Hydropower and the EPA Section 111(d) Proposal

PREPARED FOR

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Overview

- Faced with Congressional inaction, the Administration has proposed to regulate CO_2 emissions using existing authority
  - Section 111(d) for existing sources is a state-level, emission rate focused approach designed for source-level control
  - Not generally compatible with cost-effective CO_2 policy
- The §111(d) proposal attempts to incorporate cost-effective measures into this framework through innovative formulas
  - Redefines "source," "emission rate," and "system of reduction" to set state targets, and allow "outside the fence" compliance options
  - Leaves actual implementation to the states
- The EPA conducted an impact analysis illustrating the price, cost, and CO_2 impacts under an assumed set of state compliance scenarios (although actual implementation approaches will vary more widely)
- We summarize the key features and primary implications of the rule from the perspective of a hydro asset with merchant exposure (although individual asset owner's circumstances vary)

Overview

Primary Implications for Hydro

- The proposed rule introduces a number of concerns for hydro, which is effectively ignored and thus at a disadvantage compared to other CO_2 abatement options under the rule, *e.g*. coal-to-gas switching, nuclear, and non-hydro renewables

- These asymmetries could be addressed either in the EPA rule or in state implementation plans by:
  1. Establishing existing and new **hydro as a "qualifying" resource** for the purposes of both setting state emissions rate targets, as well as demonstrating compliance, and
  2. Implementing a **mass-based CO_2 allowance trading** approach (or administrative carbon-pricing approach) that uniformly applies a single carbon price for every ton of CO_2 emitted across all CO_2-emitting resource types, across the broadest regional areas possible

- Eliminating these asymmetries would not only benefit hydro, but also increase economic efficiency and move toward meeting the underlying policy objectives at lowest cost

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What are the Key Rule Provisions?

On June 2, the EPA under Section 111(d) set CO_2 emissions standards on existing fossil generation units (EGUs)

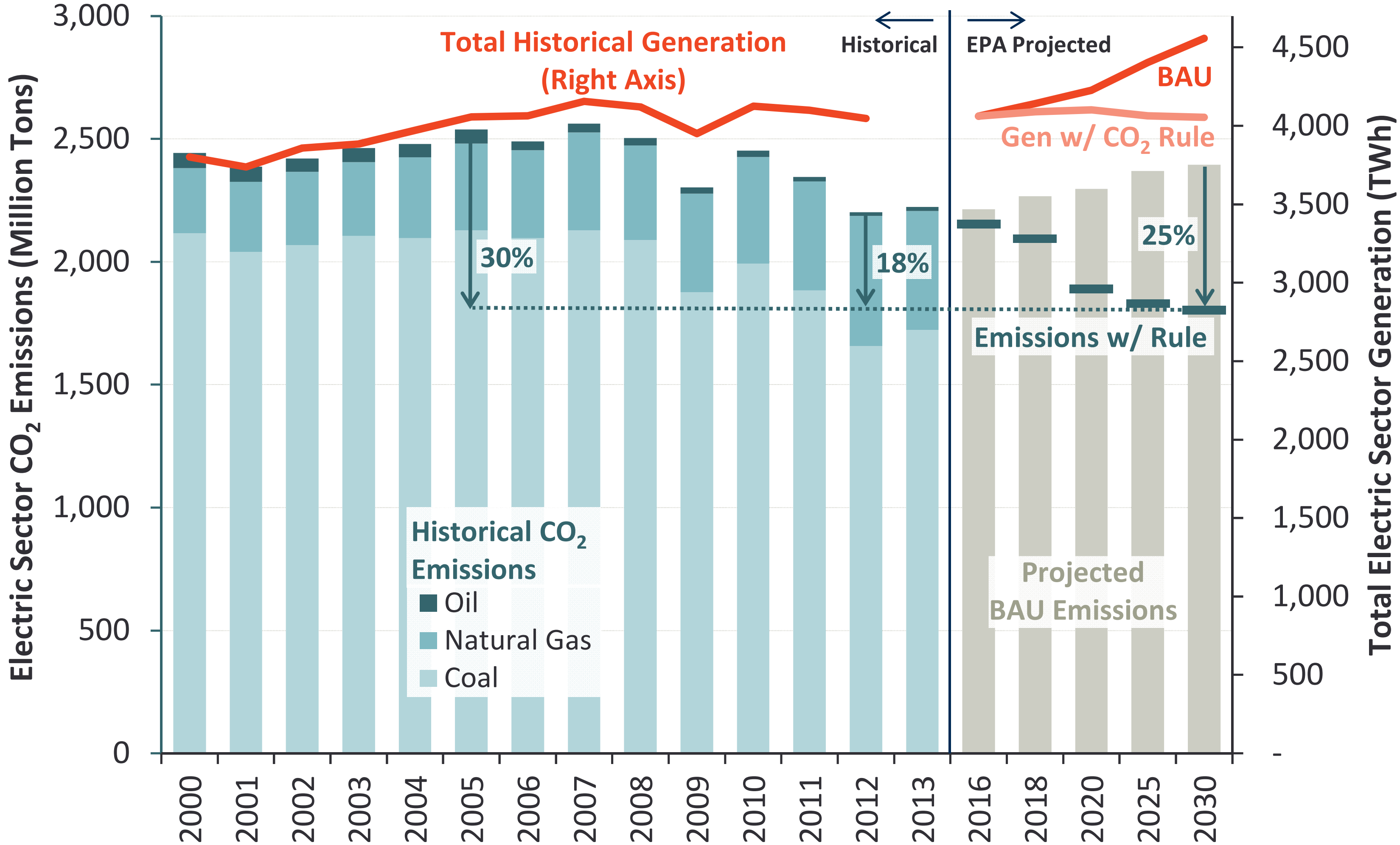
- EPA reviewed existing emissions reductions methods to establish the Best System of Emissions Reduction (BSER)
- BSER is applied to each state's current fossil EGU emissions rate to set state-specific fossil emissions rate standards for 2020 – 2030
- Option 1: interim goal for 2020 – 2029 (to meet on average) and a final goal for 2030 and beyond; EPA is also considering Option 2: less stringent but sets earlier goals over 2020 – 2024 with final goal for 2025 and beyond
- States given flexibility in how to meet the standards

Timeline for Compliance	
2014	Proposed Rule - 120 day comment period by October 16, 2014
2015	Final Rule
2016	Initial report on State Implementation Plans (SIPs)
2017	Final SIPs (for single-state plans)
2018	Final SIPs (for multi-state plans)
2020-30	Compliance period

Rule Provisions

Projected Effect of Standards on Emissions

The proposed standards are designed to bring emissions to 30% below 2005 levels.



Rule Provisions

EPA's Best System of Emissions Reductions (BSER)

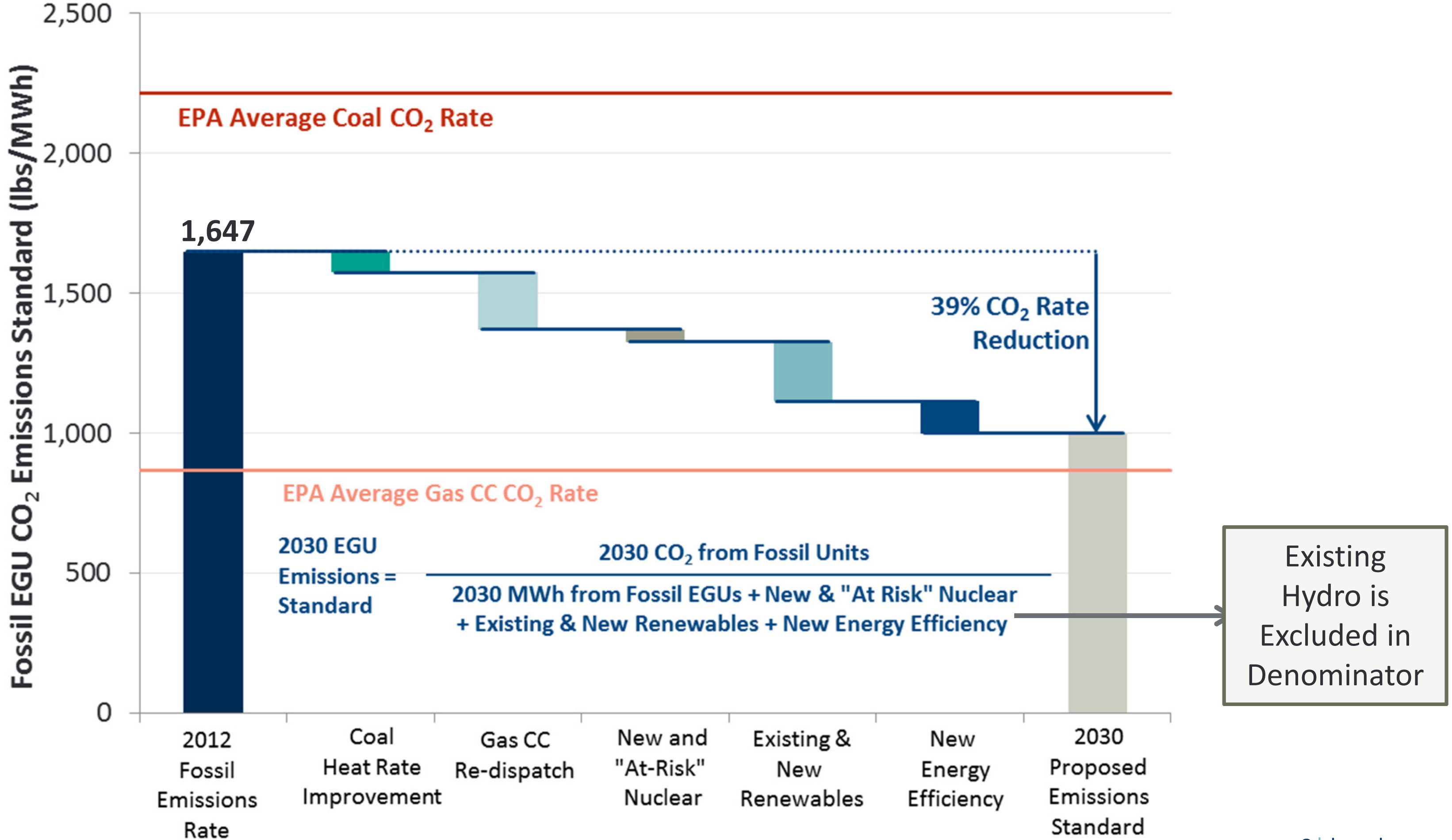
BSER includes four methods of emissions reduction, assessed for feasibility in each state.

BSER Building Block	EPA Basis for BSER Determination	EPA Estimated Average Cost	% of BSER CO_2 Reductions
1. Increase efficiency of fossil fuel power plants	EPA reviewed the opportunity for coal-fired plants to improve their heat rates through best practices and equipment upgrades, identified a possible range of 4–12%, and chose 6% as a reasonable estimate. BSER assumes all coal plants increase their efficiency by 6%.	$6–12/ton	12%
2. Switch to lower-emitting power plants	EPA determined for re-dispatching gas for coal that the average availability of gas CCs exceeds 85% and that a substantial number of CC units have operated above 70% for extended periods of time, modeled re-dispatch of gas CCs at 65–75%, and determined 70% to be technically feasible. BSER assumes all gas CCs operate up to 70% capacity factor and displace higher-emitting generation (*e.g.* , coal and gas steam units).	$30/ton	31%
3. Build more low/zero carbon generation	EPA identified 5 nuclear units currently under construction and estimated that 5.8% of all existing nuclear capacity is "at-risk" based on EIA analysis. BSER assumes the new units and retaining 5.8% of at-risk nuclear capacity will reduce CO_2 emissions by operating at 90% capacity factor.	Under Construction: $0/ton "At-Risk": $12–17/ton	7%
Existing and Potential New Hydro Excluded	EPA developed targets for existing and new renewable penetration in 6 regions based on its review of current RPS mandates, and calculated regional growth factors to achieve the target in 2030. BSER assumes that 2012 renewable generation grows in each state by its regional factor through 2030 (up to a maximum renewable target) to estimate future renewable generation.	$10–40/ton	33%
4. Use electricity more efficiently	EPA estimated EE deployment in the 12 leading states achieves annual incremental electricity savings of at least 1.5% each year. BSER assumes that all states increase their current annual savings rate by 0.2% starting in 2017 until reaching a maximum rate of 1.5%, which continues through 2030.	$16–24/ton	18%

Rule Provisions

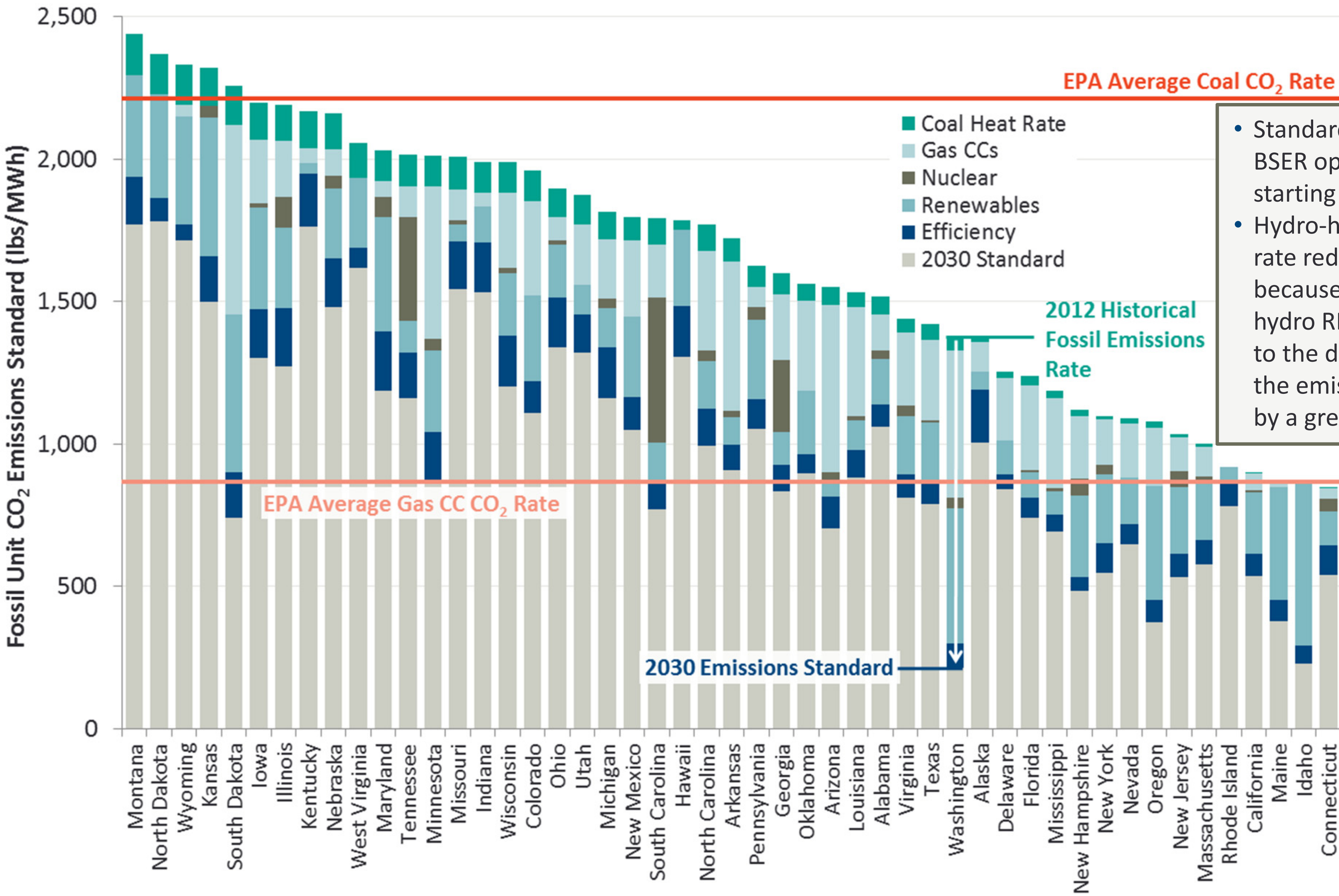
CO_2 Rate Standards on Existing Fossil Units

The EPA standards are not true emission rates for fossil plants, because some BSER elements affect the numerator (emissions) and other, non-fossil CO_2-abatement elements affect the denominator.



Rule Provisions

Fossil Unit Emission Rate Standards by State



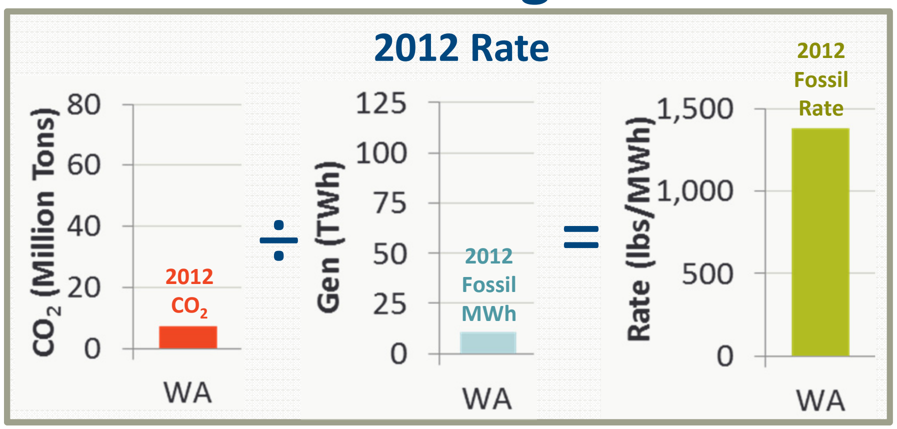
- Standards differ by estimated BSER opportunities and starting points
- Hydro-heavy states have large rate reductions, in part because the same EE (or non-hydro RE) MWh contributions to the denominator reduces the emission “rate” formula by a greater amount

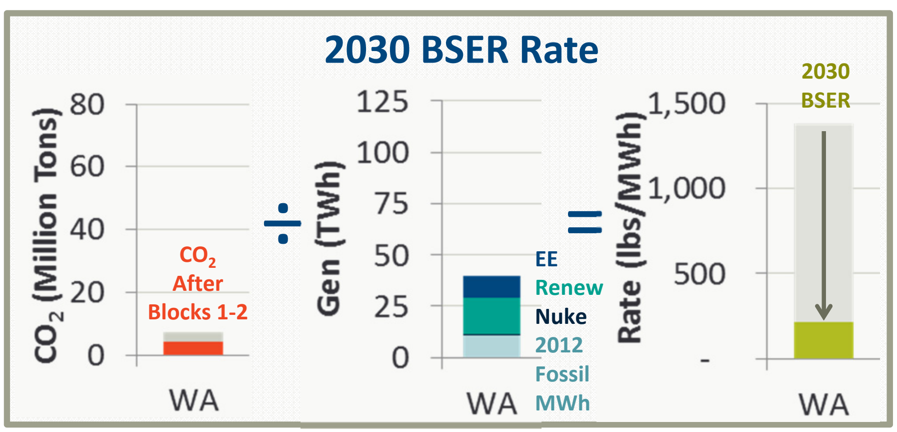
Rule Provisions

Why Rates Drop So Substantially in Hydro States

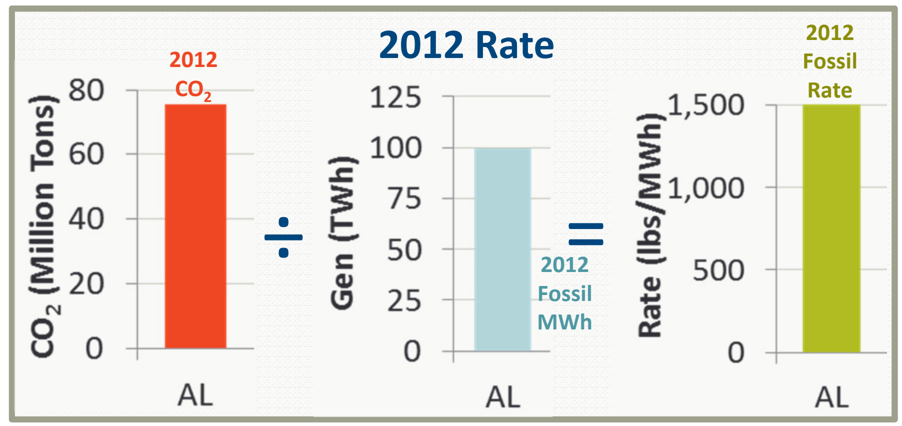
- Compare Washington to Alabama, which have similar 2012 generation and fossil rate
- Hydro states have smaller CO_2 emissions (numerator), but building blocks add similarly-sized efficiency and renewable upgrades (denominator) with bigger effects on the rate

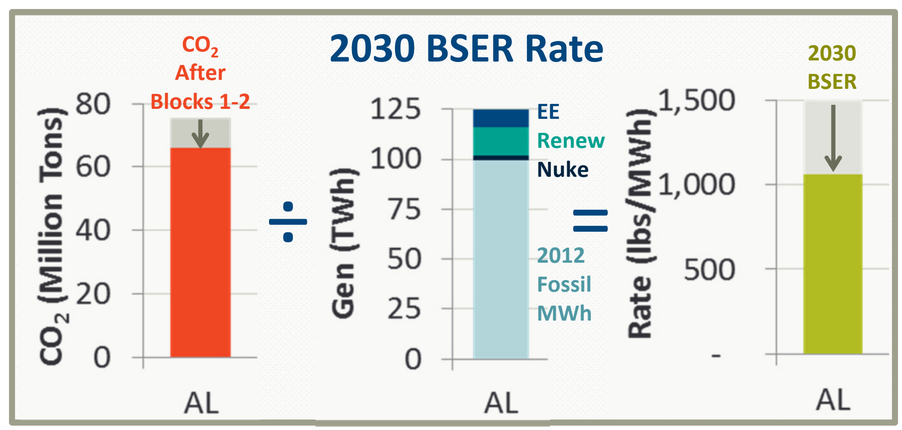
Washington





Alabama





Rule Provisions

Summary of Asymmetries in Hydro Treatment

- Hydro assets are placed at a disadvantage compared to other zero-CO_2 asset types including other renewables and “at-risk” nuclear
- A disadvantage relative to coal-to-gas switching may be an even greater concern if states implement a rate-based compliance approach (but issues can be resolved by comprehensive mass-based CO_2 pricing mechanisms)

Asset Class	Hydro Assets	Other Zero-CO_2 Assets
Existing	• **Excluded** from BSER and compliance (except possibly for a small amount of RPS-eligible hydro, not modeled in IPM)	• Other existing renewables **included** for both BSER and compliance
Existing but “At Risk” for Retirement	• Hydro is **excluded** from BSER	• 5.8% of Nuclear considered “at risk” **included** in BSER
New	• Hydro potential **excluded** from BSER (except as counted in states’ current RPS targets) • New hydro <u>may</u> count toward compliance depending on state implementation	• Renewable potential **included** for BSER and compliance

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What Impacts does the EPA Project?

- As with every new proposed rule, the EPA has conducted a Regulatory Impact Analysis (RIA), using their Integrated Planning Model (IPM) to project the potential rule impacts
- Interpretation of results requires understanding of key model input assumptions:
  - EPA assumes a particular state implementation approach (rate-based, with two scenarios showing with or without regional cooperation)
  - BSER level of energy efficiency is an input assumption (effect is to eliminate load growth)
  - **Hydro generation remains the same (does not consider new build nor hydro at risk for retirement)**
- Acknowledging these caveats, we summarize here EPA's projections regarding primary metrics of interest for hydro (prices, new builds, retirements, etc.)

EPA's Projected Impacts
2030 Fleet Capacity and Generation Mix

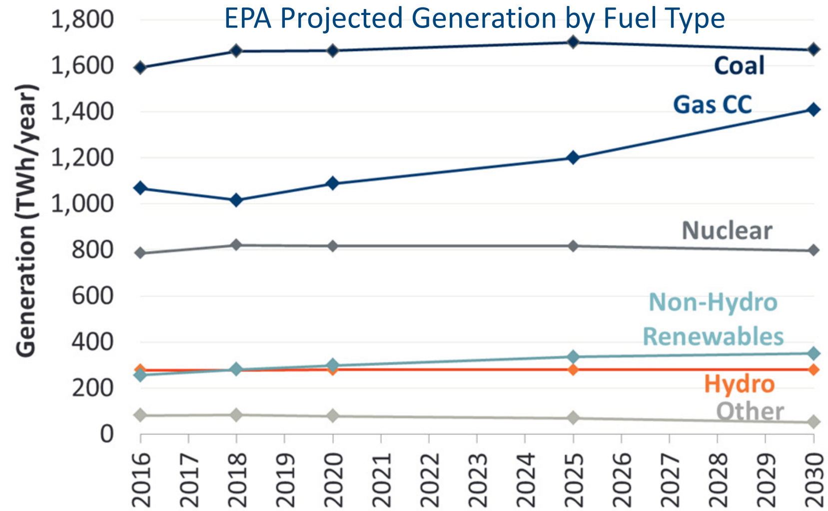
- IPM builds no hydro (by assumption)
- Even though non-hydro renewables are 33% of the BSER blocks, IPM projections add only 2% more non-hydro renewables by 2030 vs. BAU
- Assumed energy efficiency and coal-to-gas re-dispatch dominate

EPA Projected Generation (TWh) by 2030

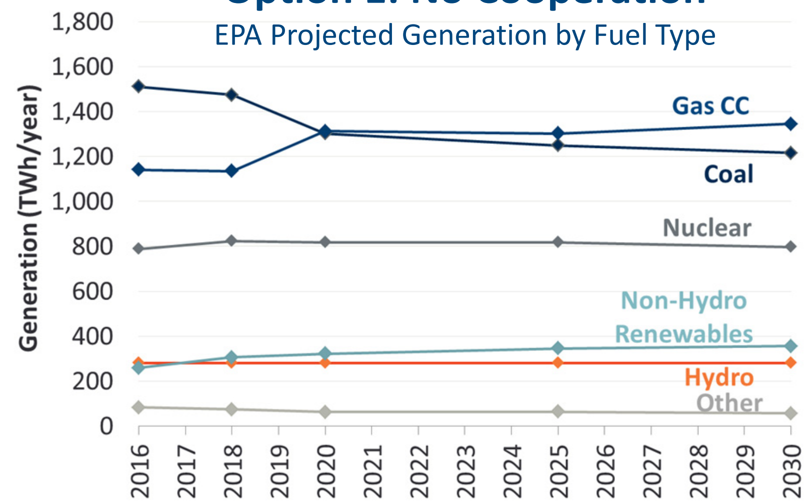
Generation	BAU *(TWh)*	Option 1: No Cooperation *(TWh)*	Change *(TWh)*
Coal	1,668	1,216	(452)
Gas CC	1,409	1,345	(64)
Hydro	280	280	0
Non-Hydro RE	350	356	6
Nuclear	797	797	0
Others	52	57	5
Total	**4,557**	**4,051**	**(506)**

Source: EPA IPM

Business as Usual

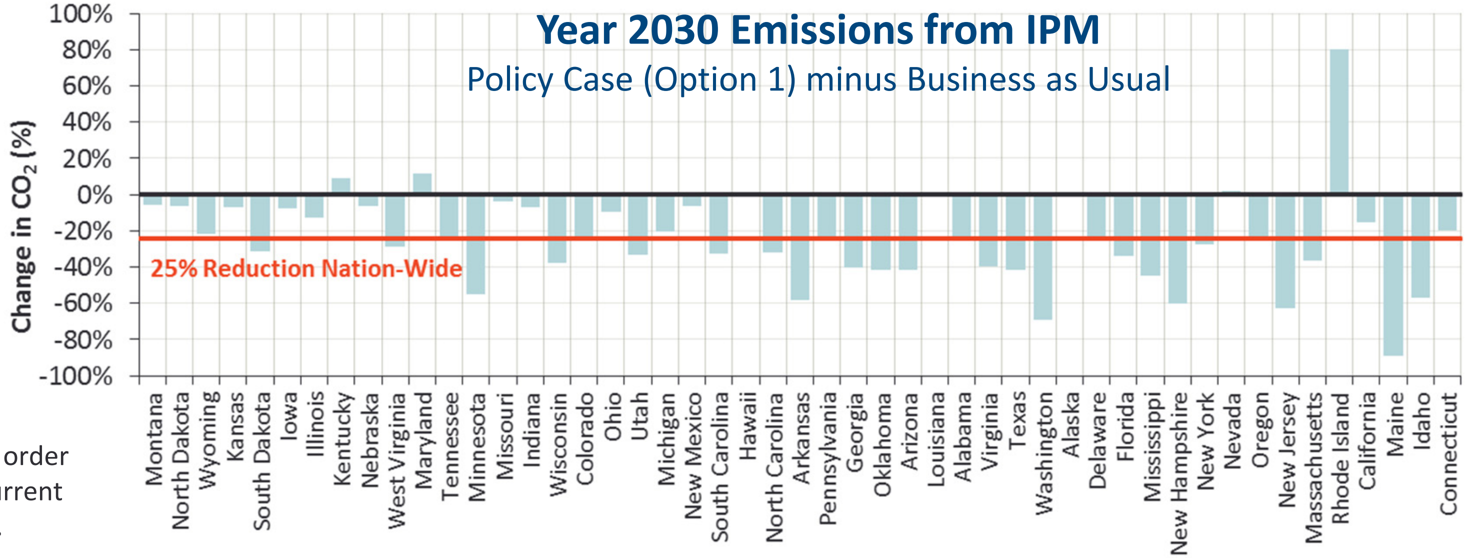


Option 1: No Cooperation

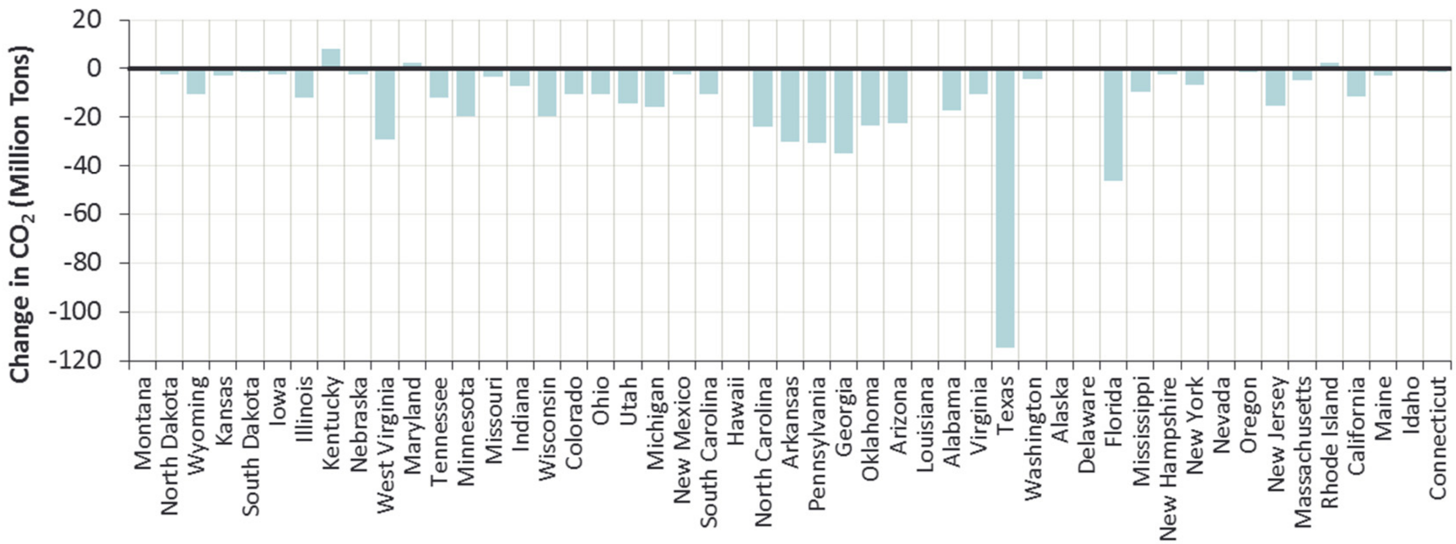


EPA's Projected Impacts

Projected 2030 Emissions Reductions

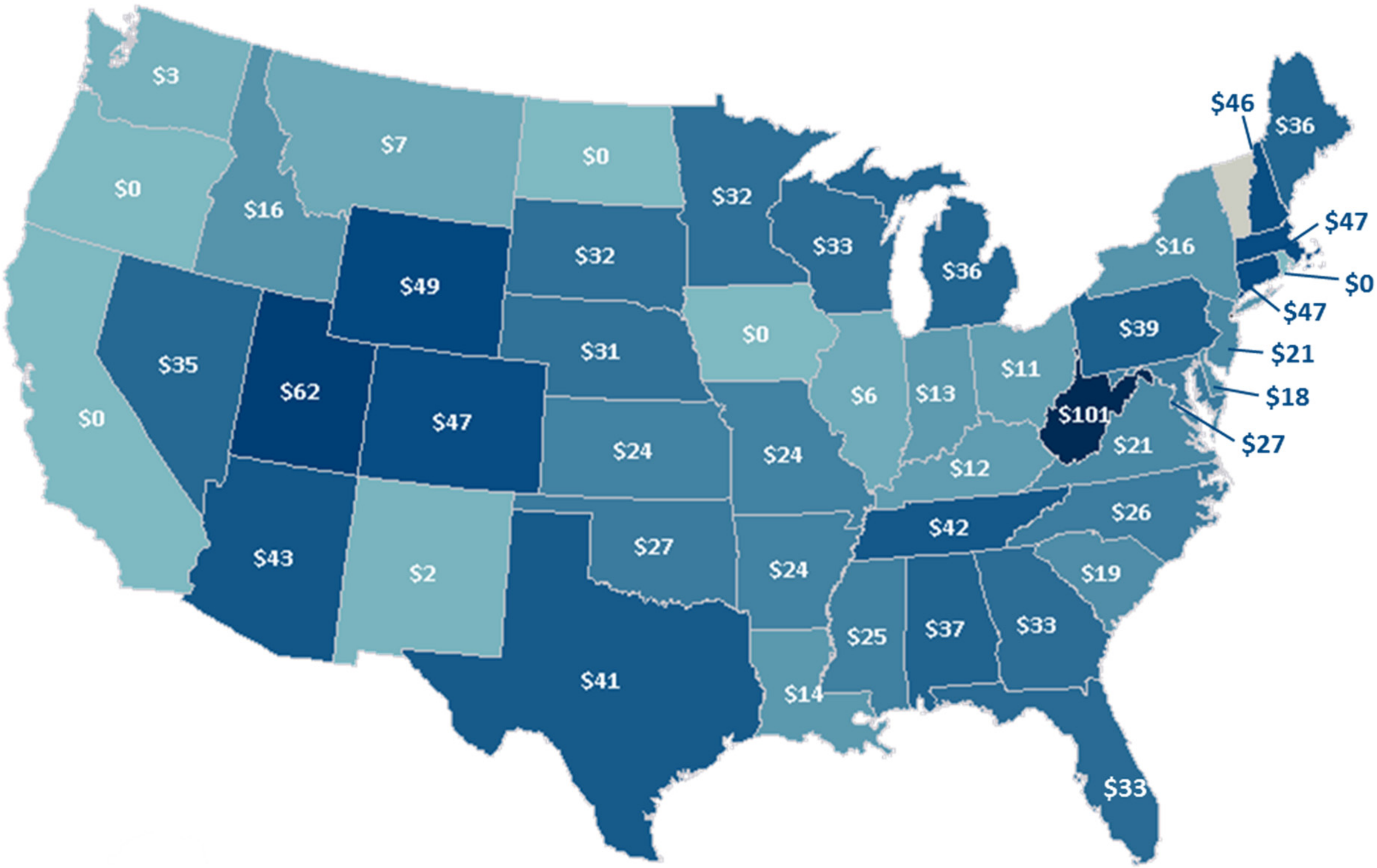


States listed in order of declining current emission rates.



Source: EPA IPM

EPA's Projected Impacts
EPA Indicative CO_2 Prices (No Cooperation)



Sources and Notes:
EPA IPM Option 1, No Cooperation scenario. Values reflect "shadow prices" on emissions rate constraint, expressed in $/ton of CO_2.

EPA's Projected Impacts

Implications of EPA Projections for Hydro

- Aside from energy efficiency (which is an IPM input assumption), EPA projects that by far the largest CO_2 abatement option selected will be coal-to-gas switching (including coal retirements)

- EPA projects only very small increases in renewable power by 2030:
  - Assumes no change to states' RPS in response to 111(d), however IPM accelerates most non-hydro renewable builds into 2017-2020 timeframe
  - IPM shows that new renewables are not cost-competitive with coal-to-gas switching under rate-based implementation in 2020-2030 timeframe

- Most important observation is the potentially counter-intuitive result that wholesale energy prices go down somewhat under rate-based compliance:
  - Existing gas units get paid for creating CO_2 offsets if they produce power at a CO_2 rate lower than the state-wide emission standard (lowering offer prices)
  - Puts existing gas units at an advantage compared to zero-emitting supply types (and even new gas)
  - Incentives for retaining at-risk hydro and nuclear decline, although nuclear risk is addressed in BSER

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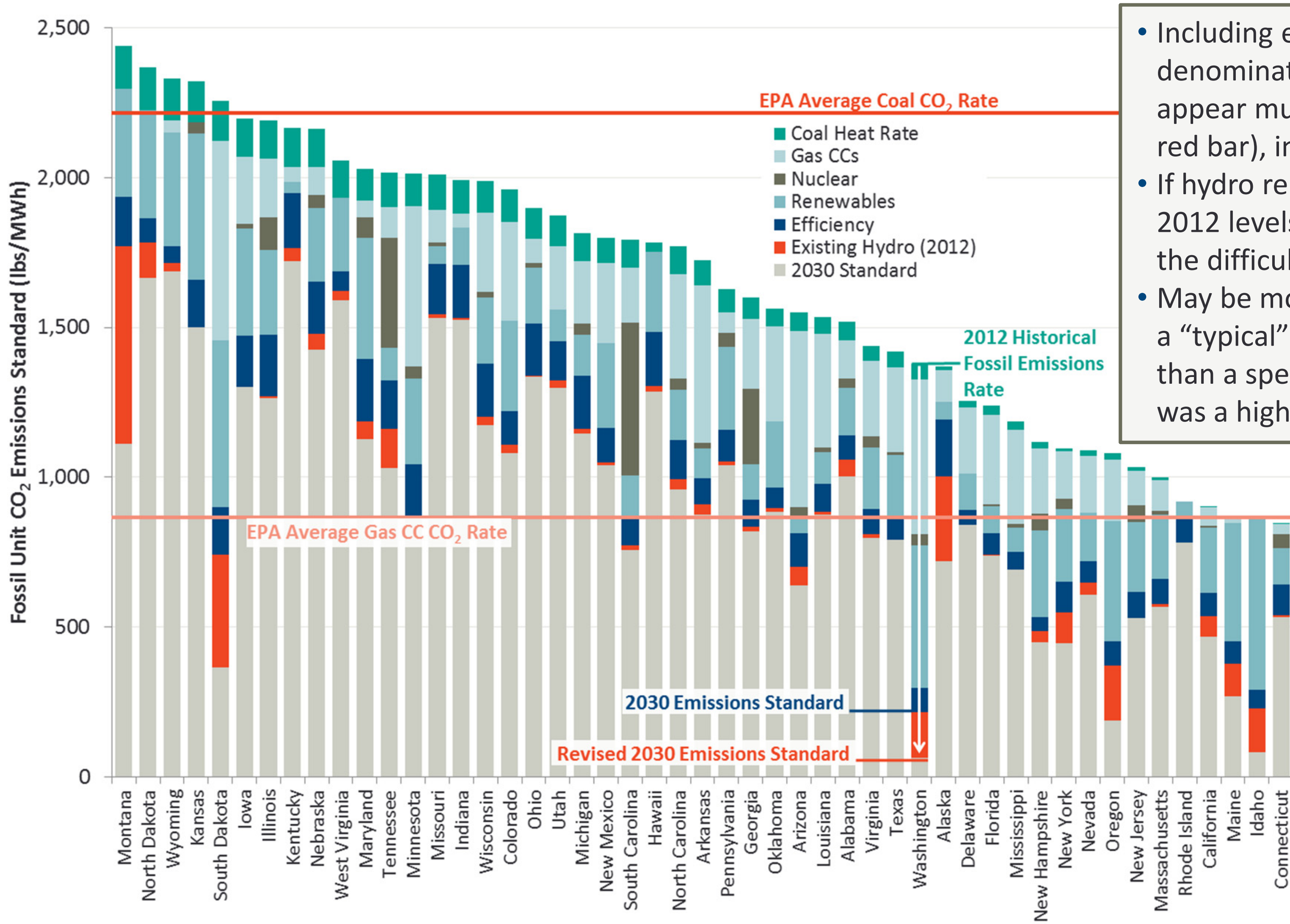
How Might BSER Revisions Affect Hydro?

- If some hydro (existing or new) were explicitly counted in BSER, it would establish that asset type as a “qualifying resource” eligible to contribute to compliance at the state level
  - Under some state compliance approaches, hydro could earn additional potential market revenues
- Including existing hydro in BSER formula would make the standards appear more stringent, but the actual impact depends on hydro changes
  - If hydro remained constant, then it would not affect level of effort required from other building blocks to attain the standard
  - If hydro declined, other efforts would have to be stepped up, and this implicitly values the retention of at-risk hydro
  - If hydro were to increase, other actions could be eased – a source of potential value for hydro, but the ability to capture the value depends on state implementation approaches and resource costs
- We examine here various levels at which hydro could be included in BSER, including: (1) All existing (like other renewables); (2) At risk (like nuclear); and (3) Potential (like other renewables)

BSER Revisions

Recognizing All Existing Hydro



- Including existing hydro in rate denominator makes standards appear much stricter (bottom of red bar), in hydro-heavy states
- If hydro remains constant at 2012 levels this does not affect the difficulty of meeting BSER
- May be most appropriate to use a "typical" hydro year rather than a specific year (e.g. 2012 was a high hydro year)

BSER Revisions

Retaining Hydro "At-Risk" for Retirement

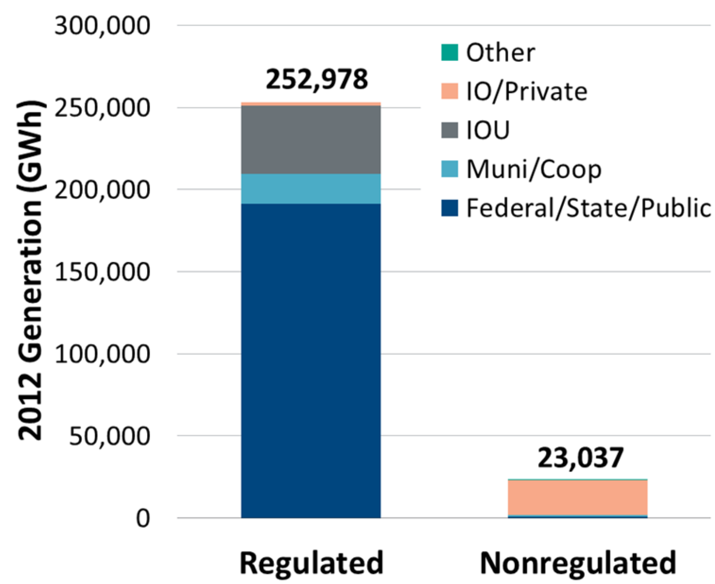
- One approach would be to include "at risk" hydro in BSER, similar to nuclear
- Hydro assets may be at risk due to low market revenues, high operating or reinvestment costs, difficulty renewing permits, or expiring PPAs, etc.
- Depending on what risk factors are considered and/or combined , 5-20% of the hydro fleet could be considered "at risk" (these risk factors represent independent sources of risk, which would require additional analysis to construct more formal screens composed of multiple risk factors, e.g. including PPA expiration and high fixed or variable O&M costs)

U.S. Hydro Capacity "at Risk"

Retirement Risk Factor	**Capacity** *(%)*
Announced Retirement by 2030	2%
Merchant Ownership	10%
Over Age 50 & < 25 MW	10%
License Expiration by 2030	29%

Sources and Notes:
Ventyx Energy Suite, and SNL Energy.
Additional risk factors such as high operating costs and expiring PPAs are not shown above since the data is available for a subset of the hydro units.

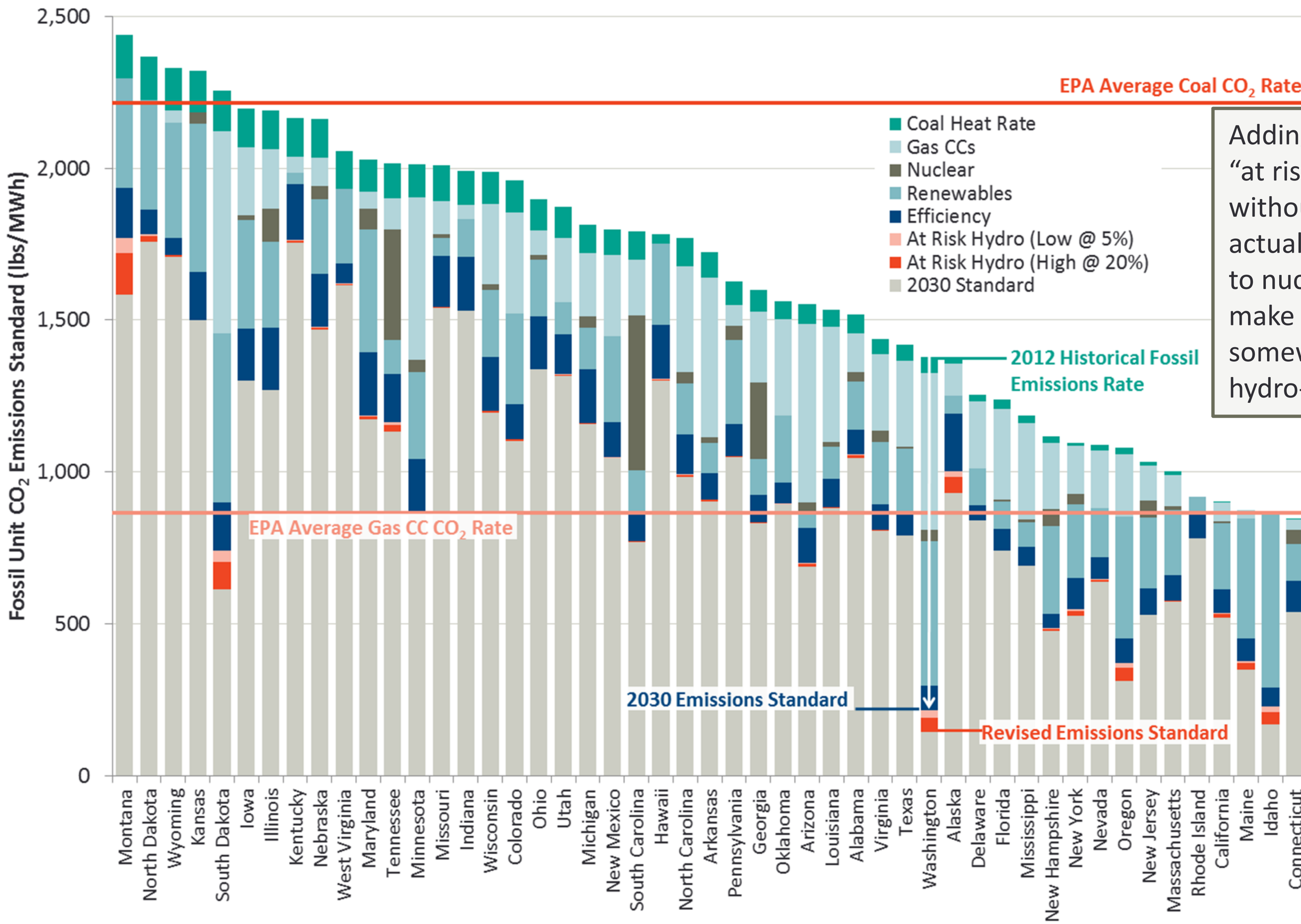
2012 Hydro Generation by Ownership Type



Source: Ventyx Energy Velocity Suite

BSER Revisions: “At Risk” Hydro

Retaining Hydro “At-Risk” for Retirement



Adding the 5-20% of “at risk” hydro to BSER without regard to actual location (similar to nuclear), would make standards somewhat stricter in hydro-heavy states.

Considering New Hydro Potential

EPA is asking comments on whether hydro potential should be included in BSER:

- RE target for each state based on NREL's estimate of technical potential, as measured above 2012 actuals
- Results in 85 TWh of additional hydro potential by 2030 (or a 31% increase above 2012 generation)
- ID, MO, and CO are the top three states

Other hydro potential estimates would result in different hydro potential estimates:

- ORNL 2014 study estimated 460 TWh from new stream development
- An ORNL 2012 study estimated 45 TWh additional from existing non-power dams
- A notional 41 GW of potential hydro capacity is "proposed" to come online by 2020 (less than 1 GW under construction)

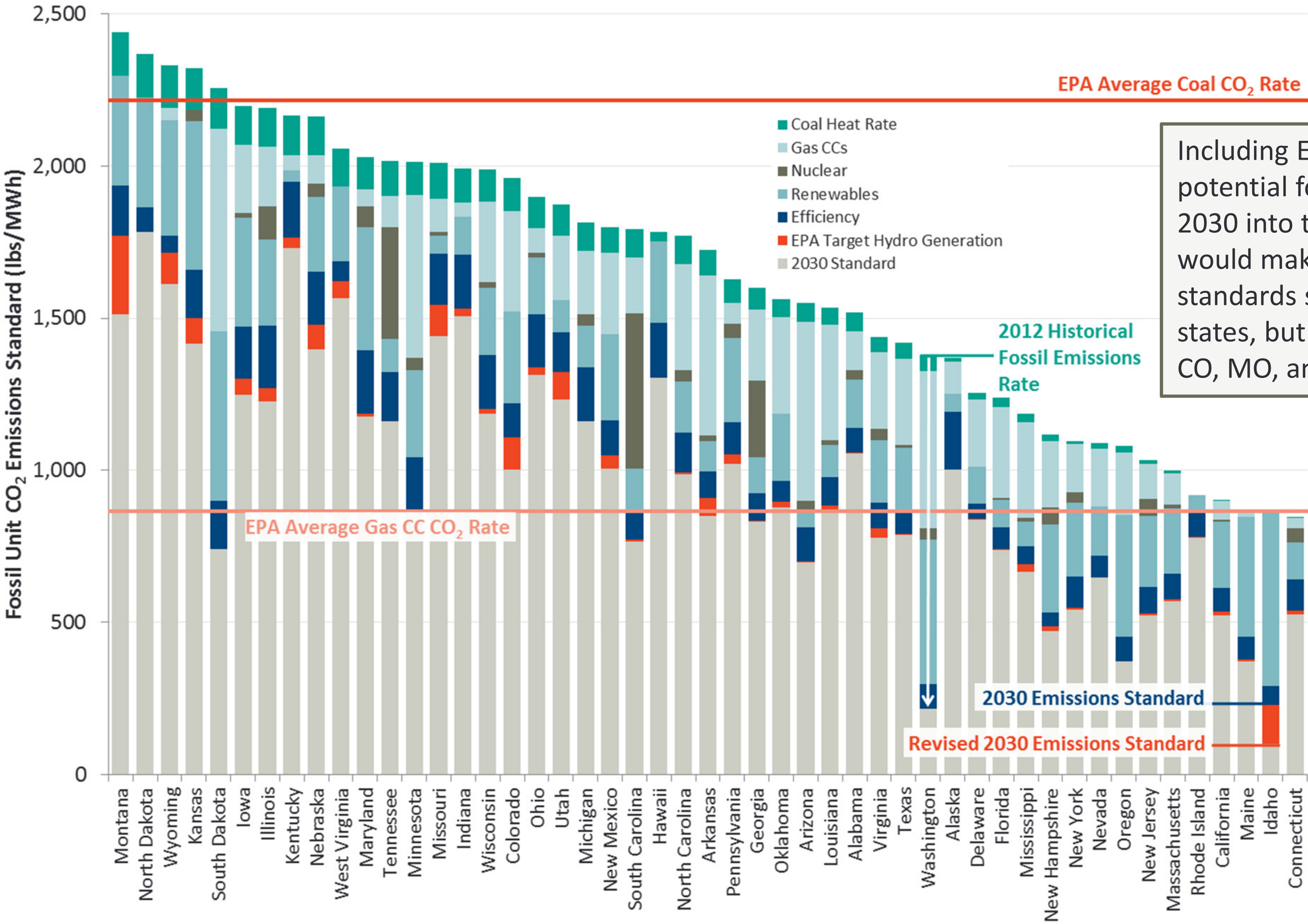
2030 EPA Additional Hydro Potential Generation by State

State	New Potential *(GWh)*
ID	7,817
MO	6,484
CO	6,292
PA	6,126
IL	4,771
CA	4,264
AR	3,895
WY	3,552
MT	3,263
WV	2,977
UT	2,781
OH	2,632
VA	2,613
KS	2,498
TX	2,422
MS	2,211
IA	2,052
IN	1,961
KY	1,894
NE	1,885
Others	12,835
Total	**85,224**

Source: EPA Alternative RE Approach Data File

BSER Revisions

Considering New Hydro Potential



Including EPA's estimate of potential for new hydro by 2030 into the formula would make the CO_2 standards stricter in most states, but largely in MT, ID, CO, MO, and UT.

Rule Revisions

Implications of Alternative Hydro Treatment

- Including all or some hydro in the rate calculation is important because it would: (a) make the standards more aggressive, and (b) establish hydro as a “qualifying” abatement option
- **More stringent standards** may or may not have a material impact:
  - If hydro generation does not change, adding existing hydro amounts to only an accounting exercise (*i.e.* the difficulty of meeting targets is unchanged), but if hydro generation changes then hydro as a resource *has value relative to other compliance options*
  - Under any CO_2 pricing or market-based trading scheme, stricter standards will translate to higher wholesale energy prices, which could benefit hydro
- **Establishing “qualifying” status** will force states to explicitly consider existing and new hydro in design (and possibly establish hydro as eligible to earn revenues from any RPS-type mechanisms):
  - Including at-risk hydro (like nuclear) may focus states on retention mechanisms and support beyond RPS when applicable
  - According to conversations with EPA, new hydro would count toward attainment with emission rate goal, even though 2012 hydro generation not used in setting state targets (will not limit “credit” to RPS-eligible hydro but believes non-RPS-eligible development is unlikely)

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How Do State Compliance Options Affect Hydro?

Biggest effects for hydro will be determined by how states construct compliance strategies:

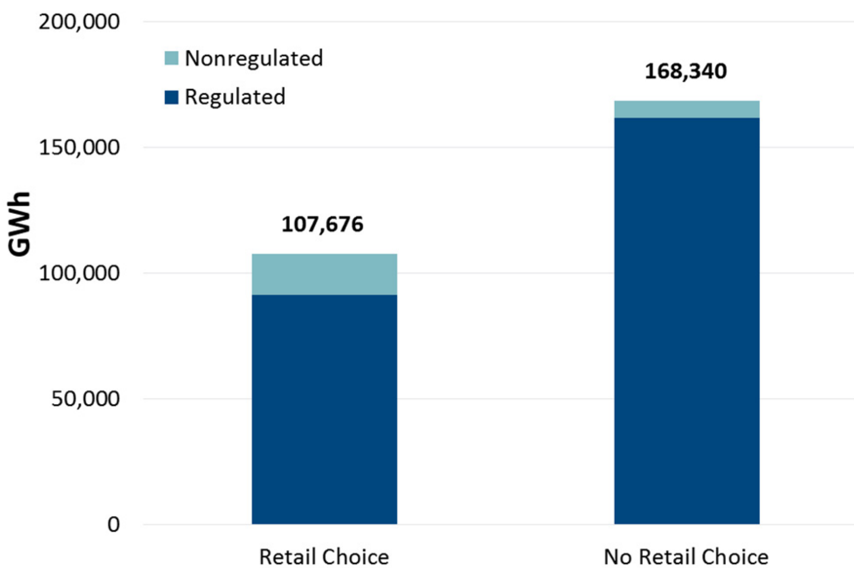
- Most advantageous outcomes for hydro (with market exposure) are those that level the economic playing field across resource types:
  - Mass-based CO_2 trading or pricing programs (will increase wholesale prices above rate-based, and also sidestep concerns about hydro not being a "qualifying" resource type)
  - Regional cooperation (tend to increase prices in hydro states compared to non-cooperation under mass-based; impact is mixed under rate-based)
- For hydro under planning regimes, the qualifying status is critical to determine if the resource can contribute to meeting the rate target (encouraging extended PPAs and life-extending reinvestments)
- Utilities with hydro assets and load-serving obligations have mixed interests:
  - Individual hydro asset values go up with power price (e.g., mass-based trading)
  - But so do costs to serve load (if the utility is net short)
- Big dollars at stake based on how the state allocates allowances (e.g. allocate to customers, auction proceeds to reduce state budget, or allocate to highest historical emitters)

State Compliance

Regulated Planning Approaches

- **Option:** States may opt to rely on regulated planning (rather than market-based approaches) to determine the resource mix that will meet the standard

2012 Net Generation by Retail Choice



Sources and Notes:

Ventyx Energy Velocity Suite and EIA.

States with retail choice include CA, CT, DC, DE, IL, MA, MD, ME, MI, MT, NH, NJ, NY, OH, OR, PA, RI, and TX. Some states, such as CA and MI, have only partial retail choice.

Regulated Planning	
Description	• State agency or utility develops a supply plan to meet the rate
Where is it most likely?	• States with vertically integrated utilities that conduct integrated planning (no retail choice) • Even most states that rely primarily on market-based approaches are likely to do at least some "planning" for a subset of the need (*e.g.*, for efficiency, expand RPS, nuclear/hydro retention, etc.)
Good for Hydro if…	• Existing or new hydro asset can win regulatory cost recovery or a PPA • CO_2 limits may compel urgency to re-invest in existing assets to prevent retirements (only if at-risk hydro can be considered a "qualifying resource")
Not Good for Hydro if…	• Existing hydro not "qualifying" • Utility plans for minimum hydro role • Leaves existing hydro (especially merchant in regulated regions) unable to capture any upside from CO_2 limits

State Compliance

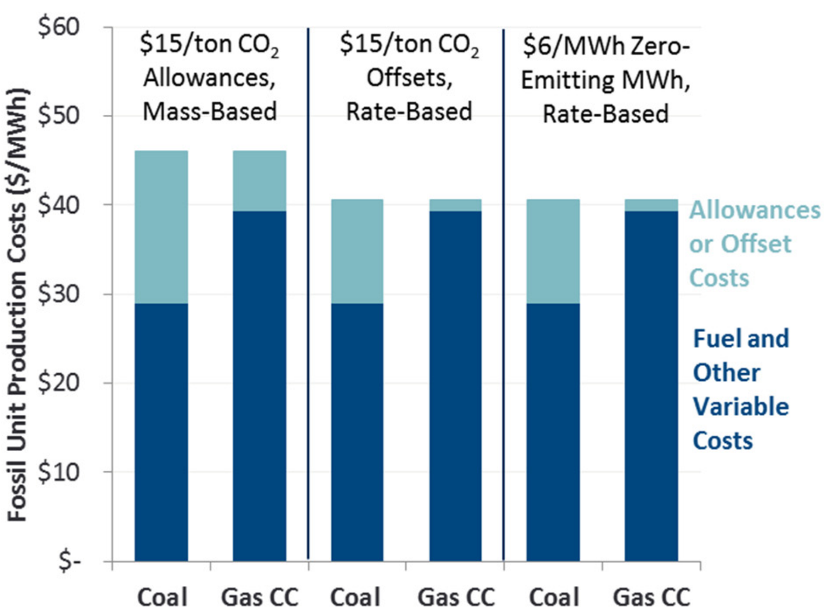
Market-Based Trading Approaches

	CO_2 Allowances (Mass-Based)	CO_2 Offsets (Rate-Based)	Zero-CO_2 MWh (Rate-Based)
Definition of Trading Product	• 1 ton of CO_2	• 1 ton of CO_2	• 1 MWh of generation from a zero-CO_2 resource (like a Renewable Energy Credit)
How Does a Fossil Plant Comply?	• Purchase 1 allowance for every ton of CO_2 emitted	• Purchase enough offsets to meet rate formula: $\frac{CO_2\ \text{Emitted} - \mathbf{CO_2\ Offsets}}{\text{MWh Generated}}$	• Purchase enough allowances to meet rate formula: $\frac{CO_2\ \text{Emitted}}{\text{MWh Gen} + \mathbf{MWh\ Credits}}$
How are Credits Allocated or Created?	• Fixed quantity is pre-set • Auctioned to highest bidder or allocated to specific entities	• Gas units create credits when running if they are under the state rate standard (coal units consume credits)	• 1 REC is created whenever a qualified zero-emitting resource produces power
Similar Existing Programs	• RGGI, California AB32, Europe, Quebec	• Alberta (somewhat similar)	• REC programs under existing state RPS
How Does Hydro Benefit?	• Higher power prices	• Prices may be higher or lower (most states somewhat lower) • Revenue from creating and selling CO_2 offsets (if qualified!)	• Prices may be higher or lower (most states lower) • Revenue from creating and selling RECs (if qualified!)

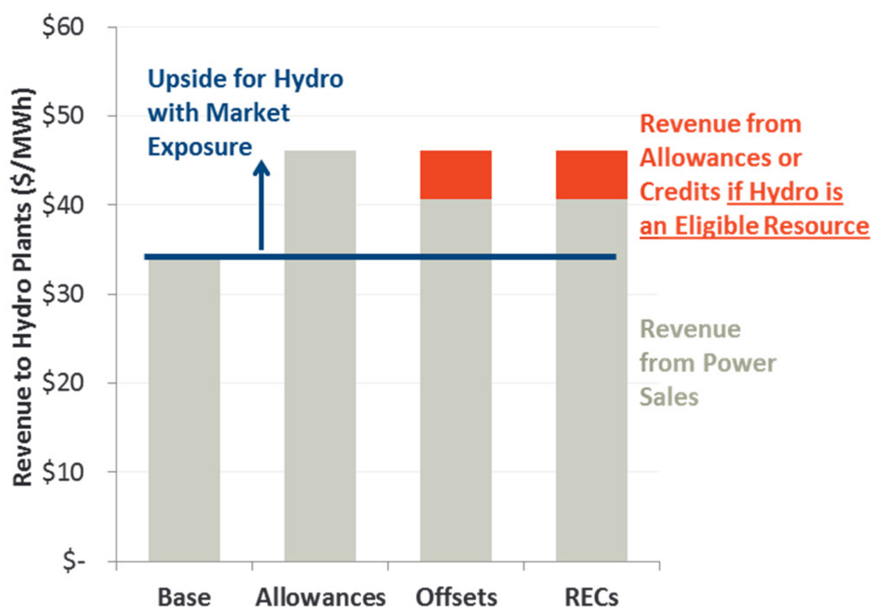
State Compliance: Trading Approaches
Example: Hydro Benefit from Allowances

- Hydro with market exposure would benefit from higher power prices under an allowance trading scheme, but power prices may go down or up with CO_2 offsets approach (examples are illustrative, details in appendix)
- **Key concern** is whether states would treat hydro as an "eligible resource" under offset or REC programs, suggesting NHA should support mass-based CO_2 allowance programs like RGGI

Coal and Gas CC Production Cost



Hydro Upside



Notes:
Illustrative example calculations reflect reasonable, self-consistent assumptions but are not a projection, detail in appendix.

State Compliance

Rate-Based vs. Mass-Based Compliance

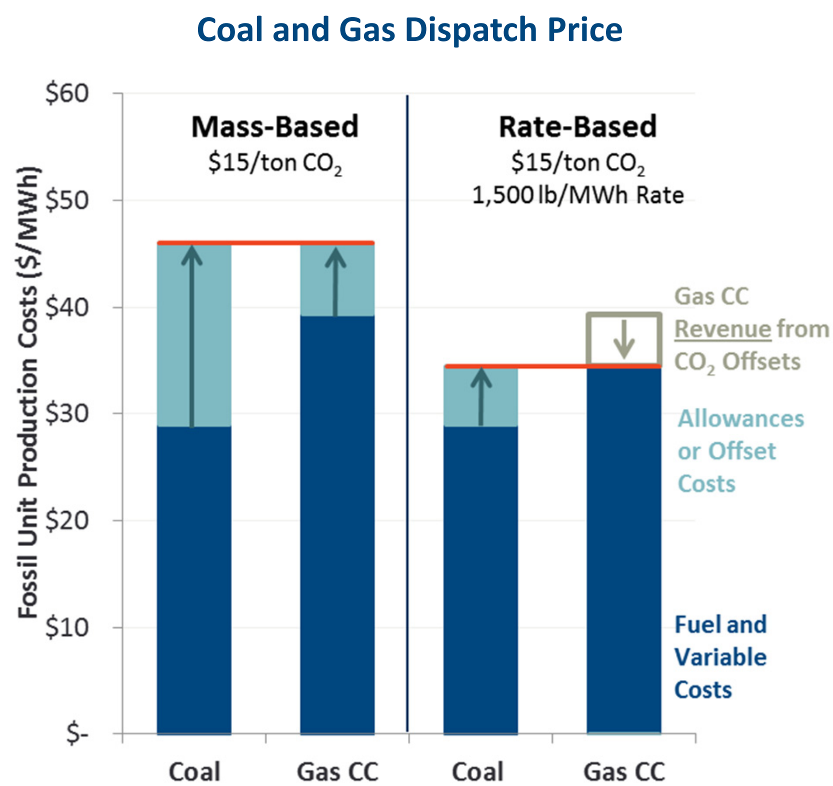
	Rate-Based	Mass-Based
Description	• State must meet emissions rate formula on an aggregate basis • May assign rate-based compliance requirements to individual entities (*e.g.*, fossil generators)	• State conducts a forecast exercise estimating CO_2 output in a but-for projection without qualifying programs, and a policy case with programs showing that the policy case meets the rate standard (subject to EPA approval) • The CO_2 emissions in the policy case determines the quantity of CO_2 allowances that can be allocated
Where is it most likely?	• Possibly states where regulators hope to keep wholesale energy prices down	• States that are already participating in mass-based programs (CA, and RGGI states of CT, DE, ME, MD, MA, NH, NY, RI, VT) • Possibly states trading heavily w/ the above
Pros	• Rate-based approach scales with economic growth • Some regulators may see the lower wholesale energy prices as an advantage	• Can maintain economic efficiency in dispatch, including cost of CO_2 (including across states if there is cooperation) • Credit auction or allocation value can be used to achieve other policy objectives (*e.g.*, reduce state deficit, offset customer impacts) • Successfully tested
Cons	• Substantial potential for economic inefficiencies and uneven playing field for hydro and other asset types (following slides) • Untested and much more complicated	• Some state regulators will see higher energy prices as a con (but impacts can be offset through allowance allocations)
Hydro Impact	• Likely worse for hydro, given substantial risk of not being "qualified"	• Good for hydro with market exposure (greatest impact on power prices)

State Compliance: Rate vs. Mass

Mass- and Rate-Based Trading are Very Different

Prices will be very different under mass-based vs. rate-based CO_2 trading

- **Mass-based:** fossil generators must pay for every ton of carbon produced, increasing dispatch costs
- **Rate-based**:
  - Fossil units only have to pay for enough CO_2 to reduce their emissions rate down to the state-specific standard
  - In many states, the rate is <u>above</u> that of a gas CC – meaning gas generators will earn revenue from creating offsets every time they run (<u>reducing</u> energy offer price!)



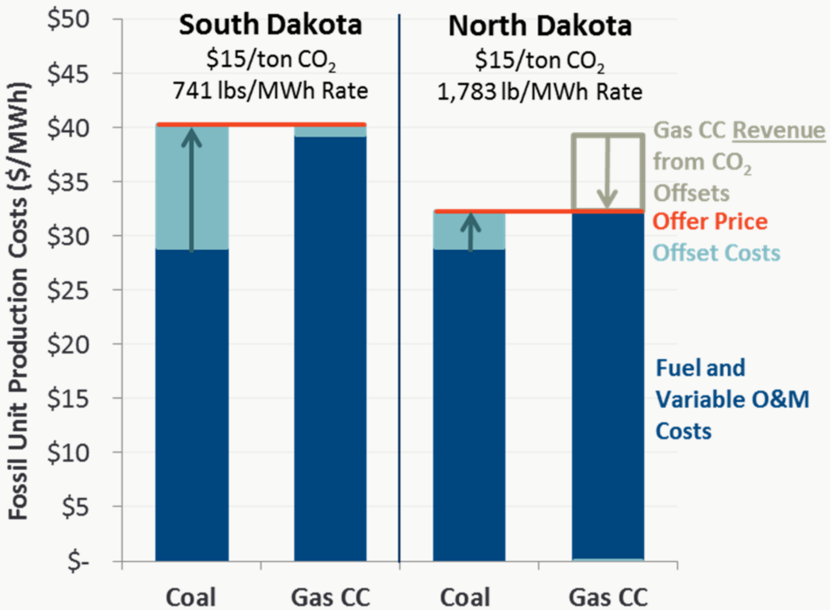
Inefficiencies Under Rate-Based Approach

Rate-based approaches will create substantial dispatch inefficiencies between states and some resource types

Example 1

Different Dispatch Prices for Identical Plants in Neighboring States

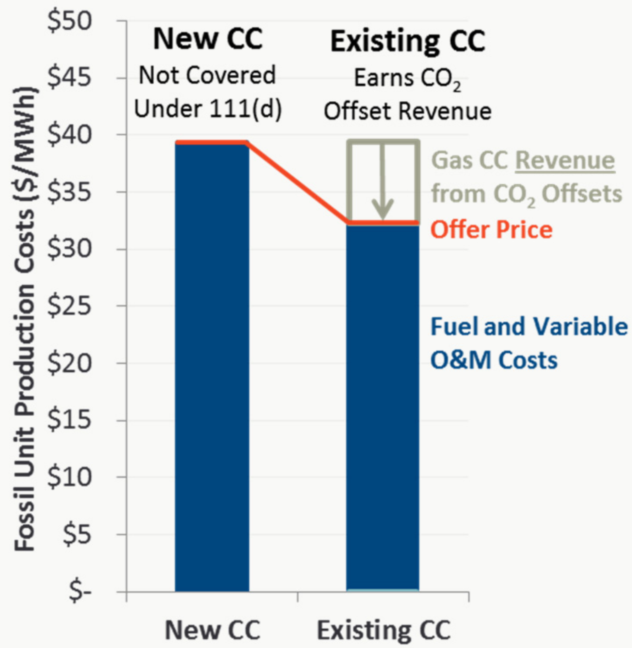
Production shifts into higher-CO_2 emitting state



Example 2

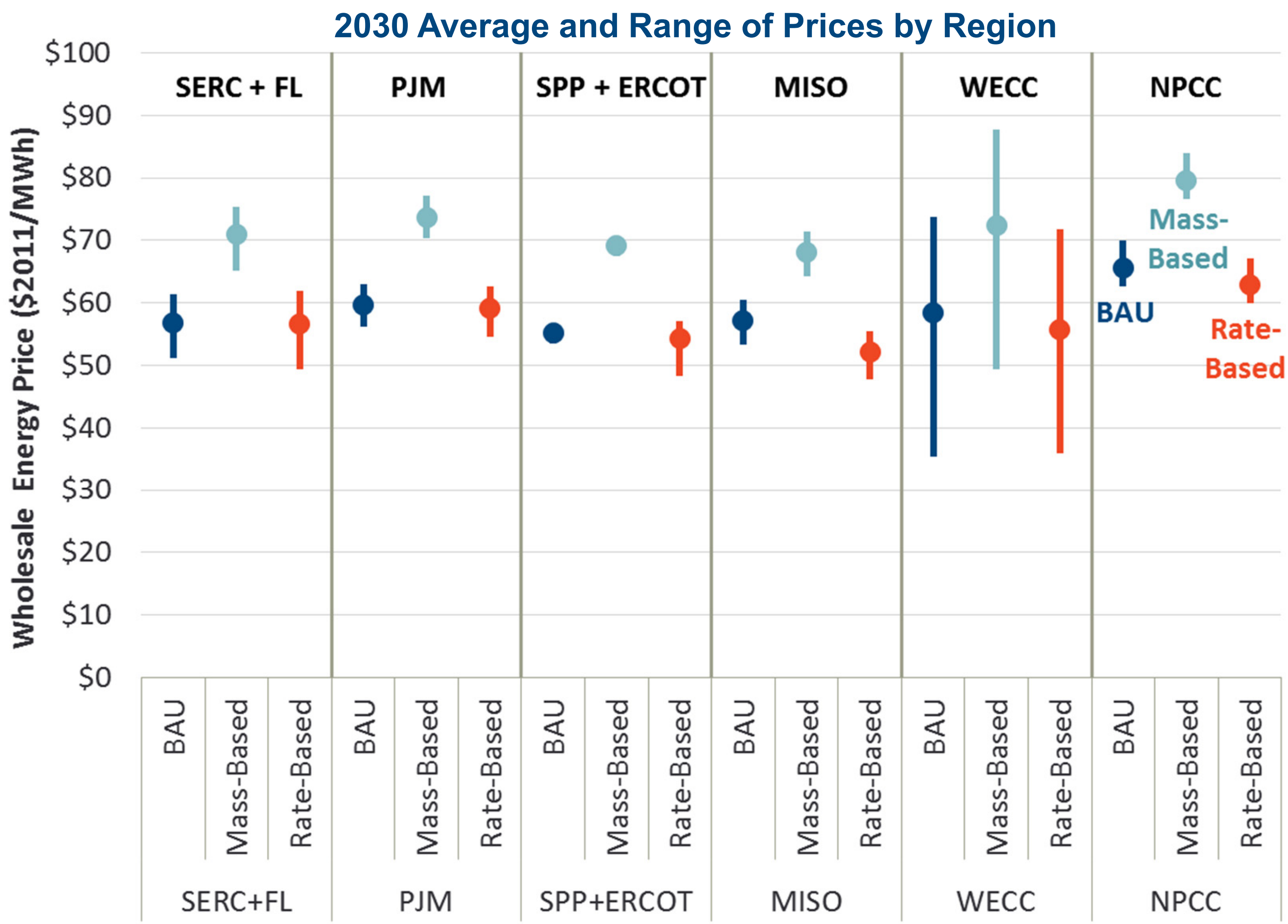
Identical "New" and "Existing" Gas CCs

Existing CCs at advantage compared to new.



State Compliance: Rate vs. Mass

Potential 2030 Energy Price Impacts



Sources and Notes:

BAU and Rate-based prices are from EPA IPM results for year 2030 under Option 1: Regional cooperation, showing simple average and range of prices by region.
Mass-based prices are approximate, starting with the BAU price and adding regional CO2 price assuming a gas CC is the marginal energy resource.

State Compliance

Administrative Carbon Pricing

- An alternative approach would be to set administratively-determined CO_2 emissions prices:
  - Would achieve dispatch and investment efficiencies similar to a mass-based CO_2 program in that all supply types would face the same CO_2 price
  - A multi-state, RTO-administered program could extend dispatch efficiencies across state borders (similar to a multi-state mass-based program)
- Price would be reviewed periodically to determine whether the required level of CO_2 reductions had been achieved, and whether an adjustment to the price would be needed

Sources and Notes:

See additional discussion of this option in a whitepaper prepared by Chang and Weiss for Great River Energy in http://www.brattle.com/system/publications/pdfs/000/005/003/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector_Chang_Weiss_Yang_Apr_2014.pdf?1397577641

State Compliance
Single-State vs. Regional Compliance

- **Option**: states can cooperate to meet the aggregate emissions mass or rate standard
- Result is converged CO_2 prices
- Cooperation more often beneficial to hydro than not under mass-based (since the most hydro-heavy states have lower CO_2 prices w/o cooperation), but impact is mixed under rate-based

EPA Estimated Annual National Compliance Costs

Scenario	Compliance Costs *(2011$ Billion)*	CO_2 Avoided *(Million tons)*	Average Cost *(2011$/ton)*
Non-Cooperation	$8.8	594	$15
Regional Cooperation	$7.3	575	$13

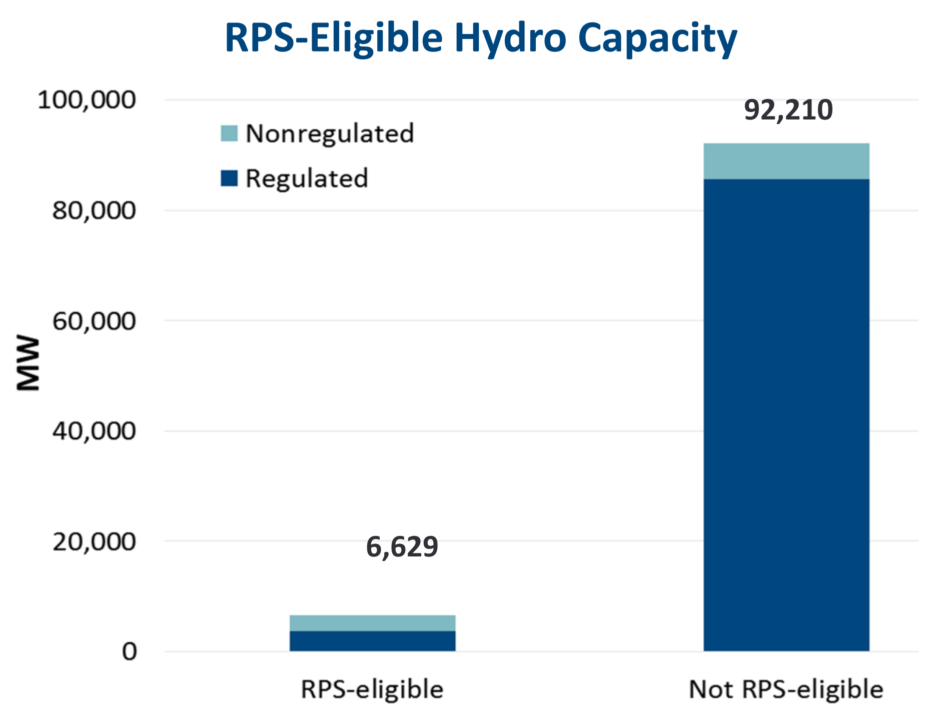
EPA Estimated 2030 Carbon Price & Approximate Equivalent Energy Price Impact Under Mass-Based Trading

Region	Non-Cooperation Scenario			Regional Cooperation Scenario		
	Marginal CO_2 Cost *(2011$/ton)*	Energy Price Increase if Gas CC is Marginal *(2011$/MWh)*	Energy Price Increase if Coal is Marginal *(2011$/MWh)*	Marginal CO_2 Cost *(2011$/ton)*	Energy Price Increase if Gas CC is Marginal *(2011$/MWh)*	Energy Price Increase if Coal is Marginal *(2011$/MWh)*
MISO	$0 - $36	$0 - $16	$0 - $40	$24.6	$11	$5
NPCC	$0 - $47	$0 - $20	$0 - $52	$32.0	$14	$35
PJM	$11 - $101	$5 - $44	$13 - $112	$31.9	$14	$35
SERC + FL	$14 - $42	$6 - $18	$15 - $46	$31.6	$14	$35
SPP + ERCOT	$24 - $41	$10 - $18	$26 - $45	$32.3	$14	$36
WECC	$0 - $62	$0 - $27	$0 - $69	$32.8	$14	$36

State Compliance

Interaction with Renewable Portfolio Standards

- Many states are likely to rely on existing or expanded renewable portfolio standards (RPS) for compliance
- **Key concerns** for hydro are that:
  - The vast majority of hydro is not treated as a qualifying resource under existing state RPS rules
  - Existing hydro is explicitly excluded from EPA's rate calculation (indicating that states relying on expanded RPS will not treat hydro as a qualifying resource, meaning that some potential revenue streams will be lost)
  - Puts RPS-excluded hydro at a continued disadvantage compared to other renewables



Sources and Notes:
Ventyx Energy Velocity Suite
The RPS-qualifying flag in Ventyx (based on fuel type, prime mover, and capacity (for hydroelectric units)) applies only to the state the unit is physically located in.

Summary of Compliance Implications for Hydro

Hydro interests are aligned with creating economically-efficient mechanisms that level the competitive playing field among all resource types to meet policy objectives at lowest cost

Option	Which Approach is Better for Hydro?	Which Approach is Most Economically Efficient?
Rate or Mass-Based	• Mass-based, with all new and existing CO_2-emitting resources needing to procure 1 allowance for each ton emitted (will result in higher energy prices)	• Mass-based, will level competitive playing field for economic dispatch including carbon emissions costs
Regional or State	• Depends on state, but regional is preferred for most hydro-heavy states under mass-based (as indicated by higher EPA estimated CO_2 prices); impact is more mixed under rate-based	• Regional will level playing field across state boundaries
CO_2 Allowances, Offsets, or Carbon Pricing?	• Allowances or carbon pricing will translate to higher energy prices and benefit hydro equal to other zero-carbon resources	• Allowances or carbon pricing will require all resources to pay the same cost to emit each ton of CO_2

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Takeaways

- The most important issues for hydro would be to level the playing field compared to other abatement options by:
  1. Establishing existing and new **hydro as a "qualifying" resource** for the purposes of both setting state emissions rates, as well as demonstrating compliance, and
  2. Implementing a **mass-based CO_2 allowance trading** approach (or administrative carbon-pricing approach) that uniformly applies a single carbon price for every ton of CO_2 emitted across all CO_2-emitting resource types, across the broadest regional areas possible
- Eliminating these asymmetries would not only benefit hydro, but also increase economic efficiency and move toward meeting the underlying policy objectives at lowest cost
- Both issues will be addressed once before EPA as the rule is finalized, and again while states develop their implementation plans

Appendix

Assumptions: Allowance Trading Impacts

- Detailed assumptions underlying illustrative allowance trading examples (from slide 30)

State Policy Scenario	Hydro Revenue: Energy Sales ($/MWh)	CO_2 Allowance Sales ($/MWh)	REC Sales ($/MWh)	**Total** ($/MWh)
Business as Usual	$34	$0	$0	**$34**
with $15/ton Carbon Allowances	$46	$0	$0	**$46**
with $15/ton Carbon Offsets	$41	$5	$0	**$46**
with $5/MWh RECs	$41	$0	$5	**$46**

Notes:
Assume power prices are average of coal and gas CC production cost.

		Coal	**Gas CC**
Plant Parameters			
CO_2 Emissions Rate	*(lbs/MWh)*	2,214	866
Fuel CO_2 Intensity	*(lbs/mmbtu)*	208	116
Heatrate	*(btu/kWh)*	10,649	7,444
VOM	*($/MWh)*	$5	$4
Fuel Price	*($/mmbtu)*	$2.25	$4.75
Base Production Cost	*($/MWh)*	$29	$39
Case 1: Mass-Based with CO_2 Allowances			
Emissions Rate Standard	*(lbs/MWh)*	n/a	n/a
CO_2 Allowance Price	*($/ton)*	$15	$15
Allowances Needed to Run	*(lbs/MWh)*	2,214	866
Production Cost Increase	*($/MWh)*	$17.09	$6.69
Case 2: Rate-Based with CO_2 Offsets			
Emissions Rate Standard	*(lbs/MWh)*	700	700
CO_2 Offset Price	*($/ton)*	$15	$15
Allowances Awarded per REC	*(lbs/MWh)*	700	700
Offsets Needed to Run	*(lbs/MWh)*	1,514	166
Production Cost Increase	*($/MWh)*	$12	$1
Case 3: Rate-Based with Zero-CO_2 MWh Credits			
Emissions Rate Standard	*(lbs/MWh)*	700	700
Zero-CO_2 MWh Price	*($/MWh)*	$5.40	$5.40
RECs Needed to Run	*(RECs/MWh)*	2.2	0.2
Production Cost Increase	*($/MWh)*	$12	$1

Notes:
Gray values are input assumptions, other values are calculated.