MW
- Community Solar Gardens: 50 MW
- Green Source Advantage: 350 MW*

*Previously authorized capacity assumed to be built in Policy Case

Coal Plant Retirement Date Assumptions (+3 year approach)

We assume that coal plants that must file a replacement plan by a certain date per H951 will retire 3 years after that date

Plant	Service Territory	Base Case	Policy Case	H951 Impact
Allen 2-4	DEC	2022		
Allen 1 & 5	**DEC**	**2024**		
Cliffside 5	**DEC**	**2026**		
Roxboro 3-4	DEP	2028		
Roxboro 1-2	**DEP**	**2029**	**2028**	**1 year**
Mayo 1	**DEP**	**2029**		
Marshall 1-2	**DEC**	**2035**	**2027**	**8 years**
Marshall 3-4	DEC	2035		
Belews Creek 1-2	DEC	2038		
Cliffside 6	DEC	2048		

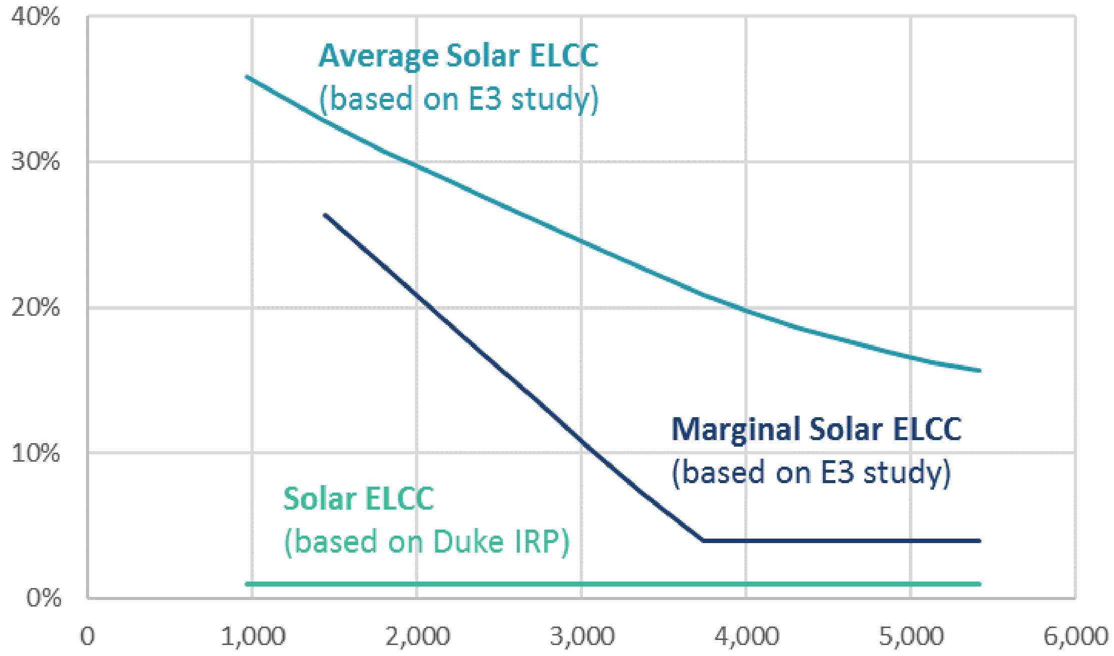
Capacity Value Assumptions

We assumed solar capacity values based on the winter-specific assumptions in the Duke 2020 IRP, which are significantly lower than the annual ELCC values estimated by E3 in their recent study; the South Carolina Public Service Commission recently required the Duke 2020 IRP values to be re-assessed

- **Duke 2020 IRP**: 1% winter ELCC at all capacity levels
- **E3 Study**: Estimated incremental (or "marginal) annual ELCC projections, which we linearized:
  - Assume long-term marginal ELCC levels off at 4% based on Astrape and E3 curves
  - Estimate average solar ELCC based on cumulative marginal ELCC

We assume 100% 4-hour battery storage capacity value and 33% wind capacity value based on the Duke 2020 IRP and no synergistic effects between solar and storage

DEC Solar ELCC Assumptions



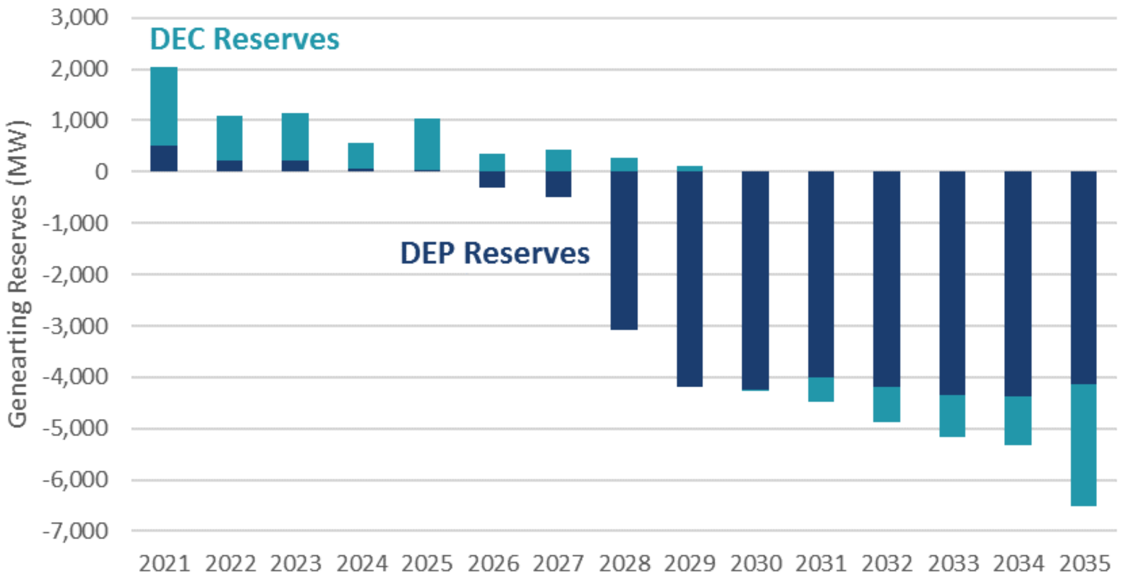
Source: Energy and Environmental Economics, Review of Duke's 2020 Integrated Resource Plan, January 2021, pp. 30-33.

Capacity Shortfall in the Policy Case

We estimated the net capacity shortfall for both DEC and DEP to meet their 17% reserve margin due to accelerating coal plant retirements and avoiding new Gas CC and CTs additions

- The capacity shortfall accounts for the lower ELCC of solar assumed in the Duke IRP; applying the E3 ELCC values would decrease the 2030 capacity shortfall by 760 MW and the 2035 capacity shortfall by 1,490 MW
- gridSIM identified the lowest cost mix of renewables and battery storage to meet Duke's reserve requirements

Projected Capacity Shortfall in the Policy Case
(prior to identifying economic new resources)



Utility-Owned Revenue Requirement Assumptions

- We assumed a 25-year life for new Gas CCs and CTs based on the sensitivity case in the Duke 2020 IRP and accounting for the long-term goal of achieving net zero emissions in North Carolina by 2050
- Revenue requirements estimated based on the most recent after-tax weighted average cost of capital approved in Duke Energy's rate case of 6.56%, assuming 48% debt fraction, 4.3% debt rate, and 9.6% equity rate

Technology	Asset Life	Tax Depreciation	First-Year Fixed O&M	Construction Period
Gas CC	25 years	20yr MACRS	$16/kW-year	3 years
Gas CT	25 years	15yr MACRS	$14/kW-year	2 years
Solar	40 years	5yr MACRS	$10/kW-year	2 years
Wind	30 years	5yr MACRS	$44/kW-year	2 years
Battery Storage	15 years	7yr MACRS	$18/kW-year	2 years
Transmission	50 years	15yr MACRS	2% of overnight costs	4 years

Capital Costs for New Resources

Capital cost assumptions based on 2020 ATB Aggressive case with regional adjustments based on AEO report unless otherwise noted

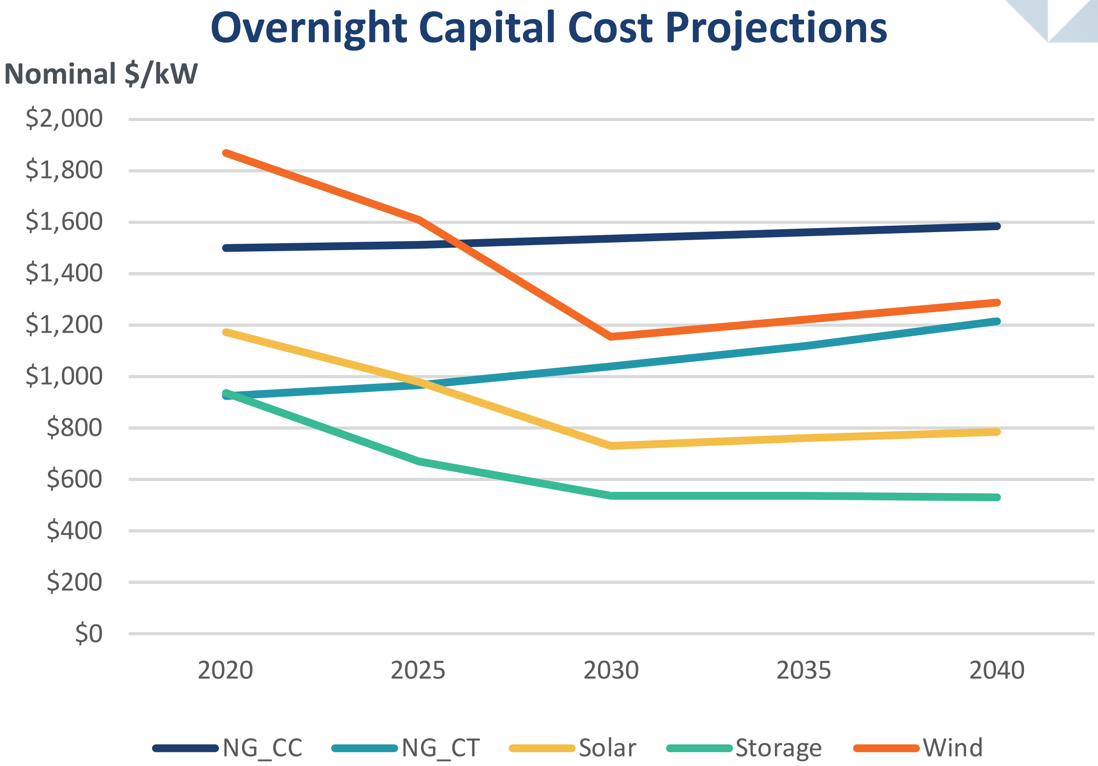
- Avoided Gas CC capital costs reflect costs of the recently built Asheville CC (about $1,500/kW in 2019)
- Gas CT capital costs based on 2020 ATB Moderate case
- Merchant solar costs based on recent CPRE prices of $37/MWh (fixed nominally), trending with ATB solar cost projections
- Community Solar Gardens assumed to be built at $1,900/kW, based on cost cap in H951

New Gas CT and CC capital costs include incremental gas pipeline costs of $125/kW and $700/kW for Roxboro based on EPA analysis

Assume ITC/PTC extended based on the changes proposed in the 2022 Biden Administration budget request

- *PTC*: Full value for onshore wind projects that begin construction by Jan 1, 2027 (online Jan 1, 2032); phased down by 20% per year
- *ITC*: 30% for solar & storage projects under construction by Jan 1, 2027 (online by Jan 1, 2032); phased down by 20% per year

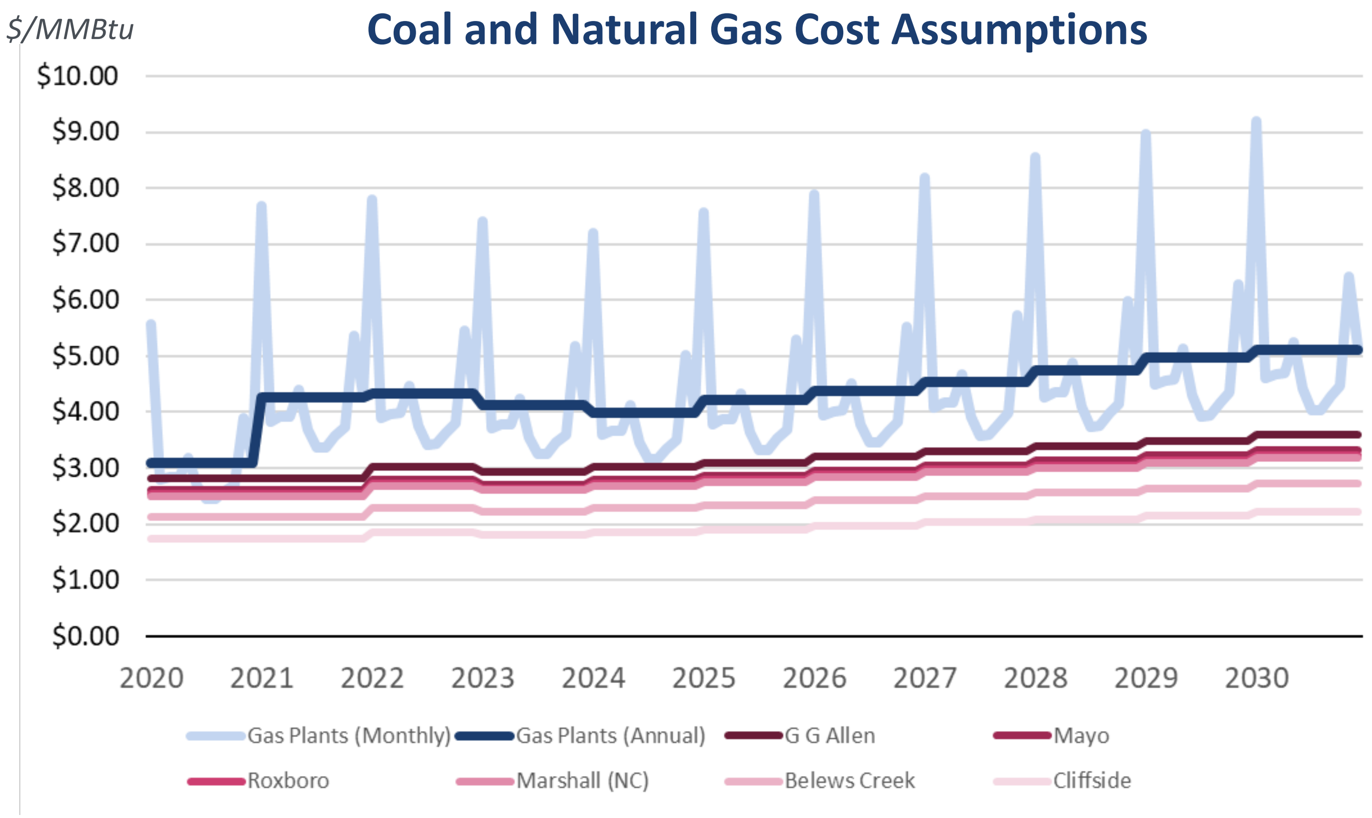
Note: Assume 5-year safe harbor period for projects to come online



Note: Renewable capital costs are based on the NREL aggressive case. Land-based wind in the Carolinas is rated as LBW Class 7 (on a class scale of 1-10 with 1 as the land areas with highest wind speeds). Gas costs are based on the NREL moderate case. NG_CC costs are adjusted for the recently built Ashville CC plant.

Delivered Fuel Price Projections

- Coal price by plant based on delivered coal prices in 2020 and escalated based on AEO2021 forecast for delivered cost of coal into SRCA region
- Delivered gas price forecast from AEO2021 with monthly shapes based on average historical shape from 2018-2020 to account for commodity price and variable delivery charges



Generation and Storage Operating Characteristics

We model several resource types as aggregated units, but included each coal unit as a separate resource.

Generation and Storage Resource Attributes

	Heat Rate (MMBtu/MWh)	Variable O&M ($/MWh)	Fixed O&M ($/ICAP MW-yr)
Existing			
Coal (Range)	8.87 - 10.61	$1.38 - $4.11	$21,337 - $33,673
Gas CC	7.07	$0.71	$16,249
Gas CT	11.26	$0.59	$7,573
Nuclear	10.43	$3.35	$86,083
Hydro	0.00	$1.55	$20,359
Pumped Hydro	0.00	$1.58	$6,816
Solar	0.00	$0.61	$6,906
New			
Gas CC	6.60	$1.39	$13,383
Gas CT	9.88	$4.50	$11,855
Solar	0.00	$0.00	$16,328
Wind Onshore	0.00	$0.00	$43,421
Storage	0.00	$5.00	$31,279
CHP	7.59	$1.39	$13,383

Notes: We assume $5/MWh for storage VOM based on assumed round-trip efficiency losses of ~15% on average energy prices of $35/MWh.

Annual Fixed O&M, Ongoing CapEx and NBV for Coal Units

Unit	Securitization Eligible	Retirement Date (Policy Case) [1]	End of Depreciation Life [2]	Annual Fixed O&M (*$ Million*) [3]	Annual Ongoing CAPEX (*$ Million*) [4]	NBV EOY 2020 (*$ Million*) [5]	NBV EOY 2025 (*$ Million*) [6]
Belews Creek_1		2038	2037	$34.3	$33.5	$756.0	$674.8
Belews Creek_2		2038	2037	$34.3	$33.5	$756.0	$674.8
G G Allen_1	Yes	2023	2026	$8.0	$5.5	$43.5	$10.7
G G Allen_2		2021	2026	$8.0	$5.5	$43.5	$8.2
G G Allen_3		2021	2026	$12.9	$8.9	$26.0	$5.8
G G Allen_4		2021	2026	$12.8	$8.8	$171.6	$30.1
G G Allen_5	Yes	2023	2026	$12.4	$8.5	$166.4	$33.1
James E. Rogers Ener_5	Yes	2025	2032	$20.1	$16.5	$350.0	$265.7
James E. Rogers Ener_6		2048	2048	$31.3	$21.0	$1,984.4	$1,727.1
Marshall (NC)_1	Yes	2026	2034	$18.2	$12.0	$208.9	$181.9
Marshall (NC)_2	Yes	2026	2034	$18.2	$12.0	$208.9	$181.9
Marshall (NC)_3		2034	2034	$24.2	$20.8	$361.8	$315.0
Marshall (NC)_4		2034	2034	$24.3	$20.8	$362.9	$315.9
Mayo_1	Yes	2028	2035	$27.5	$21.5	$676.0	$538.1
Roxboro_1	Yes	2027	2028	$18.2	$12.0	$216.4	$114.5
Roxboro_2	Yes	2027	2028	$24.8	$21.2	$269.6	$160.1
Roxboro_3	Yes	2027	2033	$25.7	$21.1	$239.8	$228.9
Roxboro_4	Yes	2027	2033	$26.2	$20.5	$244.2	$229.5

Sources/Notes:
[2]: Doss Testimony and Exhibits in 2017 rate cases (Docket E-7 Sub 1146 and Docket E-2 Sub 1142)
[3] & [4]: EIA, Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Values adjusted to 2021$.
[5]: Where possible, values from Duke 2020 10K. Otherwise, 2018 NBV taken from Spanos Rate Case and estimated 2020 using assumed ongoing CAPEX.
[6]: Started with NBV as of EOY 2020, and adjusted for depreciation and new ongoing CAPEX.

Coal Plant Securitization

House Bill 951 allows securitization financing for the remaining net book value (NBV) of eligible coal units that would be retired by 2030.

- Eligible units: remaining units at Allen plant (units 1 and 5), Marshall units 1 and 2, Roxboro plant, Cliffside unit 5, and Mayo unit 1
- End of 2020 NBVs: about $2.6B total (Source: Duke 2020 10K, Duke rate case filings, and Brattle calculations)
- NBVs at the time of retirement in Policy Case: $1.7 Billion total

H951 limits the securitization funding to a $500 million cap. We also evaluated a $859 million cap case (50% of $1.7 Billion).

Coal Units Eligible for Securitization

Unit	EOY Retirement Date (Policy Case)	NBV EOY 2020 *($ Million)*	NBV at Policy Retirement *($ Million)*
G G Allen_1	2023	$44	$32
G G Allen_5	2023	$166	$99
James E. Rogers Ener_5	2025	$350	$266
Marshall (NC)_1	2026	$209	$173
Marshall (NC)_2	2026	$209	$173
Mayo_1	2028	$676	$434
Roxboro_1	2027	$216	$49
Roxboro_2	2027	$270	$73
Roxboro_3	2027	$240	$209
Roxboro_4	2027	$244	$209
Total		**$2,624**	**$1,719**

Coal Plant Securitization (cont'd)

The securitization cap is required to be allocated to retiring units "in a manner that realizes the greatest cost savings to ratepayers as determined by the Commission".

- *Approach*: Allocate the cap to the units with the longest remaining depreciable lives (Mayo 1, Marshall 1-2, Cliffside 5) while avoiding too much fragmentation of securitization funding (to minimize upfront fixed financing/legal costs of each securitization).

Securitization is assumed to apply to the following units at their retirement:

- $500 Million Cap: Marshall 1 ($66M in 2027) and Mayo 1 ($434M in 2029)
- $859 Million Cap (50% of Total NBV): Cliffside 5 ($79M in 2026, Marshall 1-2 ($347M in 2027), and Mayo 1 ($434M in 2029)

Securitization period and interest rate: not specified in H951, so we reviewed securitization filings by Consumers Energy (2020) and PNM (2019).

- Consumers assumed a 8-year securitization period with 1.78% interest rate in Sep 2020 for securitization of $703M.
  - Transaction costs: $11.6 million upfront cost and $0.75 million annual financing costs.
- PNM assumed a 25-year securitization period with 3.38% interest rate in Jun 2019 for securitization of $360M.
  - Transaction costs: $8.7 million upfront cost and $0.5 million annual financing costs.
- We assume 8-year securitization with 1.78% interest rate, plus
  - $5 million fixed and 0.95% of securitization as upfront financing costs, and
  - $0.3 million fixed and 0.06% of securitization as annual financing costs.

Coal Plant Cost Savings under Policy Case

ANNUAL REVENUE REQUIREMENTS ASSOCIATED WITH CAPITAL AND FIXED O&M COSTS AT DUKE COAL UNITS ($ Million, Nominal)

No Securitization Case

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base Case	1,503	1,482	1,496	1,485	1,497	1,489	1,420	1,399	1,147	1,147	1,152	1,163	1,151	1,154	694
Policy Case	1,503	1,482	1,496	1,485	1,497	1,489	1,376	1,261	1,088	1,081	1,076	1,076	1,049	1,021	694
Policy minus Base	0	0	0	0	0	0	-44	-139	-58	-66	-75	-87	-102	-133	0

Base Case: $500 Million Securitization

(Marshall 1 in 2027 for $66M, and Mayo 1 in 2029 for $434M)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base Case	1,503	1,482	1,496	1,485	1,497	1,489	1,420	1,399	1,147	1,147	1,152	1,163	1,151	1,154	694
Policy Case	1,503	1,482	1,496	1,485	1,497	1,489	1,372	1,257	1,047	1,046	1,047	1,053	1,032	1,010	687
Policy minus Base	0	0	0	0	0	0	-48	-142	-100	-101	-105	-110	-119	-144	-7

Sensitivity Case: $859 Million Securitization

(Cliffside 5 in 2026 for $79M, Marshall 1-2 in 2027 for $347M, Mayo 1 in 2029 for $434M)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base Case	1,503	1,482	1,496	1,485	1,497	1,489	1,420	1,399	1,147	1,147	1,152	1,163	1,151	1,154	694
Policy Case	1,503	1,482	1,496	1,485	1,497	1,483	1,346	1,235	1,029	1,032	1,037	1,047	1,041	1,011	687
Policy minus Base	0	0	0	0	0	-6	-74	-164	-117	-115	-115	-116	-110	-143	-7

Cost Impacts of Alternative Solar Ownership Approaches

Shifting the economic new solar capacity from utility ownership to IPP ownership will increase customer cost savings through 2035

Additional Cost Savings with Increasing IPP Ownership of New Solar

Ownership of Economic Solar Additions	Annual 2030	Cumulative 2021 - 2030	Cumulative 2021 - 2035
30% IPP / 70% Utility	$60 million	$300 million	$525 million
50% IPP / 50% Utility	$100 million	$530 million	$910 million
70% IPP / 30% Utility	$150 million	$800 million	$1,340 million

Note: Applied to 9,500 MW of economic solar additions from 2026 to 2030 and the additional 2,400 MW of economic new solar additions from 2031 to 2035.

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