Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

August 27th, 2015

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. None

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ECONOMIC STUDIES WORKING GROUP

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• MINUTES •

<u>Agenda Item 1 – Administrative Items</u>

<u>Agenda Item 1a - Call to Order, Introductions</u>

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:00 PM, welcomed those in attendance, and asked for introductions.

There were 39 web conference participants, representing 13 of 13 ESWG members. (Attachment 1 – August 27, 2015 Attendance)

<u>Agenda Item 1b – Receipt of Proxies</u>

Alan Myers (ITC Great Plains) asked for any proxy statements. Three proxies were identified; Al Tamimi (Sunflower) named Ryan Yokely (Sunflower) as his proxy, Don Le (NextEra) named Jody Holland (South Central MCN) as his proxy, Kip Fox (AEP-Transource) named Wayman Smith (AEP) as his proxy. (Attachment 2 – Proxy Statements)

<u>Agenda Item 1c – Review of Agenda</u>

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – August 27, 2015 Agenda)

> **Tim Owens (NPPD) made a motion; seconded Kurt Stradley (LES) by to adopt the agenda. The motion was approved unanimously.**

<u>Agenda Item 2 – 2017 ITP10 Portfolio Consolidation Methodology</u>

Kelsey Allen (SPP Staff) presented SPP Staff's consolidation methodology recommendation. Staff suggested having two criteria: a simple inclusion approach and a project performance approach. Criteria 1: Projects included in at least two of three final Future portfolios will be included in the final consolidated portfolio. Criteria 2: Projects included in only one final Future portfolio must have a 1-year weighted sum APC B/C ratio above a 0.9 and a 1-year B/C greater than 0.7 in one other future. Staff is not currently suggested a weighting for each future. Kelsey stated his personal opinion is to place a higher weight on Future 1 (Regional CPP) due to changes to the final rule. The group expressed concern about including Future 3 in any weighting process and the possibility of deferring the weighting allocations to later on in the process. (Attachment 4 – 2017 ITP10 Portfolio Consolidation)

ACTION ITEM: Staff to bring back a brushed up portfolio consolidation proposal to the next meeting; Alan Myers to bring back a counter-proposal.

<u>Agenda Item 3 – EPA Clean Power Plan / 2017 ITP10 Futures Discussion</u>

Kelsey Allen (SPP Staff) presented SPP Staff's emission goal computation for SPP's analysis of Clean Power Plan compliance and the changes to the EPA's Clean Power Plan final rule on emission reductions under section 111D of the Clean Air Act. Staff does not currently have a strong enough proposal to make a recommendation on implementing the structure of the current plan in the 2017 ITP10 but mentioned the need to make decisions factors like responsibility of unit emissions (state-by-state and/or ownership), allowance of carbon "trading", impact to resource siting decisions, goal implementation targets (mass vs. rate, interim years vs. final goal). Members requested SPP Staff to proceed with the Resource Plan Phase 2. For Futures 1 and 2, SPP Staff will adopt the same assumptions utilized during the CPP Analysis as starting point for the 2017 ITP10 Resource Plan. SPP Staff will share the first results with members and wait for feedback in order to adjust the original assumptions. The proposed deadline for the Resource Plan Phase 2 is November 19th. (Attachment 5 – EPA Clean Power Plan)

ACTION ITEM: Staff to develop a decision tree of approval items for the members.

Agenda Item 4 – RCAR II Modeling Discussion

Josh Ross (SPP Staff) reviewed the RCAR II modeling issues and relayed current conclusions from SPP Staff and input from staff at ABB. Staff recommended Option 1b: Move wind to zonal load centers for addressing the trapped generation pockets issue. Staff recommended Option 2c: Add CTs in base for addressing the load pockets issue. The group was not prepared to make a decision on the options today. Staff needs to finalize the approach by October 22nd in order to have sufficient time to get the proper input from the RARTF and implement in the modeling phase of the RCAR II. Members acknowledged the timeline and the need for a fix in the near-term, as well as the larger issue that needs to be solved for the RCAR process. It was noted that the subjective approach to fix these issues may cause problems in the event that remedies are made out of the RCAR II. (Attachment 6 – RCAR II Modeling Discussion)

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion.

Upcoming meetings and locations:

- September 23rd, 2015: 8th Floor AEP Offices, Dallas, TX
- October 22nd, 2015: NextEra HQ, Juno Beach, FL
- November 18th-19th, 2015: SPP Corporate Offices, Little Rock, AR
- December 10th, 2015: 8th Floor AEP Offices, Dallas, TX

List of action items from the meeting:

1. Staff to bring back a brushed up portfolio consolidation proposal to the next meeting; Alan Myers to bring back a counter-proposal.
2. Staff to develop a decision tree of approval items for the members.

The meeting was adjourned at 4:00 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Company	Last Name	First Name	Attending
LS Power	Pupa	Aaron	Net Conference
ITC Great Plains, LLC	Myers	Alan	Net Conference
AEP Oklahoma Transmission Company, Inc.	Sharma	Anita	Net Conference
Xcel Energy	Weeks	Bennie	Net Conference
Empire District Electric Company	King	Bethany	Net Conference
Nebraska Power Review Board	Leung	Bill (William)	Net Conference
Western Area Power Administration - Upper Great Plains Region	Colson	C	Net Conference
Sunflower Electric Power Corporation	Yokley	Charles	Net Conference
Basin Electric Power Cooperative	Schaaf Gallagher	Daniel	Net Conference
Ameren Services Company	Burkey	Eric	Net Conference
Quanta Technology	Estes	Evan	Net Conference
ITC Great Plains, LLC	Olapurayil	Gimod	Net Conference
GDS Associates	Shook	Jason	Net Conference
Xcel Energy	Schmidt	Jason	Net Conference
City Utilities of Springfield	Bradshaw	Jerry	Net Conference
South Central MCN, LLC	Holland	Jody	Net Conference
Grand River Dam Authority	Fultz	Joe	Net Conference
City Utilities of Springfield	Boshears	John	Net Conference
Omaha Public Power District	Shipman	Jon	Net Conference
Clean Line Energy	Abebe	Jonathan	Net Conference
Xcel Energy	Schmick	Jordan	Net Conference
Southwest Power Pool	Ross	Joshua	Net Conference
Southwest Power Pool	Allen	Kelsey	Net Conference
Xcel Energy	Radl	Justin	Net Conference
Lincoln Electric System	Stradley	Kurt	Net Conference
Xcel Energy	Quillian	Lauren	Net Conference
Public Utility Commission of Texas	Thomas	Meena	Net Conference
Arkansas Electric Cooperative Corporation	MASSERY	MICHAEL	Net Conference
ITC Great Plains, LLC	Wegner	Michael	Net Conference
Oklahoma Municipal Power Authority	Watt	Michael	Net Conference
Golden Spread Electric Cooperative, Inc.	Henderson	Natasha	Net Conference
Kansas City Power & Light Company	McCool	Pat	Net Conference
Navigant Consulting Inc	Soorya	Radha	Net Conference
City Utilities of Springfield	Collier	Randy	Net Conference
Southwest Power Pool	Mittal	Rosemary	Net Conference
	Gaw	Steve	Net Conference
Nebraska Public Power District	Owens	Tim	Net Conference
Occidental Energy Ventures Corp	Soles	Tim	Net Conference
AEP	Smith	Wayman	Teleconference

1. **Al Tamimi Proxy to Ryan Yokely**

From: Tamimi, Al [mailto:atamimi@sunflower.net]
Sent: Thursday, August 27, 2015 6:40 AM
To: Myers, Alan K.; Yokley, Ryan
Subject: Proxy

I will be on the call today from 2:30 to 4pm. Ryan Yoekly has my proxy from 1 pm to 2:30 pm

2. **Don Le proxy to Jody Holland**

From: Le, Don [mailto:Don.Le@nexteraenergy.com]
Sent: Wednesday, August 26, 2015 9:17 PM
To: Kelsey Allen; amyers@itcgreatplains.com; Jody Holland
Subject: FW: ESWG 8/27/15 Agenda & Background Materials

Gents,

Yet again I am unable to attend. Jody Holland has my proxy if needed.

Don Le
System Planning Manager
Lone Star Transmission, LLC
NextEra Energy Transmission, LLC
(M) 713-366-6105
(O) 512-236-3144
Don.Le@NextEraEnergy.com

3. **Kip Fox proxy to Wayman Smith**

Please allow this email to serve as notification for Wayman Smith to be my proxy for the ESWG conference call mentioned below. Thank you for your help.

Regards, Kip

Kip Fox

214-777-1063 office
972-400-1384 cell

We power life's possibilities

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

August 27th, 2015

Net Conference

• AGENDA •

1:00pm – 4:00pm

1. Administrative items
   a. Call to Order, Introductions...Alan Myers (5 minutes)
   b. Receipt of Proxies ....Kelsey Allen (1 minute)
   c. Review of Agenda[1] ....Alan Myers (1 minute)
2. 2017 ITP10 Portfolio Consolidation Methodology ....Kelsey Allen (30 minutes)
3. EPA Clean Power Plan / 2017 ITP10 Futures Discussion ....All (90 minutes)
   a. SPP Goal Computation/CPP Final Rule Changes
   b. Futures Assumptions and Modeling
4. RCAR II Modeling Discussion ....Josh Ross (60 minutes)
5. Closing Items ....All (5 minutes)
   a. Summary of Action Items (Kelsey Allen)
   b. Future Meetings
      i. September 23rd, 2015: 8th Floor AEP Offices, Dallas, TX
      ii. October 22nd, 2015: NextEra HQ, Juno Beach, FL
      iii. November 18th-19th, 2015: SPP Corporate Offices, Little Rock, AR
      iv. December 10th, 2015: 8th Floor AEP Offices, Dallas, TX

[1] Background Material Included

2017 ITP10 Portfolio Consolidation

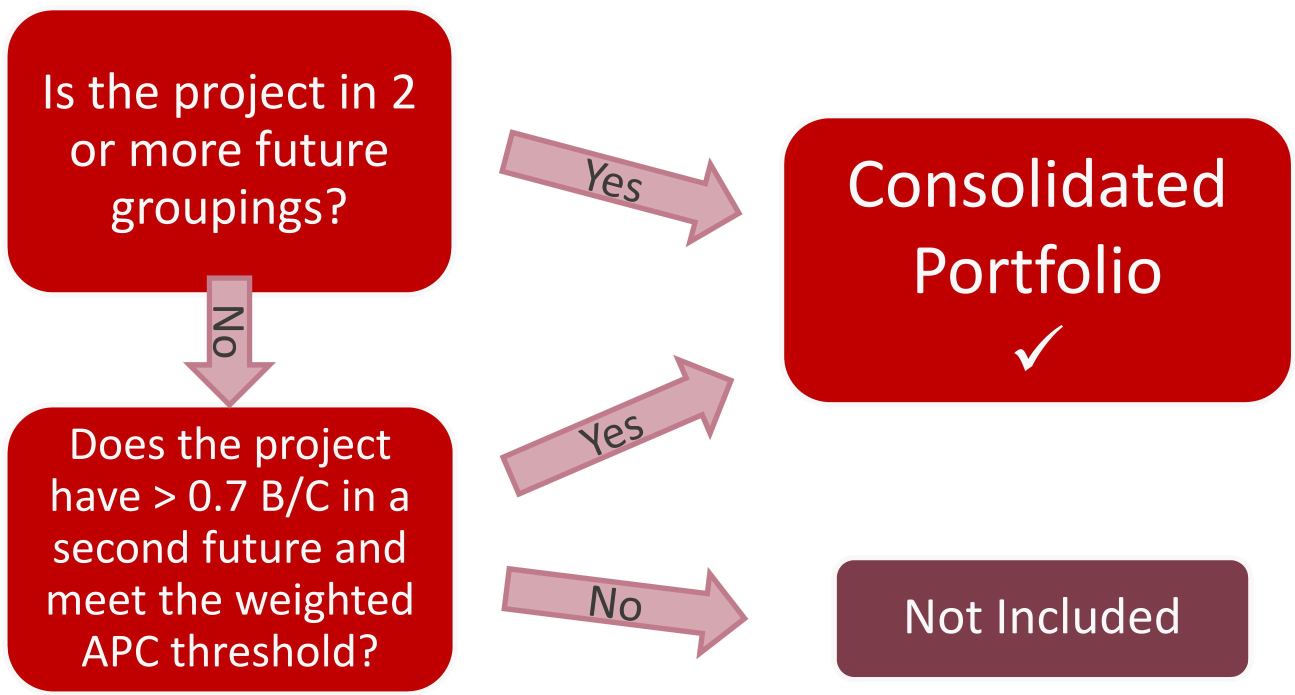
SPP Staff

August 27th, 2015

Southwest Power Pool

Consolidation Recommendation

- Criteria 1: Projects in at least 2 of 3 future portfolios are included in the consolidated portfolio
- Criteria 2: Projects in only 1 future portfolio must have a Weighted sum APC B/C ratio above 0.9 and a 1-year B/C greater than 0.7 in a second future



Consolidation

		1-year B/C Ratio Included in Future portfolio?			Consolidated
Project ID	1-Year Cost	Future 1	Future 2	Future 3	Portfolio
Project 1	$ 39,152,000	1.12 Yes	2.83 Yes	0.98 Yes	**Yes**
Project 2	$ 12,745,000	0.70 No	2.83 Yes	0.25 No	**No ***
Project 3	$ 989,000	3.60 Yes	1.20 Yes	0.30 No	**Yes**
Project 4	$ 800,000	0.25 No	1.60 Yes	0.75 No	**No ***
Project 5	$ 1,700,000	1.50 Yes	0.40 No	0.70 No	**No ***

*Project will move on for further assessment, per criteria 2

Weighted APC Threshold Options

Example 1

- **Each Future is weighted equally at 1/3**

Example 2

- **50% weighting for Future 2 (state by state implementation), 25% for Futures 1 and 3**

Weighted APC Performance Example

		1-Year Benefit B/C Ratio			Example 1*	Example 2*
Project ID	1-Year Cost	Future 1	Future 2	Future 3	Weighted B/C ratio	
Project 2	$ 12,745,000	$ 8,921,500 0.70	$ 25,247,845 **2.83**	$ 6,311,961 0.25	**1.26**	**1.65**
Project 4	$ 800,000	$ 200,000 0.25	$ 1,280,000 **1.60**	$ 600,000 0.75	**0.87**	**1.05**
Project 5	$ 1,700,000	$ 2,550,000 **1.50**	$ 680,000 0.40	$ 1,190,000 0.70	**0.87**	**0.75**

*Example 1 reflects all Futures weighted equally, Example 2 reflects Future 2 weighted 50%

APPENDIX

Additional Weighted APC Performance Example

Project ID	1-Year Cost	1-Year Benefit B/C Ratio Future 1	Future 2	Future 3	Example 1* Weighted B/C ratio	Example 2* Weighted B/C ratio
Project 1	$ 1,943,000	$ 445,249 0.23	$ (756,522) -0.39	$ 2,226,243 1.15	0.33	0.15
Project 2	$ 1,454,000	$ (8,947) -0.01	$ 4,111,481 2.83	$ (15,560) -0.01	0.94	1.41
Project 3	$ 979,088	$ 12,378,000 12.64	$ (160,000) -0.16	$ 442,000 0.45	4.31	3.19
Project 4	$ 800,000	$ (80,000) -0.10	$ (400,000) -0.50	$ 9,000,000 11.25	3.55	2.54
Project 5	$ 1,385,174	$ 1,200,000 0.87	$ 1,289,000 0.93	$ 1,210,000 0.87	0.89	0.90
Project 6	$ 478,000	$ 328,944 0.69	$ 648,248 1.36	$ 119,500 0.25	0.76	0.91
Project 7	$ 1,632,500	$ 4,066,002 2.49	$ 643,784 0.39	$ 409,989 0.25	1.05	0.88
Project 8	$ 140,000	$ 314,905 2.25	$ (29,236) -0.21	$ 88,978 0.64	0.89	0.62

*Example 1 reflects all Futures weighted equally, Example 2 reflects Future 2 weighted 50%

EPA Clean Power Plan

August 27th, 2015

ESWG

Southwest Power Pool

Draft Rule

SPP GOAL COMPUTATION

SPP Emission Goal Estimate

- Use EPA's technical support documents for Best System of Emissions Reduction (BSER)
- Identify SPP portion of each state:
  - Existing Generation Units (EGUs)
  - At-risk nuclear capacity
  - Renewable energy (existing and potential)
    - Excludes existing hydro
  - Energy efficiency
- Regional analysis: determine weighted average CO_2 emissions goal for the SPP region

BSER is Based on Four Building Blocks

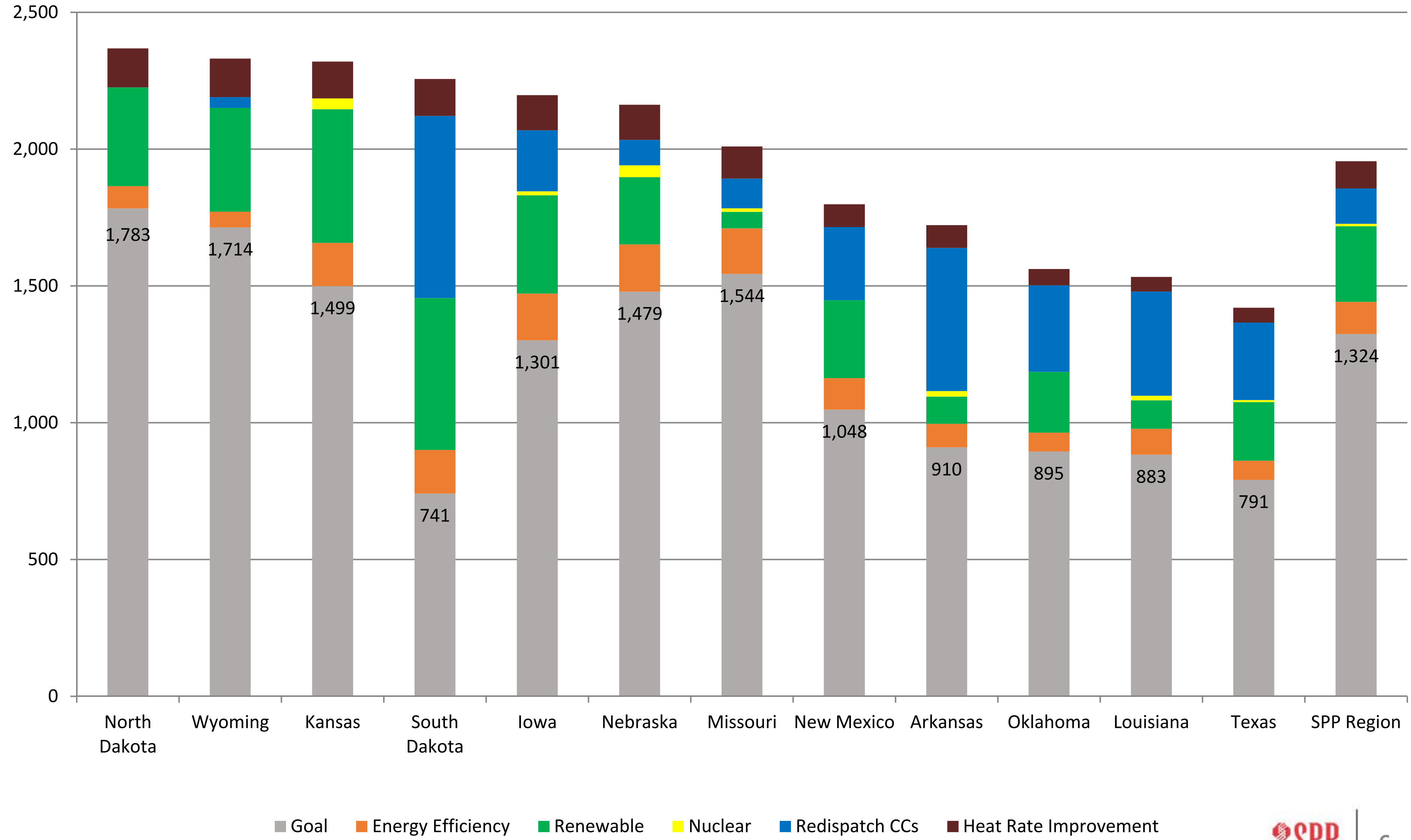
Block	Assumption
1. Improve efficiency of existing coal plants	6% efficiency improvement across fleet, assuming best practices and equipment upgrades
2. Increase reliance on CC gas units	Re-dispatch of Natural Gas CCs up to a capacity factor of 70%
3. Expand use of renewable resources and sustain nuclear power production	Meet regional non-hydro renewable target, prevent retirement of at-risk nuclear capacity and promote completion of nuclear capacity under construction
4. Expand use of demand-side energy efficiency	Scale to achieve 1.5% of prior year's annual savings rate

*Uses 2012 data for existing units and estimated data for units under construction.

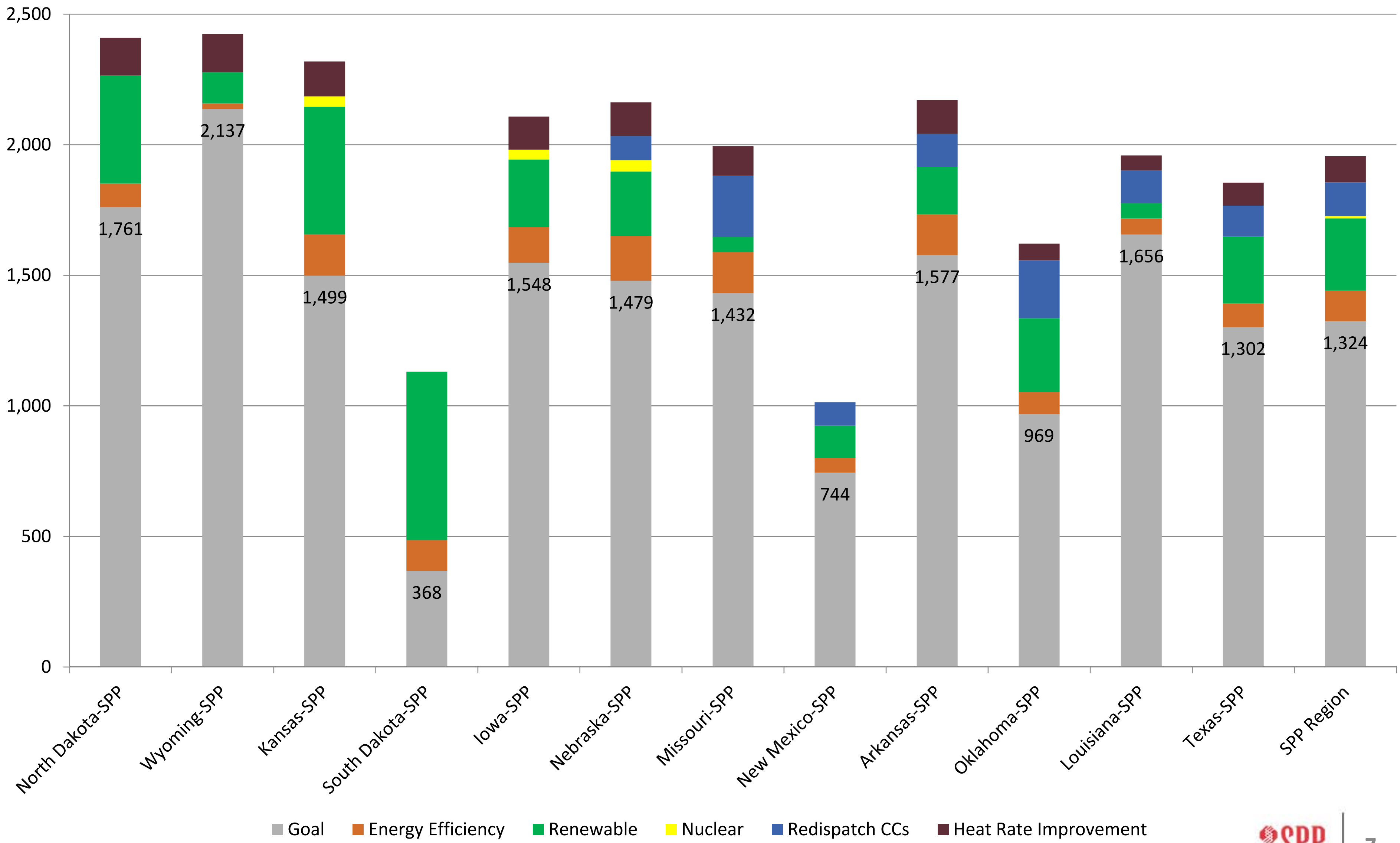
SPP Emission Goal Estimate

1. **Improve efficiency of existing coal plants**
   - Adjust coal CO_2 emission rate by 6%
2. **Increase reliance on CC gas units**
   - Adjust historical output of Coal, Oil and Gas steam based on increasing historical CC output to 70%
   - Weighted average adjustment of Coal, O/G
3. **Expand use of renewable resources and sustain nuclear power production**
   - Potential RE expansion (22%)
   - Adjusted EPA projection by % of SPP installed capacity by state
4. **Expand use of demand-side energy efficiency**
   - Projected % of avoided MWh sales
   - Adjusted EPA projection by % of SPP installed capacity by state

EPA Emission Goal Estimate (SPP States)



SPP Emission Goal Estimate



Emission Goal Estimates

State	EPA 2030 Target Rate (lbs/MWh)	SPP 2030 Target Rate (lbs/MWh)
Arkansas	910	1,577
Iowa	1,301	1,548
Kansas	1,499	1,499
Louisiana	883	1,656
Missouri	1,544	1,432
Nebraska	1,479	1,479
New Mexico	1,048	744
North Dakota	1,783	1,761
Oklahoma	895	969
South Dakota	741	368
Texas	791	1,302
SPP	N/A	1,324

Final Rule

FINAL RULE CHANGES

Changes from Proposal to Final

ITEM	PROPOSAL	FINAL
Compliance timeframe	2020	2022
Building Blocks	Four Building Blocks	Three Building Blocks (see next row) ; used grid interconnects as a basis for assessing the Building Blocks
Demand-Side Energy Efficiency	Included as a Building Block	No longer a Building Block – though EPA anticipates that, due to its low costs and large potential in every state, demand-side energy efficiency will be a significant component of state compliance plans under the CPP
Timing of reductions	S-curve. Commenters disliked the "cliff"	Steps down glide path more gradually: 2022-2024 2025-2027 2028-2029
Goal Setting	Formula included energy efficiency (EE), new nuclear, and existing renewable energy (RE) sources in the Best System of Emission Reduction (BSER)	BSER: Apply three building blocks to set two uniform CO_2 emissions rates: generally, 1. Fossil and 2. natural gas. EE, nuclear and existing RE not included in goal setting
Geographic focus	State/tribe/territory	Contiguous U.S.

Note: the EPA provided information contained in the table shown above.

Changes from Proposal to Final

ITEM	PROPOSAL	FINAL
Deadline for final state plan	June 2016 with opportunity for one or two year extension	September 2018: after initial submittal by September 2016
State plans options	Two Types: Direct emission limits and portfolio approach	Two types: emissions standards and state measures
Interstate trading mechanisms	Up-front agreements	Up-front agreements not required Trading-ready option
Clean Energy Incentive Program	Requested comment on early action	Optional state-federal matching incentive program in 2020/2021 for EE in low-income areas, and wind and solar RE
Reliability features	Time and flexibility sufficient to allow for planning	Plans must consider reliability; states can amend plans in the event of reliability challenges; safety valve

Note: the EPA provided information contained in the table shown above.

BSER Building Block Changes

- BSER BB1 Adjustments
  - Reviewed historical efficiency improvements by interconnection
    - 4.3% East
    - 2.3% ERCOT
    - 2.1% West
- BSER BB2 Adjustments
  - Reviewed historical on peak CC operation
    - Redispatch to 75% capacity factor (of "net summer capability" rather than nameplate)
- BSER BB3 Adjustments
  - Renewable energy potential 28% of resource mix, up from 22%
- BSER BB4 removed

CO_2 Emission Goals

- New rate-based targets
  - Applied directly to EGUs by source category or,
  - State level weighted average of the source category rates based on each state's baseline generation mix
- EPA calculated mass-based targets
  - State level
  - Includes only existing EGUs or projected new generation

Goal Computation Overview

- **Step 1**
  - Compile 2012 unit-level data, aggregate to state-level, make baseline adjustments, and sum to regional baseline totals
- **Step 2**
  - Aggregate the adjusted historical emissions and generation to a regional level for coal steam, OG steam, and NGCC technology categories.
- **Step 3**
  - Identify category-specific baseline emission rates for fossil steam and NGCC

Goal Computation Overview

- **Step 4**
  - Calculate regional fossil steam emission rate resulting from building block 1 heat rate improvement (HRI)
- **Step 5**
  - Calculate regional fossil steam and NGCC generation levels resulting from building block 3 (incremental RE generation)
- **Step 6**
  - Calculate regional fossil steam and NGCC generation resulting from building block 2 (incremental NGCC generation)

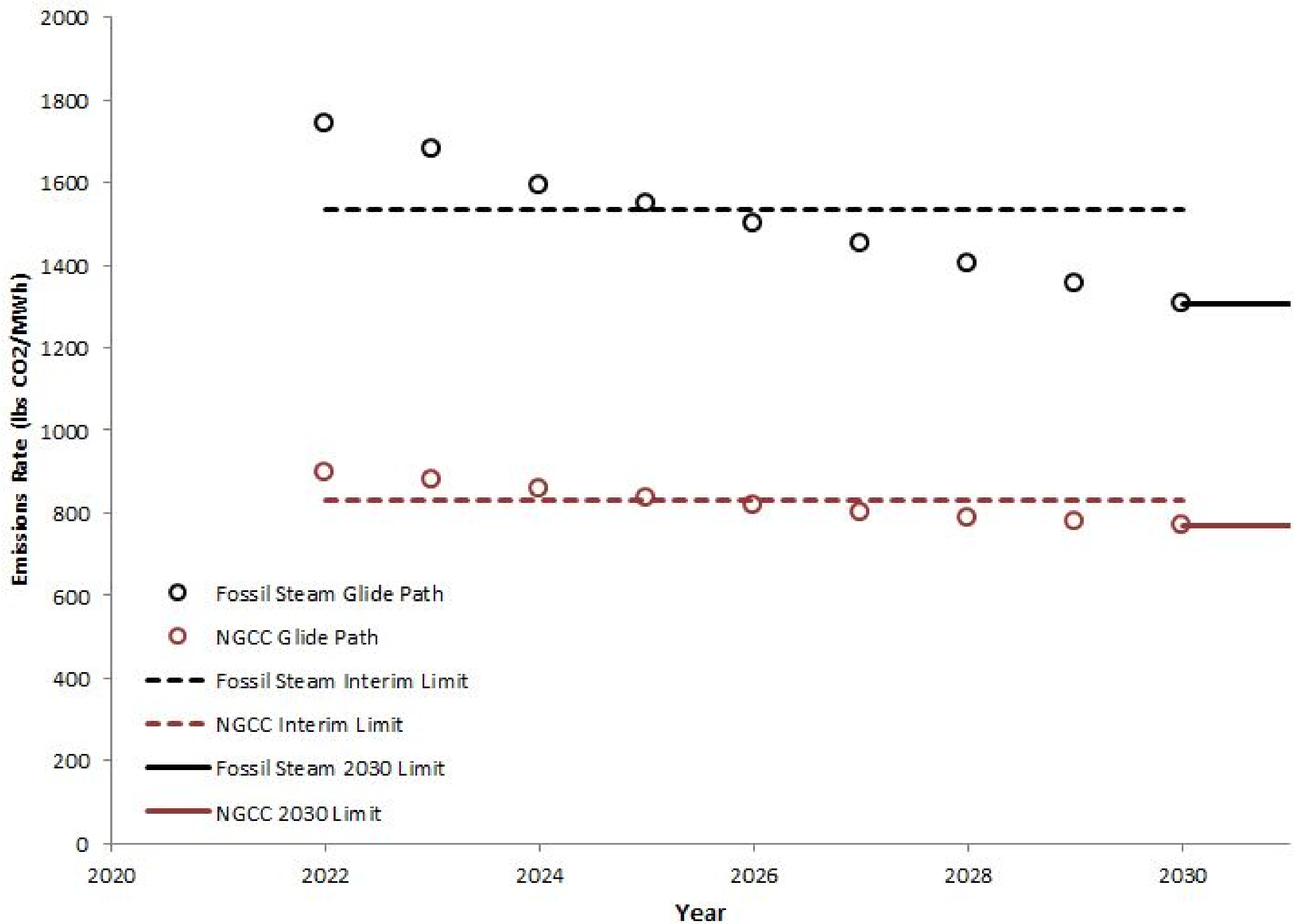
Goal Computation Overview

- **Step 7**
  - Determine the adjusted category-specific performance rates for each region reflecting the heat rate improvement and generation shifts
- **Step 8**
  - Identify the least stringent regional rate as the emission performance rate for the technology source category
- **Step 9**
  - Calculate weighted average of the source category rates based on each state's baseline generation mix

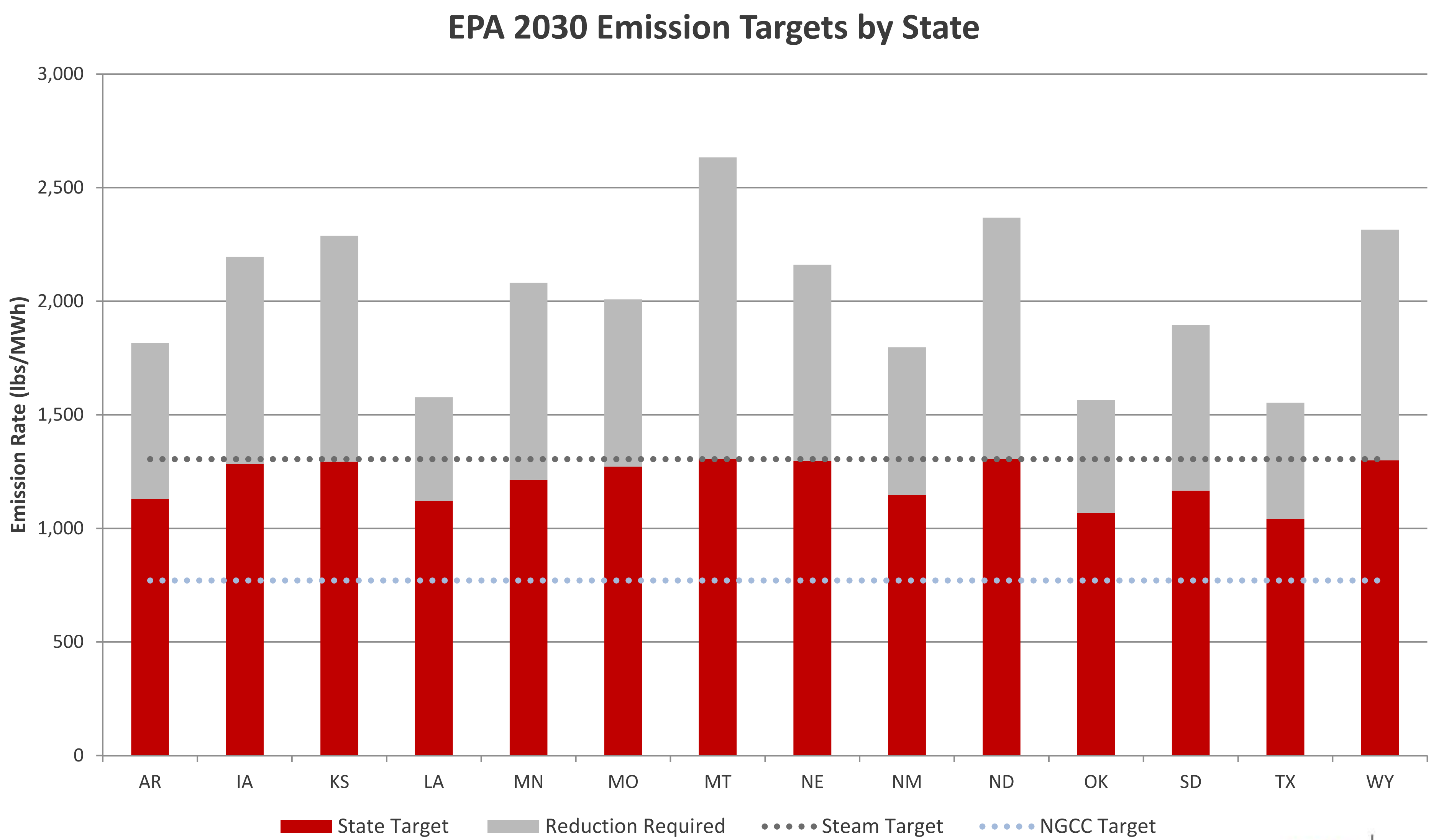
National Emission Goals by Generation Category

Affected EGU	Interim Rate (lbs/MWh)	Final Rate (lbs/MWh)
fossil fuel-fired steam generating unit (Coal/OG)	1,534	1,305
stationary combustion turbine (NGCC)	832	771

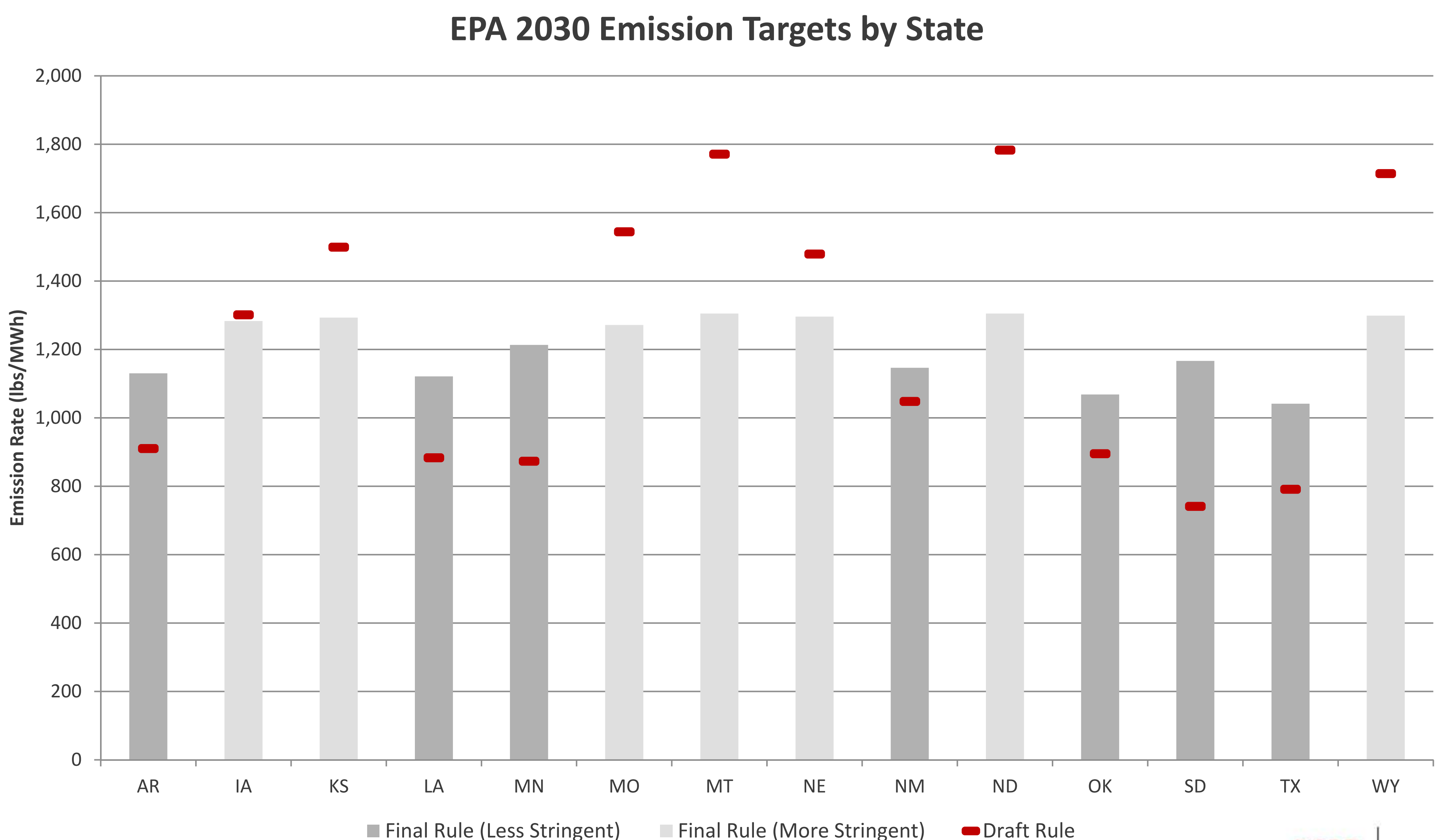
Affected EGU Glide Path



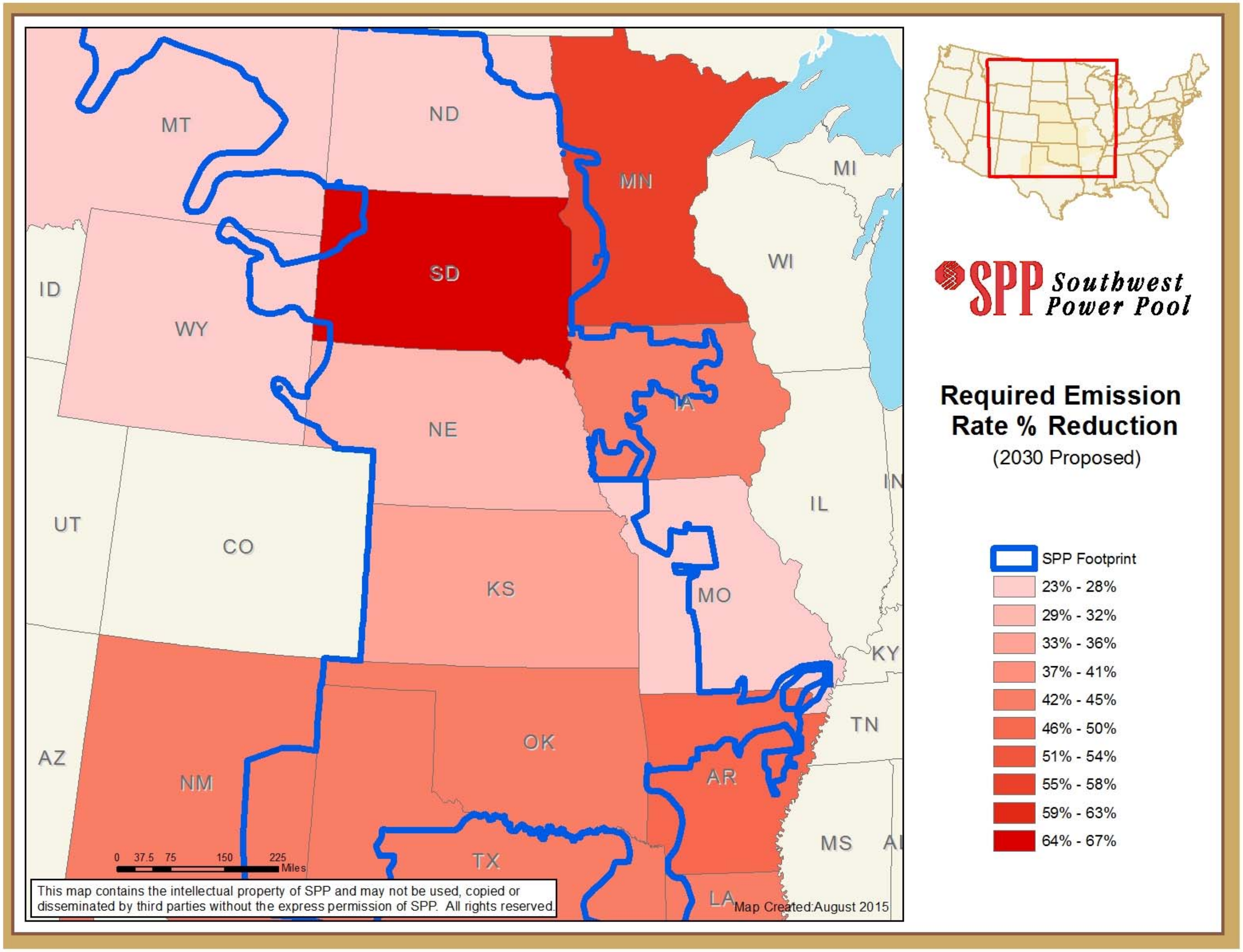
EPA 2030 Emission Targets – Final Rule



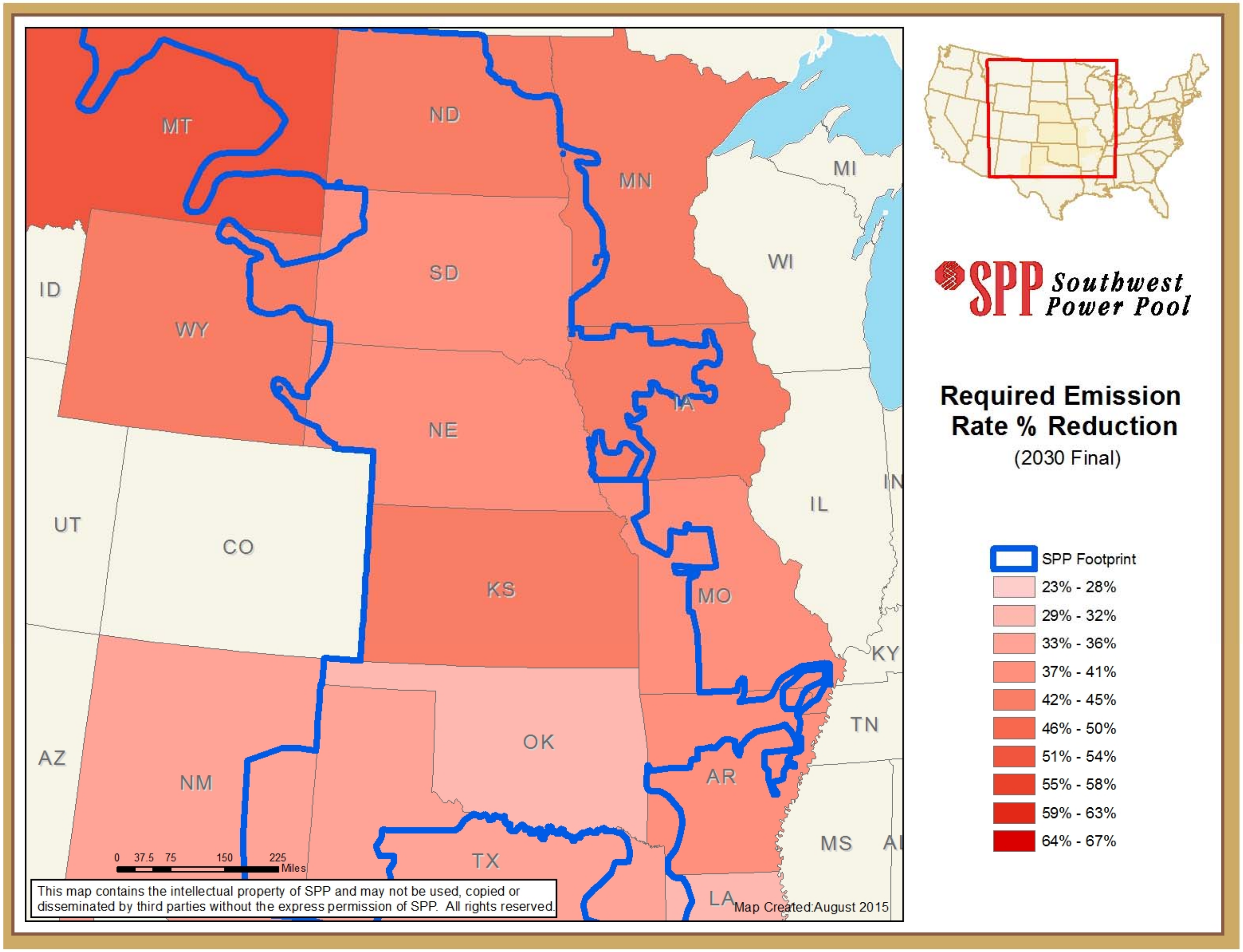
EPA 2030 Emission Targets – Rule Comparison



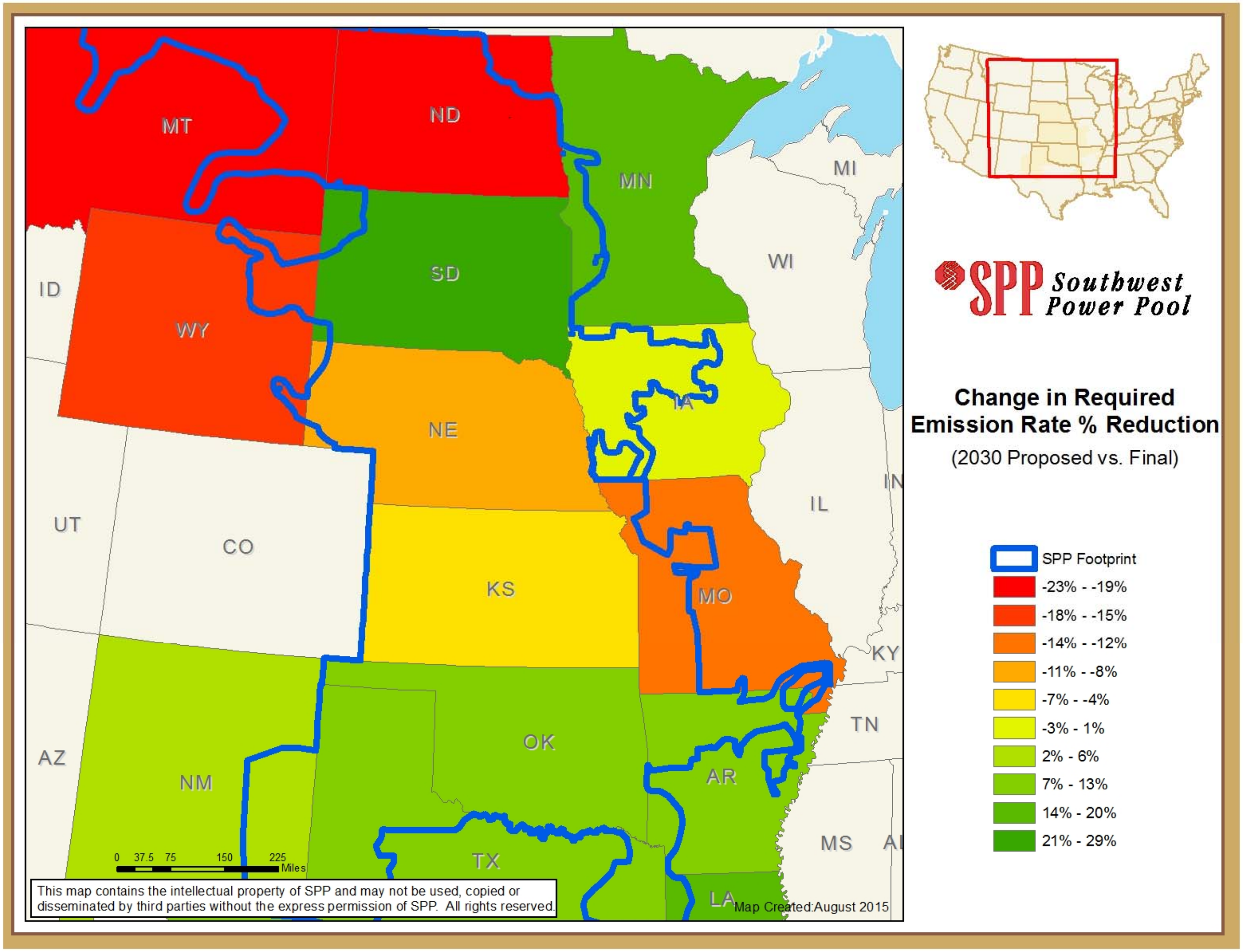
State Emission Rate Changes



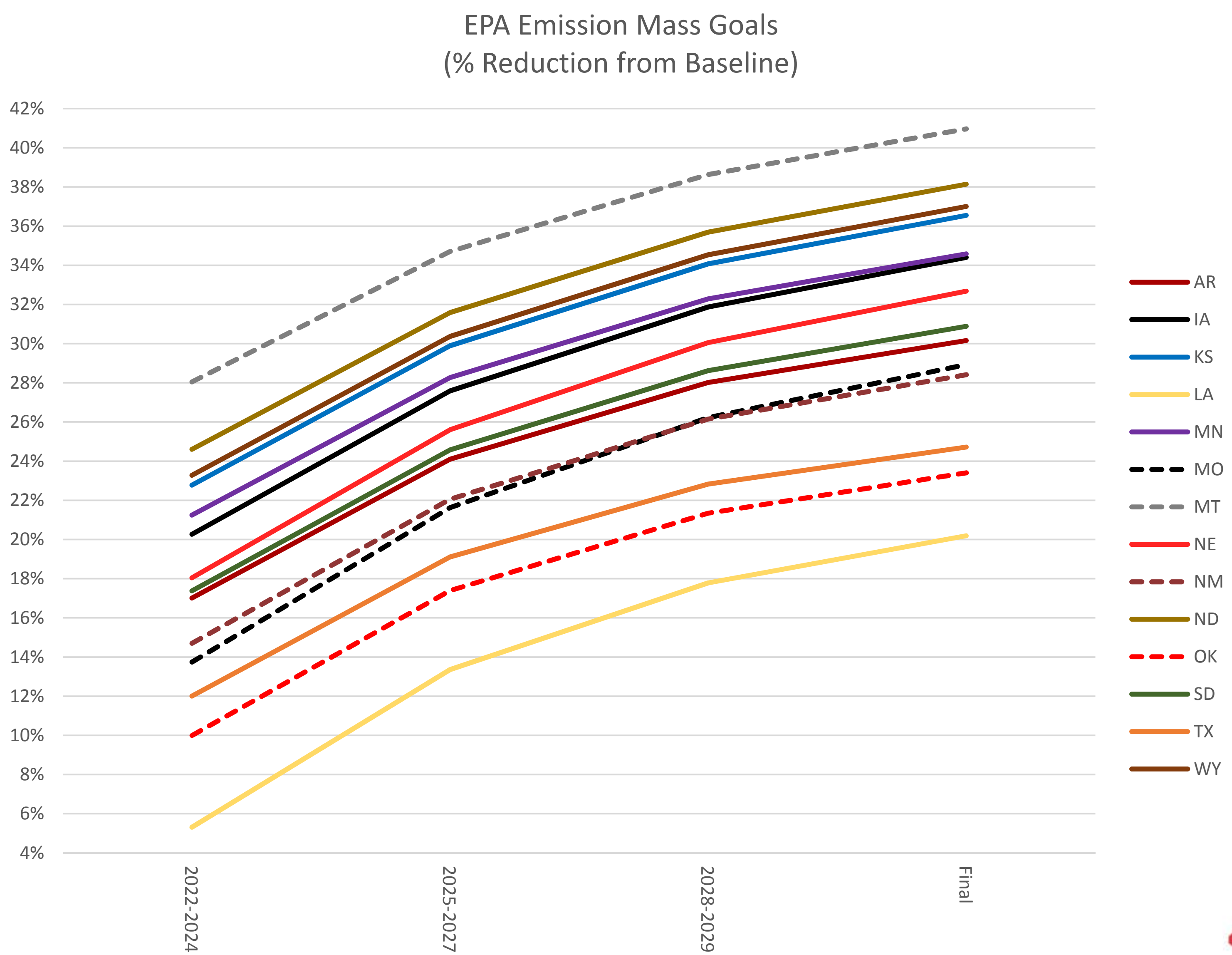
State Emission Rate Changes



State Emission Rate Changes



EPA 2030 Emission Mass Goals



State Options

- Rate- vs Mass-based goals
- Emission Standards or “state measures”
  - Source specific standards vs. state weighted average
- Only existing EGUs vs. include new
- Emissions trading proposal
  - Cap & Trade vs. CO_2 tax
- Federal Implementation Plan

Draft Federal Plan

- EPA has proposed a federal plan that would be imposed if a state does not submit an approvable plan
- EPA will accept comments over a 90-day period after publication, expect to finalize in 1 year
- Proposing two options from which one will be selected in final plan
  - Rate-based carbon trading
  - Mass-based carbon trading
- Also proposing model trading rules that could be used in rate-based and mass-based state plans
  - To be finalized early next summer

APPENDIX

Affected EGUs to be Addressed

- The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.
- (b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section...

Affected EGUs to be Addressed

- (1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity);
- (2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and
- (3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine

Clean Energy Incentive Program (CEIP)

- **Incentivize investment in certain Renewable Energy (RE) and demand-side Energy Efficiency (EE) projects**
  - Credit given to MWh generated (RE) and reduction of end-use energy demand (EE) during 2020 and or 2021
  - EPA will provide matching allowances or Emission Rate Credits (ERCs) to states that participate in the CEIP, up to an amount equal to the equivalent of 300 million short tons of CO_2 emissions
  - Wind or solar projects will receive 1 credit for 1 MWh of generation
  - Demand-side EE projects implemented in low-income communities will receive 2 credits for 1 MWh of avoided generation
- **Additional flexibility to facilitate achievement of CO_2 emission reductions required by final rule**

Clean Energy Incentive Program (CEIP)

- Additional flexibility to facilitate achievement of CO_2 emission reductions required by final rule
  - States that choose mass-based compliance may draw CO_2 emission allowances from their 2022-2029 mass-based goal and award them to eligible projects that achieve reductions in 2020 and/or 2021
  - States that choose rate-based compliance may "borrow" from the pool of ERCs they will issue during the 2022-2029 performance period and award them to eligible projects that achieve reductions in 2020 and/or 2021

Two-Rate Approach

- *The "two-rate" approach.* First, states can choose to write plans that adopt the two national emission performance rates as *enforceable limits* on their coal and gas plants.
- Under this approach, each plant needs to meet the applicable enforceable emissions rate limit through a combination of reducing its own emissions rate and investing in emission reducing actions at other locations in the power system, either in the same state or elsewhere in the country.

One-Rate Approach

- As a second option, the Clean Power Plan establishes state-specific emission rate limits. These state-specific limits are a blend of the national emission rate limits for coal and gas plants, weighted to reflect the mix of electricity generated from the two types of plants in each state at the starting point in 2012.
- As in the two-rate approach, each power plant uses a combination of its own actions and emission rate credits to meet the applicable state-specific emission rate limit.

Mass Based Differences

- Under a mass-based approach, the state issues *emission allowances* equal to the number of tons of emissions allowed in the state. Each coal or gas plant needs one emission allowance for each ton of CO_2 that it emits. The cost of allowances then figures into decisions about which plants to operate and encourages a shift to lower- or zero-emitting power. States can decide whether to auction the allowances (using the proceeds for renewables and efficiency programs or customer rebates) or to distribute them by other means.

RCAR II Modeling Discussion

August 27th, 2015

Josh Ross

Southwest Power Pool

TRAPPED GENERATION POCKETS

Trapped Generation Pockets Approaches

- Option 1a: Status Quo
  - Producing problematic zonal APC results with base case that is transmission deficient
- Option 1b: Move Wind to Zonal Load Centers
- Option 1c: Remove Wind
- Option 1d: Hybrid Approach
- Option 1e: Incremental Approach

- <u>Today</u>: Staff and ABB thoughts and recommendations on approaches, get input from stakeholders

Option 1b: Move Wind to Zonal Load Centers

Wind that is dependent on the HWBW transmission is moved the host zone's largest load center (~5.0 GW). Same capacity, but decreased capacity factors.

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Logic behind the approach is technically sound.
  - Wind would not be developed at these sites if not for the HWBW transmission
  - Zones would still need to meet their public policy mandates/goals, and this allows that to happen
- Generation assumptions are consistent between base and change cases (except for siting), as installed capacity is equal between the two

Cons:

- Moderate complexity in determining where to locate the wind at load centers, and vet
  - Sited such that new congestion at the load center is minimal or avoided; add close to load, and divide into smaller units if needed
- Could mask expected base case congestion due to power flowing into a load center (although we're not noticing this in test results)

Option 1c: Remove Wind

Wind that is dependent on the HWBW transmission is removed from the base case model (~5.0 GW).

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Logic behind the approach is somewhat technically sound
  - Wind would not be developed at these sites if not for the HWBW transmission
  - However, ignores that wind (or other generation) might be added elsewhere instead
- Easy to implement

Cons:

- Simply adding cheap capacity in the change case can overstate benefit
- Inconsistent generation assumptions between base and change cases can capture more than just the benefit of the new transmission

Option 1d: Hybrid Approach

Regional benefit = Regional benefit of **Status Quo**

Zonal allocation factors = Zonal allocation factors of **Remove Wind** approach

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Easy to implement

Cons:

- Zonal benefits calculation is still problematic
  - Example on next slide
- Mixing approaches/mixing results can produce unexpected and problematic final results (ABB)

Option 1d: Hybrid Approach Example

	Status Quo	Remove Wind	Hybrid*
Regional Benefit ($M)	$100	$500	$100
Zone A Benefit ($M)	$20	$100	$20
Zone B Benefit ($M)	($10)	$40	$8
Zone C Benefit ($M)	$50	$50	$10

$^{*}\text{Hybrid}_{\text{zone X}} = \text{Status Quo}_{\text{regional}} * (\text{Remove Wind}_{\text{zone X}} / \text{Remove Wind}_{\text{regional}})$

- Numbers are made up for example purposes
- Zone A – Benefit is not any more or less reasonable with hybrid approach vs. status quo
- Zone B – Representative of zone in a trapped generation pocket. Benefit is more reasonable with hybrid approach vs. status quo
- Zone C – Nowhere near any of the trapped generation or wind that is removed. **Their benefit is less reasonable with hybrid approach (should be ~$50M).**

Option 1e: Incremental Approach

Isolate the projects creating the trapped generation pocket ("wind" projects); measure the benefit of these projects separately from the rest of the projects, and add up the incremental benefits.

Pros:

- Avoids use of a true base case with the large LMP differentials, yet still designed to capture benefits of all projects

Cons:

- The LMP differentials still crop up when isolating the just "wind" projects
  - **Does not fix the problem with the Status Quo**
- Complex implementation
- Mixing approaches/mixing results can produce unexpected and problematic final results (ABB)

ABB Feedback

- Option 1b and 1c are the most reasonable
  - Option 1b preferable because zones could still meet renewable mandates/goals
- Option 1d and 1e are less reasonable
  - Combining approaches, or combining results from different runs to determine benefits, is asking for trouble, and can lead to final results that are less sound

Recommendation

- Staff recommends Option 1b: Move Wind to Zonal Load Centers for addressing the Trapped Generation Pockets Issue
  - Addresses the issue
  - Most technically sound alternative

LOAD POCKETS

Load Pockets Approaches

- Option 2a: Status Quo
  - Results in excessive emergency gen, breaching constraints in base case, leading to inflated APC benefit
- Option 2b: Add load pocket upgrades to base case
- Option 2c: Add CTs in base case
- Option 2d: Add CTs in base case, include capital costs
- Option 2e: Add CTs and CCs in base case
- Option 2f: Add single resource to load pocket, distributed proportionally among load buses

- Today: Staff and ABB thoughts and recommendation, get input from stakeholders

Option 2b: Add load pocket upgrades to base case

These upgrades would be in base and change cases.

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Easy to implement
- Consistent generation assumptions between base and change cases

Cons:

- Understates benefit - ignores any economic benefit of the load pocket upgrades
  - In this case, all load pocket upgrades are classified as reliability

Option 2c: Add CTs in base case

Add CT resources in the load pocket for the base case only

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
- Shows the load pocket upgrades having some economic benefit, which is expected

Cons:

- Inconsistent generation assumptions between base and change cases

Option 2d: Add CTs in base case, include capital costs

Add CT resources in the load pocket for the base case only, include the capital costs of these resources as an adder to the base case APC

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
- Shows the load pocket upgrades having some economic benefit, which is expected
- Accounts for capital costs of new resources that would be needed in theoretical base case scenario

Cons:

- Inconsistent generation assumptions between base and change cases
- Complexity
- Mixing capital costs in with APC calculation can be tricky – it is expanding the scope of what APC benefit was intended to capture

Option 2e: Add CTs and CCs in base case

Add CT and CC resources in the load pocket for the base case only

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
  - Real-world situation could include some mix of CCs/CTs
- Shows the load pocket upgrades having some economic benefit, which is expected

Cons:

- Inconsistent generation assumptions between base and change cases
- Adding lower cost CCs to load pocket could mask some of the economic benefit to be gained by new load pocket upgrades
- Increased complexity in determining how many CCs vs CTs to add, and vetting
- Doesn't account for CCs being less likely additions because of higher capital costs

Option 2f: Add single resource to load pocket, distributed proportionally among load buses

This was an idea from ABB. Distribution of resource based on magnitude of individual loads. Resource would have no fuel, emissions, or hourly profile, but just a VOM = curtailment price = $X.

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Shows the load pocket upgrades having some economic benefit, which is expected
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load. This is more of a modeling technique than a real-world implementation, but it effectively models new generation and the associated production costs.
- Slightly better control of the "trigger price" for new generation dispatch

Cons:

- Inconsistent generation assumptions between base and change cases
- Need to determine what X is (not too high, not too low)

Recommendation

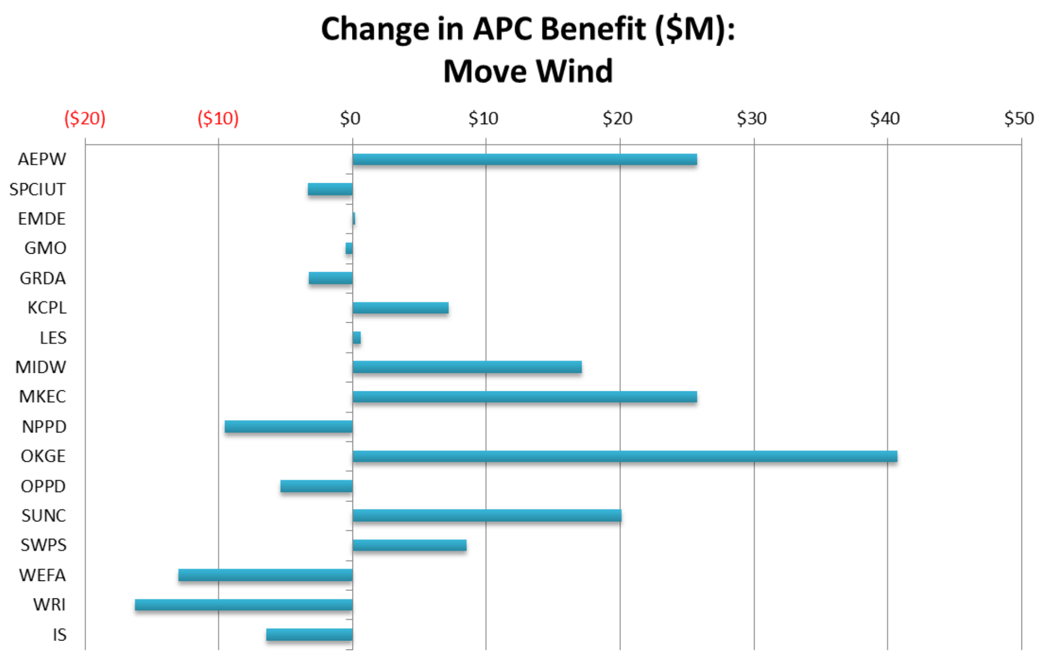
- Staff recommends Option 2c: Add CTs in base case for addressing the Load Pockets issue
  - Technically sound
  - Reasonable results – don’t appear too high or too low
  - Previously approved by ESWG
  - Option 2f (single resource) is a close second

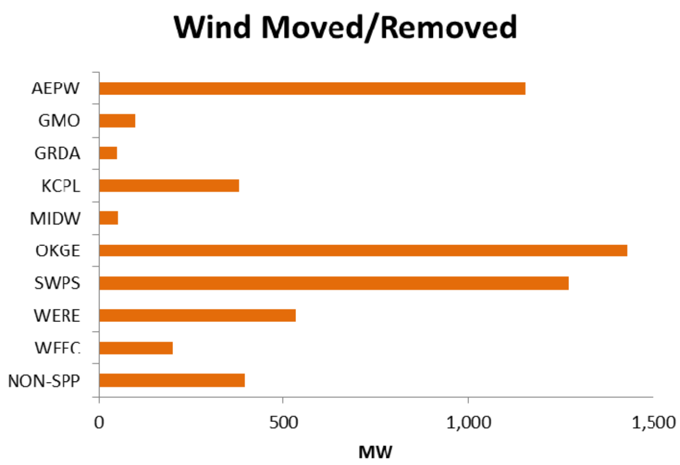
Next Steps

- Staff would like to finalize approaches to these modeling issues by October 22
  - November 18 is drop dead date

APPENDIX

Option 1b: Move Wind to Zonal Load Centers

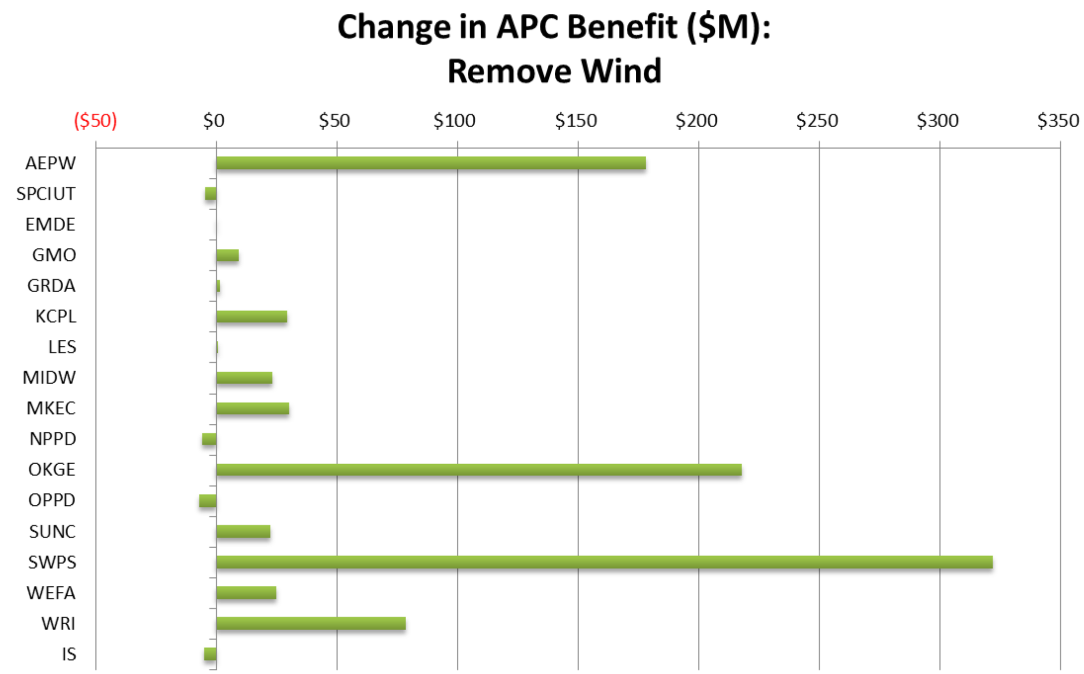


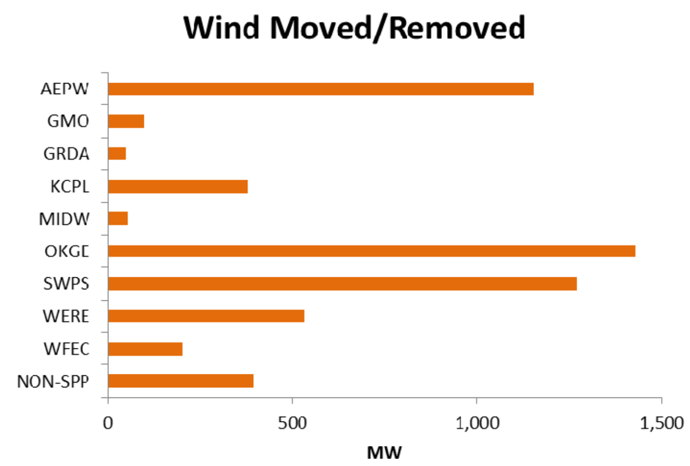


Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Option 1c: Remove Wind

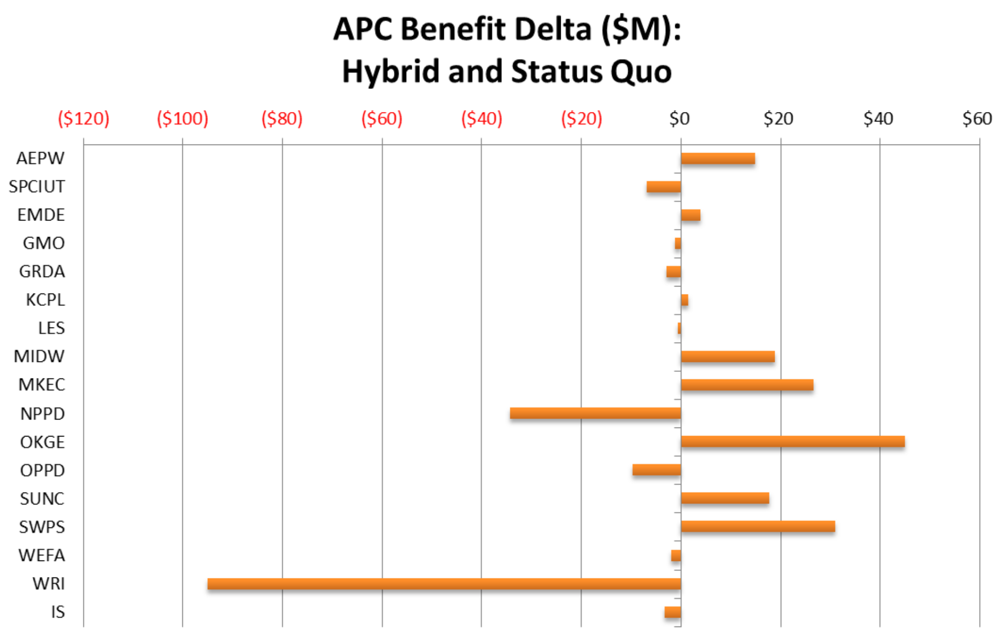


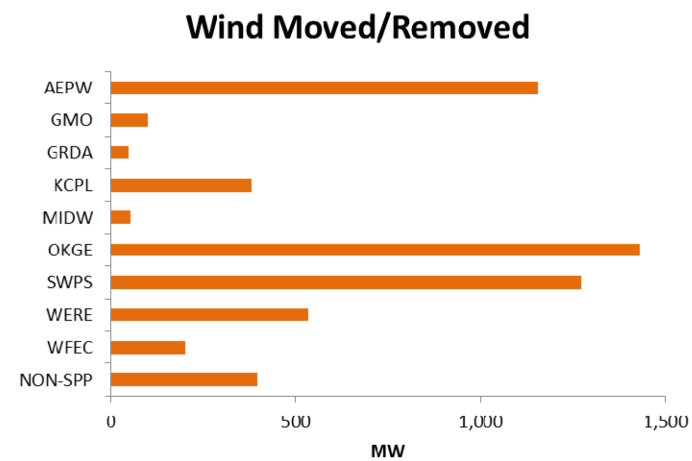


Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Option 1d: Hybrid Approach

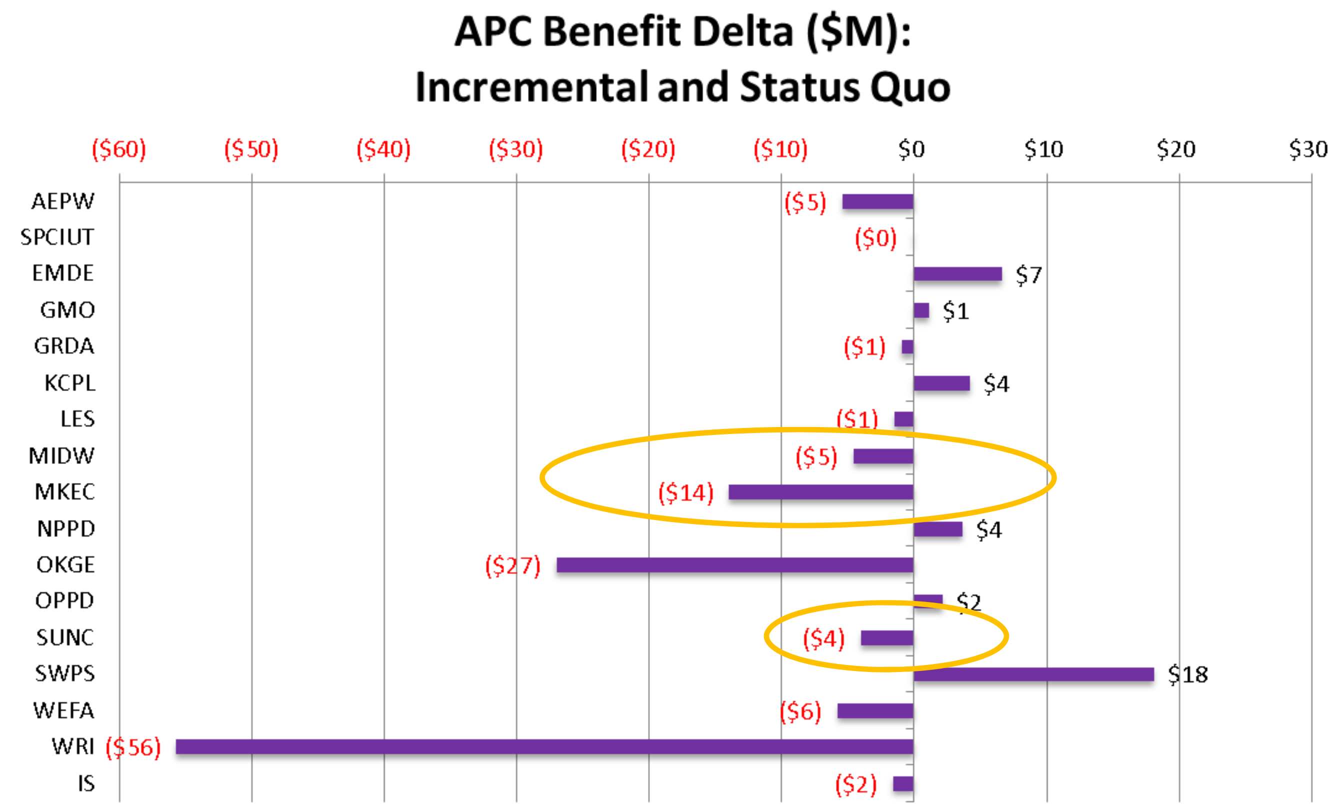




Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Option 1e: Incremental Approach



Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Load Pocket Solutions

- Options 2c and 2d effectively address the emergency generation and breaching constraint problems