Presentation to the Department of Energy
Quadrennial Energy Review
Salt Lake City, April 25, 2016

My name is Colin Jack; I'm a licensed professional electrical engineer and I am the Chief Operating Officer of Dixie Power in St. George, Utah. Dixie Power is an electric cooperative that serves about 18,000 members scattered across almost 2,000 square miles in the southwestern corner of Utah and northwestern corner of Arizona*. There are several rural electric cooperatives in the state of Utah, including our neighbor to the east which serves an area of 16,000 square miles; compared to large cities like Salt Lake and Provo, we have relatively long lines and low consumer density, therefore a higher cost and lower revenue per consumer on average. Even so, I'll compare our power system performance against any other system in the world; we enjoy some of the lowest retail rates in the country, have an outstanding safety record with an E-mod of 0.68, and enjoy 99.99% reliability year after year. And having worked 10 of my 30 years overseas, I can make my comparisons world-wide with confidence; I've worked in 26 different countries and traveled in another 26, so I've seen power systems in 52 different countries.

In my 30 year career as a power engineer I've seen and deployed many technological innovations. I've been directly involved as we've migrated meters and protective equipment from electro-mechanical devices, to solid state digital, and then to microprocessor controlled. I've seen materials evolve from wood to steel and to composite fiber/resin, and from porcelain to polymer. Currently, we have meters that read themselves and send their readings back to the office over the powerlines. We supervise and operate our power stations from the office over fiber optic lines that we run with our transmission lines. We do our engineering on computers instead of on the drafting table and with a hand calculator. All of these innovations in our power industry contribute to Dixie's success in providing low-cost but reliable service to our members, many of whom are retirees who live on fixed incomes. Rural cooperatives serve economically sensitive communities, and rural households spend a greater percentage of their household income on utilities than their urban counterparts. So even small rate increases have a greater economic toll on rural communities.

The power delivery industry sees its fair share of challenges. When I first started in this business, our greatest opponent was Mother Nature, who was very adept at turning off the lights with wind and lightning. Now, 30 years later, Mother Nature still plays a major role, but often takes a backseat to misguided government policies that can have the same result. We deal with Federal land management procedures that effectively block all new powerlines, and even upgrades and maintenance that are required to keep up with our growing population and aging facilities, are almost impossible to accomplish, and certainly impossible to complete in a timely and cost-effective manner. Federal agencies designate large areas as "roadless," and therefore unpassable, even though there have been roads through those areas for over 100 years. They designate "endangered species," making whole areas off-limits to powerlines, even though the activities we need to do to maintain our system do not, in any way, threaten those species' habitats. The federal government also takes clean, affordable coal-fired power off the menu, even though there is no presently available, viable alternative to provide plentiful, reliable power.

State governments are not a lot more helpful to us providing affordable and reliable energy to our members. Net metering requirements from the State, means that the co-op must take energy from solar home system owners, that is generated off-peak, and give it back to them on-peak, as if those two things were of equal value. Also, since the majority of a utility's fixed costs are blended into the energy rates, as members with solar systems purchase less energy, the fixed costs get shifted to their neighbors who can't afford expensive solar panels. And even though I've been warned that to tell the truth about solar power is as Quixotic as standing in front of a run-away train, let me do it anyway; and I know something about it because I not only have years of experience with SunSmart and now Dixie Solar down in Utah's sunbelt, but also because we've done thousands of solar home systems on grass huts all over the world with NRECA International: there are 3 reasons co-op members get interested in solar energy. 1. To save money; they don't. 2. To reduce CO2 emissions; they don't. and 3. To be prepared for power outages; and they don't even do that. I'd be happy to expound on any of these points in a Question and Answer session. Thank you.

Presentation to the Department of Energy - Appendix
Salt Lake City, April 25, 2016

Challenges for distribution systems:

1. Electric Cooperatives Are:
   a. Private, independent, non-profit electric utilities
   b. Owned by the customers they serve
   c. Incorporated under the laws of the states in which they operate
   d. Established to provide at-cost electric service
   e. Governed by a board of directors elected from the membership which sets policies and procedures that are implemented by the co-op's management
2. Rural electric cooperatives deal with low consumer density and relatively high costs
   a. Cooperatives have an average 7 consumers per mile of line and collect annual revenue of approximately $15,000 per mile of line
   b. IOUs have an average of 34 consumers per mile of line and collect $75,500 per mile
   c. Municipal systems have an average of 48 consumers per mile of line and collect $113,000 per mile
3. We still do a great job relative to the rest of the world – Dixie Power data:
   a. 99.99% reliability
   b. Workers Compensation Fund (WCF) Experience Modifier (E-mod) of 0.68 means that we pay 68% of the standard price for Workers Comp insurance thanks to our outstanding safety record
   c. Residential retail rate of less than 6 cents/kWh
4. We employ many technological advances in our systems, second to none:
   a. Power poles: wood, steel, fiber/resin
   b. Insulators: porcelain, polymer
   c. Relays: electromechanical to solid state digital to microprocessor
   d. Meters: electromechanical to digital powerline carrier once every 27 hours to powerline carrier once every 8 hours
   e. Engineering: manual to mainframe computer to PC to laptop
   f. Mapping: manual to AutoCAD to ESRI GIS
   g. Billing: manual to dBase to commercial program integrated with metering and engineering
   h. Communications: radio, then added microwave, and then added fiber optic lines
5. End uses:
   a. Residential – especially retirees on fixed incomes in St. George (Washington County, Utah)
   b. Commercial – pumping for municipal water supplies, schools, dairies, small businesses
   c. Irrigation – crops of corn and hay
   d. Industrial – ice cream factory, glass factory, oil wells, mines
6. Federal land management and endangered species cause us hardships
   a. Dixie's experience building 30 miles of 69kV transmission line to Beaver Dam, AZ through a designated transmission corridor (see attached sheet;)
      i. Easement holdups resolved only after involving Congressman Matheson
      ii. 3rd party environment expenses over $370,000
      iii. Unquantified expenses moving crews for birds, tortoises, and loco week
   b. Dixie's experience building 15 miles of 12.5kV distribution line to radio transmitter on Seegmiller Mountain to eliminate existing diesel generator:
      i. Approximately $120,000 has been spent in permit fees, alignment investigation, and meetings before an actual power line design could begin.

        ii. No species or cultural resource is threatened or endangered within the proposed route. Visual impact has been the basis for all environmental studies and delays.
        iii. Proposed routes were selected based of the BLM Resource Management Plan, and the lower VRM areas where existing road corridors were requested. BLM forced the route to be in a higher class VRM area that is off the main road, requiring overland travel or new access roads that will require much higher restoration measures.
        iv. Apparent visual inconsistency between projects is demonstrated by the extreme measures to install 35-45 foot wood distribution poles along a dirt road with very load traffic versus 95-110 foot tall fiberglass transmission poles constructed along I-15 and Old Hwy 91. Visual on the transmission line seems to be of a low priority where threatened and endangered species are encountered. The distribution line was forced off the dirt road so it wasn't as visual.
        v. Approximately $250,000 may be required specific to environmental measures and delays for the 15 mile distribution line. This is a heavy cost to feed a few services at the end of the line.
    c. Garkane's experiences with Hatch line: On the 38 mile long Tropic to Hatch 138 kV transmission line it was a little over 7 years from the initial right of way application to the FS Notice to Proceed. During that time we paid outside experts and consultants $2.3M to perform various studies and prepare various plans. We have ongoing cost during construction of $150k per year for environmental monitors and surveys. The project has grown from the original estimate of $2.5M to $8M today.
    d. BLM attempting to charge rent for each ROW instead of acknowledging the RUS exemption in advance, requiring each co-op to reapply for the exemption each time
7. Regulating coal out of use via "Clean Power Plan" will cause reliability problems for the whole country: see attached letters from FERC, NERC, WECC
    a. WECC letter concerns:
        i. Implementation timing
        ii. Resource and transmission adequacy
        iii. Balance of system flexibility
        iv. Natural gas dependency
        v. Grid stability/resiliency
        vi. Unintended consequences
    b. NERC letter concerns:
        i. Problems with all 4 building blocks of CPP
        ii. Building Block 1 – Coal Unit Heat Rate Improvement
            1. determine if there are remaining opportunities
            2. some coal-fired power plants retiring earlier than anticipated
        iii. Building Block 2 – Gas Unit Re-Dispatching
            1. increasing demand for natural gas
            2. timing is required to add new pipeline and generation resource
            3. increasing the risk for potential blackouts
        iv. Building Block 3 – Clean Energy
            1. overestimate the amount of energy efficiency
            2. underestimate costs and may underestimate the capital investments
            3. reliability consequences of renewable resources
            4. requires more transmission
            5. lead times may not align with the CPP implementation timeline
        v. Building Block 4 – Energy Efficiency
            1. Fossil-Fired Retirements and Accelerated Declines in Reserve Margins

    2. Transmission Planning and Timing Constraints
    3. Regional Reliability Assessment of the Proposed CPP
    4. Reliability Assurance
    5. Coal Retirements and the Increased Reliance on Natural Gas for Electric Power
    6. The Changing Resource Mix and Maintaining Essential Reliability Services
    7. Increased Penetration of Distributed Energy Resources
8. Net metering is an expense being borne by all of our members:
    a. Fixed operating costs: as members connect to the cooperative powerlines, whether or not they choose to purchase energy, they incur costs even as cooperative incurs the expenses of line crews and vehicles to keep the lines maintained and energized, technical staff to keep the system functioning and compliant, and billing and accounting staff to keep the system solvent. All of these expenses are fixed even if none of the members actually chose to take energy off the co-op's powerlines but still wanted them energized and available. Currently these costs add up to about $50 per customer per month; the difference between the current monthly Facilities Service Charge and the $50 is averaged across all kWh sales. If kWh sales diminish below the norm due to energy supply choices, then the monthly Facilities Service Charge would need to increase to $50.
    b. Demand expense: as Net Metering customers deliver their excess energy generated by their solar home systems during the hours of 10AM to 3PM, but then want to receive one-for-one energy back from the cooperative during the morning peak (6AM to 8AM) and the afternoon peak (from 5PM to 9PM) then the cooperative as a whole is stuck with unrecovered demand expenses (which are typically included in the kWh costs on residential rates.) This expense is currently $40 per customer per month; so if more customers migrated to net metering arrangements, the $40/month demand charge would either need to be applied to the net metering customers or would need to be socialized to all of the rest of the co-op members who didn't choose to have net metering installations.
    c. California is already seeing wholesale energy prices going negative during solar generation hours between 10AM and 3PM; the excess power has to be paid for twice – once to the customer and once to the neighboring utility to take the power away. Then to absorb the excess energy utilities have to turn off base-load generation and choose to run expensive peaking plants instead. (See all discussions of the "duck curve" as exposed by the California Independent System Operator (Cal ISO) of the integrated transmission system.)
9. Solar energy is a waste of money:
    a. More expensive - The best retail price on solar power right now is around $3/watt. So in round numbers, if someone installed 6kW on their roof (the average roof size,) it would cost them $18,000. But, they'd qualify for 30% in tax credits from the Federal Government ($5,400 in this case, assuming they owe at least that much in taxes) and 20%, up to $2,000, in tax credits from the State of Utah, which leaves them having paid for only 59% of their system, or $10,600. Since we know from Dixie's solar farm, SunSmart, that each kW of solar panels can generate an average of 144kWh per month, then this illustrative system would generate about 864kWh per month on average, more in the spring and less in the winter and summer. With Dixie Power's retail rates at 5.8₵/kWh, this member would save $50/month off their power bill. So, with a cost of money at 3.5%, the monthly payment on the system (at 15 years) would be over $75/month, so the member would lose money each month until the system were paid off. It's important to know that solar panels only last 20 years, so any payback has to happen before that time.
    b. No reduction in CO2 – intermittent resources such as solar and wind must be backed up by simple cycle gas engines which have the same CO2 emissions per kWh as coal-fired generation

c. Not useful for preparedness – by national safety standard (IEEE1547) net metering invertors must shut off energy production whenever the commercial grid goes off

10. Summary

From our perspective as an electricity distribution company, our top 3 concerns are:

1. Federal intrusion into our power supply, rather than allowing free markets to determine technology selection; first mandating that we use coal in the late 70's and then shutting down coal before the costs are recovered; The energy industry is a capital intensive industry. Costs for building resources and infrastructure are necessarily amortized across long periods of time, not unlike a home mortgage. These long-term financing arrangements rely upon long-term regulatory stability. Utilities cannot abandon projects and project financing mid-life in favor of alternative resources without creating significant rate shock for their rate payers. To prevent economically harming rate payers, regulations must be consistent and predictable. In addition, transitions between regulatory regimes must be conducted in an orderly manner over timeframes consistent with project financing requirements.
2. Federally mandating expensive solar projects, which don't meet the power supply or economic benefit needs of our customers.
3. Federal land blockading new powerlines and even access to existing powerlines since we live and work on small islands in a sea of Federal lands.

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The Power of Friendly Service

RIGHT OF WAY PERMIT TIMELINE – ATKINVILLE TO BEAVER DAM

January 9, 2009 (Updated Apr 2, 2009)

- October 23, 2006 Meeting with BLM (Jim Crisp) to discuss Utility Corridor between St. George and Beaver Dam.
- November 6, 2006 initiated contract with JBR Environmental Consultants
- November 20, 2006 Submitted digital route to JBR consultants
- December 12, 2006 Submitted easement application and map to BLM
- December 18, 2006 Submitted separate easements for Arizona and Utah State as requested by the BLM.
- Feb 2, 2007 received request to prepare POD "Plan of Development" to submit to the BLM
- Feb 26, 2007 received a template for the POD from the BLM
- March 26, 2007 Submitted rough draft on the POD to consultants as requested by the BLM
- Apr 16, 2007 Submitted revised POD following comments to JBR
- May 10, 2007 Submitted revised POD following more feedback from staff and BLM.
- May 14, 2007 Submitted revised Arizona easement application to the BLM which amends existing easements rather than new authorizations.
- May 21, 2007 JBR submitted final version of the POD to the BLM
- June 19, 2007 Public Scoping letter sent out to 200 people/groups for comments
- June 26, 2007 contacted BLM in regards to the possibility of moving the high impact section of line through Bulldog Pass to follow the existing road where the proposed Rio Virgin fiber line would be placed up to HWY 91
- Aug 2, 2007 relayed to JBR to discontinue alternate around Bulldog pass as timing and BLM concerns outweighed the benefits of locations. It was stated that this alternate would delay the project around 6 weeks of consultant work, and could push receiving the permit into Jan of 2008.
- Aug 22, 2007 received request from BLM to move alignment in Milk Vetch habitat to area along freeway ROW.
- Aug 23, 2007 – Mar 11, 2008 dialog and work continued on the re-route of the line and pole placement and access data.
- Mar 12, 2008 had on site meeting with the BLM to review the requested route in the Milk Vetch habitat area.
- Mar 13, 2008 JBR requested to modify contract based on additional requirements by the BLM
- Aug 14, 2008 JBR sent BLM the BA (Biological Assessment) to review prior to the EA (Environmental Assessment) being complete
- Aug 18, 2008 BLM submitted back changes on the BA to JBR
- Sep 8, 2008 received cultural report on the line from Big Horn Archeologists

- Sep 8, 2008 revised BA returned back to the BLM
- Sep 11, 2008 BLM sent comments on EA review to the JBR and requested meeting
- Sep 17, 2008 BLM met with USFWS to discuss our project and in particular the impacts to the Milk Vetch plants.
- Sept 18, 2008 JBR requested to modify contract based on additional requirements by the BLM
- Sept 18, 2008 received contact by BLM in regards to the meeting they had with the USFWS. A meeting was requested to discuss the issues
- Sept 25, 2008 attended meeting with BLM and USFWS representative on the project and to discuss mitigation and access issues. New 3 mile fence line to be added to the project proposal, included in the EA and BA. The BLM felt we should receive the permit by Jan 1, 2009.
- Oct 17, 2008 JBR submitted final BA document to the BLM
- October 27, 2008 sent to the BLM digital photos and sheets on the poles using for the project.
- Nov 7, 2008 made site visit of the entire project with several BLM employees and Cultural consultant to see the proposed structure sites and potential impacts due to access roads.
- Dec 30, 2008 JBR submitted another EA review document to BLM
- Dec 30, 2008 we submitted minor editorial comments back to JBR on the EA.
- Dec 31, 2008 BLM notified us that we will not receive the right of way permit until the USFWS submits their BO (Biological Opinion) and it is approved.
- Dec 31, 2008 JBR submitted final version of the EA back to the BLM.
- Jan 5, 2009 BLM notified us that before we are to receive the permit they must: receive the BO from the USFWS (~1-2 months), receive comments from the public following the 30 day period on the Notice of Availability to the EA, and receive a report on consultation by the State Historic Preservation Officer (~1 month).
- Jan 19, 2009 Revised BA following comments submitted to USFWS & BLM from JBR. Everyone involved in both agencies were copied.
- Jan 20, 2009 Reclamation Plan submitted as requested and sent to USFWS & BLM from JBR.
- Jan 20, 2009 Brian with USFWS corresponded to JBR that he is in process of reviewing the BA & Reclamation Plan and will have comments by end of the week if not sooner.
- Jan 23, 2009 Brian responded back that he had computer issues and time off and would be postponed a week later for comments.
- Jan 23, 2009 BLM submitted “Notice of Availability” to the public for the 30 day comment on the line.
- Jan 29, 2009 Brian (USFWS) submitted comments on the BA back to JBR after much research and consultation with other professionals.
- Jan 30, 2009 Shered (BLM) commented back to Brian (USFWS) that all the alternatives and changes he submitted should have been done long before now, that this project has gone well over 2 years.
- Jan 30 – Feb 2, 2009 BLM and USFWS representatives corresponded back and forth and finally agreed to arrange a time for a conference call to resolved the requests in changes by USFWS.

- Feb 4, 2009 conference call was made with BLM and USFWS representatives participating. Eric with JBR represented Dixie on the call and reported back with a summary of 7 main items. JBR took these agreed upon requirements to incorporate in the BA. All 7 items decided were more favorable to Dixie Escalante over the proposed measures USFWS was recommending.
- Feb 10, 2009 JBR contacted BLM and USFWS on 3 outstanding issues yet to be resolved that came out of the conference call which needed investigating and discussing.
- Feb 11, 2009 USFWS representative forwarded a document to address one of the issues in regards to seed mix for restoration. She requested a shape file (GIS) to determine additional information.
- Feb 12, 2009 JBR submitted shape file to USFWS.
- Feb 18-20, 2009 USFWS submitted updated seed mix and comments on locations of Astragulus Milk Vetch outside of the reserve boundaries.
- Feb 25, 2009 JBR contacted BLM to request their comments on unresolved issues with the BA that came out of the Feb 4th conference call. Also JBR inquired on the status of the public comment period.
- Feb 25, 2009 BLM reported that no comments were received from the public on the line. Additional BLM comments were given to JBR in regards to tortoise habitat and construction allowances along HWY 91.
- Feb 26, 2009 BLM confirmed BA would be finished in house and they submitted a figure to add to the BA.
- ~Mar 3, 2009 BLM officially submitted the BA to USFWS.
- Mar 24, 2009 BLM replied back to Dixie on the status of the permit that USFWS was going to work on the BA the rest of the week and that it sounded like it should be done soon.
- Apr 1, 2009 JBR had inquired of the USFWS when they expected the BO would be completed. Brian (USFWS) responded that he has 135 days to do this and this dead line would be July 16th. He referenced his heavy work load and "high priorities" that are taking precedence, but he would try to get it done prior to July 16th but would not commit to exact dates.
- Apr 1, 2009 JBR corresponded back to Brian to state the hopes that he has been heavily involved in the process and that he shouldn't need the 135 days to do this. It was also stated the understanding that Arizona FWS was given this project last year because the woman in the Utah FWS office was going on Maternity Leave, and this shift should expedite the permit. JBR also offered to help in any way.
- Apr 1, 2009 Brian (USFWS) stated back that he took over the project due to the lead biologist out of the Utah office was going on maternity leave, not to expedite the process. He stated he's trying his best to get it done ASAP, but would not commit to any date prior to July 16th. Brian stated that no one else can help, but to understand he's trying but is under heavy workloads and juggling multiple important projects.
- Apr 6, 2009 JBR provided a cost estimate for the survey required prior to construction.
- Apr 6, 2009 spoke to Kitti with USFW Service. Very rude conversation and she hung up on me. I tried to request authorization for JBR to do plant surveys within the Milk Vetch habitat. Reported this to the BLM.
- Apr 10, 2009 Laurie Ford with the BLM provided several maps she had prepared to encompass all the construction restricted areas and dates.

- Apr 15, 2009 submitted up to date shape files of the transmission line to the BLM.
- Apr 15, 2009 received a request from BLM to submit a full proposal with cost and time estimates to do the surveys that will be submitted to the USFWS for approval.
- May 1, 2009 BLM received draft BO from USFWS and are reviewing it. JBR was asked to correct discrepancies between it and the EA.
- May 7, 2009 BLM and USFWS are reviewing the BO.
- May 11, 2009 Dixie communicated with JBR to accept the agreement on the survey costs, but told them to wait for the BLM permit to be granted.
- May 26, 2009 received word from Laurie at the BLM that they received the BO in the mail today. They stated that they should have the ROW documents prepared to sign by tomorrow.
- May 27, 2009 obtained the BLM ROW
- June 3, 2009 training and start of the project.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

May 15, 2015

Janet G. McCabe
Acting Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Acting Assistant Administrator McCabe:

Thank you for your letter of May 6, 2015, regarding the Environmental Protection Agency's (EPA) Clean Power Plan proposal and the Commission's recent conferences on the proposal. We appreciate the attendance and participation by you and other EPA representatives at those conferences, and your openness to the perspectives offered by us and others there. We also appreciate the fact that you and others from EPA have met with each member of the Commission on more than one occasion. As you know, the conferences focused on the proposal's possible effects on three aspects of the Commission's responsibilities: electric reliability; energy infrastructure; and wholesale energy markets. Our letter today addresses the reliability issues discussed at the conferences.

First, as you know, many of the conference speakers expressed concern about the interim goals in the proposed Clean Power Plan, and suggested a need for more flexibility in the early years of compliance. This issue may be the most prominent, and most discussed, of the reliability issues raised at the conferences and elsewhere. As your letter recognizes, EPA's final rule should provide enough time and flexibility for affected entities to take the actions that they must take to ensure system reliability. These actions could include the construction of gas or electric infrastructure to support the addition of new capacity. Thus, we trust EPA will consider the concerns raised with the interim goals, and other views expressed on this issue, as EPA finalizes its rule. Various commenters indicated, for example, that more flexibility on the interim goals may lessen reliance on other processes for addressing reliability.

Apart from this issue, we will focus on how the Commission can continue to fulfill its responsibility on Bulk-Power System reliability after EPA releases any final rule on the Clean Power Plan. Numerous panelists at the conferences urged the Commission to work with EPA to address any reliability issues that arise as states comply with the Clean Power Plan. Specifically, panelists recommended that the Commission work with EPA to establish processes for modifying compliance obligations when unforeseen delays in implementation efforts could otherwise risk harm to reliability (a "Reliability Safety Valve") and for generally reviewing state plans for interstate impacts on reliability ("Reliability Monitoring and Assistance").

Reliability Safety Valve

For the purpose of this letter, we define the Reliability Safety Valve as a process through which the affected entities can petition the EPA for temporary waiver or adjustments to the emissions requirements or compliance timelines in an approved state plan to preserve Bulk-Power System reliability.

If the EPA chooses to adopt a Reliability Safety Valve, the Commission's participation should be clearly defined, as in the process for the Mercury and Air Toxics Standards (MATS) fifth year.[1] Specifically, after a plan is approved and in place, the Commission could review a petitioner's claims that unforeseen or emergency system conditions will result in violation of a Commission-approved Reliability Standard or reserve margin deficiency, unless a compliance obligation is adjusted. In addition, as we indicated for the MATS process, we could identify issues, pursuant to our other areas of authority, such as requirements in a Commission-approved tariff. Similarly, the Commission could review the petitioner's proposed mitigation as to whether it will resolve the Reliability Standard violation or reserve margin deficiency. In this narrow role, the Commission would not opine on other issues that EPA could consider, such as whether an applicant had made sufficient efforts to resolve the Reliability Standard violation without deviating from approved emissions requirements or compliance timelines or whether there were other ways to resolve the Reliability Standard violation or reserve margin violation deficiency. That is, the Commission's role would be to consider whether a specified set of loads, resources and grid facilities would cause a Reliability Standard violation or

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[1] *See Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards*, 139 FERC ¶ 61,131 (2012); The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard (Dec. 16, 2011), http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

reserve margin deficiency, not whether the applicant or EPA should pursue a different set of options and, if so, which options.

If EPA is interested in further developing this concept, our staff is available to work with EPA staff on the specific reliability-based information that applicants should be required to provide to facilitate our assessment of a request for relief. Our expectation is that this information could be similar to the information required of applicants seeking a fifth year under MATS, with any modifications needed for the context of the Clean Power Plan.

Reliability Monitoring and Assistance

As noted above, various panelists at our conferences advocated a process that takes place prior to, or in parallel with, EPA's review of state plans to identify and potentially mitigate potential reliability concerns. Industry participants suggested that this oversight consist of Commission and/or North American Electric Reliability Corporation (NERC) review of all state plans to ensure that the combined effects of state plans do not negatively impact electric reliability.

Before turning to the technical aspects of these proposals, it is important to note that the Commission's role on reliability is defined by Congress, and generally consists of approving proposed reliability standards for the Bulk-Power System, if they meet the statutory criteria, and then enforcing or overseeing enforcement of those standards. The Commission's exercise of its rate jurisdiction also, at times, has effects on reliability issues. But, reliability also depends on factors beyond the Commission's jurisdiction, such as state authority over local distribution and integrated resource planning. Similarly, state authority to propose plans for compliance with the federal Clean Air Act does not depend on, or require, Commission approval. The Commission also lacks specific statutory authority to require a public utility to build a new power plant or new transmission line. The Commission is not seeking to alter this balance of Federal and state roles or to assert authority over state plans. Any Commission role in this area must be crafted carefully to respect the authority and responsibility of states.

With this background, we believe a process to review state plans for potential reliability concerns should rely primarily on existing processes for identifying and addressing reliability issues, adjusted as appropriate for the circumstances. Planning authorities such as RTOs and ISOs or, in other areas, NERC, Regional Entities or reliability coordinators currently model the electric grid to plan and assess the reliability of the Bulk-Power System. These processes are generally adequate, although increased effort by industry will be needed as

State plans are developed. As appropriate, the Commission could then review the analyses, suggest or request additional or modified analyses or, in limited cases, perform analyses itself. Under existing FERC statutory authority, the Commission could look more closely at particular areas or issues, subject to resource availability, and taking into consideration requests by EPA, States, or others.

For areas or issues of concern, the Commission could convene technical conferences, require presentations at Commission meetings, or engage in other forms of outreach at fora such as the National Association of Regulatory Utility Commissioners and NERC meetings. If requested by EPA, the Commission could provide formal input on a particular plan or set of plans, subject to resource availability. In any event, the Commission's role generally should focus on the regional aspects of Clean Power Plan compliance. Our staff is prepared to work with EPA staff to provide this Reliability Monitoring and Assistance.

Conclusion

The Commission intends to stay informed about the development of state plans so that the Commission will be able to respond to Bulk-Power System reliability issues that might arise. We appreciate EPA's engagement with the Commission on how the Clean Power Plan may affect the reliability of the Bulk-Power System and hope to continue this dialogue as the Clean Power Plan is finalized and implemented.

Sincerely,

Norman C. Bay
Chairman

Philip D. Moeller
Commissioner

Cheryl A. LaFleur
Commissioner

Tony Clark
Commissioner

Colette D. Honorable
Commissioner

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Initial Reliability Review
November 2014

RELIABILITY | ACCOUNTABILITY




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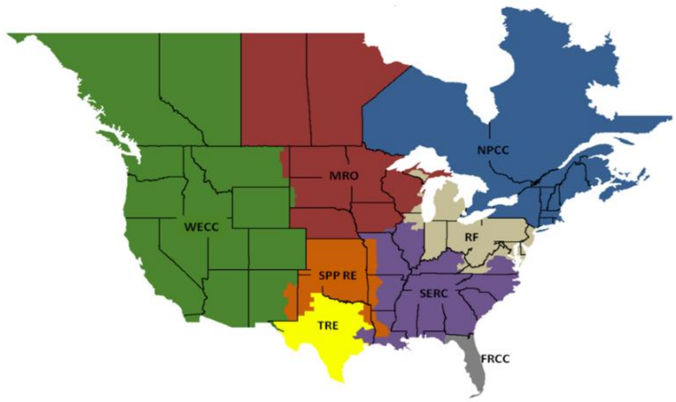
Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

NERC Regions and Assessment Areas



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

The North American Electric Reliability Corporation

Atlanta
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-2560

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1325 G Street NW, Suite 600
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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- Provide an evaluation and comparison of the assumptions supporting the CO_2 reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO_2 emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:[3]

Building Block 1: Heat rate improvements
Building Block 2: Dispatch changes among affected electric generating units (EGUs)
Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO_2 reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).[4] The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While

[4] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC's initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach** that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins
The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints
The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country's resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP
Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance
The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a "reliability back-stop." These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power
Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services
ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)
ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC's plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA's proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

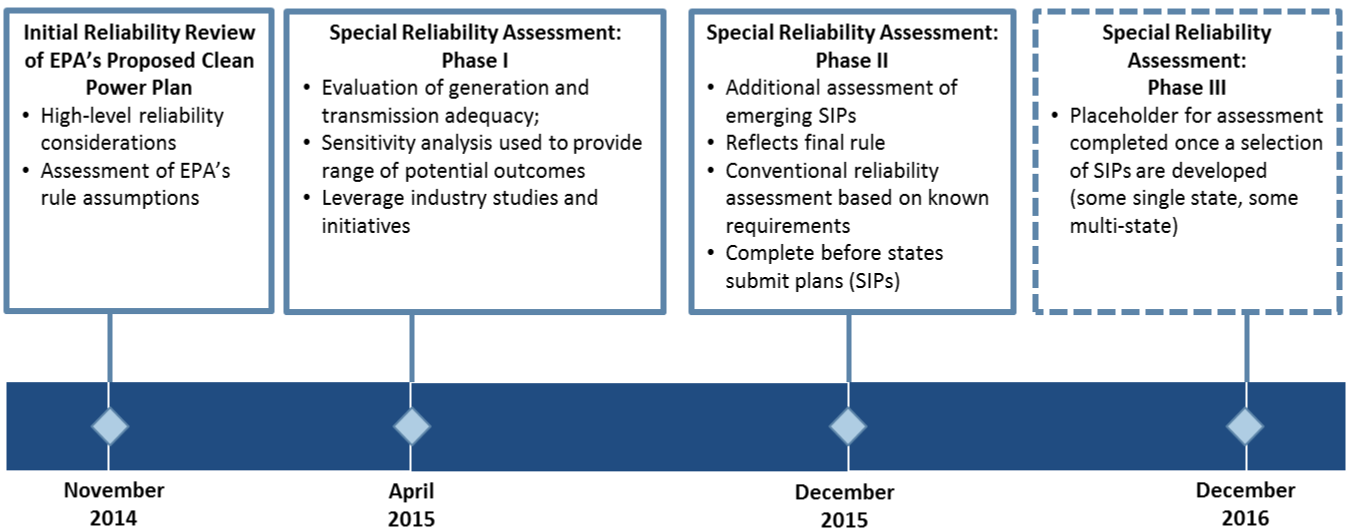

Figure 1. NERC's Assessment Actions and Schedule Timeline

Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO_2 emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO_2 reductions are required under State Implementation Plans. Under the EPA proposal, CO_2 reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).[5]

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;[6] (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[7] Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.[8] NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO_2 from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO_2 and protecting public health and the environment.[9]

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO_2 reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO_2 reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

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[5] State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

[6] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

[7] 79 FR 34854 https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating page 34854.

[8] EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

[9] EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector "*The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans*." http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-benefits.pdf.

Summary of the Proposed Clean Power Plan

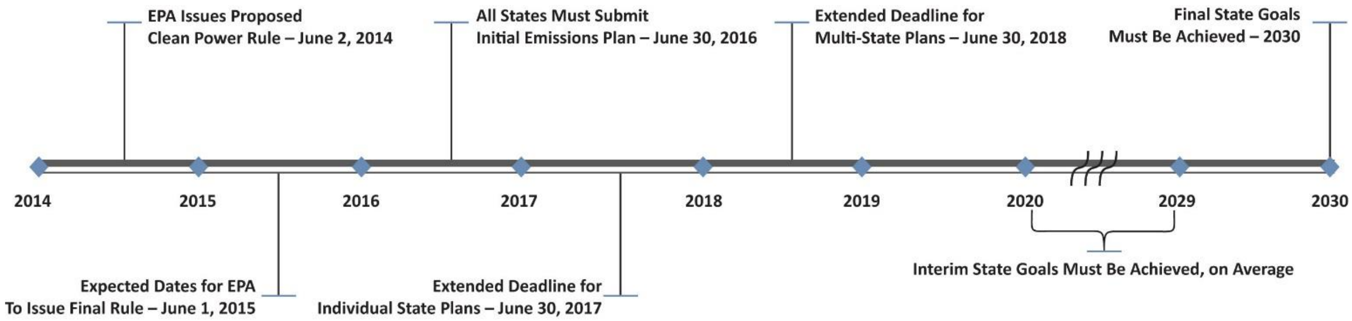


Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state's specific information, yielding a carbon intensity rate for each state.[10] There is a wide range of potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

EPA's Proposed Clean Power Plan: Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2: Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO_2 by applying four different BSER Building Blocks.[11] Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

[10] EPA Fact Sheet: Clean Power Plan - National Framework for States.

[11] EPA Clean Air Act: Section 111(d) authorizes EPA to apply "best system of emission reduction" to this section's affected sources.

The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Renewable Energy

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

Clean Power Plan – Assumption Review

This section provides a critical review of the EPA's assumptions for state-specific CO_2 emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

Plant Efficiency

The EPA's heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.[12] The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA's assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO_2 emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:[13] (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.[14] Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet's average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO_2 reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

[12] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.
[13] These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).
[14] Coal-Fired Power Plant Heat Rate Reductions (January 2009).

Building Block 2 – Gas Unit Re-Dispatching

Natural Gas

The EPA assumes that reductions in CO_2 emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than $33/metric ton CO_2.[15] In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.[16]

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA's Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO_2 emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an "all-hazards" approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.[17] When including the 54 GW of nameplate coal capacity already announced to retire by 2020[18] (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources.

As observed during the 2014 polar vortex,[19] the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

[15] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.

[16] Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation.

[17] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).

[18] Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.

[19] NERC 2014 Polar Vortex Review:
http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

Fuel Supply and Delivery

- Natural gas interruptions
  - supply injection
  - compressor outages
  - one pipeline explosion
- Oil delivery problems
- Inability to procure gas
- Fuel oil gelling

Extended Low Temperatures

- Low temperature limits for wind turbines
- Icing on hydro units
- Failed auxiliary equipment
- Stress of extended run times
- Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors)

Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

Building Block 3 – Clean Energy

Renewable Energy

Building Block 3 describes the EPA's method to reduce CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state's nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO_2 emission rate goal calculations.[20] The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO_2 reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA's assumed non-hydro renewable generation in a given state, the lower the state's calculated CO_2 emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.[21] The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA's *Regulatory Impacts Assessment* (356 TWh/year by 2030).[22]

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[23] RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps "to compare RPS policies on equal footing."[24] To determine the state effective levels in 2020, the EPA added each state's tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS "type" considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region's aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast's target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining "the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

[20] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.
[21] *Annual Energy Outlook 2013* (EIA April 2013) reference case data.
[22] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.
[23] http://www.dsireusa.org/.
[24] DSIRE. DSIRE RPS Field Definitions. April 2011. http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf p.1.

region's historic (2012) generation to reach that region's RE target"[25] by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include: hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.[26] According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.[27] New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO_2 emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.[28] Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.

- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.

- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.

- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

[25] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.
[26] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.
[27] http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf.
[28] DSIRE http://www.dsireusa.org/.

these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,[29] needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[30] as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO_2 reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.

- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.

- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

[29] See NERC's Essential Reliability Services Task Force website for more information: http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[30] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

Building Block 4 – Energy Efficiency

Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO_2 emissions. In calculating individual state CO_2 emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.[31] The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.[32] Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.[33] Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.[34] Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

[31] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.
[32] Electric Power Research Institute (EPRI) and EIA.
[33] *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).
[34] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are "breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,"[35] yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies' sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA's AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA's AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA's assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

[35] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO_2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.[36]

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO_2 reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[36] *NERC 2014 Long-Term Reliability Assessment*.

Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP's Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

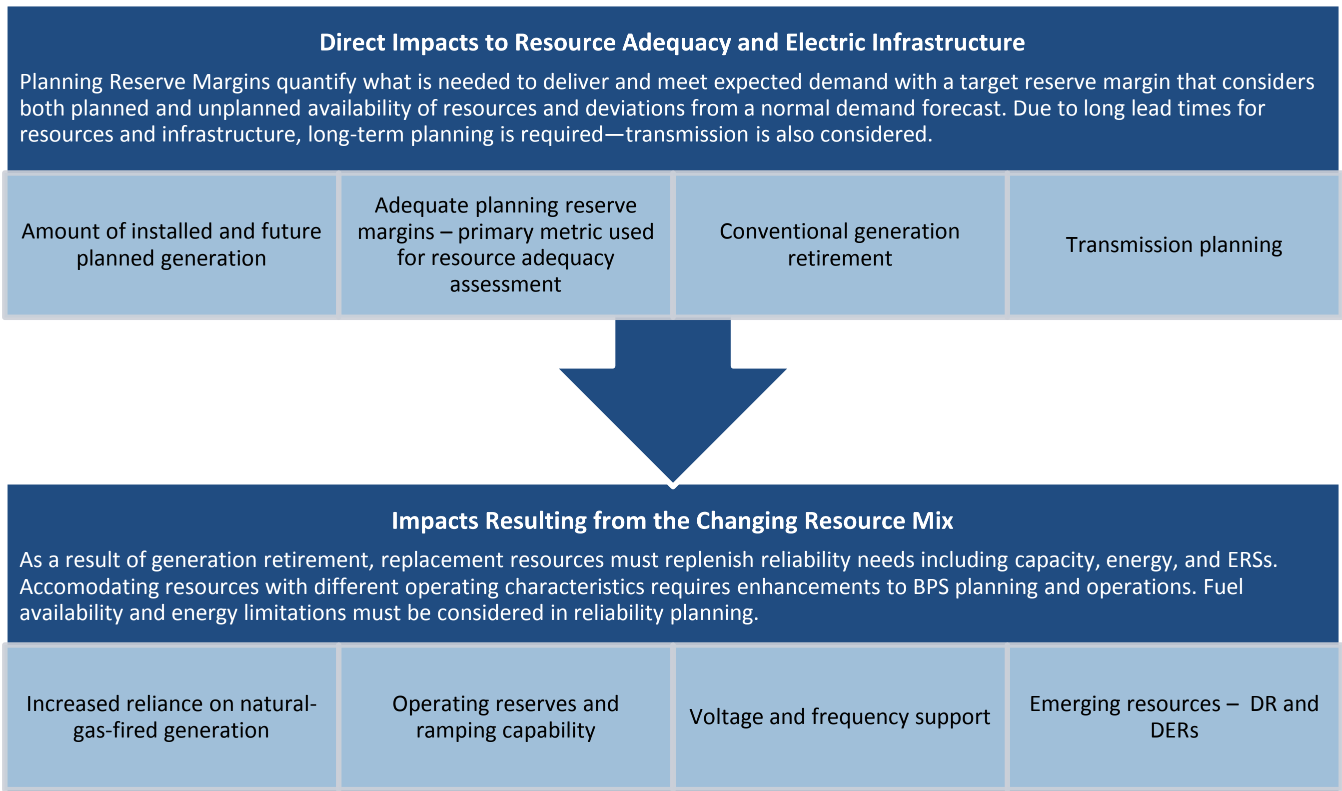


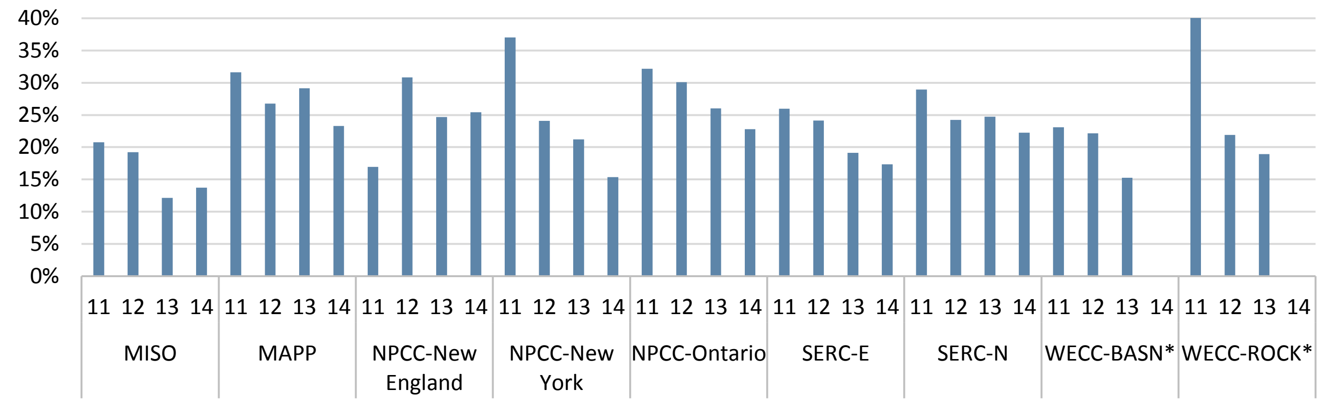
Figure 4. Summarized Reliability Challenges

Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area's Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing declines in load growth rates (Figure 6).[37]



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

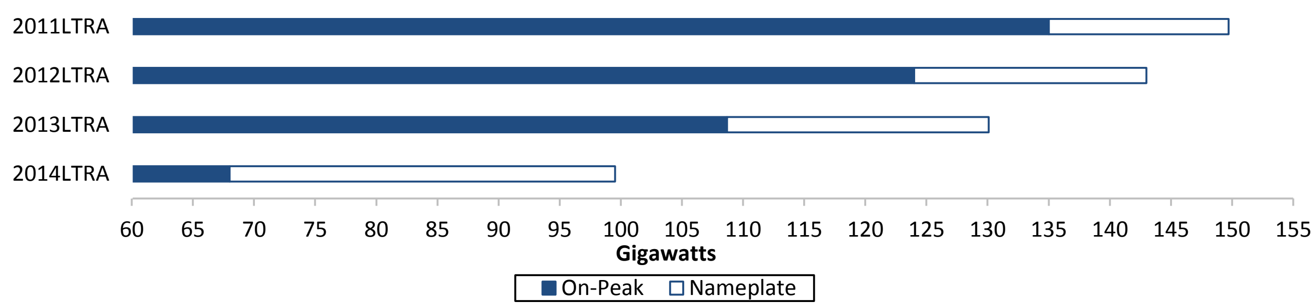


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA's supporting documents estimate that up to 19 percent of the nation's coal plants will become "uneconomical" as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into *2014 LTRA* and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis,* the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.[38]

[37] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[38] EPA Technical Support Document –Resource Adequacy and Reliability Analysis http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf.

The EPA's analysis assumes the electric system will maintain resource adequacy, even with the ongoing retirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will be needed to support these new resources. The EPA's modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA's base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA's base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the *2014LTRA* reference case. According to the *2014LTRA* reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[39] These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (Figure 7).

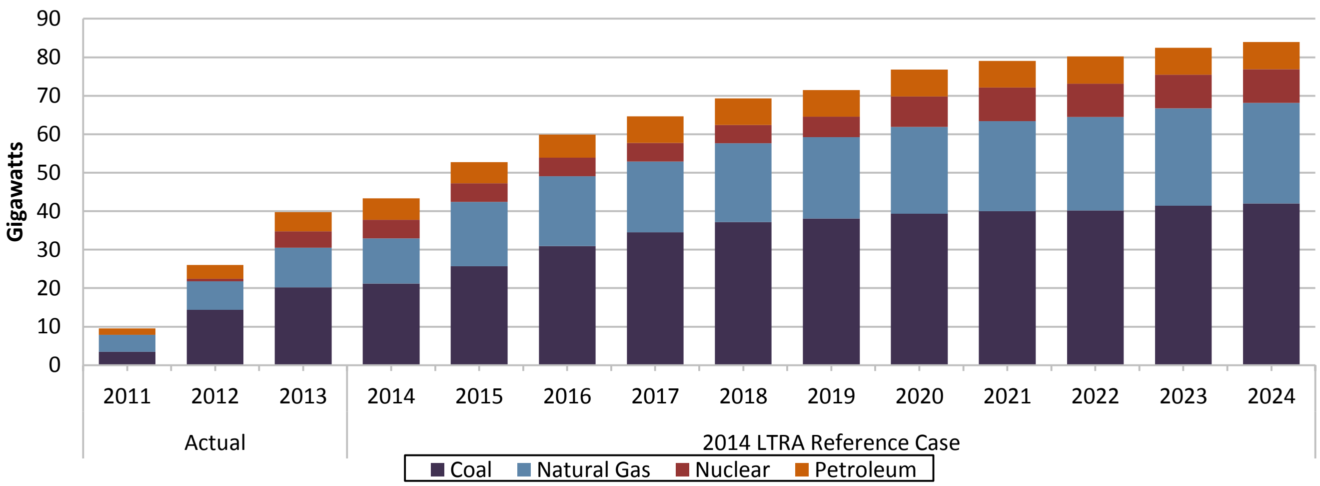


Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result in a reduction in coal to 193 GW by 2025. Option 1 and the *2014LTRA* reference case are shown in Figure 8 and Table 2.[40]

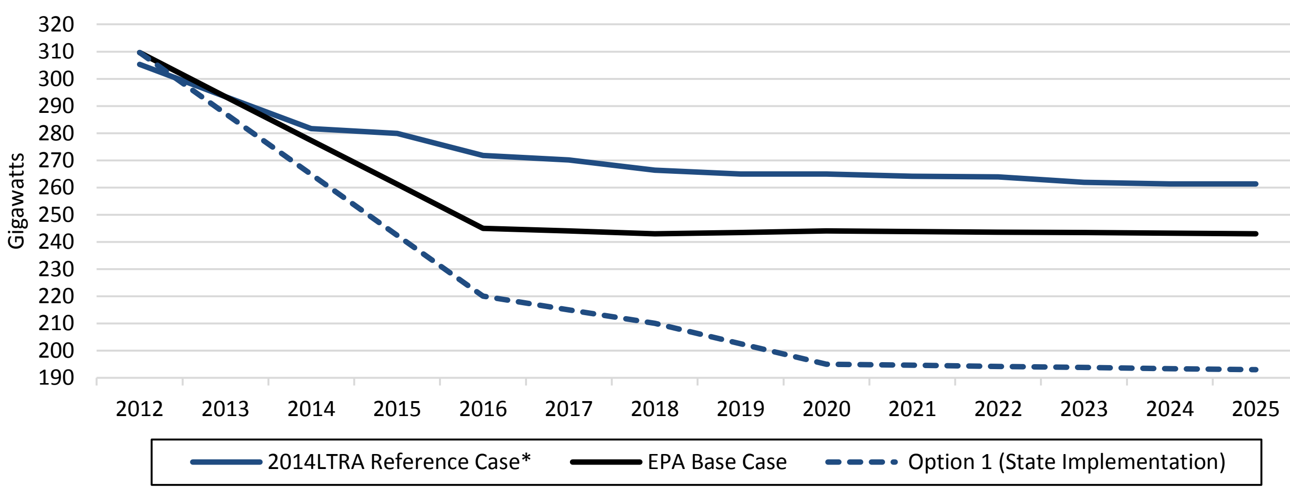


Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

[39] While the assessment period for the *2014LTRA* is 2015–2024, projected retirements for 2014 are included in NERC's *2014LTRA* analysis.
[40] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

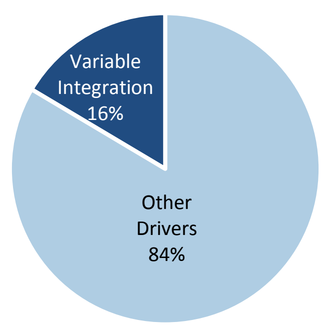
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[41] Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

[41] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in in 2016 it will operate at the reliability level of approximately 2-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.[42] Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.[43] The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[44]
- Increased exports to PJM and the removal of non-Firm imports[45]
- Inadequate Tier 1 capacity additions [46]

[42] Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.

[43] MISO GHG Regulation Impact Analysis – Initial Study Results.

[44] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[45] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[46] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.[47] The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

[47] SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule http://www.spp.org/publications/SPC%20Materials%20081914.pdf.

Direct Impacts to Resource Adequacy and Electric Infrastructure
Summary and Recommendations

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.[48] The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[49]

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity[50]

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gas-fired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.[51] This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

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[48] See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: Phase I and Phase II.

[49] Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

[50] Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment.*

[51] NERC Polar Vortex Review Report
http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.[52] Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[53] as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.[54]

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by $1/MWh to $18/MWh under the CPP[55] as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.[56] As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

[52] Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

[53] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D)

[54] NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[55] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

[56] According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040, this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. 2014 Annual Energy Outlook.

- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
• Specific generator retirement studies • Specific generator interconnection studies • Specific generator operating parameters • Power flow (thermal, voltage) • Stability and voltage security • Offsite power for nuclear facilities	• Resource adequacy • Power flow (regional) • Stability and voltage security (regional) • Gas interdependencies; pipeline constraints • Operating reserves and ramping • System restoration/blackstart

Impacts Resulting from the Changing Resource Mix
Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop special reliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impacts of the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with the industry and states as they develop their implementation plans.

Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**
   The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**
   Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, including resource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achieving the EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**
   NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

WECC Comments to EPA
Proposed Clean Power Plan
November 25, 2014

Executive Summary

The Western Electricity Coordinating Council (WECC) is the Regional Entity with delegated authority from the Electric Reliability Organization, established by Section 215 of the Federal Power Act, and with responsibility for assuring the reliability of the Bulk Electric System (BES) in the Western U.S.

The Western Interconnection has challenging resource mix characteristics where nearly one-third of the produced energy is dependent on long- or short-term weather patterns (e.g., hydro, wind, solar), a modest amount comes from traditional “firm-fuel” capacity (e.g., coal, gas/oil, nuclear), and long-haul transmission lines transmit power from remotely- located resources to large load centers.

Since WECC does not operate, site, or own generation or transmission infrastructure, it has no direct economic interest in how states comply with the EPA’s proposed Clean Power Plan. However, the implementation plans that states will develop to comply with the proposed Clean Power Plan will drive BES changes that must be assessed to assure continued reliable operation of the Western Interconnection. The following reliability issues require additional consideration:

- **Implementation timing –** New generation, and gas and electric transmission, facilities will need to be developed. Implementation timeframes must reflect siting and material supply chain realities.
- **Resource and transmission adequacy –** Increased penetration of variable energy resources and reduction in “firm-fuel” resources raise questions about resource adequacy and deliverability to meet peak load.
- **Balance of system flexibility –** The entire system will need to have adequate flexibility to accommodate the proposed amount of variable energy resource capacity.
- **Natural gas dependency –** The Western Interconnection already relies heavily on natural gas for its energy and the proposed Clean Power Plan will likely require even more gas generation to be built, heightening concerns about fuel security, gas infrastructure reliance, and gas/electric coordination.
- **Grid stability/resiliency –** The expected reduction in traditional base-load resources will impact essential reliability services (e.g., voltage and frequency support, system inertia). It is essential to understand how those services will be provided under a different resource mix.
- **Unintended consequences –** The interstate interdependencies in the Western Interconnection will call for state compliance plans to be assessed in an integrated fashion to understand any unintended consequences of one state’s proposed actions on another state’s ability to comply.

As a result of these concerns, WECC urges the EPA to consider two key recommendations:

1. **Provide adequate time to identify reliability implications of the proposed state compliance plans.**
2. **Create and communicate a process in the Clean Power Plan for reliability entities such as WECC to highlight reliability implications of any state compliance plan in the Western Interconnection.**

WESTERN ELECTRICITY COORDINATING COUNCIL
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WECC's Unique Interconnection-wide Perspective

WECC's interest in the EPA's proposed Clean Power Plan focuses on the implementation process and how Western states' compliance plans may affect the operational and reliability characteristics of the BES. WECC's comments are focused solely on the potential reliability impacts to the Western Interconnection resulting from individual and collective compliance plans.

WECC actively collaborates with a diverse set of stakeholders to analyze and provide an understanding of the electric reliability issues facing the BES. In addition, as an Interconnection-wide Regional Entity, WECC has unique access to the Western states' executive branches and regulatory institutions through the Western Interconnection Regional Advisory Body, WIRAB. With a robust set of analytical tools and capabilities, and active stakeholder engagement and support, WECC conducts reliability assessments such as resource adequacy, power flow, and transmission system stability.

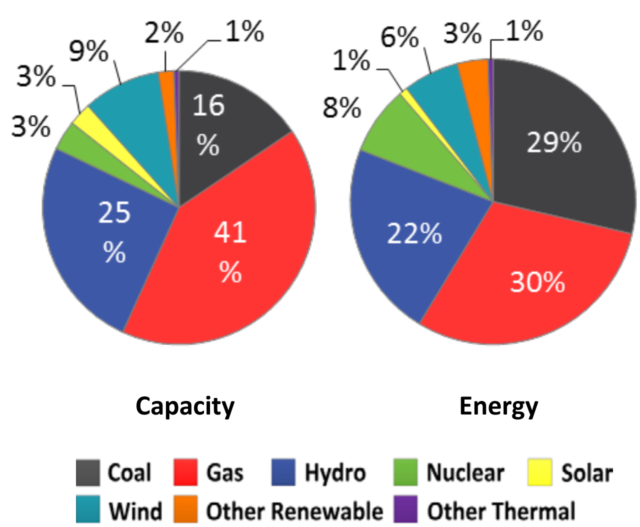
Through its Transmission Expansion Planning Policy Committee (TEPPC), WECC develops 10- and 20-year transmission adequacy plans in response to industry and policy maker needs. These plans are built using a production cost model and the WECC Long-term Planning Tool (developed under a grant from the U.S. Department of Energy). TEPPC's work incorporates environmental considerations into its assessments of the resiliency of the Western Interconnection to unexpected disturbances and studies the potential impacts of technological, socio-economic, and policy scenarios in future resource mix and transmission levels.

Background on the Western Interconnection

The Western Interconnection is a large and complex system with diverse energy resources, many of which are located in remote locations. Long-distance transmission lines often constructed over environmentally sensitive land and challenging terrain transfer power from these remote locations to load centers.

The resource mix is shown in Figure 1. Approximately 41% of the capacity and 30% of the energy is derived from natural gas, while traditional base-load coal and nuclear represent 19% of the capacity and 37% of the energy mix. The balance of the resource mix includes

Figure 1: Resource Mix in the Western Interconnection



substantial hydro-electric power (25% of capacity and 22% of energy), as well as wind and solar resources (12% of capacity and 7% of energy)[1]. Reliance of the Western Interconnection on such weather-dependent resources (in total, hydroelectric, wind, and solar resources make up 37% of the capacity and 29% of the energy generation) poses a key reliability challenge. A 2013 TEPPC Transmission Plan scenario study[2] found increased thermal generation (with concomitant emissions) was needed to replace lost hydro resources resulting from a severe drought scenario.

Further, the geographic structure of the resource base and load centers makes the states highly interdependent electrically[3]. For example, over 32**%** of the energy consumed in California is generated outside the state, while Wyoming exports over 60**%** of the energy it generates. Finally, the Western Interconnection does not have a centralized market structure,[4] which may mean that some practices suggested in the proposed Clean Power Plan (e.g., the re-dispatch of gas assets) will be challenging to implement in the Western Interconnection.

Reliability Challenges in the West under the proposed Clean Power Plan

The proposed Clean Power Plan creates a number of potential reliability concerns due to the Western Interconnection's unique geographic and system conditions.

- **Implementation timing –** Geographic diversity and a complex regulatory environment present challenges to the development of electric power infrastructure. The time required for these facilities to be developed and placed in service may exceed the proposed Clean Power Plan's compliance timelines. In addition, all regions throughout the United States will be implementing their plans simultaneously. Therefore, it is uncertain whether adequate equipment (e.g., turbines, conductor) and resources (e.g., engineering, procurement, construction) will be available.
- **Resource and transmission adequacy –** There are two key adequacy issues that will need future analyses. First, is the ability of the changing resource mix to adequately fulfill coincident peak demands over the course of a year. With the installed capacity of variable energy resources likely to approach and potentially exceed 20% of the total installed base, improved modeling will be required to determine the capability of the changed resource mix to reliably serve load. WECC supports the development of probabilistic planning tools to

[1] 2013 WECC report – The State of the Interconnection: https://www.wecc.biz/Reliability/2013_WECC_SOTI_Report.pdf
[2] TEPPC (and PCC) study case PC 7- Western Governor's Association Drought Study: https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/TEPPC_2022_StudyReport_PC7-Drought.docx&action=default&DefaultItemOpen=1
[3] Appendix A- 2013 Power Supply Assessment – Zonal Topology Diagrams (https://www.wecc.biz/Reliability/2014PSA_draft.pdf)
[4] The majority of California and Alberta do have organized markets overseen by CAISO and AESO, respectively.

assist in scenario-based studies that determine likely on-peak availability of the variable energy resources as well as hydro generation, and natural gas deliverability. The second issue is the ability of the transmission system to reliably transmit power to load. WECC, in collaboration with its members, uses a well-established path-rating process for the BES. Those ratings may be affected due to the changing resource mix, resulting in a need for path re-rating and transmission utilization analysis to ensure available generation can actually be delivered to load centers.

- **Grid stability/resiliency –** To comply with the proposed Clean Power Plan, state implementation plans in the Western Interconnection will likely include acceleration in retirements of carbon-intensive resources (coal, oil and gas steam). The potential reliability impacts associated with the transition from these traditional high-inertia resources (and related loss of essential reliability services such as frequency and voltage support) to other forms of generation need to be studied to ensure that proposed state compliance plans do not reduce the reliability of the BES.
- **Balance of system flexibility –** The proposed Clean Power Plan will likely result in increased penetration of variable energy resources that will impact the operating characteristics and practices of the power system. The balance of the generation fleet will need to have adequate flexibility to integrate intermittency and to provide regulation and other system reserve services.
- **Natural gas interdependency –** A future resource mix that relies heavily on natural gas as a base-load resource raises a number of important concerns, such as:
    1. The desirability of and need for firm natural gas supply and pipeline capacity contracts by generators;
    2. The interruption protocols for natural gas delivery during cold weather events and the ability of pipelines to provide very short-term-supply flexibility (pack and draft); and
    3. The ability of the gas transmission industry to make timely infrastructure investments.
- **Unintended consequences –** Because the Western states are electrically interdependent[5], state compliance plans need to be evaluated early in development to identify any unintended consequences that may result. An individual state's compliance plan could adversely impact other states' ability to comply.

[5] Ibid, Page 1, Reference 3.

<u>WECC Recommendations on the proposed Clean Power Plan</u>

WECC has two principal recommendations for the EPA to consider:

1. **The EPA should provide additional time to study the potential reliability impacts of the proposed Clean Power Plan.**

   The EPA should allow **at least** 180 days following the filing of state compliance plans for the North American Electric Reliability Corporation (NERC), WECC, and other reliability entities to concurrently evaluate the potential reliability impacts of those plans. The proposed Clean Power Plan is complex and could have far-reaching and possibly unforeseen impacts. The success of a state's compliance plan and the reliability of the BES are best served if the complying states and participating utilities, transmission planning regions, and other stakeholders are provided ample time for reliability analyses. This would provide additional time for the following:

   - <u>Evaluation of reliability implications</u> – All stakeholders identified above would require time to evaluate the reliability impacts of the state plans and for complying entities to develop remedial response plans. Additional studies – voltage, transient and post-transient stability – must also be conducted as part of any reliability assessment. The challenges identified in these comments must be addressed during the planning and implementation phases of the proposed Clean Power Plan process. However, until individual states develop compliance plans, it is difficult to identify and analyze specific reliability issues associated with the plans.
   - <u>Multi-state planning</u> – Optimal compliance plans will require time for interstate coordination and negotiation. Given the uniqueness of the Western Interconnection and the interdependence of Western states in terms of energy use and supply, additional time will be required to evaluate reliability implications.
   - <u>Infrastructure investments</u> – The industry will need time to invest in generation and transmission infrastructure once states have developed their implementation plans and WECC and other entities have evaluated the reliability impacts of those plans. Additional time will be required for industry and states to make effective, prudent, and cost-effective decisions to implement state-approved plans due to the characteristically long lead times required for BES infrastructure modifications.

2. **The EPA should create and communicate a process for reliability entities such as WECC to highlight reliability implications of any state compliance plan in the Western Interconnection.**

   As the reliability assurer for the Western Interconnection, WECC requests that the EPA consider the range of BES reliability issues that may result from the implementation of the proposed Clean Power Plan and allow time for necessary studies and reliability assessments, state planning, and industry development processes. WECC recommends creating a process within the proposed Clean Power Plan that considers timing adjustments or the granting of extensions if there is a demonstrable reliability need identified. Once states develop implementation plans, WECC will be able to consider additional analyses to understand the reliability impact on an interconnection-wide basis.

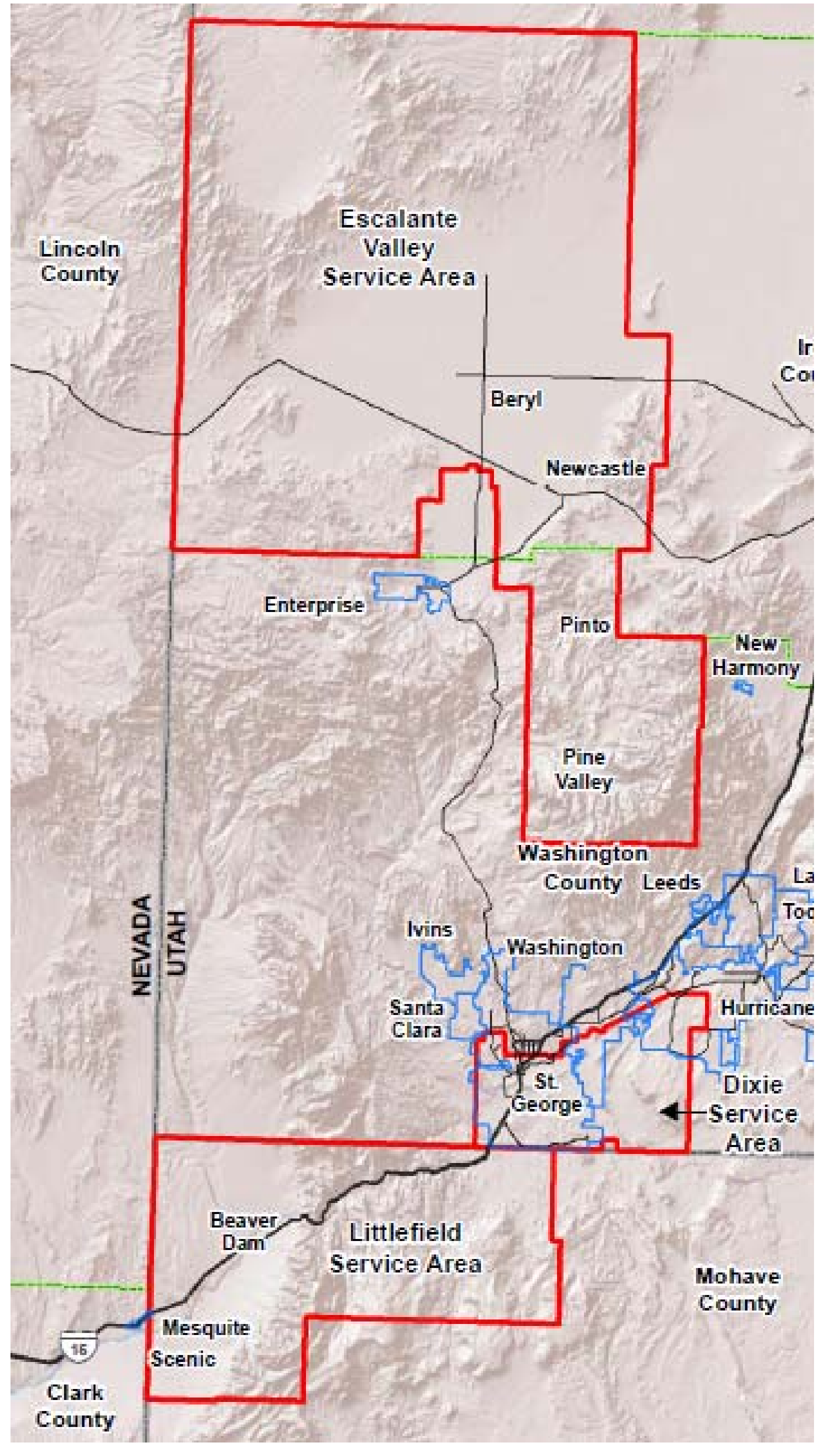
Conclusions

WECC's perspective and comments on the proposed Clean Power Plan are not intended to recommend any specific compliance plan, or to support or oppose the proposed regulation. WECC's role is to assure reliability for the Western Interconnection and WECC will continue working[6] with the EPA, individual states and utilities, and other stakeholders in the Western Interconnection as the proposed Clean Power Plan is finalized. WECC has already-established regular channels of communication with its Regional Advisory Body, WIRAB, to respond to policy questions and compliance plan design or modeling issues that may arise during the design, approval, or implementation processes.

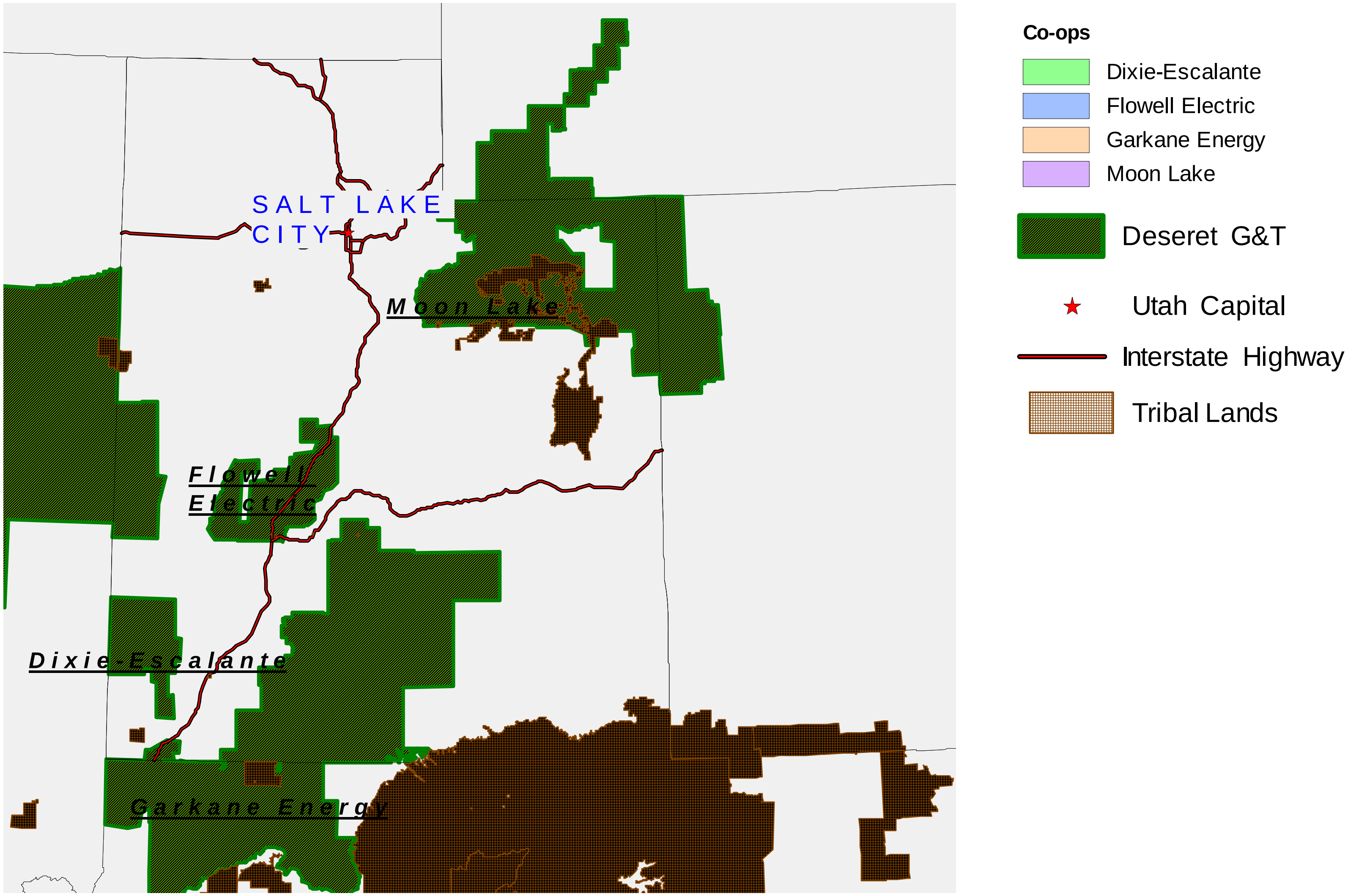
[6] "WECC's Phase 1 Preliminary Technical Report of EPA 111(d) Proposed Clean Power Plan"

Dixie Power

- Headquartered in Beryl Jct. & St. George, Utah
- 18,000 members in Southern UT & Northern AZ
- 114MW peak in summer, 420GWh/year
- All-requirements member of Deseret Power



Utah Electric Cooperatives
All Tribal Lands



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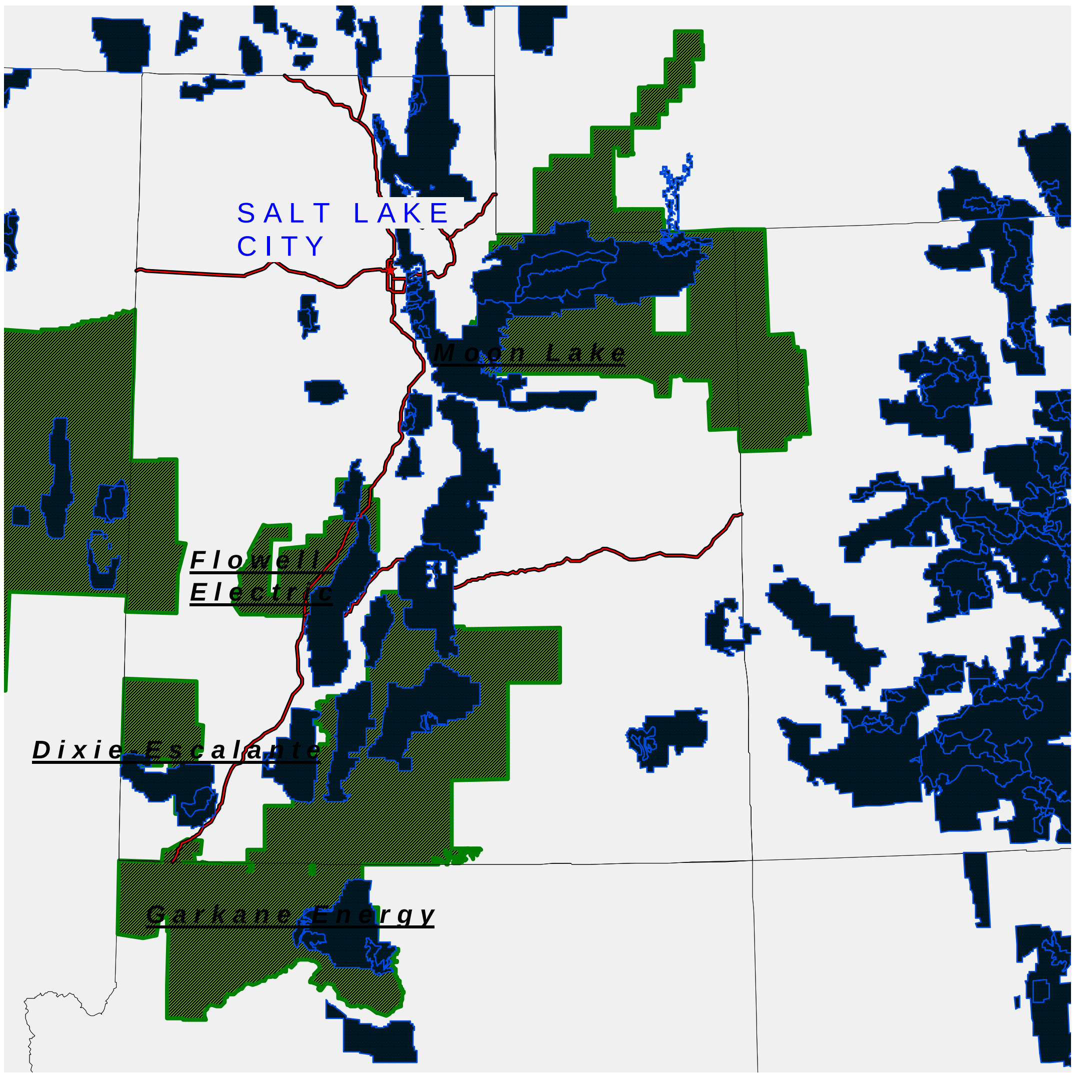
National Forest Service



Co-ops

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- Flowell Electric
- Garkane Energy
- Moon Lake
- Deseret G&T
- Utah Capital
- Interstate Highway
- National Forest Service

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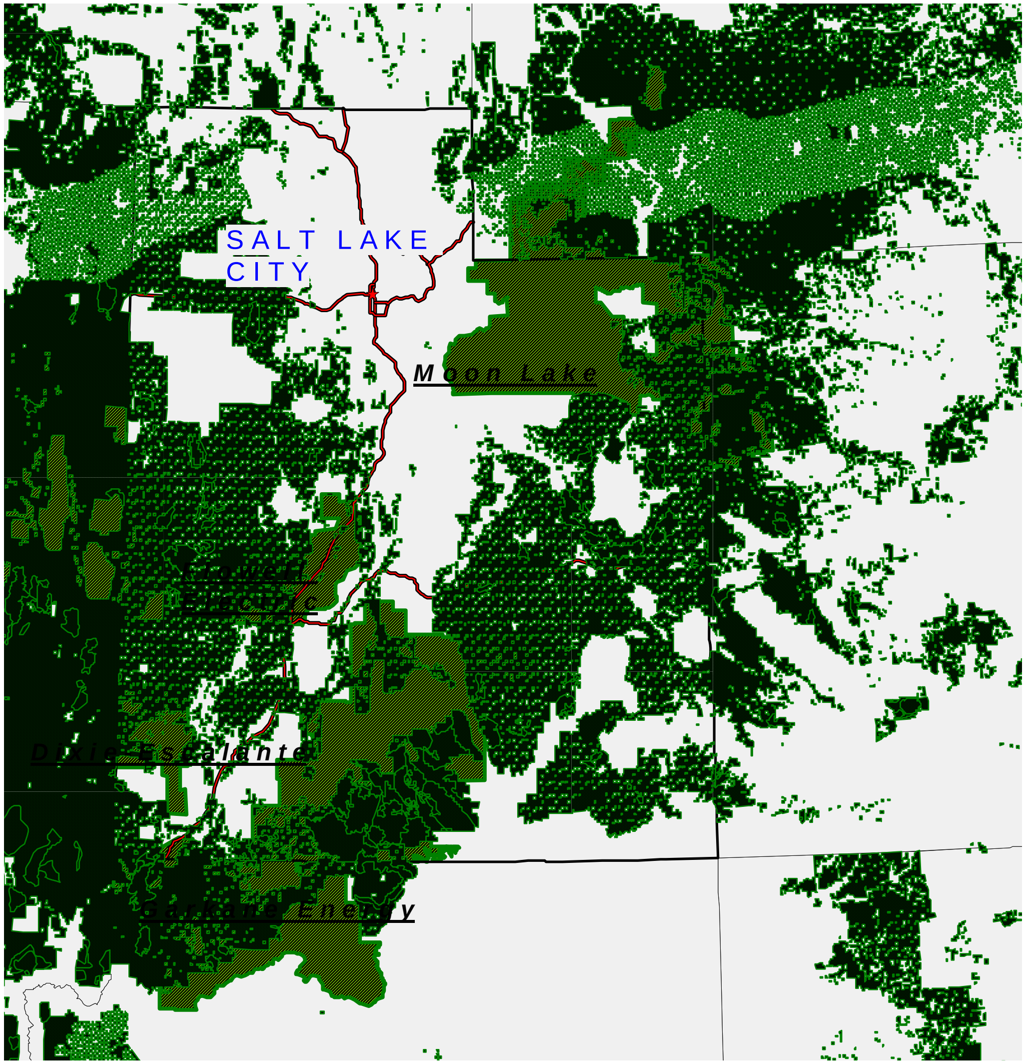
Utah Electric Cooperatives
Bureau of Land Management*



Co-ops

- Dixie-Escalante
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Deseret G&T

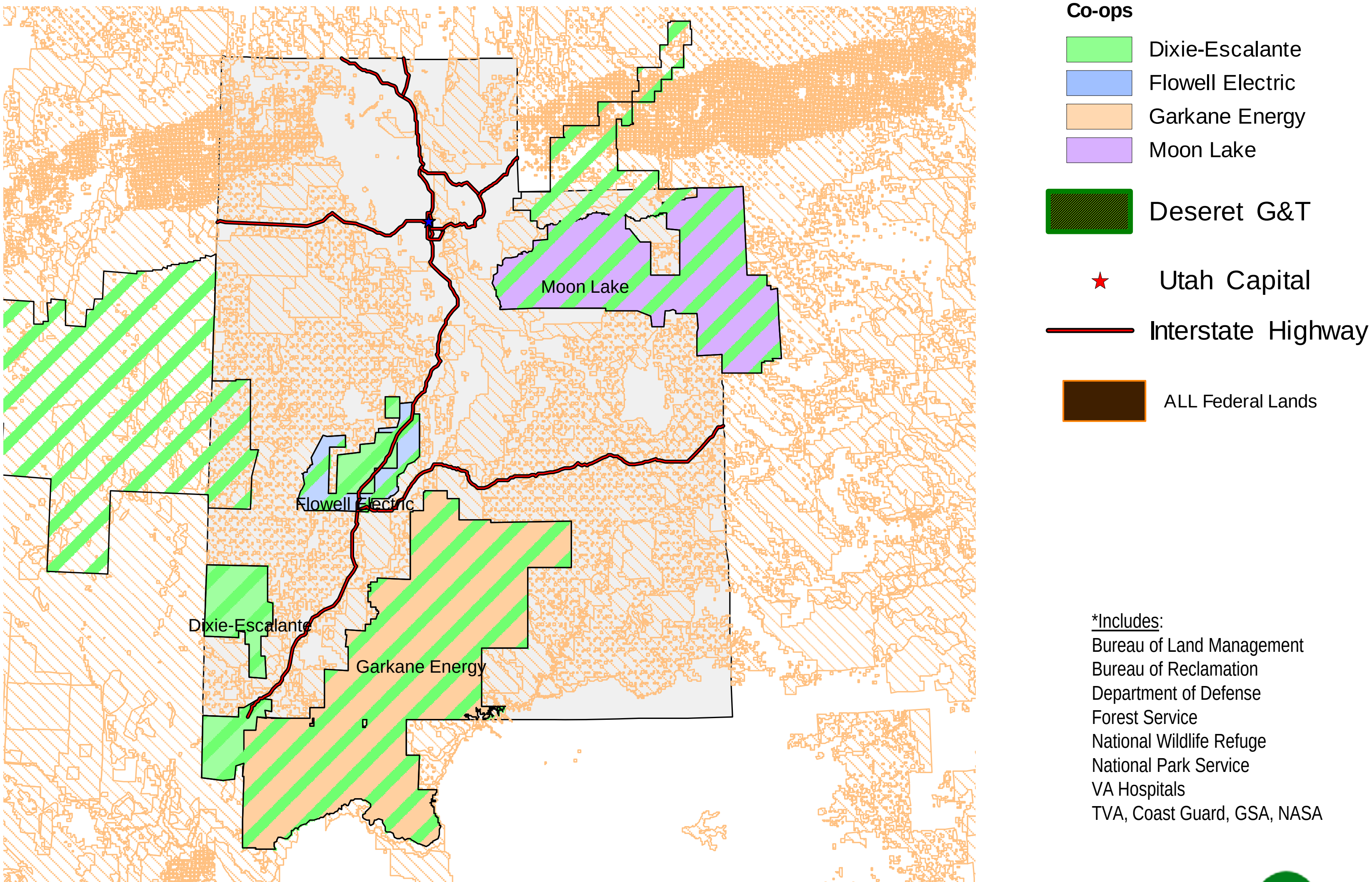
Utah Capital

Interstate Highway

Bureau of Land Management

* Includes Public Lands

Utah Electric Cooperatives
ALL Federal Lands*



*Includes:
Bureau of Land Management
Bureau of Reclamation
Department of Defense
Forest Service
National Wildlife Refuge
National Park Service
VA Hospitals
TVA, Coast Guard, GSA, NASA

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