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Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP

Introduction

Power sector dispatch modeling helps utilities, regulators, and stakeholders understand the costs and benefits of different policy choices and power portfolios at state, regional, and national levels. The Natural Resources Defense Council (NRDC) commissioned energy consultant ICF to perform a power sector analysis using its Integrated Planning Model (IPM®), with assumptions developed by NRDC. IPM is a national model – not a model of the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems – but the model does provide reporting at a state and regional level. NRDC's IPM analysis detailed below focuses on the state-level reporting for North Carolina.

NRDC commissioned ICF to develop two modeling scenarios for North Carolina: (1) an "economically optimized" case designed to select the least-cost future energy portfolio for the state; and (2) an "IRP" scenario designed to replicate as closely as possible DEP and DEC's "No CO_2 Base Case" portfolios in their 2018 Integrated Resource Plans. NRDC's IPM analysis, which will include these two scenarios in addition to other scenarios, is also intended to help inform the state's ongoing Executive Order 80 discussions and drafting of a Clean Energy Plan.

The key findings from NRDC's IPM analysis are:

1. ***The state sees a significant reduction in coal capacity in the near term.***
2. ***Reduced coal capacity and generation is replaced primarily by new solar capacity.***
3. ***The only additional natural gas capacity added is from units already under construction.***
4. ***Renewable energy generation more than makes up for the generation reductions from other sources leading to significant emission reductions without impacting in-state generation totals.***
5. ***The IRP case depends much more heavily on natural gas.***
6. ***The IRP case sees higher – and rising – carbon pollution over the next two decades.***
7. ***The IRP case comes at a higher cost for the state's energy system.***
8. ***Under the IRP case, the average residential customer would see higher bills.***

The findings are explained in greater detail below.

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What is the Integrated Planning Model?

IPM is a detailed model of the U.S. electric power system routinely used by the electricity industry and regulators. Utilities and regulators, including the U.S. Environmental Protection Agency, Regional Greenhouse Gas Initiative, Dominion Energy, and Virginia Department of Environmental Quality, have used IPM to assess the effects of environmental regulations and policy. IPM determines the least-cost means of meeting electric energy and capacity requirements while complying with specified constraints, including air pollution regulations, transmission constraints (e.g. security-constrained economic dispatch, or SCEDs), and plant-specific operational constraints. IPM integrates extensive information on power capacity and generation, technology performance, transmission, energy demand, electricity and fuel prices, policies, reserve margin requirements, reliability standards, and other factors. IPM then determines the most cost-effective future capacity and generation mixes to meet electricity needs, based on its detailed representation of the U.S. electricity system. It can build new power plants, retire existing plants, and ramp these facilities up and down to meet demand in the least-cost way. IPM provides a range of outputs for modeled scenarios, including: capacity, capacity factors, generation, net exports, wholesale energy prices, fuel prices and costs, retail bills, total system costs, and emissions (including carbon dioxide, sulfur dioxide, and nitrogen oxide) by fuel and technology type.

NRDC's scenarios, inputs, and assumptions provided to ICF

ICF ran IPM with two different cases based on NRDC's assumptions: an "economically optimized" reference case and an "IRP" case.

- **In the "economically optimized" case**, the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations. This included the North Carolina Renewable and Efficiency Portfolio Standard (REPS), House Bill 589 (HB 589), and federal regulations like the Mercury and Air Toxics Standards, but excluded the federal Clean Power Plan and Affordable Clean Energy rules or any future state policies (including those related to Executive Order 80). This case is illustrative of a more holistic assessment and determination of a "least-cost" portfolio, as recommended in the report completed by Applied Economics Clinic on behalf of NRDC, the Sierra Club and Southern Alliance for Clean Energy, which is also attached to our comments on the Duke IRPs.

- **In the "IRP" Case,** the model was forced to build the new natural gas capacity (CT and CC) included in DEC's and DEP's "Base Case No CO2" for the years 2019 – 2032. The model was allowed to economically retire coal (unlike in Duke's own IRP modeling), but the model was prevented from closing nuclear facilities before the end of a 60-year license. Annual solar builds were capped at the levels included in the DEC and DEP IRP

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Base Cases (the model could build less, if least-cost, but could not build more than the combined additions identified in each year in the IRP base cases). This case was designed to more closely match the long-term resource plans submitted by DEP and DEC, and allow for a direct comparison of costs, generation, and emissions outcomes between an "economically optimized" portfolio and a scenario more representative of the utilities' proposed future portfolios. However, it likely underestimates total costs and emissions since it is allowed to economically retire coal capacity, which Duke's modeling did not allow.

Assumptions for this analysis were developed by NRDC, relying primarily on publicly available projections from various parts of the U.S. Department of Energy (DOE):

- For gas prices and energy demand, we relied on reference case ("business as usual") projections from the Energy Information Administration (EIA), which is an independent statistical agency of the DOE. The projections came from EIA's Annual Energy Outlook 2019 (AEO2019), published January 2019.
- We also relied on EIA's AEO2019 for conventional power plant costs, or the costs of building new fossil fuel-fired generation and new nuclear plants.
- NRDC used the DOE's National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline projections for the costs of building new wind and solar projects, which represent the agency's expert view on the future costs of renewable technologies.
- Limits on variable renewable generation were also incorporated to approximate the amount of solar and wind the grid can accommodate without additional transmission investments based on research by and discussions between ICF and NRDC.[1]
- NRDC used IPM v6 (the most current version) for this analysis, which incorporates modeling improvements to solar and wind resources including: hourly generation profiles (8760 hourly profiles) customized for each resource "tranche" and state combination in IPM based on NREL data; seasonal capacity factors; and revised reserve margin assumptions for intermittent resources to estimate the capacity credit of wind and solar resources at a unit level based on the modeled penetration of solar and wind within each region. This allows the model to endogenously account for the decline of capacity credit for intermittent resources with their rising penetration.

[1] This included a robust review of historical performance at the individual utility and ISO/RTO levels, utility near-term operating plans, and renewable integration studies to assess feasibility and costs of varying wind, solar, and wind & solar penetration levels. Historical performance included data from CAISO, ERCOT, SPP, Kansas, Xcel (CO), Xcel (Upper Midwest), MidAmerican (IA), and DTE. Studies included SPP's Wind Integration study, PJM Renewable Integration study, Western Wind and Solar Integration study, Eastern Wind Integration and Transmission study, New England Wind Integration study, California Low Carbon Grid study, and NREL's Renewable Electricity Future Study, International studies and performance in the UK, Denmark, and Germany were also reviewed.

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A detailed list of our assumptions is included below:

	2019 Reference Case
Assumption	**Reference Case Proposed Sources**
IPM Version	IPM EPAv6
Electric Demand	AEO 2019
Peak Demand	AEO 2019
Capacity Build Costs - Conventional	AEO 2019
Capacity Build Costs - Renewable	NREL 2018 ATB. ITC and PTC assumed per 2015 omnibus.
Capacity Build Costs - Storage	Storage allowed as an economic addition. Costs reflect NRDC assumed trajectory, reflecting a mid-case projection between ICF's default costs, McKinzie, Lazard, and Bloomberg New Energy Finance.
Coal Supply/Prices	EPA v6
Gas Supply/Prices	Fuel Supply Curves (AEO 2019).
Firm capacity additions and retrofits	Latest market information (Q1 2019) and NRDC input; NC units explicitly reviewed by ICF: Reidsville, Asheville, & King's Mountain are firm builds, as well as Amazon Wind 2.
Nuclear Retirements	Any nuclear reactors that reach age 40 can receive a subsequent license renewal and operate for 20 more years. One additional 20-year renewal is allowed at age 60 (max lifetime is 80 years).
Pollution Control Retrofit Costs	EPA v6
CCS Retrofit cost and performance - Coal	EPA v6
CCS Retrofit cost and performance - Gas	Include new build options only; EPA v6
Biomass co-firing at coal facilities	EPA v6
Gas co-firing at coal facilities	EPA v6; NC units with co-firing capabilities in the model include Marshall units 1-4, Cliffside 5
Coal-to-gas conversions	EPA v6; NC units Cliffside 6 and Belews Creek modeled as conversions.
Unit-level heat rates	EPA NEEDS v6
(Regulatory) RPS & State Policies	Reflects RPS as of January 2019. HB 589 in NC is explicitly modeled (model required to have 6.2 GW of solar online by 2022 in NC, at minimum)
(Regulatory) SO2/NOx	CAIR and CSAPR
(Regulatory) MATS	As finalized; allow HCl compliance via low-chlorine PRB coals
(Regulatory) Coal Combustion Residuals	Include
(Regulatory) Water Intake Structures	Include
(Regulatory) RGGI	Include new model rule; NJ and VA join at NRDC's recommended levels in 2020.
(Regulatory) CA AB32	Include
(Regulatory) Regional Haze	Include
(Regulatory) CPP Constraints	No Banking. No CPP in Base Case.
(Structure) Run years	(state reporting 2020 - 2050)
(Structure) EE Supply Curves	3 supply curve steps per region with utility program costs in line with NRDC 2017 analysis
(Structure) Heat Rate Improvements	EPA v6 (not included in Reference Case)
EE penetration	Based on NRDC analysis
FOM and VOM	EPA v6

Results for NRDC's IPM Economically Optimized Case

As set forth above, ICF's Integrated Planning Model determines the least-cost means of meeting electric generation energy and capacity requirements while complying with specified

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constraints, including air pollution regulations, transmission constraints, and plant-specific operational constraints. NRDC developed a set of modeling assumptions, reflecting what NRDC believes are the best publicly available forecasts and data sources, to produce defensible and reasonable projections of the state's electric sector over the next two decades.

The economically optimized model run aims to represent a future, optimized electric sector where the model is allowed to select the least-cost resources available. This "optimized" case reflects existing requirements (like HB 589 and the state's REPS), announced power plant retirements, future electricity demand, and expected natural gas prices – but otherwise allows the model to add or retire resources as it sees fit to select the least-cost portfolio. The results from this case are used to benchmark other cases, like the IRP case.

However, this "optimized" case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information and utilities are driven by incentives that do not always align with their customers' interests. Even so, we hope this case provides a view into what is possible - and economical - for the state's power sector in the future.

Key Findings:

1. ***The state sees a significant reduction in coal capacity in the near-term.***

The state's coal fleet shrinks in response to both economic and announced retirements in the next 5 years. In run year 2020 (which is inclusive of years 2019 – 2022), operating capacity falls to 6.5 GW – or a 4 GW reduction from 2018 levels. (See Table 1)

Installed Capacity (GW)	2018 (P)	2020	2025	2030	2035
Coal	10.5	6.5	6.5	5.8	5.8
NGCC	5.2	5.8*	6.3*	6.3	6.3
NG CT	6.2	6.2	6.2	6.2	6.2
Nuclear	5.1	4.8	4.8	4.8	4.8
Solar	3.7	6.0	11.7	11.7	11.7
Wind	0.2	0.2	0.3	0.3	0.3
Storage	0.0	0.0	0.0	1.3	1.3

*Table 1. In-state capacity results for North Carolina in the "economically optimized" case. * denotes firm (i.e. hard-wired) addition.*

Despite these coal closures, coal generation does not decrease as significantly from 2018 levels. (See Table 2) This is driven by the model's increased utilization of the remaining fleet.[2] As noted in Duke's

[2] For example, Duke has several units that have been converted to run with either coal or gas. The IPM results suggest that, contrary to Duke's findings, the economics of running these units on gas are poor. The IPM model finds that the co-fired facilities are less efficient at burning gas than a NGCC unit. Based on the gas prices used, the lack of a carbon price or other policy that would disadvantage coal, the model finds it more economical to utilize other resource options, including use of coal at those co-fired facilities. At a minimum, this suggests that the investment in co-firing at coal plants may only be economic in a narrow range of gas and coal price futures.

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IRP, Duke currently runs some coal plants as "peaking units" with very low capacity factors. The report produced by Applied Economics Clinic on behalf of the intervenors provides additional detail on forecasted unit operations and associated cost and operational impacts from this type of implementation.

The coal closures projected in the "economically optimized" case in the next few years allows the remaining fleet to run at higher capacity factors in the modeled future. In our model runs, the capacity factor or utilization for the state's coal fleet remains between 50-55% annually from 2020 to 2040.

2. ***Reduced coal capacity and generation is replaced primarily by new solar capacity.***

By 2025, the reduction in coal capacity and generation has been predominantly replaced by clean solar energy. 8 GW of new utility-scale solar is projected to come online by run year 2025 (representing years 2023 – 2027). In total, 11.7 GW of utility-scale solar is operating in the state by this time – representing not only additions required under HB 589, but also a substantial number of additions economically chosen by the model.

By 2030, the model finds it economic to build about 1.3 GW of battery storage. The battery storage is built instead of new natural gas combined cycle (CC) units or combustion turbines (CT) to help balance and integrate higher renewable generation in the state.

3. ***The only additional natural gas capacity added is from units already under construction.***

There are a few modest additions of natural gas combined cycle capacity. However, it should be noted that all these additions are already approved and under construction; the model does not economically add any additional natural gas capacity. Despite the addition of these three new NGCC plants in the next few years, natural gas generation in this optimized case is relatively stable, with total gas generation remaining below or in line with 2018 generation through 2040.

Generation (TWh)	2018 (P)	2020	2025	2030	2035
Coal	31.7	28.5	31.2	31.0	28.9
Natural Gas	44.1	40.1	43.1	45.0	40.0
Nuclear	42.1	39.2	38.8	38.8	38.8
Solar	7.0	13.5	22.6	22.6	22.6
Wind	0.5	0.6	0.8	0.8	0.8
Other RE	5.0	4.2	4.2	4.2	4.2
Other Non-RE	3.7	0.9	1.0	1.0	1.0
Total	**134.1**	**127.0**	**141.6**	**143.5**	**136.5**

Table 2. In-state Generation for North Carolina in "optimized" case

4. ***Renewable energy generation more than makes up for the generation reductions from other sources leading to significant emission reductions without impacting in-state generation totals***

Reductions in non-renewable generation are more than replaced by solar additions by 2025, with total utility-scale generation remaining above 2018 levels between 2025 and 2035 (Table 2). With the addition of zero-carbon resources and a shift away from coal, the state's power sector sees carbon emissions fall from current levels in the future. Between 2018 and 2020, emissions fall by 15% to 45.7

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million short tons. If North Carolina were to follow this optimized path, electric sector carbon emissions would fall to 41% below 2005 levels by 2025.

Results for NRDC's "IRP" IPM Case

As noted above, the "optimized" case only represents one possible future – and a future that differs significantly from the Base Cases in DEC and DEP's IRPs. NRDC also ran an "IRP" case, which was designed to more closely match the long-term resource plans submitted by DEP and DEC. Running both cases allows for a comparison of costs, generation, and emissions outcomes between an "economically optimized" portfolio and a scenario more representative of the utilities' proposed capacity build-out.

We recognize that NRDC's "IRP" case does not perfectly match the Duke IRPs. In NRDC's analysis, the model was still allowed to economically retire fossil capacity; the only constraints were on the capacity addition side. In this run, the model was required to build the new NGCC and NGCT capacity included in the Base Case "No CO_2" scenarios for both DEP and DEC and annual solar builds were capped at the annual MW additions included in these two Base Cases. Because the model could chose to economically retire fossil capacity, it is likely that the IPM run results underestimate costs and carbon emissions when compared to the scenario set forth in Duke's IRPs, but NRDC's "IRP" case nevertheless provides a useful comparison.

<u>Key Findings:</u>

5. ***The "IRP" case depends much more heavily on natural gas***

The assumptions in the "IRP" case result in significant changes to the capacity and generation mix, as compared to the economically optimized case (see Table 3). The additional natural gas plants crowd-out economic investments in solar and storage technologies. Storage builds drop from 1.3 GW by 2030 to 0.2 GW by 2030. Solar deployment is also delayed significantly. This is partly a product of the imposition of caps during the 2019 – 2032 timeframe, but also likely in response to the higher fossil capacity and generation in this "IRP" case.

Note that in this "IRP" case, the model still retires the same amount of coal capacity as in the economically optimized case.

Capacity (GW)	2018 (P)	2020	2025	2030	2035
Coal	10.5	6.5	6.5	5.8	5.8
NGCC	5.2	5.8	7.6	8.9	8.9
NG CT	6.2	6.2	6.7	9.9	12.7
Nuclear	5.1	5.2	5.2	5.2	5.2
Solar	3.7	7.3	9.5	10.2	10.3
Wind	0.2	0.2	0.3	0.3	0.3
Storage	0	0	0.2	0.2	0.2

Table 3. In-state capacity results for North Carolina in the "IRP" case.

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The generation mix also sees substantial changes, as compared to the economically optimized case (see Table 4). Coal generation falls compared to current levels. Coal generation is also slightly lower than in the optimized case in 2020, as additional gas builds tamp down utilization of the remaining coal fleet. However, coal generation is the same as the optimized case in 2025 and beyond. While coal looks similar between the two cases, natural gas generation grows significantly in the IRP case, increasing by about 40 percent in 2030 from both current levels and 2030 levels in the economically optimized case.

Generation (TWh)	2018 (P)	2020	2025	2030	2035
Coal	31.9	27.1	31.2	31.0	28.9
Natural Gas	44.5	39.6	49.9	62.6	62.2
Nuclear	41.7	42.0	42.1	42.1	42.1
Solar	7.3	15.6	19.1	20.3	20.3
Wind	0.5	0.6	0.8	0.8	0.8
Other RE	4.7	4.2	4.2	4.3	4.3
Other Non-RE	3.7	0.9	1.0	1.0	1.1
Total	**134.3**	**129.9**	**148.3**	**162.1**	**159.7**

Table 4. In-state Generation for North Carolina in "IRP" case.

6. The "IRP" case sees higher – and rising – carbon pollution over the next two decades

This large increase in natural gas generation results in both steady growth of in-state generation and power sector carbon emissions, especially in the later years. By 2030, carbon dioxide emissions from the state's power sector are 2.4 million tons higher annually, as compared to the economically optimized case. This grows to 8.5 million tons higher annually by 2035. Cumulatively, power emissions are 46.9 million tons higher between 2020 and 2035 in the "IRP" case than in the economically optimized case.

7. The "IRP" case comes at a higher cost for the state's energy system

Lastly, total system costs for the state's energy system are also higher in the "IRP" case. The total system costs below include the capital, fuel, and other operations and maintenance costs of running the state's energy system, as well as energy costs associated with importing power to meet state energy needs. (See Table 5).

As shown in Table 5 below, not only is the "IRP" case more expensive for the state than the economically optimized case, but the incremental cost of the "IRP" case increases over time as more NGCC and NGCT capacity is added to the system (as outlined in DEC and DEP's IRPs and incorporated in the "IRP" case in NRDC's modeling). By 2030, the "IRP" case comes at a net cost of $389 million annually. By 2035, that cost is $590 million annually. Between run years 2020 and 2035, the cumulative cost of the "IRP" case – over and above the system costs of the cleaner, economically optimized case – total almost $5.6 billion.

The numbers below include the energy cost savings seen in the "IRP" case from reduced electricity imports (due to higher in-state generation). However, the additional costs of building this new gas capacity substantially outweigh these savings from reduced market purchases.

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Millions $	2020	2025	2030	2035	Total
Economically Optimized	$4,679.8	$5,351.8	$5,672.8	$5,885.3	$103,268.8
“IRP”	$4,738.5	$5,441.7	$6,062.1	$6,475.2	$108,849.5
Net Cost of IRP Case	**$58.7**	**$89.9**	**$389.3**	**$590.0**	**$5,580.7**

Table 5. Total System Costs (inclusive of electricity imports) for North Carolina in the economically optimized and IRP cases.

8. Under the IRP case, the average residential customer would see higher bills.

The proposed buildout of new natural gas capacity outlined in the utilities’ plans results in substantial costs for the average consumer, as compared to the solar and storage buildout projected to occur in the economically optimized case.

By 2030, the IRP case results in bills that are more than 3% higher than in our economically optimized case. By 2035, bills are about 5% higher than in the optimized case.

Residential Retail Bills (2012$)	2020	2025	2030	2035
Avg. Annual Bill Impact under “IRP” case (compared to optimized case)	$5.89	$8.68	$35.90	$52.52
% increase in monthly bill in “IRP” case (compared to optimized case)	0.6%	0.8%	3.4%	4.9%