US Solar & Alternative Energy

Distilling the Essence of the Clean Power Plan (Incl Conf Call Transcript)

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We provide a deep dive summary of EPA's final CPP regulations

We held our latest conference call at Crowell & Moring to analyze the nuances in the EPA's Final CPP Rules, designed to regulate both new and existing sources of carbon emissions. The final rules would provide for a 32% reduction off 2005 levels by 2030 (vs. 30% previously), with interim targets beginning in 2022 (28% reduction by 2025). States must submit final Statement Implementation Plans (SIPs) back to EPA by Sept, 2018. While there is likely a long period of legal uncertainty ahead, we see this as the most substantial development in the sector YTD, providing an inflection point in the sector's capex outlook, particularly for (vertically integrated) regulated utilities.

Who wins? Renewables first-and-foremost, followed by gas

Among the clearest beneficiaries of the regulations are renewables, with the final plan implying ~28% of the overall generation mix by 2030; vs. ~22% in the proposed plan, supported by the creation of the Clean Energy Incentive Plan (CEIP) and of ~300mn tons of Emission Rate Credits (ERCs) which would be given for early adoption of renewables (generated in 2020-2021 period). While other sources of reductions (outside of the electric sector) will likely be found to cost-effectively address reductions, the EPA's initial projections suggest a wide range, with modeling supporting 2GW/yr, and building block reconciliation suggesting much more (~90TWh/yr). Bottom line, this is the most important driver for states to 'double-down' on RPS targets.

Gas to gain substantial market share with target for 75% capacity factor

The second basis for the regulations aims to increase CCGT utilization up to 75%, up from the mid-40s in recent years. While meaningful increases in generation should be positive for gas generation, this is seemingly most constructive for gas demand and midstream opportunities to deliver incremental gas to plants. We see the 'pull' for pipelines as complementing years of E&P sponsored push-oriented projects.

Possible dis-incentive for renewables from 2017-2020 in case states delay SIP

In the near-term, early action installations only begin to earn double credits for projects generating in 2020-2021 even if in-service after SIP is filed, suggesting this may actually slow installations for 2017-18. We suspect this may well garner greater attention in the near-term as states advocate for earlier credit on renewables installed after SIP is filed.

Incentivizing cap-and-trade solutions: pushing for a mass-based approach

The final CPP rules provide a clear incentivize for states to adopt a 'mass-based' solution, which is effectively a single reduction target statewide – and critical to driving states towards a state-based cap-and-trade emission scheme (and ultimately likely regional in nature via RTOs and other regional power organizations). While the EPA does not appear to have the legal authority to mandate a mass-based program, the scheme does clearly afford greater latitude and incentivize states to pursue such a program; expect this to feature prominently in litigation. The initial scheme had contemplated a rate-base scheme, with separate emission thresholds for new and existing units. The significant hole is that new plants could conceivably be built to reduce existing emissions. Importantly, adopting a mass based program allows states to adjust interim targets and allows states to take advantage of early reductions (CEIP). Bottom line, mass-based appears the new qui-pro-quo on states adopting the program.

For more please also see our CPP preview note from last Monday

How does the final plan treat nuclear? Bit of a mixed bag in the final plan

Although the EPA in its final rules recognizes that nuclear plants under construction should count toward compliance (including increased output from uprates) when they are operating, they remain exempt from the goal-setting calculation; this provides 'upside' to states pursuing such projects.

However the final rule does not incorporate the carbon-abatement value of existing nuclear power plants. We think this places a substantial hurdle on states to allow further retirements to occur – and should help push EXC's argument for a nuclear legislative deal in Illinois to maintain the portfolio at least through CPP implementation in 2022 (scheme would be temporary from 2016-2021). The final rules also do not give credit for possible licence extensions for nuclear plants – this was an issue that the Nuclear Energy Institute (NEI) had brought up in its comments to the proposed plans. This further incentivizes states to pursue 'subsequent' relicensing of plants to 80-years from their current 60-year lives (likely a much bigger issue in 2020's).

Although EE is not a part of the building blocks; it counts towards compliance

According to the Clean Energy Incentive Program within the CPP, states can award emission rate credits and allowances to renewable energy or demand-side EE projects which can have an impact in 2020 and 2021, according to the final rule. Although we think EE will continue to be considered by the states as a part of their compliance plan, there might be a near term 'signaling' impact from the decision to bump EE off from the list of building blocks. Net-net, it would appear EPA couldn't legally back energy efficiency as a building block to arrive at reductions, rather than any inherent issues at EPA with the efficiency (we see this as likely the cheapest source of carbon reductions irrespective of legal technicality).

Safety valve: Adding an avenue for reliability? But narrowly defined.

Amidst widespread concerns from critics of the rule, EPA has adopted a 'safety valve' concept strictly for those specific units which are critical to reliability and cannot be addressed adequately through rate plans. We see this as strictly applying in the case in which states opt for rate-based approaches, rather than mass based programs which can allow for trading of emissions between plants (and target an overall level, rather than a unit specific requirement).

<u>Expect pressure to mount for a wider definition</u>

While EPA nominally allowed for this valve, critics had been arguing that FERC or RTOs be given wider authority over determining reliability impediments in implementation. While we suspect EPA (and state EPAs) will largely maintain their authority over the safety valve, we expect states to approach implementation with the same joint implementation between EPA and RTOs under MATS implementation.

Final rules 'equalize' the target' across states; tougher to hit for many

The final CPP regulations effectively narrow the final targets, loosening targets for those with the greatest reductions, while ratcheting up pressure on those with the least stringent initial demands such as Kentucky. See our state specific comparison of proposed and final targets.

How final is final: legal issues and litigations remain

Crowell & Moring highlighted that the legal questions surrounding the Clean Power Plan remain, even though the contours of the rule have changed; and the key question is whether regulation of coal-fired EGUs barred because of MATS and whether EPA promulgated the required predecessor Section 111(b) rule. We won't be surprised if some states consider waiting for the next administration before proceeding.

Will the rule pass judicial review?

According to Crowell, if this rule is invalidated by the courts, there will be no obligation by the states to submit SIPs, the rule either becomes dead or may have to be remanded to the agency for further proceedings and kept in place (like MATS recently). If, however, it passes all judicial review, then the subsequent administration will be somewhat bound by the terms of the rule as promulgated since it would have become law. Given the clearly 'activist' history of judicial review in the sector with nearly *every* major environmental market successfully challenged in one form or another in recent memory, the question remains *how* and *to what extent* judicial review will take place.

But how will states react?

We suspect implementation details will be key, as future EPA administrations will be responsible for accepting or rejecting specific State Implementation Plans (SIPs). Given the September 2018 timeframe for final acceptance of final programs, acceptance of specific state approaches will be left to be dictated by future administrations; as such, we see risk around overall dilution in the context of a Republican administration.

What about those states needing legislative authority?

We note the final EPA regulations make allusion to the potential need for legislative approval by certain states to achieve implementation. Given likely strong opposition in these states, we expect to hear in the near-term around which states expect to pursue legislative routes – and to what extent they provide meaningful roadblocks to any implementation.

High Level Summary: The Final CPP has stronger targets; but giving the states more time

The new existing-source rules announced by the EPA target power-sector emissions 32% below 2005 levels by 2030 vs 30% aimed in the previous version. Compared to the older version, it also pushes back the initial compliance deadline back two years to 2022 vs 2020 in the earlier version. The emission guidelines submitted with the plan today do not apply to the states of Alaska and Hawaii; and also not to Puerto Rico and Guam (EPA cites lack of data for this omission).

Essentially the CPP sets interim and final CO2 emission performance rates for states, and then the states need to develop, submit and implement (under EPA CPP guidelines) their *own* plans that establish standards of performance or other measures for affected generation units in order to implement the interim and final target rates set by the CPP.

Figure 1: High level summary of changes in Proposed vs Final CPP

	Proposals	Final
Compliance timeframe	2020	2022
Building Blocks	Four Building Blocks	Three Building Blocks (see next row) and refinements to 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 CO2 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.
Deadline for final state plan	September 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

Source: EPA

The ball is in the State's court

The States can either decide to place all requirements directly on impacted units and all requirements will be federally enforceable (*this is the Emission Standards Plan Type*) **<u>or</u>** the States can include a mix of measures that may apply to affected units – requirements on the units will be federally enforceable; other measures may be enforceable at the state level (*this is the State Measures Plan Type*). The EPA also says that states can chose other methods to comply such as demand-side EE, transmission upgrades, and nuclear and hydropower uprates in their state plans.

States need to submit their plans within 13 months

States are required to submit plans on the schedule required by this EPA action. The EPA states that the state plans must be submitted to the EPA in 2016, though an extension to 2018 is available to allow for the completion of stakeholder and administrative processes [we expect *most* states to pursue this avenue]. These plans must:

- ensure that the period for emission reductions from the affected EGUs begin no later than 2022
- show how goals for the interim and final periods will be met
- ensure that, during the period from 2022 to 2029, affected EGUs in the state collectively meet the equivalent of the interim subcategory-specific CO2 emission performance rates
- provide for periodic state-level demonstrations prior to and during the 2022-2029 period that will ensure required CO2 emission reductions are being accomplished and no increases in emissions relative to each state's planned emission reduction trajectory are occurring

Figure 2: State timings for plan submittal and interim goals

Submittals	Dates
State Plan OR initial submittal with extension request	September 6, 2016
Progress Update, for states with extensions	September 6, 2017
State Plan, for states with extensions	September 6, 2018
Milestone (Status) Report	July 1, 2021
Interim and Final Goal Periods1	Reporting
Interim goal performance period (2022-2029)	
- Interim Step 1 Period (2022-2024)	July 1, 2025
- Interim Step 2 Period (2025-2027)	July 1, 2028
- Interim Step 3 Period (2028-2029)	July 1, 2030
Interim Goal (2022-2029)	July 1, 2030
Final Goal (2030)	July 1, 2032 and every 2 years beyond

Source: EPA

The Devil is in the Details of course: looking under the Hood

Concentrating on the Supply side: EE removed from building block

The final plan does not include demand side energy efficiency (EE) as a building block; thus the final plan has just three building blocks as opposed to four in the proposed plan. Nuances within the three building blocks retained have also changed given latest data used. We understand the administration saw less legal authority in designating Energy Efficiency as a formal Best System of Emission

Reduction (BSER) as required under rule design. Despite the removal of EE, the final standard is actually more onerous.

- **Building block 1: Improved plant efficiency**. This essentially incorporates heat rate improvements which would imply lower CO2 per MWh. In the final plan this contributes 2.1-4.3% improvement (varies by region) vs. 6% improved efficiency at all coal and oil units in the proposed plans.
- **Building block 2: Shifting from coal to gas.** Calculations from this component in the final plan are based on 75% of net summer capacity to reflect actual operating conditions vs. 70% of nameplate capacity as assumed in the proposed plan.
- **Building block 3: Renewables addition.** The final plan considers higher renewables additions vs. proposed plan based on latest costs and trajectory for continued cost improvements for renewables. In the final plan this block does not include existing or under construction nuclear power or existing utility scale renewables.

Figure 3: EPA estimate for 2030 Building Block Potential*

	Heat Rate Improvement for Coal Fleet	TWh of Total NGCC Generation at 75 % Utilization, (Amount of NGCC Generation Potential Incremental to Baseline)	Incremental RE Potential (TWh)
Eastern Interconnection	4.3%	988, (253)	438
Western Interconnection	2.1%	306, (108)	161
Texas Interconnection	2.3%	204, (66)	107
Total			706

Source: EPA (* not all of the building block potential is utilized in establishing BSER category-specific rates and state goals)

In the final plan, rather than having a complicated calculation for each state based on their ability to implement each of these building blocks, the EPA took those building blocks into account in deriving two uniform emission rates - one that applies to coal-fired EGUs, and one that applies to natural gas - 1,305 pounds of CO2 per MWh for coal-fired EGUs, and 771 pounds of CO2 per MWh for natural gas.

Those rates apply uniformly to every unit of that type across the country. To calculate each state's goals, the EPA took the weighted average of emissions from the two types of EGUs. (the fossil fuel fired EGUs in each state); and applying those rates, the EPA calculated the overall weighted average rate for that state.

As a result of this methodology, the state targets, which had been widely divergent under the proposed rule, became more similar. We do a more detailed state by state analysis looking at changes b/w proposed and final plans in Figure 4 below.

Renewables gets a larger boost vs. proposed plan

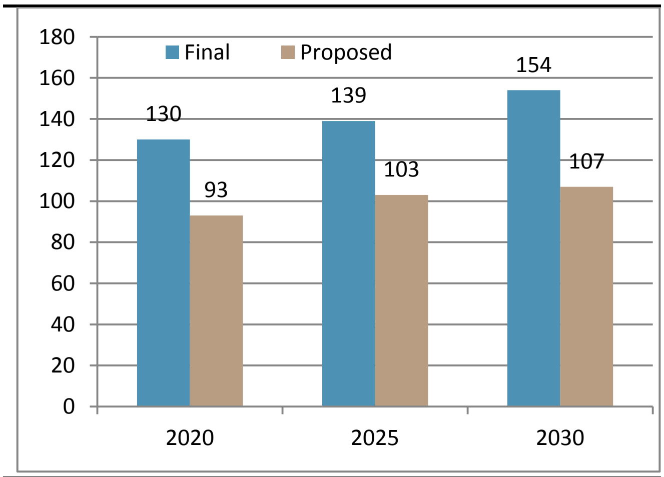
The final plan implies a larger share for renewables at ~28% of the overall generation mix by 2030; vs. that number being ~22% in the proposed plan. This is made possible also by the creation of the Clean Energy Incentive Plan (CEIP) and also the creation of ~300mn Emission Rate Credits (ERCs) which would be given for early adoption of renewables (mostly wind and solar).

Below we show the EPA's forecast incremental renewable increase associated with the mas goals. We show a more detailed breakup of the overall generation and capacity mix in the final plan (compared to what was in the proposed plan) later in this note.

In contrast to EPA's modeling renewable energy mandate suggests greater increase by quarter.

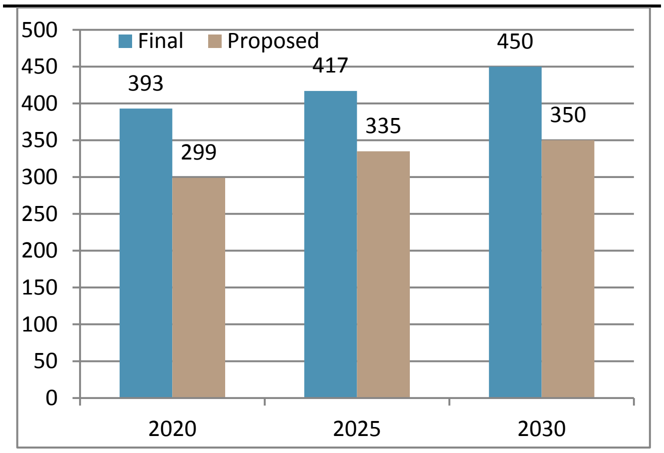
Looking at the renewable targets in aggregate, we initially estimate the annual ~90 TWh per annum increase targeted translates to roughly ~35 GW/yr of solar (such projections were reflected in the buildup of the Renewable Energy piece of building block 3 in EPA's enclosed XLS documentation). In contrast the final rule projects 2020 renewables at 393 TWh, climbing to 450 TWh by 2030, implying a substantially more modest pace of growth. This would translate to 293TWh through the decade, or ~20GW if entirely solar (more likely it will be split between wind and solar in respective regions), adding only modestly to the overall adoption of renewables. We remain generally more bullish than EPA's modeling of the renewable pie.

Figure 4: Non-hydro Renewables Installed Capacity (GW)



Source: EPA

Figure 5: Non-hydro Renewables Generation (GWh)



Source: EPA

But wait... modeling doesn't jive with the building block renewable projections provided

We also include below a state by state break out of what the EPA views as possible incremental renewable increase associated with the mass goals. We note that the numbers look aggressive; and give a sense of EPA's reliance now on the renewables building block. For context, ~90TWh would equate to roughly 35WG/yr of solar or ~20GW/yr of wind (or more likely, some mix of both).

Figure 6: Incremental RE Increase Associated with Mass Goals – Meaningful Increases via Building Block

GWh	2022	2023	2024	2025	2026	2027	2028	2029	2030
Alabama	3,482	3,326	3,408	3,763	4,071	4,160	4,837	5,505	6,095
Arkansas	1,672	1,597	1,637	1,807	1,955	1,998	2,323	2,644	2,927
Arizona	1,824	1,742	1,786	1,971	2,133	2,179	2,534	2,884	3,193
California	3,644	3,480	3,567	3,938	4,260	4,353	5,062	5,761	6,379
Colorado	1,587	1,516	1,554	1,715	1,856	1,896	2,205	2,510	2,778
Connecticut	550	526	539	595	644	658	765	870	964
Delaware	321	306	314	346	375	383	445	507	561
Florida	7,127	6,807	6,977	7,702	8,332	8,515	9,901	11,269	12,476
Fort Mojave	48	45	47	51	56	57	66	75	83
Georgia	2,753	2,630	2,695	2,975	3,219	3,289	3,825	4,353	4,820
Iowa	1,215	1,161	1,190	1,313	1,421	1,452	1,688	1,921	2,127
Idaho	121	115	118	130	141	144	168	191	211
Illinois	3,327	3,177	3,256	3,595	3,889	3,974	4,621	5,260	5,823
Indiana	3,819	3,647	3,738	4,127	4,464	4,562	5,305	6,038	6,684
Kansas	1,060	1,012	1,037	1,145	1,239	1,266	1,472	1,676	1,855
Kentucky	3,059	2,922	2,994	3,306	3,576	3,654	4,249	4,836	5,355
Louisiana	1,969	1,880	1,927	2,128	2,302	2,352	2,735	3,113	3,446
Massachusetts	915	874	896	989	1,070	1,093	1,271	1,447	1,602
Maryland	695	664	680	751	812	830	965	1,099	1,216
Maine	166	159	162	179	194	198	231	262	291
Michigan	2,535	2,421	2,482	2,740	2,964	3,029	3,522	4,009	4,438
Minnesota	1,165	1,113	1,140	1,259	1,362	1,392	1,618	1,842	2,039
Missouri	2,718	2,596	2,661	2,937	3,178	3,247	3,776	4,298	4,758
Mississippi	1,669	1,594	1,633	1,803	1,951	1,993	2,318	2,638	2,921
Montana	540	516	528	583	631	645	750	853	945
Navajo	1,036	990	1,014	1,120	1,212	1,238	1,440	1,639	1,814
North Carolina	2,813	2,687	2,754	3,040	3,289	3,361	3,908	4,448	4,925
North Dakota	997	953	976	1,078	1,166	1,191	1,385	1,577	1,746
Nebraska	879	839	860	950	1,027	1,050	1,221	1,389	1,538
New Hampshire	290	277	284	314	339	347	403	459	508
New Jersey	1,275	1,217	1,248	1,377	1,490	1,523	1,771	2,015	2,231
New Mexico	675	645	661	729	789	806	937	1,067	1,181
Nevada	986	942	965	1,066	1,153	1,178	1,370	1,559	1,726
New York	2,123	2,028	2,078	2,294	2,482	2,536	2,949	3,357	3,716
Ohio	3,862	3,689	3,780	4,173	4,515	4,614	5,365	6,106	6,760
Oklahoma	2,362	2,256	2,312	2,553	2,761	2,822	3,281	3,735	4,135
Oregon	581	555	568	628	679	694	807	918	1,017
Pennsylvania	5,111	4,882	5,003	5,523	5,975	6,106	7,100	8,082	8,947
Rhode Island	285	272	279	308	333	340	396	450	498
South Carolina	1,402	1,339	1,372	1,515	1,639	1,675	1,948	2,217	2,454
South Dakota	189	181	185	204	221	226	263	299	331
Tennessee	1,459	1,393	1,428	1,576	1,705	1,743	2,026	2,306	2,554
Texas	11,344	10,835	11,104	12,259	13,262	13,553	15,759	17,937	19,858
Ute	108	103	106	117	126	129	150	171	189
Utah	1,257	1,201	1,230	1,358	1,470	1,502	1,746	1,987	2,200
Virginia	1,829	1,747	1,791	1,977	2,139	2,186	2,541	2,893	3,203
Washington	681	650	666	736	796	813	946	1,076	1,192
Wisconsin	1,483	1,417	1,452	1,603	1,734	1,772	2,060	2,345	2,596
West Virginia	2,451	2,341	2,399	2,649	2,865	2,928	3,405	3,875	4,291
Wyoming	1,518	1,450	1,486	1,640	1,774	1,813	2,108	2,400	2,657
Total	94,976	90,713	92,966	102,634	111,034	113,468	131,937	150,168	166,255

Source: EPA

Disincentive for renewables between 2017-20?

This is likely to feature significantly in the timeline for future renewable procurement

Because the plan does not give credit to renewables coming on line before 2020 towards meeting state targets, we think this may create a disincentive for renewables in the window b/w 2017-20 for projects brought online *after* the SIP submission; they only generate 'early action' credits in 2020-2021. While eligible projects begin once the state SIP is filed (creating incentive to file sooner), it still only generates credits in that 2-year initial window from 2020-2021.

The Clean Energy Incentive Program (CEIP) comes into play under mass based (which is more of a cap and trade's approach); here EGUs would be allocated or allowed to purchase, allowances up to their identified budgets, and they could either free up allowances through investments in clean energy or, alternately, they could purchase what are being called CEIP offset credits which are renewable allowances. Further, the CEIP program is capped at 300 Mn tons.

On the rate base side, EPA allows projects that were "implemented after 2012," to be counted and generate ERCs – but only generate those ERCs during the compliance period. So, according to the Crowell & Moring team, zero carbon and gas units would be able to sell ERCs that would be allocated to them for future compliance during the compliance periods; or if a state chooses to alter the compliance period to allow for greater banking and borrowing to sell those ERCs under the state plans.

We suspect the early action element of the program will garner more meaningful attention in the medium term, as utilities attempting to comply with the regulations push to maximize their early action credit programs – and align these programs with their near-term capex budgets. We flag such comments from Dominion already as its primary initial reaction to the program.

Summarizing the final State targets vs. draft targets

Below we show a state by state breakup for the targets under the new finalized CPP vs. the older version released in 2014. We also compare what these targets imply for the states when compared to their actual 2012 emission levels – both for the interim targets and the final targets. We note that several states the reductions from 2012 levels are actually lower now when compared to the old targets.

The keys states which we highlight where the new targets imply larger cuts from 2012 now are Illinois, Missouri, Ohio, Kansas amongst others. In contrast states that are meaningfully better off are those with the lowest carbon intensities to begin with, including California, Oregon, Washington, Idaho, and Maine among others.

Figure 7: New EPA target vs. 2014 targets for States (lbs/MWh)

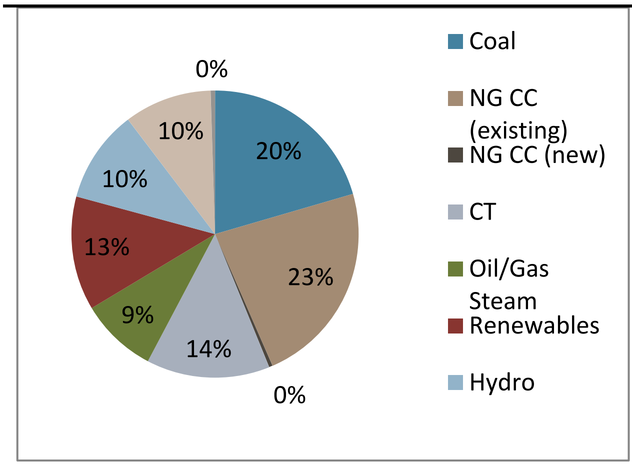
State Goals (lbs/MWh)		New (32% below 2005 levels by 2030)		Old (30% below 2005 levels by 2030)		% Change in Interim Target		% Change in Final Target		States in red need a higher reduction from 2012 levels in the new plan vs. old plan	
State	2012 (lbs/MWh)	Interim (2022-2029)	Final (2030+)	Interim (2020-2029)	Final (2030+)	Reduction from 2012 as per New Target (A)	Reduction from 2012 as per Old Target (B)	Reduction from 2012 as per New Target (C)	Reduction from 2012 as per Old Target (D)	Interim Plan Delta (A)-(B)	Final Plan Delta (C)-(D)
Alabama	1,518	1,157	1,018	1,147	1,059	-24%	-24%	-33%	-30%	1%	-3%
Alaska	1368			1,097	1,003		-20%		-27%		
Arizona	1,551	1,173	1,031	735	702	-24%	-53%	-34%	-55%	28%	21%
Arkansas	1,722	1,304	1,130	968	910	-24%	-44%	-34%	-47%	20%	13%
California	900	907	828	556	537	1%	-38%	-8%	-40%	39%	32%
Colorado	1959	1362	1174	1,159	1,108	-30%	-41%	-40%	-43%	10%	3%
Connecticut	844	852	786	597	540	1%	-29%	-7%	-36%	30%	29%
Delaware	1,255	1,023	916	913	841	-18%	-27%	-27%	-33%	9%	6%
Florida	1,238	1,026	919	794	740	-17%	-36%	-26%	-40%	19%	14%
Georgia	1598	1198	1049	891	834	-25%	-44%	-34%	-48%	19%	13%
Hawaii	1,783			1,378	1,306		-23%		-27%		
Idaho	858	832	771	244	228	-3%	-72%	-10%	-73%	69%	63%
Illinois	2,189	1,456	1,245	1,366	1,271	-33%	-38%	-43%	-42%	4%	-1%
Indiana	1991	1451	1242	1,607	1,531	-27%	-19%	-38%	-23%	-8%	-15%
Iowa	2,197	1,505	1,283	1,341	1,301	-31%	-39%	-42%	-41%	7%	-1%
Kansas	2,320	1,519	1,293	1,578	1,499	-35%	-32%	-44%	-35%	-3%	-9%
Kentucky	2,166	1,509	1,286	1,844	1,763	-30%	-15%	-41%	-19%	-15%	-22%
Louisiana	1533	1293	1121	948	883	-16%	-38%	-27%	-42%	23%	16%
Maine	873	842	779	393	378	-4%	-55%	-11%	-57%	51%	46%
Maryland	2,029	1,510	1,287	1,347	1,187	-26%	-34%	-37%	-41%	8%	5%
Massachusetts	1,001	902	824	655	576	-10%	-35%	-18%	-42%	25%	25%
Michigan	1814	1355	1169	1,227	1,161	-25%	-32%	-36%	-36%	7%	0%
Minnesota	2,013	1,414	1,213	911	873	-30%	-55%	-40%	-57%	25%	17%
Mississippi	1,140	1,061	945	732	692	-7%	-36%	-17%	-39%	29%	22%
Missouri	2,010	1,490	1,272	1,621	1,544	-26%	-19%	-37%	-23%	-7%	-14%
Montana	2439	1534	1305	1,882	1,771	-37%	-23%	-46%	-27%	-14%	-19%
Nebraska	2,162	1,522	1,296	1,596	1,479	-30%	-26%	-40%	-32%	-3%	-8%
Nevada	1,091	942	855	697	647	-14%	-36%	-22%	-41%	22%	19%
New Hampshire	1,119	947	858	546	486	-15%	-51%	-23%	-57%	36%	33%
New Jersey	1035	885	812	647	531	-14%	-37%	-22%	-49%	23%	27%
New Mexico	1,798	1,325	1,146	1,107	1,048	-26%	-38%	-36%	-42%	12%	5%
New York	1,096	1,025	918	635	549	-6%	-42%	-16%	-50%	36%	34%
North Carolina	1,772	1,311	1,136	1,077	992	-26%	-39%	-36%	-44%	13%	8%
North Dakota	2368	1534	1305	1,817	1,783	-35%	-23%	-45%	-25%	-12%	-20%
Ohio	1,897	1,383	1,190	1,452	1,338	-27%	-23%	-37%	-29%	-4%	-8%
Oklahoma	1,562	1,223	1,068	931	895	-22%	-40%	-32%	-43%	19%	11%
Oregon	1,081	964	871	407	372	-11%	-62%	-19%	-66%	52%	46%
Pennsylvania	1627	1258	1095	1,179	1,052	-23%	-28%	-33%	-35%	5%	3%
Rhode Island	918	832	771	822	782	-9%	-10%	-16%	-15%	1%	-1%
South Carolina	1,791	1,338	1,156	840	772	-25%	-53%	-35%	-57%	28%	21%
South Dakota	2,256	1,352	1,167	800	741	-40%	-65%	-48%	-67%	24%	19%
Tennessee	2015	1411	1211	1,354	1,163	-30%	-33%	-40%	-42%	3%	2%
Texas	1,420	1,188	1,042	853	791	-16%	-40%	-27%	-44%	24%	18%
Utah	1,874	1,368	1,179	1,378	1,322	-27%	-26%	-37%	-29%	-1%	-8%
Virginia	1,438	1,047	934	884	810	-27%	-39%	-35%	-44%	11%	9%
Washington	1379	1111	983	264	215	-19%	-81%	-29%	-84%	61%	56%
West Virginia	2,056	1,534	1,305	1,748	1,620	-25%	-15%	-37%	-21%	-10%	-15%
Wisconsin	1,988	1,364	1,176	1,281	1,203	-31%	-36%	-41%	-39%	4%	-1%
Wyoming	2,331	1,526	1,299	1,808	1,714	-35%	-22%	-44%	-26%	-12%	-18%

Source: EPA

Installed Capacity Mix: Final vs Proposed in the EPA Base Case

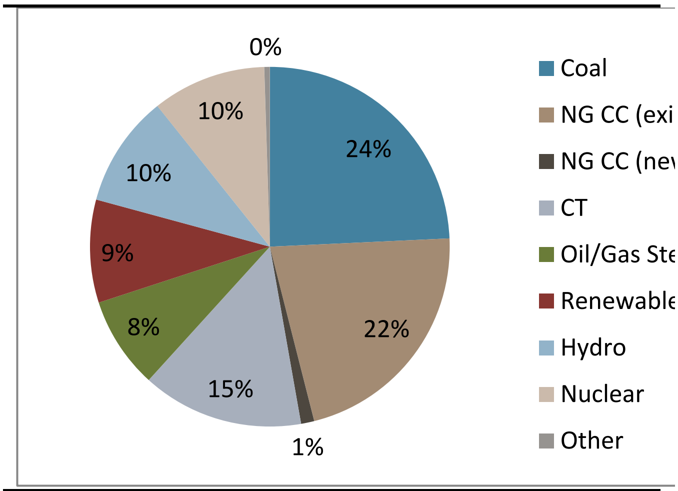
Below we summarize the installed capacity mix as forecasted by the EPA under the final plan and how that has changed vs. the prosed plan.

Figure 8: Final CPP Capacity Mix 2020 (Total = 1,016GW)



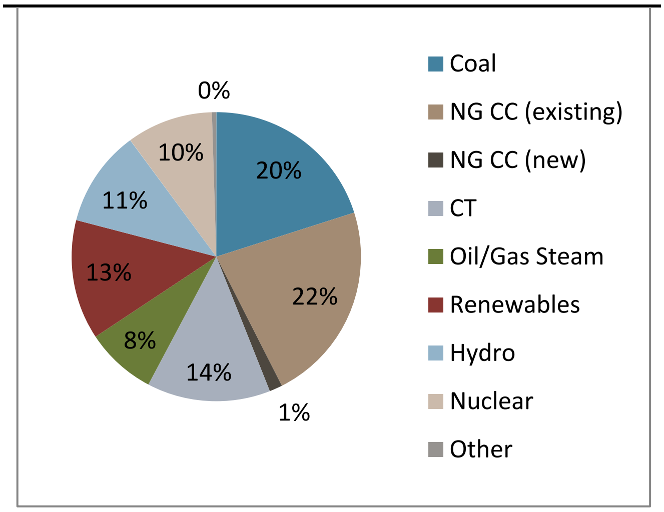
Source: EPA

Figure 9: Proposed CPP Capacity Mix 2020 (Total = 1,005GW)



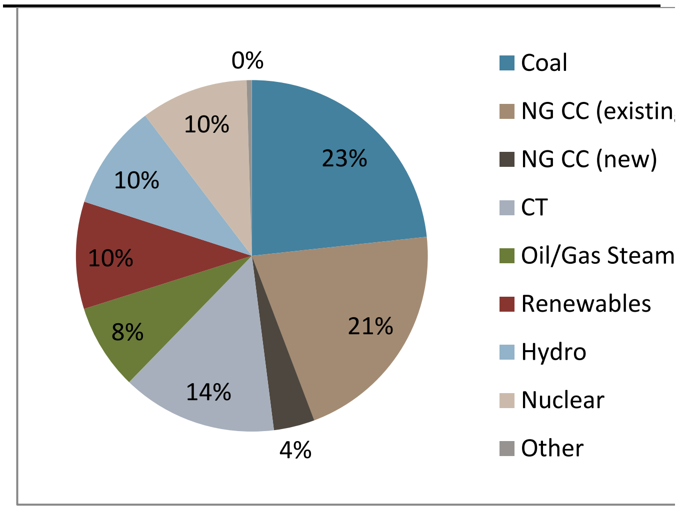
Source: EPA

Figure 10: Final CPP Capacity Mix 2025 (Total = 1,037GW)



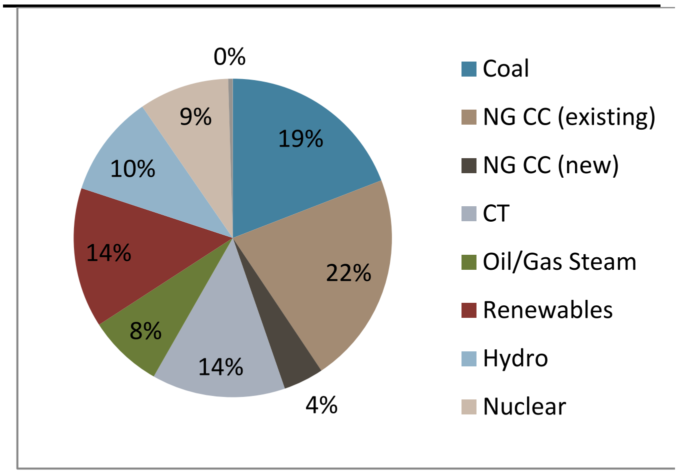
Source: EPA

Figure 11: Proposed CPP Capacity Mix 2020 (Total = 1,044 GW)



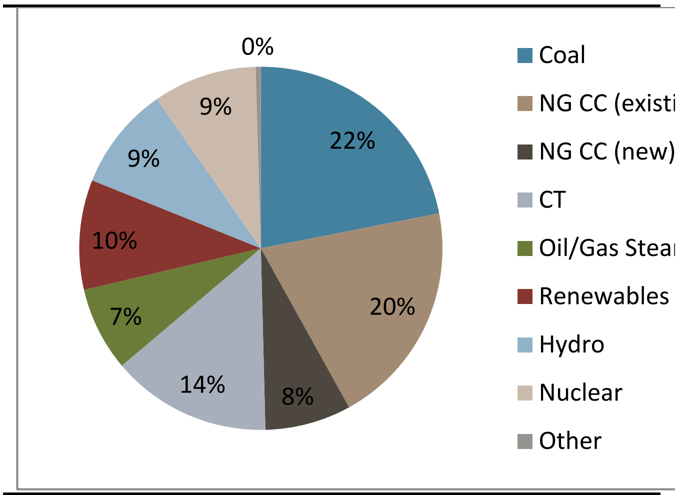
Source: EPA

Figure 12: Final CPP Capacity Mix 2025 (Total = 1,082GW)



Source: EPA

Figure 13: Proposed CPP Capacity Mix 2020 (Total = 1,095 GW)



Source: EPA

Conference Call on CPP

We present below highlights from our call with Richard Lehfeldt, Tom Lorenzen and Cameron Prell and the broader Clean Power Plan team at the law firm Crowell & Moring, to analyze the nuances in the EPA's Final CPP Rules, and impacts thereof.

Please let us know if you would like a copy of the slides referred to in the transcript below.

To listen to a replay of the call, use the dial in details below:

Replay Info:
Toll Free: 800-633-8284
Toll: 402-977-9140
Passcode: 21773633

Julien Dumoulin Smith: Thank you, operator, and good afternoon everyone. I appreciate you joining us to discuss the Clean Power Plan (CPP) - aka, the climate change rules. We're joined this afternoon by Thomas Lorenz and the team over at Crowell & Moring to go through in depth the CPP rules; and implications for the investment community.

With that, I will turn it over to Tom to go through the initial overview of the rules. Good afternoon, Tom.

Thomas Lorenz: Hello. Thank you, Julien, and thank you all for joining us today. I'm going to try to give you a ten minute

summary of a 1500 page rule, so let's see how we can do that. I don't know if you all remember the proposed Clean Power Plan. It was built on four building blocks - heat rate improvements at the individual EGUs, re-dispatched and natural gas, increased use of renewables and nuclear, and then building block four - user energy efficiency improvements.

The new clean power plan contains many of the same ingredients, but it's a whole new dish, so throw out a lot of what you thought you knew because the final rule is much different.

So let's talk about what's in it. The major elements of the rule - first of all, it starts with three of those four building blocks that were in the proposed rule. **Heat rate improvements, at the individual EGUs are still part of the mix but it is refined somewhat. Instead of a 6% uniform standard, it is now based on a regional target that varied from 2.1% to 4.3%.**

Building block two, which is natural gas, was previously supposed to be based on re-dispatched and natural gas up to 70% of nameplate capacity. It is now based on re-dispatched, up to 75% of summer capacity.

Building block three, renewables, the focus is now strictly on new renewables and nuclear is gone from the mix. It is no longer used in setting the target, so under construction and at risk, nuclear is not part of target setting.

Building block four and user energy efficiency is no longer part of the building block. Now, all that said, the building blocks are baked into the mix already.

What EPA did in the final rule, rather than having a very complicated calculation for each state based on their ability to implement each of these building blocks, is it took those building blocks into account in deriving two uniform emission rates - one that applies to coal-fired EGUs, and one that applies to natural gas.

And the two <u>are 1,305 pounds of CO2 per MWh for coal-fired EGUs, and 771 pounds of CO2 per MWh for natural gas</u>. That's it. Building blocks are done at that point because those rates, as I said, **apply uniformly to every unit of that type across the country.**

To calculate each state's goals, the EPA looked simply to the weighted average of emissions from the two types of EGUs, coal-fired EGUs and natural gas-fired EGUs. I should also mention oil. But basically the fossil fuel fired EGUs in each state. And applying those rates, it came up with an overall weighted average rate for that state.

This has some significant effect. First of all, it **constrained the range of states targets. They were quite widely divergent under the proposed rule**. Some states, such as Washington State had to reduce their emissions by over 70% because they had a lot of renewables available to them and not a lot of coal in the mix. Other states, like Kentucky, which were almost exclusively dependent on coal, have very high emission rates, over 1700 pounds per MWh that were simply because they had nothing but coal.

That's gone. Now we have a range of about 700 pounds per MWh for the most leniently regulated state to about 1300 pounds per MWh for the most stringent.

What this means is **states that didn't have to do much before, like Kentucky, now have to do a whole lot more. States that had to do a whole lot before now have to do a little bit less, so there are clear winners and losers in this as compared to the proposal.**

Now, what do the states do with those rates? They have options available to them - remember that <u>the states take these rates and they develop individual state plans that specify how they're going to meet both interim reduction targets and the final emission reduction goals</u>.

And the two options that they have are an **emissions standards plan** under which they basically assign to each EGU in the state an emission reduction rate that is designed to get to that overall average emission reduction target.

Or they can do something that's a broader **state measure plan**. This is the equivalent of the proposed rule's portfolio plan. The reason it is now a state measures plan instead of a portfolio plan is that EPA was directly imposing those other types of requirements from units before, things such as end user efficiency and other programs that states could implement under state law but not under federal law.

EPA has recognized that those are beyond its authority under the Clean Air Act to impose. But the states are still permitted to do this. It is simply up to the states. If the states adopt the state measures plan rather than an emissions standards plan, it has to include in its plan, **federally enforceable backstop measures**.

In other words, rates that apply to the individual EGUs in the state if it looks like the state is not on target to meet its goals. What else has changed about the plans and the rule in general?

The deadlines - the deadlines used to be that you had to submit plans in 2016 with final plans do in 2017 or 2018, depending on whether you were a single state or part of a multi-state shift.

Now we have a single regime for submissions of plans. Every state must make either a **final plan submission or an initial submission by September 6th of 2016**. If they're making an initial submission, they **may request from EPA an extension of up to two years to submit a final plan.**

This initial submission date is largely a mechanism to draw out those dates that are part of the "Just Say No" campaign. If your state is one that has vowed not to submit any plan under any circumstances or to submit a plan that is based on an emission rate that is substantially more lenient than EPA's, they want to know early and you can expect to be hit with a federal plan pretty quickly.

And we now know what the federal plan looks like, too. EPA has promised that it will approve or disapprove these plans within a year of their submission after taking notice and comment on them.

Another significant change from the proposal is that the interim compliance period, the period leading up to 2030, is now a shorter period that begins later. If you remember from the proposal, it was a ten year average rate that you had to achieve in the years between 2020 and 2029.

Now the interim compliance period does not begin until 2022. It still ends in 2029. So there's an eight year period instead of a ten year period.

Within that interim period, there are **three interim step periods - 2022 through 2024, 2025 through 2027 and 2028 and 2029 as a combined period at the end**. **Each of them has its own interim reduction target for each state that the states must meet by the end of that period, and that they must report on by July of the following year**.

Significantly, the states are permitted to adopt these interim periods or they are permitted to depart from them and come up with their own interim periods. There is a caveat to that. If you read the rule, it looks like you can do that under either a rate based or a mass based approach, and we will talk about this a little bit more in a minute. But at a Webinar that we ran yesterday with EPA, Janet McCabe said that no, in fact, if a state wishes to depart from the interim step period that EPA has created and come up with a own path, they may do so, but only using a mass based program.

Rate based will not work for that, and that's because there are problems with borrowing credits among those interim periods. Final compliance is still 2030 and so bear that in mind.

The ultimate goal of the plan is now to achieve a 32% reduction compared to 2005 levels, instead of a 30% reduction. Some other significant things that you should pay attention to, there is now a reliability safety valve

provision in the rules that allows states to apply to EPA for amendment of their plans.

If there's a significant reliability concern, it is expected that EPA will really grant those because providing the states two years additional time gives them time to build out their infrastructure so they shouldn't have, at least in EPA's view, reliability concerns.

Second, there is a **provision that allows individual utilities to get some relief from the plan's target where you have been exceptional event such as an extended heat wave or another polar vortex** and you need to ramp up generation for a while to meet demand.

There is an emphasis in these plans on trading-ready programs so that the states do not need to have multi-state plans to enable trading of emission reduction credits or allowances between them.

And then finally, there is the Clean Energy Incentive Program that allows credit early action in renewable energy, demand side energy, efficiency during the years 2020 and 2021. And my colleagues will be describing that for you. With that, I'm going to turn it over to Richard Leyfeld to talk about some of the energy implications.

Richard Leyfeld: Thanks, Tom. I'm going to briefly touch on three topics that evolved out of the rules that were promulgated on Monday. Assuming, for these purposes, that the rule has survived the major legal challenges and is, for all intents and purposes, now the law of the land.

I'm going to touch quickly on three - reliability, fuels, and the third one is most generally, how to build a power plant. Much of the confusion here comes from the fact that we are dealing in broad brush with two very, very different statutory frameworks - the Clean Air Act, which looks upon power plants as things that emit pollutants, and the Federal Power Act, which looks upon power plants is things that produce electrons.

Those two statutes are extraordinarily different views of what a power plant is and does. Different agencies administer the two regimes and in most important respects, the two statutory frameworks and regulations do not speak precisely the same language.

On reliability, during the development of the final rule, there was a lot of discussion about reliability. Was there going to be a reliability problem and if so, how might it be addressed? The rules issued on Monday did at least four things to address those questions.

First of all, it gave states more time - the additional two years that Tom was talking about, to develop their plans. Second of all, the states are tasked with considering reliability in the plans that the device.

Third, the plan may be revised. **The state plans may be revised under certain circumstances for "Unanticipated and significant reliability challenges."**

And last, but not least, there's the more lasered, I'd call it a force majeure clause which allows the plan to interceded and foreclose reliability, in the case of **reliability safety valve.**

Something - despite all the best plans of mice, men and regulator, something goes awry and you have to address a reliability issue. So one of the unanswered questions here is who owns the problem?

And this is one that is going to get addressed over the years to come because, in varying respects, at least the following agencies have at least a say in the matter – NERC, FERC and the DOE under certain circumstances.

There are the states which are responsible for building the infrastructure, both generation and transmission, that addresses reliability. There are the ISOs. And last but not least, of course, there's EPA itself. So what exactly is to happen in the event of one of these instances? Significantly, several days ago, PJM issued a study with regards to the proposed Clean Air Rule that basically came to the somewhat sobering conclusion

that there could, indeed, be reliability issues that arise under certain circumstances.

And to quote the study, "If generators deactivate sooner than replacement generation is built, PJM could face capacity shortages and the inability to serve reliably. In reality, the rate of generation additions will vary depending on a range of factors.

"While transmission issues were assumed away for the purpose of examining resource adequacy, PJM reiterates that in RTO that cannot meet capacity needs internally must rely on transmission to import power in order to keep the lights on."

The second question is on fuels.

Starting with renewables - **renewables appears to be the clear winner with the creation of the Clean Energy Incentive Program and the creation of up to 300 million emission rate credits that would be given for early mobilization of renewable resources specifically wind and solar.**

The EPA estimates that this tweak will result in **renewables occupying a market share of 28% as opposed to 22% under the proposed rule**. Second fuel, natural gas, is flat to declining as compared to the original proposed rule largely because renewables have gotten a head start that I just discussed which allows them to occupy a larger part of the pie and to get there earlier.

Third, **nuclear is essentially a split decision**. **New nuclear plants that are either under construction or with actively planned upgrades will be given full credit as a significant zero emission baseload facility.**

The only poison lining to the solar cloud is the fact that nuclear is extremely expensive and the way to build a nuclear plant these days is, at best, challenging. As far as existing plants, the central problem has gone a little bit back and forth between the proposed rule and the final rule.

The proposed rule had assumed that all of the so-called challenged nuclear facilities would continue to operate, therefore, can't [count] towards achievement of the targets. That is no longer assumed here, but there's no doubt that the elimination of a lot of the plants that have at least announced challenges, or outright announced retirement, are going to add to the burdens of the individual states in reaching their targets.

Last but not least, **coal's got a slight break in the 111B final rule and that the resource requirements for a new coal plant is now a supercritical pulverized coal facility with, not complete, but limited carbon capture and sequestration, approximately 20%.**

New coal plants continue to be a rare event in the near term under both the proposed in the final rule. Finally, the last topic, how to build a power plant. We are in a situation where it's the states alone that had the clear legal authority to authorize the construction of new plants; EPA clearly has a role on the Clean Air Act.

FERC clearly has a role under the Federal Power Act, but it's the states that ultimately determine what is built and where it's built and when it's built and what mix of resources they are going to use.

In the states with organized markets and particularly the 20 or so states that have capacity markets currently were already up against several issues about how to make up for the so-called missing money which is to say the revenues that either, an existing plant needs in order to continue to operate, such as an aging new, or the revenues that a new facility would need in order to be developed and constructed.

FERC and courts, so far, have taken the view that, in these organized markets in the 20 states, the sole source of revenue potentially is going to be the auction rate.

The auction rate is not sufficient to sustain aging nuclear plants or to build most new facilities that are contemplated under this, so there are a lot of issues still to be resolved and how to actually build the things that this sweeping new rule is contemplating. So with that, I will turn it over to Cameron.

Cameron Prell: Well, I appreciate it. So I'm going to talk a little bit about the market design outlines that are in the final rule. So one of the major changes that Tom and Richard mentioned was the alterations to the building blocks.

An additional new wrinkle here that is a major **change from the proposed rule is the increased emphasis on emissions trading**. And so it is being integrated now and to the metrics so that's probably the best place to start.

So as Tom was mentioning, in addition to a rate based compliance goal, there is now a uniform source specific to performance rate that applies to the two source categories.

And one of the reasons that that was integrated is because it provides the backbone for two other metrics for stakeholders which is the rate base compliance approach and then the mass based compliance approach.

A third corollary to why they did that was because it also facilitates harmonized trading between states under what they're calling trade ready standards that states can integrate into their state plan.

So in collaboration with issuance of the final rule, there was a proposed rulemaking for the federal enforcement plan, or federal plan, as it's being called.

And **the federal plan breaks out into four different distinct parts - a rate based federal plan for each state with effected EGUs, a mass based federal plan for each state with effected EGUs, a rate based model training rule for potential use by any**

state, as well as a mass based training rule for potential use by any state.

And those four breakdowns are important to note. The federal plans in the models are intended to focus on the use of emission trading as the core mechanism for implementation. As an anecdote, in the proposed rulemaking the term carbon trade appeared twice, the term emission trading appeared four times. In the final rule, carbon trade appears 17 times, and the term emission trading appears 76 times. The two approaches to the federal plan/model rule, because they're very similar on both the mass and the rate based side of things, is that the intent to ultimately decide on one approach in finalizing the federal plan and model rule tandem proposal that was issued on Monday.

The intent there from a trading perspective is to have a common currency or commodity that states can utilize as part of their state plans or reliance as part of their federal plans should the states decide not to submit an approvable plan.

The affected EGUs in any state covered by a federal plan or a state using the model trading rules could trade compliance instruments with any affected EGUs in any other state. There is also potential that zero carbon and low carbon sources can also generate what are now called ERCs or emission reduction credits on the rate-based side of things.

And on the mass based side of things, generate or free up allowances for EGUs and have some form of allocation of what EPA is calling renewable allowances or set-asides.

So let's break it down by rate based and mass based real quickly in terms of design. **Under the rate based approach, EPA would apply the sub categorized emission rates covered EGUs starting with the first compliance period rate of 1,671 for EGUs and IGCC plants and 877 for stationary combustion turbine category units.**

The key here is that under federal plan, the EGUs would be allocated or under potentially a state plan using the model rule, the EGUs themselves, on the mass based side of things, would be allocated or purchased allowances from the state or from ETA.

And on the ER- the rate based side of things, they would be able to go procure ERCs on the market base from other sources that are generating ERCs, which could be renewable sources and/or natural gas sources.

The additional components or this new commodity ERC, their credits that would be allocable to zero emitting generation sources in EGUs natural gas plan performing below their compliance rates.

And the **key issue for the early actions here which is different than the mass based side of things is that EPA is allowing projects that were "implemented after 2012," to be counted and generate ERCs – but only generate those ERCs during the compliance period.**

Under this approach, zero carbon and natural gas units would be able to sell those ERCs that would be allocated to them for future compliance during the compliance periods, or if a state chooses to alter the compliance period to allow for greater banking and borrowing to sell those ERCs under the state plans.

Switching to the **mass based side of things, which is more of a cap and trade's approach**; **under the mass based plan, that's where this whole concept of the Clean Energy Incentive Program (CEIP) comes into play.**

EPA has created an approach where EGUs would be allocated or allowed to purchase, allowances up to their identified budgets, and they could either free up allowances through investments in clean energy or, alternately, they could purchase what are being called CEIP offset credits which are renewable allowances.

It's unclear, at this point, how EPA intends to do that. It is likely it would be resolved in a final issuance of the federal plan. But the <u>Clean Energy Incentive Program, or CEIP, would provide early action credits, and potentially enter efficiency projects under a state plan to those projects implemented prior to 2022 but only for the first compliance period in 2020 and through 2022, and not for projects implemented or generating electrons after the final submission and approval of their state plans which would be September 7, 2018.</u>

It remains unclear how those allowances and outside credits would be integrated, but in these proposed federal plan and model rules, a state that uses them to design something that utilizes trading on a mass based side of things would be obligated to harmonize with the fit approach in the platform that EPA is offering and what looks to be almost like an opt-in: very similar to what was structured for the Clean Air Mercury Rule many years ago.

There are two separate allocations on the mass based side of things that also are worth noting. In addition to the CEIP, there's an output based allocation set aside and there's a renewable energy set aside.

We can talk, and I'm sure there will be a lot of questions about what counts and what does not come from a qualifying renewable energy perspective. But just note <u>that the CEIP, as Richard states, has **a cap of 300 million short tons**, **which is a key metric to keep in mind;**</u> **and then the mass-based there's a 5% renewables allowance set-aside to out-of-states, to other eligible renewable energy projects.**

It's a lot to digest, I know we've gone through quite a bit very quickly, Julien, and I know that there's probably a number of different questions, so I will stop there.

Julien Dumoulin Smith: Great, excellent, thank you guys for such a thorough review. But let me start off with this question because it helps complement where you just left off with. Where do you think states are going to go with this? I know it is a little bit prospective, but is it emission-based or is it a mass-based do you think?

Cameron: What EPA has done is it has responded to a chorus of commenters that were urging a more palatable mass based approach largely because that's what states and others are more familiar with. I would not want to conclude which way things are going, but just from my judgment **it appears there's a lot of momentum on the mass-based side** of things, but each state is going to have to figure that out based on the revised numbers and the targets that have been set.

Tom: I agree with Cameron. I agree that states likely will be thinking heavily about mass-based approach. I think **EPA also puts its thumb on the scale a bit in terms of the mass-based approach**. **There are incentives that are available to those who adopt mass-based approaches that are not available if you adopt a rate-based approach.** I think that's because the EPA views a mass-based approach as more likely to lead to real reductions in greenhouse gas emissions than a rate-based approach which really allows for unlimited growth, almost.

Julien Dumoulin Smith: And just to be very clear about that, the rate-based approach has the fundamental issue of leakage for news sources rather than just addressing the existing sources specifically regulated under the 111(d) context here.

Cameron: Yes, it's unclear quite honestly and it's to be determined based on what the final issue is for the federal plan. But yes, you're right, on the leakage context there seems to be an attempt to move away from the rate-based approach because of an inability to close that leakage.

Speaker: I would also say that the mass-based approach is one that the EPA is both familiar with and that has been successful under the Clean Air Act amendment to the 1990, particularly in Title IV.

Julien Dumoulin Smith: Excellent. Let me follow that up - do you expect trading programs to come about? It would seem as if that too would put the thumb on the scale back towards the mass-based program if it is strictly limited to those that choose that compliance option.

Cameron: Well like I said there's the baseline in credits approach on the rate-based side and then there's the mass-based allowance and frankly offsets approach that is on the mass-based side of things. But there's potential for trading in either direction, but the way that ERC's are calculated - and it's key to note here that although energy efficiency was carved out of building block four for purposes of determining the best system of emissions reductions, from a compliance perspective states can continue to pursue energy efficiency and allow them to generate emission-reduction credits for states.

So again, it really depends on the particular state in terms of how they view which way to go from a pure math perspective. But yes, **it is clear that this rule has a backbone of emissions trading.**

Julien Dumoulin Smith: Got it, excellent. And then as you think about the rules and implementation here, how did they address leakage between states as it stands? I suppose leakage was a problem across states to begin with, and now particularly if you have differences in programs, mass versus rate based, does that only complicate the process? How do you deal with leakage between states?

Cameron: Yeah, so they note that as a potential legal issue in terms of allowing for the trading on an interstate basis, but the way that they've attempted to address it is through that harmonized, trade-ready standards and metrics through the model state rule; and if states choose to do trading to have harmonized commodity and allow states to achieve compliance on a multi-state basis.

It remains unclear honestly how the leakage, particularly in an organized market context, is really going to be resolved as part of the state planning. But EPA is requiring states once they submit their plans, to explain either on a multi-state or an individual trade-ready state basis how they're going to address that issue, if they're going to count out of state credits.

Julien Dumoulin Smith: Could a generator that is in a rate-based program trade allowances and credit that are generated in a mass-

based program? I take it from the prior answer that that is not permissible, but just confirm that.

Cameron: Yeah, that's right, never the twain shall meet, that's probably the best way of explaining it. **The rate-based is baseline and credits, the mass-based is allowance and offsets**, for lack of a better term.

Julien Dumoulin Smith: From your perspective, how do they come up with the latest targets? How do they justify the compression if you will to the narrow band - you used the example of Kentucky before.

Tom: Well, the background of this, obviously there were a lot of complaints about the proposed rule, about the inequities of the emission reduction goals for each of the states. Those who had done the most already to reduce their emissions seemed to be tagged with the obligation to do even more, while those who had done the least were getting off very light.

And EPA took those comments to heart. I think they also just found that the system that they were using, the proposed rule was inordinately complex. The way they resolved both those problems was by trying **to find a system for coming up with a uniform emission rate that applied to the two types, the two major types of EGUs, coal and natural gas.**

And what they did as I think I said before is they built the building blocks into them, where they're assessed with the building blocks, how much on average could any one unit improve its heat rate across the country. And they took the most lenient of the three regional measures that they had found, 2.1, 4.1 and 4.3%, and they applied that uniformly across the nation to determine an average heat rate improvement that all plants should be able to achieve, in EPA's view.

Then they considered the issue of re-dispatch from coal-fired units to lesser-emitting natural gas units, and determined that coal should be able to redispatch to available natural gas units until the point that those were utilized at 75% of their summer capacity. That was then built into the formula.

And finally they considered **how much renewable energy could be built into the system, that number actually went up from the proposed rule because of additional information from the Energy Information Administration that suggested they had underestimated it before**, **that was baked into the rate as well, and then you put all that together you come up with these combined rates, uniform rates, 1,305 pounds per MWh for coal-fired, 771 pounds per MWh for NGCC units.**

And that's it, as I said before. After that the building blocks are really done. They serve no purpose going forward, although they are all things that states can do as a compliance measure.

Julien Dumoulin Smith: All right, great, excellent. Just to clarify the timeline here and just how you see things going down?

Tom: Okay, well states first of all are permitted to submit a final plan any time they want. Initial submissions must be made by September of 2016, that's just over a year from now, and a state that wishes to submit a final plan on that date and get a head start can do so. **There may be incentives for them to do that, and those are in the Clean Energy Incentive Program.**

Cameron: The key component there is when early action crediting would count. And it appears on the mass-based side of things that early action would count upon finalizing a state plan or being subjected to the effectiveness of a federal plan.

<u>So the two key dates to keep an eye on would be probably no earlier than September 7 of 2016 for those states that are so inclined, and September 7 of 2018 for those states that submit an initial plan and then choose to submit a final plan, or alternately are subject to a federal enforcement plan by September 7, 2018.</u>

And largely an incentive of how much early action crediting would be eligible because that's the date for when projects on the clean energy side of things would be eligible for the Clean Energy Incentive Program.

Tom: So some trading programs could get started earlier, but I expect to see most of them start up in the 2020, 2022 time frame.

Cameron: Yeah, it's key to note there that early actioning is really different from the rate-based approach, which **EPA is allowing those units that are in the ground as of 2012 to generate ERCs but only to generate ERCs during the compliance period, which is different than on the mass-based side of things.**

Tom: Right. Mass-based side, and under the CEIP, you can start generating credits two years earlier.

Julien Dumoulin Smith: Two years prior to the rate-based.

Tom: **Two years prior, that's right, in 2020 and 2021 rather than only in 2022 and beyond. So that's one of the incentives that tries to get states to submit SIPs early, because by submitting a SIP earlier, they can start putting projects in place that will get those credits.**

Julien Dumoulin Smith: Even if you do I suppose one of the questions that's been posed by folks out there is, **isn't there a disincentive for renewables between 2017 to 2020 or prior to 2020 perhaps, those, '17, '18, '19 where the ITC goes away but ultimately you don't get the early action benefit?**

Tom: **If you've not submitted your SIP, yes, there's a disincentive.**

Julien Dumoulin Smith: Right, because the reality is if you submit your SIP early, you get big advantages as soon as that happens but perhaps fast forwarding, otherwise, if you wait until 2018 you don't get to take advantage of it until when?

Tom: Until the period starts.

Cameron: If they submit it late, **the project that would count only counts for those projects that go in the ground after the submission of the final plan. And so the period between just say September 7, 2018, those, they could take early action credits as soon as 2020, <u>but they wouldn't be eligible for those 2020 CEIP credits under a mass-based approach until September 7, 2018, or if they're in the ground before September 7, 2018.</u>**

Julien Dumoulin Smith: Got it. You could take them as soon as 2020, you're saying? Just to be very clear.

Cameron: Correct, under the CEIP, the Clean Energy Incentive Program.

Tom: But again that requires a valid SIP submitted to EPA before you can do that.

Julien Dumoulin Smith: Right and the valid SIP would need to be proposed, so the September 7, 2018, you'd submit the finalized SIP and that has to subsequently be approved by the EPA.

Tom: It does have to be approved by the EPA; I believe you can start implementing things after the SIP is submitted and before it's approved so you don't have to wait that extra year.

Cameron: No, I think the final point on this is the date of submission of the final approved plan is the date that triggers eligibility on the mass-based side of things for the Clean Energy Incentive Program. So that could be, to Tom's point, any time between now and September 6, 2016 for a state plan, and then ultimately at the end date of September 7, 2018, for a final state plan or a federal plan. Does that make sense?

Julien Dumoulin Smith: But I apologize, I don't mean to confuse us too much here. For a renewable that's built in 2018, say after September 7, 2018, is that ultimately eligible to benefit from early action?

Cameron: Assuming that if they have a federal plan out as of that date will be finalized or a federal plan will be finalized.

Tom: Yeah, this is key and I think Julian you ask a very good question here, and this is a confusing thing about the rule and the way it works. The delta between what Cameron was just describing and the world as it is right now, is what credit do you get for projects that are built between right now and September 6, 2018?

Anything that's built *after* September 6, 2018, is going to be eligible for credits during that two-year period in 2021 and '22, because either your state will have submitted its own SIP, which qualifies it for eligibility under the CEIP, or EPA will have imposed a FIP, a federal plan, which also would qualify them under the CEIP.

But **between now and 2018, if you don't have a SIP in place, you're not going to get that early credit, and that might disincent the buildout of some renewables now. I think EPA is hoping that will put pressure on the states to submit SIPs earlier**.

Julien Dumoulin Smith: And what's your impression in speaking with states, just to understand this from your perspective, do you expect many states or any state to submit something by September 7, 2016, that should be, quote unquote, final?

Tom: Some might. **Those who are far ahead of the curve and who are building out renewables may find themselves somewhat advantaged by submitting a SIP early.** Whether they can actually accomplish all they need to do by September 6, 2016, is another question, because remember one of the reasons that EPA gave the states extra time in the rule is that many states complained "We have a legislative session that only meets every other year." And that makes it very difficult to make the changes to laws that would be required to comply with this plan.

In addition, after they adopt the necessary legislation, they still have to amend their regulations to conform to. That, too, takes time. So I'm expecting very few states will actually be in a position by September 6 of next year

to submit a fully approvable SIP, but some may try, because there are advantages to getting those things in earlier. You qualify more renewable buildout for treatment under the CEIP if you submit earlier.

Speaker: If one of the handouts before the webinar here was the ECOS presentation, which you might want to take a look at and answer that question, Environmental Council of the States. Divided into two sections, one says the states have expressed some concerns and that might give you a sense of which states might not be of a mind for early action and early submission of a SIP, and Part Two is called "Arguments in Favor of the Rule" and that will give you a pretty good listing of states that might be inclined to jump early and gather some of the benefits.

Tom: And by the way, the two dates are not the only dates which you can submit a SIP. If a state is ready after September 6, 2016 but before September 6, 2018, they can jump as soon as they're ready, and as soon as they're ready and have submitted something that would be approvable by EPA, they can start taking credit. Well, they can't start taking credit, they can start building out the renewables that will eventually get those early credits.

Julien Dumoulin Smith: Got it. So let's just talk a little bit about the political dynamic here. So you have states that are more inclined that could very well have plans approved under the current administration, conceivably.

Tom: Yes.

Julien Dumoulin Smith: Right. And then subsequently, for those that submit plans that are likely to get rejected or fail to submit plans, you would have a timeline here that would suggest 2018 they failed to submit an adequate plan, that gets rejected by the EPA, what's the time limit there to think this through for those who are dragging their feet, if you will.

Tom: Well, now we're trying to figure out the gaming of this. **Do you wait for the next administration. Listen, a lot of this really depends on what happens to this**

rule in the courts. If this rule is invalidated by the courts, there will be no obligation by the states to submit SIPs, the rule becomes a dead letter unless it's remanded to the agency for further proceedings and kept in place, like MATS recently was, the Mercury and Air Toxic Standards.

If on the other hand the rule survives judicial review at the DC circuit and almost certainly review at the Supreme Court as well, then the subsequent administration, whether it's a Democratic administration or a Republican administration, is somewhat bound by the terms of the rule as promulgated. They have to abide by it because it is law. And if they do not abide by it, in other words if they are approving SIPs that don't actually meet the requirements of the rule, they could find themselves subject to lawsuits by NGOs and other states saying that this is not in compliance and that can be enforced against a future EPA.

So a lot depends on what happens with the coming judicial challenges to this rule. Because it will govern what happens in the next administration, unless or until that administration takes action to withdraw the Clean Power Plan, and that in itself is a very complicated process. So don't assume that if there's a Republican president that it will be easy to come in and undo the Clean Power Plan, it takes a new rulemaking to do that.

Julien Dumoulin Smith: Got it, all right, excellent. Ultimately what's your read on nuclear power here, right. So obviously there was a change from the preliminary to the final here. What does this do in your mind outside of give credit to those who are pursuing new nuclear and perhaps ratchet up the pressure to keep existing nuclear around?

Speaker: There are no windfalls or unexpected paths to either development or retention of the nuclear fleet, other than the fact that they obviously will be recognized and get credit for being a zero-carbon source. But it is challenging for both the existing and the underdevelopment projects, given the price tags attached and who ultimately pays for that, and in certain circumstances, in the organized market, how exactly out of market payments are going to be honored or allowed to be provided.

Julien Dumoulin Smith: Got it. What is the path to litigation just to understand the key aspects of the rule that you see as the most litigious within it? So I suppose they removed the efficiency element of it because it was seen as more litigious, but I'd be curious what other elements to you stand out.

Tom: There are still a number of risks that EPA's taking here. First of all, there is what we call this **threshold legal argument about whether EPA has any authority at all to promulgate this rule because of the existence of the Mercury and Air Toxic Standard**. There is one reading of Section 111(d) that says that when there is an existing regulation under Section 112 for hazardous air pollutants for a source category, you may not regulate that source category even for a different pollutant, such as greenhouse gases, under Section 111(d).

That issue is still live; it will have to be resolved by the DC circuit. Depending on how that goes, either EPA cannot issue this rule at all, or it might be able to go forward. Note that there is a complication there in that the Supreme Court recently invalidated the Mercury and Air Toxic rule, it didn't vacate it, it remanded to the DC circuit, but the DC circuit might well vacate MATS. If it does, that argument may go away.

Second, there is **still some question about whether EPA has overstepped its authority by prescribing binding state emission targets rather than letting the states develop their own emission targets**, because Section 111(d) says that while EPA defines the **b**est **s**ystem of **e**mission **r**eduction [BSER}, it is the states that establish the standards of performance and then apply those standards source by source based on various factors including the remaining useful life of the facility.

Third issue is this definition of the best system of emission reduction [BSER] to include all these things like re-dispatch into natural gas and increasing renewable and so forth. Typically BSER as we call it has looked to a technological measure or an operational change that you can make at the individual unit to improve its emissions performance per unit of good produced, in other words per MWh of electricity.

That is only the building block one measures here. *Everything else is non-traditional and what we call beyond the fence line, and there's a question about whether EPA has any authority to define BSER in that method, in that manner*. Those are the big legal issues. There are many others, of course, but pay attention to those ones because they're going to get a lot of attention.

What's going to happen now, and I guess we ought to be tying this thing up, is that there is already some litigation going on. The state of Oklahoma has a case that's currently in the Tenth Circuit seeking early review of the proposal. We understand that West Virginia and Murray Energy and others may try to renew if they haven't already, a petition for writ of extraordinary relief in the DC circuit right now based on the signature of the final rule.

But **I think you can expect most of the litigation will commence hot and heavy after this hits the Federal Register in about a month.** And at that point I think you can expect to see multiple stay motions and then maneuvering over how this thing is going to get briefed, expect a decision from the DC circuit by next June.

Julien Dumoulin Smith: So I suppose with that we are really out of time here at the top of the hour. That went by quite quickly; I appreciate you all taking the time, we may have to follow up here. Thank you all, have a great day.

END

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