# REGULATORY COMPLIANCE ISSUES AFFECTING EXISTING NORTHWEST GENERATING PLANTS

SEVENTH NORTHWEST POWER PLAN

TECHNICAL SUPPORT DOCUMENT

FOR THE DRAFT SEVENTH POWER PLAN

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Northwest Power and Conservation Council

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# BACKGROUND

The purpose of this paper is to assess the possible impact of compliance obligations stemming from recent and proposed federal environmental and safety rulemakings and orders on future operation of major Pacific Northwest electric generating plants. Uncommitted capital or operational costs or operational changes required for compliance can affect decisions regarding continued plant operation. Incremental variable operating costs may affect the economics of plant dispatch, even if a plant continues to operate.

Numerous federal rulemakings intended to reduce safety risks or environmental impacts of power generation have been adopted in recent years or are currently underway. Compliance with these rules often requires modifications to the design or operation of power generation facilities. These modifications may entail capital investment in pollution control and safety equipment and increased operating and maintenance costs. Plant performance and operational characteristics may also be affected.

Many of these rulemakings originate from the Clean Air Act and Clean Water Act and have been in process for many years, even decades, but have been finalized only recently. Several are not yet final, notably the proposed Clean Power Plan (greenhouse gas control) and second phase modifications to boiling water reactor equipment and operation resulting from the Fukushima Dai-ichi nuclear power station accident. Some, such as the rulemaking addressing regional haze, require periodic evaluation of progress, so may require additional controls in future years.

Environmental Protection Agency (EPA) rulemakings with potential financial or operational impacts on existing Northwest generating units include the Regional Haze Rule, the Mercury and Air Toxics Standards for Utilities (MATS), the Coal Combustion Residuals Rule (CCR), the Cooling Water Intake Structure Rule, the Effluent Guidelines for Steam Power Generation and the proposed Carbon Pollution Standards for Existing Power Plants (Clean Power Plan). A rulemaking of considerable significance in the eastern part of the country, the Cross-state Air Pollution Rule (CSAPR) does not affect Western plants. These rulemakings primarily affect coal-fired generating units though nuclear and gas-fired combined-cycle plants may incur some, probably minor, costs of compliance with the Cooling Water Intake Structure Rule and the Effluent Guidelines for Steam Power Generation. Natural gas combined-cycle plants may be positively affected by the Carbon Pollution Standards for Existing Power Plants, as one of the proposed response “building blocks” is additional dispatch of combined-cycle plants.

A set of rulemakings in response to the severe damage to the Fukushima Dai-ichi nuclear power station resulting from the 2011 Tohuku earthquake and subsequent tsunami are being issued by the Nuclear Regulatory Commission. These rules will require additional capital investment at the Columbia Generating Station.

The design and operation of the regional hydropower system have been significantly affected in the past by provisions of the National Marine Fisheries Service Biological Opinions and the Council’s Fish and Wildlife Program. However, additional operational changes or capital investment of significance are currently not anticipated. The U.S. Fish and Wildlife Service issues non-mandatory permits to wind projects authorizing limited take of threatened and endangered species protected by the Bald and Golden Eagle Protection Act and Migratory Bird Treaty. Though few wind project operators have applied for these permits, it is expected that they may become increasingly common. Elsewhere, the permits have resulted in additional mitigation costs and operational constraints for wind projects that cause heavy avian or bat mortality.

This paper focuses on federal regulatory actions. In addition, state-level proposals in Washington and Oregon regarding the import of electricity from coal-fired generating facilities could significantly affect the economics of out-of-state units, principally the Colstrip plant. These efforts are not sufficiently advanced to accurately evaluate their potential effect, but it is anticipated that they would reduce the market for and value of power originating from coal-fired generating units.

Table 1 summarizes the key characteristics of the major Pacific Northwest generating units potentially affected by federal regulatory compliance requirements.

Table 1: Pacific Northwest electric generating units potentially significantly affected by recent and prospective environmental and safety rulemaking compliance requirements

| Plant | Type | Location | Capacity ($MW_{net}$) | Year of Service | Existing Air Pollution Controls and Principal Target Pollutants | Note |
|---|---|---|---|---|---|---|
| Boardman 1 | Coal-steam | Boardman, OR | 585 | 1980 | New generation low-NOx burners and overfire air (NOx)<br>Low-sulfur coal (SOx)<br>Dry sorbent injection (SOx)<br>Activated carbon injection (Hg)<br>ESP (Particulates, SOx, Hg) | Scheduled to cease coal-firing by end of 2020. |
| Centralia (TransAlta Centralia) | Coal-steam | Centralia, WA | Unit 1 - 670<br>Unit 2 - 670 | Unit 1 - 1973<br>Unit 2 - 1975 | Low-NOx burners, overfire air, SNCR (NOx)<br>Coal blending (SOx)<br>Activated carbon injection (Hg)<br>FGD (SOx, Hg) | One unit to retire in 2020; second unit to retire in 2025. |
| Colstrip | Coal-steam | Colstrip, MT | Unit 1 - 307<br>Unit 2 - 307<br>Unit 3 - 740<br>Unit 4 - 740 | Unit 1 - 1973<br>Unit 2 - 1975<br>Unit 3 - 1976<br>Unit 4 - 1984 | U1 & U2 Low-NOx burners (NOx)<br>U3 & U4 Low-NOx burners w/overfire air (NOx)<br>Bromine coal treatment (All units); Activated carbon injection (all units); FGD additive (U3 & U4) (Hg)<br>Wet FGD (all units) (SOx, Hg) | |
| J. E. Corette | Coal-steam | Billings, MT | 153 | 1968 | Low-sulfur coal (SOx)<br>Activated carbon injection (Hg)<br>ESP (Particulates, Hg) | Scheduled to retire in August 2015 |
| Jim Bridger | Coal-steam | Point of Rocks, WY | Unit 1 - 531<br>Unit 2 - 523<br>Unit 3 - 527<br>Unit 4 - 530 | Unit 1 - 1974<br>Unit 2 - 1975<br>Unit 3 - 1976<br>Unit 4 - 1979 | Low-NOx burners (NOx)<br>SCR[a] (NOx)<br>ACI (Hg)<br>Wet FGD (SOx, Hg)<br>ESPs (Particulates) | |

| Plant | Type | Location | Capacity ($MW_{net}$) | Year of Service | Existing Air Pollution Controls and Principal Target Pollutants | Note |
|---|---|---|---|---|---|---|
| North Valmy | Coal-steam | North Valmy, NV | Unit 1 - 254<br>Unit 2 - 268 | Unit 1 - 1981<br>Unit 2 - 1985 | Low-NOx burners (NOx)<br>Dry FGD (U2) SOx<br>Fabric filters (Particulates) | |
| Columbia Generating Station | Boiling Water Reactor | Richland, WA | 1,140 | 1984 | | |

[a] Operational on unit 3 in 2015 and unit 4 in 2015.

# REGULATORY COMPLIANCE ACTIONS WITH POTENTIALLY SIGNIFICANT CONSEQUENCES FOR EXISTING NORTHWEST GENERATING UNITS

## National Ambient Air Quality Standards

The Clean Air Act of 1970 (subsequently amended in 1977 and 1990) requires the EPA to establish ambient air quality standards for common and widespread air pollutants. The EPA has established standards for six "criteria pollutants". These are particulate matter[1], ozone, sulfur dioxide ($SO_2$), nitrogen dioxide ($NO_2$), carbon monoxide (CO) and lead. Two levels of standards are established: Primary standards, based on human health impacts and Secondary standards, based on environmental and property damage. The standards are established based on scientific evidence, and reviewed every five years.

The National Ambient Air Quality Standards (NAAQS) are attained and maintained through emission reduction strategies set forth in State Implementation Plans (SIPs). The EPA designates counties and other areas as "attainment" or "non-attainment" based on data supplied by the states. If insufficient monitoring data are available, areas may receive interim designations of "unclassifiable" (insufficient monitoring data) or "unclassifiable/attainment" (insufficient monitoring data, but expected to be in attainment). The states then develop a SIP designed to bring non-attainment areas into compliance by deadlines established by EPA. The SIPs are reviewed and approved by the EPA. The SIPs may require existing power generation facilities to install Best Available Retrofit Technology (BART) to control specific pollutants as part of the plan to bring non-attainment areas into compliance. Costs of compliance are considered in developing the implementation plans. Non-attainment areas, once brought into compliance, are designated "maintenance areas" and the SIPs must include provisions for maintaining these as attainment areas. (The general aspects of this implementation process are used for most EPA rulemakings described in this section.)

Coal-fired power generating facilities are important potential sources of "criteria pollutants," including sulfur dioxide, nitrogen oxides and particulates. Natural gas-fired power plants are potential sources of nitrogen oxides. Reduction of sulfur dioxide, nitrogen oxides and particulate emissions is accomplished by fuel selection, combustion controls and post-combustion (flue gas) cleanup. All Northwest coal and gas-fired units are currently in compliance with NAAQS.

Recent revisions to the NAAQS include:

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[1] Particulate regulations address two classes of particulates: $PM_{2.5}$ (fine, less than 2.5 microns in diameter) and $PM_{10}$ (coarser, less than 10 microns in diameter).

- Adoption of more stringent Primary one-hour nitrogen dioxide standards in January 2010. Currently, all areas of the country are designated as “unclassifiable/attainment”. Designations will be reviewed after 2015 when additional monitoring data are available.
- Adoption of more stringent Primary one-hour sulfur dioxide standards in June 2010. Currently, no counties in Montana, Nevada, Oregon, Washington and Wyoming are projected to violate the revised standards through at least 2020.
- Adoption of more stringent annual particulate standards in December 2012. Final designation of most areas was completed in December 2014. All areas of Montana, Nevada, Oregon, Washington and Wyoming are classified as “unclassifiable/attainment”. This suggests that it is unlikely that compliance actions will be needed in these states, though this will require confirmation through further monitoring.
- Proposed revisions to ground-level ozone standards. These standards are currently under review. Final standards are proposed for adoption October 2015 with compliance required from 2020 – 2037. These could potentially impact coal and natural gas-fired power plants; however the extent and nature of impact has not been determined.

# Regional Haze

Regional haze is geographically widespread impairment of atmospheric clarity, visual range or coloration. Regional haze is produced by airborne fine particulate matter and secondary products of nitrogen oxides, sulfur dioxide and other air pollutants. Though episodic natural events such as wildfire and dust storms may increase regional haze on a short-term basis, certain power generation and industrial facilities and motor vehicles are chronic sources of the pollutants that create regional haze.

The 1977 amendments to the Clean Air Act created a program to restore and protect visibility in national parks, wilderness areas and other visually sensitive areas. The 1990 amendments to the Clean Air Act specifically addressed regional haze and established 2007 as the deadline for states to submit implementation plans for regional haze control. The EPA adopted the Regional Haze Rule in 1999 for the purpose of improving visibility in 156 national parks and wilderness areas. The Regional Haze Rule is generally implemented through SIPs. While the majority of states opted to establish SIPs for control of regional haze, several, including Montana, opted not to prepare a regional haze SIP. In these cases, the EPA prepares a Federal Implementation Plan (FIP).

The 1999 Regional Haze Rule includes provisions for a comprehensive analysis of the regional haze state implementation plans every 10 years and a progress report every five years. Should progress in reducing regional haze not be satisfactory, installation of additional controls on electric generating units may be required.

Reduction in emissions of particulates and precursors of haze-inducing compounds from power generation facilities is typically accomplished by installation of controls for sulfur dioxide, nitrogen oxides and particulate matter. The technologies for haze control are generally similar to those required for compliance with NAAQS, although more stringent levels of control may be required.

Boardman, Centralia 1 & 2, and North Valmy 1 & 2 are currently in compliance with the Regional Haze Rule. Additional controls are being installed, or are scheduled for installation at Colstrip 1 & 2 (2017), Bridger 1 (2022), Bridger 2 (2021), Bridger 3 (2015) and Bridger 4 (2016). The future progress provision of the Regional Haze rule is expected to require additional nitrogen oxide controls on Colstrip 3 & 4 by 2027[2]. Future control upgrades might be required on North Valmy 1 and 2, depending on future progress[3].

# Mercury and Air Toxics

The Mercury and Air Toxics Standards (MATS) are intended to reduce air emissions of heavy metals including mercury, arsenic, chromium and nickel, and acid gasses including hydrochloric (HCl) and hydrofluoric acid (HF). These pollutants, released during the combustion of certain coals or oils, are known or suspected of causing cancer and other serious health effects.

The EPA issued the Clean Air Mercury Rule (CAMR) in March 2005 to reduce mercury emissions under a cap and trade program. However, the CAMR was vacated in February 2008 with the court finding the rule inconsistent with the Clean Air Act. In December 2011, the vacated CAMR was replaced by Final New Source Performance Standards (NSPS) for the release of mercury and other air toxics from new and existing coal and oil-fired steam-electric power plants. Updates to MATS for new plants were finalized in March 2013. Subsequent updates pertain to reporting requirements and monitoring and testing requirements relating to startup and shutdown of new coal and oil-fired power plants. The final rule sets numerical limits for release of mercury and other air toxics. Compliance requires use of maximum achievable control technology though alternative compliance measures, including a more restrictive sulfur dioxide emission limit in lieu of the hydrochloric acid limit, are allowed. The standards for existing units take effect in 2015 with a one-year extension available at state option and a second year extension available under extreme circumstances. MATS is estimated to reduce mercury emissions from coal-fired power plants by 90 percent and reduce acid gas emissions by 88 percent. The rule is also projected to reduce sulfur dioxide emissions[4].

MATS control strategies vary, depending upon coal qualities, existing pollutant control technologies, unit operating conditions and ash disposal practices. Combinations of controls are frequently employed. Some capture of mercury occurs in wet flue gas desulfurization systems. This can be enhanced by treating the coal with a mercury oxidizing agent, but is often not sufficiently effective to meet MATS emission standards. Additional controls often consist of injection of powdered activated carbon (PAC or ACI) or proprietary non-carbon dry sorbents into

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[2] Portland General Electric. 2013 Integrated Resource Plan. March 2014.  P 123.

[3] Idaho Power Company. 2011 IRP Update:  Coal Unit Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants.  February 2013.

[4] U.S. Environmental Protection Agency, Final Mercury and Air Toxics Standards (MATS) for Power Plants, http://www.epa.gov/mats/actions.html; Resources for the Future.  Mercury and Air Toxics Standards Analysis Deconstructed: Changing Assumptions, Changing Results.  April 2013.

the flue gas in combination with treatment of the coal with an oxidizing agent. Mercury and other heavy metals and their compounds are absorbed onto the particles which are captured by the plant's particulate control or flue gas desulfurization (FGD) system. A downside of this approach may be a reduction in the market value of fly ash (a key ingredient in concrete) as a result of increased mercury levels and heavy metal contamination.

Acid gasses are neutralized by dry injection of sorbents (DSI) such as hydrated lime into the flue gas stream with downstream capture of the particles in the plant's particulate control system.

Because of variations in coal composition and type of FGD, particulate controls and instrumentation that may already be installed on a unit, the extent of retrofit required for MATS compliance varies widely. The MATS potentially affect all power plants of 25 MW capacity or greater that are fired by coal, petroleum coke or oil. Among major Northwest coal units, Boardman[5], Centralia 1 & 2[6] and North Valmy 2 are in compliance. Plants needing additional control or monitoring equipment to comply with MATS include Bridger 1 – 4 (activated carbon injection), Colstrip 1 - 4 (addition of sieve trays to the existing wet FGD systems to improve particulate capture) and North Valmy 1 (dry sorbent injection for acid gas control).

The capital and fixed operating and maintenance (O&M) costs of mercury control technology are relatively low. The capital and O&M costs of ACI assumed for this study are based on the mercury control methodology developed by Sargent & Lundy for the EPA Integrated Planning Model (IPM)[7]. While the capital cost estimates of this model (~ $14/kW) are somewhat greater than other sources (e.g., $6/kW from EIA), the greater specificity of the Sargent & Lundy model calculations should more accurately represent costs where unit-specific owner's cost estimates are not available.

The major impact of ACI control on plant economics are variable operating costs, principally the cost of the sorbent, foregone revenues from sales of fly ash rendered unsuitable for use in manufacturing concrete and landfill disposal costs of contaminated ash. The variable cost calculation of the Sargent & Lundy methodology, while accounting for the cost of disposal for fly ash rendered unsuitable for cement manufacturing, does not account for loss of revenue from curtailed sales of fly ash to concrete manufacturers. The incremental variable O&M cost shown in Table 2 for ACI retrofits has been increased, as noted in the table to account for reduced ash sales revenue.

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[5] PGE Boardman Plant Air Emissions (portlandgeneral.com). Boardman is also in compliance re: NOx and SO2 emissions.

[6] SWCAA Permit No. SW98-8-R4

[7] Sargent & Lundy. IPM Model - Revisions to Cost and Performance for APC Technologies Mercury Control Cost Development Technology. March 2011. At http://www.epa.gov/airmarkets/documents/ipm/append5_3.pdf.

A federal appellate court upheld the new mercury and air toxics standards in the face of a number of challenges.[8] The U.S. Supreme Court accepted petitions for further review from the State of Michigan, the Utility Air Regulatory Group, and the National Mining Association. The Supreme Court heard oral arguments in March of 2015, and a decision is expected later in the spring or early summer of 2015.[9]

# Cross-state Ozone and Fine Particulates

On July 6, 2011 the EPA issued the final Cross-state Air Pollution Rule. This rule requires affected power plants to reduce emissions contributing to ozone or fine particle pollution in other states. Plants in five states are required to reduce seasonal nitrogen dioxide emissions and plants in 28 states are required to reduce annual sulfur dioxide and nitrogen dioxide emissions. No Pacific Northwest plants are affected.

# Coal Combustion Residuals

Coal combustion residuals (CCRs) include boiler bottom ash, fly ash (ash carried in the flue gas), boiler slag and products of flue gas desulfurization. As produced, these may be in dry or slurry form and contain varying concentrations of toxic substances originally present in the coal. Nationwide, about 40 percent of CCRs are recycled for concrete, road fill and other purposes. The remainder is transferred to impoundments or dewatered and disposed in landfills, most on-site. CCRs have historically been exempt from federal regulation under an amendment to the Resource Conservation and Recovery Act (RCRA). Concerns rising from groundwater contamination, blowing of contaminants into the air as dust and catastrophic impoundment failure led the EPA in June 2010 to propose regulation of the disposal of these materials. The EPA Administrator signed the final rule establishing technical requirements for CCR landfills and surface impoundments on December 19, 2014.

The final rule defines CCRs as non-hazardous waste, regulated under Section 316(d) of the RCRA. The rule establishes minimum federal criteria for both existing and new CCR landfills, surface impoundments and expansions to existing landfills and surface impoundments. The criteria include structural integrity requirements and periodic safety inspections for surface impoundments; groundwater monitoring requirements; groundwater remediation requirements where contamination has been detected; location and design requirements for new CCR landfills and surface impoundments; operating, record keeping and notification criteria; and, provisions regarding inactive units. The EPA anticipates that the new CCR regulations will be

[8] *White Stallion Energy Center, LLC v Environmental Protection Agency*, United States Court of Appeals for the District of Columbia, No. 12-1100 (April 15, 2014).

[9] *Michigan v EPA* No. 14-46, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-46.htm; *Utility Air Group v. EPA*, No. 14-47, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-47.htm; *National Mining Assn v. EPA*, No. 14-49, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-49.htm.

implemented through revision to state Solid Waste Management Plans. The rule does not affect CCRs determined to be beneficially used or CCRs disposed in coal mines. The EPA is encouraging states to implement the rule through amendment to state Solid Waste Management Plans.

EPA is finalizing national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and lateral expansions. These criteria consist of location restrictions, design and operating criteria, groundwater monitoring, corrective action for existing groundwater contamination, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements.[10] The rule requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances. It also requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Finally, those CCR surface impoundments that do not receive CCR after the effective date of the rule, but still contain water and CCR will be subject to all applicable regulatory requirements, unless the owner or operator of the facility dewaters and installs a final cover system on these inactive units within three years from publication of the rule.

All coal plants will be subject to the inspection and reporting requirements of the rule. The incremental cost of these requirements is not expected to be significant. Landfill disposal is used at Boardman, Centralia and North Valmy, so it is unlikely that significant additional costs will be incurred for CCA compliance at these plants.

More costly structural modifications are expected to be required at Colstrip and Jim Bridger where impoundments are used for CCR disposal. Nationwide, it is expected that most plants using impoundment disposal will shift to dry landfill disposal[11]. This will typically require the addition of dewatering equipment, slurry transportation facilities, landfill expansion and impoundment decommissioning. Puget Sound Energy (PSE), a co-owner of Colstrip 1 and 2, in its 2013 IRP estimated the costs for Colstrip to comply with the various CCR rules under consideration at the time. PSE assumed that installation of an on-site dry ash system (ash slurry dewatering system) would be required by 2018 for compliance with a Subtitle D (non-hazardous) rulemaking[12]. Portland General Electric (PGE), a co-owner of Colstrip 3 and 4, in its 2013 IRP plans on lining of the existing slurry disposal ponds by 2020.

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[10] Environmental Protection Agency. Pre-Publication Version of Coal Combustion Residuals Final Rule. December 19, 2014.

[11] Power Engineering. "The Coal Ash Rule: How the EPA's recent ruling will affect the way plants manage CCRS". February 2015.

[12] At the time, CCR options under consideration included treatment as hazardous and non-hazardous material. The non-hazardous option was chosen in the final rulemaking.

No specific CCR compliance actions for Jim Bridger are identified in the draft PacifiCorp 2015 IRP case fact sheets[13], though all cases include the cost of meeting known and assumed compliance obligations for CCR (and other) rules. Idaho Power Company, a co-owner of Jim Bridger in its 2013 Coal Unit Investment Analysis assumed that CCR disposal at Jim Bridger would be shifted to landfills in 2014[14], though no estimate of compliance cost was provided. In 2013 the EPA completed a survey of above ground impoundments containing coal combustion residuals, rating both the hazard potential and structural integrity. The Bridger impoundments were rated as “significant” hazard and in “fair” condition[15]. The cost of structural deficiency remediation has not been reported but would be incurred irrespective of future plant operation.

The incremental O&M costs of shifting to landfill disposal are likely to be minor and not substantially affect plant dispatch.

## Cooling Water Intake Structures

Water withdrawal from surface water bodies may result in the injury or death of aquatic organisms by heat, chemicals or physical stress as a result of impingement on intake screens or entrainment in the intake water. Under the authority of the Clean Water Act Section 316(b), the EPA in August 2014 concluded a multiphase rulemaking process with the publication of the National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities; Final Rule[16], effective October 14, 2014. The purpose of the rule is “to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities for the withdrawal of cooling water from waters of the United States.”

The general rule applies to existing power generation and industrial facilities withdrawing more than two million gallons per day and using at least 25% of withdrawn water for cooling purposes. Compliance is based on the Best Technology Available (BTA) for minimizing adverse environmental impacts. Separate standards apply to impingement mortality and entrainment. Impingement mortality standards consist of implementation of BTA, defined as any one of seven alternatives. These include closed-cycle recirculating cooling systems. Entrainment standards apply to cooling water intake structures having average intake flows of 125 million gallons per day, or more. An Entrainment Characterization Study is required for these facilities. Compliance

[13] PacifiCorp. 2015 IRP Handout – Core Case Fact Sheets with Draft Results. November 14, 2014.

[14] Idaho Power Company. 2013 IRP Coal Study Presentation “Coal Unit Investment Analysis”.

[15] US EPA letter of August 13, 2013 to Nathan Graves Safety of Dams Engineer, Wyoming State Engineers Office.

[16] U.S. EPA, Water: Cooling Water Intakes (316b), http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/; 40 C.F.R. Parts 122 and 125

requirements are then established on a case-by-case basis, based on the permitting agency's determination of BTA for entrainment reduction.

The rule will be implemented through the National Pollutant Discharge Elimination System (NPDES) permit program as NPDES permits are renewed. Permit renewal applications submitted after July 2018 (45 months following the effective date) will require full and complete studies. Applications due before this date may request that certain studies be submitted later on an agreed-upon schedule because of the time needed to complete the monitoring and analysis required for these studies. Interim BTA requirements must be proposed in these applications, however.

Any impingement or entrainment of a federally listed species is considered a taking under the Endangered Species Act, and will require a taking permit or Incidental Take Statement provided through a Fish and Wildlife Service or National Marine Fisheries Service biological opinion.

All major Northwest coal, nuclear and gas combined-cycle generating units are equipped with closed-cycle recirculating cooling systems and are therefore likely to be in compliance with the impingement standards. Boardman is the only major thermal unit with cooling water intake exceeding 125 million gallons per day and potentially subject to entrainment standards. However, the Boardman NPDES does not expire until April 2023 so an entrainment analysis and BTA recommendations would only be required if the plant were converted to a biomass-fired facility and continued operation beyond 2020. Moreover, if the converted plant, as contemplated, operated only during peak periods, intake flows may drop below the 125 MMgpd annual average trigger for entrainment regulation.

Though outside of the scope of the EPA's new cooling water intake regulations, a pending lawsuit may affect Columbia Generating Station's (CGS) cooling water intake structure. The Washington Energy Facility Site Evaluation Council (EFSEC) and Washington Department of Ecology renewed CGS's NPDES permit (discharge permit under the Clean Water Act) on September 30, 2014. CGS's permit was renewed against the advice of the National Marine Fisheries Service, which argued that CGS's intake structures fail to employ BTA and represent a risk to juvenile salmon.[17] Washington Fish and Wildlife disagreed in a formal memo in September 2014, and the permit was issued. Environmental organizations filed suit in Washington State Superior Court on Oct. 30, 2014. The environmental plaintiffs' claims include an assertion that CGS's water intake structure does not employ BTA and should be modernized to protect juvenile salmon. The suit is pending. A resolution in favor of the plaintiffs could result in significant costs for CGS.[18]

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[17] Letter from NMFS to Jim La Spina, Energy Facility Siting Specialist, Washington EFSEC (August 6, 2013), *available at*: http://pbadupws.nrc.gov/docs/ML1409/ML14091A228.pdf.

[18] http://www.tri-cityherald.com/2014/10/30/3232860/conservation-groups-sue-state.html.

# Effluent Guidelines for Steam Electric Power Generation

In June 2013, the EPA proposed revisions to its effluent regulations for steam electric power generators pursuant to its authority under the Clean Water Act. The revisions would strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants, including mercury, arsenic, lead and selenium, into surface waters. Because the rule is targeted at reducing wastewater discharges associated with coal-fired generators, the region's existing coal plants are the only facilities likely to be significantly impacted by the proposed regulations.

The EPA first adopted its regulations for steam electric power generation facilities in 1974, subsequently amending them in 1977, 1978, 1980, and most recently in 1982. In the years since they were last revised, new and shifting waste streams from coal steam-electric units have resulted in increasing levels of pollutant discharges; levels that the EPA estimates currently account for 50%-60% of all toxic pollutants discharged into surface waters by regulated industries.[19] Those pollutants can cause harm to human life as well as fish and wildlife, and the toxic materials can build up in sediments. Many of those discharges are the result of the installation of air pollution control technologies that utilize water for capturing and transporting air pollutants and precursors.

The proposed regulations would apply to the steam electric power generating point source category, which includes thermal generators using fossil or nuclear fuels, and would limit discharges associated with flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. Coal and petroleum coke-fuelled generators are the most likely to be impacted by the proposed rule, because the higher volume waste streams that the rule proposes to regulate originate from flue gas pollution control systems and ash handling systems. Nuclear and gas-fired combined cycle plants may be affected to a minor degree because the rule also addresses metal cleaning and other low volume wastes that might originate from these plants. Because of the low volume of these wastes, the compliance costs for nuclear and gas combined-cycle plants are expected to be minimal.

The EPA intends the proposed effluent limitations guidelines regulations for steam electric generators to operate in conjunction with its proposed coal combustion residuals (CCR) rule under the Resource Conservation and Recovery Act (RCRA). That proposed rule would regulate the disposal of fly ash, bottom ash, and flue gas desulfurization (FGD) wastes not used for beneficial purposes.

The EPA's proposal contains four preferred regulatory options for existing steam electric facilities that discharge into surface waters pursuant to an NPDES permit. Those alternatives vary in the waste streams covered, the size of the units covered, and the stringency of the

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[19] Federal Register Vol. 78, No. 110, June 7, 2013 at 34435, *available at***:** http://www.gpo.gov/fdsys/pkg/FR-2013-06-07/pdf/2013-10191.pdf.

controls. All four preferred alternatives for existing units would prohibit the discharge of pollutants associated with fly ash and flue gas mercury control systems, place limits on metals and other wastes associated with gasification processes and nonchemical metal cleaning, and set effluent limits equal to Best Practicable Control Technology Currently Available (BPT) for bottom ash transport water, combustion residual leachate from landfills and surface impoundments. Under the proposed regulations, coal plants would have the incentive to reduce the water use in their air pollution control systems, and therefore produce less wastewater, and to install additional technologies to treat the remaining effluent discharges. EPA's proposed regulations also include effluent guidelines for new steam electric generators. Steam electric facilities would be required to comply with the new regulations upon renewal of their NPDES permits. The permitting authority will determine the precise date of compliance, but EPA's proposed regulations require that it be as soon as possible within the next permit cycle after July 1, 2017.[20]

In March 2012, the District Court of the District of Columbia approved a consent decree between the EPA and environmental organizations (Defenders of Wildlife and the Sierra Club), which obligated the EPA to take final action on steam electric effluent guidelines no later than January 31, 2014.[21] That deadline for final EPA action was extended by mutual agreement of the parties until September 30, 2015.[22]

All of the Northwest's coal plants employ some, if not all, of the technologies and processes targeted by the EPA's proposed effluent limitations guidelines for steam electric generation. For example, all of the coal plants in the Northwest employ wet or wet and dry bottom ash transport handling systems, one of the regulated waste streams under the proposed rule, while only two facilities use wet flue gas desulfurization systems.[23]

Two Northwest coal plants may be affected by the proposed regulations: Boardman and Centralia are scheduled to cease burning coal or retire in the next decade, Boardman in 2020 and Centralia in 2020 (one unit) and 2025 (unit two), but EPA will presumably require both to

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[20] Fed. Reg. at 34461.

[21] Consent Decree, *Defenders of Wildlife and Sierra Club v. Lisa P. Jackson* (DC Cir. March 19, 2012), *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/consentdecree.pdf

[22] Consent Decree Modification and Joint Stipulation, *Defenders of Wildlife and Sierra Club v. Lisa P. Jackson* (DC Cir., April 27, 2014), *available at:* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Consent-Decree-Extension-4-April-7-2014.pdf

[23] EPA Technical Questionnaire Database, 2010, *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/questionnaire.cfm. *See also* EPA, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA-821-R-13-002 (April 2003) at 4-22 – 4-26, *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf

comply with effluent limitations guidelines as long as they are in operation. J.E. Corette is slated for retirement in August 2015, before the regulations take effect. Colstrip, Jim Bridger and North Valmy are “Zero Liquid Discharge” (ZLD) facilities and unlikely to be affected. Some of the region’s gas-fired plants and the Columbia Generating Station might be affected by the provisions of the proposed regulation regarding metal cleaning waste streams. Metal cleaning wastes are a very minor waste stream, however, so compliance is unlikely to have a major financial impact.

Because of the uncertainty regarding the contours of EPA’s final effluent limitations guidelines, it is difficult to predict the precise cost of compliance to coal plants in the Northwest. One potential reference point for the region is EPA’s range of estimates of compliance costs across the EPA’s four preferred alternatives. For the Western Electricity Coordinating Council (WECC), which hosts 194 steam electric generators and includes the Northwest coal plants,[24] annualized compliance cost estimates for the four preferred alternatives range from $3.7 to $16.9 million. The WECC is comprised of 11 Western states and two Canadian provinces, suggesting that the Northwest’s compliance costs would be a fraction of those estimates.

# Carbon Pollution Standards for Existing Power Plants

In June 2014 the EPA released its proposed Carbon Pollution Standards for Existing Power Plants (the “Clean Power Plan”), a companion proposal to the September 2013 Carbon Pollution Standards for New Power Plants. The proposed standards for new power plants (111b) establish specific carbon dioxide emission rates (1,100 lb/MWh) for individual new plants. In contrast, the proposed standards for existing power plants (111d) establish target carbon dioxide emission rates at the state level with the objective of achieving 30 percent reduction, nationwide, from 2005 levels by 2030[25]. Similar to other EPA pollutant control regulations, the standards are set at the federal level and the means of achieving the standards are to be established and administered by state implementation plans. The proposed Clean Power Plan identifies four “building blocks” for achieving emission reduction targets: (1) Improving the efficiency (heat rate) of coal-fired steam-electric power plants by best operating practices and equipment upgrades; (2) expanded use of existing natural gas combined-cycle power plants where excess capacity is available; (3) expanded use of existing and new zero and low-carbon emission power sources including renewable and nuclear generating capacity; and (4) reducing electricity demand by efficiency improvements. The proposed state goals are a

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[24] EPA, *Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source* Category, EPA-821-R-13-005, Table 3-3 (April 19, 2013), *available at*: [http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_RIA_Proposed-rule_2013.pdf](http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_RIA_Proposed-rule_2013.pdf)

[25] While the overall national objective is 30% reduction in carbon emissions from 2005 levels, state-specific reduction targets vary depending on baseline rates and the estimated cost and availability of potential reductions.

function of the estimated capability of individual states to achieve carbon dioxide emission reductions through application of measures contained in the four building blocks.

The EPA proposed carbon pollution standards for new and existing plants in response to a 2011 decision of the Supreme Court[26] requiring the EPA to regulate greenhouse gasses under Section 111d of the Clean Air Act, if it finds them a danger to public health and welfare. The proposed rule was published on June 18, 2014 and comments were due December 1, 2014. The EPA proposes to adopt a final rule by June 2015. The proposed target date for states to submit implementation plans to the EPA is June 30, 2016, with provision for extension for final SIPs. Under the proposed rule, states would have to commence reductions by 2020 with full compliance achieved by 2030.

The State Implementation Plans are expected to include a portfolio of measures within the proposed building blocks with the objective of securing the most effective approach to meeting state reduction targets (regional approaches also may be adopted). The most significant effect on existing power generation plants is expected to be reduced operation (re-dispatch) of coal-fired units. The shortfall would be provided by additional operation of existing gas-fired combined cycle plants, development of new renewable, nuclear or other low-carbon electricity sources and offset by energy efficiency improvements. The proposed rule does not mandate or estimate a re-dispatch level for any given coal steam unit. Rather, overall state-level re-dispatch potential is estimated based on available unused gas combined-cycle capacity, additional generation potential from renewable, nuclear and other low or zero carbon sources and energy efficiency improvements. All coal-fired units in the Northwest would potentially be affected except for Boardman and Centralia, which would comply through their retirement agreements.

The EPA's Clean Power Plan proposed regulations are controversial and may face significant revision before issuance of the final rule. In the 165-day comment period for the draft Clean Power Plan regulations, the EPA received over two million public comments. In addition, many states and businesses are preparing to challenge the Clean Power Plan once the EPA promulgates the final regulations.[27] The challenging states are likely to argue that the EPA's regulations are a broad overreach of the agency's authority to regulate power plants. Twelve states have already brought suit against the EPA.[28] The likely legal challenges simply add to the uncertainty and risks already associated with the proposed regulations.

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[26] American Electric Power Co. v. Connecticut, 131 S. Ct. 2527, 2537-38 (2011).

[27] *See, e.g.,* Emily Holden and Rod Kuckro, *Lawyers gird for fight against EPA's Clean Power Plan based on states' rights*, E&E Publishing (Dec. 12, 2014), *available at*: http://www.eenews.net/stories/1060010446

[28] *See* Andrew Zajac and Mark Drajem, *EPA Coal Plant Emissions Limits Challenged by 12 States,* BloombergBusiness (Aug. 1, 2014), *available at*: http://www.bloomberg.com/news/articles/2014-08-01/west-virginia-11-other-states-sue-epa-over-coal-plant-rule-1- . The case is West Virginia v. EPA, 14-1146, U.S. Court of Appeals, District of Columbia (Washington).

Efforts are underway in Washington to establish a state-level emissions allowance trading program for the purposes of reducing the production of greenhouse gasses associated with the production of electricity, transportation and other uses. The Centralia plant is exempted under terms of the agreement to cease operations at the plant by 2025. However, under the proposed Carbon Pollution Accountability Act, greenhouse gas production associated with import of electricity for sale within the state would be subject to the allowance trading program. This could affect exports from the Colstrip and Bridger plants, which are partly owned by utilities engaged in retail electricity sales in Washington, and other western plants exporting electricity to Washington. House and Senate bills have been introduced in the 2015 legislative session[29]. The House bill has cleared the House Environment Committee, however majority opposition in the Senate is likely to preclude adoption this session.

## Fukushima Upgrades

On March 11, 2011 the magnitude 9.0 Tohoku earthquake struck off the coast of the Japanese island of Honshu, the site of the six-unit Fukushima Dai-ichi nuclear power plant. Grid power was lost and units 1, 2 and 3 automatically shut down (Units 4, 5 and 6 were offline for refueling and maintenance). Emergency diesel generators supplied power to critical systems and plant conditions were stabilized. About 40 minutes following the earthquake a tsunami estimated at 46 feet in height inundated the plant, causing extensive damage and the loss of all emergency power to units 1 - 4. One diesel-generator supplying power to units 5 and 6 continued to operate, enabling these units to be maintained in safe shutdown. Steam and battery-power safety systems at Units 1, 2 and 3 failed within 24 hours. Emergency core cooling was subsequently lost and all three reactors overheated, causing fuel damage, coolant system over-pressurization and hydrogen leaks to the containment. Operators were unable to operate the containment venting systems, leading to containment over-pressurization and hydrogen explosions that destroyed the containment buildings of Units 1, 2 and 4. Radioactive contamination spread over large areas requiring relocation of tens of thousands of people. The reactors were eventually stabilized but work continues to isolate the damaged reactors and radioactive contamination.

Following a review of the Fukushima events, the Nuclear Regulatory Commission (NRC) concluded that a sequence of events such as those leading to the Fukushima accident is unlikely to occur in the U.S. and continued operation of nuclear plants of similar design would not pose an imminent threat to public health and safety. However, the NRC also concluded that upgrades to the design and operation of U.S. plants are needed to cope with external events beyond design criteria. In March 2012, the NRC issued three orders requiring operators of U.S. reactors to:

- Obtain and protect additional on- and off-site emergency equipment, such as pumps, generators, batteries and fuel to support reactors in case of natural disaster and loss of off-site power (applicable to all reactor designs)

[29] HB 1314; SB 5283.

- Install improved instrumentation for monitoring the spent fuel pool water level (applicable to all reactor designs)
- Improve and install emergency containment venting systems ("reliable hardened vents[30]") that can relieve pressure in case of a serious accident (applicable to boiling water reactors (BWRs) employing Mark I or Mark II containment systems)

Plants are to be in compliance with respect to these orders by the end of 2016.

The NRC acknowledged that questions remained regarding maintaining containment integrity and limiting release of radioactive materials if the containment venting system was used during severe accident conditions. Regarding these concerns, NRC staff in November 2012 presented the Commission with four options for consideration[31]. These were: 1) reliable hardened containment vents as ordered in March 2012, 2) reliable hardened containment vents capable of reliable operation under severe accident conditions, including situations involving core damage, 3) installation of an engineered filter on the containment venting system to prevent the release of significant amounts of radioactive material following dominant severe accident sequences, and 4) performance-based confinement strategies. NRC staff recommended approval of Option 3.

In March 2013, the Commission directed staff to issue an order for modification of hardened BWR containment venting systems to be capable of reliable operation under severe accident conditions, including situations involving core damage (Option 2). The Commission also instructed staff to initiate a rulemaking regarding filtering strategies (Filtering Strategies Rulemaking) (Option 3). In June 2013, the Commission ordered the modification of hardened BWR containment venting systems to be capable of reliable operation under severe accident conditions.[32]

The filtering strategies rulemaking is in process. In recognition of a less costly alternative to filtration that may provide collateral benefits (addition of water to the containment drywell under severe accident conditions) the rulemaking has been renamed Containment Protection and Release Reduction with Mark I and II Containments (CPRR Rulemaking). A proposed rule is scheduled for December 2015 and the final rule by March 2017.

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[30] "Hardened" means these vents must withstand the pressure and temperature of the steam generated early in an accident. The vents must also withstand possible fires and small explosions if they are used to release hydrogen later in an accident. The vents must be reliable enough to be operated even if the reactor loses all electrical power or if other hazardous conditions exist. (NRC at http://public-blog.nrc-gateway.gov/2012/04/24/whats-so-hardened-about-vents)

[31] Nuclear Regulatory Commission SECY-12-0157. November 26, 2012. http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2012/2012-0157scy.pdf

[32] Nuclear Regulatory Commission. EA-13-109. Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation under Severe Accident Conditions. June 6, 2013. http://pbadupws.nrc.gov/docs/ML1314/ML13143A321.pdf

Generic estimates of the costs of certain Fukushima-related compliance actions in addition to those currently ordered have been prepared by the Nuclear Energy Institute. The capital cost of severe accident capable water injection is estimated to be $3.72 million per unit. The capital cost of containment vent filtration is estimated to range from $35.4 million (small filter) to $54.9 million (large filter). These costs include direct and indirect (engineering, project management and other indirect costs) plus a 50% contingency as befitting their preliminary and generic nature.[33] Incremental operating, maintenance and decommissioning costs were not estimated.

The Columbia Generating Station is a boiling water reactor employing a Mark II containment system, so is subject to all NRC orders to date regarding actions in response to the Fukushima accident. Energy Northwest is in the process of implementing the NRC March 2012 and June 2013 orders. A total of $53 million from FY 2015 through FY 2019 is budgeted to this effort[34]. The outcome of the CPRR Rulemaking is uncertain and, as noted above, the potential cost of actions resulting from this rulemaking could vary widely. Currently, Energy Northwest has included a Fukushima Filter Requirements Risk in its Management Discretion - Special Projects budget line item. This line item totals $20.3 million from FY 2016 through FY 2024[35].

Additional evaluations are being undertaken in response to the Fukushima accident including assessments of station blackout, fire, flooding and seismic risks. Possible station upgrades and other actions in response to these issues have not yet been determined.

# Main-stem Hydropower System Operations

Mainstem dams and reservoirs are required to operate in a manner to protect and restore ecosystem function and habitat, and to enable fish passage and survival through the hydropower system. These operations are established as part of the “reasonable and prudent alternative” actions set forth in the Federal Columbia Power River System Biological Opinions prepared by the National Marine Fisheries Service and the U.S. Fish and Wildlife Service under the Endangered Species Act and in the Council’s *Columbia River Basin Fish and Wildlife Program* developed under the Northwest Power Act. The hydropower system is currently operated in compliance with the 2008 Biological Opinion and the May 2010 and January 2014 supplements and the hydrosystem passage and water management measures in the 2014 Fish and Wildlife Program. Further changes to hydropower system design and operation that would significantly affect cost or system output are not anticipated at this time.

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[33] Nuclear Energy Institute and Boiling Water Reactor Owners’ Group. Industry Incremental Cost Estimate – External Filtration and Water Addition. NRC Public Meeting, June 18, 2014. http://pbadupws.nrc.gov/docs/ML1417/ML14170A055.pdf. Year dollars not specified.

[34] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan.

[35] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan.

# Fugitive Methane Reduction

The electric industry is increasingly turning to natural gas as an alternative fuel source to coal,[36] at least partly for the perceived carbon emissions reduction benefits. However, the production and transportation of natural gas results in the release of methane, a potent greenhouse gas with the potential to negate the climate change benefits associated with switching fuels. Concerns about the environmental impacts of methane emissions led the Obama Administration, on January 14, 2015, to announce plans to cut methane emissions from the oil and gas industry by 40%-45% from 2012 levels by 2025.[37] To accomplish these reductions, the President directed the EPA to propose new methane and volatile organic compound (VOC) emissions regulations. The EPA will issue its proposed rule in summer 2015, with final guidelines due in 2016.[38] The EPA does not currently impose limits on methane emissions, instead operating a voluntary methane emissions reduction program. These new regulations will impact the Northwest electric industry by increasing the compliance costs associated with producing and transporting natural gas for the oil and gas industry, which will translate to higher fuel costs for the electric industry.

Switching from coal to natural gas as a fuel source for electricity generation may have climate benefits, as long as methane leakage is minimized. Natural gas combustion emits about half as much carbon dioxide as coal combustion in relation to the energy that each produces,[39] a fact that has led some policymakers to view the fuel as a bridge to a clean energy future.[40] However, methane, the primary component of natural gas, is a greenhouse gas with a global warming potential in the atmosphere of 25 times that of carbon dioxide over a 100-year period.[41] So, while natural gas may represent a net climate benefit as compared to coal, that benefit will only be realized if methane leakage remains below 3.2% from well delivery to power plant.[42]

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[36] *See, e.g.,* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

[37] http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1

[38] http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/ba7961bf631c87bf85257dcd00526ff7!OpenDocument

[39] http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

[40] See President Obama, *State of the Union*, 2014, http://www.whitehouse.gov/the-press-office/2014/01/28/president-barack-obamas-state-union-address

[41] http://epa.gov/climatechange/ghgemissions/gases/ch4.html

[42] http://www.pnas.org/content/109/17/6435.full#ref-6

According to EPA estimates, the oil and gas industry accounts for around 30% of U.S. methane emissions. In 2009, the EPA estimated methane leakage rates in the oil and gas industry to be 2.4%. That estimate has been the subject of controversy, however, with some studies measuring leakage rates of over 10% in certain oil and gas basins.[43] The current climate calculus, then, may favor natural gas over coal, but that distinction is not as clear as it seems when looking solely at carbon dioxide emissions from combustion. Complicating the equation is the fact that coal extraction also releases methane.

The EPA does not currently limit methane emissions from the oil and gas industry, instead offering a voluntary methane emissions reduction program called Natural Gas STAR.[44] The Natural Gas STAR program provides the oil and gas industry with technical guidance, and opportunities for information sharing and technology transfer to encourage fugitive methane capture and emissions reductions. The oil and gas industry has long maintained that voluntary programs are sufficient to restrict methane emissions, because the nature of natural gas as a commodity provides the industry an economic incentive to bring it to market. The EPA's proposed methane emissions regulations will impose enforceable standards on the oil and gas industry.

The EPA plans to regulate methane and VOC emissions from new sources pursuant its authority to set New Source Performance Standards (NSPS) under Section 111(b) of the Clean Air Act (CAA).[45] The NSPS program requires certain sources of emissions to comply with standards performance consistent with the best adequately demonstrated system of emissions reductions.[46] These NSPS regulations will not affect existing oil and gas facilities. Instead, existing sources in National Ambient Air Quality Standards (NAAQS) nonattainment areas will face VOC reduction requirements pursuant to the EPA's authority under Sections 108 and 109 of the CAA.[47] The EPA classifies methane as a VOC,[48] so any requirements to reduce VOCs will necessarily also limit methane emissions.

In addition to establishing methane emissions standards, the EPA would also ramp up voluntary emissions reductions programs already in place. The EPA proposed creating a more stringent voluntary program, called Natural Gas STAR Gold, that would provide participants the

[43] http://www.eenews.net/stories/1060007693

[44] http://www.epa.gov/gasstar/

[45] 42 U.S.C. § 7411.

[46] 42 U.S.C. § 7411(a)(1).

[47] 42 U.S.C. §§ 7408-7409.

[48] 40 CFR 51.100(s)

opportunity to be recognized as "Gas STAR Gold" facilities in exchange for meeting certain protocols.[49]

The costs associated with the EPA's impending methane emissions regulations for the Northwest electric industry are difficult to estimate, because the EPA has not yet issued a notice of proposed rulemaking that lays out the contours of the planned regulations. Economic impacts for the electric industry in the short term are likely to be minimal, as existing oil and gas facilities will largely escape regulation under the EPA's proposal. As the compliance costs associated with the methane emissions regulations rise for the oil and gas industry, however, those costs will be passed along to Northwest utilities through increased fuel prices for natural gas plants. These cost increases will likely be mitigated somewhat by the fact that any captured methane leakage can be brought to market. At this point, it can be assumed that the EPA's actions on this matter will have an economic impact on the electric industry in the Northwest, but the costs associated with the proposed methane emissions regulations are not clear at this time.

# Migratory Bird and Eagle Take Permits

The Bald and Golden Eagle Protection Act (BGEPA) and the Migratory Bird Treaty Act (MBTA) both impact the Northwest electric industry, and recent regulatory changes and federal court cases have the potential to affect the extent to which the industry is impacted. The statutes make it a violation of federal law to kill, or "take," an array of bird species. Because birds are particularly susceptible to fatal encounters with wind energy facilities, the statutes primarily affect Northwest wind developers and project owners.

Wind energy projects in the U.S. kill an estimated 140,000 – 328,000 birds annually, [50] a substantial number, but one that represents only a fraction of the number of birds killed by domestic cats, buildings and vehicles in the same timeframe. Wind facilities cause bird deaths through direct contact with the spinning blades and habitat fragmentation. Most wind projects in the U.S. employ mitigation practices, including pre-construction site evaluations that dramatically limit bird mortality as a result of contact with wind facilities. As a result of evolving mitigation practices, the average wind project reports fewer than four bird fatalities per megawatt annually, the majority of which are songbirds.[51] While bird deaths caused by wind energy projects are a serious concern, wind facilities are not likely among the major causes of bird deaths in the U.S. Even so, they are a source of mortality, and thus wind projects are

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[49] http://www.epa.gov/methane/gasstar/documents/Gas_STAR_Gold_proposedframework.pdf#page=9

[50] Scott R. Loss, et al, Estimates of bird collision mortality at wind facilities in the contiguous United States, Biological Conservation, Vol. 168 201-209 (Dec. 2013), available at: http://www.sciencedirect.com/science/article/pii/S0006320713003522

[51] *Wind Turbine Interactions with Birds, Bats, and Their* Habitats, National Wind Coordinating Collaborative (Spring 2010), *available at:* http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf

required to comply with BGEPA and MBTA regulations restricting the “take” of eagles and migratory birds.

Pursuant to its authority under BGEPA, the U.S. Fish and Wildlife Service (FWS) recently issued a rule extending the duration of eagle take permits from five to 30 years; the rule has some small potential to affect wind energy project owners and developers in the Northwest.

BGEPA makes it unlawful for any individual to “knowingly or with wanton disregard for the consequences of his act take… any bald eagle commonly known as the American eagle or any golden eagle.” [52] As defined in BGEPA, “take” includes “pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb.” [53] Under BGEPA, the FWS may draft regulations to permit the incidental take of bald and golden eagles, if the take cannot be practicably avoided and occurs during the course of otherwise lawful activities. Pursuant to that authority, FWS issued Programmatic Incidental Take Permit regulations on September 11, 2009. Those regulations allowed FWS to issue permits to individuals for the recurring incidental take of eagles for a period of up to five years. On December 9, 2013, FWS extended the permit duration from five years to 30 years in a final rule, reasoning that the 30-year period would better align with the lifespan of wind energy projects.[54] In addition to extending the permit duration, FWS’s new regulations increased the price of a permit from $1,000 for five years, to $36,000 for 30 years, with a $2,600 fee due upon review every five years. The 30-year permit allows project developers to avoid the uncertainty associated both with BGEPA liability and with the potential evolution of permit requirements over time.

In order to get an eagle take permit, wind project developers must demonstrate that eagle takes are unavoidable after the implementation of Advanced Conservation Practices (ACPs). ACPs are defined as “scientifically supportable measures that are approved by the Service and represent the best available techniques to reduce eagle disturbance and ongoing mortalities to a level where remaining take is unavoidable.”[55] The FWS has not yet approved any ACPs, but the FWS is working with project developers on adaptive management practices that will provide the scientific data necessary to develop ACPs. After implementing ACPs and determining that take is unavoidable, permit applicants will be required to develop an Eagle Conservation Plan that includes a site assessment, a site survey, a risk assessment, impact avoidance and mitigation measures, and ongoing monitoring. The FWS has issued guidelines for wind energy developers to follow in drafting Eagle Conservation Plans.

Wind energy developers are not required to get an eagle permit to operate, and several factors militate against developers applying for a permit. First, the costs associated with getting a permit can be significant. In addition to the $36,000 permit cost and $2,600 review fee, wind energy

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[52] 16 U.S.C. § 668

[53] 16 U.S.C. § 668c

[54] 78 FR 73704, *available at:* [http://www.gpo.gov/fdsys/pkg/FR-2013-12-09/pdf/2013-29088.pdf](http://www.gpo.gov/fdsys/pkg/FR-2013-12-09/pdf/2013-29088.pdf)

[55] 50 C.F.R. 22.3

project developers are required to prepare an Eagle Conservation Plan. Compliance with the requirements in the FWS's Eagle Conservation Plan guidelines represents an additional cost to developers. Second, the permit process triggers review under the National Environmental Policy Act (NEPA), which can lengthen the amount of time required to bring a project online. NEPA contains procedural requirements for federal agency actions significantly affecting the human environment, and the review process can take between one month and one year, depending on the level of review required. Third, the government has pursued few BGEPA enforcement actions against wind developers or project owners, if any. BGEPA does not allow citizen enforcement of the law, so any such action must be initiated by FWS. A cursory search yielded no instances in which the government has pursued enforcement for eagle takes by wind developers under BGEPA. The fact that government has pursued limited enforcement of BGEPA may cause wind developers to elect not to expend resources and take the time required to apply for an eagle permit. Fourth, FWS has yet to issue a 30-year eagle take permit and has rejected at least one application. The perceived difficulty of receiving an eagle take permit may discourage potential applicants from pursuing one.

It is difficult to predict the appetite of wind project developers and owners to apply for eagle take permits in the future. Most project owners and developers currently appear to be holding back from applying for the new permits, assuming the risk of violating BGEPA rather than the costs associated with the certainty that a permit provides. It is possible that once FWS issues a 30-year permit to a wind facility, others will follow suit, but, unless a significant number of the region's wind facilities pursue eagle take permits, the economic impact of that shift is likely to be minimal. Alternatively, financing of new wind projects with low but non-zero risk of eagle mortality may become contingent on securing an eagle take permit, causing wind project developers to be compelled to pursue eagle take permits by risk-averse investors. Under that scenario, wind facilities would have to absorb the costs associated with applying for and maintaining an eagle take permit.

Recent MBTA decisions in several federal district courts have the potential to impact wind developers and project owners in the Northwest.

The MBTA makes it unlawful to "pursue, hunt, take, capture, [or] kill"[56] over 800 migratory bird species protected by of a number of international conventions.[57] The MBTA, unlike BGEPA, does not include a provision authorizing incidental take of protected species. Consequently, courts have traditionally interpreted the MBTA as a strict liability statute; any action that results in the death or take of a protected species is a de facto violation of the law, regardless of intent.[58] That does not mean that wind developers and project owners are at constant risk of liability for bird deaths at their facility, however. FWS is the agency responsible for enforcement

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[56] 16 U.S.C. § 703(a).

[57] U.S. Fish and Wildlife Service, List of migratory bird species protected by the MBTA, *available at*: http://www.fws.gov/migratorybirds/regulationspolicies/mbta/mbtandx.html.

[58] *See, e.g., U.S. v. Manning*, 787 F.2d 431, 435 n.4 (8th Cir. 1986).

of the MBTA. To avoid potential liability, wind developers typically enter into handshake agreements with FWS under which FWS will not pursue enforcement against a developer for bird deaths as long as the developer has made a good faith effort to avoid migratory bird take. A developer that takes steps to comply with FWS's Land-Based Wind Energy Guidelines is generally insulated from FWS enforcement.

On the other hand, FWS has pursued MBTA enforcement against at least two wind project owners that failed to follow the agency's guidance. In 2013, Duke Energy pleaded guilty to violations of the MBTA in U.S. District Court in Wyoming for the deaths of 14 golden eagles and 149 other migratory birds.[59] The court ordered Duke Energy to pay $1 million worth in restitution, fines and community service payments, in addition to imposing a five-year probationary period. Similarly, in 2014, PacifiCorp entered a settlement agreement with the government to pay $2.5 million in fines for migratory bird deaths at the company's Wyoming wind facilities.[60]

Recent federal district court cases in North Dakota, New Mexico, and Louisiana highlight a potential shift away from strict liability in the MBTA context, which, if adopted in the Northwest, may impact wind project owners and developers in the region. As an example of the trend away from strict liability, the federal District Court of North Dakota in 2012 dismissed misdemeanor criminal charges against three oil and gas companies for migratory bird deaths, because the conduct that resulted in the bird deaths represented a "legal, commercially useful activity,"[61] and was not intended to harm protected birds. The court further held that the MBTA was not intended to cover accidental bird deaths or the unintended consequences of otherwise lawful conduct. While that decision applied to oil and gas companies, the principle could be extended to wind project owners and developers, which similarly harm migratory birds in the process of conducting legal commercial activity.

It is unlikely, however, that those federal district court decisions will impact Northwest wind project owners and developers for several reasons. First, district court decisions have no precedential value, so courts in the region have no obligation to follow the District Court of North Dakota's decision. Second, courts in the Northwest have not shown the inclination to adopt the

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[59] Department of Justice Press Release, Utility Company Sentenced in Wyoming for Killing Protected Birds at Wind Projects (Nov. 22, 2013), *available at*

http://www.justice.gov/opa/pr/utility-company-sentenced-wyoming-killing-protected-birds-wind-projects

[60] *See* Richard A. Kessler, *Buffet's PacifiCorp fined $2.5m for bird deaths at Wyoming wind farm*, Recharge (Dec. 19, 2014), *available at:* http://www.rechargenews.com/wind/1387234/Buffetts-PacifiCorp-fined-2.5m-for-bird-deaths-at-Wyoming-wind-farms

[61] *U.S. v. Brigham Oil and Gas, L.P.* (D. N.D. Jan. 17, 2012). *See also,* Stoel Rives, *Federal Court Holds That the Migratory Bird Treaty Act Does Not Apply to Lawful Activities That Result in the Incidental Taking of Migratory Birds* (Jan. 30, 2012), *available at:* http://www.stoel.com/federal-court-holds-that-the-migratory-bird-treaty .

position of the courts in North Dakota, New Mexico and Louisiana. Third, wind farms kill more birds than oil and gas facilities, which makes it less likely that a court will insulate wind projects from the requirements of the MBTA. Consequently, the recent case law in federal district courts is not likely to alter the MBTA's status as a strict liability statute as it is applied to Northwest wind project owners and developers.

# EFFECT OF REGULATORY COMPLIANCE REQUIREMENTS ON THE CONTINUED COST-EFFECTIVENESS OF AFFECTED GENERATING PLANTS

Table 2 summarizes the recent and prospective compliance actions for the major Pacific Northwest generating units affected by the regulations described above. Estimates of incremental capital investment costs and fixed and variable operating and maintenance costs are provided where available.

Budget-authorization quality, or better, plant-specific cost estimates are the preferred source of compliance cost information. These, however, are not available for all compliance actions. Next-best are plant-specific feasibility or conceptual estimates. In cases where these are not located, the best available generic cost estimates have been used.

In some cases, no cost estimates appear to be available. This is either because final regulations have not yet been adopted, or have only recently been adopted and the compliance actions have not been determined, or because the compliance actions are highly plant-specific and the costs have not been released by the plant owners. In general, it appears that actions for which cost information is not available are those whose costs are expected to be relatively minor (cooling water intake modifications), or those that are remedial in nature (such as retention pond cleanup). The capital costs of the latter will have to be expended irrespective of future plant operation, so will not affect the future of the plant. Moreover, the operational costs of these measures are likely to be small, and not significantly affecting plant dispatch or going forward costs.

Uncommitted capital costs and fixed and variable costs of non-remedial compliance actions could be avoided if the plant were retired, and thus bear on decisions regarding continued plant operation. Some actions are "remedial" in nature (e.g., cleanup of contaminated groundwater) and would have to be accomplished no matter what future plant operation might be. These will normally not greatly affect decisions regarding future plant operation. Incremental variable operating costs affect the hour-to-hour economic dispatch of a plant, so bear on short-term operational decisions as well as long-term investment and retirement decisions.

Certain compliance actions increase consumption of power or steam for internal loads or otherwise affect plant performance parameters such as net output and heat rate. Little quantitative information is available regarding these effects. These effects tend to be fairly minor for most compliance actions.

The “Assumed Status of Investment” in the fourth column of Table 2 represent the assumed status of the investment in response to the compliance action. This is an important staff assumption as it divides the estimated compliance costs by committed and near-term uncommitted costs – estimates that are fairly certain to occur and therefore included in the Regional Portfolio Model’s (RPM) existing power system and potentially affecting dispatch – and long-term uncommitted costs that are uncertain both in whether they will even occur and the accuracy of the estimates and therefore not included in the RPM at this time. This breakdown is more evident as it is carried through to Table 3, where the cost estimates included and not included in the RPM at this time are clearly identified.

The costs shown in Table 2 have been normalized to year 2012 dollar values and to common metrics (capital investment and fixed O&M in $/kW(net)-yr; variable O&M in $/MWh) to remain consistent with and to facilitate comparison to other costs appearing in the draft Seventh Power Plan work. The original sources are indicated in the footnotes.

Table 2: Current and prospective environmental compliance actions for major Northwest units
(Costs normalized to 2012 year dollar values unless indicated)

| Unit | Regulation | Controls or Actions[a]; Compliance Date | Assumed Status of Investment[b] | Capital Investment | Incremental O&M Cost | Operational Impacts |
|---|---|---|---|---|---|---|
| Boardman | NAAQS | In compliance (DSI and low-sulfur coal, 2014) | -- | -- | -- | -- |
| | Regional Haze | In compliance (LNB & MOFA, 2011); Termination of coal firing (2020) | -- | -- | -- | -- |
| | MATS | In compliance (ACI, 2011) | -- | -- | -- | -- |
| | Coal Combustion Residuals | Unknown | -- | -- | -- | -- |
| | Cooling Water Intakes | IMS - Probable compliance (recirculating cooling system)<br>EMS – Evaluation probably required for continued operation as biomass unit | -- | Unknown EMS cost (if converted to biomass operation) | Unknown EMS cost (if converted to biomass operation) | -- |
| | Effluent Limitation Guidelines | Final control requirements not established | -- | Expected to be minor | Expected to be minor | -- |
| | Carbon Pollution Standards | Termination of coal firing (Dec 2020) | -- | -- | -- | Termination of coal firing |
| Centralia (TransAlta Centralia) 1 & 2 | NAAQS | Currently in compliance (LNB, OFA, SNCR, 2012), Coal blending, FGD, DESP) | -- | -- | -- | -- |
| | Regional haze | In compliance (Flex Fuel, SNCR, 2012)[c] | -- | -- | -- | -- |
| | MATS | In compliance (ACI, 2011) | -- | -- | -- | -- |
| | Coal combustion residuals | In compliance (Dry ash sold for beneficial use; balance disposed in former coal mine; wet scrubber waste treatment in compliance) | -- | -- | -- | -- |
| | Cooling Water Intakes | IMS - Probable compliance (recirculating cooling system)<br>EMS – Probable exemption (< 125 MMgpd) | -- | -- | -- | -- |

| Unit | Regulation | Controls or Actions[a]; Compliance Date | Assumed Status of Investment[b] | Capital Investment | Incremental O&M Cost | Operational Impacts |
|---|---|---|---|---|---|---|
| | Effluent Limitation Guidelines | Final control requirements not established | -- | Expected to be minor | Expected to be minor | -- |
| | Carbon Pollution Standards | Termination of coal firing for one unit (Dec 2020)<br>Termination of coal firing for second unit (Dec 2025) | -- | -- | -- | Scheduled retirement |
| Colstrip 1&2 | NAAQS | Currently in compliance | -- | -- | -- | -- |
| | Regional Haze | SOFA + SNCR (NOx); Lime injection (DSI) and additional scrubber vessel (SOx) (2017) | Uncommitted (Near-term) | $140/kW[d] | Vr: $1.49/MWh | Minor derate |
| | MATS | Addition of sieve trays to FGD system for enhanced particulate removal (2016)[e] | Committed | $30/kW[f] | Fx: $0.33/kW-yr<br>Vr: $0.00/MWh | Negligible |
| | Coal Combustion Residuals | Onsite dry ash disposal system (2018)<br>Slurry pond lining (2020) | Dry ash: Uncommitted (Near-term)<br>Lining: Committed | Dry ash: $23/kW[g]<br>Lining: $36/kW[h] | Fx: $1.63/kW-yr<br>Vr: $0.23/MWh<br>Lining: negligible | -- |
| | Cooling Water Intakes | IMS - Probable compliance (recirculating cooling system)<br>EMS – Probable exemption (< 125 MMgpd) | -- | -- | -- | -- |
| | Effluent Limitation Guidelines | Zero liquid discharge (ZDL) facility | -- | -- | -- | -- |
| | Carbon Pollution Standards | Heat Rate improvement, Redispatch (2020 -30) | -- | Not determined at this time | Not determined at this time | Potential redispatch (reduction in capacity factor) |
| Colstrip 3 & 4 | NAAQS | Currently in compliance | -- | -- | -- | -- |
| | Regional Haze | Currently in compliance; 5-year “reasonable progress” reviews will likely require SCR retrofit by 2027. | Uncommitted (Long-term) | $514/kW[i] | Fx: $0.27/kW-yr<br>Vr: $1.00/MWh | Minor derate |

| Unit | Regulation | Controls or Actions[a]; Compliance Date | Assumed Status of Investment[b] | Capital Investment | Incremental O&M Cost | Operational Impacts |
|---|---|---|---|---|---|---|
| | MATS | Addition of sieve trays to FGD system for enhanced particulate removal (2016)[j] | Committed | See MATS costs for Colstrip 1 & 2 | See MATS costs for Colstrip 1 & 2 | -- |
| | Coal Combustion Residuals | Onsite dry ash disposal system (2018)<br>Slurry pond lining (2020) | Dry Ash: Uncommitted (Near-term)<br>Lining: Committed | See CCR costs for Colstrip 1 & 2 | See CCR costs for Colstrip 1 & 2 | -- |
| | Cooling Water Intakes | IM - Probable compliance (recirculating cooling system)<br>EM – Probable exemption (< 125 MMgpd) | -- | -- | -- | -- |
| | Effluent Limitation Guidelines | Zero liquid discharge (ZDL) facility | -- | -- | -- | -- |
| | Carbon Pollution Standards | Heat Rate improvement, Redispatch (2020 -30) | -- | Not determined at this time | Not determined at this time | Potential redispatch (reduction in capacity factor) |
| Jim Bridger 1 & 2 | NAAQS | Currently in compliance | -- | -- | -- | |
| | Regional Haze | SCR (Unit 1, 2022; Unit 2, 2021) | Uncommitted (Near-term) | $257/kW[k] | Fx: $0.86/kW-yr<br>Vr: $0.41/MWh | Minor derate |
| | MATS | ACI + wet FGD additive + coal additive (2015) | Committed | $14/kW[l] | Fx: $0.10/kW-yr<br>Vr: $2.80/MWh | |
| | Carbon Pollution Standards | Heat Rate improvement, Redispatch (Prospective, 2020 -30) | -- | Not determined at this time | Not determined at this time | Potential redispatch (reduction in capacity factor) |
| Jim Bridger 3 & 4 | NAAQS | Currently in compliance | -- | -- | -- | |
| | Regional Haze | SCR (Unit 3 completion by Dec 2015; Unit 4 completion by Dec 2016 ) (LNB & SOFA in place 2010) | Committed | Unit 3: $326/kW<br>Unit 4: $380/kW[m] | Assume similar to JB1. | Minor derate |
| | MATS | ACI wet FGD additive + coal additive (2015) | Committed | $14/kW[n] | Fx: $0.10/kW-yr<br>Vr: $2.80/MWh | |

| Unit | Regulation | Controls or Actions[a]; Compliance Date | Assumed Status of Investment[b] | Capital Investment | Incremental O&M Cost | Operational Impacts |
|---|---|---|---|---|---|---|
| | Carbon Pollution Standards | Heat Rate improvement, Redispatch (Prospective, 2020 -30) | -- | Not determined at this time | Not determined at this time | Potential redispatch (reduction in capacity factor) |
| Jim Bridger (Plant) | Coal combustion residuals | Possible impoundment modifications and further shift to landfill disposal. | -- | Not available | Not available | |
| | Cooling Water Intakes | IMS - Probable compliance (recirculating cooling system)<br>EMS – Probable exemption (< 125 MMgpd) | -- | -- | -- | |
| | Effluent Limitation Guidelines | Zero liquid discharge (ZDL) facility | | -- | -- | |
| North Valmy 1 & 2 | NAAQS | Currently in compliance | -- | -- | -- | -- |
| | Regional Haze | Currently in compliance. 5-year "reasonable progress" reviews may require addition of SCR and wet FGD in the future (~2025-30) | Uncommitted (Long-term) | SCR: $257/kW[o]<br>FGD: $603/kW | Fx: $0.91/kW-yr<br>Vr: $1.70/MWh<br>Fx: $16.95/kW-yr<br>Vr: $1.41/MWh | |
| | MATS (HCL) | Unit 1 DSI (2015) | Committed | $14/kW[p] | Fx: $1.16/kW-yr<br>Vr: $5.83/MWh | |
| | Coal Combustion Residuals | Probable compliance (landfill disposal in current use) | -- | -- | -- | -- |
| | Cooling Water Intakes | IMS & EMS - Probable exemption (wellfield supply) | -- | -- | -- | -- |
| | Effluent Limitation Guidelines | Zero liquid discharge (ZDL) facility | -- | -- | -- | |
| | Carbon Pollution Standards | Heat Rate improvement, Redispatch (Prospective, 2020 -30) | -- | Not determined at this time | Not determined at this time | Potential redispatch (reduction in capacity factor) |

| Unit | Regulation | Controls or Actions[a]; Compliance Date | Assumed Status of Investment[b] | Capital Investment | Incremental O&M Cost | Operational Impacts |
|---|---|---|---|---|---|---|
| Columbia Generating Station | Fukushima Upgrades (Ordered) | Mitigation strategies<br>Spent fuel instrumentation<br>Containment vents capable of operating under severe accident conditions | Committed | $46/kW[q] | Not available | -- |
| | CPRR Rulemaking (In-process) | Accident- capable drywell water injection,<br>or Containment vent filters<br>Actions relating to station blackout, fire, flooding or seismic hazards (NRC) | Uncertain; rulemaking in process | Water injection - $3/kW<br>Vent filters - $30 - $46/kW[r] | Not available | -- |
| | Cooling Water Intakes | IM - Probable compliance (recirculating cooling system)<br>EM – Probable exemption (< 125 MMgpd) | -- | -- | -- | -- |
| | Effluent Limitation Guidelines | Possible minor impacts | -- | -- | -- | -- |

[a] See Abbreviations section for definitions.
[b] Assumed status of investment for compliance actions: Committed (Obligated, Under Construction), Uncommitted (Near-term through 2022), Uncommitted (Long-term post 2022). This status is an assumption from Council staff and leads to a division of near-term and long-term costs in Table 3.
[c] Flex Fuel – Use of Powder River Basin coal and associated boiler modifications to reduce haze precursors.
[d] Capital and O&M costs derived from Environmental Protection Agency Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan, Proposed Rule (77 Federal Register No. 77 (April 20, 2012) p. 23988 – 24101). Cost estimates submitted by PPL Montana were adopted for the final rulemaking. 2012 year $. Fixed and variable O&M costs were not separately reported, all O&M costs normalized as variable assuming a 90% capacity factor.
[e] State of Montana Department of Environmental Quality. Operating Permit Technical Review Document. Colstrip Steam Electric Station. February 9, 2015. The MT DEQ granted PPL Montana a one-year extension for MATS compliance.
[f] Capital and O&M costs for upgrade to existing scrubber system from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J, Case 1 - Low Cost Colstrip 1 & 2. May 2013. PSE share is pro-rated to full capacity.
[g] Capital and O&M costs for onsite dry ash disposal system from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J. May 2013. Colstrip 1 & 2 Low and Mid-cost cases (Non-hazardous CCR determination). PSE share is pro-rated to full capacity. Pond lining is assumed to have negligible effect on operating costs.
[h] Capital costs for pond lining from Portland General Electric 2013 Integrated Resource Plan. March 2014 T. 7-4. Average of estimated PGE share of Colstrip 3 & 4 ($9.8 – 12.0 MM) extrapolated to all Colstrip units and expressed as 2012 $/kW. Cost is likely committed irrespective of future operation of Colstrip units. Pond lining assumed to have negligible effect on operating costs.
[i] Capital and O&M costs from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J. May 2013. Mid-cost case Colstrip 3 & 4. PSE costs pro-rated to entire unit.

[j] While Colstrip Units 3 and 4 are in compliance with MATS, Units 1 and 2 are not. The compliance strategy chosen by the plant owners is to improve FGD system particulate removal for all four units by the installation of sieve trays, and comply with MATS emission requirements using weighted average emission rates from all four units. The MT DEQ granted the extension on January 5, 2015.
[k] Capital and O&M costs from CH2M-Hill (2007): BART Analysis for Jim Bridger Unit 1. Prepared by CH2M-Hill for PacifiCorp. Dec 2007. Economic Analysis Summary. T. 3-3, LNB + OFA + SCR less LNB w/OFA. Normalized to 2012 year dollars. Unit 2 costs assumed to be similar to those of Unit 1.
[l] Capital and fixed O&M costs were estimated using methodology of Table 1 of Sargent & Lundy. IPM Model - Revisions to Cost and Performance for APC Technologies, Mercury Control Cost Development Technology. March 2011. Variable O&M costs will vary depending on lost revenue and corresponding disposal cost from previously marketed fly ash rendered unsuitable for cement production and other alternative uses. The variable O&M value shown assumes 44% of fly ash was previously marketed at $30/ton and must be landfilled at $50 ton following installation of mercury control equipment.
[m] Commitment cost estimates, including AFUDC (adjusted to 100% unit shares), Section V.14 of Idaho Public Utilities Commission. Case No. IPC-E-13-16 Investment in Selective Catalytic Reduction Controls for Jim Bridger Units 3 and 4 - Idaho Power Company's Application and Direct Testimony. June 28, 2013. Normalized to 2012 $/kW (overnight cost).
[n] Capital and fixed O&M costs were estimated using methodology of Table 1 of Sargent & Lundy. IPM Model - Revisions to Cost and Performance for APC Technologies, Mercury Control Cost Development Technology. March 2011. Variable O&M costs will vary depending on lost revenue and corresponding disposal cost from previously marketed fly ash rendered unsuitable for cement production and other alternative uses. The variable O&M value shown assumes 44% of fly ash was previously marketed (US average) at $30/ton and is landfilled at $50 ton following installation of mercury control equipment.
[o] Capital and O&M costs for SCR and FGD retrofits are from Energy Information Administration. Annual Energy Outlook 2014: Electricity Working Group Meeting. July 24, 2013. Slide 6, Average cost of environmental retrofits. Normalized to 2012 year dollars.
[p] Capital cost from Application of Sierra Pacific Power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2014-2033 and Approval of its Energy Supply Plan for the period 2014-2016. Vol 11 of 16 Generation, Fuel and Purchase Power, Fuel, Renewable Narrative, and Technical Appendix. Year dollars not specified, assumed to approximate 2012 year dollars. O&M costs from Energy Information Administration. Annual Energy Outlook 2014: Electricity Working Group Meeting. July 24, 2013. Slide 6, Average cost of environmental retrofits (Dry Sorbent Injection, 100 – 299 MW unit).
[q] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan, adjusted to 2012 yr dollars.
[r] Assuming the Nuclear Energy Institute estimates are in 2014 year dollar values.

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Costs of complying with recent and proposed environmental and safety regulations can affect the economics of existing power generation facilities in several ways. Some compliance costs, such as those associated with upgrades to existing effluent ponds are likely to be required irrespective of future plant operation. Obligated compliance costs such as these are equivalent to sunk costs and unlikely to greatly affect decisions regarding future plant operation. In contrast, high capital cost compliance actions required to be undertaken only if a plant continues in service, for example, installation of flue gas desulfurization equipment for regional haze control, can render alternative resource options such as new generation, demand side options or market purchases, more attractive than retrofit for continued operation. Compliance actions with significant variable costs such as sorbent injection for mercury control, will affect dispatch cost and thereby the extent to which the plant can compete in the power market against other power generation facilities or demand-side measures. A plant thus affected may continue to operate, though to a lesser extent than previously.

Compliance actions or combinations of compliance actions potentially affect decisions regarding future plant operation when variable costs increase to a level significantly affecting the number of hours in which a unit can economically dispatch against competing units or when avoidable going forward costs increase to levels comparable to the cost of alternative resource options. In the former case, a unit might continue to serve as an economic source of capacity. In the latter, retirement in favor of more cost-effective resource options might be a preferred course of action. The capacity as well as the energy value of an existing plant must be considered in these comparisons. Wholesale energy market prices do not include capacity value except during resource shortages. Nor do all potential new supply or demand-side resource options supply the capacity value of the coal or nuclear units most affected by recent regulatory actions.

Remaining plant life affects capital investment decisions. Most coal-fired units in the Northwest have been operating 30 to 40 years. Though coal steam-electric plants can operate for 60 years or more, and nuclear operating licenses are routinely extended to 60 years (and potentially 80 years), increasing routine maintenance costs, declining efficiency compared to newer plants, and, for coal units, exhaustion of nearby sources of fuel may limit the attractiveness of investing in compliance actions.

A final consideration is the risk to continued operation of coal units posed by climate change policy. Unlike most environmental and safety regulatory actions, the proposed compliance requirements of the Clean Power Plan are not targeted at individual units. Rather, a mix of demand and supply-side actions are proposed, including a shift of dispatch from coal to gas combined-cycle units. Also, proposed state-level climate policy in Washington and Oregon prohibiting or taxing import of electricity from coal-fired plants would further reduce the value of power from these units.

Table 3 provides estimates of the impact of regulatory compliance actions on dispatch (variable) costs and total going forward costs for the major affected Northwest generating units. This is an important differentiation because Boardman, Centralia and Corette are omitted since these units are scheduled for early retirement or cession of coal-firing. Two rows are shown for Colstrip 3 and 4, and Valmy 1 and 2. The first row includes committed and uncommitted near-term actions and the second, uncertain future actions a decade or more in the future – as described above in Table 2.

The fifth column of Table 3 provides estimates of total dispatch costs, including the variable costs of the compliance actions, over the next 3-4 decades of the plant's lifetime. These estimates can be compared to the dispatch costs of the next most costly class of dispatchable resources to gain a sense of the post-compliance competitiveness of these units. In this sense, the CGS nuclear plant competes with coal units and coal units compete with natural gas-fired combined cycle plants. The CGS dispatch cost is expected to remain at or near its current level of approximately $1.00/MWh, whereas the dispatch costs of the coal units are expected to range from $14 to $21/MWh in the future. This suggests that "in the money" operating hours for CGS are unlikely to be significantly affected by compliance costs even if the variable operating costs of the compliance actions were significant, (which they are not expected to be). The forecast levelized dispatch cost of Northwest combined-cycle plants range from about $40 MWh for the most efficient about $52/MWh for the least-efficient plants (medium gas price forecast). As is evident in Table 3, even the most expensive compliance retrofits are unlikely to shift the dispatch order from coal to existing natural gas plants.

The right-hand column of Table 3 provides estimated total "going-forward" costs for the affected units. Retirement might be considered if these costs exceed forecast power market prices or the forecast revenue requirements of comparable resources. The 20-year levelized market price forecast for the Mid-Columbia trading hub is about $44.[62] Though this is equal to the going forward cost of CGS, the market price forecast does not include a risk premium for higher-than-expected natural gas prices or price impacts of future climate policies. Moreover, energy market prices do not fully embody capacity values. An alternative comparison is to the levelized revenue requirements of new natural gas-fired combined-cycle plant, about $71/MWh.[63] The forecast CGS going forward cost is substantially less.

The going forward costs of the Colstrip, Jim Bridger and North Valmy coal units following completion of near-term compliance actions are comfortably less than forecast market prices and the cost of a new combined-cycle plant. In the longer-term (late 2020s), however, potential requirements for additional controls on Colstrip 3 and 4 and the Valmy units to meet future regional haze progress requirements places going forward power costs in a range near forecast energy market prices. At present, the need for additional controls on Colstrip 3 and 4 is acknowledged by its owners as likely. The eventual need for additional controls on Valmy is regarded as less certain. The cost of these retrofits combined with the age of the affected units may make retirement an option at that time. The outcome of decisions to retrofit or retire at that time are highly uncertain because of uncertainties regarding reduction in regional haze by control or retirement of other sources, reduction in the cost of control technologies, prevalent natural gas prices and climate change regulations.

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[62] 2016 – 35, medium gas price forecast, no federal CO2 tax or allowance cost.

[63] 7th Plan Draft "Combined-cycle 1". IOU financing, 30-yr economic life, PNW eastside natural gas (medium case), no CO2 allowance cost or tax, 2020 service.

Table 3: Estimated revenue requirements impact of economically significant compliance actions[a]

| Units | Action | Assumed Status of Investment (from Table 2)[b] | Capital and Cumulative[c] O&M Costs | Levelized Dispatch Cost ($/MWh)[d] | Levelized Avoided Cost ($/MWh)[e] |
|---|---|---|---|---|---|
| Colstrip 1 & 2 | FGD sieve trays; SOFA, SNCR, DSI, scrubber; Dry ash disposal, slurry pond lining | Committed + Uncommitted (Near-term) | Capital - $229/kW<br>Fx O&M - $1.96/kW-yr<br>Vr O&M - $1.72/MWh | 10yr life - $16.66<br>15yr life - $16.72<br>20yr life - $16.74 | 10yr life - $34.12<br>15yr life - $32.95<br>20yr life - $32.36 |
| Colstrip 3 & 4 | FGD sieve trays; Dry ash disposal; Slurry pond lining | Committed + Uncommitted (Near-term) | Capital - $89/kW<br>Fx O&M - $1.96/kW-yr<br>Vr O&M - $0.23/MWh | 10yr life - $14.86<br>15yr life - $14.92<br>20yr life - $14.94 | 10yr life - $29.43<br>15yr life - $29.00<br>20yr life - $28.77 |
| Colstrip 3 & 4 | SCR | Uncommitted (Long-term) | Capital - $514/kW<br>Fx O&M - $2.23/kW-yr<br>Vr O&M - $1.23/MWh | 10yr life - $16.13<br>15yr life - $16.12<br>20yr life - $16.18 | 10yr life - $39.38<br>15yr life - $36.67<br>20yr life - $35.47 |
| Jim Bridger 1 & 2 | ACI; SCR | Committed + Uncommitted (Near-term) | Capital - $271/kW<br>Fx O&M - $0.96/kW-yr<br>Vr O&M - $3.21/MWh | 10yr life - $17.52<br>15yr life - $17.58<br>20yr life - $17.59 | 10yr life - $35.65<br>15yr life - $34.26<br>20yr life - $33.56 |
| Jim Bridger 3 | ACI ; SCR | Committed + Uncommitted (Near-term) | Capital - $340/kW<br>Fx O&M - $0.96/kW-yr<br>Vr O&M - $3.21/MWh | 10yr life - $17.52<br>15yr life - $17.58<br>20yr life - $17.59 | 10yr life - $37.06<br>15yr life - $35.31<br>20yr life - $34.43 |
| Jim Bridger 4 | ACI ; SCR | Committed + Uncommitted (Near-term) | Capital - $394/kW<br>Fx O&M - $0.96/kW-yr<br>Vr O&M - $3.21/MWh | 10yr life - $17.52<br>15yr life - $17.58<br>20yr life - $17.59 | 10yr life - $35.11<br>15yr life - $36.13<br>20yr life - $35.11 |
| North Valmy 1 & 2 | DSI (Unit 1 only; estimates have been normalized to include both units)[f] | Committed + Uncommitted (Near-term) | Capital - $6.72/kW<br>Fx O&M - $0.56/kW-yr<br>Vr O&M - $2.84/MWh | 10yr life - $17.48<br>15yr life - $17.53<br>20yr life - $17.55 | 10yr life - $30.26<br>15yr life - $30.25<br>20yr life - $30.23 |
| North Valmy 1 & 2 | FGD + SCR | Uncommitted (Long-term) | Capital - $860/kW<br>Fx O&M - $18.42/kW-yr<br>Vr O&M - $5.95/MWh | 10yr life - $20.85<br>15yr life - $20.84<br>20yr life - $20.91 | 10yr life - $53.39<br>15yr life - $48.86<br>20yr life - $46.81 |

| Units | Action | Assumed Status of Investment (from Table 2)[b] | Capital and Cumulative[c] O&M Costs | Levelized Dispatch Cost ($/MWh)[d] | Levelized Avoided Cost ($/MWh)[e] |
|---|---|---|---|---|---|
| Columbia Generating Station | Fukushima retrofits (Ordered) | Committed + Uncommitted (Near-term) | Capital - $46/kW<br>Fx O&M – n/a<br>Vr O&M – n/a | 10yr life - $0.98<br>15yr life - $0.98<br>20yr life - $0.98<br>30yr life - $0.98 | 10yr life - $44.33<br>15yr life - $44.04<br>20yr life - $43.87<br>30yr life - $44.04 |

[a] Assumptions: Original capital cost fully amortized, IOU financing, one yr development (10% cash flow), one year construction (90% cash flow); 60 mo tax depreciation on compliance investments, 85% capacity factor; capital recovery over expected economic life. Base (pre-compliance measure) NPCC generic subcritical coal-steam operation and maintenance costs. Excludes incremental cost of replacement power during retrofit. No CO2 allowance cost/tax.

[b] If the status of the investment is "Committed" or "Uncommitted (Near-term)", Council staff assumed these compliance actions were fairly certain and therefore the estimates were included in the Regional Portfolio Model (RPM). If the status of the investment is "Uncommitted (Long-term)", Council staff assumed there was too much uncertainty around both the occurrence of the compliance action and the cost estimates, so these estimates are for illustrative purposes only and were not included in the RPM at this time.

[c] If the assumed status is "Uncommitted (Long-term), then the capital cost is representative of that compliance order; however the O&M costs are cumulative and include the "Committed" and "Uncommitted (Near-term)" O&M costs as well.

[d] Variable fuel cost, base variable plant O&M cost, incremental variable O&M cost of compliance retrofits, variable transmission cost and variable component of cost of losses. Rounded.

[e] Total revenue requirements at point of wholesale delivery (includes transmission costs & losses) assuming a fully depreciated plant except for compliance capital investment. Rounded.

[f] DSI is being installed on Unit 1 for reduction in acid gas emissions. The costs shown, assume that the unit 1 installation brings the entire plant into compliance and are therefore allocated to the full plant capacity.

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# FINDINGS AND CONCLUSIONS

- Numerous federal rulemakings intended to reduce safety risks or environmental impacts of power generation have been adopted in recent years or are currently underway. Compliance with these rules often requires modifications to the design or operation of power generation facilities. These modifications may entail capital investment in pollution control and safety equipment and increased operating and maintenance costs. Plant performance and operational characteristics may also be affected.
- The major Northwest plants potentially affected by environmental rulemakings are the large coal-fired steam-electric generating plants including Boardman, Centralia, Colstrip, Corette, Jim Bridger and North Valmy. These plants are potentially affected by regulations addressing regional haze, mercury and air toxics, coal combustion residuals and effluent discharge. Proposed rules addressing water intake impingement and entrainment appear not to greatly affect Northwest thermal plants. The Columbia Generating Station nuclear plant is affected by rulemakings resulting from the Fukushima accident.
- Plant owners have moved rapidly to implement the requirements of regulations as state or federal implementation plans are approved.
- The costs of complying with scheduled compliance actions are unlikely to greatly affect the dispatch order of nuclear, coal natural gas combined-cycle plants. The full going forward costs of the Colstrip, Jim Bridger and North Valmy coal units following completion of scheduled compliance actions are comfortably below than forecast market prices or the cost of a new combined-cycle plant.
- A lack of satisfactory progress in reducing regional haze affecting Class I airsheds may lead to costly retrofit requirements on Colstrip 3 and 4 and the North Valmy plant in the mid- to late-2020s. The cost of these retrofits combined with the age of the affected units may make retirement an attractive option at that time. The need to retrofit Colstrip 3 and 4 is considered likely by the plant's owners, whereas the need to retrofit Valmy is less certain. The outcome of decisions to retrofit or retire either plant at that time are uncertain because of uncertainties regarding reduction in regional haze by control or retirement of other sources, reduction in the cost of control technologies, prevalent natural gas prices and climate change regulations.
- Proposed federal greenhouse gas control regulation in EPA's draft Clean Power Plan would significantly affect the above conclusions. Among other effects, the proposed regulation would reduce the dispatch of coal units in favor of gas-combined-cycle plants and likely accelerate retirement of older, less-efficient units.
- Proposed regulations seeking to control the inadvertent release of methane will affect the natural gas exploration, production, processing and transportation industry. The cost consequences are unclear at this time.
- Financing of new wind projects with low but non-zero risk of eagle mortality may become contingent developing an Eagle Conservation Plan and securing an eagle take permit.

# ABBREVIATIONS AND ACRONYMS

ACI – Activated carbon injection
BART - Best Available Retrofit Technology
BGEPA - The Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act (MBTA)
BPT - Best Practicable Control Technology Currently Available
BTA - Best Technology Available
CAA – Clean Air Act
CaBr2 – Calcium bromide treatment of coal
CCR – Coal Combustion Residuals
DESP – Dual electrostatic precipitators
DSI – Dry sorbent Injection
EMS – Entrainment mortality standards
EPA – Environmental Protection Agency
ESP – Electrostatic precipitator
FGD – Flue gas desulfurization
FIP – Federal Implementation Plan
FWS – Fish and Wildlife Service
IMS – Impingement mortality standards
LNB – Low NOx burners
MATS – Mercury and Air Toxics Standards
MBTA - Migratory Bird Treaty Act
MOFA – Modified overfire air
NAAQS – National Ambient Air Quality Standards
NPDES - National Pollutant Discharge Elimination System
NRC – Nuclear Regulatory Commission
NSPS – New Source Performance Standards
OFA – Over fire air
PAC – Powdered activated carbon
RCRA - Resource Conservation and Recovery Act
SIP – State Implementation Plan
SNCR – Selective non-catalytic reduction
SOFA – Separated overfire air
ZDL – Zero liquid discharge