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**Comments of the American Public Power Association**
**On the U.S. Environmental Protection Agency's**
**Clean Energy Incentive Program Design Details; Proposed Rule**

**81 Fed. Reg. 42,940 (June 30, 2016)**
**Docket Id. No. EPA-HQ-OAR-2016-0033**

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## I. Executive Summary

The Clean Energy Incentive Program (CEIP) is an important component of the final Carbon Pollution Emission Guidelines for Existing Stationary Sources (111(d) Rule, Clean Power Plan (CPP)) and the Proposed Model Trading Rules and Federal Plan promulgated by the Environmental Protection Agency (EPA) on October 23, 2015. The American Public Power Association (APPA) appreciates EPA's effort to address public power's concerns that the 111(d) Rule did not adequately and appropriately credit early utility investments in renewable energy and energy efficiency and notes that issuance of the CEIP seeks to remedy our concerns. APPA also appreciates the numerous changes EPA has made to improve the breadth and feasibility of the CEIP by incorporating design details based on comments the agency received on the Proposed Model Trading Rules.

Thus, APPA is generally supportive of the CEIP, or a CEIP-like mechanism, to more fully credit early action to reduce carbon dioxide ($CO_2$) emissions. At the same time, APPA believes the proposed rule to implement the CEIP's design details still does not go far enough to recognize such investments. Accordingly, APPA's comments focus on further modifications to the program that would expand the eligibility of renewable energy and energy efficiency investments under both state and federal plans, and provide states with additional flexibility in implementing the program.

APPA also notes that the CEIP was not included in the proposed 111(d) Rule and that the Final 111(d) Rule, which the CEIP seeks to amend and implement in part, is currently under judicial review by the federal courts. Therefore, if the courts uphold the final rule, EPA is required by law to re-propose the CEIP in its entirety and accept comments on it before incorporating it into any state or federal plan under the 111(d) Rule.

In these comments, APPA makes the following key observations and recommendations, among others. With respect to issues of general applicability, APPA believes:

- EPA should allow states more decision-making authority, flexibility, and discretion on various elements of the CEIP;
- Earlier dates should be established for project and program eligibility;
- EPA should provide emission reduction credits (ERCs) or allowances that would not otherwise be available, so that the CEIP adds to the pool of available credits and allowances;
- The mandatory forward capacity markets, and their ever-changing rules, in the eastern regional transmission organizations continue to significantly impede the ability of states and utilities to comply with the 111(d) Rule in general and to take advantage of the incentives in the CEIP in particular; and
- Additional discretion should also be afforded to states in apportioning credits and allowances.

With respect to renewable energy, APPA believes:

- Eligibility should be expanded to include other zero-emitting generation sources, including biomass and uprates of existing nuclear facilities; and

- EPA appropriately included eligibility for hydropower, and that should be retained in any final rule.

With respect to energy efficiency, APPA believes:

- EPA should allow all demand-side energy efficiency and demand reduction programs to qualify for the CEIP, and agrees that EPA should emphasize programs in low-income communities;
- EPA appropriately granted some additional flexibility to states to determine eligible energy efficiency projects;
- Transmission and distribution-related improvements, and other supply-side resources that improve efficiency, should be included; and
- Additional discretion should be afforded to states in defining what constitutes "low-income" communities.

## II. Introduction

The American Public Power Association (APPA) welcomes the opportunity to submit the following comments on the U.S. Environmental Protection Agency (EPA or Agency) proposed rule entitled, "Clean Energy Incentive Program Design Details" (Proposed CEIP or CEIP).[1]

APPA is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the United States. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA. Collectively, public power utilities deliver electricity to one of every seven electricity consumers in the country. We serve some of the nation's largest cities, including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. However, most public power utilities serve small communities of 10,000 people or less. APPA participates on behalf of its members collectively in EPA rulemakings and other proceedings under the Clean Air Act (CAA or Act) that affect the interests of public power utilities.

Public power utilities provide over 15 percent of all kilowatt-hour sales of electricity to consumers. All APPA utility members are load-serving entities (LSEs) with the primary goal of providing customers in the communities they serve with reliable electric service at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA utility members with the long-term interests of the residents and businesses in their communities.

## III. Background

The Proposed CEIP is an important component of the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (111(d) Rule) and the Proposed Federal Plan and Model Trading Rules (Proposed Model Trading Rules) issued pursuant to CAA Section 111(d) on October 23, 2015. APPA filed a joint petition for review of the 111(d) Rule in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit). Petitions challenging the rule were consolidated under the lead case *West Virginia, et. al. v. EPA, No. 15-1363.* Oral arguments in the case were heard by the court *en banc* on September 27, 2016.

Industry petitioners sought and were granted a stay of the 111(d) Rule by the U.S. Supreme Court on February 9, 2016. EPA should not interpret APPA's participation in this rulemaking as an acknowledgement that the 111(d) Rule nor proposed CEIP are lawful or proper. Rather our involvement is consistent with our goal to seek constructive engagement in all rulemakings affecting public power utilities.

[1] 81 Fed. Reg. 42,940.

APPA welcomes the opportunity to provide these comments and appreciates EPA's recognition of the industry's early efforts to reduce greenhouse gas (GHG) emissions. However, it is our position that the CEIP must provide the maximum amount of flexibility to states that participate in this voluntary program. We believe this program may alter the operations of APPA member utilities and the electric power markets in which they operate, and could, if implemented as proposed, impose significant costs and regulatory burdens on APPA utility members. APPA therefore has a clear and significant interest in the outcome of the present rulemaking, as well as other related rulemakings that are part of the Agency's overall effort under the CAA to regulate carbon dioxide ($CO_2$) and other GHG emissions.

APPA is a member of the Utility Air Regulatory Group (UARG), and we support UARG's comments and APPA member's comments in this docket. APPA is incorporating by reference its comments in the proposed 111(d) Rule (Docket Id. No. EPA-HQ-OAR-2013-0602-22871) and Federal Plan and Model Trading rulemaking (Docket Id. No. EPA-HQ-OAR-2015-0199-0719).

## IV. The CEIP Violates the Supreme Court Stay and Suffers from Procedural Defects

EPA promulgated the CEIP in the final 111(d) Rule without providing the public notice or an opportunity to comment fully on the program.[2] EPA states the goal of the CEIP is to "promote early action," and "encourage early investment in renewable energy (RE) and demand side energy efficiency (EE)" before the compliance performance period begins.[3] In promulgating the CEIP as part of the final 111(d) Rule without proposing it, EPA violated section 307(d) of the CAA, as well as fundamental administrative rulemaking principles. The 111(d) Rule contained several requirements that were not proposed, such as the CEIP framework, which authorizes states to award ERCs or allowances for certain RE or EE projects that are implemented prior to the 111(d) Rule's first interim plan performance period.[4] A state would award qualified projects ERCs or allowances during 2020 and 2021, for generation or avoided generation during this period. Further, the rulemaking violates the letter and spirt of the U.S. Supreme Court stay, pending judicial review of the regulation.

### A. EPA Must Address the CEIP's Procedural Flaws and Re-Propose the CEIP in Its Entirely if the 111(d) Rule Is Upheld

When EPA established the CEIP as part of the final 111(d) Rule, EPA violated §307(d) of the CAA and the Administrative Procedure Act (APA). EPA acknowledges that the 111(d) Rule was governed by CAA§ 307(d).[5] EPA has acknowledged that the CEIP was "outlined and initiated" for the first time in the final 111(d) Rule.[6] If the 111(d) Rule is upheld in litigation, EPA must re-propose the CEIP in its entirety in a rulemaking docket and accept public comments on all aspects of the proposal. The CEIP seeks to amend the following key parts of the 111(d) Rule, 40 Code of Federal Regulations (CFR) §§ 60.5737, 60.5800, 60.5815, 60.5865, 60.5870, 60.5880 and two tables in Part 60 Subpart UUUU. However, the Agency will not take comment on the CEIP framework:

[2] 80 Fed. Reg.64,943.
[3] 80 Fed. Reg. 64,669 and 64,670.
[4] 80 Fed. Reg. 64,829.
[5] 80 Fed. Reg. 64,641.
[6] 80 Fed. Reg. 64,969.

> In this action, the EPA is not reopening its decision to establish the CEIP, the maximum size of the matching pool, the requirements for states to include a mechanism in their plans that ensures that the awards of early action allowances or early action ERCs will not be impact the $CO_2$ emission performance of affected of affected [electric generating units] EGUs required to meet $CO_2$ emission standards under the CPP emission guidelines….[7]

EPA has never established a detailed docket for the entire basis for the final 111(d) Rule, including the CEIP. Rather, the Agency established a "non-regulatory" CEIP docket, the Proposed Model Trading Rule docket, and a separate docket for this rulemaking. All elements of the CEIP and supporting documents must be proposed together in its entirety so the public has an opportunity to comment. This piecemeal approach is confusing and illustrates the procedural defects in the CEIP rulemaking. Re-proposing the CEIP would provide EPA additional time to develop supporting evidence for many of the assumptions the agency relied on for the general outlines and specific details in the CEIP.

The CEIP and the availability of early action allowances or ERCs is centrally relevant to the 111(d) Rule's stringency and therefore the CEIP should be withdrawn and re-proposed if upheld at the conclusion of the litigation. The CEIP advances EPA's assertion that states using the CEIP must ensure that the program "will not impact the $CO_2$ emission performance of affected EGUs required to meet rate- and mass-based $CO_2$ emission standards during the plan performance period."[8] How can EPA rely on the "voluntary" nature of the CEIP to justify compliance with the 111(d) Rule? States that participate in the CEIP are faced with a difficult choice, comply with state emission budgets and measures to main their stringency or forgo the opportunity to receive additional allowances or ERCs. EPA admits declining to participate in the CEIP "could be perceived as 'a double disadvantage:' Not only is the state electing to not received matching allowances/ ERCs, it is also electing to have other states' matching allowances/ ERCs shares increased."[9] Participation in the CEIP limits a state's flexibility because it requires states to remove and reallocate state pool allowances from their budgets or to retire or withhold ERCs generated in the first compliance period. It is for these reasons APPA recommends EPA cure the procedural flaws created when it issued the CEIP and re-propose the CEIP in its entirety.

### B. The CEIP Violates the 111(d) Rule Stay and Must Be Withdrawn or Held Open Until the Stay Is Lifted

The CEIP seeks to amend key parts of the 111(d) Rule, 40 CFR §§ 60.5737, 60.5800, 60.5815, 60.5865, 60.5870, 60.5880 and two tables in Part 60 Subpart UUUU that have been stayed by the U.S. Supreme Court. The CEIP violates the stay because it compels stakeholders to submit comments and expend resources before the stay has been lifted, thereby assuming the 111(d) Rule will be upheld. As a result of the stay, some stakeholders may not submit comments on the Proposed CEIP, thereby foreclosing the opportunity for EPA to become aware and resolve stakeholder issues during the rulemaking process. The U.S. Supreme Court's Order provides that

[7] 81 Fed. Reg. 42,944.
[8] 81 Fed. Reg.42,958.
[9] 81 Fed. Reg. 42,955.

if the 111(d) Rule is upheld, all deadlines would be tolled which means the CEIP would not begin in 2020 as originally conceived, but at some later date. Twenty-seven State Attorneys General have requested EPA extend the comment period on the proposed CEIP for at "least sixty days following the termination of the Power Plan stay. If the Power Plan does not survive judicial review, the CEIP should then simply be withdrawn."[10] APPA recommends EPA withdraw the CEIP until the underlining 111(d) litigation is concluded.

## V. Comments on Proposed Changes to Model Trading Rules and Federal Plan

EPA is re-proposing certain CEIP provisions in the Proposed Model Trading Rules. EPA should provide stakeholders the opportunity to provide input on how the proposed changes to the CEIP impact other parts of the Model Trading Rules and Federal Plan. The CEIP removes and re-proposes provisions that were included in the Proposed Model Trading Rule with "CEIP optional example regulatory text" in this rulemaking.[11] EPA also requests comment on the use of the CEIP optional example regulatory text as the means to implement the CEIP in federal plans.[12]

### A. States Should Be Allowed to Elect CEIP Participation in a Federal Plan

APPA is supportive of EPA's intention to make CEIP participation available to a state(s) that receives a federal plan.[13] States that receive a federal plan would be unfairly disadvantaged if excluded from participation in the CEIP. States under a federal plan should be allowed to participate in the CEIP, especially if the state administers the allocation of trading instruments under a federal emissions trading program. However, if a state chooses to submit a partial state plan, they should have the option to opt-out of participation in the CEIP. An opt-out provision is critically important for some states given the CEIP set-aside could substantially reduce the number of state issued allowances or ERCs during the first compliance period.

EPA should accept comment on the entire federal plan before a federal plan is imposed on a state. APPA's comments on the Proposed Model Trading Rules addressed this issue and are incorporated by reference and summarized here.[14] The Proposed Model Rules indicated EPA did not intend to provide "specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied."[15] EPA's proposal to issue a final federal plan for specific states without first proposing these plans would violate both the CAA and APA. EPA acknowledges that the general provisions it has proposed will need to be modified to fit each state's unique circumstances. Further, there are a number of unanswered questions in the Proposed Model Trading Rules that illustrate that the public cannot reasonability be expected to have adequate notice on the issues. It is for these reasons we believe EPA must propose the actual regulatory text of a federal plan for a specific state before a state's federal plan is finalized.

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[10] EPA-HQ-OAR- 2016-0033-0079 "Request of Extension of Time to Comment on the Proposed Rule, Clean Energy Incentive Program Design Details," August 1, 2016.
[11] 81 Fed. Reg. 42,957.
[12] 81 Fed. Reg. 42,956.
[13] 81 Fed. Reg. 42,942.
[14] EPA-HQ-OAR-2015-0199-0719; pg. 15.
[15] 80 Fed. Reg. 64,975.

## VI. Comments on CEIP Design Elements

APPA believes EPA should leave the decision of how and when to allocate early action credits to states. EPA should grant states additional flexibility with regard to the timing and types of projects that are eligible for early action allowances or ERCs under the CEIP. EPA should award matching allowances or ERCs to any type of project that a state believes advances the goals and purposes of the CEIP. Invariably, states will come up with programs that are optimized for their regional and local circumstances, resulting in a more workable outcome for states and project developers. As proposed, the CEIP requires too much administrative burden on the part of states and project developers. States that decide to implement the CEIP should at least be given the flexibility to effect a reduction in administrative burden and increase participation by project developers, with the objective of ultimately reducing costs to comply with the 111(d) Rule.

### A. Stringency Adjustments Reduce the Value of Compliance Instruments

The 111(d) Rule requires any state which chooses to participate in the CEIP to demonstrate that its state plan has a mechanism to ensure that the allocation of early action allowances or issuance of early action ERCs to CEIP eligible projects will not impact the $CO_2$ emission performance of affected EGUs in a rate or mass based program.[16] EPA should not require states to verify that their participation in the CEIP will not cause state budget exceedances. In a mass-based program, a state maintains the program's stringency though its allowance set-aside.[17] EPA's CEIP proposes applying an "adjustment factor" to all quantified and verified megawatt hours (MWh) from eligible ERC resources that are achieved during the first compliance period for a rate-based state that participates in the CEIP.[18] APPA recommends that EPA eliminate the penalty CEIP-eligible projects will experience in the first interim period due to the adjustment factor. Projects eligible to generate ERCs in the first compliance period will have difficulty planning their financial and revenue models because they will not know until at least a year into the three-year compliance period how many ERCs might be available to be awarded.

The CEIP would be potentially more effective if it constituted an addition to the aggregate emission performance mandated in state goals. As proposed, the CEIP removes allowances and adjusts the compliance period ERC downward and therefore reduces some flexibility offered by a trading program. The impact of the proposal dilutes the benefit of early action credits (allowances or ERCs). EPA should rectify this structural flaw by making the CEIP early action credits additional or "above and beyond" the emissions allowances or ERCs taken for a state's budget. APPA believes the pool of early action allowances or ERCs should not be taken away from state budgets because doing so would result in fewer compliance instruments.

If the CEIP is intended to incentivize early action, it should be revised to provide allowances or ERCs that would not otherwise be available. For example, EPA's Compliance Supplement Pool program under the Phase I Clean Air Interstate Rule (CAIR) NOx Annual Trading Program availed additional NOx allowances to be earned in advance of the compliance start date, helping startup the trading programs.[19] Sources were able to earn Compliance Supplement Pool

[16] 40 CFR 60.5737(c).
[17] 81 Fed. Reg. 42,959.
[18] *Id.*
[19] 40 CFR 96.143.

allowances based on early NOx emissions reductions, thereby receiving “credit for early action.” This mechanism worked and produced early NOx reductions. EPA should consider implementing mechanisms in the CEIP to help fully recognize without penalty the early $CO_2$ reductions achieved. Further, the Acid Rain Program under Title IV of the 1990 CAA amendments allowed banking, which awarded early emission reduction actions that were directly targeted at the regulated EGUs.

In another example, the development of a conversion factor to allow fungibility between allowances and ERCs after the initial “adjustment factor” proposed in a rate-based CEIP program is necessary to help support the highly undefined ERC or allowance market. Conversion could be an important process for a significant number of states and therefore EPA should develop options for public comment. APPA believes that allowing trading between rate- and mass-based states would expand market liquidity and provide flexibility to market participants. Further, EPA should give states the ability to issue either ERCs or allowances for CEIP-eligible projects in their state. If the CEIP is designed to provide financial incentives for RE and EE, there may be less of an incentive for projects located in certain states if the national trading market is skewed to a mass- or rate-based program. APPA supports allowing trading between mass- and rate-based states as outlined in our Proposed Model Trading Rule comments.[20]

### B. State Must Have Discretion Apportioning the Matching Pool of Early Action Credits

The Proposed CEIP contemplates dividing each state share of the matching 300 million allowances and or 375 million ERCs received from EPA into two reserve pools, one for eligible RE projects and the second reserve for EE and solar projects implemented in low-income communities.[21] APPA believes states are best situated to determine the appropriate apportionment of any matching pool of allowances or ERCs to projects that meet the eligibility criteria for RE or EE projects deployed in low-income communities. EPA has noted that the electric power sector continues to undergo a transformation due to various factors, particularly lower costs of distributed generation, technology improvements in RE resources, and rapid innovation in energy efficiency technologies.[22] These transformative changes are largely being driven by state policy decisions. Because states have already taken a leading role, they should continue to do so by selecting a matching reserve apportionment strategy that reflects state policy objectives in line with a state’s unique circumstances, such as a state’s electricity generation mix and electricity demand. For certain states where electricity demand is not growing quickly, there may not be a current need for investment in new generation capacity. Other states may desire to incentivize alternate RE technologies. APPA recommends EPA remove the proposed matching pool 50/50 split between RE and low-income projects and provide states with the discretion to apportion the CEIP matching pool of early action credits.

### C. Reapportionment of Unused CEIP Credits Should Be Allowed

EPA should include a reapportionment mechanism for undistributed matching pool allowances or ERCs, so they may be made available in some other way rather than being retired. The

[20] EPA-HQ-OAR-2015-0199-0719; pg. 39.
[21] 81 Fed Reg. 42,951.
[22] 81 Fed. Reg. 42,952.

reappointment of unused matching allowances or ERCs is just another way to provide compliance flexibility. States with unused matching CEIP credits are likely to be those where additional capacity is too expensive to build in the 2020 and 2021 timeframe. APPA recommends that states have discretion in reapportioning matching credits, as well as in determining if and when these credits would be retired as EPA suggests be done by January 1, 2023. In the 111(d) Rule, EPA stated it would redistribute "[a]ny matching allowances or ERCs that remain undisturbed after September 6, 2018," to "those states with approved state plans that included requirements for CEIP participation."[23] In the Proposed CEIP, EPA seeks to reverse its position because of timing considerations, the impact of the renewable energy tax credit extensions, administrative challenges in reapportioning ERCs and allowances, and concerns that states might opt into the CEIP only to prevent their apportioned ERCs and allowances from going to other states.[24] However, EPA has provided no information to support the assertion that there is insufficient time for reapportionment. APPA believes the Agency's concerns about reapportionment can be addressed by altering the CEIP timelines and removing the size restrictions on the matching pool. EPA should retain the reapportionment mechanism because it allows as many matching pool allowances and ERCs to enter the market, thus promoting early action. EPA also could allow the reappointment mechanism to redistribute unused matching allowances or ERCs by the time state plans are approved. This approach would incentivize developers to commit to their project because of the possibility of a state gaining additional allowances and ERCs through reapportionment.

### D. State-Specific Limits on Credits: Project Location Verses Benefit State(s)

EPA proposes to establish state shares of a matching pool of allowances or ERCs, divided into two reserves, one for RE projects and the second for a low-income reserve.[25] The proposal also maintains the notion that credits for a project can go to CEIP participating state(s) where the project is located or where the benefit occurs.[26] This raises the question of whether projects can self-determine whether the "location" state(s) or the state(s) that receives the benefit can receive the credit. This scenario also raises the question of whether there can be a mix of allowances and ERCs awarded for a single project, if both a rate- and mass-based state are involved. APPA would recommend that EPA offer clarifying language in the CEIP to indicate that the benefit (i.e., CEIP credit) follows the load.

### E. CEIP Eligibility Dates for RE and EE CEIP Projects Should Be Based on a "Commence Commercial Operation" Date of October 23, 2015

The U.S. Supreme Court's stay of the 111(d) rule in *West Virginia, et al. v. EPA et al.*, No. 15A773 (February 9, 2016) precludes EPA from enforcing the deadlines in the 111(d) Rule and thus it is unclear what adjustments need to be made to implement the rules timing upon the conclusion of the litigation. As a general matter, the proposed CEIP maintains the timing elements of the CEIP that have already been finalized in the 111(d) Rule. However, EPA notes timelines may need to be readjusted in concert with other elements of 111(d).[27] Therefore, as

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[23] 80 Fed. Reg. 64,830.
[24] 81 Fed. Reg. 42,955.
[25] 81 Fed. Reg. 42,974, Tables 5 and 6.
[26] 81 Fed. Reg. 42,971.
[27] 81 Fed. Reg. 42,946.

EPA has done in prior rules that have been stayed, such as the Cross States Air Pollution Rule (CSAPR), APPA suggests EPA propose a 1:1 day delay of the program dates and tolling of relevant deadlines in the CEIP after the stay has been lifted if the underlining 111(d) Rule is affirmed.

EPA proposes to amend the CEIP trigger dates for RE projects that commence commercial operation to January 1, 2020, and low-income demand-side EE and solar projects to September 6, 2018. APPA supports establishing an early eligibility date for RE and EE projects based on the promulgation date of the 111(d) Rule, October 23, 2015. Most RE and EE projects take time to develop and follow similar project development steps: project sales/outreach; contract negotiations between project developer and end-user customer; negotiations between project host and developer; negotiations with equipment provider; financing; permitting; construction/installation; testing/shake-out; and commencing commercial operation in the case of RE, and commencing operation in the case of demand side EE projects. Allowing earlier eligibility dates encourages greater emission reductions.

EPA is proposing to replace the definition of "commence construction" for CEIP-eligible RE projects to "commence commercial operation," as well as to clarify the term "commence operation" for CEIP eligible-low-income projects.[28] APPA supports replacing the term "commence construction" with "commence commercial operation" because this approach is consistent with other EPA-administered programs and is commonly understood by the electric power industry.

### F. Participation by States, Tribes, and Territories Without Affected Sources

APPA supports including eligible projects located in states without 111(d) emission performance goals in the CEIP. However, these projects must be connected to the U.S. electric grid and to states with affected sources. Jurisdictions without affected sources wishing to participate in the CEIP should submit notification of their intent to participate to EPA. The Agency could allocate a portion of its matching pool to these jurisdictions using the same formula it uses for states. Vermont is an example of a state without a $CO_2$ emission goal under the 111(d) Rule, but is connected to the contiguous grid. Vermont has the potential to create emission-saving opportunities for neighboring states that participate in the CEIP due to recently passed legislation updating the state's renewable generation targets to 75 percent by 2032.[29]

[28] 81 Fed. Reg. 42,963.

[29] Vermont H.B. 40, The SPEED goal, enacted in 2005, sets a nonbinding target of 20 percent renewables by 2017. Vermont's new renewable portfolio standard (RPS), H.40, also known as Renewable Energy Standard and Energy Transformation (RESET), has an interim goal of 55 percent by 2017 and also includes provisions for cutting emissions in the residential and transportation sectors. In December 2014, the 604 megawatt Vermont Yankee nuclear plant was retired.

## VII. All Zero Emitting Resources Should Receive Early Action Credit

APPA agrees with EPA's decision to expand CEIP project eligibility to include geothermal and hydropower generation projects. APPA advocated for a more inclusive list of eligible zero-emitting energy projects in its Model Trading Rule comments and recommends EPA continue to expand its list of eligible projects to include all projects that would qualify for ERCs issued under Section 60.5800(4)(i-vii).[30] Specifically, EPA should expand its list of CEIP-eligible projects to include wave, tidal, qualified biomass, biogenic portion of waste-to-energy, nuclear power, non-affected combined heat and power (CHP), waste-to-energy (WTE), landfill gas, demand-side EE, and EE management measures, and not just wind, solar, geothermal, and hydropower resources. The Agency should affirm that hydropower includes wave-based and tidal-generated energy. EPA should also create a path for states to add and qualify other forms of non-emitting energy resources. A more inclusive list would remove unjustified bias against certain technologies, allow states the maximum flexibility in their compliance plans, and permit new and developing technologies to compete effectively.

Limiting the list of all non-emitting power generation technologies significantly limits the opportunities to participate in a "credit for early action" program. The CEIP as proposed, arbitrarily chooses a truncated set of non-emitting technologies. To ensure usefulness of the CEIP to all states and to improve the value of EPA's stated goal of incentivizing early action,[31] the expanded list of CEIP-eligible resources should also include:

- Qualified biomass: All forms of biomass should be available for the generation of ERCs. EPA should pre-approve and qualify biomass resources for inclusion in the CEIP in a blanket fashion providing only the details necessary to allow states to make their own informed decisions on the relative $CO_2$ neutrality of various feedstocks.

  Biomass-derived fuels play an important role in controlling increases of $CO_2$ levels in the atmosphere. The use of some kinds of biomass has the potential to offer a wide range of environmental benefits. These benefits are realized regardless of how biomass feedstocks are sourced. For example, biomass can be used to actively offset fossil fuel use at the times when the least efficient marginal units are dispatched. In addition, biomass can be used to actively lower $CO_2$ emissions when solar and wind resources are not available. In both cases, the $CO_2$ reductions are much greater than identified because the biomass is being optimally used to reduce emissions.

- Biomass waste-to-energy: Several forms of biomass would otherwise be waste without conversion to energy. Through the CEIP, EPA has the opportunity to recognize biomass waste-to-energy technology that reduces or eliminates waste and reduces power system emissions. For example, biogas that is being flared from a wastewater treatment facility, a landfill that has a biogas collection system in place, or an animal farm that uses anaerobic digestion to manage manure, are all highly environmentally friendly opportunities for RE generation and the agency should recognize them in the CEIP.

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[30] EPA-HQ-OAR-2015-0199-0719 pg 57.
[31] 81 Fed. Reg. 42, 940.

- Nuclear power: Both EPA and the White House recognize the benefits of nuclear power as a non-emitting resource that promotes economic growth, job creation, and economic competitiveness.[32] Under-construction nuclear is fully eligible to receive ERCs under the 111(d) rule and, as a non-emitting resource, should also be fully eligible to receive credits under the CEIP. See the discussion in Section V.A. for further details on including new, relicensed, and uprated nuclear facilities as eligible technologies under the proposed CEIP.

- Non-affected combined heat and power (CHP) units, including waste heat power: CHP and waste-heat-to-power (WHP) should be CEIP-eligible energy efficiency approaches. The CEIP applies to solar and wind generation and end-use energy efficiency benefitting low-income communities. CHP provides energy efficiency benefits at or near the site of energy demand, but is instead construed as low-emission power generation rather than being a form of end-use energy efficiency. These definitional matters can have adverse impacts on opportunities for enhancing energy efficiency in low-income communities in support of the CEIP's objectives.

  EPA acknowledges and supports the implementation of CHP to benefit low-income communities while reducing emissions. Beyond housing, there are various examples of CHP being implemented at hospitals, schools, municipal facilities, and other installations to provide economic and emission-reduction benefits. The Agency should also include CHP and WHP serving low-income communities as CEIP-eligible approaches under the end-use efficiency category.

### A. APPA Supports Awarding CEIP Credits to New, Relicensed, Uprated Zero-Emitting Nuclear Units

Nuclear energy is an important source of emissions-free electric power generation and plays an important role in meeting $CO_2$ emission reduction targets. APPA recommends EPA further expand the list of CEIP-eligible projects to include nuclear units that are new, relicensed, or uprated and that operate as such during the CEIP early action crediting period. Nuclear satisfies EPA's key proposed criteria for determining eligible technologies under the CEIP. Nuclear generation (whether from new, relicensed, or uprate units) is a zero-emitting resource, is essential to long-term climate strategies, and should be fully eligible to earn CEIP ERCs during the CEIP early action period. New nuclear units that commence commercial operation prior to the 111(d) compliance period should qualify to earn CEIP ERCs. Nuclear units that commenced relicensing after the 111(d) Rule was published in the *Federal Register* should qualify to earn CEIP ERCs. Uprated nuclear units that began operation after the final 111(d) Rule was published in the *Federal Register* should also qualify to earn CEIP ERCs.

[32] EPA Fact Sheet, "The Clean Power Plan, Opportunities for Nuclear Power," November 5, 2015, posted at http://www.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-opportunities-nuclear-power and White House Fact Sheet, "Obama Administration Announces Actions to Ensure that Nuclear Energy Remains a Vibrant Component of the United States' Clean Energy Strategy," November 6, 2015.

Importantly, without relicensing, an existing nuclear unit may not operate beyond the expiration date of its current license. Existing nuclear units operate at high capacity factors and their electricity production simply cannot be replaced by intermittent generation sources, such as wind or solar. It is likely that the capacity and energy replacement for an existing nuclear unit with an expired license would be primarily fossil generation that emits $CO_2$.[33]

### B. APPA Supports the Eligibility of Hydropower to Receive CEIP Credits and Highlights Existing Barriers to Further Development of Hydropower Projects

APPA supports EPA's proposal to recognize the importance of including hydropower as an eligible technology to receive early action credits. Hydropower is the nation's largest source of emissions-free, renewable electricity, accounting for 47.6 percent of domestic renewable generation and 6.2 percent of total electricity generation (according to the most recent Energy Information Administration data from 2014). It is a reliable source of energy, being available most of the time, unlike some other renewable resources. Furthermore, hydroelectric generators can be started or stopped quickly, which makes them more responsive than most other energy sources for meeting demand for electricity at its "peak" or highest volume. These units also often have "black start" capability that makes them especially valuable in restoring power when there are widespread outages or disruptions on the system. This capability allows the generating units to cycle back on quickly if they have been tripped off in a power outage. Given these characteristics, hydropower plays a significant role in ensuring reliable, zero-emissions electric service at low-cost and thus should be eligible to receive CEIP credits.

Despite the beneficial use of hydropower, there are a number of regulatory, financial, and other barriers impeding the commercial development of this hydropower potential. Congress has begun to focus its attention on removing these barriers through the passage of legislation addressing small hydropower, by introduction of new legislation addressing existing hydropower, and by holding hearings to examine these issues. APPA has actively supported, and continues to support, legislative and regulatory efforts to remove or reduce these barriers and facilitate the development of additional hydropower resources.

Both the House and Senate versions of comprehensive energy bill legislation (H.R.8 and S.2012, respectively) in the 114th Congress include bipartisan provisions intended to modernize the hydropower licensing and relicensing process to make it more efficient and transparent while maintaining environmental protections. APPA was actively involved in the development of these provisions; APPA President and CEO Sue Kelly testified before the Senate Energy & Natural Resources Committee in May 2015 on the need for hydropower licensing and relicensing reforms and in support of the concepts included in discussion drafts of legislation on which S.2012 was based.

APPA and its members have worked to promote the benefits of hydropower, and the need for licensing reform, outside of the context of the energy bills as well. Most recently in April 2016, the House Natural Resources Committee's Subcommittee on Water, Power, and Oceans held a hearing that spotlighted the need for hydropower licensing reform. Two representatives from APPA members, Snohomish Co. Public Utility District and Turlock Irrigation District testified

[33] EPA-HQ-OAR-2015-0199-0719, pg 58.

on the difficulty they each have had relicensing hydro projects that are important sources of non-emitting power in their generation portfolios.

In the 113th Congress, APPA strongly supported two small hydropower bills that were signed into law: H.R. 267, the Hydropower Regulatory Efficiency Act, and H.R. 678, the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act. H.R. 267 sought to promote hydropower development at conduits by excluding projects under 5 MW from federal licensing requirements if the project meets certain criteria. It also intended to facilitate conduit project development by exempting projects between 5-40 MW from federal licensing requirements, upon approval of FERC, among other things. H.R. 678 amended the Reclamation Project Act of 1939 to authorize the Secretary of the Interior (acting through the Bureau of Reclamation) to contract for the development of small conduit hydropower at Bureau facilities. The law also requires that power privilege leases be offered first to an irrigation district or water users association operating or receiving water from the applicable transferred or reserved work. Finally, the law increases the size of applicable projects from 1.5 to 5 MW.

### C. Synergies Between Municipal Utilities That Operate Water and Electrical Services

The majority of APPA's members own and operate public water and wastewater systems. Water and wastewater utilities are critically dependent upon a high level of reliability and a resilient electric grid to perform essential public health services. APPA believes the proposed CEIP should more fully consider the opportunities for EE projects completed at public water and waste water systems. A growing number of public power utilities that operate water and electrical systems are improving their energy management systems in an effort to take advantage of the natural synergies of these interdependent systems. In addition, new technologies offer water utilities an opportunity to convert excess pressure into electricity.

### D. Treatment of Tax Incentive for Wind and Solar Projects Under the CEIP

The CEIP framework included in the 111(d) Rule was designed to incentivize generation in 2020 and 2021 from zero-emitting projects (wind, solar, and other renewables). To qualify, construction of such projects would have to begin following submission of a state plan or by September 6, 2018, at the latest. The amount of ERCs and allowances to be granted under the CEIP was selected at a time when it was expected that federal tax credits for investments in, and production from, certain renewable energy sources would "expire" – or decline in value – at the end of 2015. Instead:

- The beginning-of-construction date for non-wind renewable power facilities to claim the electricity production tax credit (PTC) (or investment tax credit (ITC) in lieu of the PTC) is December 31, 2016;
- The beginning-of-construction date for wind renewable power facilities to claim the PTC (or ITC in lieu of the PTC) is December 31, 2019;
- The beginning-of-construction date for solar power facilities to claim the higher (30 percent) ITC rate is December 31, 2019 (with projects begun in 2020 receiving a 26

percent credit; in 2021 a 22 percent credit; and a 10 percent credit for projects begun in 2022 or later).

As a result of these extensions, generation capacity of solar and wind power will increase substantially through 2022.[34] As a result of this additional generation capacity, the amount of additional solar and wind energy generation in 2020 and 2021 could exceed the amount of new zero-emitting generation intended to be incented by the CEIP.[35] Some stakeholders have suggested that CEIP ERCs and allowances for renewable power generation should be reconsidered in light of the extended availability of these tax credits.[36] Likewise, EPA has requested comments on whether it would be appropriate to include in the CEIP a mechanism to limit the number of ERCs and allowances overall or to limit ERCs and allowances for wind and solar projects benefitting from the ITC or PTC.

### 1. Overall Reduction in ERCs and Allowances Is Not Merited

While gains in renewable power generation resulting from the extension of the ITC and PTC and resulting from CEIP ERCs and allowances regime may be comparable at a national aggregate level, they would be quite different in their effects.

First, the extension of the ITC and PTC beyond 2016 are targeted to utility-scale wind and solar projects. Tax credits are not available for geothermal and qualified hydropower facilities construction that begin after December 31, 2016. As a result, extension of the wind and solar ITC and PTC beyond 2016 is expected to result in less power generation from non-wind and solar renewable energy sources than if the ITC and PTC were not extended.[37]

Second, the CEIP apportions EPA matching ERCs and allowances to states based upon emissions reductions required of those states. Conversely, projects benefitting from the ITC and PTC have been built, and will continue to be built, in states where conditions are most favorable to wind and solar—and, generally, those wind and solar states are not states required to make the greatest reductions under the CPP. For example, the 10 states with 86 percent of the nation's current solar power generating capacity are apportioned merely 19 percent of the CEIP's renewable energy reserve.[38] Likewise, the 10 states with 74 percent of the nation's current wind power generating capacity are apportioned only 30 percent of the CEIP's renewable energy reserve.[39] One exception is Texas, which is apportioned roughly 10 percent of the renewable

[34] Trieu Mai et alia, National Renewable Energy Laboratory "Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions," 13 (2016) (estimating annual average renewable energy additions will be 10,600 MWs greater as a result of tax credit extensions); John Laron, et alia., Rhodium Group, "What Happens to Renewable Energy without the Clean Power Plan?" (Feb. 25, 2016)(http://rhg.com/notes/renewable-energy-without-the-clean-power-plan) (estimating that annual utility scale solar and wind capacity additions will total roughly 20,000 MWs in 2019 and 2020 and roughly 5,000 MWs in 2021).
[35] Laron, supra note [1] (estimating that wind and solar generation in 2020 and 2021 will exceed 200 million MWhs).
[36] Kevin Steinberger, Natural Resources Defense Council, "Renewable Energy Tax Credits Will Play a Critical Role in the Clean Power Plan" (Feb. 25, 2016) (https://www.nrdc.org/experts/kevin-steinberger/renewable-energy-tax-credits-will-play-critical-role-clean-power-plan).
[37] Laron, supra note [1].
[38] EPA, EERE, supra note [5].
[39] EPA, SEIA, supra note [5].

energy reserve and is already one of the top 10 producers of wind and solar power. Nonetheless, generally, the CEIP matching program would provide the most help where help is most needed, while the PTC and ITC would continue to incentivize investments in states where those investments are already occurring.

Finally, the ITC and PTC cannot be claimed by not-for-profit entities, including public power utilities, which generate roughly one-fifth of the nation's election power. Public power utilities include solar and wind power in their generation portfolios through power-purchase agreements and through a limited amount of direct ownership. In such transactions, some of the benefit of the ITC and PTC ultimately flow to customers in the form of lower rates, but a significant portion is retained to provide return on investment for third-party generators and tax-equity investors. As a result, relying on the ITC and PTC to provide the incentives intended by the CEIP indirectly disadvantage not-for-profit utilities relative to for-profit generators facing reduction obligations.

#### 2. Targeted Limits Could Avoid Shortcomings of Overall ERC Allowance Reductions

EPA has suggested that projects benefitting from the PTC or ITC might not be allowed to receive ERC's or allowances. Given the financial incentives provided by the PTC and ITC, in 2020 and 2021 there likely will be substantial generation from new solar and wind investments with or without the CEIP.[40] However, limiting ERCs and allowances to projects not receiving the PTC or ITC would reduce the bias against hydropower and geothermal investments.

Limiting ERCs and allowances to projects not benefiting from the PTC and ITC would also incentivize direct investments (rather than power purchase agreements) in wind, solar, hydropower and geothermal by not-for-profit entities. With the investing not-for-profit receiving 100 percent of the ERC or allowance, there would be none of the efficiency losses currently associated with the PTC and ITC and power purchase agreements by not-for-profits. However, the exact effects of limiting ERCs and allowances to projects which have not benefited from the PTC and ITC ultimately would hinge on expectations of the value of ERCs and allowances earned for early investments.

## VIII. All EE Projects Should Be Eligible for CEIP Credits

In the proposed CEIP, EPA sets out incentives for EE projects taking place in low-income communities. APPA understands the emphasis the Agency is placing on EE in low-income communities, however if the goal is to reduce $CO_2$ emissions, all EE programs should be eligible for CEIP credit irrespective of the projects location. APPA encourages EPA to allow any demand-side energy efficiency program, project, or measure that results in MWh savings to become eligible for CEIP awards, assuming the measures meet state requirements.

APPA recommends EPA broaden the CEIP to more fairly incentivize EE projects across the board, in addition to projects located in low-income communities. If the Agency chooses not to provide early action credit to all EE programs, we suggest the following alternative. If an EE

[40] Laron, supra note [1].

program is not offered in a low-income community, the EE program should still receive some credit, perhaps similar to the one-to one credit offered for RE projects. APPA believes that EE should be treated in the same manner due to the numerous benefits seen by participants of EE programs.

Energy efficiency projects, similar to renewables, will continue to be part of the solution to reduce $CO_2$ emissions. Efficiency investments cost significantly less than building new power plants and save consumers money on their energy bills and often are the least cost options to deploy.[41] As such, EPA should use the same methodology behind the proposed CEIP incentives for both EE and RE projects deployed throughout the community.

### A. APPA Supports the Flexibility Offered to States to Determine Eligible EE Projects

Public power utilities across the nation have undertaken and continue to implement a wide variety of EE measures. Due to the varied nature of EE projects undertaken by public power utilities, it is important for EPA to remain flexible when determining requirements for EE projects. APPA encourages the agency to find the types of EE programs referenced in APPA's Energy Efficiency Resource Central website portal, and in the case studies submitted in response to the 111(d) Rule by the National Association of State Energy Officials (NASEO), as qualified for CEIP awards.[42,43] APPA's research and development program, the Demonstration of Energy and Efficiency Developments program (DEED), has helped fund numerous EE projects by public power utilities.[44] The program has helped develop and accelerate deployment of the most practical and cost-effective efficiency technologies with our members for almost 35 years.

Technologies such as CHP, which is uniquely suited to reduce the emissions from affected EGUs and reduce demand for generation, should be eligible for EE credits under the CEIP. EPA has stated that CHP requires less fuel to produce a given energy output and avoids transmission and distribution (T&D) system losses that would have otherwise been incurred. This avoidance results in GHG emission reductions alongside other economic benefits.[45] As such, the Agency should further encourage the implementation and development of other technologies that are more energy efficient and reduce $CO_2$ emissions.

Local governments in many public power communities work closely with their utilities and are knowledgeable about the types of EE programs, projects, and measures that are taking place within their region. This relationship can encourage cross-sector approaches that are uniquely suited for that locality, state, or region. For example, states can take advantage of the EE synergies offered by public power utilities that operate both water and electric utilities. An increasing number of water utilities are optimizing system processes and managing water pressure thorough out their systems and throughout the demand cycle to achieve energy

[41] Natural Resources Defense Council, "Clean Energy Brings Jobs and Savings to Low-Income, Urban Communities," https://www.nrdc.org/sites/default/files/clean-energy-benefits-FS-urban.pdf.
[42] http://www.publicpower.org/Topics/Landing.cfm?ItemNumber=38508&navItemNumber=37540.
[43] http://111d.naseo.org/Data/Sites/5/naseo-ee-for-cpp-2015-july-30.pdf.
[44] http://www.publicpower.org/Programs/Landing.cfm?ItemNumber=31245&navItemNumber=37529
[45] https://www.epa.gov/chp/chp-benefits.

efficiency objectives. EPA's requirements for qualifying EE programs and projects should be flexible and inclusive of these and other forms of new and innovative technologies and projects that result in reduced emissions.

### B. APPA Supports the Inclusion of Commercial and Transmission Distribution Projects

APPA fully supports EPA's proposal to include commercial and transmission/distribution (supply-side) projects as eligible projects under the CEIP. Transmission and distribution upgrades, and other supply-side projects, such as conservation voltage reduction, will help utilities reduce peak demand, provide savings for customers, and may also increase reliability. Common supply-side efficiency projects include: reconductoring, transformer upgrades, application of power factor correction capacitors, voltage upgrades, and voltage control.

A study prepared by the Electric Power Research Institute (EPRI), which used detailed system models of 66 distribution circuits as part of the Green Circuit Program, revealed that approximately 75 percent of circuits reported losses exceeding 2.52 percent and 25 percent of circuits reported losses exceeding 4.32 percent.[46] The EPRI study, among others, show that there is room for economic efficiency improvements on distribution systems. Some projects utilities implement to mitigate losses can also help utilities to better manage demand on their systems, which can offset the need to add new peak generation capacity.[47] These benefits, when quantified, are useful to the end consumer and can be a low-cost option to reduce $CO_2$ emissions. EPA should further encourage these projects and allow them to be eligible for credit under the CEIP.

### C. Definition of "Low-Income Communities" Should Be Broad and Flexible

EPA's proposed key principles that provide guidance for states on defining low-income communities should be flexible and allow for the eligibility of a wide variety of programs. States ultimately should have discretion to make the final decision on which projects or programs are considered "low-income." In some instances, it may make sense to define a low-income community geographically, which would rightfully allow building retrofit programs, CHP, community solar, hydropower, geothermal, and other renewable technologies in businesses, schools/university campuses, commercial facilities, small communities, (group homes, shelters, etc.) to qualify for the CEIP awards. On the other hand, there are situations where it could be sensible to include low-income households within the definition. For example, if a low-income EE fund approves an efficiency improvement loan or grant to provide energy assistance or self-sufficiency services to low-income households, that should be considered a sufficient definition of "low-income" for purposes of the CEIP.

In the proposed rule, the two-for-one CEIP incentive is awarded to solar projects built to serve low-income communities.[48] In order to qualify for CEIP awards, solar generation projects must provide direct electricity benefits to low-income community customers. However, the proposed

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[46] Electric Power Research Institute (EPRI), Inc., Green Circuits Distribution Efficiency Case Studies, October 2010.
[47] http://aceee.org/topics/energy-efficiency-resource.
[48] 81 Fed. Reg. 42,948.

rule also states that the projects must exclusively benefit low-income customers.[49] This distinction narrows the scope of the definition of "low-income," which would prevent some projects from being eligible for CEIP awards. EPA needs to provide further guidance on how the "direct electricity" benefit should be substantiated to receive a CEIP award from the low-income reserve. The physics of the system prevent the direct apportionment to a particular technology.

Utilities should be allowed to expand their projects to include low-income households within the community and receive CEIP awards. This expansion could be a result of overall land cost, system benefit, developer willingness, etc., and if there are low-income households within that community that are receiving those benefits, the program should be eligible for the additional incentive under the CEIP. When a public power utility, school, or other local organization reduces energy use at its facilities and sees results in savings, the benefits of that reduction will continue to feedback into the community. EPA should incentivize these efficiency projects to be implemented in communities that contain portions of low-income residents since the benefits are applicable to the residents within the community, including low-income customers.

As an example, through a Department of Energy (DOE) Energy Efficiency and Conservation Block Grant, the Western Electricity Coordinating Council (WECC) implemented several community-based energy efficiency pilots to evaluate customer acceptance and verify the efficacy of community EE programs.[50] One particular case study, the Wisconsin Energy Efficiency ($We^2$) program, made an effort to reach medium- to low-income residents and make it more affordable for them to participate. Programs such as these, which experience successful outreach and quantifiable savings for low-income residents, should be eligible for CEIP awards, even if the program is not solely directed at a community of only low-income residents. Additionally, EPA should consider on-bill crediting programs for qualifying low-income customers, which occur in mixed income neighborhoods, but are highly beneficial to low-income customers.

APPA encourages the hybrid, general approach to defining "low-income" to allow greater flexibility, which will encourage the deployment of more projects to help the low-income population save energy and money. EPA should allow flexibility and encourage states to determine which programs and projects help low-income communities and households.

## IX. Wholesale Market Impediments to State Promotion of Non-$CO_2$ Emitting Resources

APPA offers the below discussion to further illustrate market impediments to reducing $CO_2$ emissions in the context of recent state actions to reduce carbon emissions, such as New England states' procurement of renewable resources and New York's Clean Energy Plan and Zero Emissions Credits. In the restructured wholesale electricity markets there are increasing concerns among public power utilities and the states about whether the market rules will increase costs and deter the development of resources needed to meet policy goals, especially $CO_2$ emission reduction goals. While we recognize $CO_2$ emission reductions are occurring, they will be more difficult, costlier, and likely have unintended long term consequences that are not reflected in the

[49] 81 Fed. Reg. 42,972.
[50] Western Electricity Coordinating Council, "Community-Based Energy Efficiency Programs," http://www.weccusa.org/sites/www.weccusa.org/files/pdfs/sell%20sheets/communitybasedsellsheet.pdf.

marketplace. While the problematic wholesale electricity market rules are approved and overseen by the Federal Energy Regulatory Commission (FERC) and not EPA, it is essential that EPA communicates more strongly to FERC the impact of these markets on the development of lower and non-$CO_2$ emitting resources.

The markets with significant impediments to CEIP resources are known as mandatory capacity markets, and are operated by three regional transmission organizations (RTOs); the New York Independent System Operator (NYISO), the New England Independent System Operator (ISO-NE), and the PJM Interconnection (PJM), covering the mid-Atlantic and part of the Midwest (Ohio and northern Illinois). (See the Appendix for more background on RTOs and capacity markets.) Known as the "Eastern RTOs," these markets accounted for just five percent of the new wind and four percent of the new solar capacity constructed in 2015, although these regions represent about one-fourth of U.S. electricity consumption.[51,52] While there are many factors providing certain advantages for renewable resource development in certain geographic areas (i.e., the availability of land, strength of the wind, or amount of cloud cover), there are also features of the Eastern RTO capacity market rules that disadvantage renewable resources, as described in the next section.

In one positive sign, these RTOs have initiated processes to try to develop rule changes to allow markets to better accommodate resources developed pursuant to state policies, as described herein. Based on the pace of these efforts, it is uncertain if any resulting market reforms will be produced in sufficient time to avoid impacting resource availability for the CEIP in 2020 and 2021. It would therefore be beneficial for EPA to weigh in on such RTO initiated efforts to integrate state public policies, as well as directly to FERC.

### A. Capacity Auctions Offer Limited Opportunities for Renewable Resources

While originally intended to be a "residual" market that would supplement ownership and bilateral contracting as the primary means of capacity procurement, the mandatory capacity markets have become an increasingly significant source of revenue for generation owners. As natural gas prices have fallen and renewable energy has entered the market, energy prices paid to generators has fallen. As a result, merchant generation owners and the RTOs have successfully advocated for changes to the capacity market rules that will constrain supply and increase prices.[53] Two categories of rule changes, Minimum Offer Price Rules and Capacity Performance, described in this section, have created significant impediments to renewable energy.

#### 1. Minimum Offer Price Rules/Buyer-Side Mitigation

Within a mandatory capacity market, resources must "clear" the auction to be used by the LSE for resource adequacy purposes. If an LSE owns or contracts for a resource and it does not clear,

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[51] Calculated from data provided by the Energy Information Administration, Electric Power Monthly, February 2016, Table 6.3. New Utility Scale Generating Units by Operating Company, Plant, Month, and Year.
[52] Calculated from Sales to Ultimate Customers (Megawatt hours) by State by Sector by Provider, 2014, Energy Information Administration.
[53] For a discussion of the merchant generator pressures to increase prices in the PJM capacity market and resulting rule changes, see "Missing Money" Revisited -- Evolution of PJM's RPM Capacity Construct," prepared by James F. Wilson, Wilson Energy Economics for the American Public Power Association, August 2016.

the LSE would have to purchase that same amount of capacity from the market – paying twice for the same number of MW. The rules discussed in this section were developed precisely to make it more difficult for resources to clear the market and interfere with all new resource development, including renewable resources.

Many of the states within the RTOs with mandatory capacity markets implemented “retail access” where the investor-owned utilities (IOUs) were required to permit alternative suppliers to sell electricity to their retail customers. As part of this transition, the IOUs were frequently required or incented to sell off their generation to merchant generators who are not regulated by state utility commissions. As a result, there are a number of states who no longer have control over the types of generation resources that are constructed. About five years ago, several retail access states within the Eastern RTOs became frustrated with the lack of new power generation being developed despite billions of dollars spent on capacity payments, and took measures to re-take control of energy resource decisions. New Jersey, Maryland, and Connecticut all established competitive bidding processes for the procurement of new, more efficient natural gas capacity through long-term bilateral contracts with distribution utilities. Such capacity could replace retiring coal plants and provide needed flexible backup for the increasing penetration of renewable resources.[54] Most notably, in January 2011, New Jersey Governor Chris Christie signed legislation to create a competitive bidding process for long-term fixed-price contracts for new power plants and, at about the same time, the Maryland Public Service Commission issued an order to procure long-term contracts for new capacity.

Fearful of lower prices that would result from entry of new generation constructed under these state efforts, owners of existing power plants sought to block this competition through changes to the capacity market rules. In 2011, FERC approved changes to what is known as PJM’s “minimum offer price rule” (MOPR). The rationale behind a MOPR is to prevent the exercise of the theoretical notion of “buyer-side market power,” a theoretical notion whereby an entity that is purchasing from the market would find it advantageous to construct a new resource for the sole purpose of expanding supply and lowering prices. A MOPR seeks to prevent such actions by replacing low- or zero-price offers from new generation with higher price offers, making it more difficult for these new plants to “clear” the capacity auctions. When PJM’s capacity market, known as the Reliability Pricing Model (RPM), was originally instituted, as the product of extended negotiations, there were two exemptions from the MOPR – one for state-sponsored resources to address a reliability need and the other to serve customer load by integrated utilities, including public power and cooperative utilities (known as “self-supply”). In 2011, in response to generator complaints, FERC however changed the rules to make it easier to trigger the MOPR and also removed these two exemptions.

ISO-NE, in accordance with an order from FERC, modified its rules to create a similar MOPR to PJM in December 2012, also following a complaint by merchant generators over actions taken by Connecticut to develop new resources, despite the absence of support from stakeholders in the region. In the New York ISO, the capacity markets in New York City and the lower Hudson

[54] See for example, Evaluation of a Draft Request for Proposals for Generating Capacity Resources Under Long-Term Contract, presented to the Maryland Public Service Commission by Boston Pacific Company, Inc., August 12, 2011, finding that Maryland could face significant retirement of its coal-fired generation, and that “flexible new generation – such as natural gas-fired combined-cycle – will be needed to accommodate new renewable supply.”

Valley have always had similar "buyer-side mitigation rules" that allow for the replacement of a capacity offer with a higher offer.

In addition to seeking RTO rule changes, the merchant generation owners sought protections from the courts by filing suit in the federal district courts in Maryland and New Jersey. These courts invalidated the Maryland order and New Jersey law, respectively, because FERC has jurisdiction over wholesale power rates and states cannot take actions that impact wholesale power markets. These decisions were appealed and upheld by the U.S. Courts of Appeals for the Third and Fourth Circuits, and appealed to the U.S. Supreme Court. In a narrowly written decision[55] issued on April 19, 2016, the Supreme Court affirmed the Fourth Circuit and invalidated the Maryland long-term contract because the contract would guarantee the owner of the new power plant a wholesale interstate rate, and therefore "disregards an interstate wholesale rate required by FERC" and is preempted by the Federal Power Act. The Court also let stand the Third Circuit's decision with regard to the preemption of the New Jersey contracts. The decision explicitly states: "Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures "untethered to a generator's wholesale market participation." But the *Hughes* decision has cast a pall of uncertainty over what the states can and cannot do to implement energy resource policies.

While PJM's MOPR applies only to new natural gas facilities at the present, the frequently changing nature of the market rules raises uncertainty as to whether the MOPR will be expanded to include renewable resources. More direct impediments to renewable energy development are contained in the ISO-NE and New York ISO's buyer-side mitigation rules, which apply to all resources, including renewable energy and demand response. In New England, a small 200 MW exemption from the MOPR was granted for renewable energy developed pursuant to state policies. In New York, following a complaint by the New York Power Authority (NYPA), the New York Public Service Commission (NYPSC), and the New York State Energy Research and Development Authority (NYSERDA), FERC approved in October 2015 an exemption from the buyer-side mitigation rules for both self-supply resources and renewable energy up to a cap, with the terms of the exemption to be developed by the NYISO itself. So far, no exemption has been agreed to. The terms of the exemption filed by the NYISO in April of this year were found by a number of parties, including NYPA, NYPSC, and NYSERDA, to be "difficult to qualify for and to maintain, which may thereby render these exemptions ineffectual."[56]

The NYPSC summarized the concerns about the NY ISO's buyer-side mitigation in an August 1, 2016 order implementing a 50 percent by 2030 Renewable Energy Standard:

> FERC's current policy of imposing "buyer-side mitigation measures" upon various resources participating in the downstate installed capacity markets creates significant risk that a PPA backed by a public resource (including utility ratepayers) could fail to clear the capacity market thereby forcing ratepayers to purchase capacity from other resources

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[55] Hughes, Chairman, Maryland Public Service Commission, et al. *v*. Talen Energy Marketing, LLC, FKA PPL EnergyPlus, LLC, et al., Supreme Court of the United States, April 19, 2016.
[56] Protest of the New York Public Service Commission, the New York Power Authority, and the New York State Energy Research and Development Authority to the New York Independent System Operator, Inc.'s Compliance Filing, Federal Energy Regulatory Commission, Docket EL15-64, ER16-1404 **(**May 31, 2016), p. 6.

that would not otherwise be needed. Although exemptions for certain renewable resources or other policy-driven procurements have been discussed in various orders, no clear policy delineations exist at this time. For instance, a proposal currently pending before FERC would allow limited exemptions from buyer-side mitigation for certain intermittent renewable resources below a 1,000 MW annual cap.[76] Whether this policy is ultimately adopted or not, FERC's current approach to capacity markets, and presumptions against bilateral contracts of major retail suppliers, cast a shadow over a reliance on mandated PPAs to achieve RES targets.[57]

### 2. Performance Incentives/Capacity Performance

A second set of changes to the capacity market rules, referred to as "capacity performance" in PJM or "performance incentives" in ISO-NE, also place significant impediments to renewable resource development. While the MOPR provides impediments to all new resources, these rules are more of a direct barrier to renewable energy and demand response participation in the capacity markets.

Capacity performance and performance incentive rules were developed when both RTOs found there to be peak usage times during which a significant number of generators were not available to delivery energy. But in both cases, the resulting changes to the capacity market rules go beyond what is needed to improve generator availability.

In ISO-NE, under rule changes approved by FERC in May, 2014,[58] generators that clear the Forward Capacity Market (FCM), and are not operating during scarcity conditions are now subject to stringent penalties, with almost no exemptions (such as maintenance outages). New England public power utilities noted in their protest against the ISO's performance incentives proposal, that this harsh penalty system "will create strong FCM biases in favor of base-load resources with high availability factors, quick-start resources, and some kinds of demand-response resources… At the same time, the ISO's proposal will create equally strong FCM biases *against* intermittent and other non-dispatchable resources and mid-range resources without quick-start capabilities." In other words, the proposal, which was almost entirely approved by FERC, incorporated into the capacity market rules a bias against renewable resources.

In the most recent ISO-NE capacity auction, held this past February to procure capacity from mid-2019 through mid-2020, just 200 MW or 0.6 percent of the capacity clearing the auction was wind and solar resources, and just 71 MW (0.2 percent) was new wind and solar.[59]

PJM also received approval from FERC for changes to its capacity market rules that will require all capacity resources to meet a new "Capacity Performance" (CP) standard to participate in

[57] New York State Public Service Commission, Order Adopting a Clean Energy Standard, Cases 15-E-0302 and 16-E-0270, August 1, 2016, P. 100-101.
[58] Order On Tariff Filing And Instituting Section 206 Proceeding, Federal Energy Regulatory Commission, 147 FERC ¶ 61,172 (May 30, 2014).
[59] ISO-NE Capacity Auction Secures Sufficient Power System Resources, At a Lower Price, for Grid Reliability in 2019-2020, ISO-NE Press Release, February 11, 2016.

capacity market auctions.[60] This CP rule has been phased in, and by the next auction, to be held in May, 2017, all resource will be required to meet the CP standard. This standard requires that a resource to be able to demonstrate a reasonable ability to perform during all emergency conditions – essentially to be available at all times. Resources that cannot meet this standard have some options to aggregate with other resources to attempt to meet the CP standard.

In their joint protest[61] of the Capacity Performance proposal, the Environmental Defense Fund, Natural Resources Defense Council (NRDC), Sierra Club Environmental Law Program, Sustainable FERC Project, and the Union of Concerned Scientists (UCS) stated that PJM's capacity market rule changes "would unduly discriminate against certain renewable energy and demand-side resources, effectively restrict capacity market competition to certain types of more costly resources, and result in unjust and unreasonable rates."

Similarly, American Municipal Power, Inc., Old Dominion Electric Cooperative, and the Southern Maryland Electric Cooperative, Inc., stated in their protest[62] that the Capacity Performance proposal "is unduly discriminatory (and contrary to enhanced reliability) is in its treatment of renewable generation, which is usually intermittent in nature, and possibly in its treatment of demand response, as well. PJM's proposal burdens these resource types to an extent that effectively precludes them from participating as Capacity Performance Resources. For example, American Municipal Power (AMP) is constructing the largest new hydroelectric generation deployment of its kind today. That run-of- river deployment totals more than 300 MW of power and more than $2.7 billion in capital investment. Should PJM's proposal be approved, the AMP Member communities that invested billions of dollars in the development of renewable resources to 'self- supply' capacity and renewable energy under the existing RPM rules will not get their full value, and the additional financial burden will be borne by the residents and commercial businesses of these Municipalities." AMP's experience could therefore deter the development of additional hydropower or other resources that would be eligible for CEIP but deterred by PJM's capacity performance rules.

Several environmental organizations, including NRDC, UCS, the Sierra Club, and EarthJustice filed a petition for review of FERC's approval of Capacity performance at the DC Circuit Court of Appeals, as have APPA, the National Rural Electric Cooperative Association, the New Jersey Board of Public Utilities, the Public Power Association of New Jersey, American Municipal Power, Inc., and the Advanced Energy Management Alliance.[63] In a joint brief, these petitioners note that "the new rules would drive renewable and demand resources out of the market…".[64]

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[60] Order On Proposed Tariff Revisions, Federal Energy Regulatory Commission, 151 FERC ¶ 61,208 (June 9, 2015).
[61] Protest of Public Interest Organizations, Federal Energy Regulatory Commission, Dockets ER15-623 and EL15-29 (January 20, 2015).
[62] Protest and Motion to Reject Filing or, in the Alternative, for Suspension and Hearings, by American Municipal Power, Inc., Old Dominion Electric Cooperative, and Southern Maryland Electric Cooperative, Inc. Federal Energy Regulatory Commission, Docket ER15-623 (January 20, 2015).
[63] Advanced Energy Management Alliance, Et Al., *Petitioners*, V. Federal Energy Regulatory Commission, *Respondent.* United States Court of Appeals for The District of Columbia Circuit, Nos. 16-1234, 16-1235, 16-1236, And 16-1239.
[64] Joint Opening Brief of Petitioners Advanced Energy Management Alliance, American Public Power Association, National Rural Electric Cooperative Association, New Jersey Board of Public Utilities, Public Power Association Of New Jersey, Natural Resources Defense Council, Sierra Club, Union Of Concerned Scientists, And American

### 3. RTO Efforts to Integrate State Policies

The Eastern RTOs have all undertaken efforts to begin a discussion of how the wholesale markets can better accommodate resources developed under state policies, and would also apply to resources developed by public power entities. These efforts demonstrate the rising concern among many stakeholders that state policy goals, most of which are aimed at increasing the level of low or no carbon resources, can be impeded by current market rules. The outcome of these efforts will be critical to the development resources that would be eligible for the CEIP. APPA therefore encourages EPA to submit comments or otherwise communicate to the RTOs the importance of undertaking market reforms and remove impediments to state and local resource choices.

Several New England states have undertaken efforts to develop new renewable resources through competitive bidding and long-term contracts. Massachusetts, Connecticut and Rhode Island issued a Clean Energy Request for Proposal and recently selected winning bidders for contracts for 460 megawatts of renewable resources.[65] Massachusetts also passed legislation, signed by Governor Baker in August 2016, that would require the states' utilities to sign long-term contracts for 1,600 MW of offshore wind power and another 1,200 MW of hydropower or other renewable resources. The procurement for these resources would begin in 2017 with the resources operational within 18 months to 3 years from that time.[66]

Utilities procuring resources under the Clean Energy RFP or the Massachusetts legislation will face significant financial burdens if the resources do not clear the auction due to buyer-side mitigation as well possible performance penalties. These economic barriers to implementation state energy policies led the New England Power Pool to initiate what is known as the "Integrating Markets and Public Policy" (IMAPP) effort to examine potential market reforms that would reduce such market rule impediments to state policy implementation. In the IMAPP problem statement, NEPOOL notes that "markets must reasonably accommodate various policy requirements such as, for example, carbon-emissions reductions or fuel source diversity. However, when states provide economic support to resources to enable compliance with public policy requirements consumer costs increase even more if the wholesale electric markets preclude those resources." An inability to reach an agreement on market reforms has delayed the IMAPP process, however.

PJM has also initiate an effort to examine potential market reforms that can better accommodate public policies. Thus far, PJM held a workshop on August 18, with the intent to "explore various pathways in which market rules can accommodate policy goals without distorting market principles."[67] PJM also issued a discussion paper that would allow "subsidized resources," such as renewable resources subject to long-term contracts, to avoid the need to clear the capacity

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Municipal Power, Inc. United States Court of Appeals for The District Of Columbia Circuit, Nos. 16-1234, 16-1235, 16-1236, And 16-1239, September 23, 2016, p. 37.

[65] New England Clean Energy RFP website, updated October 25, 2016, https://cleanenergyrfp.com/.

[66] Gov. Charlie Baker signs hydropower, wind energy bill into law, MassLive, August 8, 206, http://www.masslive.com/politics/index.ssf/2016/08/gov_charlie_baker_signs_hydrop.html.

[67] PJM Grid 20/20: Focus on Public Policy Goals and Market Efficiency, held on August 18, 2016.

market.[68] Similarly, the New York ISO has just initiated a stakeholder process to examine the impact of the states clean energy goals on the markets and examine whether a market redesign is needed.[69]

### B. Market Challenges to Supporting Other Non-$CO_2$ Emitting Resources

About twelve gigawatts (GW) of nuclear power plants have either retired or announced plans to retire since 2013.[70] Almost all of these (over 90 percent of the total GW) are located within an RTO-operated market. According to DOE, nuclear energy makes up 60 percent of the non-$CO_2$ emitting energy portfolio in the U.S.[71] These closures therefore will greatly weaken efforts to reduce $CO_2$ emissions.

The primary reason cited for the closures is an inability to recover the costs of operating and maintaining the plants in markets with declining energy prices due to reduced natural gas costs and increasing levels of renewable energy. Meanwhile, five reactors, totaling about 5.6 GW are under construction or recently came into service, within non-RTO regions all of which have some public power ownership.[72] Those plants are part of vertically integrated utilities and therefore can have their actual costs directly funded.

Recent efforts by merchant nuclear plant owners to increase the earnings of the nuclear plants have generally involved changes to both capacity market and energy rules, as well as efforts at the state level to provide subsidies to nuclear power plants. The first category includes the aforementioned capacity performance and performance incentive rules. Such rules provide an advantage to nuclear power because these facilities are able to operate at all times.[73] In the energy market arena, the focus has been on FERC efforts in the arena of what is known as "price formation," and has thus far included measures to increase the shortage pricing events where energy prices spike during operating reserve shortfalls and the removal of current energy price offer caps.[74] The Nuclear Energy Institute (NEI) has been urging FERC to accelerate its efforts,

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[68] Potential Alternative Approach to Expanding the Minimum Offer Price Rule to Existing Resources, PJM Interconnection, August 11, 2016.
[69] 2017 Integrated Public Policy - Detailed Scope, Market Issues Working Group, New York ISO, October 19, 2016.
[70] Retired nuclear plants include San Onofre 2&3, Kewaunee, Crystal River, Vermont Yankee, and Fort Calhoun. Announcements of planned retirements have been made for: Oyster Creek, Pilgrim, Fitzpatrick, Quad Cities, Clinton, and Diablo Canyon, although Fitzpatrick's closure may be prevented under its sale to Exelon and the New York ZEC program.
[71] DOE Summit on Improving the Economics of America's Nuclear Power Plants US Department of Energy, May 19, 2016.
[72] These include Watts Bar 3, which began commercial operation in October 2016, Vogtle 3 & 4, and VC Summer 2 & 3, planned to come on-line in 2019 and 2020.
[73] For example, the Nuclear Energy Institute stated that PJM's capacity performance rule "should improve the economic advantage for the 33 nuclear power plants in PJM's operating area." FERC Approves PJM Plan to Keep Power On When Electricity Demand Peaks, Nuclear Energy Institute, June 18, 2015.
[74] Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Federal Energy Regulatory Commission, Final Rule, 155 FERC ¶ 61,276 (Issued June 16, 2016); Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Docket No. RM16–5–000 (Issued January 21, 2016).

calling on FERC for "a greater sense of urgency and transparency from this agency than we've seen to date."[75]

There are two difficulties in these efforts to prevent nuclear plant retirement through adjustments to capacity and energy markets. First, because capacity and energy markets are, by their design, resource neutral, such changes raise the price for all capacity or all energy sold at a particular time and can raise the costs beyond what is needed to preserve the nuclear facilities. Second, the market outcomes are volatile and unpredictable and therefore may not actually direct revenues to the nuclear facilities and prevent the retirement of nuclear plants. For example, Exelon in May announced the retirement of the Quad Cities nuclear facility in Illinois when the plant failed to clear the most recent PJM capacity market auction, and in the absence of state legislation to provide funding for the nuclear plants.[76]

Without a successful market solution to preserve the nuclear plants, the merchant nuclear plant owners have turned their attention to the states with different levels of success. For example, in Illinois, the legislature considered and failed to pass a bill that would have created a clean energy standard and added a charge to electric utility bills that would provide a direct subsidy to the state's nuclear power plants.[77] The NYPSC on August 1, 2016, issued an order requiring the state's utilities to purchase zero emission credits (ZECs) from a group of nuclear plants found to be in danger of retirement.[78]

For states within RTO markets that have undergone retail restructuring and where the investor-owned utilities no longer own generation, determining how to best preserve nuclear power plants can be difficult. States need to carefully consider whether the strategies employed are "tethered to the wholesale markets" as the *Hughes* decision stated. Moreover, with market rules continually in flux, such state efforts nuclear facilities could lead to complaints from other merchant generators and further changes in the market rules as a result. For example, when FirstEnergy attempted to create purchased power agreements aimed at preventing the retirement of merchant coal and nuclear facilities, a group of merchant generators filed a complaint with PJM requesting that the MOPR be extended to existing generation subject to state subsidies.[79]

The NYPSC carefully determined an approach intended to fall within the state's jurisdiction – the purchase of the ZECs rather than any direct contracts or ownership. But a group of merchant

[75] Wake-Up Call, Improving the Economics of America's Nuclear Reactors, Comments as Written by Marvin S. Fertel**,** President and Chief Executive Officer**,** Nuclear Energy Institute**,** Department of Energy's Nuclear Summit, May 19, 2016.
[76] Exelon Announces Outcome of 2019-2020 PJM Capacity Auction, Exelon Press Release, May 25, 2016.
[77] Exelon makes another try for energy changes that critics call bailout, Chicago Tribune, by Kim Geiger, May 27, 2016.
[78] New York State Public Service Commission, Order Adopting a Clean Energy Standard, Cases 15-E-0302 and 16-E-0270, August 1, 2016.
[79] Complaint Requesting Fast Track Processing, Calpine Corporation, et al, v. PJM Interconnection, Federal Energy Regulatory Commission, Docket EL16-49 (Filed March 21, 2016). APPA has not taken a position on the FirstEnergy proposal, but has objected to the changes to the MOPR requested by Calpine, et al.

generators has since filed suit in the Southern District of New York asking that the court invalidate the ZEC program.[80]

APPA has long argued that the best approach for implementing state environmental and other policies within the restructured wholesale markets is to remove the mandatory capacity markets, and procure needed capacity through bilateral contracts and ownership. Such an approach would allow for targeted approaches to preserving nuclear facilities, such as contracts or ownership, without continual uncertain and costly tweaking of the markets or the constant threat of pre-emption of state efforts by market rule changes. EPA could take steps to ensure a more successful outcome for the CEIP by recognizing the interconnection between the wholesale market design and policies aimed at reducing $CO_2$ emissions. It would be beneficial for EPA to weigh in at FERC and encourage reforms that minimize a reliance on the problematic markets and allow greater use of bilateral contracting and resource ownership.

## X. Conclusion

APPA appreciates the opportunity to comment on the proposed CEIP. We look forward to working with the agency as it works to develop policies designed to mitigate increases in GHG emissions. Please contact Ms. Carolyn Slaughter at cslaughter@publicpower.org with questions regarding the above comments.

Sincerely,

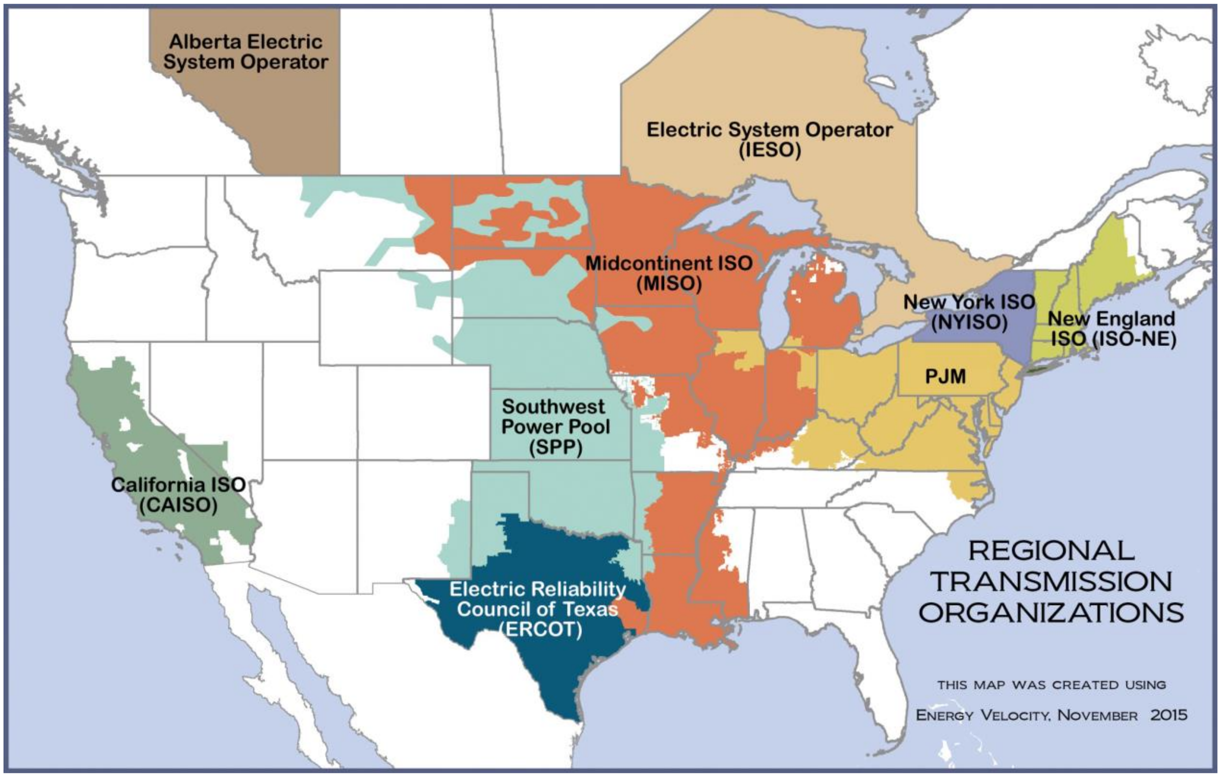
Carolyn Slaughter

Carolyn Slaughter, Director Environmental Policy
American Public Power Association

[80] Coalition for Competitive Electricity et al v. Zibelman et al, (1:16-cv-08164), US District Court, Southern District of New York, October 19, 2016

## XI. APPENDIX

A brief overview of RTOs and the markets they operate is provided. RTOs cover much of the Northeast, Mid-Atlantic, Midwest, California, and Texas, as shown in the map below.




Under Federal Energy Regulatory Commission (FERC) oversight, the RTOs operate markets for the wholesale sale of electric energy (both day-ahead and real-time purchases), as well as ancillary services. ISO-New England (ISO-NE), the PJM Interconnection (PJM), New York ISO (NYISO), and the Midcontinent ISO (MISO) also operate what are known as capacity markets, which were created to provide revenue to a power plant owner to stand ready to supply power when needed or for an end-user to curtail load when called upon ("demand response"). An electric power utility or other load-serving entity (LSE) purchases or owns capacity to ensure that sufficient resources are standing ready to provide a reliable supply of power, or curtail load, during peaks in demand (generally the hottest and coldest times of the year).

PJM, ISO-NE and parts of the NYISO operate what are known as "mandatory" capacity markets where capacity must be bought and sold through periodic capacity auctions. Capacity that is owned or contracted for bilaterally still must be offered into and clear the auctions. PJM and ISO-NE both operate a "forward" market where capacity is procured three years in advance for a one-year period. The capacity auctions in the NYISO are shorter term and procure capacity closer to the period when the capacity will be needed.

MISO's capacity market is voluntary and LSEs can choose whether to participate. Neither the California ISO nor the Southwest Power Pool operates a capacity market. The Electric

Reliability Council of Texas, which functions as an RTO but is not under FERC's jurisdiction because of the intrastate nature of its grid, does not operate a capacity market.

The capacity auctions produce a single price per megawatt (MW) that will be paid to all capacity resources that clear, regardless of the type and cost. Under the mandatory capacity market rules, resources can only be counted toward the LSE's resource adequacy requirement if they "clear" the auction for the applicable year, meaning that the resource has submitted an offer below the clearing price. Until a few years ago, capacity owned by a utility or sold under a long-term contract to an LSE to serve their load, or capacity developed by a state to meet a reliability need, could be offered into the auction at a zero price that would ensure such clearing. Because such resources are paid under another arrangement, they are indifferent to the capacity auction price and submit a zero offer as a "price taker." But, as explained in Section IX this is no longer permitted for certain resources.