

# EPA's November 2018 IPM v6 Reference Case

February 28, 2019

# EPA's Power Sector Modeling Update

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- ▶ Last year EPA released a major update to its power sector modeling platform, IPM v6 (on May 31<sup>st</sup> 2018) with accompanying
  - ▶ Full-fledged documentation
  - ▶ NEEDS
  - ▶ Results of a suite of runs
  - ▶ Results Viewer
- ▶ This presentation discusses latest updates to IPM v6 incremental to May 2018 version.
  - ▶ <https://www.epa.gov/airmarkets/results-using-epas-power-sector-modeling-platform-v6>

*EPA projections are not predictions of what will happen, but rather modeled projections of what may happen given certain assumptions and methodologies.*

# EPA's Power Sector Modeling Update

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IPM v6 November 2018 Reference Case reflects latest data and regulations affecting the power sector.

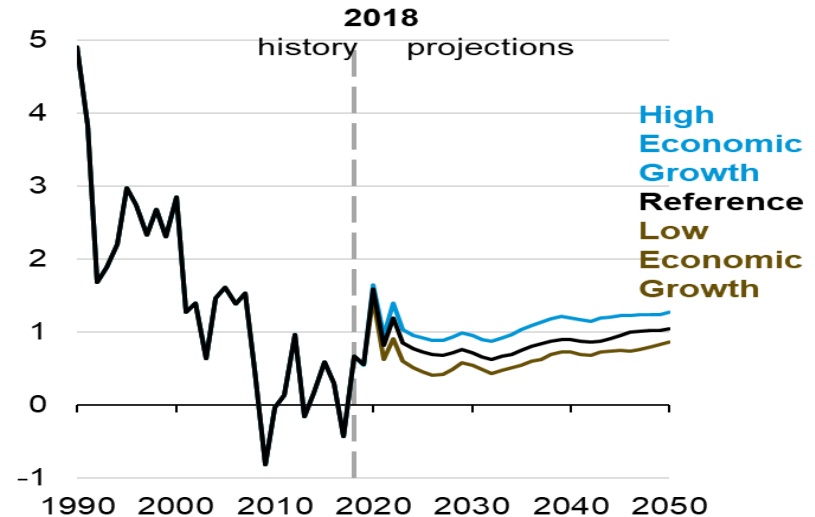
- ▶ Updates incremental to the May 2018 Initial Run:
  - ▶ AEO 2018 demand (national)
  - ▶ Updated NEEDS
  - ▶ Changes to corporate income taxes based on the December 2017 Tax Reform Bill
  - ▶ Updated (higher) operating costs for nuclear units (from EIA)
  - ▶ More accurate (lower) NOx emission rates in CA and elsewhere for small fossil units
  - ▶ New State laws/regulations:
    - NY oil rule, energy storage mandates in CA, NY, NJ, OR and MA, revised RPS standards for CT and NJ
  - ▶ New energy storage projects

# Putting Emissions Projections into Context

- ▶ What are the primary drivers?

- ▶ Demand
- ▶ Fuel resource availability/price
- ▶ Generation technology costs
- ▶ Environmental regulations

Electricity use growth rate  
percent growth (three-year rolling average)



Source: US Energy Information Administration

- ▶ As electricity demand grows modestly, new capacity additions and the retirements of older/less-efficient fossil fuel units are shaped by
  - ▶ low natural gas prices
  - ▶ the continued decline in the capital cost of renewables
  - ▶ the near-term availability of renewable energy tax credits
- ▶ Type of projection tool/method

# Factors Influencing NG Projections

► A confluence of factors occurring between 2017 and 2020 drives sharp growth in power sector natural gas consumption in EPA's outlook:

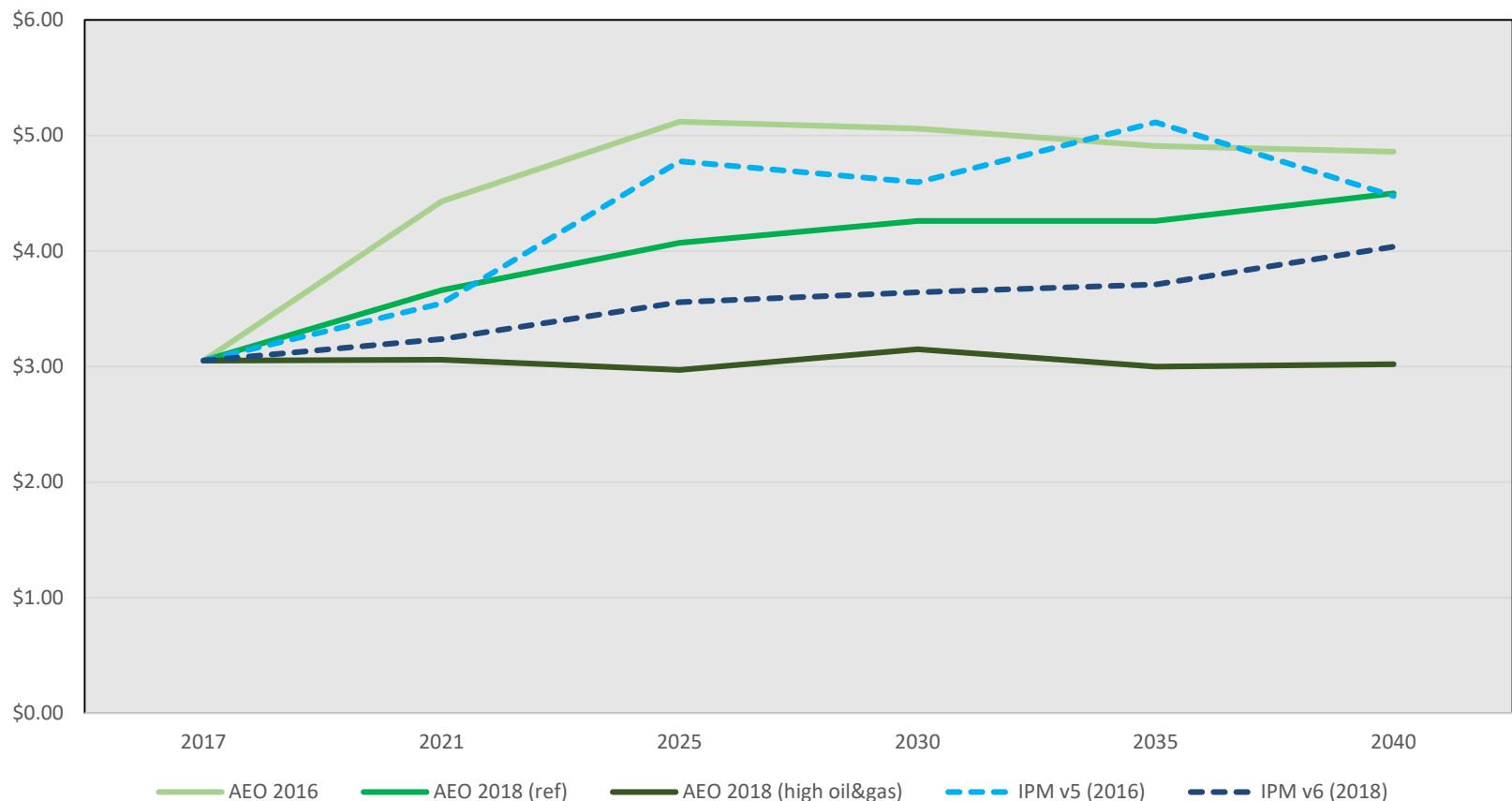
1. Natural gas production expected to grow ~20%
2. NGCC build out: 15% growth in NGCC fleet
3. Natural gas pipeline capacity expected to expand (>40% in some areas)



# Natural Gas Price Projections

- Natural gas price outlooks have been revised down, driving additional coal to gas switching in projections
- IPM v.6 natural gas projections are informed by updated gas supply curves. Projections fall between the AEO reference case and high oil & gas productivity scenarios.

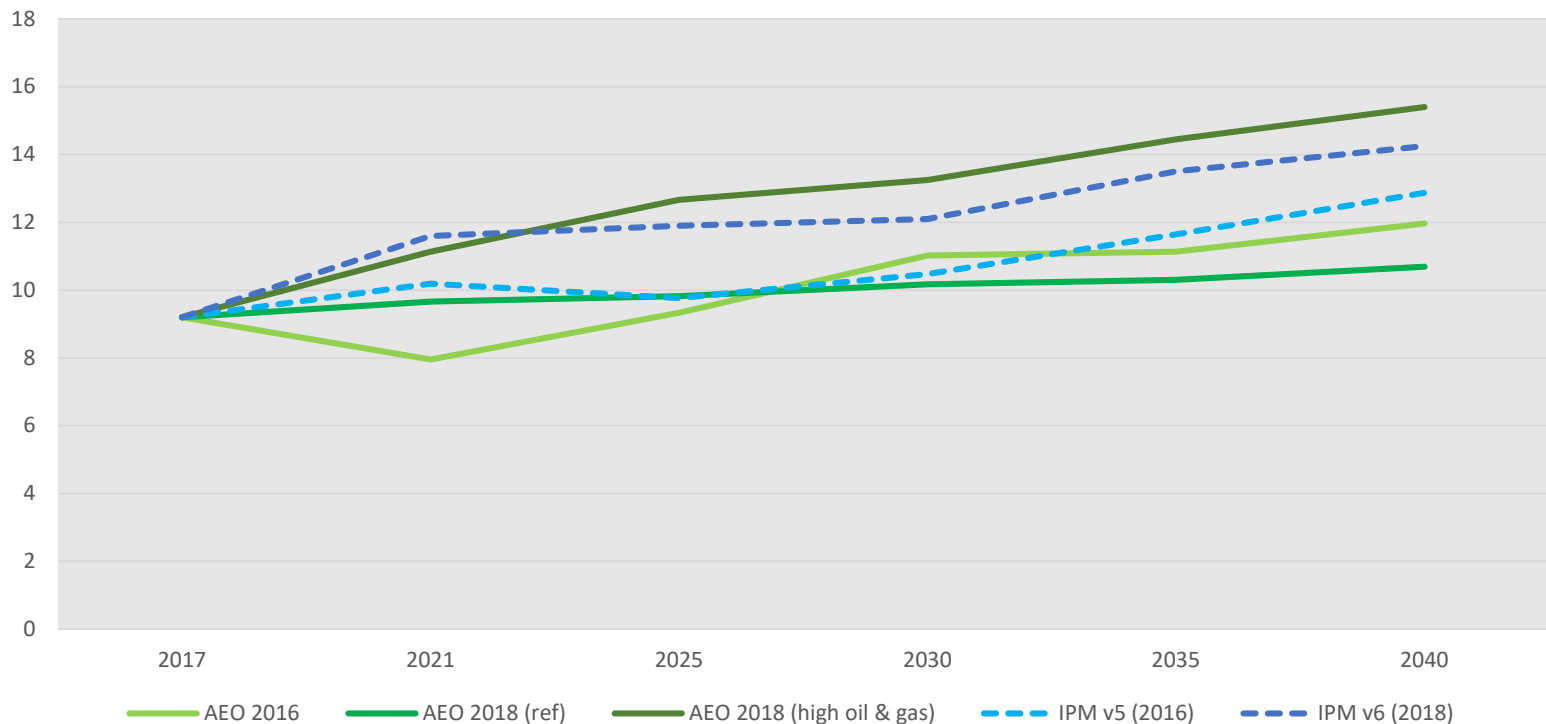
Natural Gas Price Projections at Henry Hub (\$/mmBtu)



# Natural Gas Consumption Projections

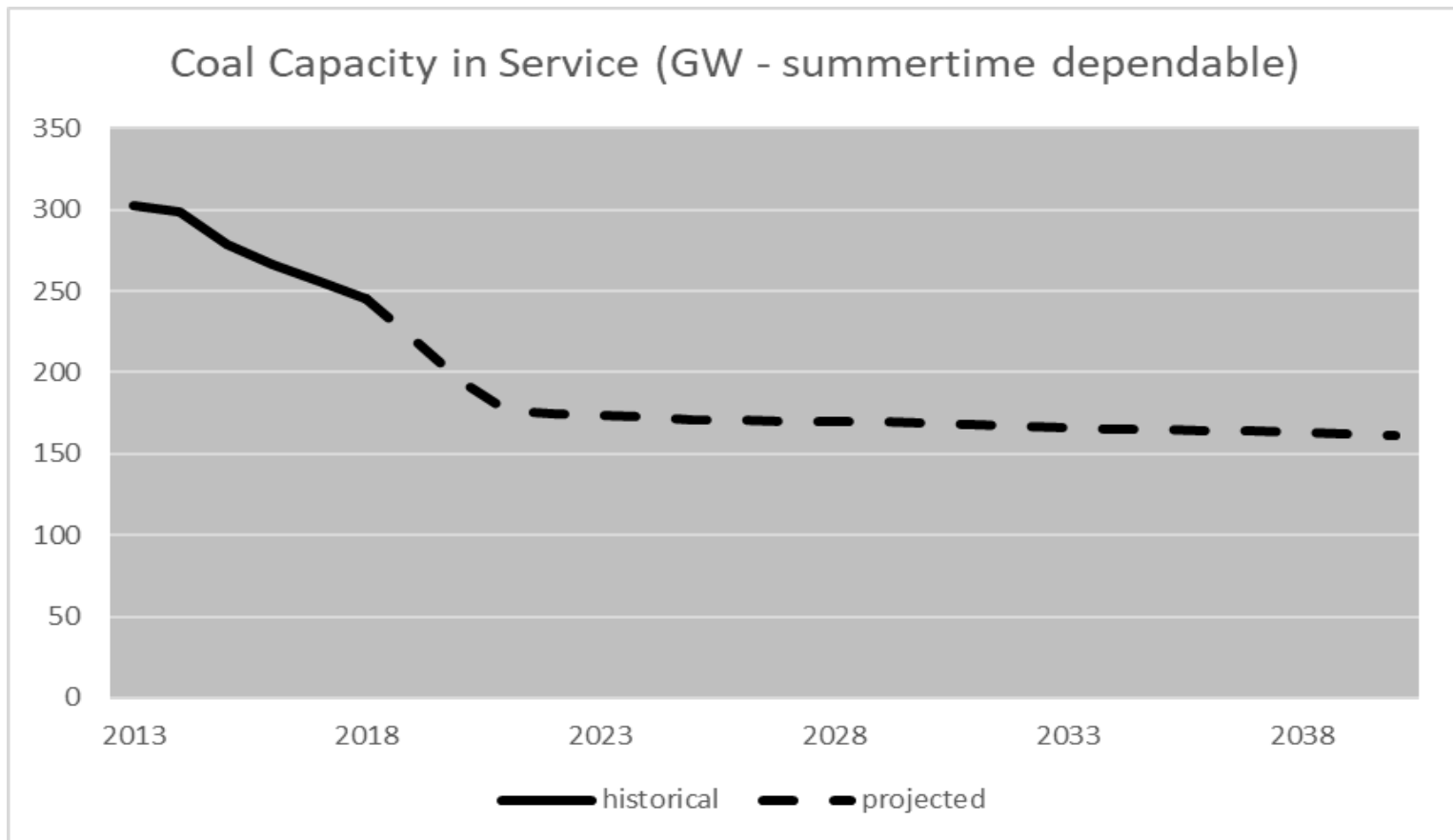
- Projected power sector consumption of natural gas is up 20% or more from historical maximum levels of ~ 10 Tcf, reflecting planned (15% increase in NGCC capacity alone from under construction capacity) and projected new builds.
- Also reflects higher projected capacity factors at NGCCs (in the 60% range)
- EPA projections are between the AEO 2018 reference case and high oil and gas productivity scenario

Natural Gas Consumption for Electric Power (Tcf)



# Retiring Coal Generation

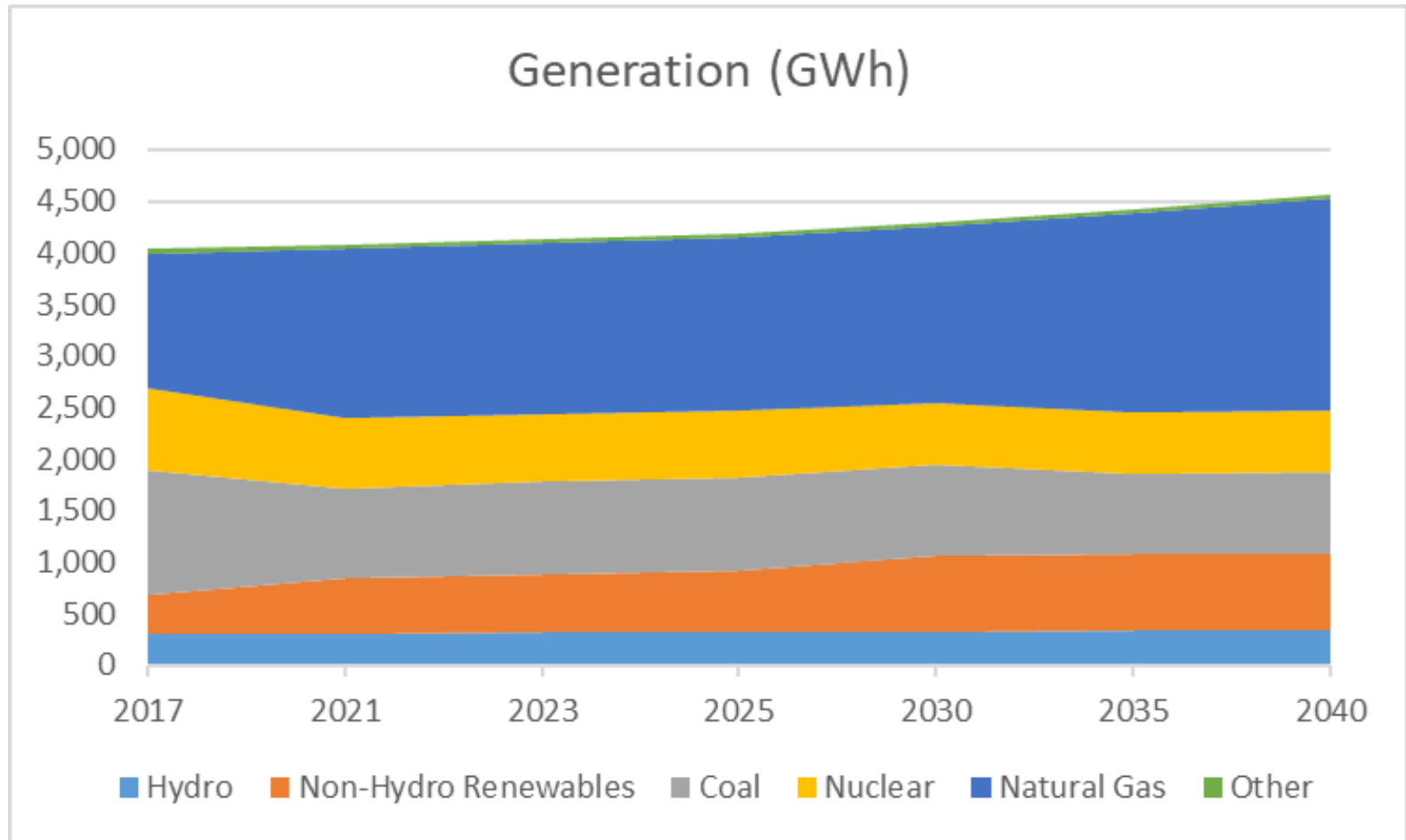
- EPA projects the coal retirement trend to continue through early next decade, and then begin to level off.
- This near-term trend continuation is consistent with the pace of announced retirements.
  - At the end of 2020 NEEDS has 195 GW of coal remaining in service
  - IPM projects this capacity to drop to ~176 GW in 2021 and ~161 GW by 2040





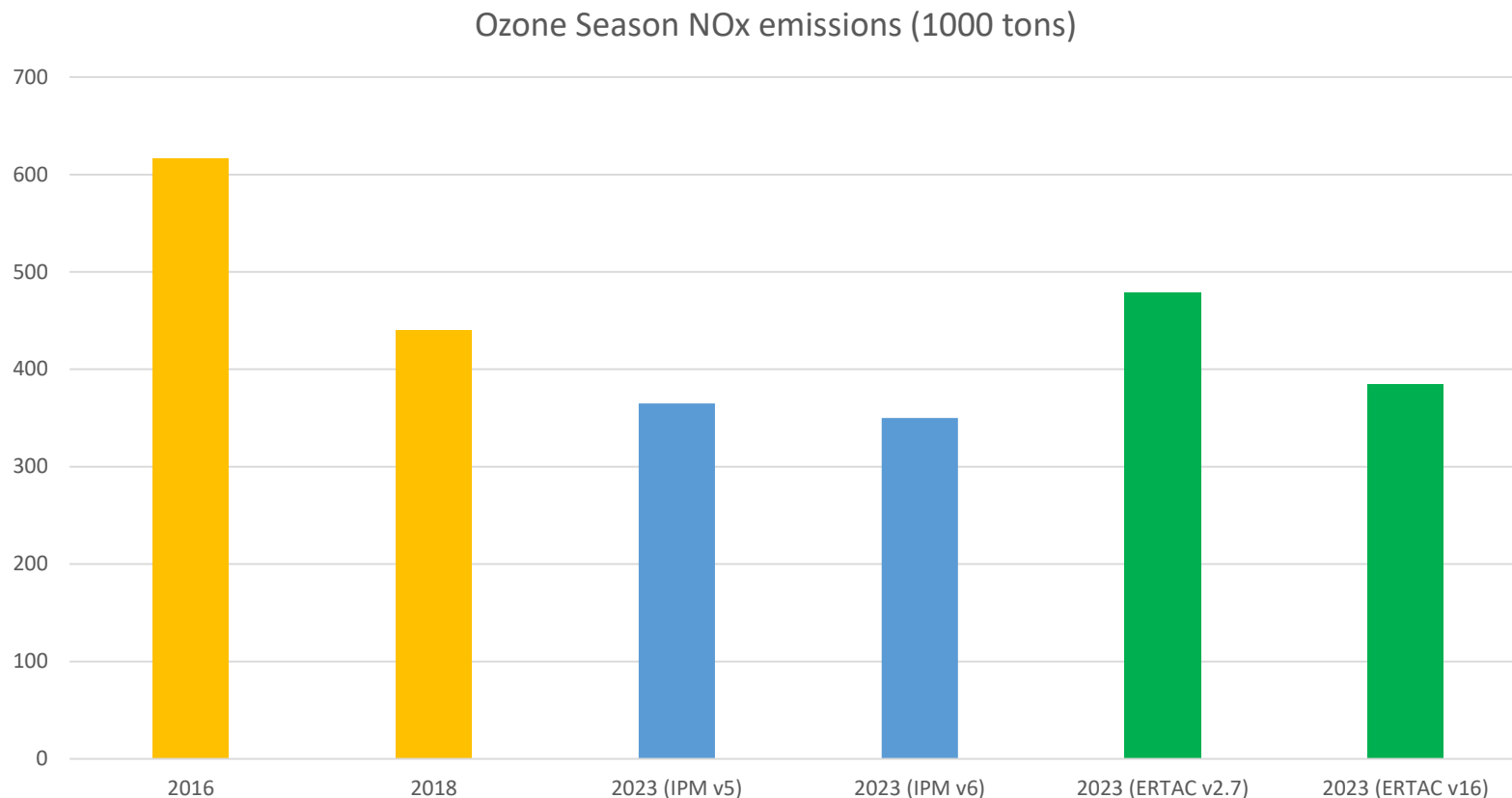
# Changing Generation Portfolio

- As coal declines, it is replaced by natural gas generation and renewables



# Ozone Season NOx Emissions

- ▶ IPM projections assume EGUs operate at the same Ozone Season NOx emission rate as observed in 2018 for CSAPR Update compliance (for those reporting data)
- ▶ Any announced control installations are factored into 2023 projections
- ▶ The decrease in projected emissions are largely driven by announced retirements and rate improvements



# Comparing 2016 Beta Inventory with IPM and ERTAC Projections

- ▶ The “annual fuel” tab has all units from IPM and ERTAC, matched as best as possible; includes all pollutants. The README file explains all of the columns.
- ▶ The “Zero in IPM- Non-zero in ERTAC” tab lists all of the NOx units where ERTAC has non-zero emissions in 2028, but IPM has zero emissions in 2030 (and the emissions are non-zero in 2016).
- ▶ The “Zero in ERTAC- Non-zero in IPM” worksheet lists all of the NOx units where IPM has non-zero emissions in 2028, but ERTAC has zero emissions in 2028 (and the emissions are non-zero in 2016).

The image displays two Excel spreadsheets side-by-side, comparing 2016 Beta Inventory with IPM and ERTAC Projections.

**Left Spreadsheet: 2016 Beta Inventory**

State	State No	FIPS	Facility Name	Facility	Unit ID	NEEDS	NEEDS ID	Retire	IPM 202	IPM 203	2016beta	2016
ND	North Dak	38057	Coyote Station	8086611	64297413 8222_B_1				Coal Retire	Coal Retire	Lignite	coal
IN	Indiana	18125	Indianapolis Power and Light	7362411	10578713 994_B_4				Coal Retire	Coal Retire	Bituminou	coal
LA	Louisiana	22031	CLECO Power LLC - Dolet Hills Pow	7354411	80274313 51_B_1				Coal Retire	Coal Retire	Lignite, Su	coal
NM	New Mexi	35045	PNM - San Juan Generating Station	7991911	82425313 2451_B_3						Bituminou	coal
TB	Tribal Dat	88780	NAVAJO GENERATING STATION	13606211	79759513 4941_B_1						Bituminou	coal
KY	Kentucky	21177	Tennessee Valley Authority - Parak	5196711	86762413 1378_B_3				Coal Retire	Coal Retire	Bituminou	coal
TB	Tribal Dat	88780	NAVAJO GENERATING STATION	13606211	79759513 4941_B_3			2019			Bituminou	coal
TB	Tribal Dat	88780	NAVAJO GENERATING STATION	13606211	79759513 4941_B_2			2019			Bituminou	coal
WV	West Virg	54073	ALLEGHENY ENERGY SUPPLY CO L	4782811	71785513 6004_B_1			2022			Bituminou	coal
WV	West Virg	54073	ALLEGHENY ENERGY SUPPLY CO L	4782811	71785513 6004_B_2			2022			Bituminou	coal
KY	Kentucky	21041	KY Utilities Co - Ghent Station	5198511	25720613 1356_B_2 1356_B_2						Bituminou	coal
NM	New Mexi	35045	PNM - San Juan Generating Station	7991911	82423513 2451_B_2						Bituminou	coal
IN	Indiana	18165	Duke Energy Indiana LLC - Cayuga	7248511	7458513 1001_B_1				Coal Retire	Coal Retire	Bituminou	coal
MT	Montana	30087	COLSTRIP STEAM ELECTRIC STATI	7765611	1786213 6076_B_1			2022	Coal Retire	Coal Retire	Subbitumi	coal
PA	Pennsylva	42063	GENON NE MGMT CO/CONEMAU	2905911	38673013 3118_B_1				Coal Retire	Coal Retire	Bituminou	coal
KY	Kentucky	21111	Louisville Gas & Electric Co., Mill C	7353711	9603513 1364_B_1				Coal Retire	Coal Retire	Bituminou	coal
NM	New Mexi	35045	PNM - San Juan Generating Station	7991911	82423613 2451_B_1				Coal Retire	Coal Retire	Subbitumi	coal
TN	Tennessee	47161	TVA CUMBERLAND FOSSIL PLANT	4979311	30040713 3399_B_2				Coal Retire	Coal Retire	Bituminou	coal
OH	Ohio	39093	Avon Lake Power Plant	8130811	6011813 2836_B_12						Bituminou	coal
AL	Alabama	01127	Alabama Power Company	7917311	3531813 8_B_10				Coal Retire	Coal Retire	Bituminou	coal
NE	Nebraska	31055	Omaha Public Power District - Nor	6732411	10552651 2291_B_5				Coal to Ga	Coal to Ga	Subbitumi	coal
KY	Kentucky	21111	Louisville Gas & Electric Co., Mill C	7353711	9603613 1364_B_2				Coal Retire	Coal Retire	Bituminou	coal
IN	Indiana	18125	Indianapolis Power and Light	7362411	10579213 994_B_1				Coal Retire	Coal Retire	Bituminou	coal
WY	Wyoming	56037	Jim Bridger Plant	3962711	72209613 8066_B_BW71				Coal Retire	Coal Retire	Subbitumi	coal
KY	Kentucky	21041	KY Utilities Co - Ghent Station	5198511	25720413 1356_B_3				Coal Retire	Coal Retire	Bituminou	coal
LA	Louisiana	22079	CLECO - Brame Energy Center	7446811	81274013 6190_B_2				Coal Retire	Coal Retire	Subbitumi	coal

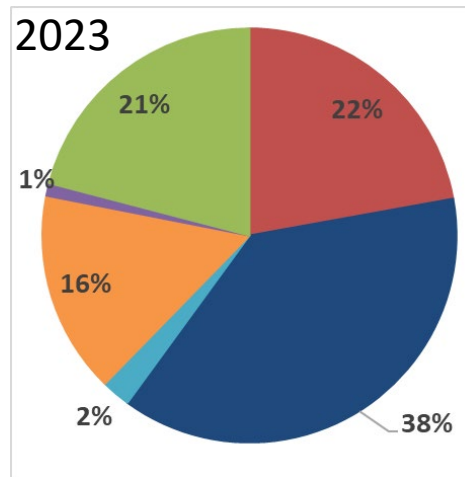
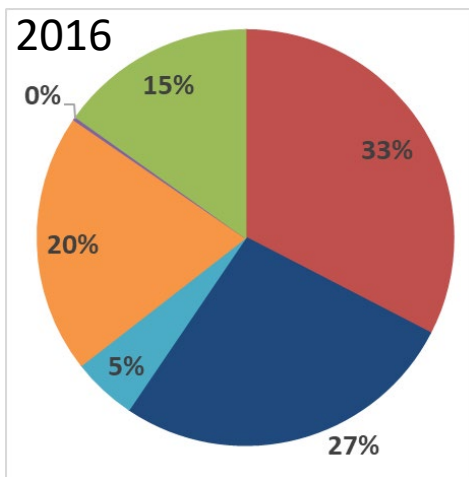
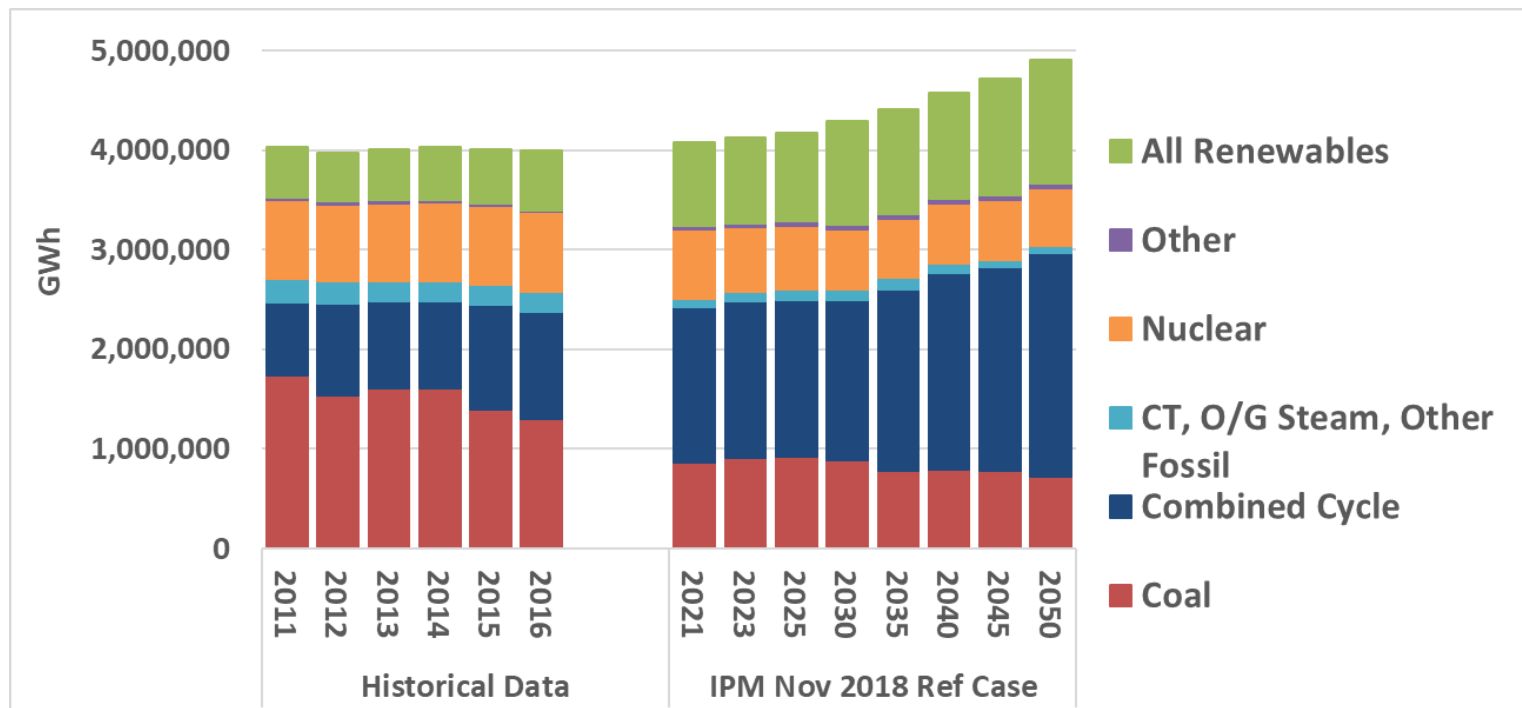
**Right Spreadsheet: 2023 pivot table**

Row Labels	Sum of 2023 IPM Heat Input (mmBTU)	Sum of ERTAC 2023 Heat Input (mmBTU)	Sum of 2023 IPM Generation (GW/hr)	Sum of ERTAC 2023 Generation (GW/hr)	Sum of 2016beta IPM	Sum of 2023 ERTAC
Alabama	474,518,603	582,263,001	57,489	74,941	28,835	9,793
01001						10,430
Southern Power Company - E B Har	37,307,155	49,539,609	5,199	7,322	216	369
Tenaska Central Alabama Gen Stat	22,563,770	46,339,790	3,085	6,113	181	108
Tenaska Central Alabama Generating Stn						83
Tenaska Lindsay Hill Generating	21,209,649	25,295,691	2,933	3,590	88	107
01015						
Calhoun Power Company I LLC Ge	156,238	2,236,837	15	208	41	3
01033						
TVA Colbert		67,975		5	1,993	17
01039						
PowerSouth Energy Coop - McWil	16,711,750	33,882,352	2,196	3,121	226	284
01049						
Sand Valley Power Station						49
01055						
Alabama Power - Gadsden		2,314,243		194	151	129
01063						
Alabama Power - Greene Cty	6,522,760	8,663,408	648	813	1,483	397
01073						
ALABAMA POWER COMPANY (MI	116,524,701	55,599,479	11,307	5,248	6,964	3,903
01081						1,884
Sum of ERTAC 2023 Heat Input (mmBTU)						
Value: No value						
Row: Alabama - 01081						
Column: Sum of ERTAC 2023 Heat Input (mmBTU)						

# Using Results Viewer for both IPM and ERTAC Projections

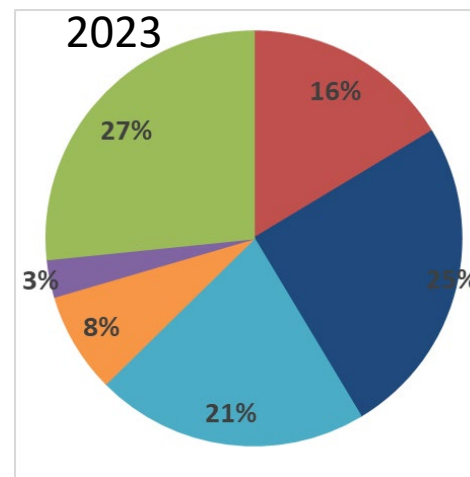
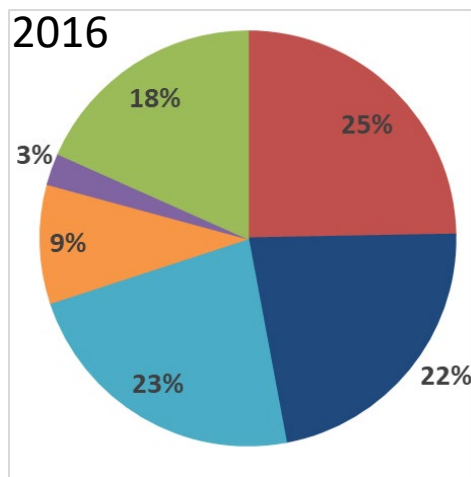
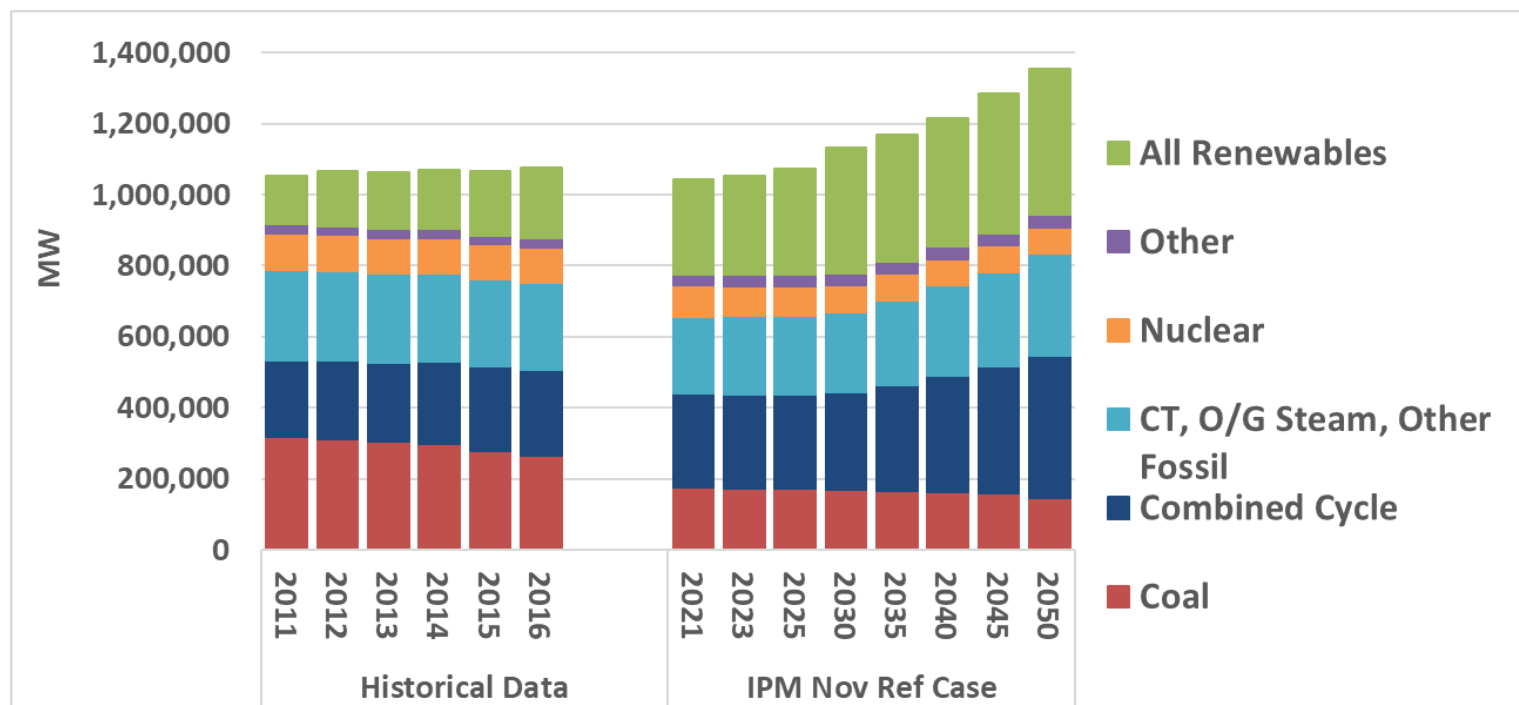
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# Annual Generation (GWh) for IPM v6 November 2018 Reference Case



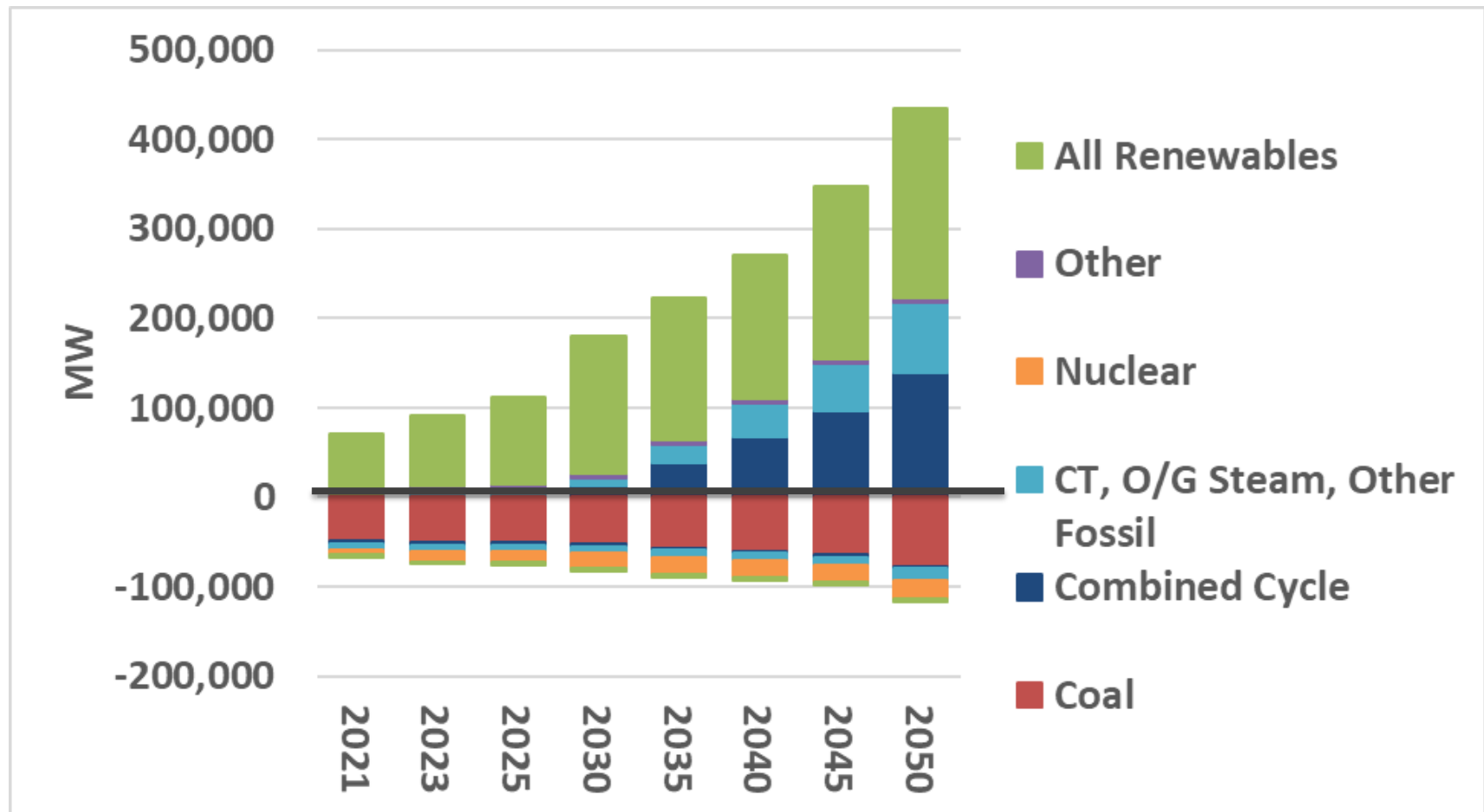
Historical Data is a combination of data reported to CAMD and EIA form 923. It currently is incomplete and excludes fossil fired EGUs < 25 MW.

# Capacity (MW) for IPM v6 November 2018 Reference Case



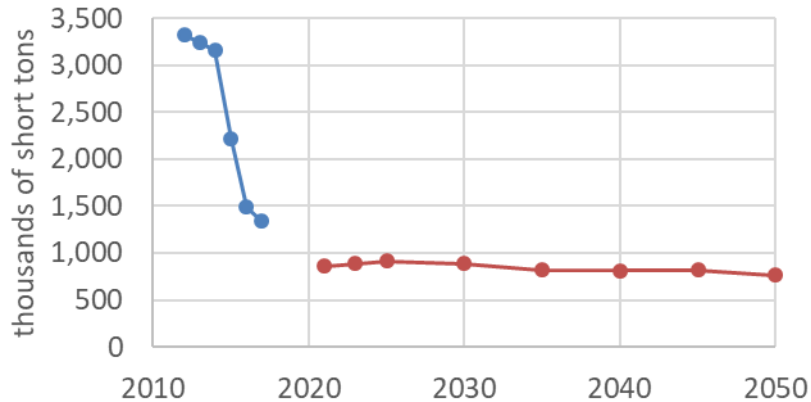
Historical Data is a combination of data reported to CAMD and EIA form 923. It currently is incomplete and excludes fossil fired EGUs < 25 MW.

# New and Retired Capacity (MW) for IPM v6 November 2018 Reference Case

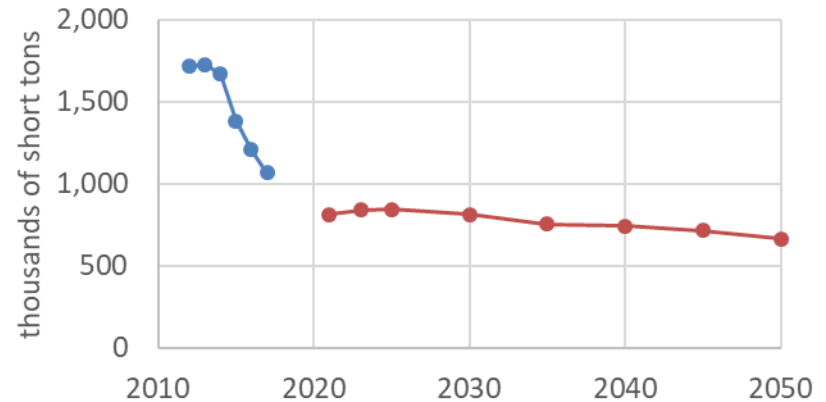


# Emissions from Fossil > 25 MW, compared to CAMD data

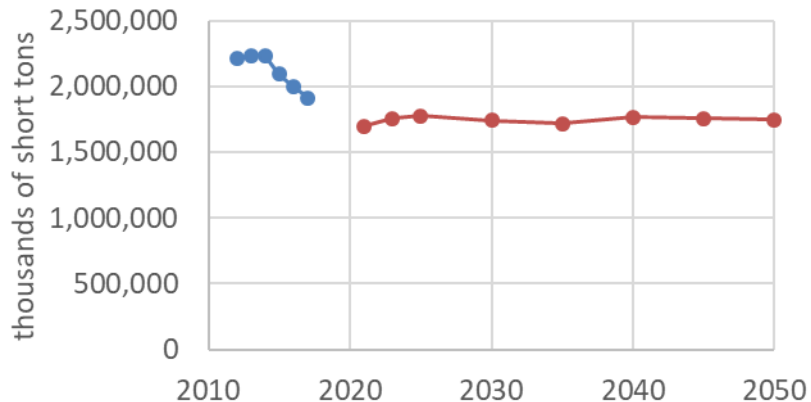
Annual SO<sub>2</sub> (thousand short tons)



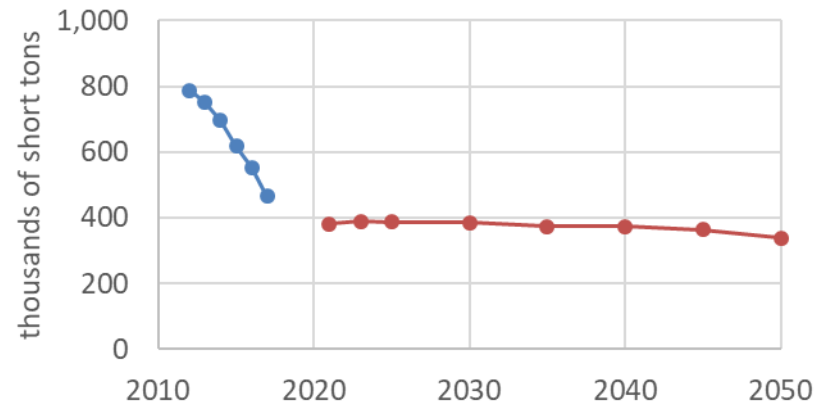
Annual NO<sub>x</sub> (thousand short tons)



Annual CO<sub>2</sub> (thousand short tons)



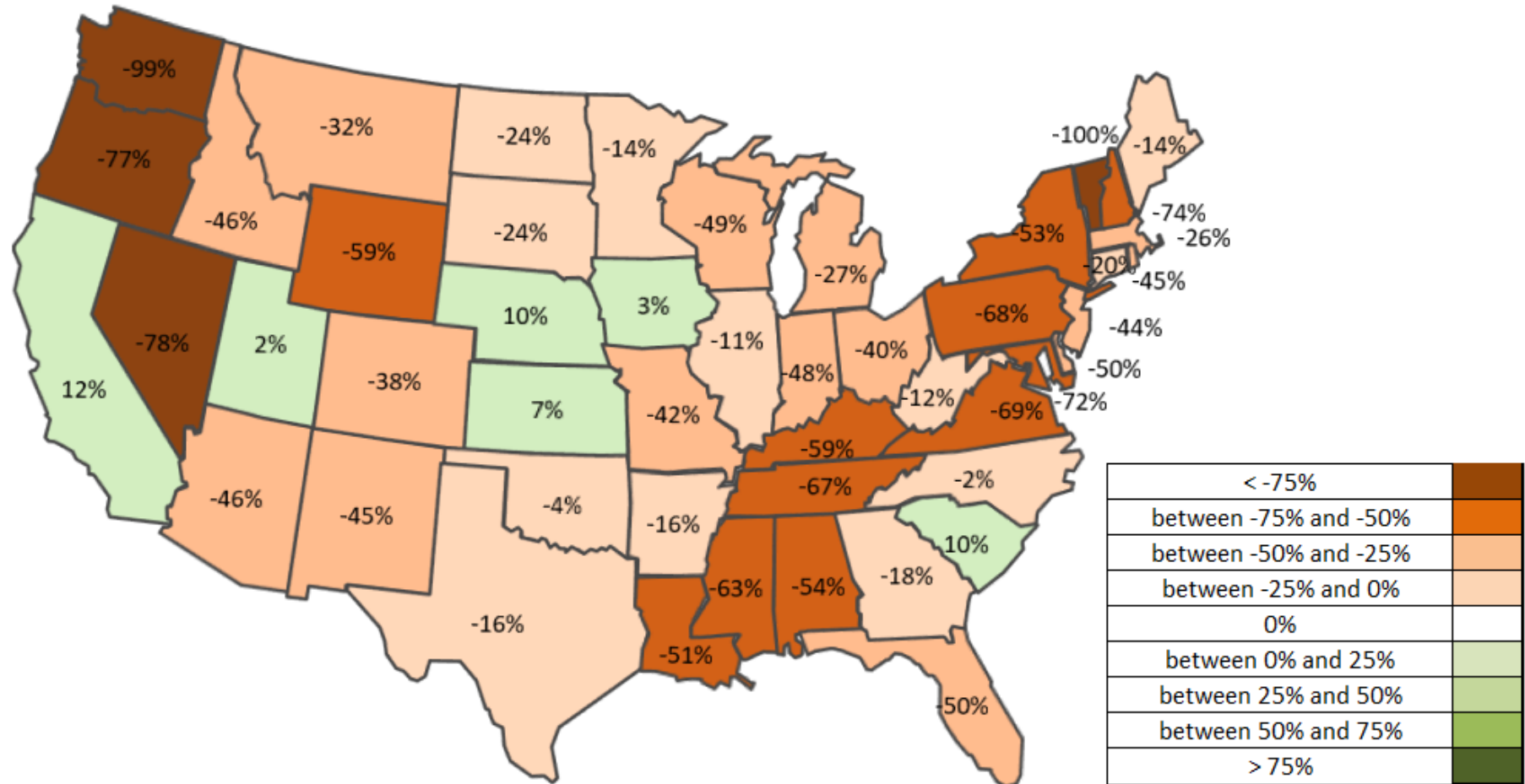
Ozone Season NO<sub>x</sub> (thousand short tons)



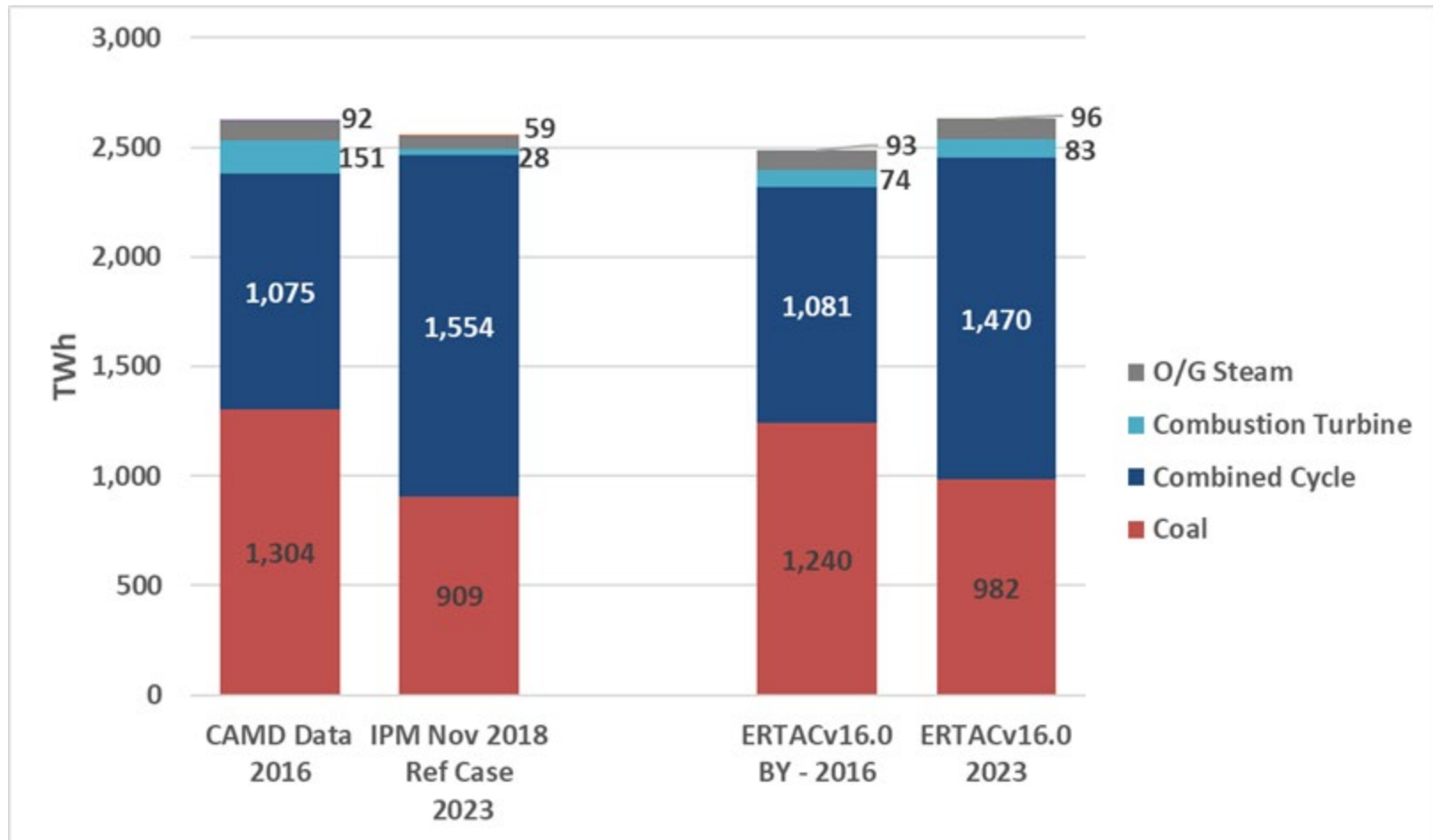
*Blue line* is historical CAMD data; *red line* is IPM v6 November 2018 Reference Case, fossil > 25 MW



# Percent change in Ozone Season NO<sub>x</sub> Emissions from 2016 CAMD data to **2023** IPM v6 November 2018 Reference Case, fossil > 25 MW

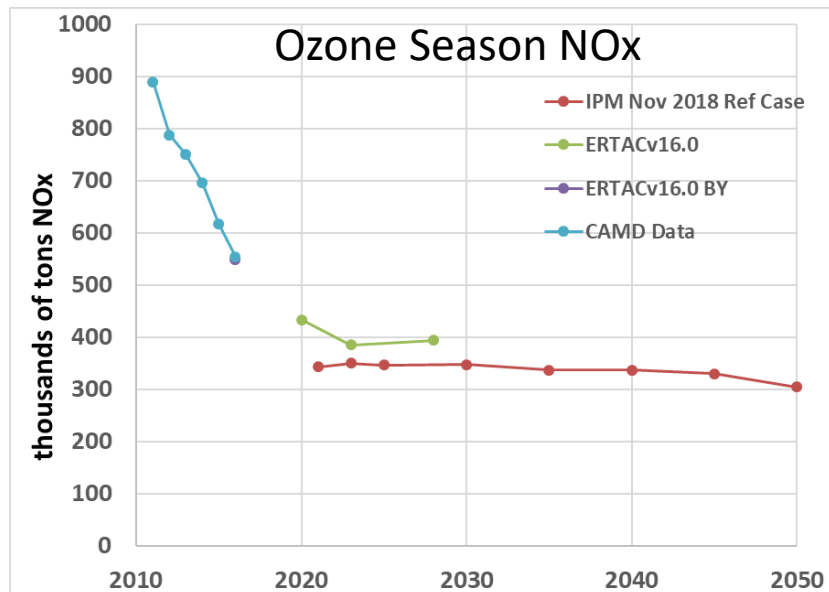
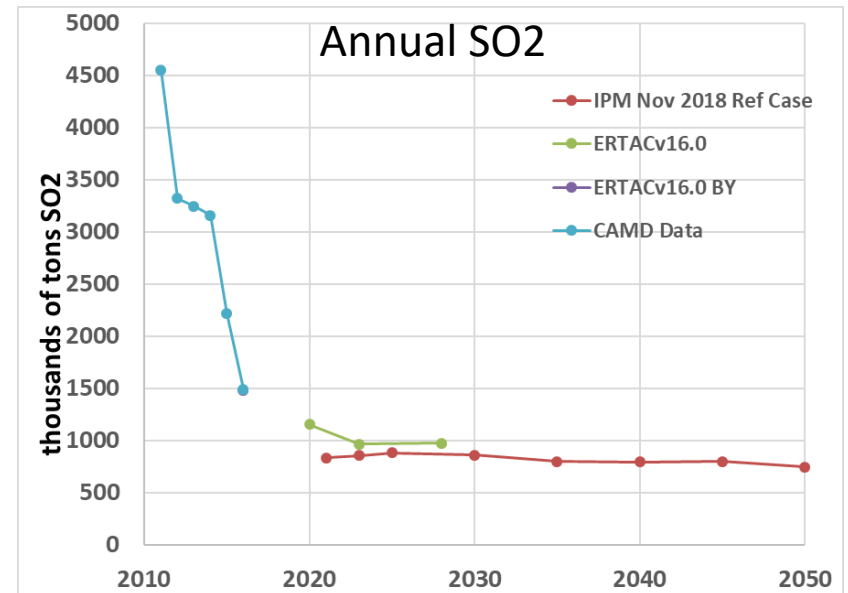
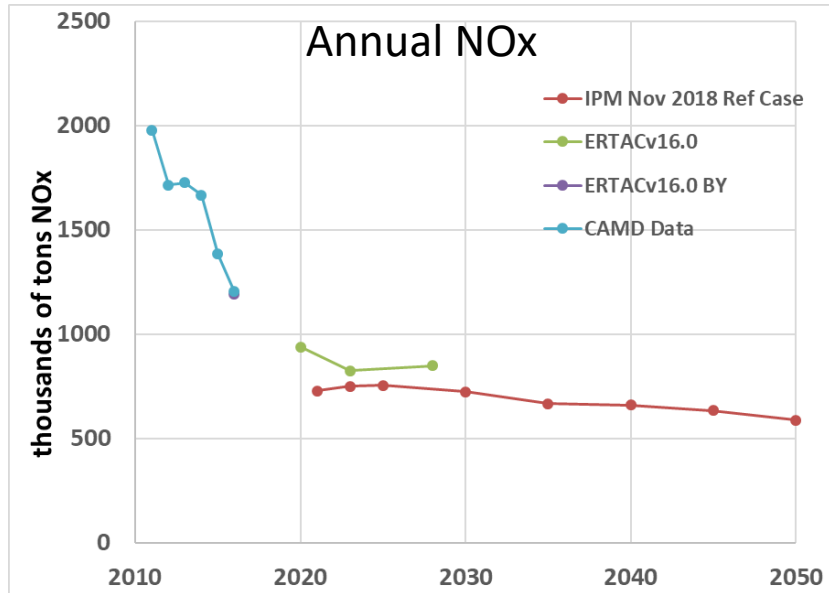


# Annual Generation (TWh) 2016 and 2023 for IPM Nov 2018 Reference Case and ERTACv16.0



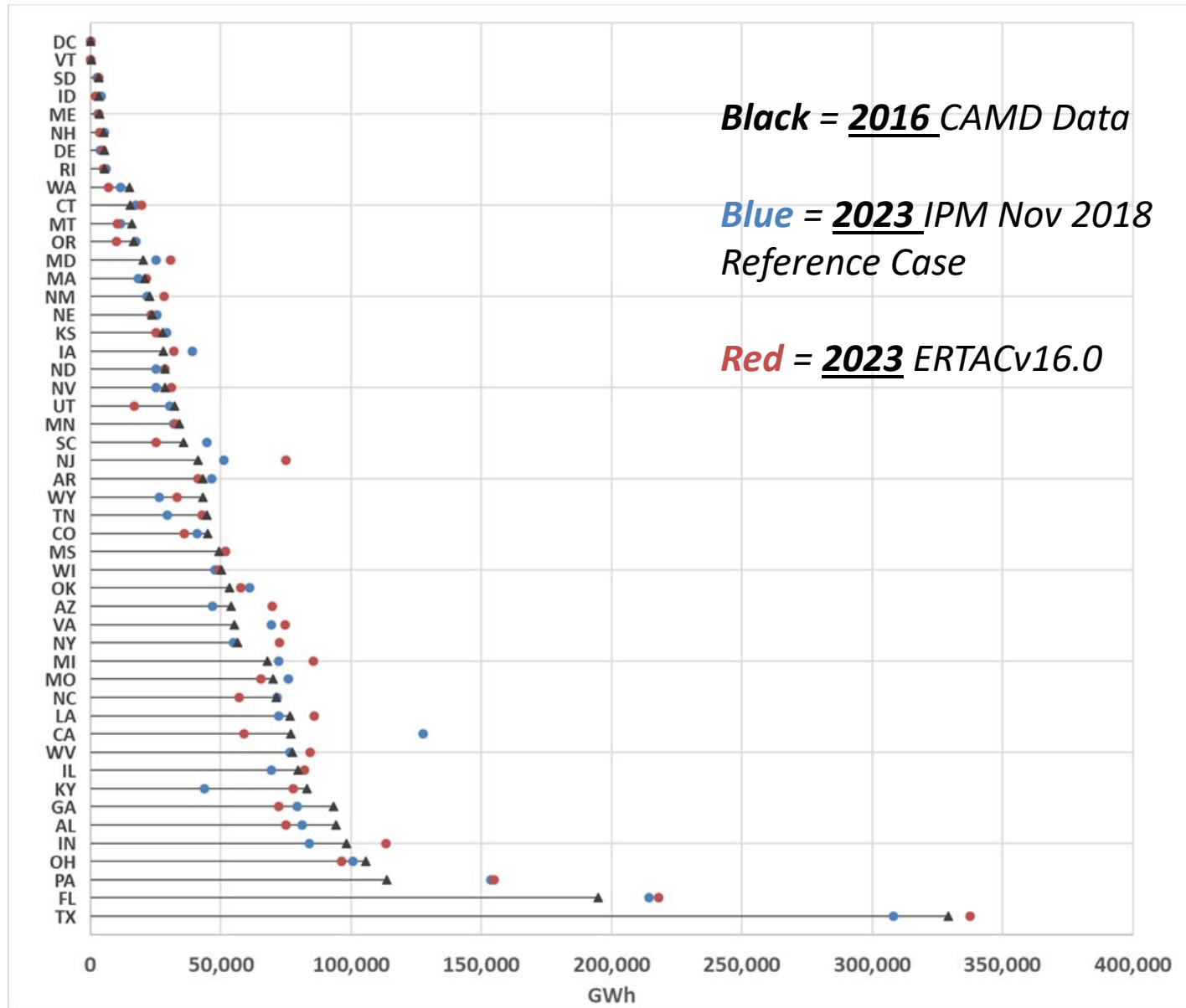
*Comparing 2023 projections to relevant 2016 historical data sets. IPM data is for fossil units > 25 MW.*

# Emissions (thousands of tons) for IPM Nov 2018 Reference Case and ERTACv16.0

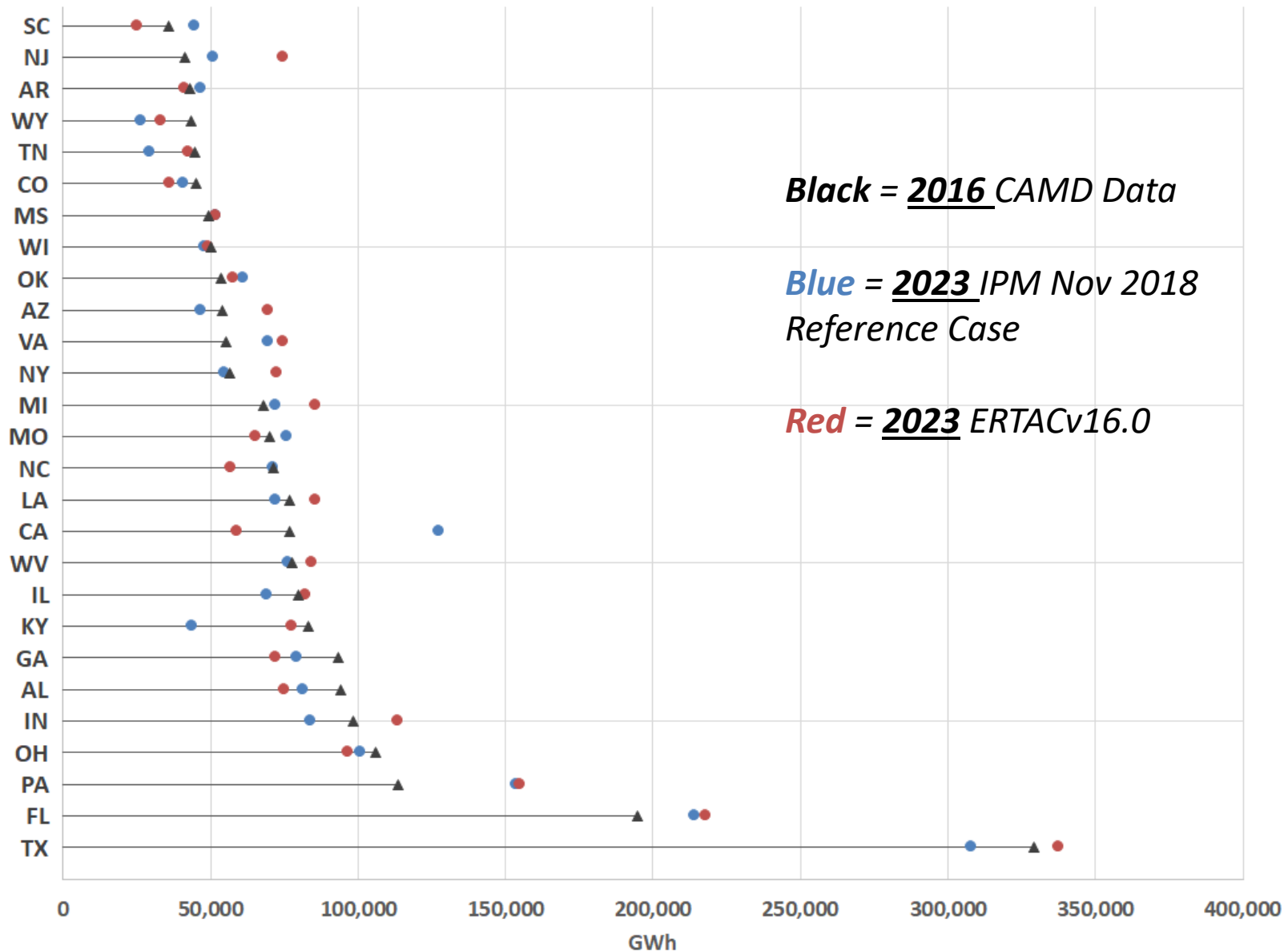


- 1) CAMD Data for 2016 very similar to ERTAC BY emissions (purple dot almost hidden)
- 2) Both IPM and ERTAC show decreases in SO2 and NOx from 2016 to 2023.
- 3) The differences in SO2 between IPM and ERTAC in 2023 are due to differences in generation from coal
- 4) The differences in NOx are driven by IPM's lower CT & O/G Steam generation and lower coal generation. [for OS NOx in 2023, difference in CT and O/G Steam generation is responsible for ~75% of the difference]

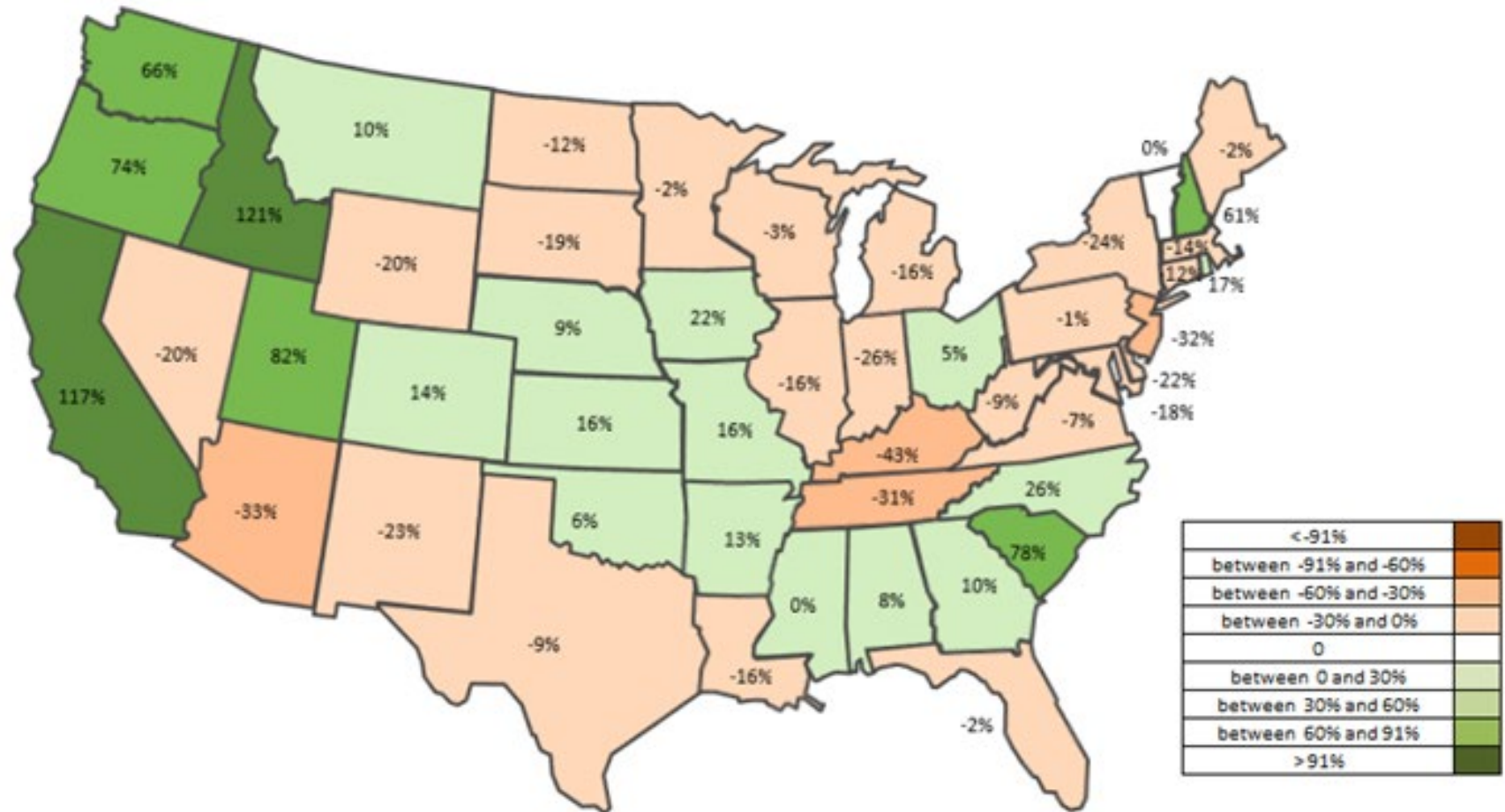
# 2023 Annual Generation by State



# 2023 Annual Generation by State (zooming in)

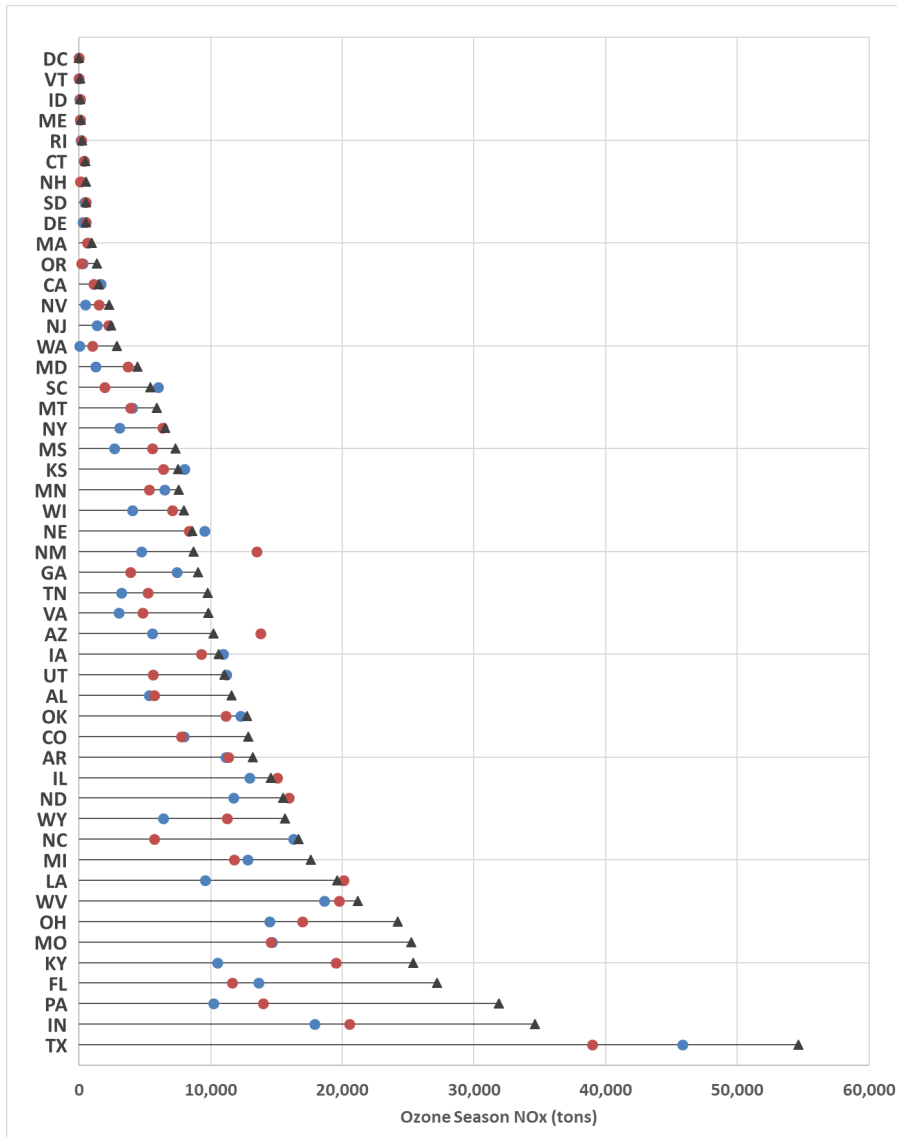


# 2023 Annual Generation in IPM as a Percent Change from ERTAC



*Green states have more annual generation in IPM Nov 2018 Ref Case*  
*Orange states have more annual generation in ERTACv16.0*

# 2023 Ozone Season NOx emissions



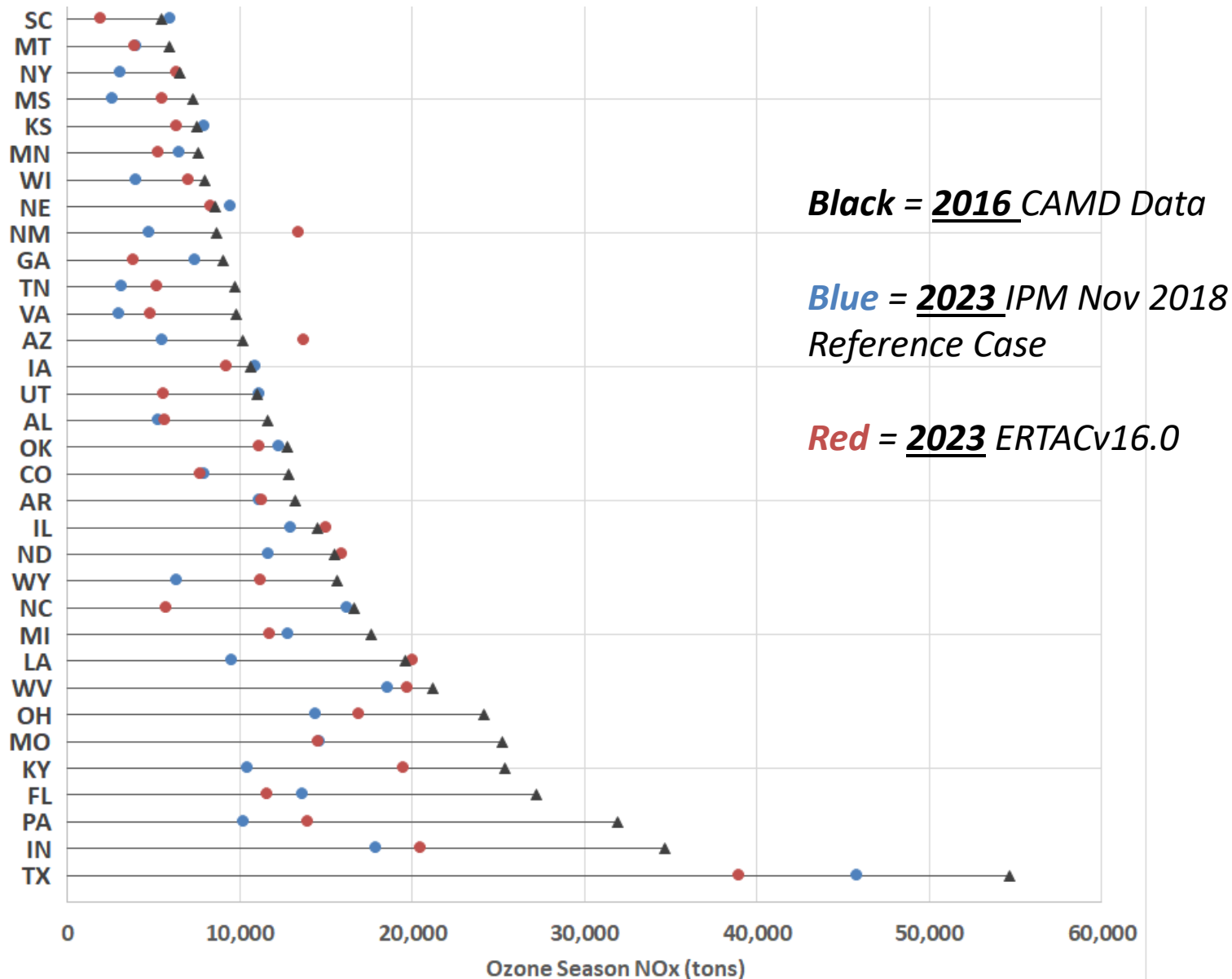
**Black** = 2016 CAMD Data

**Blue** = 2023 IPM Nov 2018  
Reference Case

**Red** = 2023 ERTACv16.0

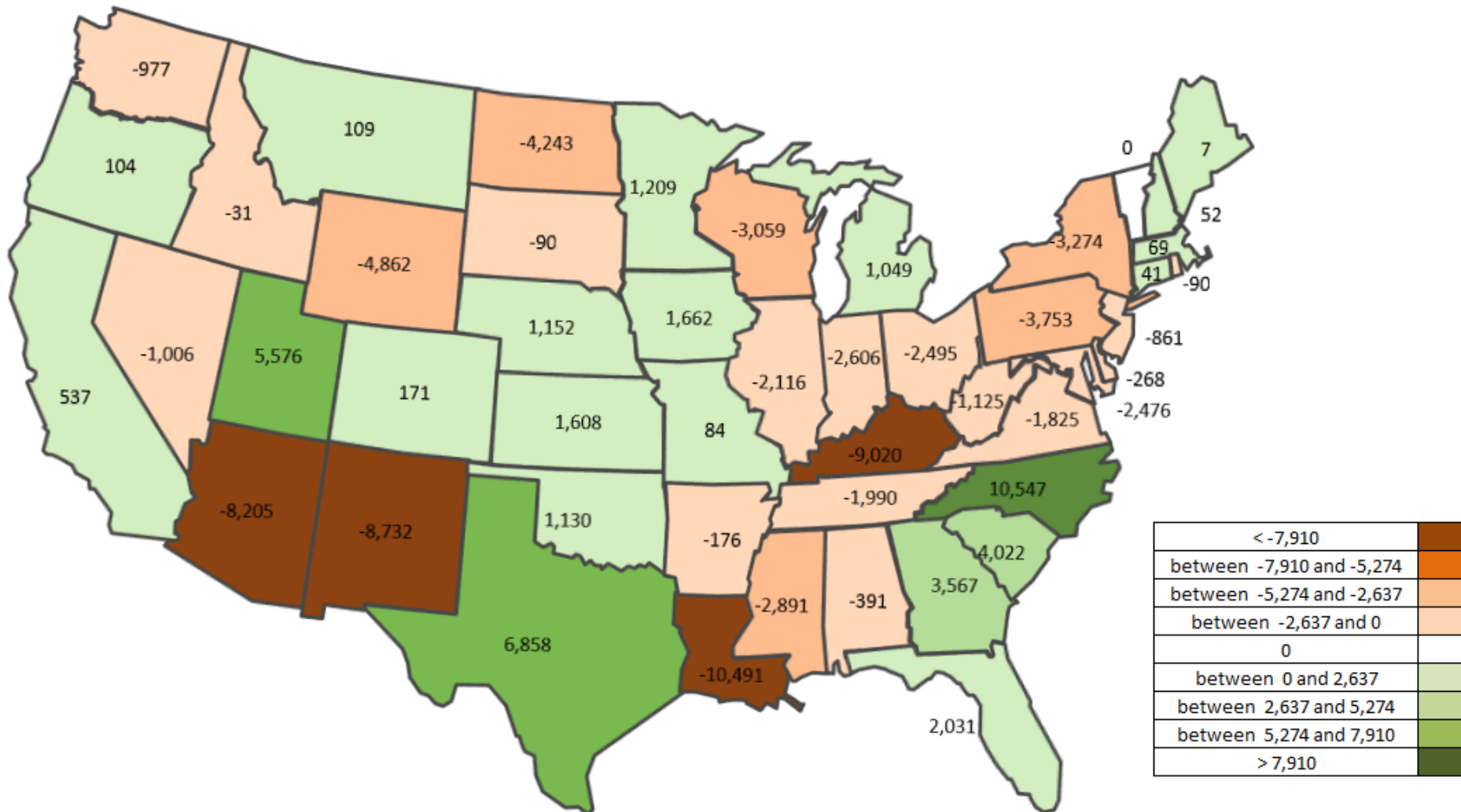
Ozone Season NOx (tons)

# 2023 Ozone Season NOx emissions (zooming in)





# Difference in 2023 Ozone Season NO<sub>x</sub> (tons) (IPM values as a change from ERTAC values)



*Green states have more OS NO<sub>x</sub> emissions in IPM Nov 2018 Ref Case  
Orange states have more OS NO<sub>x</sub> emissions in ERTACv16.0*

# Appendix

# EPA's Power Sector Modeling Update

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IPM v6 May 2018 initial run already incorporated a number of bottom-up data and structural platform updates compared to IPM v5. Some noteworthy ones:

- Time-of-day implementation of load segments
- NERC 2017 peak load/total load ratio projections through 2027, after that AEO peak/total ratios
- 60 year cost adder for nuclear life extension
- ATB 2017 (lower wind and solar costs)
- Latest data on committed units
- Hg EMF factors (all units comply with MATS without adding new retrofits)
- 2017 OS NO<sub>x</sub> rates
- Solar tariffs implementation
- CO<sub>2</sub> risk premium for new fossil units (coal and NGCC) at 3% capital charge rate penalty

# Type of Projection Method

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## ▶ ERTAC EGU Forecasting Tool

- Grows a base year hourly data into future projection years by employing scaling/growth factors using AEO demand projections by NEMS region and generation type.
- Mimics historical base year unit level hourly behavior into the future; units are not retired beyond known/announced retirements.
- ERTAC is currently using AEO high oil&gas case (switched from AEO ref case)
- ERTAC is using 2016 NOx rates.
- ERTAC's latest fleet reflects recent (2018) retirements.

## ▶ IPM

- Makes retirement and new capacity addition decisions based on least-cost optimization.
- Does not mimic a historical year dispatch behavior at the unit level.
- IPM's gas price/consumption projections are usually closer to AEO high oil&gas than AEO Ref case.
- IPM is using 2018 NOx rates.
- IPM's latest fleet reflects recent (2018) retirements.
- IPM outputs seasonal average values. Temporalization of unit level outputs into hourly data is done through a post-processing step.

