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# **Modeling the Evolving Power Sector and Impacts of the Final Clean Power Plan**

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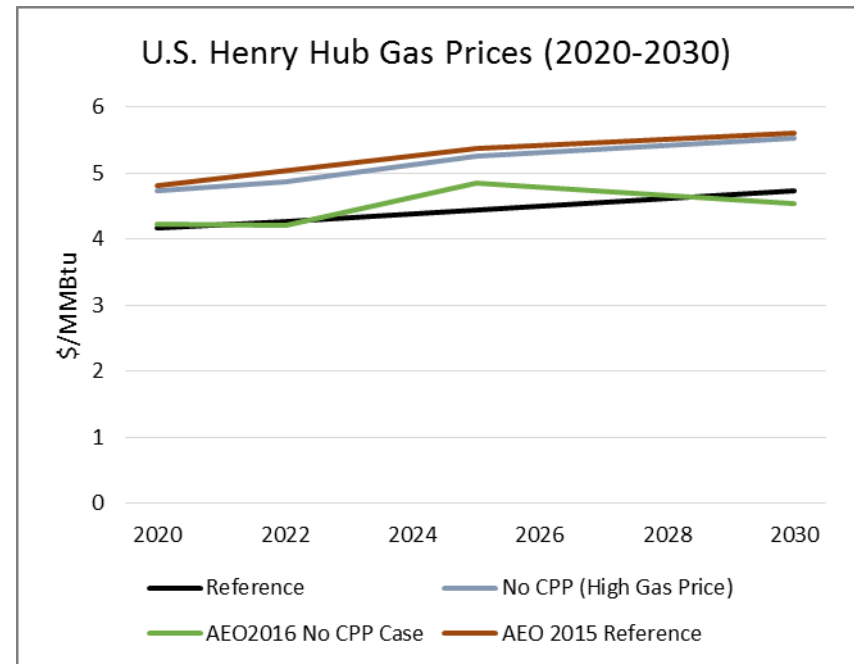


# High-Level Insights

# HIGH-LEVEL INSIGHTS: GAS PRICE DRIVING TRENDS



- Low natural gas prices are expected to drive many of the power sector trends projected under the Clean Power Plan (CPP)
- Lower gas prices:
  - Increase the share of natural gas in the generation mix
  - Lead to additional coal retirements
  - Depress wholesale electricity prices, which make some of the existing nuclear fleet vulnerable to early retirement
  - Influence how gas-fired generation competes with renewable investments to displace coal in compliance scenarios

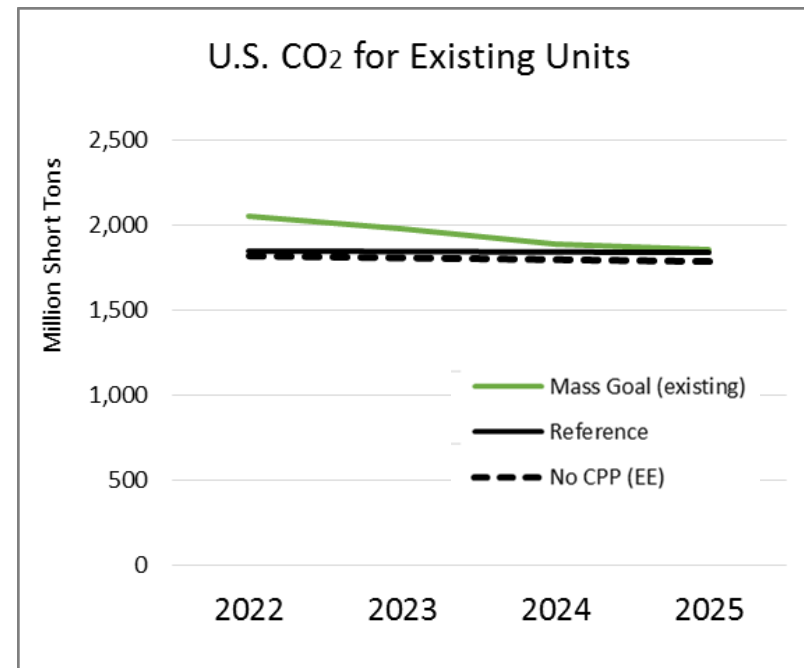


2030 Henry Hub Prices (2012\$/MMBtu)	
AEO 2015 Reference	\$5.61
BPC No CPP (High Gas Price)	\$5.53
BPC Reference	\$4.74
AEO 2016 No CPP Case	\$4.53

## HIGH-LEVEL INSIGHTS: EVOLVING BASELINE



- State energy policies, falling natural gas prices, and the extension of federal tax incentives for renewables mean many states are currently on track to comply with the Clean Power Plan
  - The Production Tax Credit (PTC) and Investment Tax Credit (ITC) accelerate wind and solar deployment, increase coal retirements, and reduce CO<sub>2</sub> (even in the absence of the CPP)
- The CPP is not binding in the early years
  - In most individual states, and
  - Where states participate in trading approaches at the interconnect level, whether rate-based, mass-based with existing units only, or mass-based with existing and new units
- Even so, the CPP is projected to accelerate and drive additional CO<sub>2</sub> reduction and clean energy investment

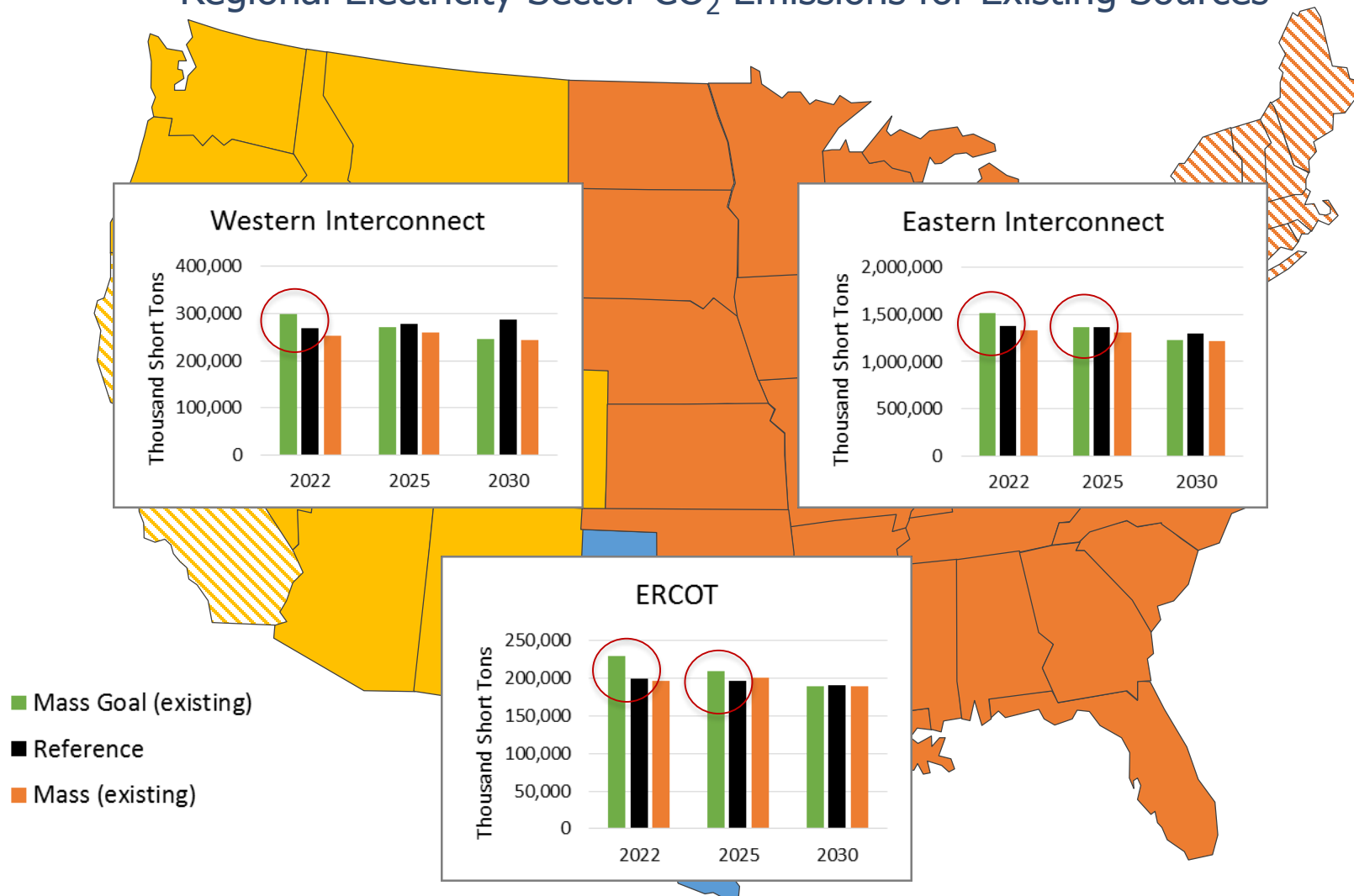


Note: The No CPP (EE) case is a business-as-usual case with additional energy efficiency investments available.

# CO2 IS BELOW CPP GOALS IN EARLY YEARS



## Regional Electricity-Sector CO<sub>2</sub> Emissions for Existing Sources



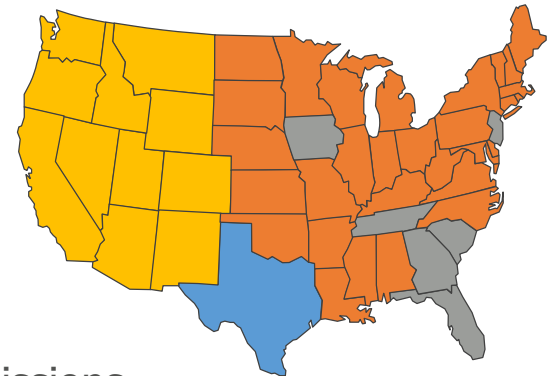
Note: The electricity-sector emissions shown above include all covered CO<sub>2</sub> emissions from existing utility-scale generation in the contiguous U.S. Emissions from new units and units that are not covered by the CPP are not included. The scenario Mass (existing) assumes all states implement mass-based interconnect trading covering only existing units under the CPP.



## HIGH-LEVEL INSIGHTS: STATE POLICY CHOICE



- State implementation policy choices will influence the cost of compliance, as well as the effectiveness of the program
  - Broad adoption of rate-based trading with the subcategory rates would be more expensive than broad adoption of mass-based trading
  - Broad adoption of mass-based trading covering both new and existing units, with each state choosing the new source complement (NSC), would result in both lower cumulative CO<sub>2</sub> emissions and lower cost than rate-based trading
- For the Eastern Interconnect,
  - A patchwork scenario, with most states adopting mass-based trading (w/NSC) and 6 ERC-surplus states adopting rate-based policy
    - Increases generation and CO<sub>2</sub> in rate states
    - Lowers cost for many *mass-based* states
    - But would not be as effective at reducing CO<sub>2</sub> emissions
  - While least expensive, broad adoption of mass-based policies covering only existing units would be least effective in terms of CO<sub>2</sub> emissions







## Nuclear

- The fate of vulnerable nuclear plants is sensitive to state CPP policy choice
  - The CPP, particularly mass-based policy with the new source complement, helps protect existing vulnerable nuclear plants from premature retirement
  - If future CO<sub>2</sub> stringency beyond CPP is expected, a least-cost path would retain existing nuclear and avoid most premature nuclear retirements

## Renewable Energy (RE)

- Even with relatively low gas prices, additional RE deployment beyond that driven by the PTC/ITC is expected in most policy scenarios
- In the Eastern Interconnect, the modeled rate-based scenario projects somewhat more RE than mass-based scenarios (without RE allocations)
- Mass-based scenarios may deploy more RE if states provide RE/energy efficiency incentives beyond the mass-based CPP goal
  - For example, through the allocation process or by strengthening state incentives in conjunction with CPP goals
  - States may want to consider whether additional RE/energy efficiency incentives are warranted in conjunction with mass-based policy frameworks



- Modeling highlights the importance of energy efficiency (EE) for cost containment and for smoothing the transition in generation and capacity mix
- When offered beyond the level of EE built into AEO2015 demand projections, efficiency reduces the price of allowances and ERCs under the policy cases, along with the costs for each case relative to the cases without efficiency
  - Policy scenarios with demand and supply side efficiency options allow more coal generation and, as a result, do not build as much new NGCC or renewable generation
- Efficiency, as an additional compliance option, has the largest impact in the dual rate run, where EE supplies a significant amount of lower cost ERCs and allows 2030 coal generation to increase significantly over other cases (that are limited to EE levels as built into the AEO demand forecast)
  - Relatively higher coal generation increases co-pollutant sulfur dioxide (SO<sub>2</sub>)

# HIGH-LEVEL INSIGHTS: TREATMENT OF NEW UNITS



- Potential risk/magnitude of leakage is dependent on various assumptions (e.g., gas prices, EE) and factors that may not be fully captured in modeling
  - Potential for leakage tends to increase the more CPP goals diverge from the baseline
  - Low allowance price diminishes leakage concerns, particularly in early years
  - Factoring the future risk of CO<sub>2</sub> emissions into investment decisions would tend to accelerate the shift to cleaner generation and dampen potential for leakage
- Mass-based policy coverage of existing units is projected to result in higher CO<sub>2</sub> emissions than either dual rate or mass with new units, in part because:
  - The rate-to-mass conversion varies between existing units and new source complement
  - New NGCC, that would in many cases be built regardless, is treated differently and, frees up room under the mass (existing) budget for more coal generation
- The need to protect against leakage varies by state
  - If “CPP-defined leakage” is occurring, more NGCC builds and/or a reduction in existing gas capacity factors might be expected when only existing units are covered under mass
  - Modeling with updated assumptions about the evolving baseline shows evidence of CPP-defined leakage in some states, but many states do not have such indicators
- While coverage of new units under mass may prevent CPP-defined leakage within mass states, it could increase “rate-state leakage”, or CO<sub>2</sub> increases in rate states
  - Updating output-based allocation could help mitigate both forms of leakage



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# Assumptions and Scenarios



- This Clean Power Plan (CPP) analysis is informed by economic modeling using the commercial version of the Integrated Planning Model (IPM) run by ICF and is based on assumptions and scenarios defined by the Bipartisan Policy Center
  - IPM is a national dispatch model intended to show broad trends and highlight key drivers through multi-scenario analysis
    - The model determines the least-cost means of meeting electric generation requirements while complying with constraints, such as: air regulations, transmission constraints, and plant-specific operational constraints
  - Caution is important when interpreting localized state-level results
    - IPM is optimized at the regional/national level and may not capture all local or company-specific factors
  - Modeling results should be viewed as a tool to supplement other inputs
    - No single scenario and/or set of assumptions should be interpreted as providing “the answer”

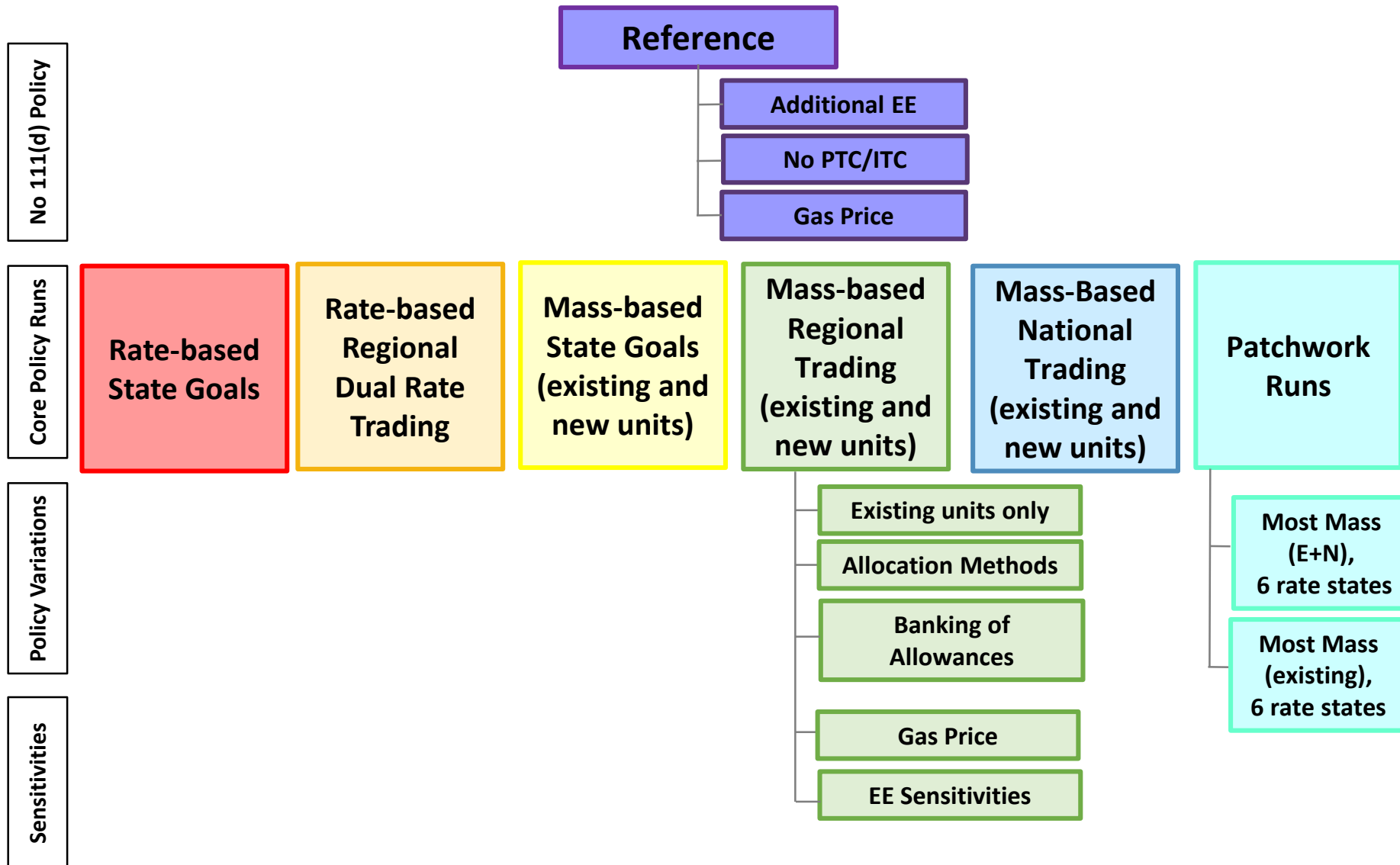
# SUMMARY OF KEY ASSUMPTIONS



	Source of Assumptions
Unit-level characteristics	AEO 2015 & NEEDSv.5.15
Natural Gas Supply & Costs	AEO 2015 Fuel supply curves based on mid-point between AEO Reference case & High Gas Resource (low gas price) cases
Renewable Energy Cost	ICF market research (PTC/ITC extension included)
Nuclear Retirements	All units retire at their 60-year relicensing date
Electricity Demand	AEO 2015 demand forecast
Transmission	No new transmission is built. The cost of new generation includes a representative cost for tying into the existing grid
Banking of Allowances	None; except in banking sensitivity run
Renewable Portfolio Standards	Represented at the IPM Zonal level
CPP Policy Regions	Eastern Interconnect, Western Interconnect, ERCOT
EE Sensitivities:	
Cost of Additional EE	3-step cost curve: (2.3-3.2 cents/KWh)*
Supply of Additional EE	½ EE supply from EPA
Heat Rate Improvements	EPA

Note: 2.3-3.2 cents/KWh represents only 55% of the total resource cost of EE investments, assumed to be the utility portion of ratepayer-funded EE; the assumed total resource cost is 4.2-5.8 cents/KWh.

# MODELING SCENARIOS





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# **Evolving Baseline: Natural Gas and Renewables**





- A combination of recent policy changes and evolving market forces brings business-as-usual (BAU) CO<sub>2</sub> emissions below the early Clean Power Plan trajectory

## Key Areas of Change in the Baseline



- **Decreasing Gas Price:** Between the AEO 2015 Reference case and the AEO 2016 No CPP Case, the projected 2030 price for natural gas dropped by \$1.08/MMBtu



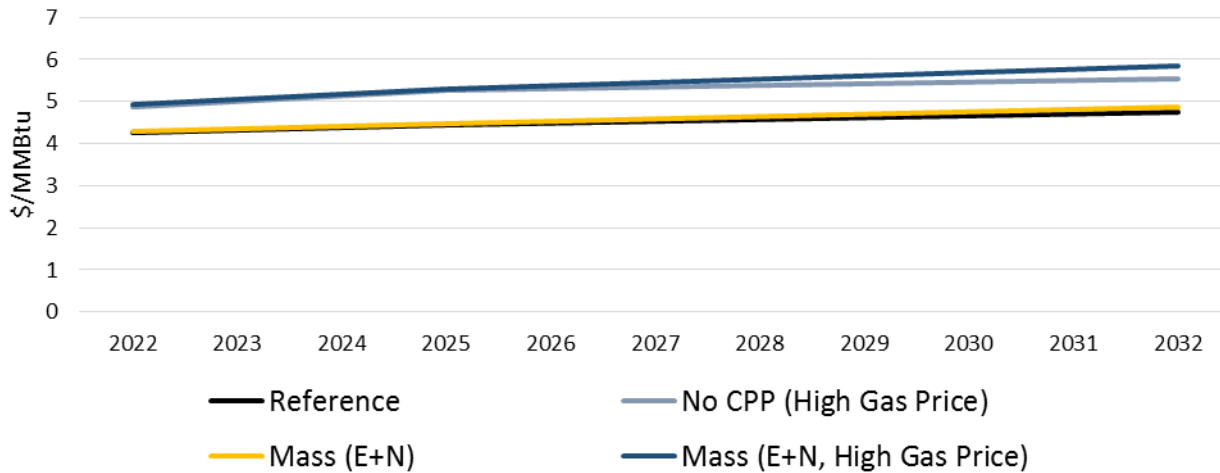
- **PTC/ITC:** In 2015, Congress passed a PTC/ITC extension, lowering near-term costs for utility-scale wind projects that begin construction by 2020 and solar projects that begin construction by 2022 (and, to a smaller extent, for continuing solar deployment)
- **Decreasing RE Costs:** The projected total overnight costs for new deployments of utility-scale wind and solar fell by about 18% and 26% between AEO 2015 and AEO 2016

Note: BPC's business-as-usual projections do not include 111(d) or 111(b) policies. Final state and federal environmental policies as of August 2015 are represented, as is the extension of the federal Production Tax Credit (PTC) and Investment Tax Credit (ITC). AEO 2016's Reference case includes the Clean Power Plan. The AEO 2016 No CPP Case is a business-as-usual case that does not.

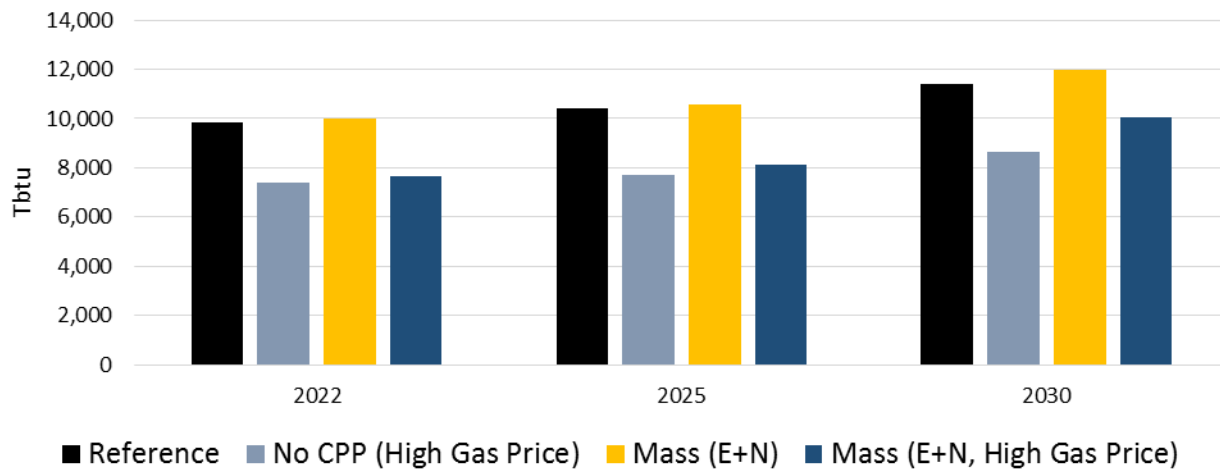
# INTERACTION BETWEEN GAS PRICE AND CONSUMPTION



U.S. Henry Hub Gas Prices (2022-2032)



U.S. Gas Consumption (2022-2030)

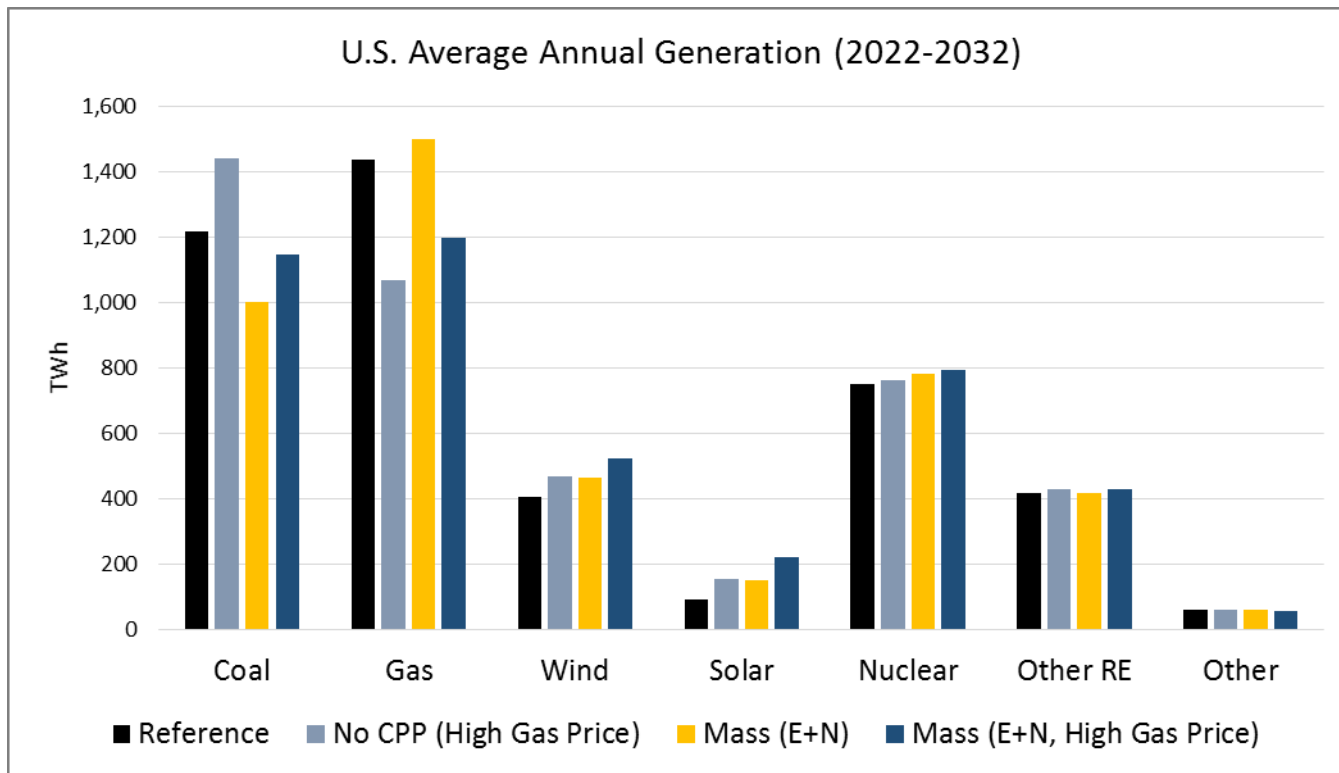


- Lower natural gas prices lead to increased gas usage which, in turn, puts upward pressure on gas prices
  - The price feedback is dynamically factored into consumption choices in IPM
- Input gas supply/price assumptions have significantly more impact on gas usage than the CPP policy
- In 2030, CPP increases gas consumption over Reference case-levels by 5% and gas prices by 3%, when states implement Mass (E+N) trading

# LOW GAS PRICES DECREASE COAL GENERATION



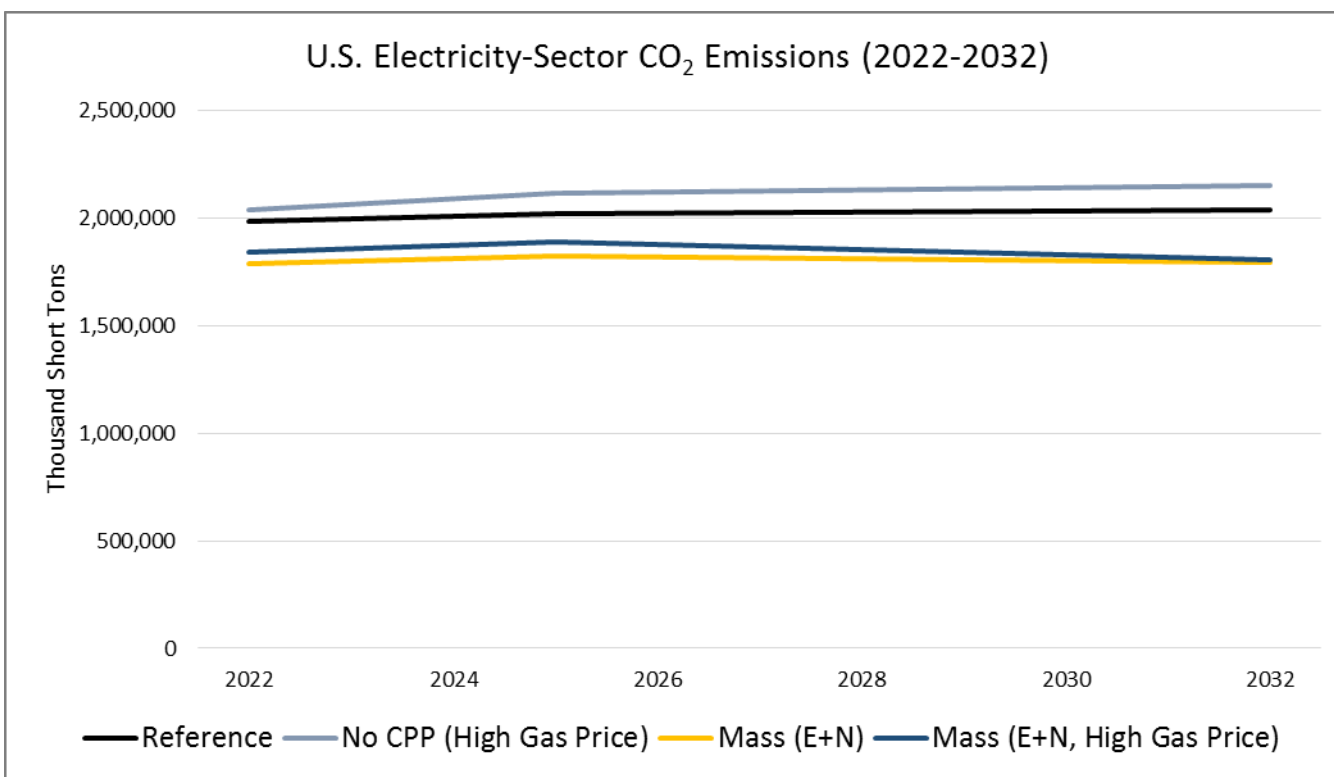
- The Reference case natural gas price curve results in more gas and less coal generation than a no CPP case with higher assumed gas prices
  - Compared to a higher gas price case, the Reference case leads to:
    - 35% increase in gas generation
    - 16% decrease in coal generation, and 24 GW more coal retirements



# LOW GAS PRICES LEAD TO ADDITIONAL CO<sub>2</sub> REDUCTIONS



- Reference case gas assumptions lead to lower electricity-sector CO<sub>2</sub> emissions in the business-as-usual case and in the early years of a mass-based CPP case, compared to higher gas price scenarios
  - CO<sub>2</sub> is 3% lower in 2022 and 5% lower in 2030 Reference case

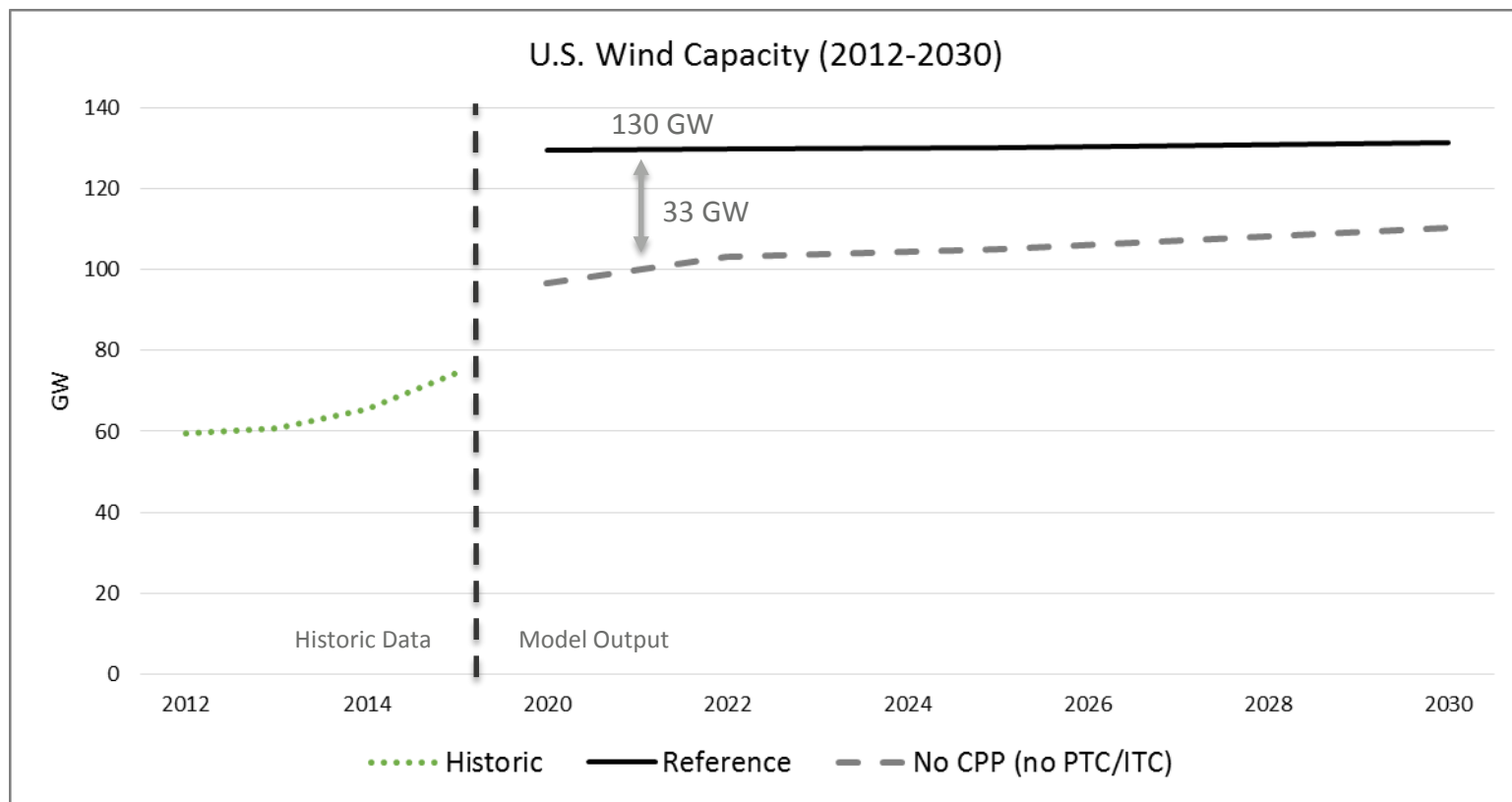


Note: The electricity-sector emissions shown above include all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., both covered and uncovered by the CPP.

# PTC/ITC LEADS TO INCREASED U.S. WIND CAPACITY



- The Reference case, which includes the PTC/ITC, approaches 130 GW installed wind capacity by 2021 (adding 55 GW beyond 2015)
  - On top of expected/projected additions, an additional 33 GW of wind is projected to be built by 2021 with the tax extenders

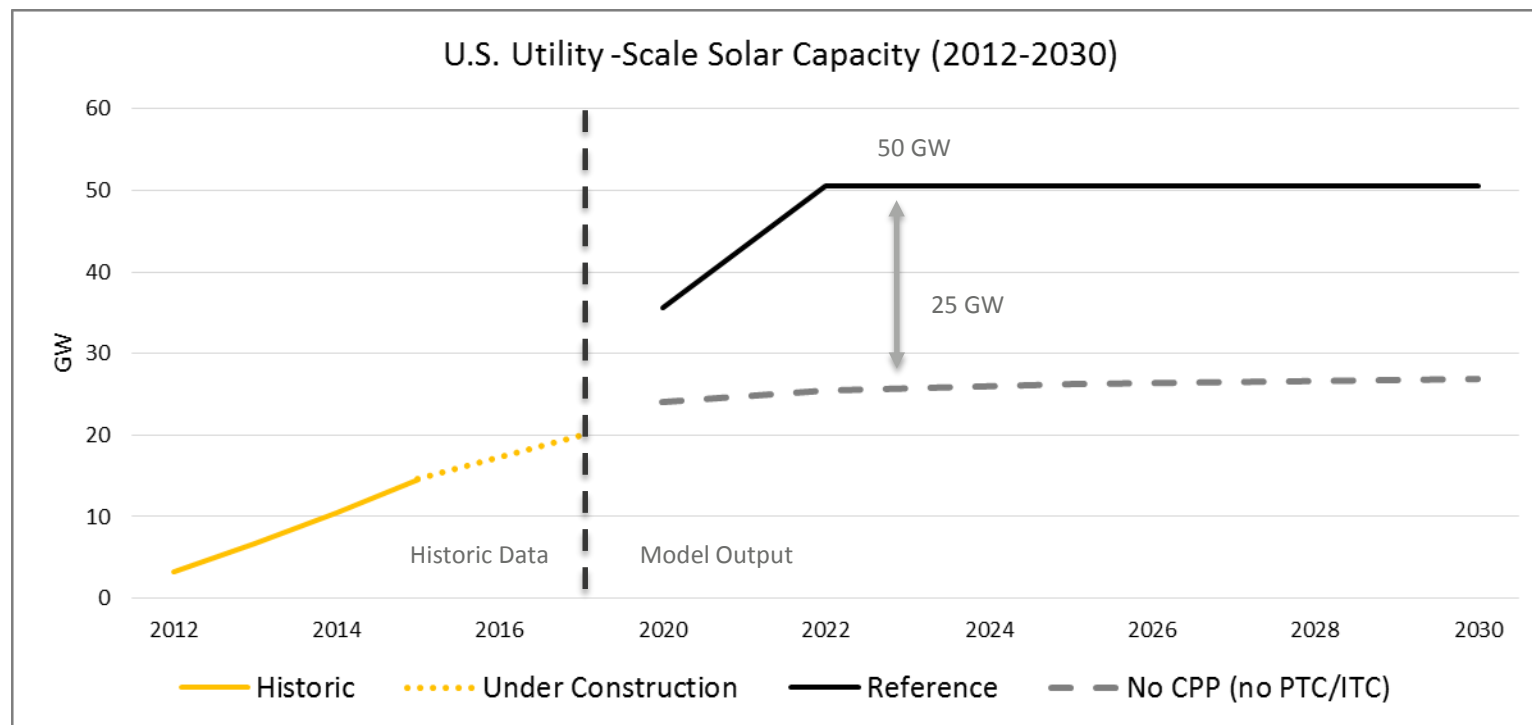


Sources: EIA: Electric Power Annual 2012, 2013, and 2014. AWEA: "U.S. Wind Industry Fourth Quarter 2015 Market Report."  
Projected data from BPC scenarios using IPM.  
Note: No CPP (no PTC/ITC) is a business-as-usual case with no PTC/ITC extension.

# PTC/ITC LEADS TO INCREASED U.S. SOLAR CAPACITY




- The Reference case, which includes the PTC/ITC, reaches national 50 GW installed utility-scale solar capacity by 2023 (adding 36 GW beyond 2015)
  - On top of expected/projected additions, an additional 25 GW of utility-scale solar is projected to be built by 2023 with the tax extenders
  - More aggressive assumptions about future declines in the price of solar could be expected to trigger additional solar deployment beyond 2023



Sources: EIA: Electric Power Annual 2012, 2013, and 2014. SEIA: "U.S. Solar Market Insight 2015 Q4." Projected data from BPC scenarios using IPM.



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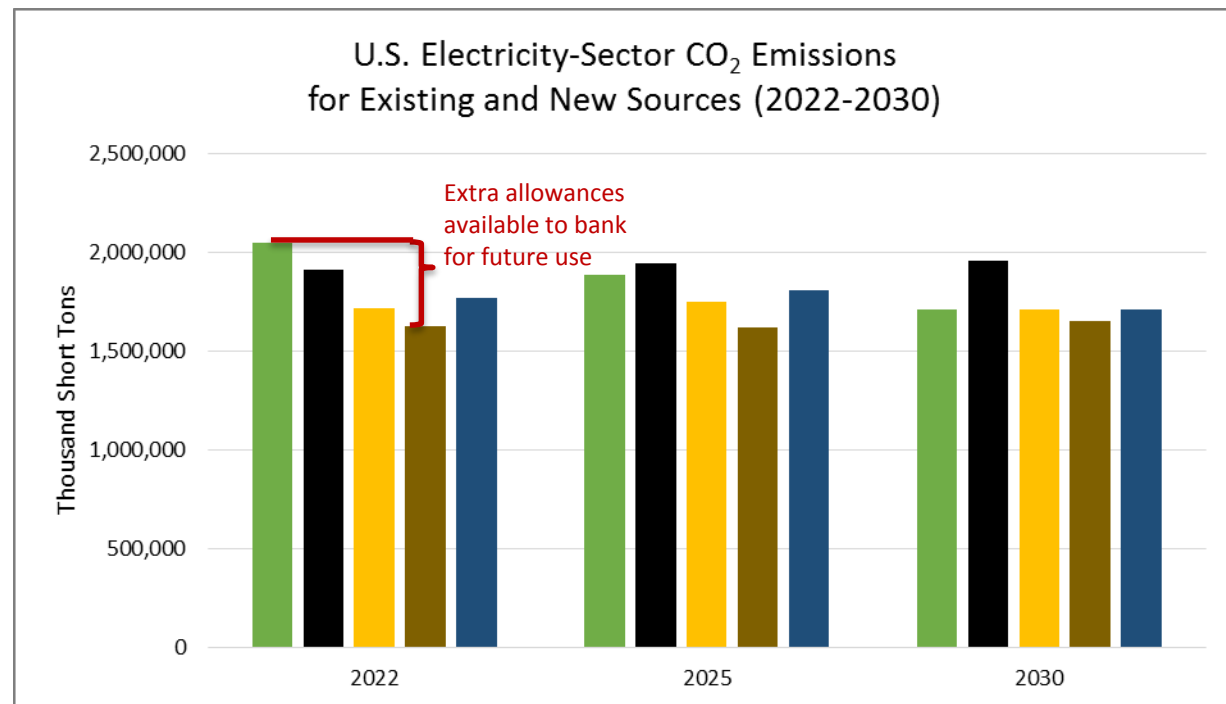


# **Clean Power Plan Drives CO<sub>2</sub> Below Baseline**

# CO2 EMISSIONS ARE BELOW CPP MASS GOALS IN 2022



- Although business-as-usual emissions are projected to comply with the CPP in most states in 2022, the policy drives additional reductions
- In scenarios with interconnect trading, CO<sub>2</sub> is lower than new source complement mass goals for most of the interim period
  - Expectations of future CPP requirements drive additional early reductions
  - The ability to bank allowances for future use adds value to early CO<sub>2</sub> reductions, accelerating reductions and lowering future allowance prices



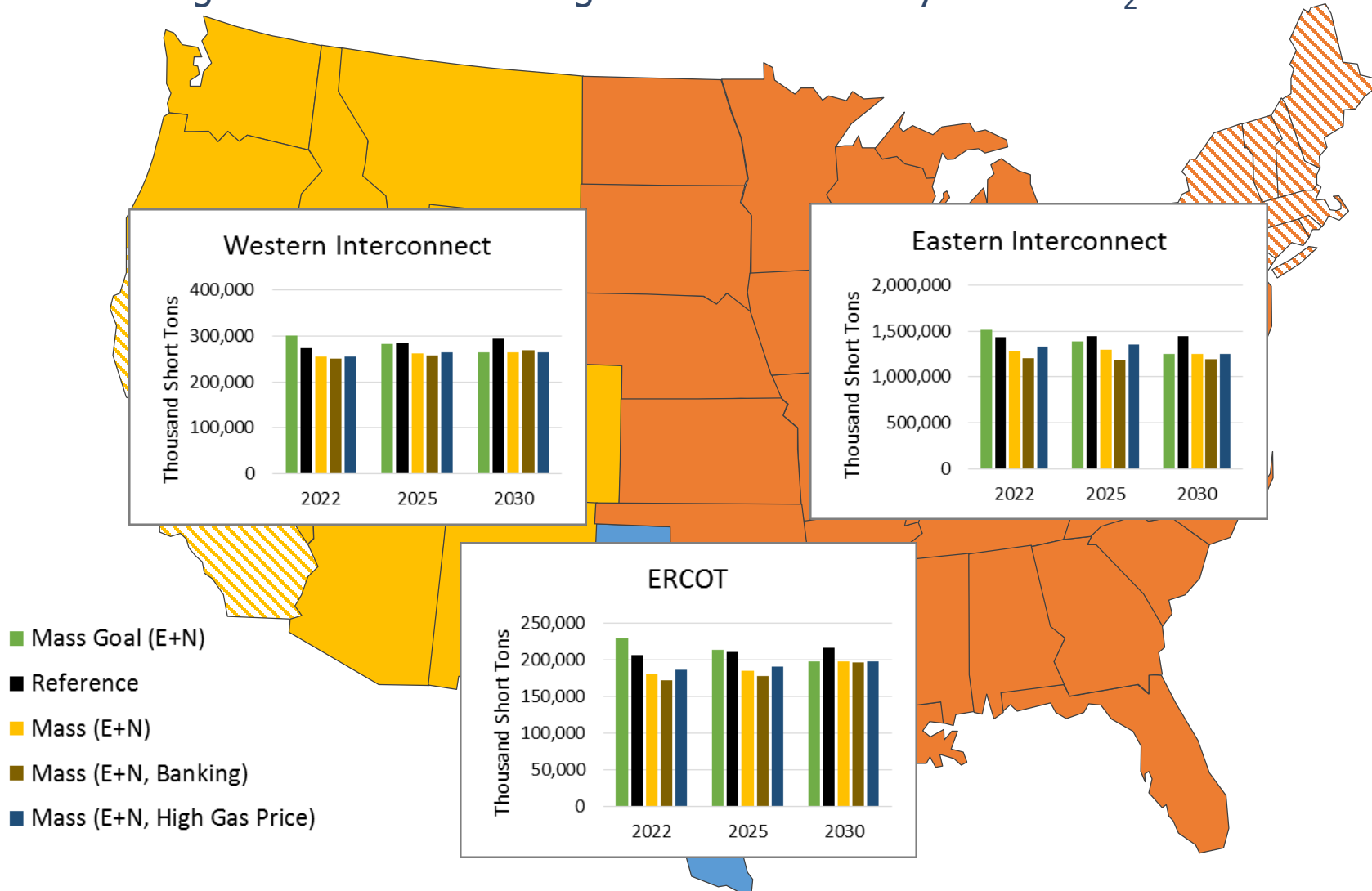
Note: The electricity-sector emissions shown above includes all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., except emissions that are not covered by the CPP, such as small fossil units.



# REGIONAL CO2 IS BELOW CPP MASS GOALS IN 2022



## Regional Covered Existing and New Electricity-Sector CO<sub>2</sub> Emissions

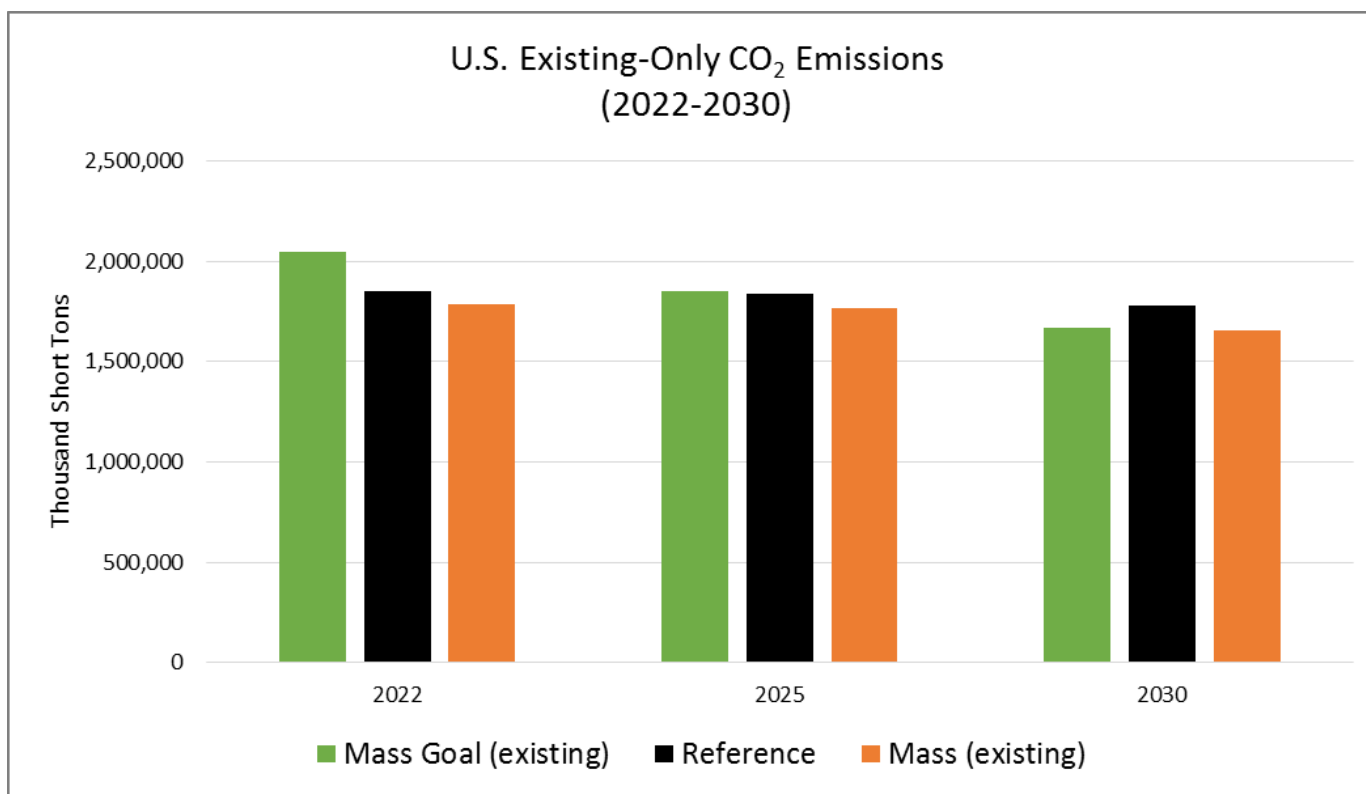


Note: The electricity-sector emissions shown above includes all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., except emissions that are not covered by the CPP, such as small fossil units.

# EXISTING SOURCE CO<sub>2</sub> IS BELOW EARLY CPP GOALS



- At the U.S. level and in the majority of states, if only existing-fleet CO<sub>2</sub> is considered, BAU emissions remain below CPP mass goals through much of the interim period, building a bank of allowances for use in 2030 and beyond
  - The BAU emissions trajectory would create a bank of 446 million tons by 2028



Note: The electricity-sector emissions shown above includes all covered CO<sub>2</sub> emissions from existing utility-scale generation in the contiguous U.S. Emissions from new units and units that are not covered by the CPP are not included.



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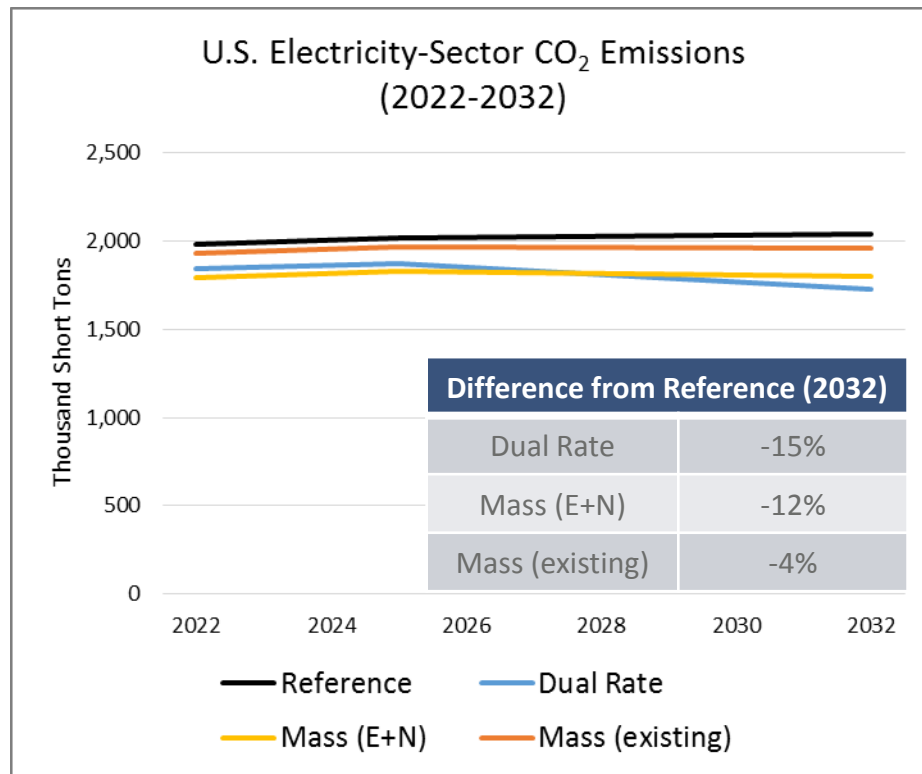
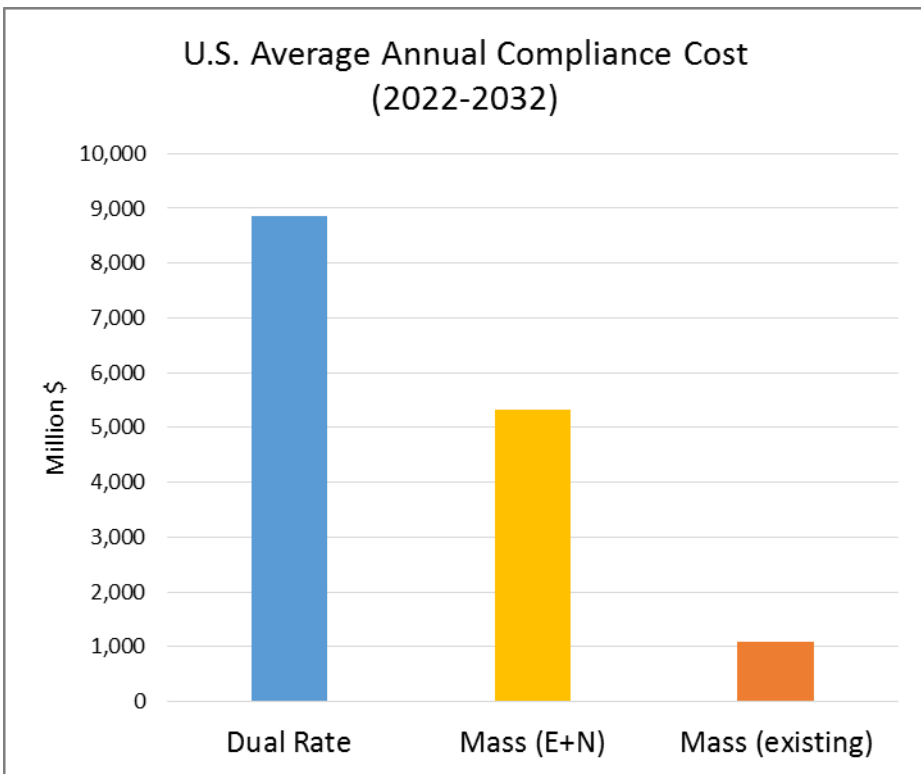


# **Impact of Policy Pathway: Dual Rate vs. Mass**

# SYSTEM COSTS ARE HIGHER UNDER DUAL RATE



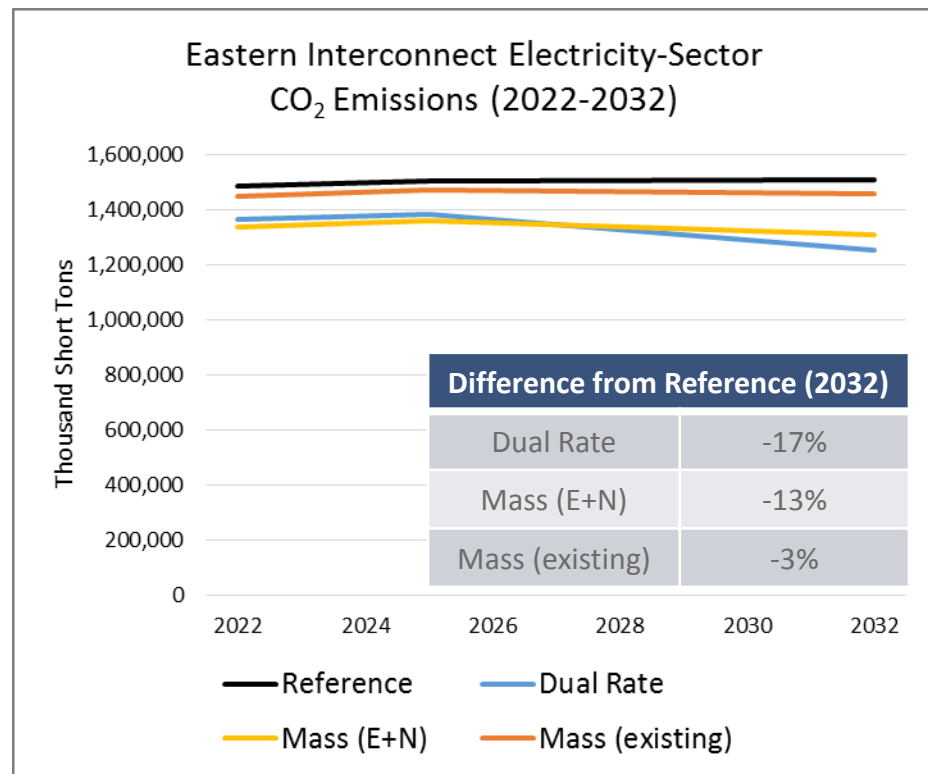
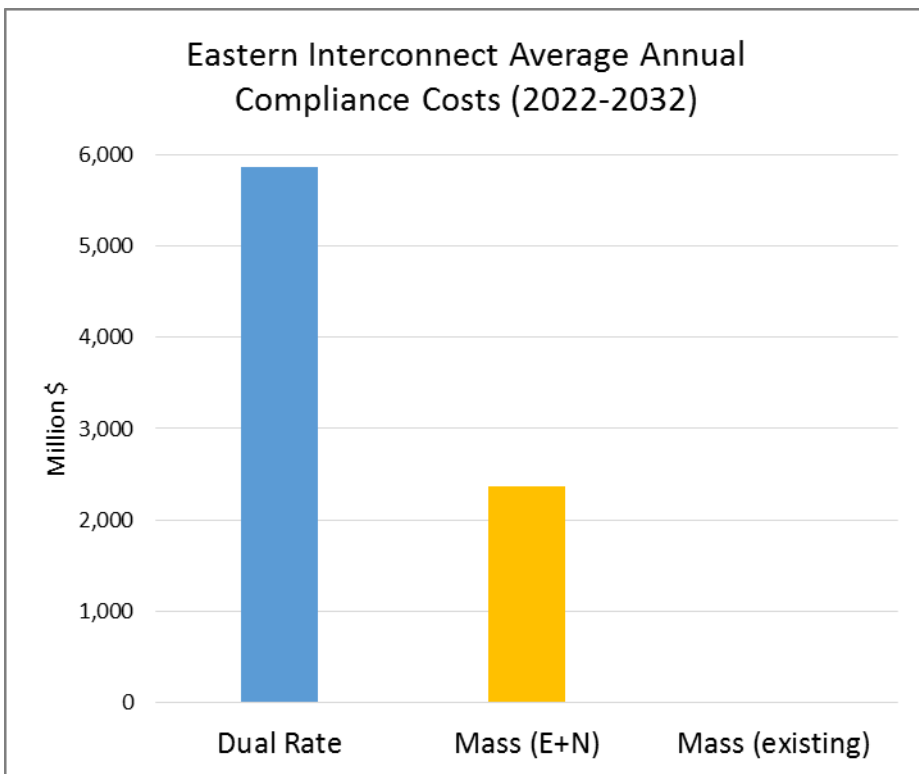
- At the U.S. level, compliance costs are higher when all states comply using dual-rate compared to mass-based approaches
- Mass (existing) has the lowest cost and is the least stringent of the three runs
  - Some individual states have lower cost under Dual Rate or Mass (N+E)
- While all costs decrease, comparative trends remain largely the same when incremental EE is available



# COSTS AND EMISSIONS IN THE EAST TRACK U.S. TRENDS



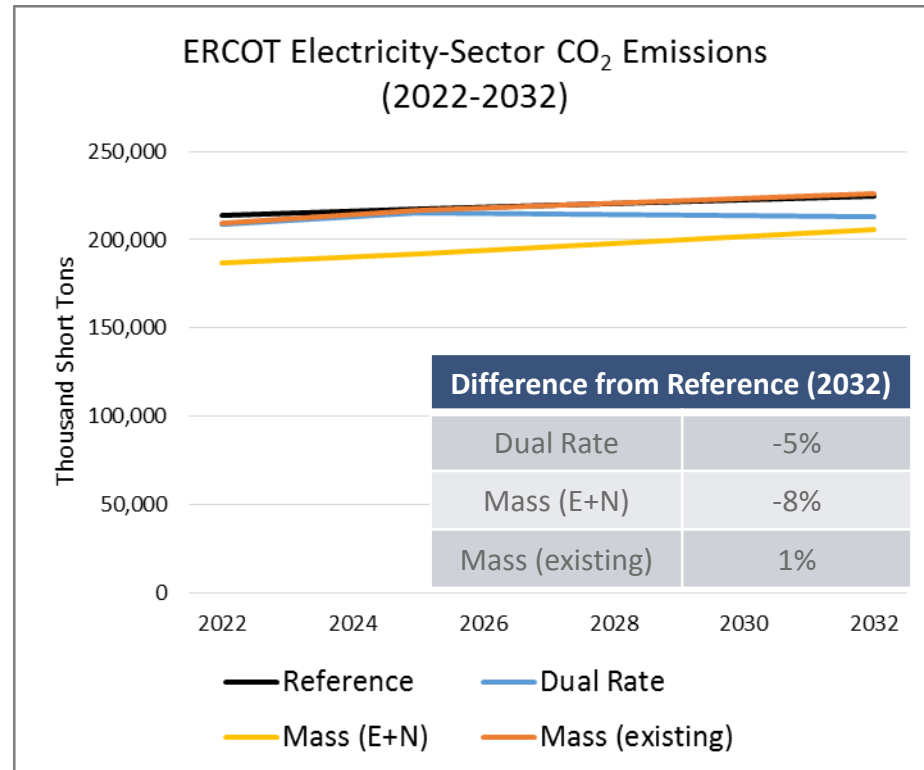
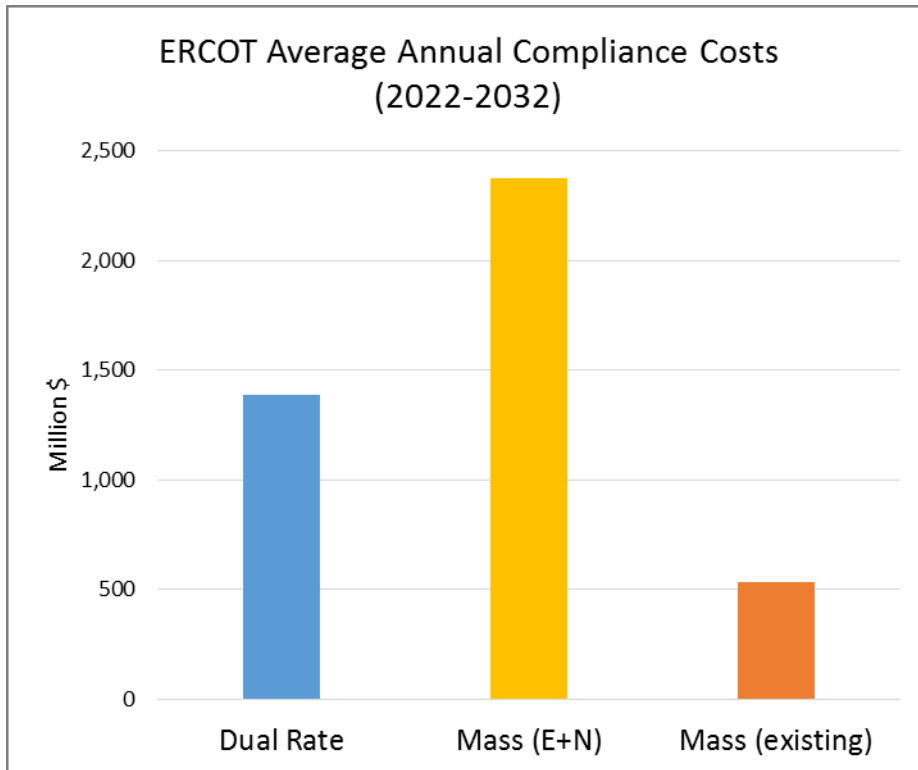
- Similar to U.S. trends, in the Eastern Interconnect as a whole,
  - Compliance costs are higher when all states comply using dual-rate
  - Without additional features, such as to mitigate leakage, Mass (existing) achieves a small reduction in CO<sub>2</sub> at minimal cost, compared to Reference
  - Individual state results vary and depend on choices of surrounding states



# ERCOT BENEFITS IF ALL STATES CHOOSE DUAL RATE



- Trends in ERCOT differ from U.S. trends, when all states choose the same policy
  - ERCOT has higher costs and lower CO<sub>2</sub> with broad adoption of Mass (E+N)
  - Dual Rate follows the business-as-usual trajectory until 2025, then trends down
  - Mass (existing) is lowest cost, but CO<sub>2</sub> emissions grow above Reference case levels
  - ERCOT/TX is not assumed to trade with other states, but is influenced by the policy choices and wholesale price impacts of some other states

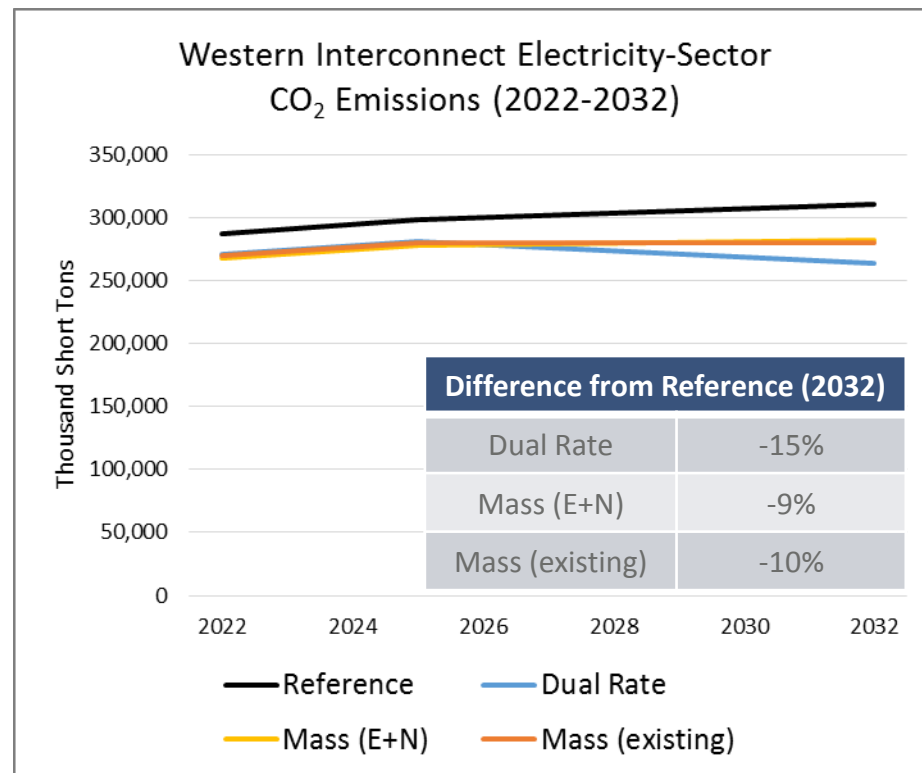
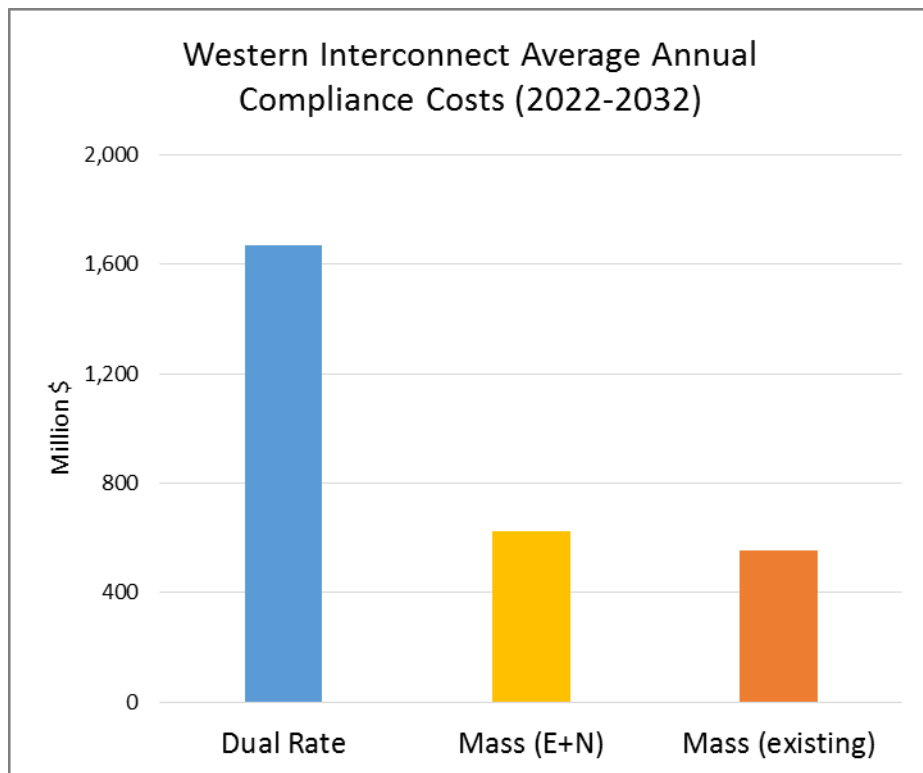


Note: Absolute costs shown above do not reflect the downward pressure energy efficiency is expected to have on generation costs. 30  
 Emissions shown above include all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., both covered and uncovered by the CPP.

# IN THE WEST, POLICY TREATMENT OF NEW UNITS HAS LESS IMPACT ON COST AND CO2



- In the Western Interconnect, like in the U.S. as a whole, the Dual Rate run is the most costly
- However, the treatment of new units is less impactful in the West, and the two mass runs have similar costs and CO<sub>2</sub> emissions





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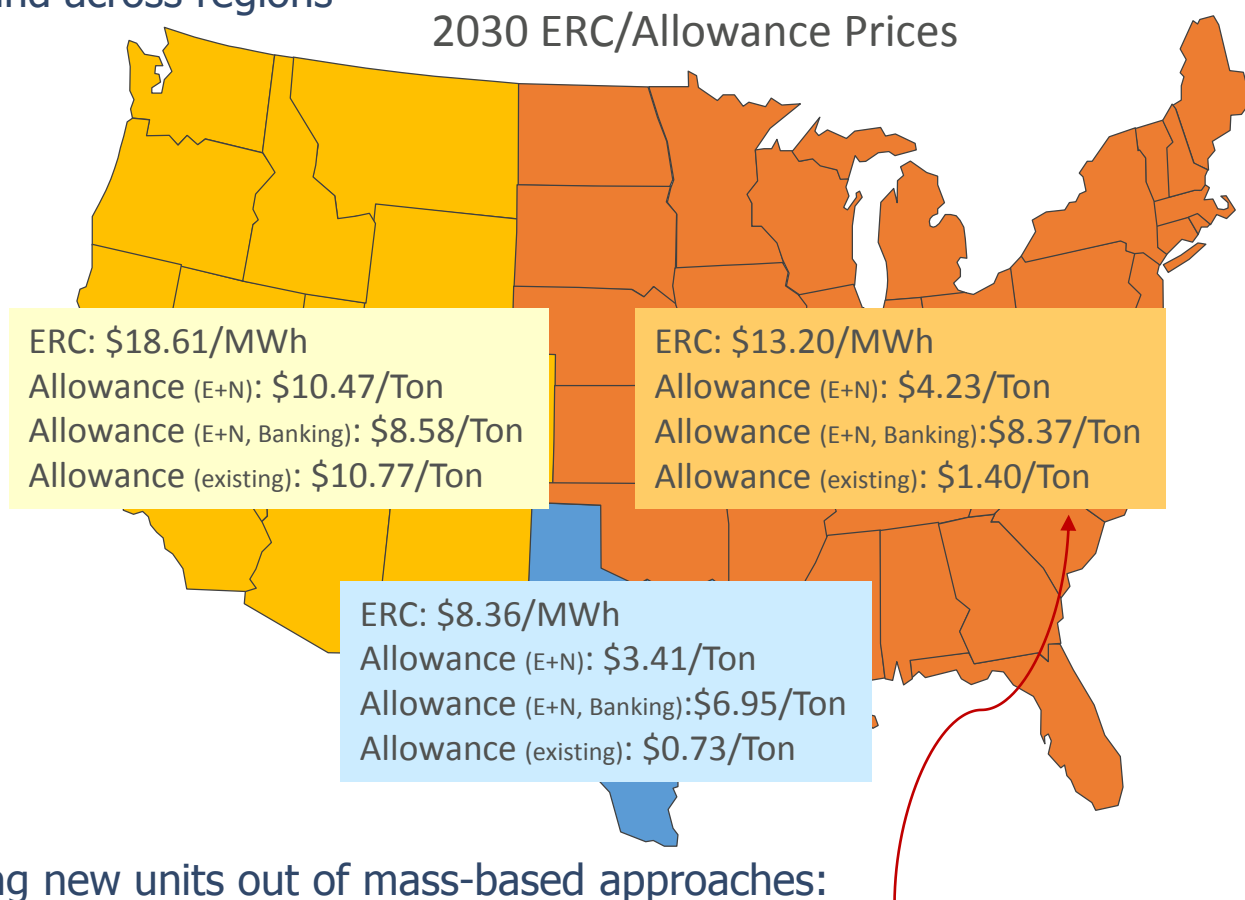
# Credit and Allowance Prices



# ERC & ALLOWANCE PRICES VARY BY POLICY DESIGN



- Without banking, prices for ERCs/allowances would be zero in the interim period
- Banking adds value to early reductions and stabilizes the allowance price over time and across regions



- Leaving new units out of mass-based approaches:
  - In the East and ERCOT, results in a lower allowance price
  - In the West, results in a higher allowance price (until 2040)

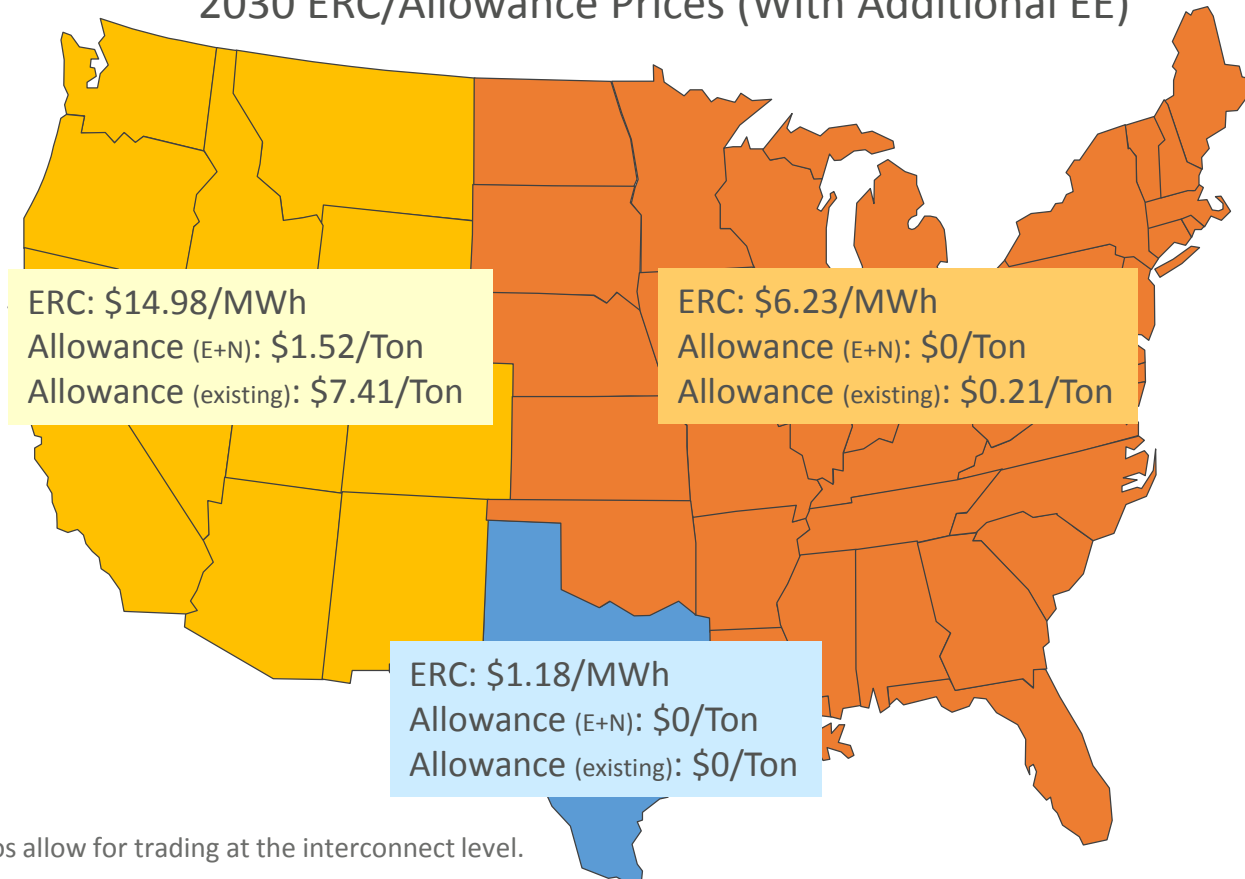
Note: Prices are from scenarios that no have additional EE beyond EE included in AEO forecast demand. Scenarios allow for trading at the interconnect level. The Mass (E+N, Banking) scenario allows banking of allowances from 2022-2040.

# EE IMPACT ON ALLOWANCE/CREDIT PRICE



- Availability of EE for compliance lowers both ERC and allowance prices
- If additional EE is available, then including new units under a mass-based approach lowers the allowance price in 2030
  - If only existing sources are covered, allowance prices drop off in later years

2030 ERC/Allowance Prices (With Additional EE)



Note: Scenarios allow for trading at the interconnect level.



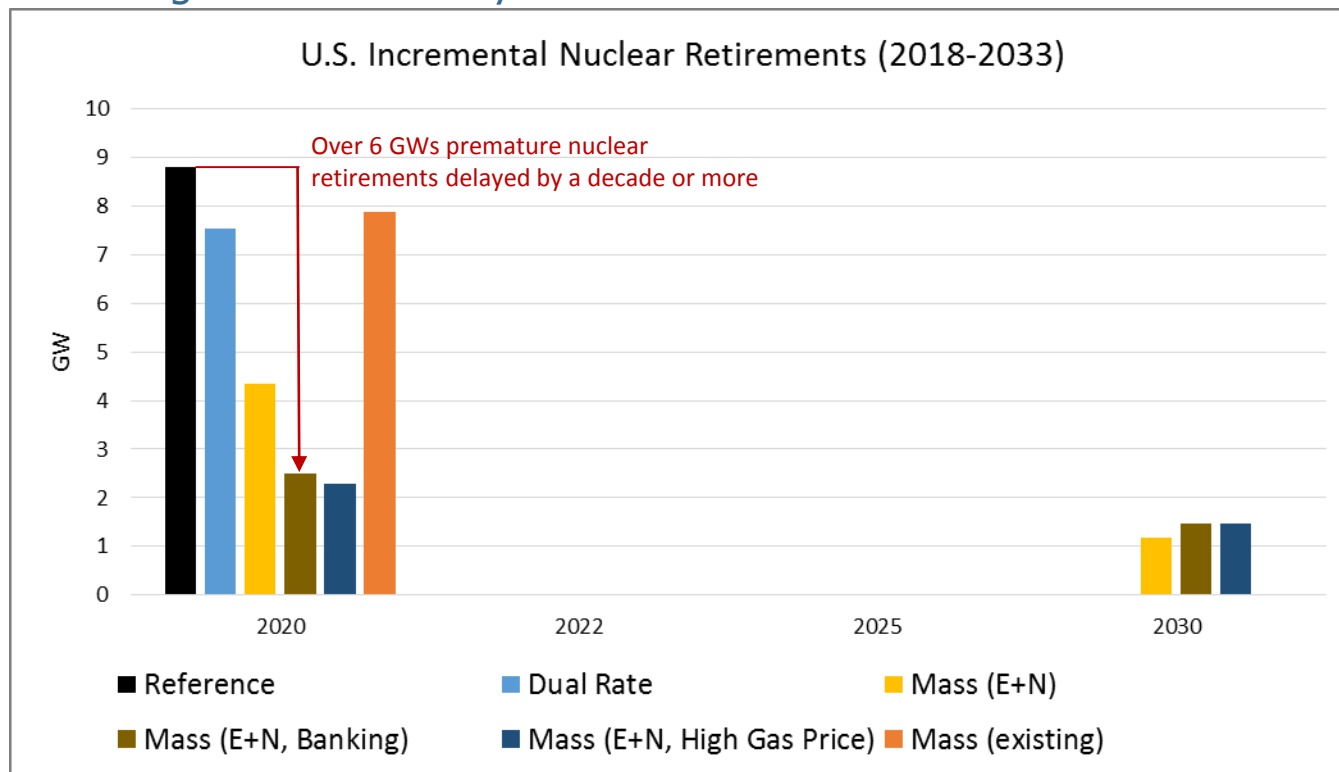
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# Impacts on the Generation Fleet

# NUCLEAR RETIREMENTS ARE SENSITIVE TO GAS PRICES AND CPP POLICY



- With \$4/MMBtu gas, some existing nuclear is vulnerable to early retirement
  - If gas is in the \$5 range, premature retirements are cut in half
- State CPP policy choice has the potential to help vulnerable nuclear
  - Mass (E+N) delays at least half and, when accounting for banking, delays more than 3/4 of the premature nuclear retirements
  - However, the advantage of a mass-based framework for the economics of existing nuclear is nearly lost in scenarios where new units are not covered

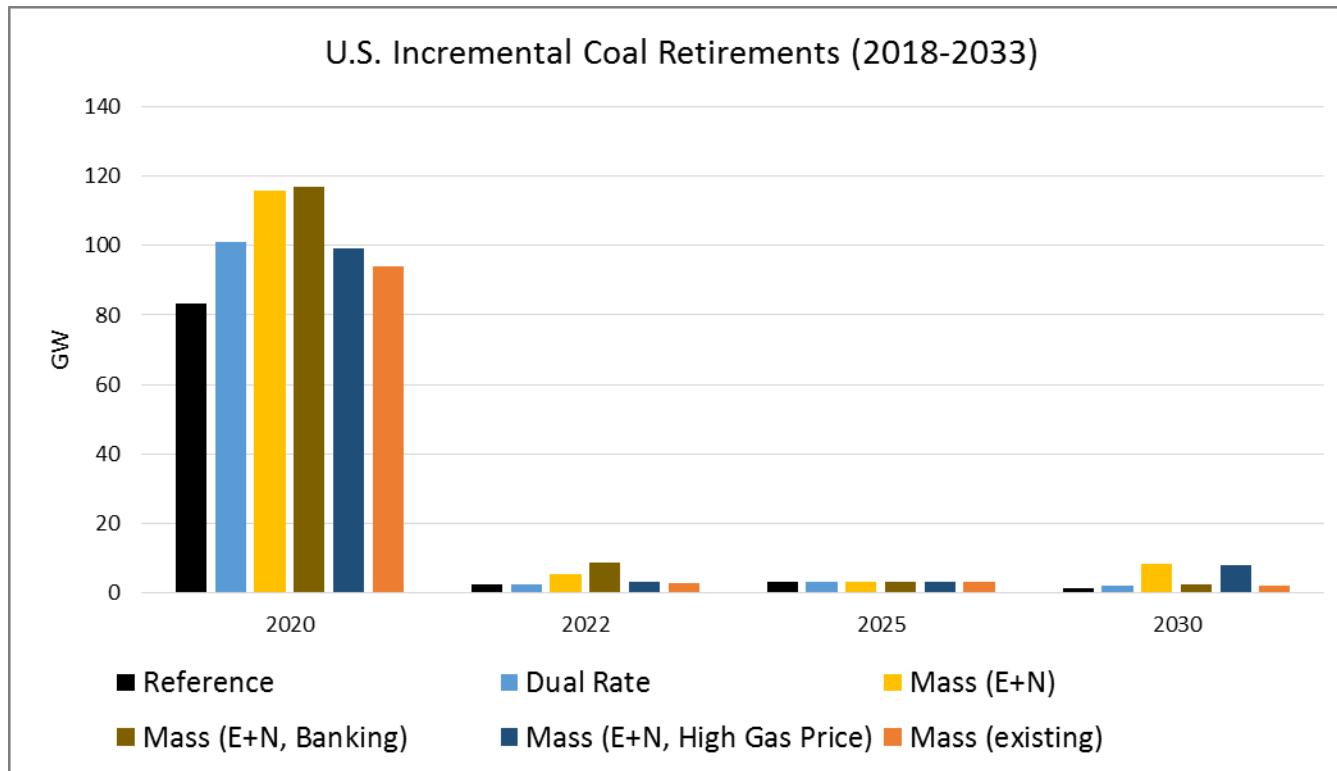


Note: These scenarios have no additional EE beyond EE included in the AEO 2015 forecast demand

# TRADEOFFS BETWEEN COAL AND NUCLEAR CAPACITY



- Lower gas and renewable prices spur additional coal retirements
- The most coal retires under the Mass (E+N) scenario, in part due to the policy's incentive to keep nuclear capacity online longer
- Policy runs with additional EE (not shown below) have relatively fewer coal retirements (e.g., 11 GW of CPP-driven coal retiring between 2018 & 2033 in Dual Rate with EE compared to 19 GW in Dual Rate)
  - Without CPP, energy efficiency investments would increase coal retirements

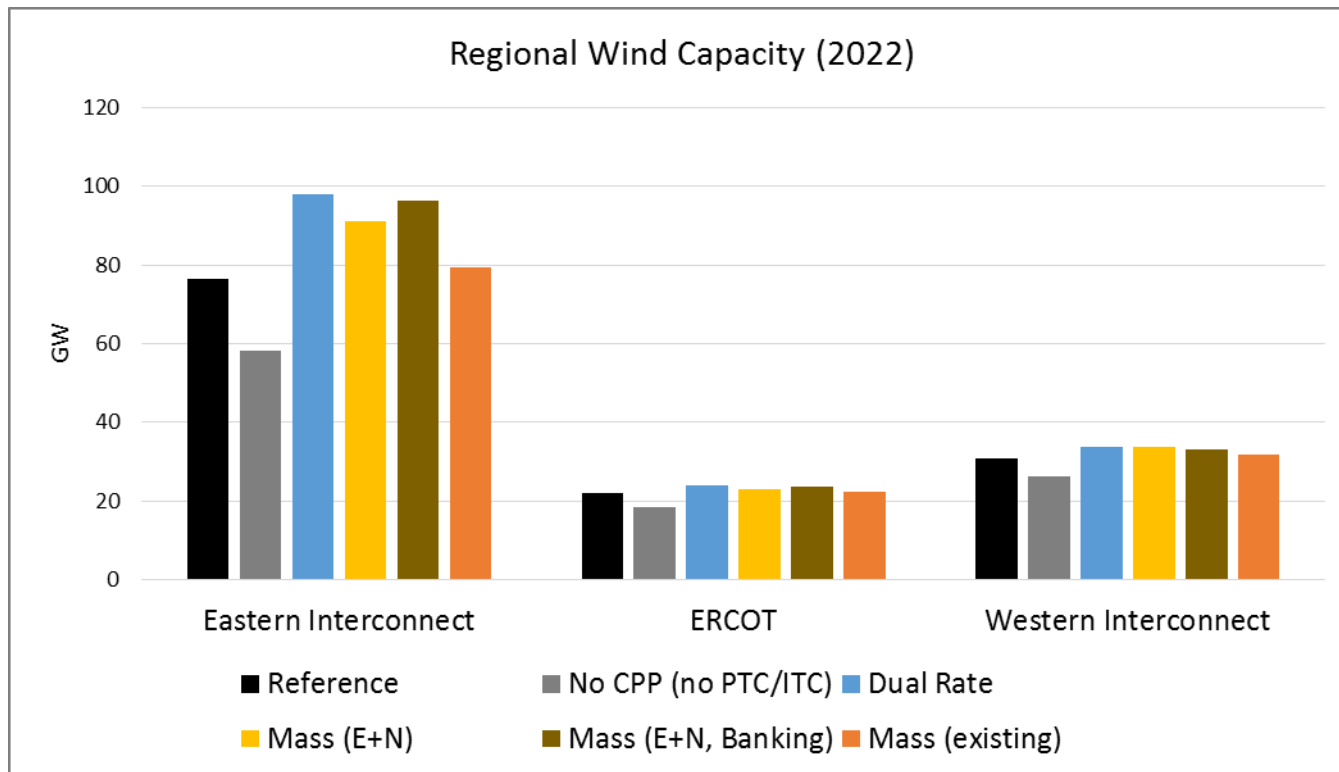


Note: Scenarios have no additional EE beyond EE included in the AEO 2015 forecast demand

# REGIONAL WIND CAPACITY



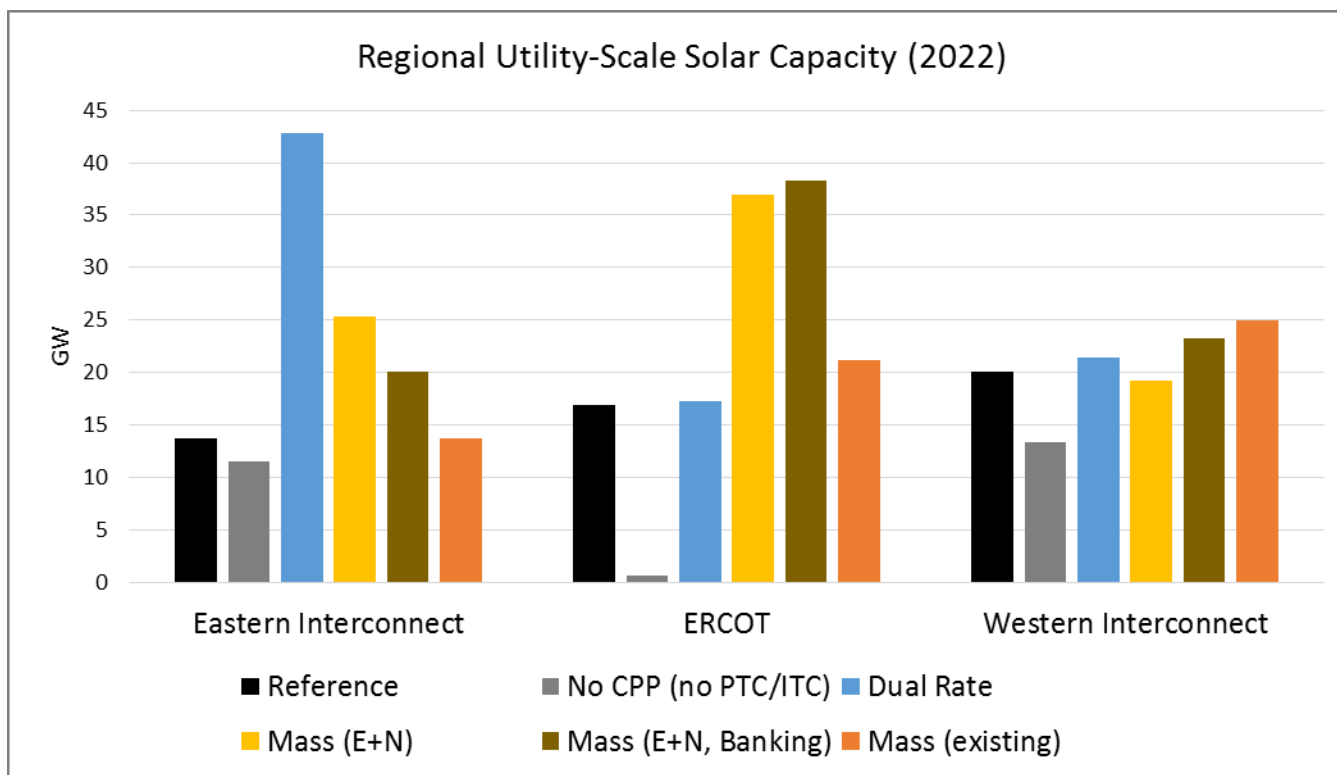
- Even before the CPP begins, CPP runs have more near-term wind to capture tax credits before they phase out, particularly in the East
- In the absence of additional RE incentives (e.g., allocations, state policies), the mass-based approach generally drives fewer RE builds than dual rate in the East; however
  - Banking strengthens early mass-based incentives for wind deployment



# REGIONAL UTILITY-SCALE SOLAR CAPACITY



- The PTC/ITC extension incentivizes additional utility-scale solar capacity, particularly in ERCOT
- CPP policy impacts on solar vary by region
  - While broad adoption of dual rate incents more solar in the East, broad adoption of mass-based policy spurs more solar in ERCOT
  - Utility-scale solar deployment is less dependent on CPP path in West





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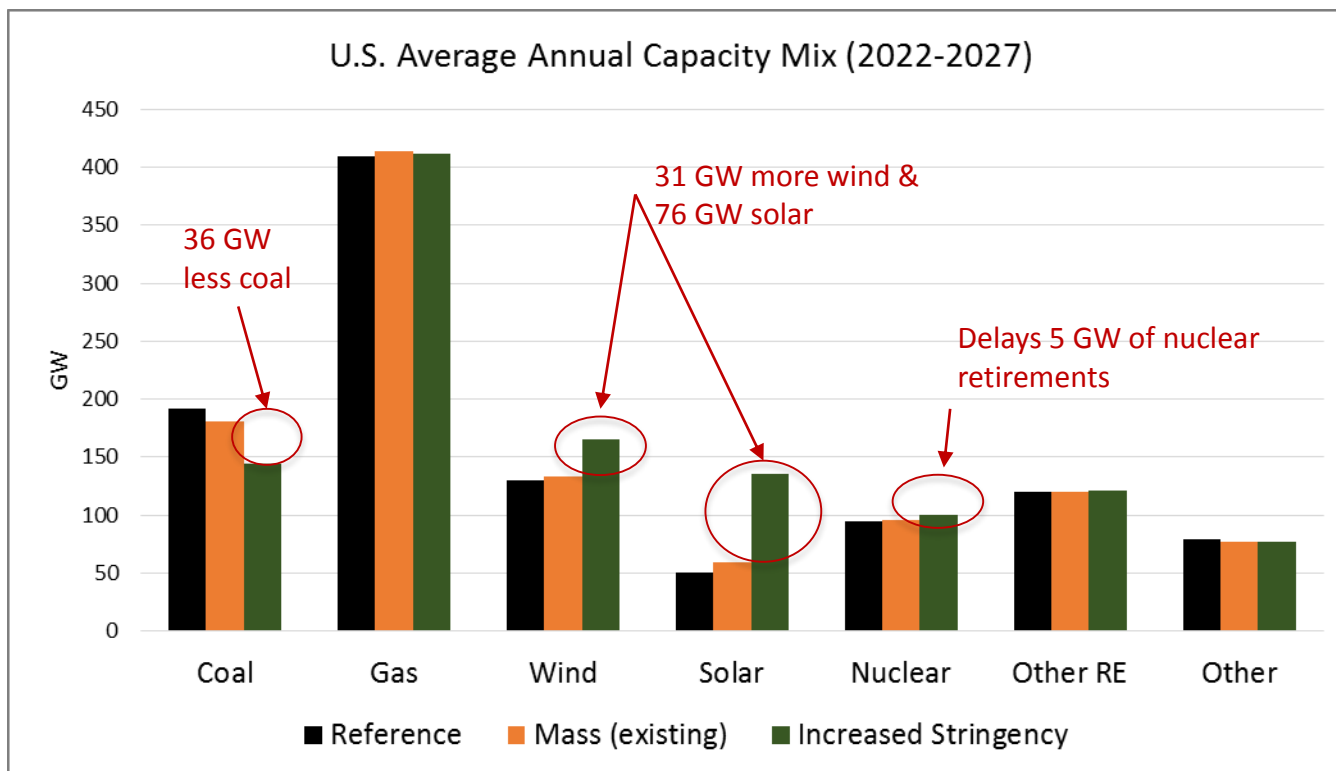
# Factoring in Future CO<sub>2</sub> Constraints



# EXPECTATION OF TIGHTER CARBON CONSTRAINTS IN 2030 AND BEYOND COULD ALTER NEAR TERM INVESTMENTS



- The Increased Stringency scenario assumes states comply with existing source CPP mass until 2030, when more stringent limits apply to both new and existing sources and escalate to a 65% reduction of CO<sub>2</sub> from 2005 levels by 2040. The scenario does not allow banking of allowances.
- Expectations of future carbon policies impact near-term capacity mix
  - With a future constraint in the forecast, IPM predicts additional wind/solar builds, more coal retirements, and fewer nuclear retirements as the least-cost path, even in years before the increased stringency policy takes effect





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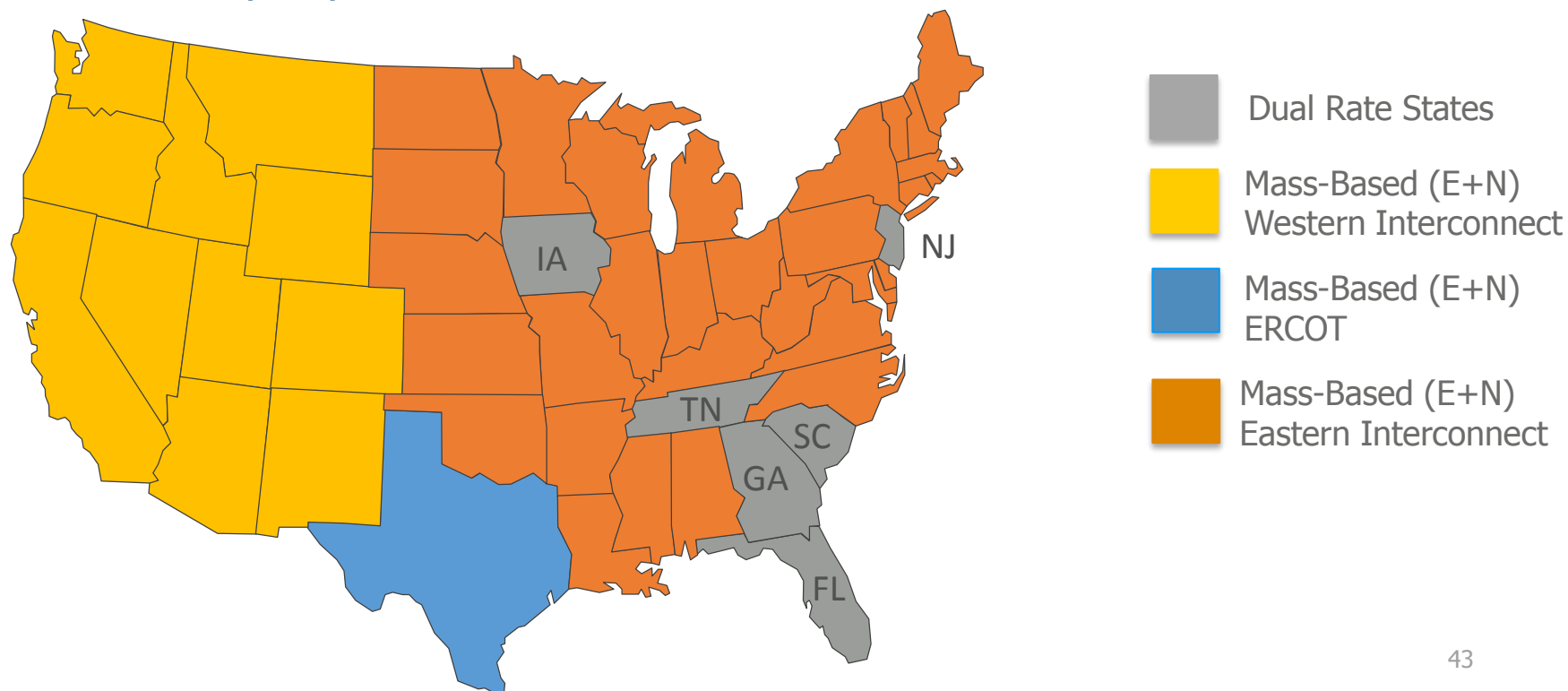


# **Patchwork of State Policy Choices**

# PATCHWORK (E+N)



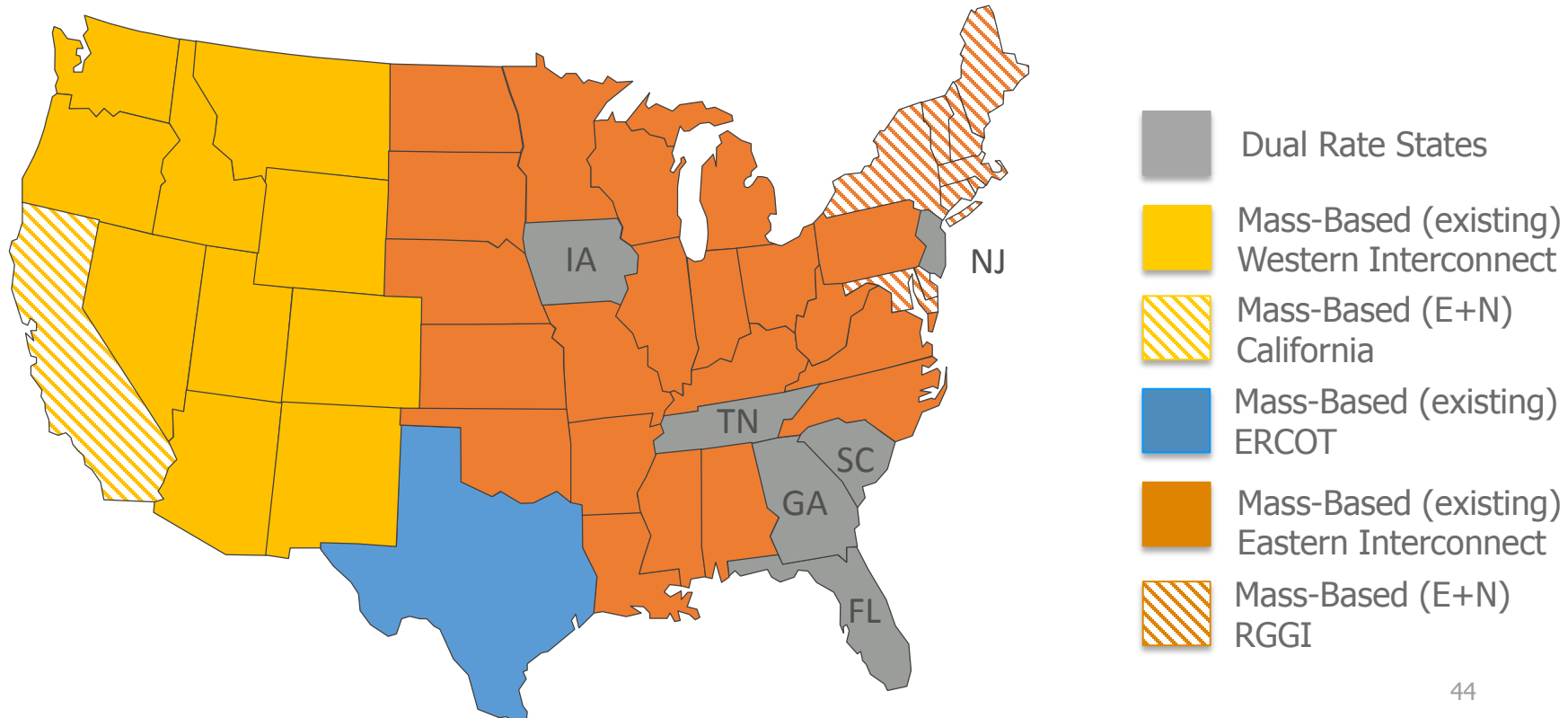
- This analysis includes two patchwork scenarios to test what happens when states choose different compliance pathways
  - The scenarios are meant to be illustrative rather than predictive and are not intended to capture all probable combinations of state policy choices
- Patchwork (E+N) assumes most states comply using Mass (E+N) with interconnect trading and 6 states choose dual-rate trading
  - Dual Rate: FL, GA, IA, NJ, SC, and TN
  - Mass (E+N): All other states



# PATCHWORK (EXISTING)



- Patchwork (existing) assumes most states use Mass (existing) with interconnect trading and 6 states choose dual-rate trading
  - Dual Rate: FL, GA, IA, NJ, SC, and TN
  - Mass (existing): Most other states
- CA and RGGI states comply using Mass (E+N) and do not trade with Mass (existing) states
  - RGGI states continue to trade within RGGI



# PATCHWORK SHOWS POTENTIAL RATE-STATE LEAKAGE



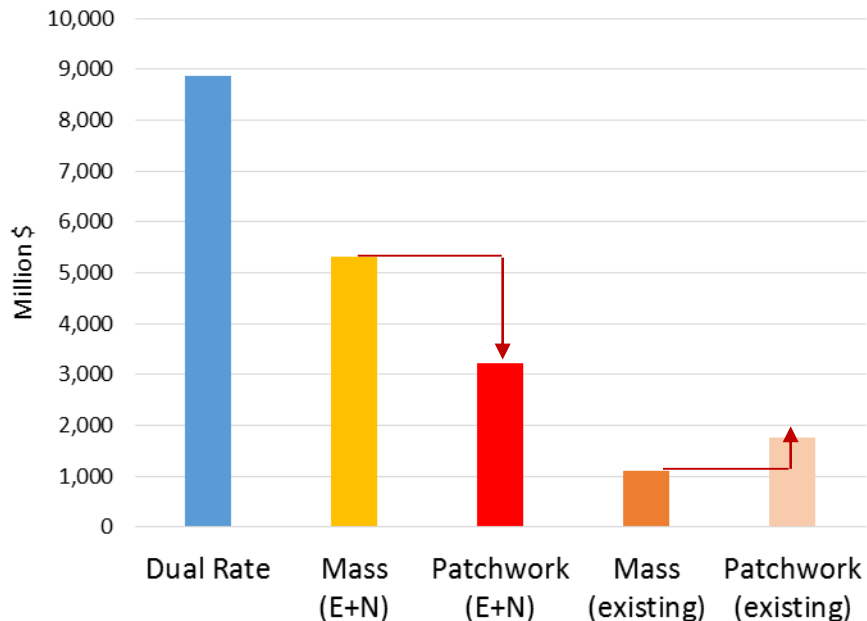
- The mix of implementation approaches in Patchwork (E+N) leads to ramped up generation in dual-rate states
  - This includes coal, gas, and wind generation above Reference case levels
  - In many dual-rate states, emissions in Patchwork (E+N) are above BAU
  - Real world factors (e.g., regulator reviews) may limit some coal increases
- Differing state policies lead to differing operating costs and incentives
  - Because the assumed rate-based states have low-cost ERC generation and limited options to sell ERCs, their ERC surplus allows increased fossil generation in-state
  - When mass states are assumed to cover new units, new NGCC units face higher operating costs if built in mass states than in other rate states, spurring CO<sub>2</sub> rate-state leakage
- However, in the second patchwork run, Patchwork (existing), when most mass states are assumed to only cover existing units, the potential for leakage to rate states is diminished
- While Patchwork runs do not model measures to mitigate leakage, updating output-based allocation approaches have the potential to mitigate both forms of potential leakage (i.e., rate-state leakage and CPP-defined leakage)

# PATCHWORK IMPACTS COST AND CO2

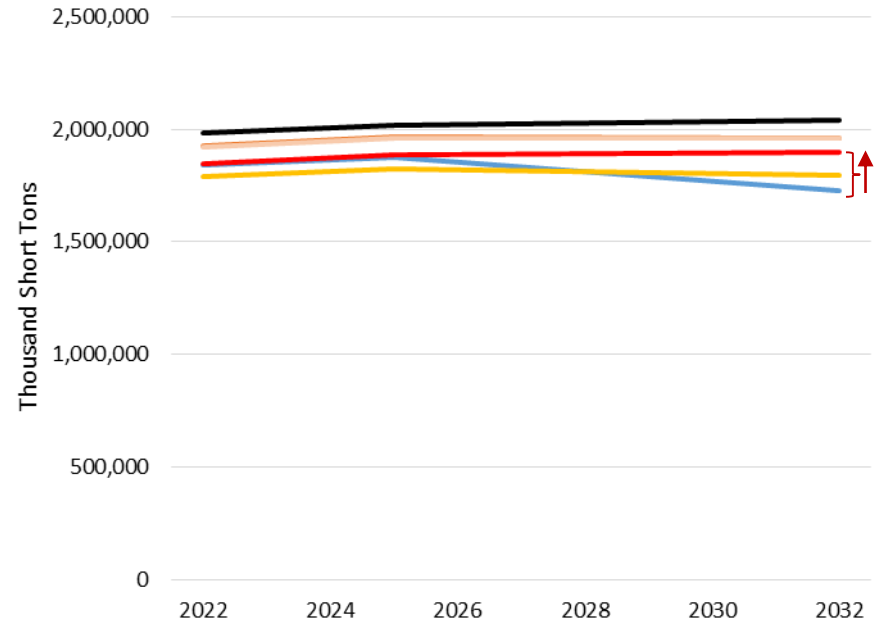


- Comparing policy options, lower cost generally corresponds with more CO<sub>2</sub>
  - An exception is Mass (E+N), which has lower cost than & similar cumulative CO<sub>2</sub> to rate
- Adding a few rate states in Patchwork (E+N) reduces compliance costs, b/c rate-state leakage weakens CO<sub>2</sub> stringency
- However, adding a few rate states in Patchwork (existing) adds cost, b/c
  - Compared to Mass (existing), rate lowers CO<sub>2</sub>
  - CA/RGGI were assumed not to trade with other Mass (existing) states

U.S. Average Annual Compliance Costs  
(2022-2032)



U.S. Electricity-Sector CO<sub>2</sub> Emissions  
(2022-2032)

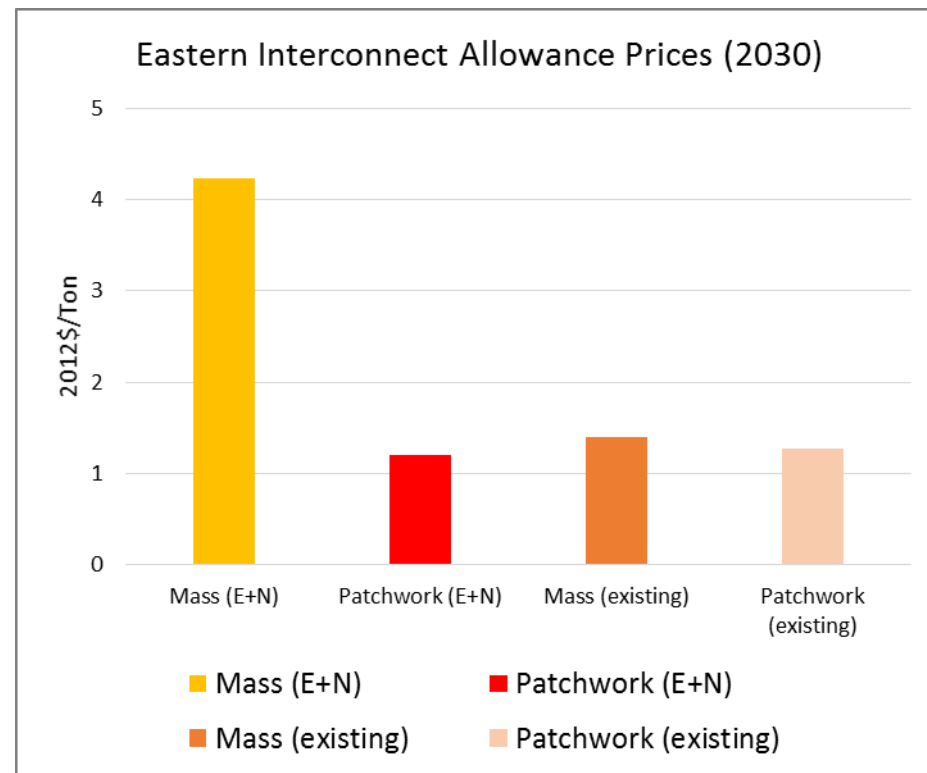
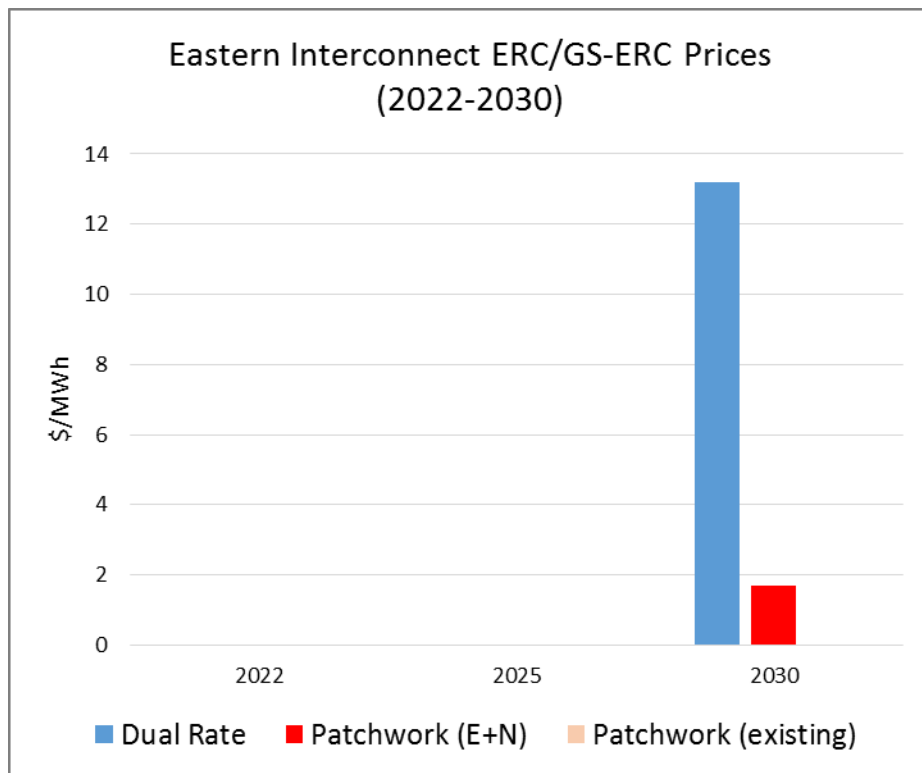


Note: Emissions include all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., both covered and uncovered by the CPP.

# “ERC ISLANDS” LOWER ERC AND ALLOWANCE PRICES



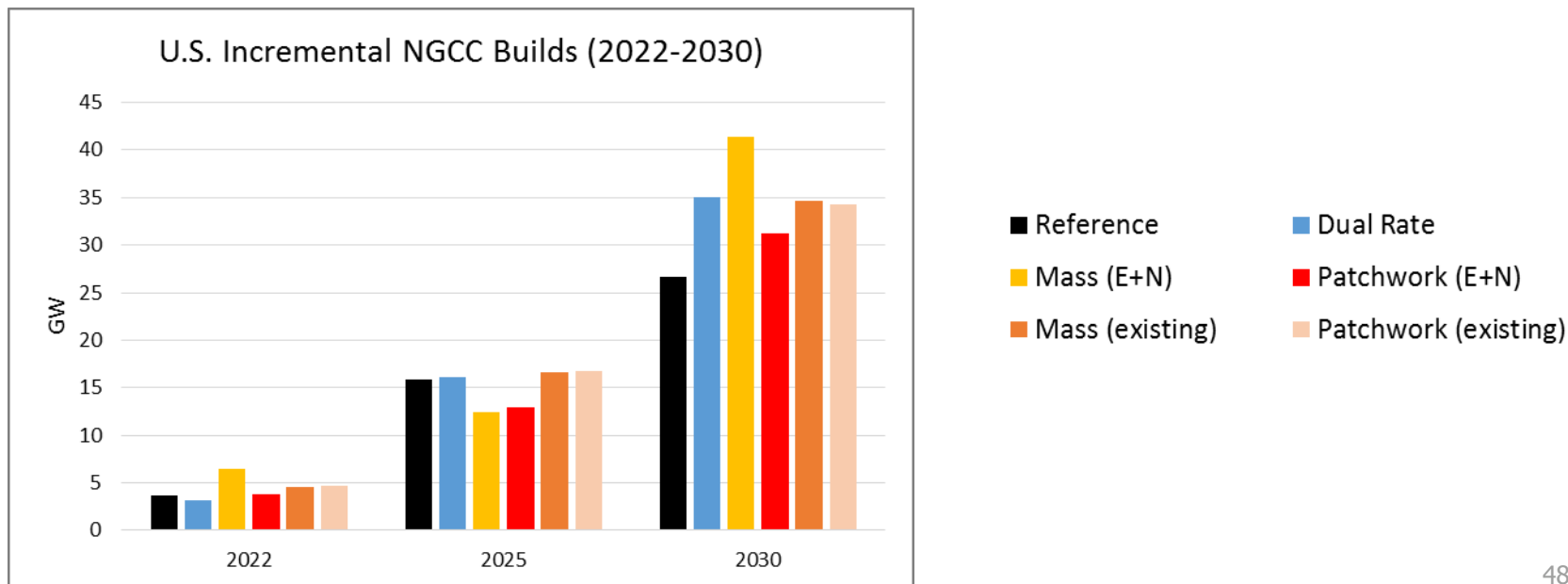
- ERC prices decrease under the Patchwork runs as the dual-rate states assumed in these runs are largely generators of ERCs
  - ERC prices are not binding in Patchwork (existing) until 2034
- The dual-rate states ramp up generation, particularly in Patchwork (E+N), to both earn and use ERCs and provide some of this electricity to neighboring mass-based states. This decreases pressure on the mass caps and lowers allowance prices in the East



# SIGNS OF CO2 LEAKAGE TO RATE-BASED STATES

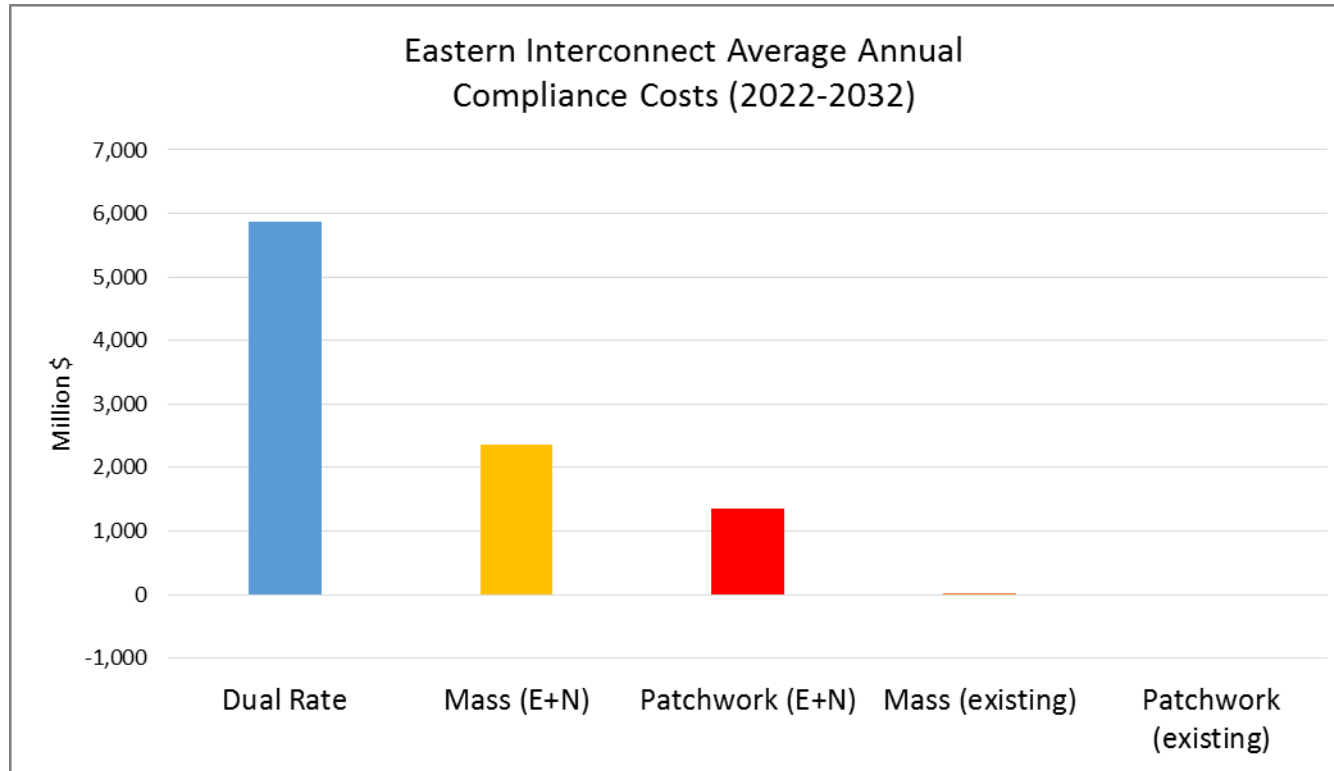


- At the U.S. level, there are fewer NGCC builds under Patchwork (E+N)
- Patchwork (existing) and Mass (existing) have similar new NGCC builds and similar stringency (the least stringent of all policy runs)
- At the state level, NGCC build decisions are impacted by whether or not the majority of mass-based states cover new units
  - About 70% of new NGCC builds in Patchwork (E+N) occur in dual-rate states, as new units are not covered by the rate policy but are covered under the Mass (E+N) scenario
  - When the mass-based policy covers existing units only, new builds in dual-rate states fall from 30 GW to 13 GW by 2033






# IMPLICATIONS OF PATCHWORK POLICY CHOICES ON COSTS



- Policy choices of surrounding states impact generation shifts, ERC/allowance prices, and thus, total system costs
- Although Patchwork (E+N) has relatively lower overall costs for the East, it has higher costs in many of the dual-rate states (GA, IA, NJ, TN)
  - Increased costs are driven by increased in-state generation
- All 6 rate states in Patchwork (existing) had higher costs from choosing rate, compared to if they chose Mass (existing)



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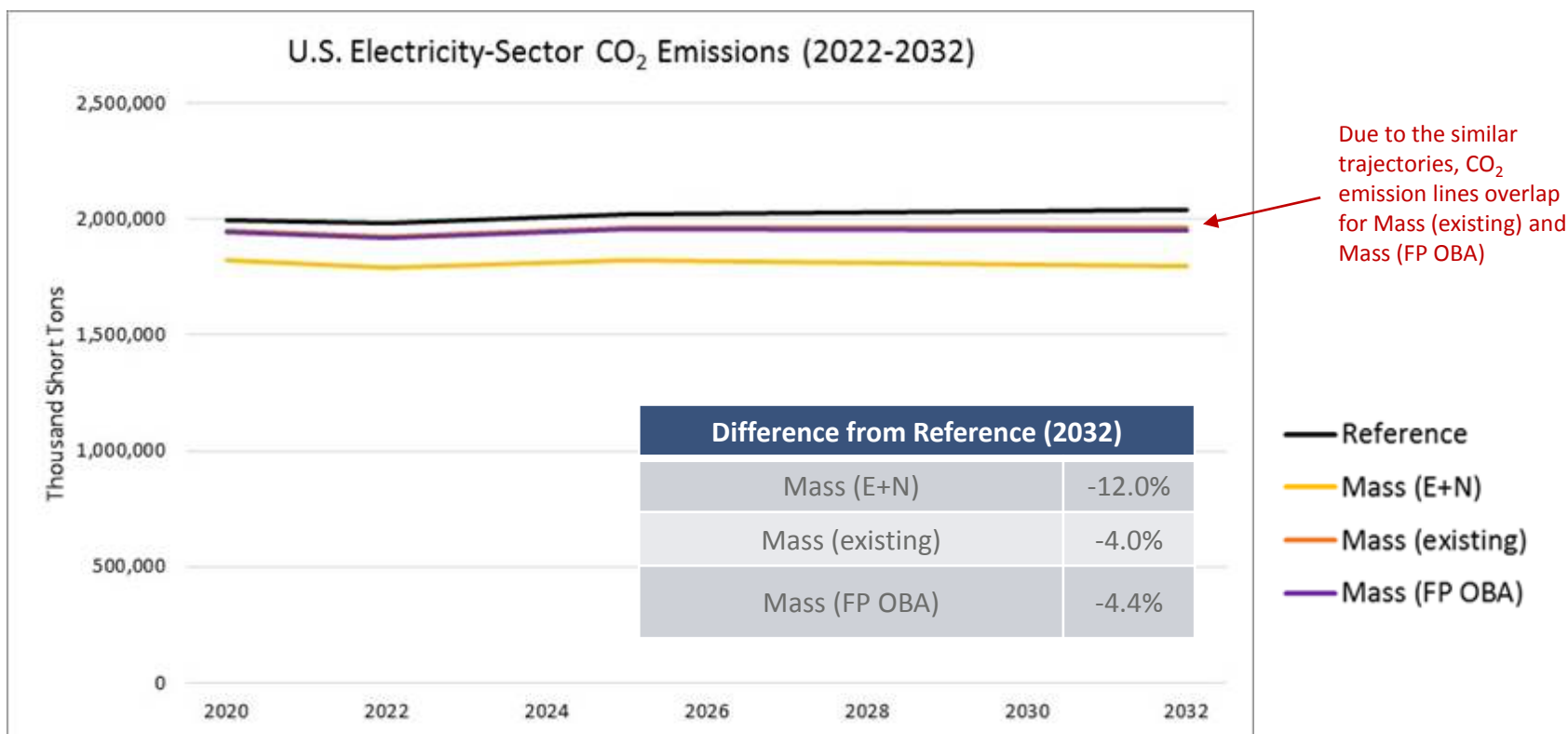


# **New Units and Updating Allocations**

# U.S. CO<sub>2</sub> EMISSIONS ARE LOWER WHEN CPP MASS-BASED POLICY COVERS NEW UNITS



- CO<sub>2</sub> emissions vary depending on the policy treatment of new units
- Given these baseline assumptions, changing mass (existing) allocation to EPA's proposed Federal Plan approach does not have a significant impact
  - In large part, b/c Reference case existing-source CO<sub>2</sub> is already below CPP goals for most of the interim period and allowance prices remain low

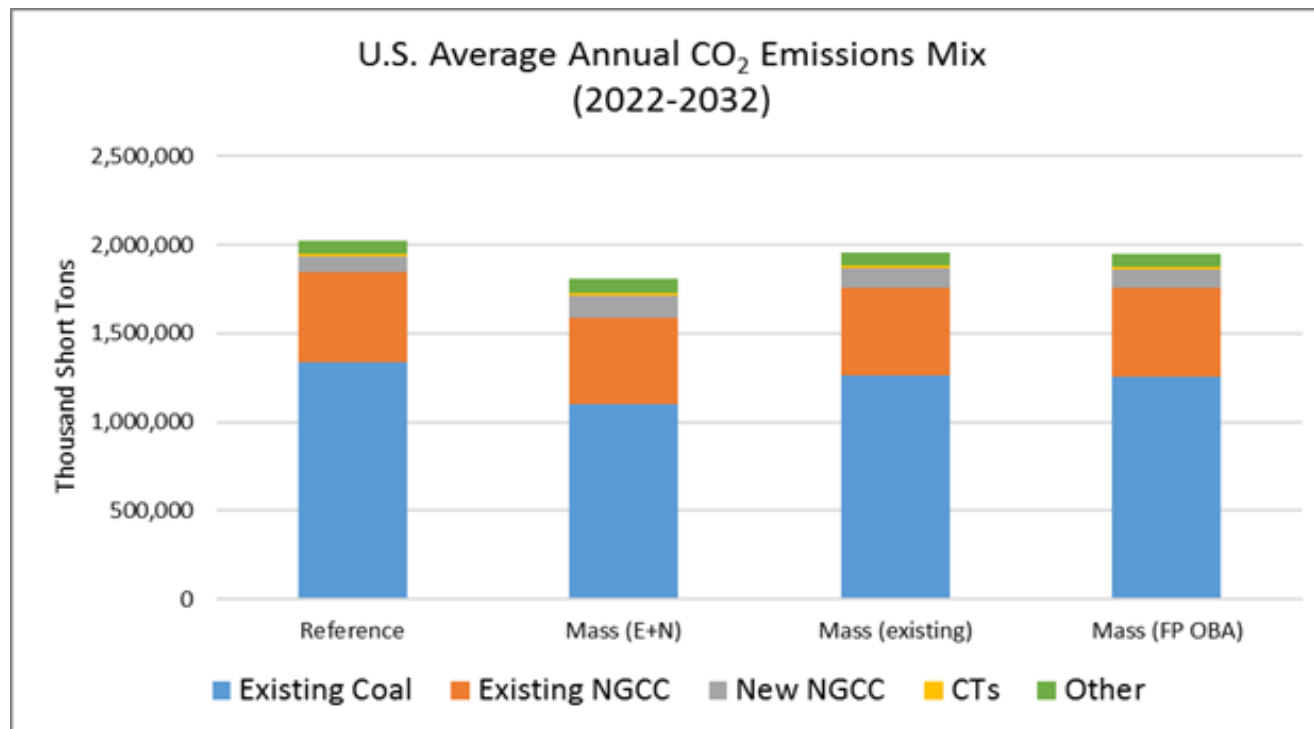


Note: Mass (FP OBA) covers existing units only and allocates a portion of allowances by updating OBA per EPA's proposed federal plan/model rule. Emissions include all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., both covered and uncovered by the CPP.

# MORE COAL GENERATION REMAINS WHEN NEW UNITS ARE NOT COVERED BY MASS



- At U.S. level, comparing generation mix under Mass (E+N) vs. Mass (existing):
  - CO<sub>2</sub> emissions from new NGCC are similar
  - Because CO<sub>2</sub> from new NGCC does not count toward the goal, there is more room for additional coal generation under Mass (existing)
- Compared to Mass (existing), in Mass (FP OBA): gas generation decreases by 0.3%, RE generation increases by 1.2%, and CO<sub>2</sub> emissions in 2022-2032 decrease by 0.4%

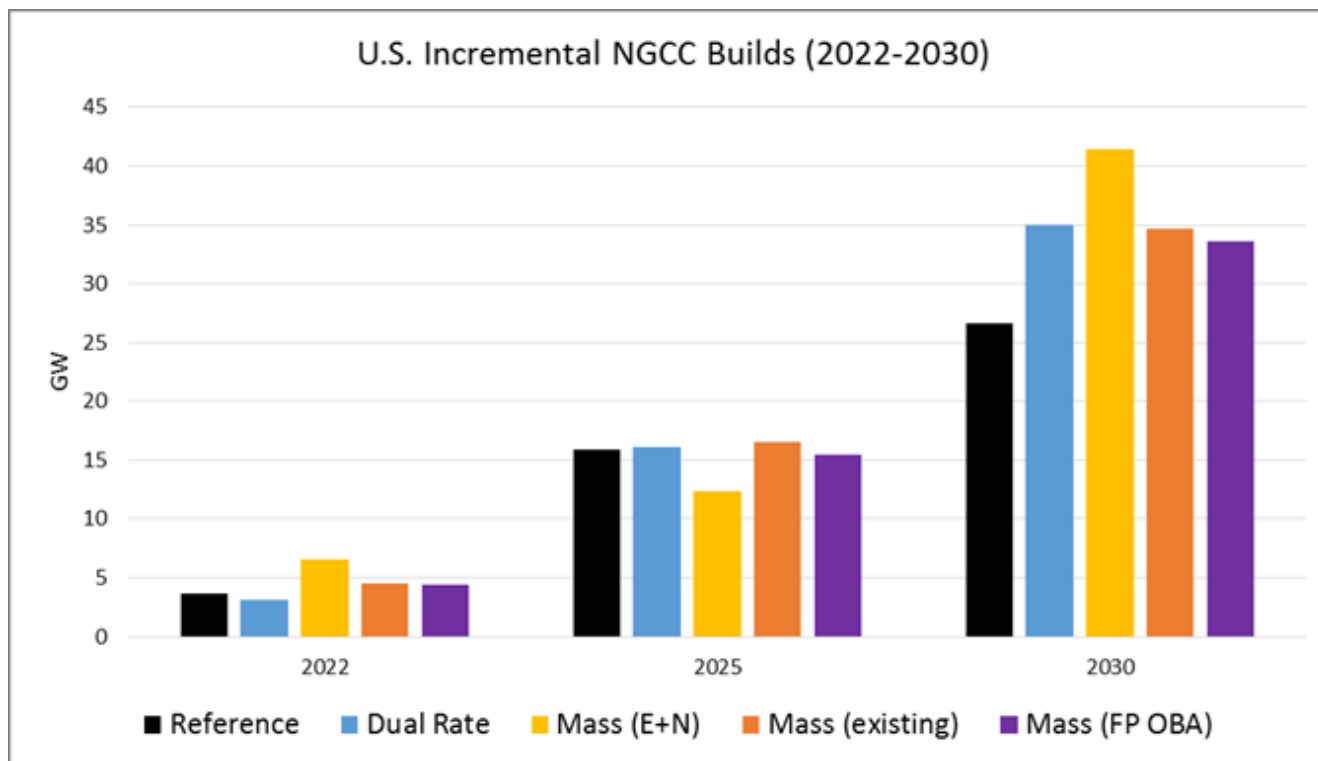


Note: Emissions include all CO<sub>2</sub> emissions from utility-scale generation in the contiguous U.S., both covered and uncovered by the CPP.

# POTENTIAL LEAKAGE TO NEW NGCC BUILDS



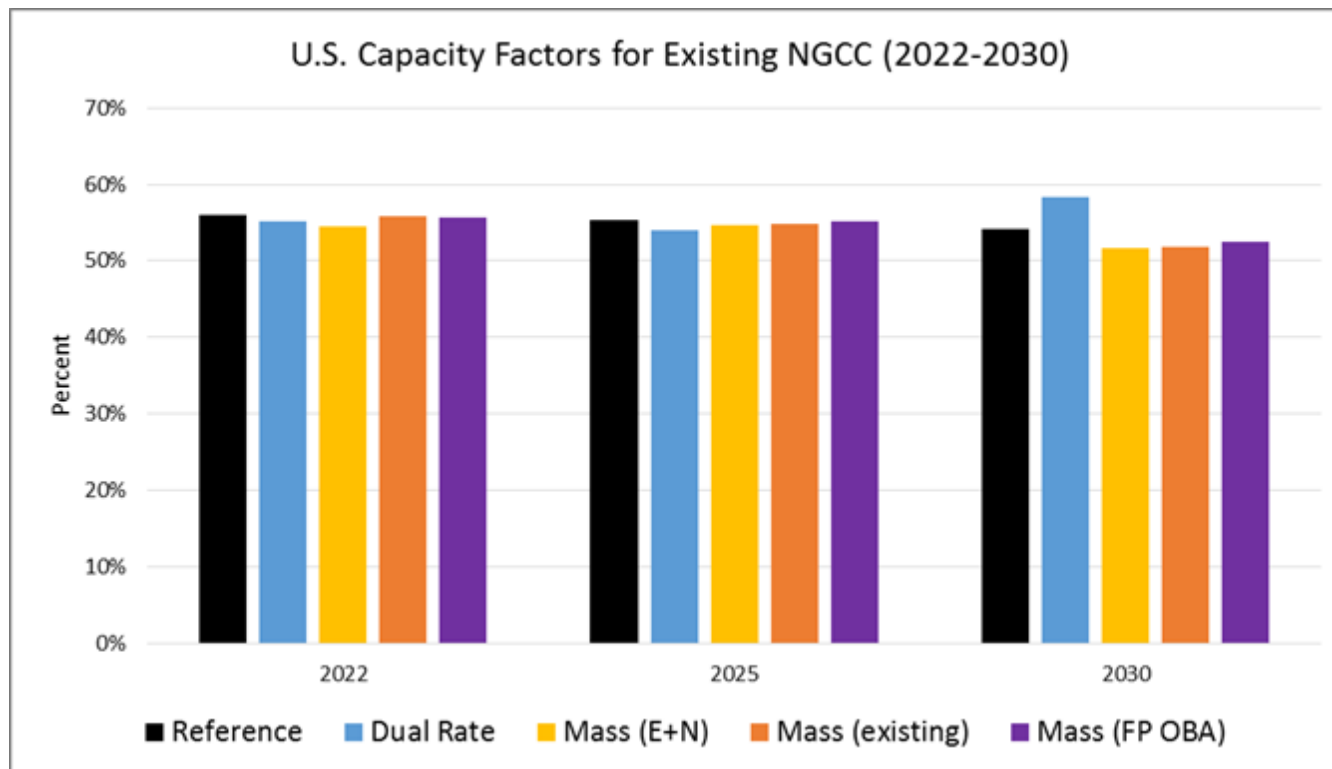
- Between 2022 and 2030, more reductions are required and, thus, more new NGCC units are built nationwide in the scenario that covers new units, compared to scenarios that do not
  - However, Mass (existing) increases new NGCC builds in some states and, in some cases, updating OBA helps balance incentives between new & existing gas
- Relatively low gas and renewable energy price assumptions keep allowance prices low and limit the incentive for CPP-defined leakage to new NGCC



# POTENTIAL LEAKAGE INDICATOR: CAPACITY FACTORS FOR EXISTING GAS GENERATION



- Nationwide, capacity factors for existing NGCC units are relatively constant across scenarios with \$0 allowance/ERC prices in the early years
- By 2030, positive GS-ERC prices under Dual Rate shift generation to existing gas units, while Mass (E+N) helps maintain existing nuclear generation instead
  - The portion of updating output-based allocation to existing gas in Mass (FP OBA) helps maintain capacity factors at existing gas units in some individual states





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# Appendix

# IPM BACKGROUND



- IPM is a dispatch model that seeks to minimize total production costs across North America.
- IPM represents economic activity in key components of energy markets – fuel markets, emission markets, and electricity markets.
- Since the model captures the linkages in electricity markets, it is well-suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector.
- Past applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

## IPM® Modeling Structure





# MODELING CAVEATS: IPM STRUCTURAL LIMITATIONS



- Input electricity demand forecasts are at a regional level over 75 regions, which do not correspond with state boundaries.
- The model sites new generation builds in the least-cost location available to meet regional demand. The model does not fully capture transmission constraints or other real-world limitations that may make siting new units more favorable in one state as compared to another.
- IPM has a detailed representation of utility-scale generation. It does not capture the impact of distributed generation beyond what is included in the AEO demand forecast.
- IPM does capture transmission bottlenecks, but the model is not a granular transmission model.
- State RPS policies are modeled as regional RPS policies to reflect REC trading. However, the model does not account for power purchase agreements that designate out-of-state ownership of RECs.
- State energy efficiency policies are also modeled as regional policies.
- The model does not capture all factors related to the integration of variable resources, including some real-world transmission constraints. The model includes some assumptions to capture limitations to RE deployment, including:
  - Utility-scale solar builds are limited to 7.5 GW per calendar year. Utility-scale wind builds are limited to 15.7 GW per calendar year. Builds that exceed these limits face increased capital costs.
  - Utility-scale wind and solar generation is limited to 20 percent of net energy load by technology type. The model also imposes capacity limits for each technology type.

## MODELING CAVEATS: BPC INPUT ASSUMPTIONS



- Scenarios include the level of energy efficiency that is built into the AEO 2015 electricity demand forecast, unless otherwise noted.
  - Only energy efficiency sensitivity runs offer additional demand-side energy efficiency and coal plant heat rate improvement options.
- To help with comparisons across scenarios, core runs do not bank allowances/ERCs for future use.
  - The banking sensitivity run highlights expectations for a more stable allowance price and lower cumulative costs than core runs indicate.
- The model does not award ERCs to the existing end-use energy efficiency that is included in the AEO 2015 demand forecast.
  - EE ERCs are awarded to additional energy efficiency investments in the energy efficiency sensitivity runs.
- The model does not attempt to capture transaction costs associated with buying ERCs, such as the costs of performing due diligence to minimize the risk of challenges.
- In all policy runs, CA and RGGI are assumed to comply with Mass (E+N).
  - CA does not trade with the rest of the West in the Dual Rate runs or in Patchwork (existing). Only Patchwork (existing) captures the latest RPS requirements in CA.
  - RGGI trades only with itself in the Dual Rate run and Patchwork (existing).
  - In the results reported in this analysis, costs from CA are always included with the Western Interconnect and costs for RGGI are always included in Eastern Interconnect.

# SCENARIO DESCRIPTIONS



Scenario	Description
<b>Reference</b>	<p>This is the business-as-usual case absent a 111(d) or 111(b) policy. Final state environmental policies as of August 2015 are represented, including renewable portfolio standards, energy efficiency standards, and criteria pollutant rules. Final federal environmental policies are also represented, as is the extension of the federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) passed by Congress in 2015. No incremental EE.</p>
<b>No CPP (EE)</b> Reference case with EE	<p>Identical to Reference, but includes the option for incremental EE beyond what is captured in AEO 2015 demand forecast.</p>
<b>No CPP (No PTC/ITC)</b> Reference case without the PTC/ITC	<p>Identical to Reference, but does not include the extension of the federal PTC and ITC passed by Congress in 2015.</p>
<b>No CPP (High Gas Price)</b> Reference case with High Gas Price	<p>Identical to Reference, except gas prices are based on the AEO 2015's Base Case.</p>
<b>State Rate</b> Rate-Based State Goals	<p>Each state must comply with the blended, state-specific rate-based targets. Trading is permitted among sources within a give state. No incremental EE or banking of allowances.</p>

# SCENARIO DESCRIPTIONS



Scenario	Description
<b>Dual Rate</b> Dual Rate Interconnect Trading	Each state must comply with the dual rate standards, which apply separate steam boiler and NGCC emission rate standards. Trading of ERCs and GS-ERCs is permitted among sources within a given interconnect. No incremental EE (above AEO demand forecast). No ERCs issued for EE built into the AEO demand forecast.
<b>Dual Rate (EE)</b> Dual Rate Interconnect Trading with EE	Identical to Dual Rate, but includes the option for incremental EE to issue ERCs.
<b>State Mass (E+N)</b> Mass-Based State Trading (existing and new units)	Each state must comply with the state mass-based target for existing sources plus the new source complement. Trading is permitted among sources within the state. No incremental EE or banking of allowances.
<b>Mass (E+N)</b> Mass-Based Interconnect Trading (existing and new units)	Each state must comply with the state mass-based target for existing sources plus the new source complement. Trading is permitted among all sources in a given interconnect. No incremental EE or banking of allowances.
<b>Mass (E+N, EE)</b> Mass-Based Interconnect Trading (existing and new units, with EE)	Identical to Mass (E+N), but includes the option for incremental EE.

# SCENARIO DESCRIPTIONS



Scenario	Description
<b>Mass (E+N, High Gas Price)</b> High Gas Price	Identical to Mass (E+N), except gas prices are based on the AEO 2015's Base Case.
<b>Mass (E+N, Banking)</b>	Identical to Mass (E+N), except banking of allowances is allowed from 2022 to 2040.
<b>Mass (existing)</b> Mass-Based Interconnect Trading (existing only)	Each state is assigned its existing source budget. Trading is permitted among all sources in a given interconnect. CA & RGGI comply with Mass (E+N) and can trade with sources in their interconnects. No incremental EE or banking of allowances.
<b>Mass (existing, EE)</b> Mass-Based Interconnect Trading (existing only, with EE)	Identical to Mass (existing), but includes the option for incremental EE.
<b>Mass (FP OBA)</b> Proposed Federal Plan Allocation	Identical to Mass (existing), except allowances are allocated according to EPA's Proposed Federal Plan. Thus, most allowances are allocated by <i>historic</i> output-based allocation (OBA). The remaining allowances are allocated to existing NGCC based on <i>updating</i> OBA as well as a renewable energy set aside.
<b>Mass (100% OBA)</b> Updating Output-Based Allocation	Identical to Mass (existing), except allowances are allocated with 100% updating output-based allocation to all covered fossil generators, based on the output from the previous compliance period.

# SCENARIO DESCRIPTIONS



Scenario	Description
<b>National Mass (E+N)</b> Mass-Based National Trading (existing and new units)	Identical to Mass (E+N), except trading is allowed at a national level instead of a regional level.
<b>Patchwork (E+N)</b> Most states Mass (E+N), 6 Dual-Rate states	All states comply with interconnect mass-based trading with new source complement budgets. Trading is permitted among sources in a given interconnect. The exception is FL, GA, IA, NJ, SC, and TN, which comply using the dual-rate standards with interstate trading. No incremental EE or banking of allowances.
<b>Patchwork (existing)</b> Most states Mass (existing), 6 Dual-Rate states	Most states comply with interconnect mass-based trading with existing source budgets. Trading is permitted among sources in a given interconnect. The exception is FL, GA, IA, NJ, SC, and TN, which comply using the dual-rate standard with interstate trading. In addition, CA and RGGI comply with Mass (E+N). CA has intrastate trade. RGGI states trade only with each other. No incremental EE or banking of allowances.
<b>Increased Stringency</b>	Each state is assigned its existing source budget. Trading is permitted among all sources in a given interconnect. In 2030, a new carbon policy on new and existing sources is imposed, leading to a 65% reduction of electricity-sector CO <sub>2</sub> emissions from 2005 levels by 2040. There is no banking of allowances.

## OTHER ASSUMPTIONS TESTED



	Source of Assumptions
Unit-level characteristics	NEEDSv.5.13
Natural Gas Supply & Costs	ICF's 2015 Integrated Gas Module (same input as EPA RIA) & fuel supply curves based on AEO 2015 Reference case
Renewable Energy Cost	ICF market research (No PTC/ITC)
Nuclear Retirements	All units can continue to run past their 60-year relicensing date (operating costs increase with age)
Banking of Allowances	Unlimited banking throughout the modeled time horizon; Unlimited banking during the interim compliance period
CPP Policy Regions	7 trading regions: West, MISO, SPP, ERCOT, SERC, Other PJM, RGGI
EE Sensitivities:	
Supply of Additional Energy Efficiency	Various supplies tested
Heat Rate Improvements	BPC HRI methodology

# WIND & SOLAR COSTS



- Capital costs and Fixed Operating and Maintenance (FOM) costs reflect the impact of the federal PTC/ITC extension where indicated.

U.S. Overnight Capital Costs & FOM (2012\$/kW)				
Vintage	Onshore Wind (with PTC)	Onshore Wind (without PTC)	Utility-Scale Solar PV (with ITC)	Utility-Scale Solar PV (without ITC)
2016	1,103	1,766	1,393	1,990
2018	1,196	1,731	1,330	1,990
2020	1,427	1,698	1,294	1,848
2022	1,598	1,695	1,337	1,807
2025	1,616	1,616	1,571	1,746
2030	1,470	1,470	1,508	1,675
2040	1,337	1,337	1,377	1,530
FOM	32.9	32.9	23.4	23.4

Average Step 1 Average Levelized Cost of Electricity for Wind (2012\$/MWh)			
	No PTC	PTC- Model Year 2016	PTC- Model Year 2020
U.S.	66	45	57



## EE COSTS



- All scenarios are based on AEO 2015 demand forecast.
- In policy scenarios that allow incremental EE\* (beyond AEO 2015), end-use EE is available to serve electricity demand using an assumed three-step supply curve with cost increasing as the supply available at each step is exhausted. In 2020, costs are: 2.3, 2.6, and 3.2 cents/KWh. Costs in each block increase by .3 cents/KWh starting in 2021. An assumed participant portion (45% of the total resource cost of EE) is added separately to the compliance cost.

2020 EE Cost	Units = Cents/KWh			Units = \$/MWh		
	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Utility Portion	2.3	2.6	3.2	23	26	32
Participant Portion	1.9	2.1	2.6	19	21	26
Total Resource Cost	4.2	4.7	5.8	42	47	58

\* Except for the High Cost EE scenario, where costs are increased by 50% at each step in the three-step cost curve

# RUN YEAR MAPPING



Calendar Year	Model Year	Calendar Year	Model Year
2016	2016	2029	2030
2017	2016	2030	2030
2018	2020	2031	2030
2019	2020	2032	2030
2020	2020	2033	2030
2021	2020	2034	2040
2022	2022	2035	2040
2023	2022	2036	2040
2024	2025	2037	2040
2025	2025	2038	2040
2026	2025	2039	2040
2027	2025	2040	2040
2028	2030		

# COMPONENTS OF TOTAL ADJUSTED COST (TAC)



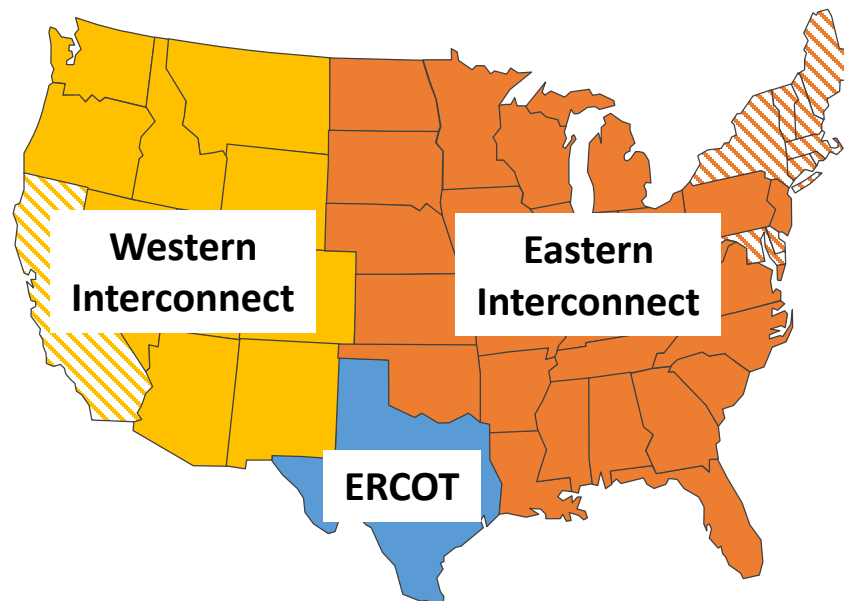
TAC= TSC + EE Participant Costs + Import/Export + Net Allowance/Credit Cost

- Total System Cost (TSC): Includes all costs associated with generation, such as new capacity, fuel, and other operating & maintenance costs, as well as compliance costs such as the utility portion of end-use energy efficiency. For a state, this includes in-state generation only.
- EE Participant costs: We assume 55% of the total resource cost of an end-use energy efficiency measure is born by the utility and 45% of the cost is paid by the consumer/participant. While the utility portion is included in TSC, and thus impacts wholesale electricity costs, the participant portion is a separate line item.
- Generation shift adjustment: Some scenarios result in generation shifts between states/regions so that the cost of in-state generation may go down, while the cost of importing power goes up (or vice versa). To better account for total costs to deliver energy, this adjustment estimates the cost associated with changes in net electricity imports/exports. Because IPM uses regional (rather than state-level) electricity demand, state-level imports are estimated compared to the Reference case.
- Net allowance/credit cost: The value of the net position in emission credits or allowances (i.e., to what degree is state a net buyer or seller of credits/allowances in a regional trading program). For state implementation, credits don't cross borders; thus this cost is zero. For regional scenarios, this nets to zero at the regional level.

# CPP POLICY REGIONS



- In CPP policy scenarios with regional trading, electric generating units are able to trade within one of three regions
- CA is assumed to comply using a mass-based policy that covers new sources in all policy runs, including mass (existing) and dual-rate runs
  - CA does not trade with the rest of the West in dual-rate runs
- States in the Regional Greenhouse Gas Initiative (RGGI) also comply using a mass-based policy that covers new sources in all policy runs
  - RGGI states continue to trade with RGGI states in dual-rate runs
- The model dispatches EGUs according to electricity markets with represented transmission bottlenecks





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