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Energy in the Law

## What Will Greenhouse Gas Emission Limits Mean for the Oil and Gas Industry?

By: Jim Martin

It's been difficult to miss the debate that has been occurring over the President's climate action plan, including the Environmental Protection Agency's (EPA) proposals to reduce emission from new and existing electric generating units. It would be a mistake, though, to think that these proposals affect only electric utilities. In fact, these proposals present both tremendous opportunities and challenges for the natural gas industry and they deserve our attention.

In June 2013, the President outlined an ambitious plan for addressing the issue of climate change [view]. The President's plan is multi-faceted, but the responsibility for carrying out measures intended to reduce emissions of climate-forcing gases falls to the EPA. On September 20, 2013, EPA issued a proposal to set $CO_2$ emission limits for new natural gas-fired combustion turbines, fossil fuel-fired utility boilers, and integrated gasification combined cycle (IGCC) units. This proposal was issued pursuant to section 111(b) of the Clean Air Act. While the proposal potentially expands markets for natural gas, the proposal effectively precludes construction of new coal-fired generation without carbon capture and sequestration (CCS), sparking a debate about whether CCS is the Best System of Emissions Reduction (BSER) adequately demonstrated (the legal standard). As a result, judicial challenges to this proposal already have commenced, and will certainly expand. While there is no formal deadline for finalizing EPA's proposal for new sources – known as New Source Performance Standards, or NSPS – the agency almost certainly will complete action before June 2015, to clear the way for finalization of its standards for existing sources.

Section 111 of the Clean Air Act commands that once EPA proposes standards for new sources, the agency also must consider emissions standards for existing sources (Existing Source Performance Standards, or ESPS) under CAA section 111(d). Not unlike the State Implementation Plan (SIP) process, section 111(d) requires EPA to formulate "guidelines" for states' use in developing plans for meeting performance standards established by EPA. EPA then must review state plans and approve those deemed "satisfactory." Section 111(d) has been little-used over the course of its 40-year life, but as explained below, EPA is now proposing a dramatically broad interpretation of its scope.

On June 2, 2014, EPA released its proposed guidelines for reducing $CO_2$ emissions from the existing power plant fleet. EPA cast its proposal as a Clean Power Plan, since it is intended to both reduce emissions and stimulate expansion of lower-emitting sources of electricity. The Plan sets $CO_2$ emissions reduction goals (expressed as emission rates but convertible to mass limits) for each state, with an overall goal of reducing $CO_2$ emissions by 30% from 2005 levels by 2030, with a 2020-2029 interim goal.

In setting each state's individual goal, EPA first determined what constitutes the BSER currently available. In this instance, though, instead of identifying add-on technologies or other measures that could be undertaken at an existing electric generating unit, EPA identified four "building blocks" that it concludes represent BSER:

1. Requiring heat rate improvements at electric generating units, totaling approximately 6% at existing coal-fired generating units;
2. Changing dispatch of electric generating units to increase generation from existing gas units (and those under construction) to a 70% utilization rate while commensurately reducing dispatch from more carbon-intensive sources (coal);
3. Discouraging retirement of existing nuclear units while increasing generation from renewable resources over time, to reduce output from fossil resources; and,
4. Increasing investments in efficiency and other demand-side measures to reduce demand for electrical energy, thereby reducing emissions of $CO_2$ from fossil units.

Using computer modeling, EPA calculated an individual emission rate goal for each state with affected units, assuming both the heat rate improvements and increased dispatch of gas resources, as well as what the agency believes are "reasonable" estimates of the potential for penetration by renewables and demand-side management. However, EPA insists that states have wide flexibility to assemble plans that reach the goal set by EPA and that states are not restricted to the four building blocks.

EPA also encouraged states to enter into regional plans, arguing that multi-state plans likely will be more cost-effective than individual state plans. EPA pointed specifically to the Regional Greenhouse Gas Initiative (RGGI) as one model, but also suggested that states consider working through or with Regional Transmission Organizations (RTO) and Independent Service Operators (ISO) to develop multi-state plans. While there appears to be at least some interest in the West in evaluating the efficacy of multi-state plans, the absence of either RTOs or ISOs in the region would require states to find other collaborative models in a highly time-constrained process.

EPA is operating under an accelerated timeline. The comment period for EPA's 111(d) proposal closes **October 16, 2014** and EPA's administrator has so far rebuffed requests for an extension of time for comment. At the President's direction, EPA is working to release its final guidelines by June 2015, and to require that states submit their plans within one year (though there are opportunities for one- and two-year extensions under certain circumstances).

This proposal is of obvious interest to all electrical energy producers (and efficiency providers) and the proposal may set records for public comment. The proposal and the underlying calculations of individual state goals are extremely complex; the proposal envisions an unprecedented level of coordination between environmental and utility regulators, as well as utilities and merchant power companies; and in many states new legislation might be needed to enable development and submission of state plans. Beyond that, the proposal raises a number of specific issues that should be of interest to oil and gas producers as well as others:

- First and foremost, may a state rely upon new gas-fired generation (not under construction as of June 2014) as one measure to meet the state's goal? What kind of cross-walk exists between new units that meet the 111(b) emission standards, and inclusion of those resources in a 111(d) plan? And is it even advisable to include new units in the plan? Fundamentally, what does the proposal mean for increased natural gas utilization? Of course, this also begs the question of whether new gas-fired units will be able to meet the 111(b) emission standards over the lifetime of the unit.

- Do existing gas units have permit limits on hours of operation that restrict their ability to run at a 70% utilization rate? How many, and where are they located?

- Would increasing utilization of existing units implicate New Source Review? (The proposal is silent on this issue.) Or risk violation of the 1-hour $NO_x$ limit? And how would increased gas utilization affect state plans to meet the new ozone standard currently working its way through EPA.

- Is there sufficient pipeline capacity to allow this level of utilization?

- Can states look to other sectors for emissions reductions that could be counted? For example, can Colorado count the $CO_2$-equivalent reductions it will attain by opting to regulate methane emissions in the upstream sector? Similarly, if companies are injecting sour gas as a pollution control measure, are there opportunities to capture $CO_2$ from nearby coal-fired units for injection and generate revenue at the same time?

- If utilities make investments to improve their units' heat rates (and make other investments to comply with emissions limits for ozone, regional haze, or mercury and toxic substances), do those facilities become must-run plants, and can that be squared with the other building blocks?

- Of great interest to states like Colorado, is 2012 the baseline for some or all of the building blocks, thereby excluding the benefit of actions taken before 2012? What would that mean for Colorado and similarly situated states?

- EPA's proposed guidelines and timelines for meeting interim goals would front-load required emissions reductions (since emissions get averaged over a ten-year period), yet at the very earliest state plans will not be approved by EPA until 2017. That schedule would make compliance by a utility challenging, at best.

- If, as EPA seems to insist, elements of a state plan must be federally enforceable, what does that mean? Would EPA second-guess decisions made by state utility regulators on cost recovery, integrated resource plans, dispatch, and other matters? Would the elements of the state plan become enforceable by outside parties (presumably yes)? Collaterally, does EPA have the authority to impose a federal plan on a state if the state submits what the agency views as an unsatisfactory plan, or fails to submit a plan at all? How would the agency effect a federal plan in states where merchant operators supply electrical energy but have no ability to adopt and implement demand side programs? How would the agency ensure cost recovery for utilities the agency directs to make investments absent approval from a state utility regulator?

- Conversely, are there investment opportunities for energy companies outside the oil and gas arena? Or for merchant generation that might rate favorable dispatch?

Beatty & Wozniak attorneys will follow this process closely and are available to provide assistance on this matter. Please do not hesitate to contact Jim Martin for additional information.