Kenneth E. Traum Qualifications

My name is Kenneth E. Traum. I was the Assistant Consumer Advocate for the Office of Consumer Advocate (OCA) located at 21 S. Fruit Street, Suite 18, Concord, New Hampshire 03301. I had been affiliated with the OCA for over twenty one (21) years. I retired from the OCA in late June, 2011. I am now serving in the role of a Consultant for the OCA.

I received a B.S. in Mathematics from the University of New Hampshire in June, 1971, and an MBA from UNH in June, 1973. Upon graduation, I first worked as an accountant/auditor for a private contractor and then for the New Hampshire State Council on Aging, before going to the New Hampshire Public Utilities Commission (NHPUC) in February, 1976. At the NHPUC I started as an Accountant III, advanced to a PUC Examiner and later become Assistant Finance Director.

In my positions with the NHPUC, I was involved in all aspects of rate cases, assisted others in the preparation of testimony and presented direct testimony, conducted cross examination of witnesses, directed and participated in audits of utilities, and performed other duties as required. While employed at the NHPUC, I was a member of the NARUC Regulatory Studies Program at Michigan State.

In 1984, I left the NHPUC for Bay State Gas Company. With Bay State, I was involved in various aspects of financial analysis for Northern Utilities, Inc., Granite State Gas Transmission, Inc., and Bay State Gas Company, as well as regulatory activities with regard to Maine, New Hampshire, Massachusetts and the FERC.

In early 1986, I returned to New Hampshire to join the EnergyNorth companies, where my areas of responsibility included cash management, regulatory affairs, forecasting and other financial matters. While with EnergyNorth, I was a member of the New England Utility Rate Forum and the New England Gas Association. I also represented the utility, which is the largest natural gas utility in New Hampshire, over a two year period in the generic Commission docket (DE 86-208) which developed a methodology for conducting gas marginal cost studies.

In 1989 I joined the Office of Consumer Advocate with overall responsibility for advising the Consumer Advocate and its Advisory Board on all Financial, Accounting, Economic and Rate Design issues which arise in the course of utility ratemaking or cases concerning determinations of revenue responsibility, competition, mergers, acquisitions and supply/demand issues. I assist the Consumer Advocate and the OCA Advisory Board in formulating policy, and in implementation of that policy. In that role, I have testified before the NHPUC on many occasions. In early 2005, I was promoted to Assistant Consumer Advocate.

I was a member of the NASUCA (National Association of State Utility Consumer

Advocates), Committees on Electricity and Gas. I am currently on the Board of Directors for Granite State Independent Living (GSIL) and formerly served as Chair as well as a member on the GSIL's Finance and Audit Committees.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 2

NESCAUM

A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability

Updated March 30, 2011

Prepared by

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* The Northeast States for Coordinated Air Use Management (NESCAUM) is the regional association of air pollution control agencies representing Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Any views or opinions expressed in this paper are the author's, and do not necessarily reflect those of NESCAUM as an organization or of its member state air agencies.

A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability

Executive Summary

The purpose of this primer is to provide a basic background on pending and potential U.S. Environmental Protection Agency (USEPA) rules affecting the electric power generation sector (with coal power plants being a major focus). Several studies are briefly summarized that have assessed the environmental regulations' possible collective impact on power plant retirements and electric system reliability. Where available, USEPA analyses of the costs and benefits of proposed rules are presented. Also presented are planning options identified in several of the scenario studies that can help mitigate potential reliability issues.

The forthcoming environmental rules reflect long standing requirements contained within national environmental laws that Congress adopted and charged the USEPA with the responsibility for implementing. In a number of cases, the USEPA is now under court order to promulgate rules that have been deferred for years, or were deemed legally deficient in their original form. These rules will impose costs upon the electric generation sector, but they also have public health and environmental benefits that in some cases far exceed their projected costs.

Power plant owners will have to decide how to cost-effectively respond to the coming environmental requirements. One outcome could be that a significant number of older un- or under-controlled coal-fired plants will be retired, rather than fit with new add-on technologies. Concerns have been raised that closing these plants for economic reasons could have a significant impact on the reliability of the electric grid due to lost generation capacity. Others contend that grid reliability concerns are overstated in light of the industry's historical track record in retrofitting and replacing comparable amounts of generation under past rules, current reserve margins throughout the country, the under-utilized capacity of natural gas generators, growing energy efficiency efforts, demand-side management opportunities, rapidly expanding renewable supplies, and other planning options.

A number of studies have been performed that suggest a range of outcomes under different assumptions regarding environmental rule stringency. Taken together, the studies give a range of 25 – 76 GW in possible electric generation capacity retirements by 2020 as a result of pending environmental rules. Greater rule stringency regarding compliance time and degree of required technology coincides with higher amounts of projected capacity retirements. Cumulatively, the studies generally indicate a likelihood of locally confined reliability impacts, to the extent they may occur.

Historically, the electric power sector has been able to build new generation capacity over the span of a relatively few years well in excess of the upper end of projected generation capacity reductions. For example, between 2001 and 2003, over 160 GW of new generation capacity was built in the U.S. In addition, current peak electricity demand reserve margins in most areas of the U.S. are well above target reserve margins set by the North American Electric Reliability Corporation. This excess generation capacity can act as a further cushion in maintaining system reliability in many areas.

While the full scope and application of some of the USEPA's forthcoming rules are not yet known, the agency has indicated its intent to provide compliance flexibility for power plants. When final rules are promulgated, a range of control technology options, where needed, should be available for compliance purposes. As the rules take effect, there are a number of options available to address supply and demand needs while shoring up system reliability, such as transmission upgrades, distributed generation sources, and energy efficiency programs. Where threats to electric system reliability legitimately arise, regulatory tools exist, and have previously been used, to mitigate potential problems on a location-specific basis.

A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability

I. Background on Issues

The U.S. Environmental Protection Agency (USEPA) has proposed, or soon will propose, a series of air, water, and waste regulations for the electric power sector with the potential to promote significant changes in this industry. Power plant owners will have to decide how to cost-effectively respond to these requirements. One outcome could be that a significant number of older un- or under-controlled coal-fired plants will be retired, rather than fit with scrubbers or other emission control devices. Concerns have been raised that closing these plants for economic reasons could have a significant impact on the reliability of the electric grid due to lost generation capacity. Others contend that grid reliability concerns are overstated in light of the industry's historical track record in retrofitting and replacing comparable amounts of generation under past rules, current reserve margins throughout the country, the under-utilized capacity of natural gas generators, growing energy efficiency efforts, demand-side management opportunities, rapidly expanding renewable supplies, and other planning options.

A number of studies have been performed that indicate a range of outcomes under different assumptions regarding environmental rule stringency. Cumulatively, these generally indicate a likelihood of locally confined reliability impacts, to the extent they may occur.

Under the Clean Air Act ("CAA" or "the Act"),[1] the rules of interest include:

- the "Transport Rule" addressing the interstate flow of air pollution,
- the "Mercury and Air Toxics Standards" for hazardous air pollutants (HAPs),[2]
- the "Tailoring Rule" for large sources of greenhouse gases, and
- New Source Performance Standards (NSPS) for greenhouse gases from fossil fuel power plants.

The USEPA in 2011 is also expected to strengthen primary and secondary national ambient air quality standards (NAAQS)[3] for ozone and fine particulate matter under the Act, along with possibly proposing a secondary national ambient air quality standard for nitrogen and sulfur oxides (NOx/SOx) to address continuing acid deposition. These potential new national standards may result in the need for further reductions in the long

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[1] A number of acronyms are associated with Clean Air Act provisions. These acronyms, as well as chemical formulas, are indicated at the first appearance of the wording they are associated with, but for ease of reading, these shorthand terms are generally not repeated throughout the text.

[2] This rule has also been called the "Utility HAPs" or the "Utility MACT" rule. "MACT" is taken from language in the Clean Air Act referring to "maximum achievable control technology" (MACT) for limiting emissions of hazardous air pollutants (Clean Air Act section 112).

[3] The Clean Air Act provides for two types of national ambient air quality standards. A "primary" standard is to protect public health. A "secondary" standard is to protect public welfare, which is defined to include, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate. ("Welfare" values are defined in Clean Air Act sec. 302(h).)

range transport of air pollution, of which fossil fuel power plants are large contributors. They will also create greater scrutiny of dirtier power generation brought on-line during "high electric demand days." These days are typically the hottest summer days most conducive to air pollution episodes when electricity usage also often peaks to meet increased demand (e.g., greater use of air conditioning). Addressing the impacts associated with the highest emitting power plants ramping up to meet peak demand on the worst pollution days will create an additional sharp point of conflict between reliability concerns and clean air/climate goals if not cooperatively and proactively addressed.

In addition to pending and potential new Clean Air Act rules, other non-air environmental rules must also be considered in assessing electric system reliability concerns. Under section 316(b) of the Clean Water Act (CWA), the USEPA has proposed a rule that will target the environmental impacts of cooling water use at thermal power plants. The USEPA has also proposed a rule under the Resource Conservation and Recovery Act (RCRA) to govern the disposal of coal combustion residuals (i.e., coal ash).

II. Overview of USEPA Rulemakings

In reviewing the USEPA's regulatory agenda, it must be kept in mind that many of the rules under development or now coming into place are not by the USEPA's own initiative, but rather are due to court decisions or settlement agreements compelling the USEPA to either replace previously adopted rules deemed illegal, or establish schedules to develop new rules where the USEPA has previously failed to act. For these rules, the USEPA's discretion is legally constrained with regard to the agency's schedule for issuing proposed or final rules. The final rules themselves, however, can have varying levels of discretion in timing and breadth of application in keeping with the statutory provisions under which they are promulgated.

The rules briefly described in the following sections are tabulated in Table 1 along with the dates they were or will be proposed and finalized, and the environmental statutes under which Congress authorized the USEPA to act. Not all the pending rules immediately affect the electric power sector. For example, establishing new national ambient air quality standards starts a process for the states to develop plans that will achieve the standards within a set period of time. The state plans developed to meet the standards may require some level of pollution control from power plants, but this would be determined through the state planning process and not directly from the establishment of an air quality standard.

Table 1: Summary table of current or pending USEPA rulemakings.

Rule/Standard	Proposal Date	Final Rule Date	Statutory Authority
Transport Rule	Aug 2010	June 2011	Clean Air Act
Mercury and Air Toxics Standards	Mar 2011	Nov 2011	Clean Air Act
Tailoring Rule	Sep 2009	May 2010	Clean Air Act
Greenhouse Gas NSPS	Jul 2011	May 2012	Clean Air Act
$PM_{2.5}$ NAAQS	Spring 2011	Oct 2011	Clean Air Act
Ozone NAAQS	Jan 2010	Jul 2011	Clean Air Act
NO_2 NAAQS	Jul 2009	Jan 2010	Clean Air Act
Secondary NAAQS NOx/SOx	Jul 2011	Mar 2012	Clean Air Act
Coal Combustion Residuals Rule	Jun 2010	---	Resource Conservation and Recovery Act
316(b) Cooling Water	Mar 2011	Jul 2012	Clean Water Act

Note: Future dates are current as of January 2011, but may change due to court actions, slippage in USEPA schedules, or other factors.

A. Clean Air Act Rules

1. Transport Rule

Overview: The Transport Rule addresses emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) from fossil fuel power plants in the eastern United States that contribute to downwind formation of fine particulate matter and ground-level ozone.[4] The proposed rule comes under Clean Air Act section 110(a)(2)(D) prohibiting air pollutants from being emitted in an upwind state that "contribute significantly" to poor air quality in a downwind state.

Status: The proposed Transport Rule was published in August 2010, and the USEPA plans to finalize the rule by June 2011. The Transport Rule is the replacement for the earlier Clean Air Interstate Rule (CAIR), which was remanded back to the USEPA by the D.C. Circuit Court of Appeals in 2008. While the D.C. Circuit remanded the earlier rule back to the USEPA, it did not vacate it, hence power plants have had to comply with the Clean Air Interstate Rule's requirements in the interim as the USEPA developed the replacement Transport Rule. The proposed Transport Rule does not significantly change the overall reduction requirements from the earlier rule for the electric power sector in the aggregate, although it has constrained the ability of individual power plants to meet their reduction requirements through interstate trading of pollution allowances. While the D.C. Circuit rejected the original interstate trading approach, the proposed Transport Rule

[4] Power plants located in 30 eastern states and the District of Columbia would be subject to reduction requirements under the proposed Transport Rule for NOx and/or SO_2 emissions.

does retain intrastate trading of pollution allowances, and some reduced ability for interstate trading. As of the end of 2010, preliminary data from the covered power plants indicated their collective annual emissions were already approaching the proposed Transport Rule's national 2012 emissions targets for sulfur dioxide and nitrogen oxides (Table 2). The Transport Rule, however, allocates emissions by state, such that with limited interstate trading, meeting state-level reduction targets under the rule could have greater local reliability impacts in some areas than suggested by looking at collective emissions from all affected power plants across all states covered by the proposed rule.

Table 2: Comparison of actual power plant emissions (2005-2010) and Transport Rule annual emissions (million tons).[5]

	2005	2008	2009	2010*	2012	2014
	Actual Emissions				Transport Rule**	
Sulfur dioxide	8.9	6.7	5.0	4.4	3.9	2.4
Nitrogen oxides	2.7	2.3	1.3	1.4	1.4	1.4

* Based on preliminary 2010 data received by the USEPA as of March 30, 2011 (see footnote).

** Does not account for allowed year-to-year variability in emissions in proposed Transport Rule.

2. Mercury and Air Toxics Standards

Overview: Under section 112 of the Clean Air Act, the proposed Mercury and Air Toxics Standards would require coal- and oil-fueled power plants to reduce their emissions of certain hazardous air pollutants, including mercury, non-mercury toxic metals, acid gases, and organic air toxics. For mercury, non-mercury toxic metals, and acid gases, the proposed rule would require installing "maximum achievable control technology" (MACT) to meet numerical emission limits. For organic air toxics, such as dioxins and furans, the proposed rule would require that work practice standards be followed to minimize emissions by optimizing combustion conditions, rather than specifying numerical emission limits to be achieved through pollution controls.[6]

The proposed rule affects in particular the coal-fired power plant fleet as coal combustion is the dominant source of mercury emissions among the fossil fuels used in the electric power sector. The rule is considered "technology-based" in that its requirements typically are met through emission controls installed at affected power plants rather than achieved through emissions trading.

[5] Transport Rule annual emissions from "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone," 75 Fed. Reg. 45210 (August 2, 2010); at 45291, Table IV.E-1. Actual Emissions from 75 Fed. Reg. at 45217, Table III.A-3 (2005); U.S. EPA Clean Air Markets Division, Data and Maps, Quick Reports (2008, 2009) & Preliminary Quick Reports (2010), http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard (accessed March 30, 2011).

[6] U.S. EPA, "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," March 16, 2011. Pre-publication version available at http://www.epa.gov/airquality/powerplanttoxics/actions.html (accessed March 17, 2011). As previously noted, this rule has often been referred to as the Utility MACT rule or Utility HAPs rule.

Status: The USEPA proposed the rule on March 16, 2011, with a final rule due by November 16, 2011. This timeline was set according to a court-ordered schedule requiring the USEPA to issue a replacement rule for the Clean Air Mercury Rule (CAMR) vacated in 2008. The D.C. Circuit vacated the earlier rule in its entirety, rather than keeping it in place while the USEPA revised it (unlike the previously mentioned Clean Air Interstate Rule), so no portion of it has been implemented at the national level. A number of states, however, have adopted their own power plant mercury rules that require greater mercury reductions on a quicker timeline than would have been required under the vacated Clean Air Mercury Rule. While the vacated rule was specific to mercury, the USEPA's proposed replacement rule covers additional hazardous air pollutants, such as arsenic, chromium, nickel, acid gases, dioxins, and furans.

Of the air rules currently underway, the Mercury and Air Toxics Standards have drawn the greatest concern from the electric power sector due to the possible stringency of power plant-specific control technology requirements and, therefore, the cost of controls. Emissions trading is not a compliance option due to the source-specific control requirements under section 112 of the Clean Air Act. There is also a statutorily constrained compliance deadline of three years, with a possible extension of an additional year granted by the USEPA, and further extensions granted by the President under special circumstances. While the compliance timeline is relatively short, power plant owners have been on notice of a pending rule since late 2000 when the USEPA determined as part of a study required by the Clean Air Act that regulating mercury and other toxic air emissions from power plants was "appropriate and necessary."[7] Furthermore, a number of states have already adopted state mercury rules for power plants, with controls in place at a growing number of units.[8] Therefore, power plant owners, if not already subject to regulatory requirements, have been aware of existing or pending regulatory programs for the past decade.

3. Greenhouse Gas Tailoring Rule

Overview: This rule governs the emissions of greenhouse gases from any large source that will be built or modified after January 2, 2011. It applies to power plants (and other large stationary sources) emitting 75,000 tons or more of carbon dioxide-equivalent (CO_2e)[9] annually. The Tailoring Rule comes under the Clean Air Act's Prevention of Significant Deterioration (PSD) program, which establishes pre-construction permit requirements for new and modified sources. The Tailoring Rule also applies under Title V of the Clean Air Act, which requires major sources to obtain operating permits from a state or other issuing authority that incorporate all applicable air pollution requirements.

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[7] "Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units," 65 Fed. Reg. 79825 (December 20, 2000).

[8] National Association of Clean Air Agencies (NACAA), "State/Local Mercury/Toxics Programs for Utilities," April 6, 2010, available at http://www.4cleanair.org/Documents/StateTableupdatedApril2010.doc (accessed January 18, 2011).

[9] "Carbon dioxide-equivalent" (CO_2e) is an internationally accepted method of comparing the global warming potential (GWP) of a given mass of a greenhouse gas over a defined period of time expressed relative to a reference gas, CO_2, which is assigned a GWP = 1. For a non-CO_2 greenhouse gas, its CO_2e for a given mass is expressed as its mass multiplied by its GWP (e.g., methane's GWP = 21 over a 100 year period).

Unlike a pre-construction permit, operating permits do not impose pollution reduction requirements on sources, but rather are a compilation of all applicable requirements from other provisions of the Clean Air Act.

Status: The Tailoring Rule went into effect January 2, 2011. Affected sources need to analyze and adopt "best available control technology" (BACT) for greenhouse gases to obtain a pre-construction permit under the Clean Air Act. They must also incorporate these measures into their operating permits at the time the permits are first issued or are renewed. With the exception of Texas, all state and local permitting authorities are planning to implement the rule's requirements.[10]

Due to the relatively high emissions threshold for affected sources (≥75,000 tons CO_2e), the Tailoring Rule does not greatly expand the universe of affected sources already subject to Clean Air Act permitting requirements. Title V operating permits do not impose pollution control requirements, and are essentially a record-keeping tool for compiling all Clean Air Act requirements in one location for enforcement and public information purposes. As such, it is more a record keeping requirement than a control requirement. In the case of power plants, it will apply to sources that already are required to have operating permits, hence does not represent a major change in circumstances.

For pre-construction permits, the Tailoring Rule has greater implications after January 2, 2011. Affected sources will have to perform an analysis of best available control technologies for greenhouse gases. In late 2010, the USEPA issued guidance on what it considers an appropriate approach in analyzing greenhouse gas control technologies.[11] The approach is the same "top down" analysis that fossil fuel power plants and air agency permitting authorities are already familiar with in doing control technology determinations of other previously covered air pollutants under the Clean Air Act, such as sulfur dioxide and nitrogen oxides. Under this approach, technical feasibility and cost can be considered in determining a "best available" control option for a source. The USEPA also indicates that the best available options, at least in the early years, will likely be tied to efficiency measures that sources would consider in any event, rather than still emerging options, like carbon capture and sequestration, which the USEPA indicates could be discarded on technical feasibility or cost considerations during the review process.

In light of the USEPA guidance, it appears that the Tailoring Rule does not incorporate significant new requirements for greenhouse gases, at least in the early years, beyond what the affected sources would likely already consider with regards to efficiency improvements. For example, even prior to the USEPA guidance, a proposed new 612 MW natural gas combined cycle power plant in California voluntarily requested, and

[10] National Association of Clean Air Agencies (NACAA), "GHG Permitting Programs Ready to Go by January 2nd," October 28, 2010. Available at http://www.4cleanair.org/Documents/NACAAGHGSIPCallletterssummaryfinal.pdf (accessed January 24, 2011).
[11] "PSD and Title V Permitting Guidance for Greenhouse Gases," 75 Fed. Reg. 70254 (November 17, 2010).

was granted, enforceable greenhouse gas emission limits that incorporated energy efficiency measures, such as heat recovery, in its pre-construction permit.[12]

The Tailoring Rule is currently being challenged in the U.S. Court of Appeals for the D.C. Circuit. The USEPA argues that the Tailoring Rule is required under the statutory language of the Clean Air Act, and the agency is compelled to act as a result of the U.S. Supreme Court decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that greenhouse gases are air pollutants as defined under the Clean Air Act.[13]

4. Greenhouse Gas New Source Performance Standards

Overview: For new or modified industrial sources, the USEPA is required to set new source performance standards (NSPS) that reflect the best achievable pollution limitation based on costs, any non-air quality health and environmental impacts, and energy requirements. When new source performance standards are issued for new or modified sources within a source category, the Clean Air Act requires that the USEPA establish guidelines for state standards of performance to control emissions from existing sources in the same category. The guidelines are to provide targets based on demonstrated controls, emission reductions, costs, and expected timeframes for installation and compliance. These guidelines for existing sources can be less stringent than new source requirements. States have discretion to require less stringent requirements if they can demonstrate the USEPA guidelines are unreasonably cost-prohibitive, physically impossible, or that there are other factors that prevent reasonably meeting the guidelines.

Status: As a result of legal petitions filed by a number of states and environmental groups challenging the USEPA's failure to establish greenhouse gas new source performance standards for fossil fuel power plants, the agency announced on December 23, 2010 a proposed settlement agreement establishing a schedule for rulemaking.[14] Under the settlement agreement, the USEPA must propose greenhouse gas new source performance standards for fossil fuel power plants by July 26, 2011, and a final rule no later than May 26, 2012. With no rule proposed, it is not possible at this time to evaluate the stringency of a greenhouse gas performance standard (if any) and its implications for electric system reliability.

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[12] Bay Area Air Quality Management District, "Prevention of Significant Deterioration Permit Issued Pursuant to the Requirements of 40 CFR § 52.21," Russell Center Energy Center, Hayward, CA, PSD Permit Application No. 15487 (February 3, 2010).

[13] The USEPA had originally declined to regulate greenhouse gas emissions under the Clean Air Act, but its decision was successfully challenged in *Massachusetts v. EPA*. As a result, the USEPA reversed its earlier denial, and issued a rule setting greenhouse gas emission limits for new motor vehicles under Clean Air Act section 202(a). The motor vehicle regulation in turn triggered the Clean Air Act stationary source permitting program that requires assessments of best available control technologies for pollutants "subject to regulation" under the Act (in this case, greenhouse gases from motor vehicles). The greenhouse gas measures resulting from the control technology assessment must then be incorporated into the facility's Clean Air Act Title V operating permit.

[14] "Proposed Settlement Agreement, Clean Air Act Citizen Suit," 75 Fed. Reg. 82392 (December 30, 2010).

5. National Ambient Air Quality Standards

Overview: Under the Clean Air Act, the USEPA is required to review and revise, if needed, national ambient air quality standards (NAAQS) every five years. There are two types of national standards – a "primary" standard whose level is set with an adequate margin of safety to protect public health, and a "secondary" standard whose level is set to protect public welfare values.[15] New and existing national ambient air quality standards in and of themselves do not directly impose pollution control requirements on the electric power sector. State planning authorities develop control measures that can include power plant control requirements as part of their state implementation plans (SIPs) required under the Clean Air Act to meet or maintain compliance with a national ambient air quality standard. In addition, the USEPA can and has issued "SIP calls" requiring upwind states to revise their state implementation plans in order to reduce emissions of particular pollutants from in-state sources that the USEPA finds are significantly contributing to downwind nonattainment or interfering with maintenance of a national ambient air quality standard in another state. While the USEPA cannot directly require control requirements on specific sources in a SIP call, it can and has proposed model rules encompassing reductions from power plants that, if adopted by a state, would be deemed as complying with Clean Air Act requirements. In the absence of a state addressing its downwind contribution in a timely manner, the USEPA can issue a federal implementation plan (FIP) that would require specific measures on sources within a state. SIP calls have been EPA's approach for ozone and fine particulate matter ($PM_{2.5}$ – fine particulate matter having a diameter of 2.5 microns or less), and states subject to the calls have generally followed the USEPA's proposed model rule approach to target power plants.

Status: The USEPA is under court order to reconsider its recently revised fine particulate matter annual primary and secondary national ambient air quality standards. The USEPA plans to propose possible revised standards in spring 2011, with a final rule by October 2011. The USEPA also is reconsidering the recently revised ozone primary and secondary national ambient air quality standards in light of similar legal challenges as with the fine particulate matter standards. The USEPA plans to announce a final decision on its ozone reconsideration by July 29, 2011. The USEPA, however, may change these timelines and defer proposing or adopting new standards until later dates.

The USEPA also recently revised the nitrogen dioxide (NO_2) primary national ambient air quality standard. The revised nitrogen dioxide standard may have implications for power plants because it is a component of a fossil fuel power plant's emissions of nitrogen oxides (nitrogen oxides collectively include nitric oxide and nitrogen dioxide).

As part of a court-ordered consent decree, the USEPA is also currently considering a possible secondary national ambient air quality standard for nitrogen oxides and sulfur oxides (NOx/SOx) to protect sensitive aquatic ecosystems from continuing acidic

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[15] The CAA § 302(h) definition of "effects on welfare" includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate.

deposition.[16] The USEPA plans to propose a possible secondary standard by July 12, 2011, and issue a final rule by May 20, 2012.

B. Other Rules

1. Coal Combustion Residuals Rule

Overview: The Coal Combustion Residuals (CCR) Rule would establish for the first time requirements under the Resource Conservation and Recovery Act (RCRA) for the proper disposal of coal ash generated by coal combustion at electric power plants. The USEPA has proposed two options for coal ash disposal:[17] 1) regulating coal ash as a "special waste" under RCRA subtitle C, or 2) regulating coal ash as non-hazardous waste under RCRA subtitle D. If coal ash were regulated as a special waste, existing surface ash impoundments would be phased-out. If regulated as non-hazardous waste, existing impoundment ponds would need to install liners.

Status: The USEPA proposed its options for regulating coal ash on June 21, 2010, but has not set a date for a final rule, stating it would need to fully evaluate all of the information and comments it receives on the proposed rule before finalizing. The USEPA indicated that neither proposed option would alter the current regulatory status of coal ash that is beneficially used (e.g., in concrete and wallboard), nor was it seeking to alter the regulatory status of coal ash beneficial uses at the present time.

2. Thermal Power Plant Cooling Water Intake Structures Rule

Overview: The purpose of the thermal power plant cooling water intake structures rule under section 316(b) of the Clean Water Act (CWA) is to reduce environmental harm from existing power plant cooling systems. The types of harms identified by the USEPA are trapping ("impingement") of large fish and other aquatic life against screens at cooling water intakes and "entrainment" of smaller aquatic life (e.g., eggs and larvae) in water sucked into the intakes, leading to death. In addition, for "once-through" cooling systems where water passes through a power plant heat exchanger only once before discharging back to a water body, thermal heating of natural water bodies may also cause environmental harm.

Prior to proposing the cooling water structures intake rule, the USEPA indicated that it did not favor a "one size fits all approach" that would require the same type of cooling system (e.g., "closed-cycle") on every power plant.[18] When it proposed its rule, the USEPA indicated a preferred option ("Option 1") that reflects this. In its preferred option, the USEPA would apply the rule in three ways depending on the facility (in addition to power plants, the proposed rule would also cover some types of manufacturers, such as aluminum, iron, steel, petroleum, paper, chemicals, and food

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[16] U.S. EPA, "Nitrogen Dioxide (NO_2) and Sulfur Dioxide (SO_2) Secondary Standards," U.S. EPA Technology Transfer Network National Ambient Air Quality Standards (NAAQS), available at http://www.epa.gov/ttnnaaqs/standards/no2so2sec/index.html (accessed January 24, 2011).

[17] "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule," 75 Fed. Reg. 35128 (June 21, 2010).

[18] U.S. EPA, Letter to Rep. Fred Upton, U.S. House of Representatives, from USEPA Administrator Lisa Jackson (December 16, 2010).

processing). The first part would set uniform impingement controls (e.g., fish screens) at existing power plants and manufacturing facilities getting at least 25% of their cooling water from a nearby water body, and having a design intake flow greater than 2 million gallons per day. The second part would require existing facilities that withdraw at least 125 million gallons per day to conduct studies to assist their permitting authority in determining what, if any, site-specific entrainment controls should be required. The third part would require new electric generating units installed at existing facilities to add "closed-cycle" cooling systems or equivalent technology. Affected facilities would have up to eight years to comply after the effective rule date.[19]

The USEPA estimates that the proposed rule would apply to about 1,260 facilities, of which about 670 are power plants. Of the roughly 1,260 covered facilities, the USEPA estimates about 740 of these are already compliant with the technology requirements of its preferred option in the rule proposal.[20]

Status: The USEPA proposed the cooling water intake structures rule on March 28, 2011, with the final rule due by July 2012. Leading up to its latest rule proposal, the USEPA had been under court order since 1995 to develop a cooling water rule, and under another court order since 2007 to reconsider parts of the original rule it promulgated in 2004.

C. Ranking of Potential Rule Impacts and Regulatory Timelines

An analysis by the North American Reliability Corporation (NERC) looked at four potential USEPA rules and, under the assumptions of the study, predicted that the rules having the greatest projected impacts on power plant retirements and electric system reliability are, in order of projected greatest to least impact, 1) CWA section 316(b) cooling water rule, 2) Mercury and Air Toxics Standards, 3) Transport Rule, and 4) Coal Combustion Residuals rule.[21] Figure 1 displays the current timing for these and other pending rules.

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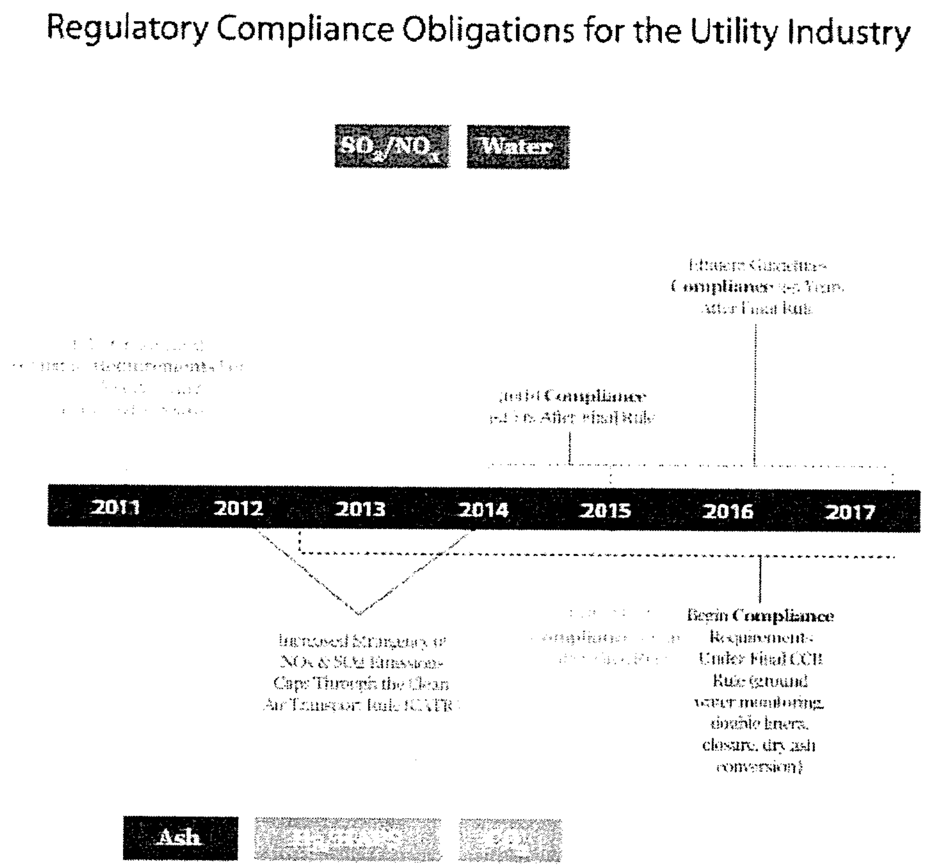
[19] U.S. EPA, *National Pollutant Discharge Elimination System — Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, March 28, 2011. Pre-publication version available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm (accessed March 29, 2011).

[20] U.S. EPA, *Clean Water Act Section 316(b) Existing Facilities Proposed Rule Qs and As*, March 28, 2011. Available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm (accessed March 29, 2011).

[21] North American Electric Reliability Corporation (NERC), "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations," NERC, Princeton, NJ (October 2010) (*hereinafter* "NERC Report"). Available at http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf (accessed January 24, 2011).

Figure 1: Timeline of regulatory compliance and control requirements affecting fossil fuel power plants.[22]



[22] Larsen, J., "Response to EEI's Timeline of Environmental Regulations for the Utility Industry," World Resources Institute (December 3, 2010). Available at http://www.wri.org/stories/2010/12/response-eeis-timeline-environmental-regulations-utility-industry (accessed January 24, 2011).

For clarity, the timeline of Figure 1 does not include actions or milestones that 1) do not establish requirements on power plants, e.g., court remands or vacaturs of rules deemed illegal, 2) are rules already in place, thus not new requirements, 3) are procedural steps only, such as public notice and comment requirements, or 4) establish a national ambient air quality standard, which affect state air quality planning but are not direct control requirements on pollution sources. The Edison Electric Institute has developed a timeline incorporating these additional items, which can be found at: Edison Electric Institute (EEI), "Environmental Regulatory Timeline for Coal Units," EEI (2010). Available at http://www.eei.org/meetings/Meeting%20Documents/EPA-CAAUtilityRegTimelineTrainWreckChart.ppt (accessed January 24, 2011).

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III. Summaries of USEPA Analyses on Rule Benefits and Costs

For the USEPA's currently proposed rules and standards, the agency has estimated the rules' benefits and costs as part of required regulatory impact analyses, and these are summarized in this section. Not included are possible greenhouse gas new source performance standards for power plants, which have not yet been proposed at the time of this writing.

A. Transport Rule (proposed)

The USEPA has estimated the benefits and costs of its proposed Transport Rule, and presented its estimates in the Regulatory Impact Analysis that is part of the rulemaking docket.[23] The USEPA estimates that the combined health and welfare benefits of the proposed rule are much larger than the rule's estimated costs (Table 3).

Table 3: Estimated benefits and costs of the USEPA proposed Transport Rule.

Category	Monetized benefits or costs (2006$)
Estimated public health benefits	$120 - $290 billion in 2014
Estimated public welfare benefits	$3.6 billion in 2014
Estimated costs – limited trading option (USEPA preferred option)	$3.7 billion in 2012; $2.8 billion in 2014
Estimated costs – no trading option (direct control)	$4.3 billion in 2012; $3.4 billion in 2014

Public health benefits include avoiding approximately 14,000 – 36,000 premature deaths, 22,000 nonfatal heart attacks, 11,000 hospitalizations for respiratory and cardiovascular diseases, 1.8 million lost work days, 100,000 school absences, and 10 million days when adults restrict normal activities because of respiratory symptoms exacerbated by fine particulate matter and ozone pollution.

The USEPA limited its public welfare benefits analysis to visibility improvements in U.S. national parks. The USEPA identifies additional welfare benefits, but does not monetize these (e.g., reduced nitrogen and acidic deposition, reduced mercury deposition, increased agricultural crop and commercial forest yields).

Costs are largely incurred by the power plant sector, with the USEPA assuming intrastate trading occurring along with some limited interstate trading in its preferred option. The USEPA projected retail electricity prices to increase nationally by an average of 2.5% in 2012 and 1.5% in 2014. The USEPA also estimated costs for a "direct control" option that does not allow trading among affected facilities, which is also shown in Table 3.

B. Mercury and Air Toxics Standards (proposed)

In the regulatory impact analysis for the proposed Mercury and Air Toxics Standards, the USEPA estimated benefits and costs associated with reductions in mercury and

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[23] U.S. EPA, *Regulatory Impact Analysis for the Proposed Federal Transport Rule*, Docket ID No. EPA-HQ-OAR-2009-0491, U.S. EPA Office of Air and Radiation, June 2010. Available at http://www.epa.gov/ttn/ecas/ria.html (accessed January 24, 2011).

particulate matter (used as the surrogate for non-mercury toxic metals).[24] Co-benefits from avoided premature mortality due to reductions in particulate matter accounted for over 90% of the monetized benefits. The USEPA did not quantify benefits for a number of health and welfare end points, such as those associated with reductions in non-mercury hazardous air pollutants. As a result, the monetized benefits are a lower bound of the potential benefits resulting from reductions of the full suite of air toxics under the proposed rule. The USEPA also made an effort to separate the particulate matter reductions due to the implementation of the Transport Rule from the additional particulate matter reductions expected from the air toxics rule to avoid double counting of benefits. Table 4 presents the summarized benefits and costs of the proposed Mercury and Air Toxics Standards estimated in the USEPA's regulatory impact analysis.

Table 4. Estimated benefits and costs of USEPA proposed Mercury and Air Toxics Standards.

Category	Monetized benefits or costs in 2016 (2007$)	
	3% Discount Rate	*7% Discount Rate*
Social benefits*	$59-$140 billion	$53-$130 billion
Social costs	$10.9 billion	$10.9 billion
Net benefits (benefits – costs)	$48-$130 billion	$42-$120 billion

* The USEPA indicates unquantified benefits also exist for non-mercury hazardous air pollutants not included in the regulatory impact analysis.

C. Greenhouse Gas Tailoring Rule

The USEPA's regulatory impact analysis attributed over $77 billion (2007$) in annual benefits from the initial phase of the Tailoring Rule as a result of regulatory relief in removing the need for small greenhouse gas sources to obtain permits, and reducing the number of permit applications to be processed by permitting authorities. The USEPA did not attribute any direct costs from the Tailoring Rule to the large greenhouse gas emission sources that would be subject to it on the basis that the permit requirements were already mandated by the Clean Air Act and existing rules, and were not the result of the USEPA's rulemaking.[25]

D. National Ambient Air Quality Standards

The USEPA is currently under court order to review its previous revision of the 2006 fine particulate national ambient air quality standards and has undertaken a separate reconsideration of its 2008 revision of the ozone national ambient air quality standards in light of filed legal challenges. While the Clean Air Act does not allow the USEPA to consider costs in setting the level of a revised ambient air quality standard, the agency is required under Executive Order 12866 to develop a regulatory impact analysis (RIA) summarizing estimated benefits and costs from changing a standard. While the USEPA provides estimates of costs in achieving a national ambient air quality standard, the extent

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[24] U.S. EPA, *Regulatory Impact Analysis for proposed Toxics Rule (the Utility MACT and NSPS proposals)*, U.S. EPA, March 16, 2011. Available at http://www.epa.gov/ttn/ecas/ria.html (accessed March 16, 2011).

[25] U.S. EPA, *Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, EPA 452/R-10-003, U.S. EPA Office of Air Quality Planning and Standards, May 2010. Available at http://www.epa.gov/ttn/ecas/ria.html (accessed January 24, 2011).

of pollution reductions required and sources affected are ultimately determined by individual state and local air quality planning authorities, and not directly by the USEPA. Therefore, cost estimates represent hypothetical strategies to achieve a standard, but the specific strategies eventually implemented will vary according to state or local planning decisions. Table 5 shows benefit and cost estimates from the USEPA's 2010 supplementary RIA[26] for the ozone air quality standard reconsideration and the agency's RIA for the 2006 fine particulate air quality standard revision.[27]

Table 5: USEPA benefit and cost estimates of revised ozone and $PM_{2.5}$ air quality standards.

NAAQS levels	Estimated Benefits (annual in 2020)	Estimated Costs (annual in 2020)
If ozone NAAQS = 0.070 ppm	\$13-\$17 billion	\$19-25 billion
If ozone NAAQS = 0.060 ppm	\$35-\$100 billion	\$52-\$90 billion
2006 $PM_{2.5}$* NAAQS	\$9-\$76 billion	\$5.4 billion

*2006 $PM_{2.5}$ national ambient air quality standards = 15 $\mu g/m^3$ annual; 35 $\mu g/m^3$ 24-hour

E. Thermal Power Plant Cooling Water Intake Structures Rule (proposed)

In its March 28 proposal, the USEPA estimated benefits and costs for four potential cooling water rule options. The USEPA's preferred Option 1 was previously described above. Options 2 and 3 would require closed-cycle or equivalent technologies on more facilities than Option 1, with Option 3 extending the requirements to lower intake flow facilities than Option 2. Option 4 would set a higher intake flow rate threshold than Option 1 in establishing uniform impingement requirements at existing facilities, with smaller intake flow facilities subject to site-specific determinations.

The USEPA's analysis of benefits considered reductions in deaths of fish and other aquatic life under each option that in turn will increase "use benefits," such as recreational and commercial fishing, as well as "nonuse" benefits, such as improved ecosystem function and greater protection of endangered species. The USEPA believes its estimated monetized benefits do not completely account for the full benefits of the proposed options, thus are likely a low (conservative) estimate of benefits. Table 6 shows the USEPA's cost and benefit estimates for the four options in the proposed cooling water rule.

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[26] U.S. EPA, *Summary of the updated Regulatory Impact Analysis (RIA) for the Reconsideration of the 2008 Ozone National Ambient Air Quality Standard (NAAQS)*, U.S. EPA, January 2010. Available at http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf (accessed January 24, 2011).

[27] U.S. EPA, *Regulatory Impact Analysis for the Review of the Particulate Matter National Ambient Air Quality Standards*, Docket ID No. EPA–HQ–OAR–2006–0834, U.S. EPA Office of Air and Radiation October 6, 2006. Available at http://www.epa.gov/ttn/ecas/ria.html (accessed January 24, 2011).

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Preparing for EPA Regulations:

Working to Ensure Reliable and Affordable Environmental Compliance

July 2011

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Preparing for EPA Regulations:
Working to Ensure Reliable and Affordable Environmental Compliance

Author
David Farnsworth

July 2011

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Introduction

This is an historical moment for public utility commissions. In the next several years, the United States Environmental Protection Agency (EPA) will be issuing far-reaching health and environmental regulations that will have significant effects on the utility sector. The ability of utility regulators to respond to this challenge is going to be tested. Traditionally, regulatory goals have included ensuring electric system reliability, promoting resource adequacy, and capturing lower energy bills for ratepayers. Now utility regulatory commissions and energy planning bodies will need to work with environmental regulators and utilities to find ways to meet these traditional goals and to achieve affordable environmental compliance at the same time.

Due to the extensive reach of environmental regulations, energy regulators will need to work more closely with environmental regulators as resource planning decisions are explored. Never before has building understanding between utility commissions and their sister regulatory agencies been so important. To be effective, communication among regulators can no longer be episodic; productive cooperation necessary to ensure reliable, affordable environmental compliance will require ongoing effort. By engaging with utilities and with other regulators, utility commissions will be better able to evaluate a wider array of potential compliance options, and to strike their preferred balance of cost and other policy goals, including the most affordable compliance scenarios associated with various EPA public health and environmental regulations.

Never before has building understanding between utility commissions and their sister regulatory agencies been so important.

Today there is an active debate over the potential effects on the nation's generation mix and electric system reliability as a result of the EPA's new and forthcoming health and environmental regulations. Recent studies reviewing potential capacity retirements from forthcoming EPA regulations affecting the industry suggest a range of possible retirements from 25-76 GW by 2020.[1] Many consider the EPA's actions as further compounding already-existing uncertainty associated with grid reliability and the nation's future energy choices. Others, including the National Association of Regulatory Utility Commissioners (NARUC), are taking the EPA's actions in stride, identifying key issues, engaging the EPA, and exploring possible next steps at regional and state levels.[2]

At its February 2011 Winter Meetings, NARUC issued a resolution[3] urging the EPA, among other things, "to ensure that, as it develops public health and environmental programs," the EPA will:

- Avoid compromising energy system reliability;
- Seek ways to minimize cost impacts to consumers;" and
- Consider cumulative economic and reliability impacts in the process of developing multiple environmental

1 "A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability," February 10, 2011, Paul J. Miller, Ph.D., J.D., Deputy Director, Northeast States for Coordinated Air Use Management (Miller).

2 See, e.g., NARUC Webinars: "Rulemakings Concerning Air Quality, Cooling, and Solid Waste: Implications for Utility Regulators," September 2010 http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=1; "The States Forge Ahead: Case Studies in State Clean Energy Programs." December 2010; http://www.naruc.org/Publications/livemeeting3.wmv; "Presentations from the NARUC 122nd Annual Conference," "The Climate Syndrome: Without Congressional Action, What Do State Regulators Need to Know?" http://www.naruc.org/meetingpresentations.cfm?7; "Coal Fleet Resource Planning: How States can Analyze their Generation Fleet;" NARUC has also jointly convened several meetings on these issues with the National Association of Clean Air Regulators, NACAA and the National Association of State Energy Officials, NASEO.,"

3 "Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations," February 16, 2011, http://www.naruc.org/Resolutions/Resolution%20on%20the%20Role%20of%20State%20Regulatory%20Policies%20in%20Development%20of%20Fed%20Enviro%20Regs.pdf.

rulemakings that impact the electricity sector.... [4]

NARUC further asks that the EPA "encourage the development of innovative, multi-pollutant solutions," "employ rigorous cost-benefit analyses consistent with federal law," and "provide an appropriate degree of flexibility and timeframes for compliance."[5]

Also at NARUC's winter meetings, Gina McCarthy, EPA Assistant Administrator for Air and Radiation, addressed NARUC members, thanking them for their resolution, and in turn asking NARUC members to resolve to:

- Take early action— thereby lowering costs, and ensuring better health benefits for ratepayers;
- Ask utilities to begin planning now;
- Recognize that the EPA's regulations should be an integral component of the energy sector's investment strategies;
- Review all the options, not just new generation, in considering requests for cost-recovery; and
- Coordinate generation and transmission solutions with the demand side of the equation, including energy efficiency and demand response.

These complementary resolutions underscore the need for decision makers to attain key goals: achieving the health and environmental outcomes of the EPA's regulations, respecting consumers' need for electricity at reasonable costs, and maintaining reliability — not only "resource adequacy," but also "operational reliability" or "stability," that is, the ability of the system to withstand both unanticipated disturbances and those that are anticipated, like scheduled plant outages to refuel or install environmental controls.

While utility regulators will not need to become environmental regulators, for utility regulators to meet this challenge, a general understanding of the EPA's rules will be required. Meeting this challenge will also call for up-to-date utility data, and a greater appreciation of the relationship between resource adequacy and system reliability. It will also call for a methodical review of energy system "alternatives" specific to individual states and regions. This should include not only generation alternatives across the system, but also demand and delivery alternatives as well. With that understanding, utility regulators will be better equipped to work effectively with their utilities and state environmental regulators in meeting the goals of a cleaner, reliable, and affordable electric system.

This paper provides utility regulators with an outline of initial steps for developing an in depth understanding of EPA rules and regulations. It includes a review of the EPA's proposed rules—as of May 2011 — with an eye to compliance flexibility. The paper also looks generally at utility planning, suggesting approaches that companies around the country might adopt as they take stock of their existing resources and preparedness to comply in the most effective and affordable manner with the mandates of the EPA's health and environmental regulations.

This paper initially reviews current EPA air, water, and solid waste regulatory proposals. It then shifts to the subject of utility planning, and includes a look at possible data needs, scenario development, and modeling. In light of some of the initial press coverage of EPA's proposed regulations in the fall of 2010 and associated controversy, this paper also seeks to provide a broader understanding of some relevant issues related to modeling, and some of the major findings associated with more recent modeling studies of these rules.[6] Finally, this paper sets out process recommendations for commissions to consider as they engage with companies and other regulatory agencies on these issues.

4 Id.

5 Id.

6 See, e.g., "The Unseen Carbon Agenda — The EPA wants to take away 7% of U.S. power generation," *Wall Street Journal,* October 28, 2010.

Yesterday the North American Electric Reliability Corporation, a highly regarded federal energy advisory body, released an exhaustive "special assessment" of this covert program. NERC estimates that the Environmental Protection Agency's pending electric utility regulations will subtract between 46 and 76 gigawatts of generating capacity from the U.S. grid by 2015. To put those numbers in perspective, the worst-case scenario would amount to a reduction of about 7.2% of national power generation, and almost all of it will hit coal-fired plants, the workhorse that supplies a little over half of U.S. electricity.

Id. http://online.wsj.com/article/SB10001424052702303467004575574401127641896.html; see also "EPA Rulemaking to Be Transparent," Lisa P. Jackson, EPA Administrator, November 2, 2010.

Part One

New and Forthcoming EPA Health and Environmental Regulations

Introduction

In response to legal obligations imposed by Congress and the federal courts, the EPA is in the process of promulgating a suite of public health and environmental rules that will have impact on the electric sector. The power sector is responsible for a significant share of U.S. air pollutant emissions.

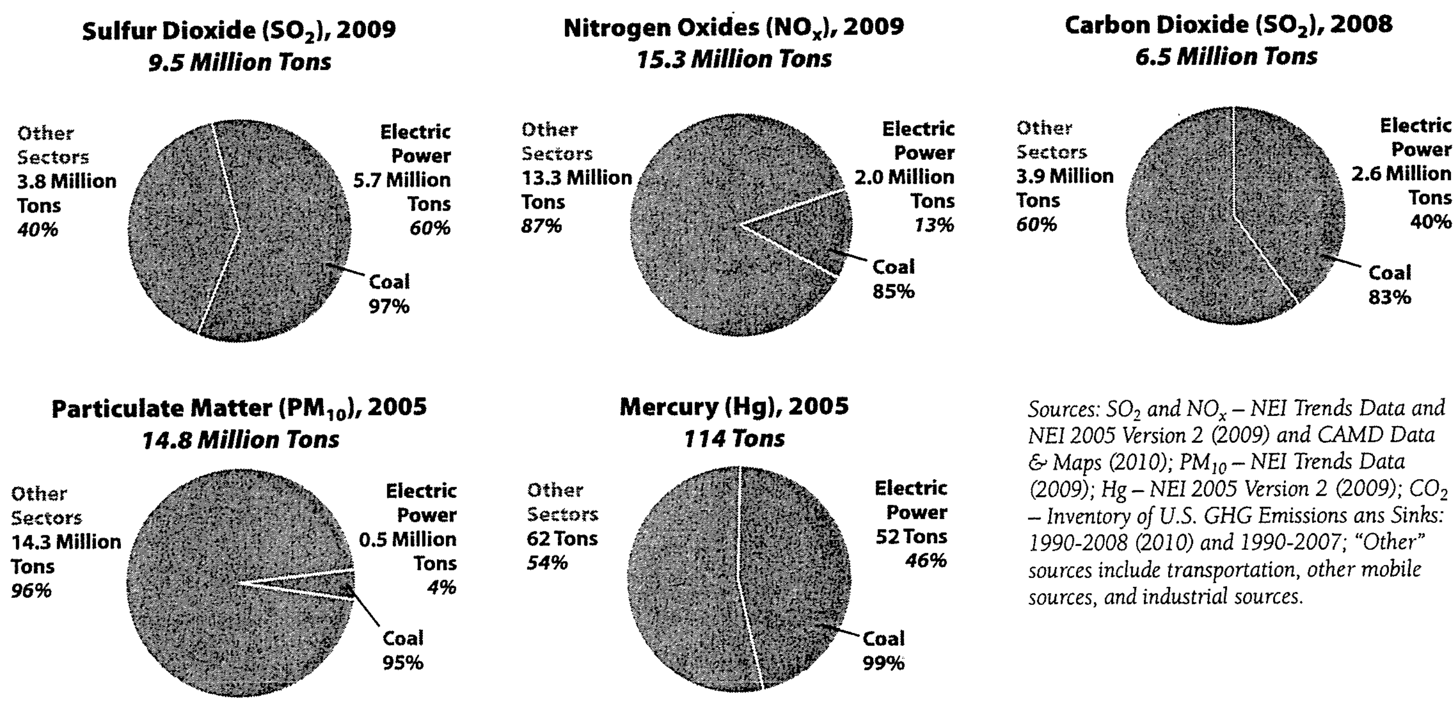
According to the EPA's Office of Air and Radiation, "power plants are among the largest U.S. emitters of air pollutants with serious health effects including premature death."[8]

While these claims may present as abstractions,

Figure 1 [7]

Power Sector: A Major Share of U.S. Air Emissions

Coal-fired power plants are the source of the vast majority of power sector air emissions



Sources: SO_2 and NO_x – NEI Trends Data and NEI 2005 Version 2 (2009) and CAMD Data & Maps (2010); PM_{10} – NEI Trends Data (2009); Hg – NEI 2005 Version 2 (2009); CO_2 – Inventory of U.S. GHG Emissions ans Sinks: 1990-2008 (2010) and 1990-2007; "Other" sources include transportation, other mobile sources, and industrial sources.

7 *Reducing Pollution from Power Plants,* Joe Bryson, U.S. EPA Office of Air and Radiation, November 16, 2010, National Association of State Utility Consumer Advocates Annual Meeting, Atlanta, Georgia.

8 Id. at 31.

9 Id.

Figure 2 [10]

Health Benefits for Millions of Americans

Benefits Greatly Exceed Costs

- EPA estimates the annual benefits from the proposed transport rule range between $120-$290 billion (2006 $) in 2014 with annual compliance costs at $2.8 billion in 2014.
- EPA estimates 2014 prices for electricity, natural gas, and coal prices increase 1 to 2%.

Estimated number of adverse health effects avoided due to implementing the proposed transport rule*

Health Effect	Number of Cases Avoided
Premature mortality	14,000 to 36,000
Non-fatal heart attacks	23,000
Hospital and emergency visits	26,000
Acute bronchitis	21,000
Upper and lower respiratory problems	440,000
Aggravated asthma	240,000
Days when people miss work or school	1,900,000
Days when people must restrict activities	11,000,000

**Impacts avoided due to improvements in PM 2.5 and ozone quality in 2014*

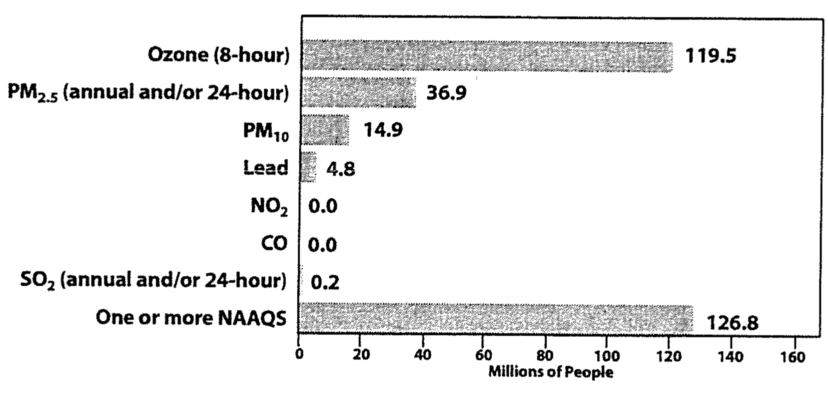
avoidable deaths and illnesses will continue to occur, according to the EPA, because important Clean Air Act-required power plant controls have been delayed more than a decade, leaving significant numbers of people living with unhealthy air.[11] See Figs. 3 & 4.

What follows is a discussion of newly- proposed and forthcoming EPA rules, their various attributes, goals, and implementation and compliance schedules. These descriptions are intended as illustrations. Readers should consult the latest administrative enactments, statements of agency policy, and judicial decisions for a more complete picture of the status of the rules. State environmental regulators can also serve as an invaluable resource in staying abreast of the status of these various initiatives.

Figure 3 [12]

Air Quality in the United States

Population living with unhealthy air quality



Clean Air Transport Rule

Schedule: Proposed August 2010; to be finalized June 2011

In August 2010, the EPA proposed the "Clean Air Transport Rule" (CATR).[13] CATR is a replacement for the "Clean Air Interstate Rule" that was overturned by the U.S. Court of Appeals in 2008 because it did not adequately protect downwind states.[14] CATR seeks to reduce the long-range transport of power plant emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) that significantly contribute to the inability of downwind states to meet "National Ambient Air Quality Standards" or "NAAQS" for fine particulates (PM) and ozone. As a result of inadequate past measures,

10 Id.

11 From Reducing Pollution from Power Plants, Joseph Goffman Senior Counsel U.S. EPA Office of Air and Radiation, October 29, 2010 (Goffman, October 2010).

12 Id.

13 75 Fed. Reg. 45210 (August 2, 2010).

14 See http://www.epa.gov/cair/. CATR will likely be further modified by outcomes associated with two other EPA rules: one, a court-ordered new standard for ozone, and the other, a new standard for fine particulate matter. The Ozone National Ambient Air Quality Standard was proposed in August 2010, Proposed Rule 75 Fed. Reg. 51,960 (August 24, 2010), http://www.epa.gov/NSR/documents/20100818fs.pdf. Pursuant to section 319 of the Clean Air Act, the EPA is seeking comments on a proposal to revise its Air Quality Index (AQI) used by states to report daily concentrations for fine particle pollution (January 15, 2009). http://www.epa.gov/pm/pdfs/20090115fr.pdf.

there is also a significant coincidence of non-attainment areas with highly populated areas. (See Figure 4) The EPA has determined that "ozone and fine particle pollution cause thousands of premature deaths and illnesses each year, and that these pollutants also reduce visibility and damage sensitive ecosystems."[15]

Focusing on states whose emissions affect their neighboring states, CATR applies to power plants in 31 states and the District of Columbia. It is scheduled to be finalized in June 2011, and compliance obligations will start within the year following.[17] The EPA sought comments on three options for structuring the emissions limits within CATR:

1. State emissions caps, with intrastate trading and limited interstate trading among power plants allowed;[18]
2. State emissions caps, with intrastate trading among power plants in a state allowed; or
3. State emissions caps with unit-specific emissions limits.

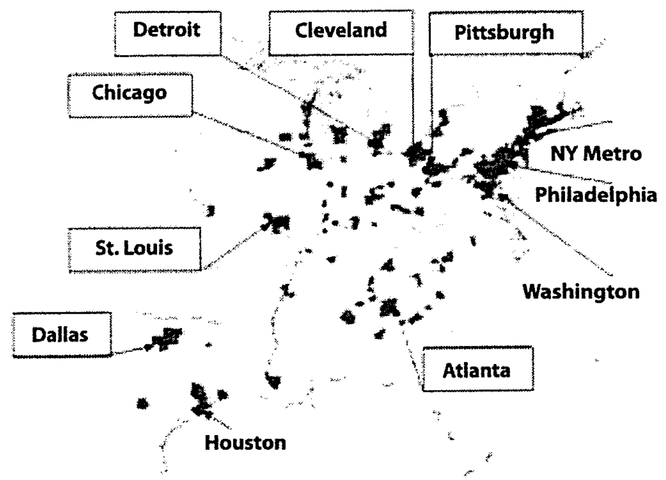
CATR compliance is envisioned in phases. For annual SO_2 and NOx, Phase I compliance is expected in January 2012, and Phase II in January 2014. For seasonal NOx (i.e., NOx emitted during the summer ozone season), Phase I compliance is expected in May 2012, and Phase II in May 2014.

CATR will require investment in controls for NOx– (typically Selective Catalytic Reduction [SCR] or Selective Non-Catalytic Reduction [SNCR]) and for SO_2 (typically flue-gas desulfurization [FGD] or "scrubbers") and dry sorbent injection (DSI).[19] A little less than half of the country's existing and "planned committed" coal steam

Figure 4[16]

Worst Air Pollution Near Population Centers

Counties violating air quality standards in the proposed transport rule region (based on 2003-07 air quality monitoring data)



Counties with violating monitors *(207)*. These counties are violating one or more of the following NAAQs: 1997 PM 2.5, 1997 Ozone, 2006 PM 2.5, and have at least one ozone and/or PM 2.5 monitor which violated the NAAQs in the periods 2003-2005, and/or 2005-2007.

15 US EPA. Air Transport Rule Information Page. June 27, 2011. http://www.epa.gov/airtransport.

16 Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, M.J. Bradley & Associates and the Analysis Group, August 2010 (Maintaining Reliability), at 20, Figure 7.

17 Reducing Air Pollution from Power Plants, Joe Goffman, U.S. EPA Office Air and Radiation, September 24, 2010 (Goffman, September 2010); "Emissions reductions will begin to take effect very quickly, in 2012 — within one year after the rule is finalized." Clean Air Transport Rule Fact Sheet, http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

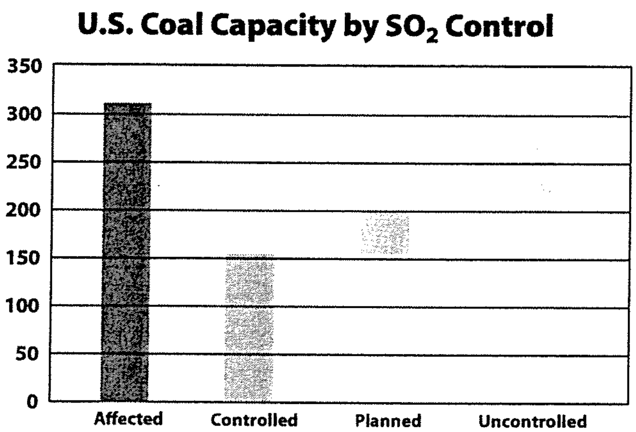
18 The EPA's preferred approach. Under this approach, SO_2 and NOx would be regulated via three cap-and-trade programs: SO_2, annual NOx, and seasonal NOx.

19 "Clean Air Act Regulation, Technologies, and Costs," Power Sector Environmental Regulations Workshop (Power Sector Workshop), David C. Foerter, Executive Director, Institute of Clean Air Companies (ICAC), October 22, 2010. According to the Clean Air Task Force, "The Toll From Coal—An Updated Assessment of Death and Disease from America's Dirtiest Energy Source" Clean Air Task Force, September 2010":
In the last five years, emissions control equipment installed at power plants around the country (flue gas desulfurization or FGD for SO_2 and selective catalytic reduction or SCR for NOx reduction) have helped coal plants achieve reductions in their emission rates of SO_2 and NOx by an average of 72 percent and 74 percent respectively.
http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf at note 3 citing to EPA Continuous Emissions Monitoring System (CEMS) data available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

capacity has installed SCR or SNCR post-combustion NOx controls.[20]

With regard to FGD, according to ICF's May 2010 report for the Interstate Natural Gas Association of America (INGAA) entitled "Coal-fired Electric Generation Unit Retirement Analysis" (INGAA Analysis), of the approximately 310 GW of coal capacity nationwide – 150 GW already have scrubbers installed, and that an additional 50 GW have scrubbers permitted or under construction (See Figure 5).[21] ICF concluded that "about one third of the U.S. coal-fired generating capacity, or about 110 GW, will have to decide whether to install the necessary control equipment or potentially shut down."[22]

Figure 5[23]



Mercury/Air Toxics Rule

Schedule: Proposed March 16, 2011; to be finalized November 16, 2011

On March 16, 2011, the EPA proposed the first national standard to reduce mercury and other toxic air pollution from coal and oil-fired power plants as required under the Clean Air Act. The EPA termed its rule "National Emissions Standards for Hazardous Pollutants," but it is commonly referred to as the "Mercury/Air Toxics Rule."[24]

Power plants are responsible for half of the nation's mercury emissions and half of the acid gases, and the utility industry has been on notice for many years that these standards would be forthcoming.[25] The EPA estimates that there are approximately 1,350 coal- and oil-fired units at 525 power plants that would be subject to this rule. Pollutant emissions that the rule covers include mercury, arsenic, other toxic metals, acid gases, and organic air toxics such as dioxin. Human health effects of exposure to these pollutants include neurologic developmental effects (mercury), inflammation and neurotoxicity (cadmium, manganese, and lead), acute inflammation and irritation (acid gases like hydrogen chloride and hydrogen fluoride), and potential cancer risks (dioxins).[26]

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20 According to the EPA, 48.93% of existing and "planned committed" "coal steam" capacity in the country has installed SCR or SNCR post-combustion NOx controls. U.S. EPA National Electric Energy Data System version 4.1 http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#needs. The EPA defines capacity as "net summer dependable capacity (in megawatts) of the unit available for generation for sale to the grid. Net summer dependable capacity is the maximum capacity that the unit can sustain over the summer peak demand period reduced by the capacity required for station services or auxiliary equipment." Id.

21 "Coal-fired Electric Generation Unit Retirement Analysis," INGAA, May 11, 2010. INGAA is the North American association representing interstate and interprovincial natural gas pipeline companies.

22 Id. at 1-2.

23 Id.

24 The Mercury/Air Toxics Rule is also known as the MACT rule. See National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposal.pdf.

25 The 1990 Clean Air Act amendments require EPA to develop an emissions control program for certain listed air toxics. Sec 112--Hazardous Air Pollutants (HAP) http://www.epa.gov/ttn/atw/utility/utilitypg.html In 2000 EPA conducted a study required by the Clean Air Act in which EPA determined that regulating mercury and other toxic emissions from power plants was "appropriate and necessary." "Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units," 65 Fed. Reg. 79825 (December 20, 2000). Subject to a 2009 consent decree, EPA was obligated to propose a toxics rule and emissions standards by March 16, 2011, and to finalize the rule by November 16, 2011. EPA's 2003 decision to "delist" mercury and regulate it, instead, as "nonhazardous" under section 111 of the Clean Air Act was overturned by the D.C. Circuit in New Jersey v. EPA, 531 F.3d 896 (D.C. Cir. 2008) DC Circuit No. 05-1097. EPA appealed the ruling until, in February 2009, Administrator Jackson withdrew the appeal and indicated that EPA would proceed with HAP regulation for electric generators under Section 112. The Mercury/Air Toxics Rule replaces the vacated Clean Air Mercury Rule that was vacated by the DC Circuit in 2008. In October 2009, EPA entered into a consent decree that required EPA to propose a MACT standard for both coal and oil plants. In December 2009, EPA indicated that it will undertake an "Information Collection Request," due to statutory requirements for establishing emission standards under CAA Section 112(d) and the recent court decisions, EPA wants to acquire additional data from both coal-fired and oil-fired electric utility steam generating units." https://utilitymacticr.rti.org/FAQ/FAQEPAPolicy.aspx#EPA-001

The Standard

Section 112 of the Clean Air Act contains standards for both existing and new sources.[27] The Section 112 standard for existing sources states that Maximum Achievable Control Technology or "MACT" "shall not be less stringent, and may be more stringent than the average emission limitation achieved by the best performing 12 percent of the existing sources…in the category or subcategory…" This calculation is referred to as the "MACT floor," and does not take cost into account but does reflect what existing and deployed technology can do. The EPA can require what are referred to as "beyond-the-floor" reductions if cost-effective technologies are available. Section 112 states that "new" sources "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator."

The proposed Mercury/Air Toxics rule sets standards based on the best-performing 12 percent of coal- and oil-fired electric generators with a capacity of ≥25 MW for all hazardous air pollutants or "HAPs" emitted. (See Table A) The EPA has also proposed two subcategories: (1) lignite-burning, mine-mouth coal-fired boilers, and (2) solid and liquid oil units.[28]

The schedule for compliance under the Mercury/Air Toxics Rule varies for existing and new sources. Existing sources are required to meet standards within 3 years from the date of the final rule, with the opportunity for a one-year extension. Compliance for new and reconstructed sources will be required going forward on issuance of final rule.

Table A

Proposed Mercury/Air Toxics Rule Emissions Limitations[29]

Subcategory	Particulate Matter	Hydrogen Chloride	Mercury
Existing coal	0.03 lb/MMBtu	0.002 lb/MMBtu	1.2 lb/TBtu[30]
Existing coal (Lignite)	0.03 lb/MMBtu	0.002 lb/MMBtu	11lb/TBtu[31]
Existing IGCC	0.05 lb/MMBtu	0.0005 lb/MMBtu	3 lb/TBtu
Existing solid-oil derived	0.2 lb/MMBtu	0.005 lb/MMBtu	0.2 lb/TBtu
New coal	0.05 lb/MMBtu	0.3 lb/MMBtu	0.00001 lb/GWh
New coal (lignite)	0.05 lb/MMBtu	0.3 lb/MMBtu	0.04lb/GWh

Flexibility

A 2010 study by the North American Electric Reliability Corporation (NERC) stated that the "only flexibility for compliance [under this rule] is for EPA to grant a one-year extension, granted on a case-by-case basis, and a Presidential exemption of no more than two years based on

26 "Understanding the Health Effects of Power Plant Emissions," Dan Greenbaum, President, Health Effects Institute, Bipartisan Policy Center Conference on "Environmental Regulation and Electric System Reliability," October 22, 2010. http://www.bipartisanpolicy.org/events/2010/10/environmental-regulation-and-electric-system-reliability. See also, e.g., "The Toll From Coal—An Updated Assessment of Death and Disease from America's Dirtiest Energy Source." Clean Air Task Force, September 2010. This is an update of similar Clean Air Task Force studies from 2000 and 2004 that looked at health impacts caused by fine particle air pollution from the nation's roughly 500 coal-fired power plants which found that "emissions from the U.S. power sector cause tens of thousands of premature deaths each year and hundreds of thousands of heart attacks, asthma attacks, emergency room visits, hospital admissions, and lost workdays." Id. at 4. The current study develops estimates of health impacts using an established and peer-reviewed methodology approved by both the EPA's Science Advisory Board and the National Academy of Sciences. It concludes that fine particle pollution from existing coal plants were expected to cause nearly 13,200 deaths in 2010, and an estimated 9,700 hospitalizations and over 20,000 heart attacks per year. Id.

27 The EPA has proposed several subcategories of emitters for purposes of this rule: mine-mouth, lignite-burning generators, and solid and liquid oil units.

28 These are included because "even though petroleum coke is derived from oil, it is a solid fuel and cannot be burned in a liquid oil-fired boiler." "Power Plant Mercury and Air Toxics Standards, Overview of Proposed Rule and Impacts," March 16, 2011.

29 Adapted from "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 19.

30 During this rulemaking, an industry representative, the Utility Air Regulatory Group (UARG), identified an error in the manner in which the EPA had calculated the MACT floor. In a May 19, 2011 letter from the EPA to UARG, the EPA proposed to reset the mercury level from 1 lb/TBtu to 1.2lb/TBtu. http://insideepa.com/iwpfile.html?file=may2011%2Fepa2011_0964a.pdf

31 The EPA has proposed a beyond-the-floor limit of 4 lb/TBtu.

availability of technology and national security interests."[32] While Presidential exemptions have been used in limited circumstances,[33] the EPA's Mercury/Air Toxics Rule actually contains a number of significant flexibility provisions.

First, the rule allows for facility-wide averaging for all HAP emissions from existing units within the same subcategory.[34] In other words, a facility might have several similar units emitting a hazardous pollutant, mercury for example. Under the rule, emissions from similar units can be averaged across the facility, in effect treating the facility as though it were one emissions source. According to the EPA, "[e]missions averaging . . . could only be used between [electric generating units] in the same subcategory at a particular affected source." This approach will allow environmentally equivalent but less costly ways of achieving emissions standards. With the opportunity to average emissions facility-wide, the Mercury/Air Toxics Rule offers the potential for significantly less onerous compliance than would be available if the rule were imposed at a unit-by-unit level."[35]

Second, the proposed rule would allow for averaging of facility emissions to accommodate generators' operational variability. Averaging would be allowed over a thirty-day period.

Third, the proposed Mercury/Air Toxics Rule also provides for flexibility and less costly compliance demonstration methods through the use of "surrogates" (i.e., the control of one pollutant as a proxy for others).[36] This would allow an emitter to demonstrate control over the emission of a pollutant that typically accompanies another pollutant by simply demonstrating control of that other pollutant. For example, there are emissions limits for particulate matter as a surrogate for non-mercury metals. In that case, non-mercury metal emissions limits can be met through a demonstration of particulate matter controls. Similarly, hydrogen chloride is being proposed as a surrogate for other acid gases. The proposed rule also preserves the more typical approach of measuring metals or individual acid gases themselves.

Fourth, the rule creates conditions that encourage fuel switching (i.e., between types of coal), an additional flexible aspect of the rule. Although the expression "maximum available control technology" implies a technology standard, MACT is a performance-based emissions rate set with regard to the performance of existing sources and technologies being used at those sources. Unlike percent-removal standards such as those found in many state mercury laws,[37] the MACT standard results in the actual amount of removal required varying by coal type. For example, Fig. 6 shows that Texas Lignite (TL) has the highest concentration of mercury content (pounds per million BTU) of the types of coal listed. Mercury content decreases progressively in Western bituminous (WB), Illinois Basin (IB), Northern Appalachian (NAP), and Powder River Basin coal. Thus, burning Texas Lignite would require greater levels of removal than would the use of other types of coal. Conversely, other types of coal would require lower levels of removal.

A similar analysis holds true for removal of hydrochloric acid from coal. (See Fig. 7). Illinois Basin coal has greater

32 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations (NERC Study), NERC, October 2010 at 60.

33 See Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, M.J. Bradley & Associates and the Analysis Group, August 2010, Michael J. Bradley, Susan F. Tierney, Christopher E. Van Atten, Paul J. Hibbard, Amlan Saha, and Carrie Jenks (M.J. Bradley Study), sponsored by the "Clean Energy Group" (i.e., Calpine Corporation, Constellation Energy, Entergy Corporation, Exelon Corporation, NextEra Energy, National Grid, PG&E Corporation, and Public Service Enterprise Group) at 22.

34 Note that this does mean averaging can occur across pollutants (e.g., mercury for benzene). EPA 40 CFR Parts 60 and 63 [EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044, FRL-9148-5] RIN 2060-AP52 "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional." Id. at 431 (Proposed MACT Rule) http://insideepa.com/iwpfile.html?file=mar2011/epa2011_0509a.pdf.

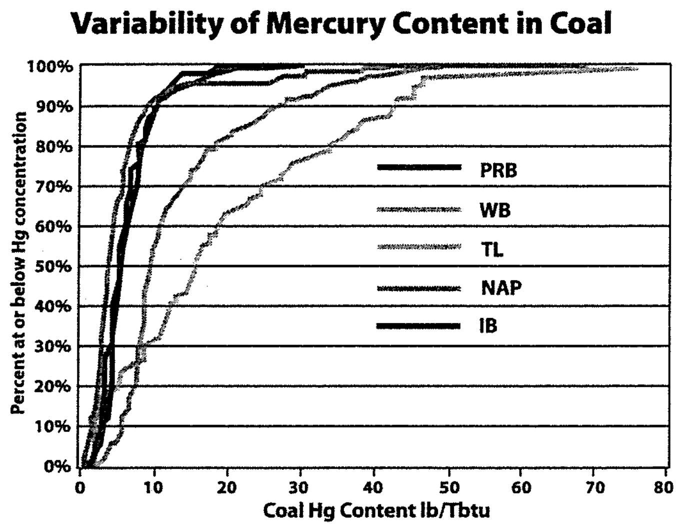
35 According to the NERC Study, the "potential EPA MACT rule will apply to all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 of new planned coal units)." The EPA estimates, however, that there are approximately 1,350 coal- and oil-fired units at 525 power plants that emit pollutants that would be subject to this rule.

36 Proposed Mercury/Air Toxics Rule at 535.

37 Over 20 states have mercury laws. See "A Patchwork Program: An Overview of State Mercury Regulations," Stephen K. Norfleet and Robert E. Barton, RMB Consulting & Research, Inc. Electric Utilities Environmental Conference Tucson, Arizona, January 21-24, 2007, http://rmb-consulting.com/papers/A%20Patchwork%20Program-An%20Overview%20of%20State%20Mercury%20Regulations.pdf.

71

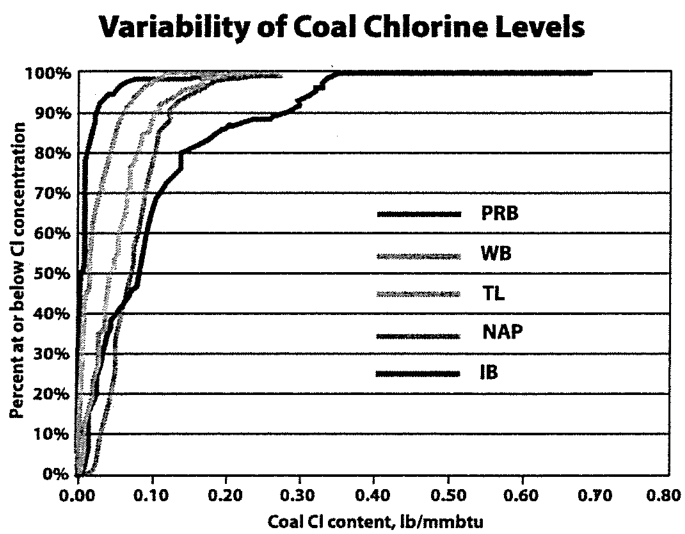
Figure 6 [38]



amounts of chlorine and will require greater levels of removal than the other types of coal shown.

Depending on the types of coal economically available,

Figure 7 [39]



the Mercury/Air Toxics Rule thus allows for the use of cleaner types of coal as part of industry compliance strategies.

Units that already have scrubbers can be expected to have less difficulty complying with the Mercury/Air Toxics Rule.[40] They are likely to be able to meet acid gas emissions requirements and, depending on coal type, may be able to meet mercury removal limits.[41] "Unscrubbed" units will need to install electrostatic precipitators (ESPs) or fabric filters for particulates, make use of alternative sorbents such as activated carbon or halogen additions for mercury,[42] and dry sorbent injection (e.g., Trona, Sodium Bicarbonate, or Hydrated Lime, also called "dry-scrubber technologies," for strong acids (hydrochloric and hydrofluoric acids).[43]

Finally, the EPA recognizes that compliance costs associated with this rule can be significantly reduced by including energy efficiency investments in compliance strategies that achieve moderate levels of energy demand reduction:

> *End-use energy efficiency can be an important part of a compliance strategy for this regulation. It can reduce the cost of compliance, lower consumer costs, reduce emissions, and help to ensure reliability of the U.S. power system. Policies to promote end-use energy efficiency are largely outside of EPA's direct control. However this rule can provide an incentive for action to promote energy efficiency.*[44]

To examine the potential impacts of federal and state energy efficiency policies, the EPA used the Integrated Planning Model (IPM). It first modeled a base case that reflected future energy prices and bills without a MACT standard. Then they modeled future prices and bills with a MACT standard (row one of Table B). Then they modeled

38 Adapted from "Surviving the Power Sector Environmental Regulations," Staudt, October 2010.

39 Id.

40 "Surviving the Power Sector Environmental Regulations," James Staudt, Ph.D., The Bipartisan Policy Center's National Commission on Energy Policy (NCEP), October 22, 2010.

41 Id.

42 Id. Activated carbon is more absorbing because it is more porous. This capacity can be enhanced by further treating carbon with a compound that reacts chemically with mercury. Halogen converts mercury to mercuric halide, and this can be absorbed by coal ash and dry flue gas desulphurization solids. Combining halogen and activated carbon also presents a lower cost approach to other sorbents such as bromated activated carbon. See "Options for High Mercury Removal at PRB-fired Units Equipped with Fabric Filters with Emphasis on Preserving Fly Ash Sales," Paradis et al. http://secure.awma.org/presentations/Mega08/presentations/6a-Dutton.pdf; see also NALCO/Mobotec, http://www.nalcomobotec.com/expertise/mercury-control.html.

43 Like other sorbents, these are injected into the furnace (i.e., upstream from the particulate removal device). They react with the acid gas and are caught by ESPs or fabric filters.

44 "Power Plant Mercury and Air Toxics Standards, Overview of Proposed Rule and Impacts," March 16, 2011 at 545.

MACT plus energy efficiency (row two of Table B).

The EPA assumed, first, that the states adopted ratepayer-funded energy efficiency programs, such as an energy efficiency resource standard. The EPA's model relied on savings estimates taken from work conducted by Lawrence Berkley National Laboratory.[45] Second, the EPA used Department of Energy estimates of "demand reductions that could be achieved from implementation of appliance efficiency standards mandated by existing statutes but not yet implemented."[46] Third, the EPA assumed that the impacts of these policies would continue through 2050.[47]

The EPA concluded that its modeled energy efficiency case would significantly reduce electricity prices and the price effects of the proposed Mercury/Air Toxics Rule. As seen in Table B, the EPA's base case modeling shows that the Mercury/Air Toxics Rule would increase retail prices "by 3.7percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030, respectively, relative to the base case."[48] If energy efficiency programs were implemented, however, the retail electricity price in 2015 would increase only 3.3 percent (i.e., lower by 0.4 percent). Prices in 2020 and 2030 would decrease by approximately 1.6 percent and 2.3 percent, respectively, relative to the EPA's base case.[49]

Table B

EPA Efficiency Modeling/ Percentage Retail Price Effect

	2015	2020	2030
Cost Effects MACT Rule	3.7%	2,6%	1.9%
Cost Effects MACT Rule with Energy Efficiency	3.3%	(1.6%)	(2.3%)

45 Proposed Mercury Air Toxics Rule at 545, citing to "The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S.," Galen Barbose, et al, October 2009, Lawrence Berkeley National Laboratory, LBNL-2258E.

46 The EPA notes that "appliance standards that have been implemented are in [EPA's] base case." Id.

47 Id. See Tables 22 and 23 at 545-546.

48 Id. at 548.

49 Id.

50 CO_2e is a measure of the global warming potential of all GHGs.

This work shows incidentally the long-term rate reducing effect of energy efficiency, all else being equal, and specifically shows how pollution control can be accomplished without adverse economic effect to consumers.

Regulations for CO_2

The EPA's regulation of greenhouse gases (GHGs) to date is largely based on four separate administrative actions and rules:

1. GHG Reporting Rule
2. Endangerment Finding/Light Duty Vehicle Rule
3. Johnson Memorandum Reconsideration
4. Tailoring Rule

The EPA, however, has also indicated that it will eventually regulate GHG emissions from power plants pursuant to its authority to develop source categories and performance standards for pollution sources under section 111 of the Clean Air Act.

Reporting Rule

In October 2009, the EPA proposed a GHG Reporting Rule that requires nearly all facilities that emit 25,000 metric tons or more per year of CO_2e[50] emissions to monitor their GHG emissions and submit detailed annual reports to the EPA starting in 2011.[51] The Final Rule was issued in October 2010, and March 2011 was the first reporting deadline.[52]

Endangerment Finding

The EPA is obligated by law to regulate CO_2 emissions pursuant to the federal Clean Air Act and consistent with the 2007 Supreme Court decision in *Massachusetts v. EPA*.[53] In response, the EPA issued its Endangerment Finding,

51 74 Fed. Reg. 56260. Created pursuant to the FY2008 Consolidates Appropriations Act (H.R. 2764; Public Law 110-161). http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

52 See 75 Fed. Reg. 66434 (October 28, 2010).

53 In Massachusetts v. EPA the Supreme Court found that GHG emissions are "air pollutants" under the Clean Air Act. The Court required the EPA to determine whether or not emissions of GHG from new motor vehicles cause or contribute to air pollution reasonably anticipated to endanger public health or welfare, and this requires the EPA to respond to petitions for rulemaking requesting the EPA to regulate CO_2 and other GHG from motor vehicles. http://www.supremecourtsus.gov/opinions/06pdf/05-1120.pdf; Status Report on Clean Air Act GHG. Regulation for Utility Regulators, Joseph Goffman, Senior Counsel, Office of Assistant Administrator Office of Air and Radiation, U.S. EPA NARUC Webinar, October 15, 2010.

stating that, "greenhouse gases in the atmosphere endanger the public health and welfare of current and future generations."[54] This finding was made with regard to motor vehicle emissions, and the EPA subsequently issued the Light Duty Vehicle Rule.[55]

Johnson Memorandum

In April 2010, the EPA issued what is known as the Johnson Memorandum Reconsideration.[56] In this memorandum, the EPA indicated that relevant permitting requirements (i.e., Prevention of Significant Deterioration [PSD] permitting) would not apply to a newly regulated pollutant until regulatory requirements to control that pollutant take effect.[57] PSD and Title V permit requirements applying to GHGs took effect on January 2, 2011. PSD is a preconstruction permit program requiring a permit before the construction of a new source or a project at an existing source that would result in a significant emissions increase. The Title V program requires an operating permit for all "major sources" (i.e., sources above a certain threshold) that have the potential to emit pollutants above a certain level. Under the memorandum, PSD and Title V programs apply automatically.

Tailoring Rule

While the Endangerment Finding and Light Duty Vehicle Rule apply to mobile sources of GHG, and the Johnson Memorandum is a general statement of policy, the Tailoring Rule, proposed by the EPA in October 2009, applies GHG regulations under PSD and Title V to major sources.[58] The EPA recognized that the existing thresholds in the Title V and PSD programs were not realistic for GHGs.[59]

Because existing PSD and Title V thresholds for air pollutants were far too low (e.g., 50-100 tons per year of carbon dioxide equivalent [CO_2e]) to apply to GHGs (which are emitted in much greater amounts), the EPA chose to "tailor" its thresholds to recognize this in a way that would allow smaller sources to avoid being required to comply with these permitting programs. The Tailoring Rule reset the thresholds for both PSD and Title V.[60] PSD is set at 75,000 tons per year, and the major source threshold for Title V is set at 100,000 tons per year of GHGs.

The Tailoring Rule focuses GHG requirements on large new emitters (including power plants) and modifications of plants that cause at least a 75,000-ton CO_2e increase. This approach makes "70 percent of the national GHG emissions from stationary sources . . . subject to permitting requirements beginning in 2011, including the nation's largest GHG emitters (i.e., power plants, refineries, and cement production facilities)." [61] Permitting will occur on a step-by-step basis.

The first step in permitting (January 2011 through June 2011) focuses on what are referred to as "anyway sources" and "anyway modifications." These are emissions sources that would be subject to PSD "anyway" based on emissions of pollutants other than GHGs. Sources that already have a Title V permit must add GHG requirements during the next revision or renewal.

The second step (July 2011 through June 2013) applies to projects that would not otherwise trigger PSD, but increase GHG emissions by more than 75,000 tons per year CO_2e or to sources that do not already have a Title V permit but which have more than 100,000 tons per year CO_2e potential to emit.[62]

The EPA plans a third step on whether to apply the

54 Proposed April 24, 2009 (74 Fed. Reg. 18,886), Final December 15, 2009 (74 Fed. Reg. 66,496)

55 Proposed September 28, 2009 (74 Fed. Reg. 49,454); Final May 7, 2010 (75 Fed. Reg. 25,324)

56 Final April 2, 2010 (75 Fed. Reg. 17,004)

57 "EPA is refining its interpretation to establish that the PSD permitting requirements will not apply to a newly regulated pollutant until a regulatory requirement to control emissions of that pollutant 'takes effect.'" Id.

58 Proposed October 27, 2009 (74 Fed. Reg. 55,292).

59 The thresholds for Title V were 100 and 250 tons per year, and had not been set for PSD. At a 25,000 tpy CO_2e threshold, "the program will remain of a manageable size, so that permitting authorities will be able to process permit applications and issue permits, which sources must have to construct or expand."

60 Final PSD and Title V GHG Tailoring Rule, June 3, 2010 (75 Fed. Reg. 31514).

61 PSD and Title V Guidance.

62 The federal regulations define "potential to emit" as: "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design." 40 C.F.R. Sections 52.21(b)(4), 51.165(a)(1)(iii), 51.166(b)(4). "Limiting Potential to Emit (PTE) in New Source Review (NSR) Permitting," http://www.epa.gov/reg3artd/permitting/limitPTEmmo.htm; see also, e.g., "Air Permit Reviewer Reference Guide APDG 5944 Potential to Emit Guidance Air Permits Division, Texas Commission on Environmental Quality, December 2008," "Potential to emit is defined in Title 30 Texas Administrative Code (30 TAC) Chapter 122 . . . as the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design or configuration." Id. at 1.

permit program to additional sources or to adjust permit thresholds. The EPA will take comments on the third step in July 2012.

State Implementation

The EPA establishes programs under the Clean Air Act, but the states typically implement and operate the programs after receiving approval from the EPA. Such federally mandated but state implemented state air regulations are delineated in "State Implementation Plans" or "SIPs". State SIPs must be revised to reflect the EPA's new PSD and Title V program changes. Most states have revised or are in the process of revising their own PSD and Title V permitting programs to implement the Tailoring Rule thresholds. The EPA has indicated that there are 13 states that will still need to revise their SIPs in order to be able to regulate GHGs.[63] At least one state (Texas) has indicated it will not regulate GHGs as part of its SIP, and is challenging the authority of the EPA to enforce its GHG requirements in the absence of state regulation.[64] If the EPA determines that states are taking too long to implement changes to their SIP, the EPA has the authority to issue a "Federal Implementation Plan" or "FIP" in its place.[65]

The EPA began regulating GHG emissions in January 2011. For their efforts to succeed, state regulators (i.e., those who will be writing the GHG permits) need to understand the best ways to set "Best Available Control Technology" or "BACT" for GHG. To this end, the EPA issued its "PSD and Title V Permitting Guidance for Greenhouse Gases" in November 2010.[66] It provides technical guidance on setting BACT. BACT is defined in section 169(3) of the Clean Air Act as the "[m]aximum degree of reduction of each pollutant subject to regulation determined on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs."

A BACT determination works on a case-by-case basis. It applies on a site-specific basis but must involve adherence of the following steps:

1) Identify Controls
2) Eliminate Technically Infeasible Controls
3) Rank Remaining Controls by Efficiency
4) Evaluate Other Environmental, Energy, and Economic Impacts
5) Select BACT.

New Source Performance Standards

Under the Clean Air Act, GHG emissions from new and existing sources may also be regulated under the New Source Performance Standards (NSPS) provisions of section 111.[68] NSPSs have been established since the 1970s and are supposed to be reviewed at least every eight years. Under this approach, the EPA issues NSPS requirements for each category of sources that it determines "contributes significantly" to air pollution that may "reasonably be anticipated to endanger public health or welfare."[69]

Under Section 111(b), the EPA sets emissions limitations on *new* and *modified* sources within each source category that it has completed (e.g., Stationary Gas Turbines[70]). The EPA is required to take "into account the cost of achieving

63 On December 13, 2010, the EPA issued a notice stating that:

> *EPA-approved state implementation plans (SIP) of 13 states (comprising 15 state and local programs) are substantially inadequate to meet Clean Air Act requirements because they do not apply Prevention of Significant Deterioration (PSD) requirements to greenhouse gas (GHG)-emitting sources.*

http://edocket.access.gpo.gov/2010/pdf/2010-30854.pdf. These states include Alaska, Arizona, Arkansas, California, Connecticut, Florida, Idaho, Kansas, Kentucky, Nebraska, Nevada, Oregon, and Texas.

64 http://www.law.upenn.edu/blogs/regblog/2011/05/texas-and-epa-battle-over-greenhouse-gas-regulations.html.

65 Section 110(c) of the Clean Air Act, 42 U.S.C. § 7410(c).

66 "PSD and Title V Permitting Guidance For Greenhouse Gases," EPA Office of Air Quality Planning and Standards, November 2010.

67 Id.

68 42 U.S.C. §§7401-7671q, ELR Stat. Clean Air Act §§101-618; 42 U.S.C. §7411(b)(1)(A). Section 111(d) only applies to pollutants—like GHGs—for which there is no standard or NAAQS and which have not been listed as hazardous air pollutants. Criteria pollutants, for which there are NAAQS, have been defined by the EPA under section 108(a) of the Clean Air Act, and include particulate matter, ground-level ozone, carbon monoxides, sulfur oxides, nitrogen oxides, and lead. In the 1990 Clean Air Act amendments, Congress listed 188 toxic air pollutants in section 112(b)(1) of the act. Neither provision includes greenhouse gases. Because GHGs have not been designated as criteria pollutants under section 108 nor listed as hazardous air pollutants under section 112, they qualify for regulation under section 111(d).

69 42 U.S.C. §7411(b)(1)(A). The NSPS requirements must be reviewed and revised at least every 8 years.

70 40 C.F.R. Part 60, subpart KKKK.

such reduction and any non-air quality health and environmental impact and energy requirements..." as the EPA determines.[71]

With regard to *existing* sources, Section 111(d) requires the EPA to issue "guidelines" to the states that they must follow in preparing state plans to meet the standards for existing categories. Under §111(d), states are required to submit a plan to impose NSPS requirements on all existing sources in the state. Guidelines contain targets based on demonstrated controls, emissions reductions, costs, and installation and compliance timeframes. Standards for existing sources can be less stringent than standards for new or modified sources. States have nine months after the publication of guidelines to submit plans for EPA approval.

It is important to understand the relationship between performance standards established under section 111 and preconstruction permitting requirements under the Clean Air Act's PSD provisions, discussed in the context of the Johnson Memorandum and the Tailoring Rule. As noted, PSD provisions require new and modified emitters to meet the BACT standard, described earlier. PSD, however, does not apply to existing facilities. New source performance standards thus end up serving as a "'floor' for BACT determinations."[72]

In December 2010, the EPA entered into a settlement agreement in which it agreed to develop NSPS for new and modified electric generators and emission guidelines for existing electric generators by July 26, 2011. Final regulations are to be promulgated by May 26, 2012.[73]

Potential Flexibility in the EPA's Air Regulations

In each of the air regulations outlined previously there exist opportunities for flexibility in meeting compliance requirements. Under the Clean Air Transport Rule, CATR, the EPA has proposed several market-based compliance mechanisms (i.e., cap-and-trade programs for SO_2 and NOx) that would allow emitters to trade allowances in order to meet compliance obligations in a least-cost manner. Cap-and-trade enables those better situated economically to make the decision to invest in compliance technology to reduce emissions and to sell/trade any extra emissions reductions (allowances) to other affected sources for which investment in technology would be a more expensive option.

In addition to the mechanisms outlined in the previous section, the Mercury/Air Toxics Rule also encourages investment in energy efficiency as a means of mitigating rate effects and lowering consumer electric bills. Limited compliance extensions are also available under Clean Air Act Section 112 and the Mercury/Air Toxics Rule. Although in the Mercury/Air Toxics Rule the initial analysis is relatively prescriptive with regard to required technology, "cost" is one of the factors in the analysis for setting "beyond-the-floor" reductions.

With regard to GHG regulation, the precise purpose of the EPA's Tailoring Rule is to avoid imposing costs too broadly. It directs application of the rule to sources already subject to the standard and then only to larger sources first. The BACT standard applied in PSD permits also takes into account "energy, environmental and economic impacts and other costs." As rulemakings go forward, stakeholders will have the opportunity to provide the EPA with input as to cost effectiveness.

Although no guidance has been issued by the EPA, the analysis under Clean Air Act Section 111 for setting NSPSs allows for the consideration of cost, non-air quality health and environmental benefits, and energy requirements[74]

71 Section 111(a)(1) states:

> *[t]he term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.*

72 For a discussion of the distinction, see "What's Ahead for Power Plants and Industry? Using the Clean Air Act to Reduce Greenhouse Gas Emissions, Building on Existing Regional Programs," F. Litz, N. Bianco, M. Gerrard, and G. Wannier, WRI Working Paper, February 2011, http://pdf.wri.org/working_papers/whats_ahead_for_power_plants_and_industry.pdf.

73 "Under today's agreement with the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York; Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF), EPA would commit to issuing proposed regulations by July 26, 2011 and final regulations by May 26, 2012," Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries Fact Sheet, http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf.

74 Sections 111(b)(1)(A), (B).

Water and Solid Waste Regulations

In addition to being subject to various air regulations, electric generators will be affected by the outcome of other rulemakings, which address effluent limitations, cooling water controls, and coal combustion wastes.

Clean Water Act Requirements [75]

There are two Clean Water Act rules in development at the EPA: (1) the Steam Electric Effluent Limitations Guideline (guideline), and (2) the section 316(b) Cooling Water Intake Structures Regulation for Existing Facilities (316(b) rule).

Effluent Rule

Schedule: The EPA is currently collecting technical and financial data for analysis for a proposed rule in 2012.

The Effluent Rule (1982) focuses on the steam electric subcategory of all electric generating activities, including fossil-fueled (coal, oil, gas) power plants. A major focus of the Effluent Rule is on toxic pollutants released into wastewater and ash ponds as part of the flue gas desulfurization (FGD) process. Currently guidelines cover suspended solids, oil and grease from ash ponds, and FGD discharges. While some of the newest power plants have zero liquid discharge (ZLD)[76] systems, most existing power plants release substantial amounts of water used in boilers, cooling systems, and pollution control systems back into the environment. Unregulated pollutants are present in ash ponds, and related discharges include metals that are bio-accumulative (e.g., mercury, selenium, arsenic), nutrients (e.g., nitrates, ammonia), and chlorides.

According to the EPA, the schedule for the development of an effluent rule requires the EPA to collect technical and financial information for analysis, an effort that is now underway. No rule has been proposed, but the EPA intends to issue proposed regulation in mid-2012 and a final rule in late 2013. Dischargers are likely to be required to apply for National Pollutant Discharge Elimination System (NPDES) permits. Compliance is expected to start 3 to 5 years after the final rule, in 2016 to 2018.

316(b) Rule

Schedule: Proposed March 28, 2011; to be finalized by July 27, 2012

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

The purpose of the rule is to "minimize adverse environmental impacts, including substantially reducing the harmful effects of impingement and entrainment."[77] Fish and smaller organisms die because they are either unable to swim away from water intakes and are "impinged" against the screen, or pass through screens and become "entrained" in the cooling system. Thermal pollution is associated with "once through" cooling systems that use water only once as it passes through a condenser to absorb heat and is then discharged. Closed-cycle cooling reuses water by recycling it through recirculating systems or towers without discharging it. The 316(b) rule would set performance standards for fish mortality caused by impingement, and establish a requirement that entrainment standards be developed by facilities on a case-by-case basis.

For nearly twenty years, 316(b) standards have been implemented on a case-by-case basis by water permitting authorities. In 2001, however, the EPA finalized the first of three 316(b) rules. Phase I set standards for new electric generators and other facilities. In 2004, Phase II focused on larger generators. In 2006, Phase III covered remaining facilities subject to section 316(b). The courts found that the EPA's rules did not fully comply with the Clean Water Act, and parts of Phases I, II, and III were remanded to the EPA to be augmented for stricter conditions.[78] The standards in the proposed 316(b) rule are written in response to these cases

75 The discussion of the Guideline and 316(b) Rule is based in part on a presentation by Julie Hewitt, EPA Office of Water, entitled "Clean Water Act Regulations Affecting Electric Utilities," NARUC Webinar, September 24, 2010. http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20WATER%20Presentation%20Sept%2024%202010%20_%20Julie%20Hewitt.pdf.

76 Case Study: California's Magnolia Power Project Utilizes HERO/Crystallizer Process For ZLD System. http://www.wateronline.com/downloads/detail.aspx?docid=0186a943-7fcd-4a5b-af88-1becafdaf375.

77 Id.

78 Phase I was challenged in Riverkeeper, Inc. v. U.S. EPA, 358 F. 3d 174, 181 (2d Cir. 2004) ("Riverkeeper I"); Phase II in Riverkeeper, Inc. v. U.S .EPA, 475 F. 3d 83 (2d Cir. 2007) ("Riverkeeper II"), and Phase III in Entergy Corp. v. Riverkeeper Inc., 129 S. Ct. 1498, 68 ERC 1001 (2009) (40 ER 770, 4/3/09); and Conoco Phillips v. EPA (5th Cir. No. 06-60662). See "National Pollutant Discharge Elimination System — Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities," at 14-15, and 38-39 (prepublication version). http://hosting-source.bronto.com/6335/public/Alert_4_4_11.pdf .

and are intended to replace the Phase II regulations and amend the Phase I and Phase III standards.[79]

The proposed 316(b) rule would establish requirements for all existing power generating facilities and existing manufacturing and industrial facilities that (a) withdraw more than 2 million gallons of water per day from waters of the U.S. and (b) use at least 25 percent of the water they withdraw exclusively for cooling purposes.[80] The EPA estimates that roughly 670 power plants would be affected by the rule.

The proposed national standards are to be implemented through National Pollutant Discharge Elimination System (NPDES) permits and would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact.[81]

Existing Facilities

Impingement

Owner/operators of existing facilities may choose one of two options for meeting BTA requirements for addressing impingement mortality under the EPA's proposed rule.[82] Existing facilities are subject to an upper limit on how many fish can be killed or pinned against intake screens or other parts of facility equipment. Facilities would be allowed to determine which technology would be best suited to meeting this limit. Alternatively, the rule allows facilities to reduce the intake velocity of their cooling water to 0.5 feet per second, a rate at which the EPA presumes fish would be able to swim away from plant cooling water intakes.[83]

Entrainment

To address entrainment mortality, the proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the best technology available for entrainment mortality would be implemented at each facility. In order to reduce the amount of organisms drawn into cooling water systems, the rule requires existing facilities that withdraw at least 125 million gallons per day to conduct studies to help their permitting authority to determine the level of site-specific control that may be necessary.

New Facilities

The proposed rule would require new units constructed at an existing facility to comply with provisions for impingement and entrainment mortality based on a closed-cycle system. These standards are similar to standards set out for new facilities.[84] This can be accomplished by either including a closed-cycle system or by making any other changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling.[85]

Under the terms of a judicial settlement, the EPA is obligated to finalize the rule by July 27, 2012. Compliance dates will be geared to when the EPA issues the final rule. When it becomes effective, technologies to meet the impingement requirements would have to be implemented as soon as possible, but within eight years at the latest. New units would have to comply when they begin operations.

Potential Flexibility in the EPA's Water Regulations

In both water regulations outlined previously, there is potential for flexibility in meeting compliance requirements. There also appear to be significant lead times. No actual effluent rule has been proposed yet, because the EPA is currently gathering technical and financial information. The EPA has indicated its intent to propose a rule in 2012 and a final rule in late 2013, with compliance starting three to five years after that in the 2016 to 2018 timeframe. As development of this rule goes forward, there should be opportunity for comment

79 Id.

80 "In today's proposed rule, EPA is defining the term 'existing facility' to include any facility that commenced construction before January 18, 2002, as provided for in §122.29(b)(4).28." http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf at 30. "EPA is proposing to establish January 17, 2002 as the date for distinguishing existing facilities from new facilities because that is the effective date of the Phase I new facility rule. Thus, existing facilities include all facilities the construction of which commenced on or before this date."

81 "Today's proposed rule would apply only to facilities that are point sources (i.e., facilities that have an NPDES permit or are required to obtain one." http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf at 80.

82 Id.

83 Id.

84 Id.

85 Id.

regarding compliance alternatives.

The 316(b) rule provides existing sources with choices of how to comply with BTA standards for impingement. For addressing entrainment mortality, the rule provides for facilities to study and develop information as part of the permit application process, and then establishes a process by which the BTA for that facility would be determined. For new facilities or modifications of existing facilities, the EPA allows generators to build a closed-cycle system or to make "other changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling."[86]

Coal Combustion Residuals

Schedule: Proposed on June 21, 2010; finalization date TBD.

The EPA proposed a rule on Coal Combustion Residuals (CCRs) from Electric Utilities ("Ash Rule") in June 2010, and has not set a date for a final rule.[87] CCRs are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. In 2008 over 136 tons of CCRs were produced in the U.S.[88] This waste is currently disposed of in various ways. It is placed in approximately 300 CCR landfills or 584 surface impoundments[89] at approximately 495 coal-fired power plants across the nation. It is also placed in mines or "beneficially" used.[90]

Applying its solid waste authority under the federal Resource Conservation and Recovery Act (RCRA), the EPA has proposed two alternative approaches for regulating the disposal of CCRs produced by electric utilities and independent power producers.[91] The first and more stringent approach, designated "Subtitle C," would treat CCRs like hazardous waste.[92] For example, under this approach parties who create, transport, or store CCRs would be subject to various requirements including permitting, ground water monitoring, and financial assurance. Existing landfills would be required to install groundwater monitoring within one 1 year of the effective date of the rule. If monitoring were to show groundwater contamination, remedial action would be required. New or expanded landfills would be required to install composite liners and groundwater monitoring before the landfill begins operation.

Under the less stringent "Subtitle D" approach, CCRs would continue to be classified by the EPA as a "non-hazardous" waste. Facilities would be subject to national minimum criteria governing CCR disposal (see Table D). Subtitle D engineering requirements (e.g., liners and groundwater monitoring) would be similar to Subtitle C. Under either proposal, a "Bevill" exemption from regulation would remain in place for beneficial uses of CCRs.[93] Likewise, mine-filling would not be covered by the proposal.

86 "Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities," http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/factsheet_proposed.pdf

87 75 Fed. Reg. 35127 (June 21, 2010),http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed Coal Combustion Residual rule based on presentation by Betsy Devlin, Associate Director, U.S. EPA Materials Recovery & Waste Management Division, entitled "Combustion Residuals," NARUC Webinar, September 24, 2010. http://www.bcatoday.org/uploadedFiles/EPA%20Proposed%20Changes%20to%20Coal%20Ash%20disposal.pdf

88 According to ICF International, the current distribution of disposal methods is as follows: 21 percent surface impoundments (wet); 36 percent landfills (dry or moist); 5 percent mines; and 38 percent recycled. "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 21.

89 The EPA indicates that 75 percent of impoundments are greater than 25 years old and ten 10 percent are greater than 50 years old.

90 According to the EPA, "[b]eneficial use refers to use of material that provides a functional benefit — that is, where the use replaces the use of an alternative material or conserves natural resources that would otherwise be obtained through extraction or other processes to obtain virgin materials." See http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/ccrfaq.htm#11

91 EPA derives its authority over solid waste disposal from the Resource Conservation and Recovery Act (RCRA), 42 U.S.C.A. §§ 690 et seq.

92 RCRA is divided into subtitles. Subtitles C and D set out the framework for the EPA's solid waste management program. Subtitle C establishes the framework for managing "hazardous" waste (from generation to its disposal), while Subtitle D sets out a system for managing primarily "nonhazardous" waste.

93 In 1980, RCRA was amended to add a provision known as the "Bevill exclusion," to exclude "solid waste from the extraction, beneficiation, and processing of ores and minerals" from regulation as hazardous waste under Subtitle C of RCRA. Id. Section 3001(b)(3)(A)(ii). "EPA, Bevill Amendment Questions" http://www.epa.gov/oecaerth/assistance/sectors/minerals/processing/bevillquestions.html#bevillexclusion

Table D[94]

Key Differences C vs. D

	Subtitle C	Subtitle D
Effective Date	Timing will vary from state to state, as each state must adopt the rule individually—can take 1-2 years or more	Six months after final rule is promulgated for most provisions.
Enforcement	State and Federal enforcement	Enforcement through citizen suits; States can act as citizens.
Corrective Action	Monitored by authorized States and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit Issuance	Federal requirement for permit issuance by States (or EPA)	No
Requirements for Storage, Including Containers, Tanks, and Containment Buildings	Yes	No
Surface Impoundments Built Before Rule is Finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments.	Must remove solids and retrofit with a composite liner or cease receiving CCRs within 5 years of effective date and close the unit
Surface Impoundments Built After Rule is Finalized	Must meet Land Disposal Restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No Land Disposal Restrictions
Landfills Built Before Rule is Finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills Built After Rule is Finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for Closure and Post-Closure Care	Yes; monitored by States and EPA	Yes; self-implementing

94 75 Fed. Reg. 35127 (June 21, 2010), http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm. In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed Coal Combustion Residual rule based on presentation by Betsy Devlin, Associate Director, U.S. EPA Materials Recovery & Waste Management Division, entitled "Combustion Residuals," NARUC Webinar, September 24, 2010. http://www.bcatoday.org/uploadedFiles/EPA%20Proposed%20Changes%20to%20Coal%20Ash%20disposal.pdf

The EPA is also considering additional alternatives to the Subtitle C or D approaches.[95]

Potential Flexibility in the EPA's CCR Regulations

The EPA's proposed CCR regulations contain significant potential for compliance flexibility. Despite one avenue of regulation (Subtitle C) being especially restrictive, the proposed rule contains a number of less stringent alternatives. It also preserves certain exemptions to CCR regulation. In addition, while the EPA proposed a rule in May 2010, the EPA has decided to refrain for the moment from setting a date for a final rule, leaving regulated entities time to consider alternatives and plan their compliance strategies.

Conclusion

Before any of the EPA's rules are finalized there is the opportunity to shape its outcome through comments and discussions with the EPA and other stakeholders. The change that the EPA recently made in its MACT floor determination mentioned previously is one example of this.[96] Administrative rulemaking is a deliberate and open process. It generally starts with a "proposed" rule or with a "notice of a proposed rulemaking," providing greater notice of agency planning and a larger window for comments. In certain cases, even before issuing a proposed rule, an agency engages in data acquisition and review, as is the case with the current 316(b) and Effluent Rules. The relatively early stage of most of these rules presents an opportunity to utility regulators to encourage their utilities and fellow environmental regulators to participate in the dialogue.

95 (1) An approach referred to as "D Prime" would provide for continued operation of existing surface impoundments until the end of their useful life. Other requirements would be the same as under Subtitle D. (2) An alternative where "wet-handled" CCRs are regulated under Subtitle C and "dry-handled" CCRs under Subtitle D. (3) An approach that would impose Subtitle C regulations unless a state develops enforceable Subtitle D regulations and submits them to the EPA for approval. In that case, if a state were to fail to develop a program within two years or if EPA did not approve one within one year, the federal Subtitle C rule would become effective in that state. (4) An approach that follows Subtitle D requirements unless there were finding of egregious violations of the requirements. In that case CCRs would be considered "special wastes" and treated pursuant to Subtitle C. Devlin.

96 See note 30 above. UARG identified an error in the manner in which the EPA had calculated the MACT floor for mercury, causing the EPA to reset the mercury level from 1 lb/TBtu to 1.2 lb/TBtu.

Part Two
Planning Considerations

Introduction

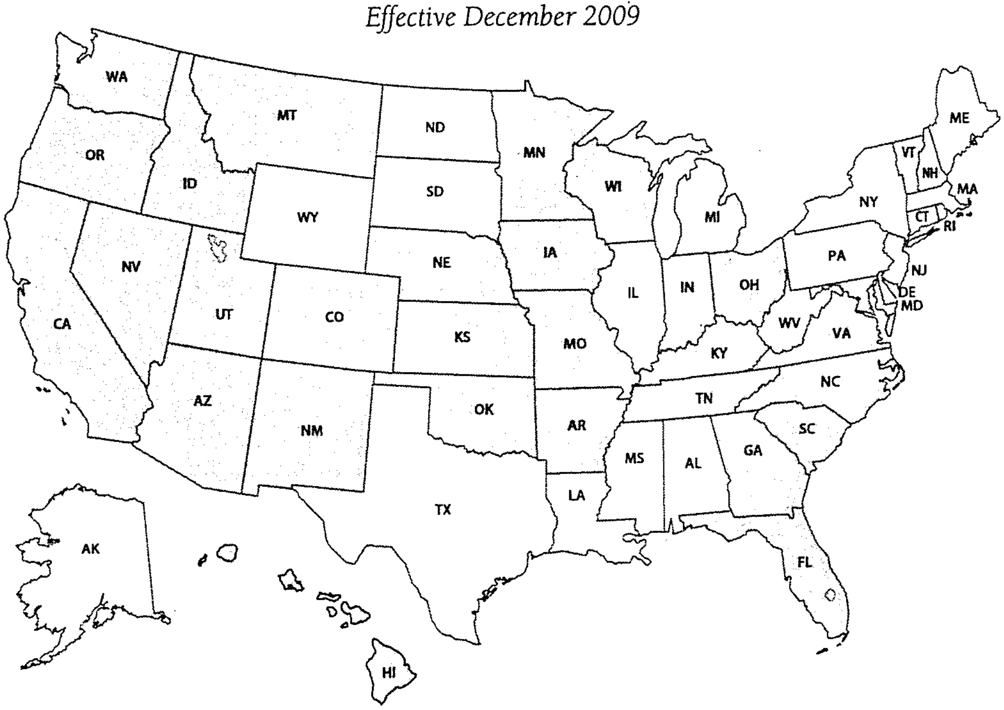
Planning is not new to the utility industry. Utilities plan constantly, and do so with or without the participation of stakeholders and regulatory authorities.[97] What has come to be known as "integrated resource planning" or simply "least-cost planning" has also been around for many years and is practiced in nearly 30 states (Fig.8). It was developed by utility regulators partly in response to large cost overruns (having to do primarily with nuclear facilities) and partly because they saw that an array of alternative resources, including end-use efficiency and renewables, whose economic and environmental characteristics could provide significant system benefits, were being consistently overlooked in traditional utility planning and investment decisions.

The central value in having a utility look ahead and plan, whether or not as part of a formal regulatory process, lies in being able to identify the best resource mix for a utility and its consumers before capital is committed and expenditures are made. The "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced."[99] The best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution." [100]

Figure 8 [98]

U.S. States with Integrated Resource Planning or Similar Process

Effective December 2009



No IRP or planning process

States with IRP or other planning process

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97 For example, while the Clean Air Interstate Rule (CAIR) was not finalized until 2005, company-wide planning at the Southern Company for FGD installations started in 2003. Implementation Strategies for Southern Company FGD Projects; Wall, Healy & Huggins; Power Plant Pollutant Control "Mega" Symposium, September 2010 cited in letter to Sen. Thomas Carper, U.S. Senate, from ICAC Executive Director David C. Foerter, November 3, 2010 at 4, http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf.

98 See the following link for a summary of IRP planning that occurs in the US. http://www.raponline.org/docs/RAP_IntegratedResourcePlanningInUS_2011_03_29.pdf

99 "Electric Regulation in the US: A Guide," Jim Lazar, March 2011 at 73 (Lazar).

100 Id.

To begin to address the challenge associated with the utility sector's compliance with forthcoming EPA health and environmental regulations, utility commissions can urge utility companies to engage in planning to help ensure the reasonableness of their decision-making in this context.[101] Recent Colorado experience provides an excellent example of utility planning and the effective coordination between utility regulators and air regulators in this context. The discussion that follows draws on recent planning experience undertaken by Xcel Energy's Public Service of Colorado and the process managed by the Colorado Public Utilities Commission.

Table E[104]

Xcel Energy's Analysis Framework for Colorado's Clean Air – Clean Jobs Act

1. Data Collection
- Identify Candidate Coal Units
- Emission Control Options and Costs
- Replacement Capacity Options
- Transmission Reliability Requirements

2. Scenario Development
- Meet NOx Reduction Targets
- Feasibility of Emission Controls
- Replace Retired Coal MW
- Transmission Needs Analysis

3. Dispatch Modeling of Scenarios
- Long-term Capacity Expansion Plan
- Cost of Transmission Fixes
- Coal and Gas Price Forecasts
- Customer Load Forecasts

4. Sensitivity Analysis
- Construction Costs
- Coal and Gas Prices
- Emissions Costs (NOx, SO_2, CO_2)
- Replacement MW for retirements
- Addition of renewable resources

Colorado's Planning Process—the Example of Xcel Energy

The "Clean Air – Clean Jobs Act" ("the Act") (see text box), passed in April 2010, anticipates new EPA regulations for criteria air pollutants (NOx, SO_2, and particulates), mercury, and CO_2.[102] It requires Colorado's two investor-owned utilities to consult with the Colorado Department of Public Health and Environment (CDPHE) on utility plans to meet current and "reasonably foreseeable EPA clean air rules," and to submit a coordinated multi-pollutant plan to the state Public Utilities Commission (Commission). Here we consider the example of Xcel Energy's Public Service of Colorado (Xcel).[103]

The Act gave a company like Xcel Energy, owner of Public Service of Colorado, four months to report to the Commission with analysis results and a proposed compliance plan (see Table E). Xcel divided its analysis into four steps. Step one is "data collection." The company identified (a) the coal plants for which the company might take "action" (i.e., install controls, retire, or retrofit for fuel

101 One interesting model of regulatory coordination is found in Michigan. Executive Directive No. 2009 – 2, requires the state environmental regulator, the Michigan Department of Environmental Quality (DEQ), to "conduct analysis of electric generation alternatives prior to issuing an air discharge permit," and as part of this inquiry, the directive requires the Michigan Public Service Commission (PSC) to provide DEQ with technical assistance. Executive Directive No. 2009 – 2, "Consideration of Feasible and Prudent Alternatives in the Processing of Air Permit Applications from Coal-Fired Power Plants," http://www.michigan.gov/granholm/0,1607,7-168-36898-208125--,00.html. The two agencies entered into a memorandum of understanding in which respective roles were articulated: DEQ would undertake air quality determinations, and the PSC would provide assistance related to determining need for new generation, and analyze alternatives, including options for energy efficiency, renewable energy and other generation.http://efile.mpsc.state.mi.us/efile/docs/15958/0001.pdf; "Statutory and Administrative Review of Power Plants in Michigan," NARUC Task Force Webinar 3, State Case Studies, Greg White, Commissioner, Michigan Public Service Commission, December 17, 2010. http://www.naruc.org/Publications/White_%20Michigan%20Coal%20Plant%20Review%20Processes.pdf

102 The "Clean Air – Clean Jobs Act, " HB 10-1365, requires "[b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/Colorado Electric Utility Company LP, ... to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units." Legal Memorandum, Office of Legislative Legal Services, March 16, 2011, on H.B. 10-1365 and Regional Haze State Implementation Plan, http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf.

103 NARUC Climate Policy Webinar 3: State Case Studies, "Dispatches from the Front: The Colorado Clean Air-Clean Jobs Act," Ron Binz, Chairman, Colorado Public Utilities Commission, December 17, 2010, http://www.naruc.org/committees.cfm?c=58; NARUC Task Force on Climate Policy Webinar, Coal Fleet Resource Planning: How States can Analyze their Generation Fleet, "Colorado Case Study," Karen T. Hyde, Vice President, Rates & Regulatory Affairs, and Jim Hill, Director, Resource Planning and Bidding; Xcel Energy, March 11, 2011, http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=3 (Hyde and Hill). All references to Xcel and Public Service of Colorado's work are based on Hyde and Hill's presentation to NARUC.

104 Adopted from Hyde and Hill.

About the Colorado Clean Air Clean Jobs Act and its Implementation

Colorado, the seventh largest coal producing state in the U.S., passed the "Clean Air Clean Jobs Act" ("the Act") in April 2010, targeting regional haze and ozone, and establishing a 70-80 percent reduction target for NOx from 2008 levels. Denver and Colorado's "Front Range" have been designated under the Clean Air Act as "non-attainment" areas for ground-level ozone, a pollutant created through the interaction of NOx, VOCs and sunlight.

The Act anticipates new EPA regulations for criteria air pollutants (NOX, SO_2, and particulates), mercury, and CO_2, and requires a utility to (a) consult with Colorado Department of Public Health and Environment (CDPHE) on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (b) submit a coordinated multi-pollutant plan to the state Public Utilities Commission (Commission).

The Act mandates that CDPHE participates in the Commission process, and conditions Commission action on CDPHE review of utility proposals, linking the two agencies' actions. The Commission cannot approve a plan that the CDPHE does not agree would meet future Clean Air Act requirements, and the company cannot build anything without the Commission's approval and a certificate of public convenience. The Act also requires the CDPHE's Air Quality Control Commission to incorporate apaproved plans into Colorado's State Implementation Plan (SIP) for addressing regional haze.

Companies are not required to adopt any particular plan, just one that meets CDPHE's requirements and passes muster with the Commission. No plan can jeopardize electric system reliability. The Act encourages companies to evaluate alternative compliance scenarios, but requires each company to develop and evaluate an "all emissions control" case, i.e., a scenario calling for installation of pollution controls on the coal fleet plus an assessment of different ranges of retirements.

The Act encourages utilities to enter into long-term contracts for natural gas supplies. It also allows utilities to recover in rates costs associated with approved long-term contracts, "notwithstanding any change in the market price during the term of the agreement." During its investigation, the Commission approved a long-term supply contract for much of the required gas associated with utilities plans.

Utilities are entitled to recover the full costs to comply with federal Clean Air Act requirements, assuming prudence in preparing and implementing these compliance plans.

The entire process was conducted quickly: the Act was signed into law in April 2010; a Commission docket was opened in May; and a final order was issued in December. In January 2011 the CDPHE adopted changes to the new Colorado SIP.

According to then Commission Chairman Ron Binz, had the legislation not required the two agencies to work together, the air agency would have made its own recommendations to EPA as to what actions would have been necessary for Colorado to meet national standards without having to even consult with the Commission.

switching); (b) emission control options and associated costs; (c) possible generation technologies that would replace retired capacity; and (d) transmission reliability requirements.

Step two is "scenario development." This involves developing combinations of various actions on coal plants and assessing replacement generation (i.e., developing "Capacity Portfolios"), and testing the feasibility of approaches for reducing emissions while maintaining reliable service.

Step three is "dispatch modeling of scenarios." This requires the company to use its "dispatch modeling" capability to evaluate the effects of various scenarios on the company's entire system.

Finally, step four involves the development of sensitivity analyses. At this step, the company performs analyses by varying certain key assumptions to see how the scenarios it developed and modeled under Steps 2 and 3 would perform in different futures.

As Commissions and other decision makers around the country evaluate the readiness of their utility companies and electric generators to comply with the

EPA's forthcoming public health and environmental rules, they can draw upon lessons and insights from the Colorado Clean Air – Clean Jobs example. The overall undertaking required cooperation between the regulatory commission and Colorado's environmental regulator, and significant effort by Xcel. The process, including a commission investigation, company analysis of alternative compliance strategies, issuance of a final order, and subsequent adoption of changes to Colorado's SIP occurred in less than eight months, demonstrating the feasibility of such a cooperative effort and the ability of decision makers to address the challenges related to maintaining system reliability while responding to health and environmental regulatory compliance challenges.

While worst-case scenarios serve a purpose of "bounding" broad statistical modeling efforts, it is important to recognize that such scenarios typically do not get implemented.

Gathering Data

Effects on Existing Capacity

The first step companies should undertake is to acquire relevant and current data. Companies will need to identify which of their existing or planned generation units may be affected by forthcoming EPA regulations. Recent nationwide studies reviewing potential capacity retirements due to forthcoming EPA regulations suggest potential effects on existing resources and possible retirements ranging from 25 to 76 GW by 2020[105] (see Table F). Actual impacts, however, will depend on local conditions and choices that companies and regulators make.

Generally these studies identify either the EPA's 316(b) or Mercury/Air Toxics Rules, or a combination of both, as having the greatest potential to affect plant retirement decisions across the country. They suggest that the CCR and CATR rules can be expected to create additional but lesser effects. It is important to remember, however, that because the EPA had yet to propose the 316(b) or MACT rules (and only proposed them in March 2011), these earlier studies listed in Table F were required to make a number of assumptions about key components of these rules. Accordingly, many drew conclusions based on assumptions that turned out to be quite different than the actual rules that were later proposed by the EPA. In addition, many of the power plants they have identified for retirement are very old, small, or uneconomic and thus may be closed by 2020 with or without new federal regulations.

While worst-case scenarios serve a purpose of "bounding" broad statistical modeling efforts, it is important to recognize that such scenarios typically do not get implemented. The actual EPA regulations— especially the Mercury/Air Toxics Rule and 316(b) rules — contain far more compliance flexibility than most modeling studies assume. The NERC worst-case scenario for the 316(b) rule, for example, projects the need to construct closed-cycle cooling systems at every thermal power plant in the country with an effect on "252 GW (1,201 units) of coal, oil and gas steam generating units across the United States, as well as approximately 60 GW of nuclear capacity (approximately a third of all resources in the U.S (sic))."[108] In its proposed regulation, however, the EPA does not specify more expensive closed-cycle cooling for existing units, and estimates that fewer than 700 facilities will be affected.

Likewise, NERC's worst-case scenario for the Mercury/Air Toxics Rule assumes the rule would apply to "all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 of new planned coal units)" [sic],[109] while EPA estimates are lower (approximately 1,350 coal and oil-fired units at 525 power plants). The October 2010 NERC study assumes that scrubbers, SCR, and carbon injection will need to be installed in power plants, while the EPA's proposed Mercury/Air Toxics Rule contains an extensive number of more flexible compliance options for controlling hazardous air pollutants, many of which are available at lower cost than presumed in the modeling studies. So, despite the value of broad, nationwide analyses, it will be critical for companies and regulators to ascertain

105 Miller at i.

106 (next page) Based on Miller at 14, which, in turn, is based in part on: The Brattle Group, "Potential Coal Plant Retirements under Emerging Environmental Regulations," The Brattle Group, Cambridge, MA (December 8, 2010) p. 11. Available at http://www.brattle.com/_documents/uploadlibrary/upload898.pdf.

107 (next page) Although the M.J. Bradley Study recognizes the presence of additional water, solid waste, and greenhouse gas rules.

108 *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (NERC Study), NERC, October 2010 at iv.

109 Id. at 50.

85

precisely which units will actually be affected.

In establishing the extent to which local generation resources may be at risk due to pending public health and environmental regulations, utility regulators may want to first determine which generating units are already uneconomic. For example, in its March 2010 "State of

Table F

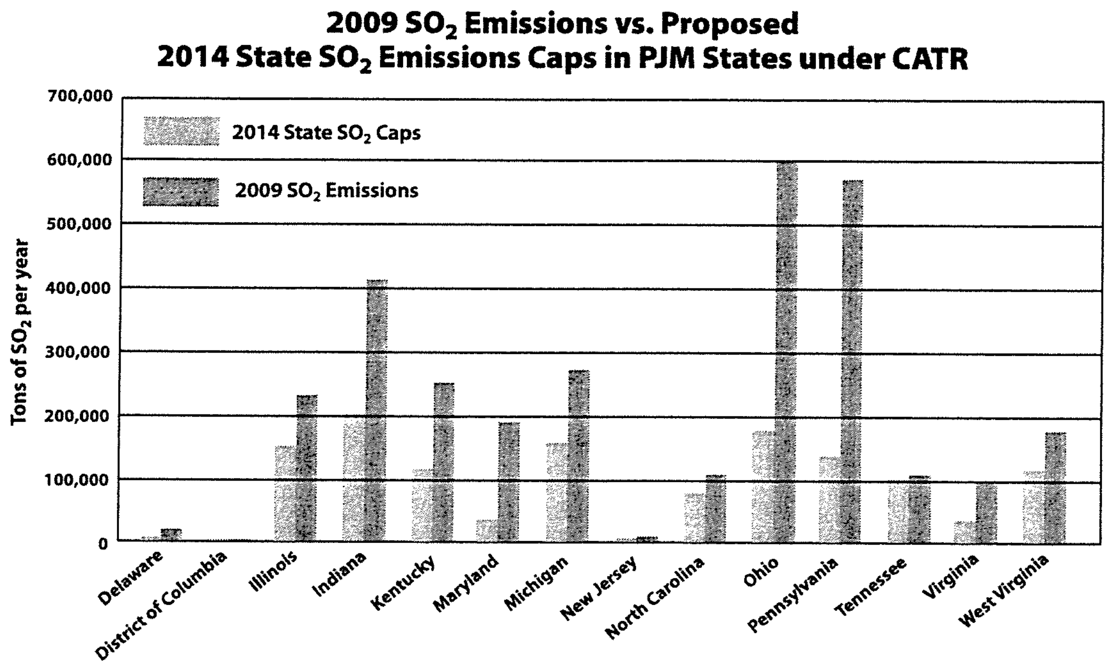
Comparison of Studies Projecting Amount of Coal Capacity at Risk for Retirement in Response to Future US EPA Regulations[106]

Study	Projected Coal Capacity to Retire or at Risk	Criteria to Identify Coal Capacity at Risk	Rules Considered (Proposed or Potential)
The Brattle Group, *Dec. 2010*	50-65 GW by 2020	***Regulated units:*** 15-year present value of cost > replacement power cost from a gas combined cycle or combustion turbine; ***Merchant units:*** 15-year present value of cost > revenues from	Transport Rule Utility MACT 316(b) Cooling Water Coal Ash
Charles River Associates *Dec. 2010*	39 GW by 2015	In house model (NEEM) optimizing costs of existing capacity and costs of potential new capacity	Transport Rule Utility MACT
NERC, *Oct. 2010*	46-76 GW by 2018 (total fossil fuel capacity, including oil and gas)	Levelized costs (@ 2008 CF) after retrofitting each unit for the environmental regulations compared to the cost of a new gas-fired unit	Transport Rule Utility MACT 316(b) Cooling Water Coal Ash
ICF, *Oct. 2010*	75 GW by 2018	Unknown	Unknown
Credit Suisse, *Sept. 2010*	60 GW	Size and existing controls	Transport Rule Utility MACT
Clean Energy Group, *August 2010 (relied upon ICF/IEE, May 2010, and others)*	25-40 GW by 2015	Age, efficiency, cost of alternative supply	Transport Rule Utility MACT[107]
Bernstein Research, *July 2010*	Net loss of coal generation 181 million MWh (291 million MWh by 2015 reduced by 110 million MWh of new coal to come online in the next five years)	Assumes approx. half of states subject to Transport Rule have emissions budgets suggesting emissions rates of 0.36 lbs/MMBtu or less, implying widespread need for scrubber installation, and further, that most of the generation in these states that falls into this category is unscrubbed coal plants smaller than 200 MW (approx. 24 GW). Presumes MACT standard requires installation of SO_2 scrubbers.	Transport Rule Utility MACT
ICF/INGAA, *May 2010*	50 GW	Age, efficiency, and existing controls	Unknown
ICF/IEE, *May 2010*	25-60 GW by 2015	Cost of retrofitting coal plant compared to cost of new gas combined cycle	Unknown

the Market Report," PJM's Independent Market Monitor identifies 11 GW of coal units at risk because they "did not recover avoidable costs even with capacity revenues."[110] In traditionally regulated markets, commissions will need to engage with individual companies and make this inquiry, although they may have relevant data from recent rate cases or other litigation.

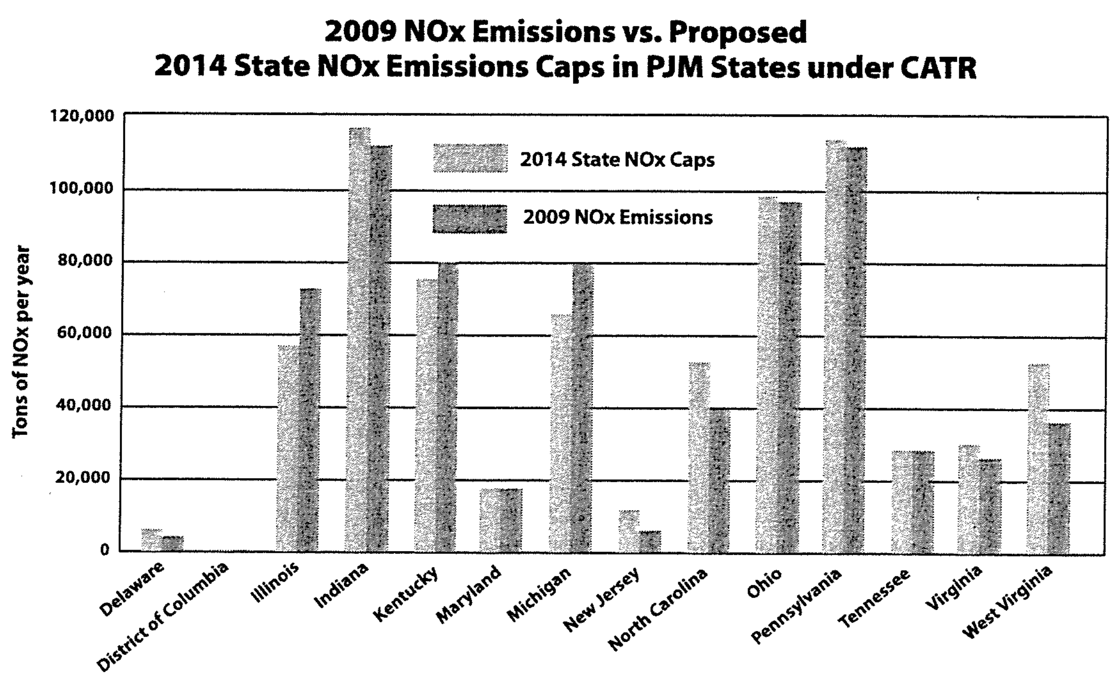
Part of establishing a list of the facilities that are likely to be affected will require a determination of what controls are already in place and how they are relevant for compliance

Figure 9[111]



In traditionally regulated markets, commissions will need to engage with individual companies and make this inquiry, although they may have relevant data from recent rate cases or other litigation.

Figure 10[112]



110 M.J. Bradley at 20, citing to PJM, *State of the Market Report*, Vol. 1, March 11, 2010, at 21.

111 Adapted from "Thinking about Potential Reliability Consequences in PJM from Forthcoming EPA Rules" and comments of Paul M. Sotkiewicz, Ph.D., Chief Economist, PJM Interconnection, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multimedia/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a.

112 Id.

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under programs being proposed. For example, the relatively stringent SO_2 limitations in CATR are expected to drive investment decisions, whereas the relatively relaxed NOx limits, on the other hand, may not (see Figs. 9 and 10).

This figure shows that 2009 NOx emissions in 9 of the 14 PJM jurisdictions are already below the proposed 2014 NOx emissions caps that the EPA would impose under CATR.

In further determining which resources will be affected by forthcoming rules, and what actions (i.e., retirement, fuel-switching, or installation of environmental controls) companies may need to take in response, it is important to remember that in the next several years there will be a significant generation surplus across the country.[113] Relying on data in part from NERC's "2009 Long-Term Reliability Assessment: 2009-2018," the Clean Energy Group indicates that "on an aggregate basis across all NERC regions, the electric sector is expected to have over 100 GW of surplus generating capacity in 2013...."[114] (see Table G)

In Xcel's review of Public Service of Colorado's fleet, the company identified eight separate coal units for which the company decided to "take action" (i.e., to retire, control, or switch to natural gas). These units, in general, tended to be older, smaller, and less efficient. They also faced higher fuel costs. Larger and newer coal units with lower fuel costs, and which typically burned Powder River Basin coal (i.e., coal with lower sulfur, mercury, and chlorine content) were targeted for retrofit with emissions controls.

Table G

Estimated Reserve Margins in All NERC Regions:

Adequate Generating Capacity, Clean Energy Group[115]

Region	Projected Reserve Margin in 2013	Cushion Above NERC Target Reserve Margin in 2013
TRE – Texas Regional Entity	23.9%	7.8 GW
FRCC – Florida Reliability Coordinating Council	28.6%	6.1 GW
MRO – Midwest Reliability Organization	22.1%	3.2 GW
NPCC – Northeast Power Coordinating Council	24.4%	5.9 GW
RFC – Reliability First Corporation	24.3%	17.1 GW
SERC – Southeast Reliability Corporation"	26.3%	23.9 GW
SPP – Southwest Power Pool	30.3%	7.7 GW
WECC – Western Electricity Coordinating Council	42.6%	35.6 GW
Total		**107.3 GW**

Controls[116]

As companies review their list of generation resources that will potentially be affected by the forthcoming EPA regulations, they will have to assess the range of relevant control strategies available to each. As explained earlier, assumptions about environmental controls are dictated largely by the standards, how they are implemented, the compliance timeframes in the regulations, and the degree of flexibility provided in each rule. CATR will require investment in controls for NOx (Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) and for SO_2 (flue-gas desulfurization (FGD) and dry sorbent injection (DSI).[117] However, according to a Bipartisan Policy Center presentation by James Staudt, the region-wide effort required for compliance with CATR will be a more modest undertaking when compared with the investment and construction associated with the EPA's NOx SIP call and Phase I of its Clean Air Interstate Rule.[118]

113 The EPA Scenario utilized data from NERC's *2009 Long-Term Reliability Assessment* rather than NERC's October *2010 Long-Term Reliability Assessment.* In the more recent NERC report, electricity generation capacity numbers are higher than those relied upon in the *EPA Scenario.* For example, the *2010 Long-Term Reliability Assessment's* total U.S. "Existing Certain & Net Firm Transactions" (932,071 MW) exceed the same figures from the *2009 Long-Term Reliability Assessment* (925,336 MW) by 6,735 MW.

114 M.J. Bradley at 8; "2009 Long-Term Reliability Assessment: 2009-2018," NERC, October 2009.

115 Table 2 Estimated Reserve Margins in All NERC Regions: Adequate Generating Capacity. Id. at 9.

116 See Appendix for a description of environmental controls available for criteria and toxic air pollutants.

117 "Clean Air Act Regulation, Technologies, and Costs," Power Sector Environmental Regulations Workshop, David C. Foerter, Executive Director, Institute of Clean Air Companies (ICAC), October 22, 2010.

The proposed Mercury/Air Toxics Rule contains significant flexibility provisions, including facility-wide and monthly emissions averaging, the use of surrogate pollutants, and fuel-switching to coals with lower mercury or chlorine content. The rule also encourages investment in energy efficiency as a means of mitigating rate effects and lowering consumer electric bills. Units that already have scrubbers can be expected to have less difficulty complying with the Mercury/Air Toxics Rule.[119] They are likely to be able to meet acid emissions requirements and, depending on coal type, may be able to meet mercury removal limits.[120] Un-scrubbed units will need to install electrostatic precipitators (ESPs) or fabric filters for particulates or make use of alternative sorbents such as activated carbon or halogen additions for mercury[121] and dry sorbent injection (e.g., Trona, Sodium Bicarbonate, or Hydrated Lime, i.e., dry-scrubber technologies) for strong (hydrochloric and hydrofluoric) acids.[122]

In the 316(b) rule, the EPA concluded that closed-cycle systems and cooling towers would not constitute the "best technology available" for addressing impingement and entrainment at existing generation facilities. Instead, it proposed an array of alternatives:

> *EPA based the impingement mortality and entrainment (I&E) performance standards on a combination of technologies because it found no single technology to be most effective at all affected facilities. For impingement standards, these technologies included: (1) fine and wide-mesh wedgewire screens, (2) barrier nets, (3) modified screens and fish return systems, (4) fish diversion systems, and (5) fine mesh traveling screens and fish return systems. With regard to entrainment reduction, these technologies include: (1) aquatic filter barrier systems, (2) fine mesh wedgewire screens, and (3) fine mesh traveling screens with fish return systems.*[123]

Depending on the exact subtitles and provisions under which the EPA chooses to regulate residuals, the CCR rule could impose requirements for containers, tanks, and containment building at storage sites. Surface impoundments and landfills, depending on whether they are built before or after the rule is finalized, will be required to meet different land disposal restrictions, including liner requirements. Post-closure requirements will also vary. Subtitle C facilities will be monitored by the State and EPA, and Subtitle D facilities will be self-implementing. There may also be a significant difference between implementation timeframes under the two subtitles. Federal permitting and enforcement under Subtitle C would require 100 percent compliance in a limited timeframe, and under Subtitle D, state enactment and enforcement might take longer.[124] There is also concern that a hazardous waste designation would stigmatize potential beneficial reuses of CCR. That treatment might result not only in tighter regulation of landfills and impoundments, but, due to limited reuse, more material going into them.

In Xcel's case, its engineering department proposed the controls they considered appropriate for the units the company concluded should be controlled for air emissions. On these units, NOx is subject to combustion controls: low NOx burners and "overfire air."[125] The company's analysis also included consideration of how much additional

118 "Surviving the Power Sector Environmental Regulations," James Staudt, Ph.D., The Bipartisan Policy Center's National Commission on Energy Policy (NCEP), October 22, 2010 (Staudt).

119 Id.

120 Id.

121 Id. Activated carbon is more absorbing because it is more porous. This capacity can be enhanced by further treating carbon with a compound that reacts chemically with mercury. Halogen converts mercury to mercuric halide, and this can be absorbed by coal ash and dry flue gas desulphurization solids. Combining halogen and activated carbon also presents a lower cost approach to other sorbents such as bromated activated carbon. See "Options for High Mercury Removal at PRB-fired Units Equipped with Fabric Filters with Emphasis on Preserving Fly Ash Sales," Paradis et al. http://secure.awma.org/presentations/Mega08/presentations/6a-Dutton.pdf; see also NALCO/Mobotec, http://www.nalcomobotec.com/expertise/mercury-control.html

122 Like other sorbents, these are injected into the furnace (i.e., upstream from the particulate removal device). They react with the acid gas and are caught by ESPs or fabric filters.

123 Prepublication version, March 28, 2011 at 30-31, http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf

124 "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 21.

125 Overfire air is also referred to as "air staging," a process that removes air (i.e., limits oxygen availability) from burners early in the combustion process and reintroduces it later on. "Often the physical arrangement dictates replacing the staged air through ports located above the combustion zone; hence the name overfire air is commonly applied to such systems. The layout of a combustion system and furnace, however, may necessitate supplying staged air at the same elevation or below the burner zone, such that [overfire air] is something of a misnomer." "Auxiliary Equipment: Overfire Air Systems" Babcock & Wilcox, http://www.babcock.com/products/auxiliary_equipment/overfire_air_systems.html

reduction would be available through the use of controls such as SCR. This included consideration of capital costs associated with installing these additional controls and also the fixed costs associated with operations and maintenance.

It should be noted that, in addition to gathering data on costs associated with various controls and control strategies, commissions may also want to consider the potential local economic stimulation associated with generator investments in environmental controls.[126] According to a recent study, the CATR and Mercury/Air Toxics Rules will provide

> *[L]ong-term economic benefits across much of the United States in the form of highly skilled, well paying jobs through infrastructure investment in the nation's generation fleet. Significantly, many of these jobs will be created over the next five years as the United States recovers from its severe economic downturn.*[127]

Replacement Capacity/Fuel Switching

It is important for companies to identify their options for replacement capacity. There are numerous alternative capacity options nationwide, including natural gas, renewable resources, and various demand-side resources like energy efficiency, demand-response, and distributed generation.

Natural Gas

The availability and favorable pricing of natural gas over time makes it a significant alternative to certain types of coal capacity, particularly for older units used only seasonally or for meeting peak demands.[128] According to EIA's Annual Energy Outlook 2011 (AEO2011), "typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 93 percent of total coal consumption."[129] However, "[f]or the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices that support increased generation from natural gas in the AEO2011 Reference case."[130]

In addition to the potential for new gas capacity, the nation already has a significant amount of underutilized existing gas capacity. Relying on EIA-860 and EIA-923 data from 2008, M.J. Bradley & Associates reports that coal plants larger than 500 MW were used 67 percent of the time, while gas plants in the same category were used only 35 percent of the time.[131] The same trend exists for plants between 200 and 500 MW: 60/32 percent, coal and gas, respectively.[132] For plants smaller than 200 MW, the split was 45/30 percent coal and gas.[133]

Generally, smaller coal plants are most susceptible to fuel switching for many reasons. First, they have relatively high retrofit costs per megawatt of capacity. Second, they tend to be older units, with lower fuel efficiency, so they are used fewer hours per year, making the retrofit costs per megawatt-hour of energy produced higher still. Third, they have high operating costs due to the staffing requirements that are independent of unit size.

There is also significant new capacity currently being brought online today: "over 55 GW of proposed generation in advanced stages of development in the queue for 2013" across all NERC regions.[134] Most of this consists of renewable and natural gas generation. The electric industry also has experience in bringing on significant amounts of new generation capacity in a short time span. For example, 270 GW of natural gas was added to the grid between 2000 and 2004[135] (see Fig. 11).

126 See "New Jobs, Cleaner Air, Employment Effects Under Planned Changes to the EPA's Air Pollution Rules," CERES, University of Massachusetts Political Economy Research Institute, James Heintz, Heidi Garrett-Peltier, and Ben Zipperer, February 2011, www.ceres.org/epajobsreport

127 Id. at 1.

128 This also assumes continuing community support for extraction practices.

129 AEO2011 Early Release Overview, http://www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf . Annual Energy Outlook (Projections in the Annual Energy Outlook 2011 [AEO2011] Reference case focus on the factors that shape U.S. energy markets in the long term. Under the assumption that current laws and regulations will remain generally unchanged throughout the projections, the AEO2011 Reference case provides the basis for examination and discussion of energy market trends and the direction they may take in the future.) Id.

130 Id. For example, comparing AEO2010 and AEO2011 Reference cases, 2008-2035, EIA reduced its projected prices of domestic natural gas at wellhead (dollars per thousand cubic feet) from $6.35 to $5.46 (2025) and from $8.06 to $6.53 (2035).

131 M.J. Bradley Study at 11, Table 4 – Estimated Utilization of U.S. Coal and Gas Plants (CCGT) by Region (2008).

132 Id.

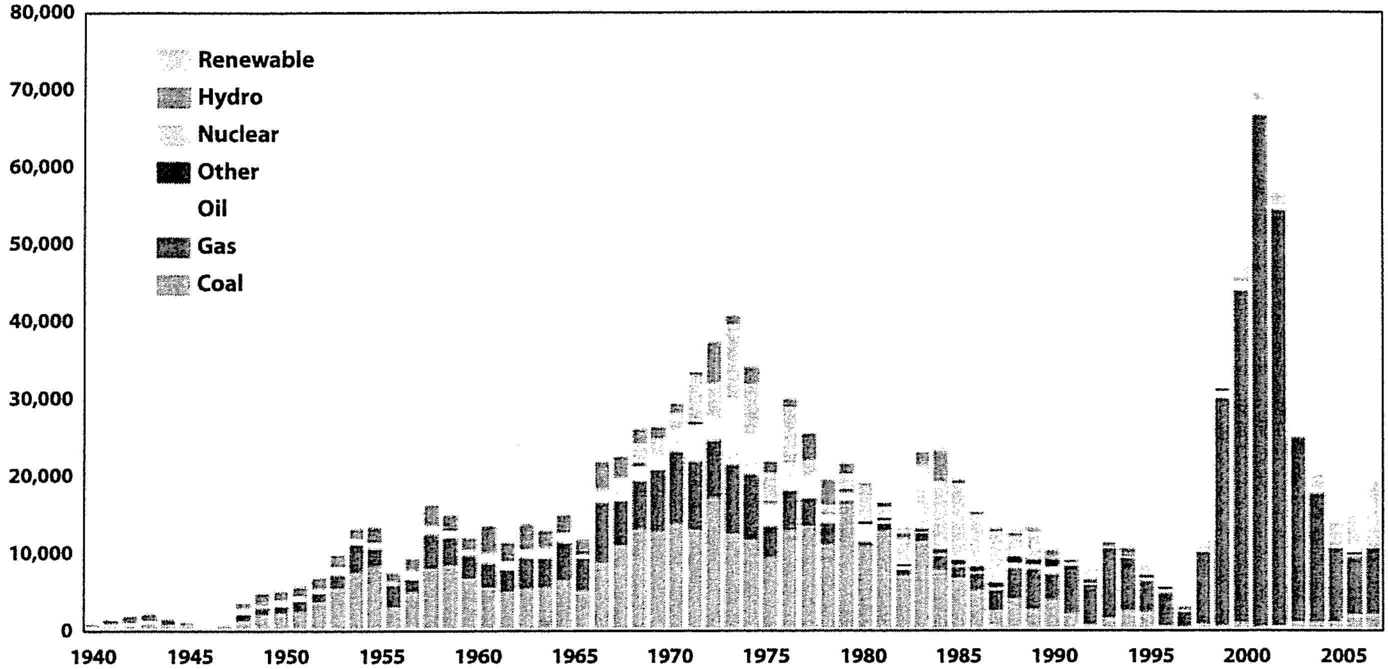
133 Id.

134 Id. at 9.

135 Id. at Fig. 3.

Figure 11

Power Plant Capacity Added by Year it Entered Service. [136]



In this context, there is another attractive aspect of generating electricity with natural gas. Because natural gas generation is not subject to the Mercury/Air Toxics Rule, coal units that switch to gas will, likewise, not be subject to obligations under the rule.[137] According to Charles River Associates, of the 264 GW of coal capacity in the Eastern Interconnection, about 41 GW have access to natural gas pipelines.[138]

Xcel in Colorado analyzed fuel switching to natural gas, and concluded that natural gas combined cycle would be the most suitable candidate for replacement capacity by the company.[139] Their analysis included an assessment of ongoing O&M costs and impacts on heat rates. More specifically, while this sort of switch can eliminate costs associated with coal handling and also reduce associated maintenance costs, there may be an associated heat-rate penalty. To the extent a plant would be retired earlier than its book life, the company also noted that it would want to accelerate the depreciation of the plant's remaining book value. Regulators will need to consider these issues very carefully.[140]

Demand-Side Resources

Demand-side resources can also play a significant role in economically and reliably meeting capacity requirements. These are customer-based resources — energy efficiency, demand response, and distributed generation — that reduce energy needs at various times of the day and year, across a few or many hours. According to M.J. Bradley & Associates,"over the years, the industry has recognized that decreasing load

136 Id. citing to CERES, et al., *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, http://www.ceres.org/Document.Doc?id=600, June 2010.

137 "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT," Charles River Associates, Dr. Ira Shavel, Barclay Gibbs, Charles River Associates, December 16, 2010 at 23.

138 Id.

139 The company also considered renewable resources and demand-side management.

140 See Lazar/Farnsworth paper on Regulatory Treatment of Emission Costs. www.raponline.org/docs/RAP_RegulatoryTreatmentofEmissionsCosts_2011_05.pdf

requirements can be more efficient and economical than increasing supply by dispatching generation."[141]

Energy Efficiency

Energy efficiency avoids load altogether over the lifetime of efficiency measures and can reduce supply capacity challenges. Energy efficiency programs reduce overall customer energy use through investment in more efficient end-use technologies like lighting, pumps, and motors, and also through other conservation measures.[142] M.J. Bradley & Associates reports that, "the total budget for all US ratepayer-funded [energy efficiency and demand response] programs has increased 80 percent since 2006 to $4.4 billion in 2009." Further, they indicate that these programs saved nearly "105,000 gigawatt hours ("GWh") of electricity in 2008," and that by 2018, new energy efficiency programs "are expected to reduce summer peak demands by almost 20,000 MW."[143]

The average cost of energy efficiency investments by utilities is significantly lower than the average cost of generated electricity. Its cost is also generally lower than retrofit and fuel costs associated with continued operation of existing power plants. Efficiency Vermont, for example, reports the average cost for its statewide energy efficiency programs to be 1.1¢ to 4.1¢/kWh.[144]

Demand Response

Demand response (DR) programs are designed "to elicit changes in customers' electric usage patterns."[145] One general approach to DR that can be characterized as "price-based" varies electricity prices to affect existing patterns of customer consumption.[146] "Incentive-based" approaches to DR seek to reward electricity users for reducing their consumption or for granting electricity providers control over a customer's electrical equipment. There are various types of programs within these two broad categories of DR (see Table H).

Table H

Common Types of Demand Response Programs[147]

Price Options	Incentive- or Event-Based Options
Time of Use Rates — Rates with fixed price blocks that differ by time of day	*Direct load control*— Customers receive incentive payments for allowing the utility a degree of control over certain equipment
Critical Peak Pricing — Rates that include a pre-specified, extra-high rate that is triggered by the utility and is in effect for a limited number of hours	*Demand bidding/buyback programs* — Customers receive incentive payments for load reductions when needed to ensure reliability
Real-time Pricing — Rates that vary continually (typically hourly) in response to wholesale market prices	*Emergency demand response programs* — Customers receive incentive payments for load reductions when needed to ensure reliability
	Capacity market programs — Customers receive incentive payments for providing load reductions as substitutes for system capacity
	Interruptible/curtailable — Customers receive a discounted rate for agreeing to reduce load on request
	Ancillary services market programs — Customers receive payments from a grid operator by committing to curtail load when needed to support operation of the electric grid

141 M.J. Bradley at 11.

142 Id. at 15 citing to Consortium for Energy Efficiency, *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts*, 2009, at 7; NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009 at 12.

143 Id.

144 Efficiency Vermont. Year 2010 Savings Claim. April 1, 2011. http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2010_Savings_Claim.pdf

145 "National Action Plan for Energy Efficiency," (2010), *Coordination of Energy Efficiency and Demand Response*, Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein. www.epa.gov/eeactionplan at 2.3 ("Goldman et al. 2010") at 2.2.

146 This distinction is made by Goldman et al. 2010

147 Based upon "Table 2-2. Common Types of Demand Response Programs," Goldman et al. 2010 at 2.3, (citations omitted).

According to Goldman et al, the large majority (over 90 percent) of DR offered in the U.S. is either incentive-based or event-driven and can be invoked in response to "a variety of trigger conditions." These conditions might include, for example, congestion conditions in a power grid or requirements related to operational reliability.[148] The Clean Energy Group reports that demand response in PJM has "increased five-fold in the past five years and continues to grow," and that, in the most recent capacity auction over 9,000 MW cleared.[149] According to the Federal Energy Regulatory Commission (FERC)'s recently released National Action Plan on Demand Response, demand response "tripled in recent years in the New England Region."[150]

Distributed Generation

Generating electricity on the customer premises and in some cases using the generation process's waste heat to serve on-site thermal needs (i.e., combined heat and power, or "CHP") is another demand-side strategy. Between 2005 and 2010, the states added approximately 1,743 MW of new CHP.[151] In addition, grid-connected photovoltaic capacity installed in the residential sector has risen steadily in the past decade, increasing by about four times between 2006 and 2009.[152]

Distributed generation saves not only generation capacity, but also transmission and distribution capacity, the associated line losses, and utility reserve capacity needs. One kilowatt of distributed capacity can replace as much as 1.4 kW of utility central generation.[153]

In Colorado, Xcel also reviewed its options for adding additional renewable resources (wind and solar) and demand side management. More recently, the Commission decided to increase Xcel's proposed energy-savings goals of 7 percent to 30 percent, in part on the basis of the energy-savings potential study developed by the company.[154]

Retirement and Reliability

As companies and others consider the possible retirement and replacement of generation resources, the issue of system reliability arises. Intuitively people may think they understand the term "reliability." After all, most of us drive a car and we know the difference between one that is reliable and one that isn't. So when someone discussing the electric system mentions "reliability," we think we have a general sense of what the person may be talking about.

Strictly speaking, however, reliability "is a measure of the transmission system's ability to meet end-use demand during all hours."[155] According to NERC, the organization responsible for ensuring bulk power system reliability in the U.S., "reliability" "consists of two fundamental concepts:

> *"Adequacy" is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components; [and]*
>
> *"Operating reliability" is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.*[156]

NERC further defines "resource adequacy" as the "ability of the electric system to supply the aggregate electrical demand

148 Id.

149 Id. at note 37 and accompanying text, citing to PJM, *Demand Response To Play Significant Role In Meeting PJM's Higher Summer Peak Electricity Use*, http://pjm.com/~/media/about-pjm/newsroom/2010-releases/20100505-summer-2010-outlook.ashx (accessed August 6, 2010); note 38 citing to "PJM, 2013/2014 RPM Base Residual Auction Results," at 1.

150 Id. at note 36 citing to The Federal Energy Regulatory Commission Staff, *National Action Plan on Demand Response*, June 17, 2010, at p. 7.

151 ACEEE, The 2010 State Energy Efficiency Scorecard, October 2010.

152 Interstate Renewable Energy Council, US Solar Market Trends 2009, July 2010.

153 Jim Lazar, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, The Regulatory Assistance Project, July 2011, http://www.raponline.org/docs/RAP_Lazar_ValuingtheContributionofEE_2011_07

154 "Colorado Utility Commissioners Raise the Bar on Energy Savings for Xcel Energy Customers," Southwest Energy Efficiency Project, March 31, 2011, http://swenergy.org/news/press/documents/PRESS%20RELEASE%20-%20CO%20Utility%20Commissioners%20Raise%20Bar%20on%20Energy%20Savings%2003-31-11.pdf

155 "Resource Adequacy — Alphabet Soup!," Stanford Washington Research Group Policy Research, Stanford Group Company, Electricity Policy Bulletin, Christine Tezak, (Tezak) June 24, 2005, at 2. http://www.hks.harvard.edu/hepg/Papers/Stanford.Washington.Resource.Adequacy.pdf.

156 North American Electric Reliability Corporation (NERC), "Definition of "Adequate Level of Reliability," approved by Operating Committee and Planning Committee at their December 2007 OC and PC meetings, at 5, citations omitted. http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

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and energy requirements of the end-use customers at all times."[157] Resource adequacy standards around the U.S. are set by Regional Electric Reliability Councils for generation adequacy, typically based on a "1-day-in-10-years Loss of Load Expectation."[158]

In practice, determining impacts on reliability is less a matter of broad statistical analysis and more of a focus on local conditions in specific regions and markets.

While much of the recent debate stemming from the NERC Study relies upon the term "reliability," it is actually "adequacy" that NERC modeled in its *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.* Recognizing the limited nature of that analysis, NERC noted that:

> *Resource deliverability, outage scheduling/construction constraints, local pockets of retirements, and transmission needs may also affect bulk power system reliability. While these issues were not studied in this assessment, industry will need to resolve these concerns.*[159]

In practice, determining impacts on reliability is less a matter of broad statistical analysis and more of a focus on local conditions in specific regions and markets. Ensuring the adequacy of transmission so that generation capacity is deliverable without violating reliability criteria is an example of this more localized analysis. It calls for modeling power flows in parts of the grid to determine the specific circumstances under which reliability criteria may be affected.

If a generating unit is critical for maintaining reliability under certain scenarios, it may qualify for reliability-must-run (RMR) status. "RMR contracts are out-of-market contractual obligations paid to a facility that otherwise would meet the criteria for retirement but that the grid operator wants to maintain in order to facilitate reliability."[160] RMR status also entitles the generator to distinct compensation and dispatch practices. RMR is not a permanent designation and alternatives to meeting reliability standards are encouraged.[161] Market participants also argue that the extensive use of RMR contracts constitutes a barrier to the entry of new (transmission or supply) resources, unnecessarily prolonging the lives of less efficient and dirty resources.[162]

157 NERC Glossary of Terms Used in Reliability Standards, April 20, 2009, at http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf. http://www.raponline.org/docs/RAP_Gottstein_Schwartz_RoleofFCM_Experienceand-Prospects2_2010_05_04.pdf.

158 Tezak at 2. See ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, Effective Date: March 5, 2010.

Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.

a. The possibility that load forecasts may be exceeded as a result of weather variations.
b. Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.
c. Due allowance for scheduled outages and deratings.
d. Seasonal adjustment of resource capability.
e. Proper maintenance requirements.
f. Available operating procedures.
g. The reliability benefits of interconnections with systems that are not Governance Participants.
h. Such other factors as may from time-to-time be appropriate.

159 NERC Study at 6.

160 Tezak at note 11.

161 Reliability must run status, however, is not permanent. See, e.g., FERC, Docket 133 FERC ¶ 61,230, Order ER10-2477-000, December 16, 2010. In this order addressing contentions associated with the results of New England ISO's Forward Capacity Auction, FERC reviewed the ISO's conclusion that de-listing (i.e., retirement) Salem Harbor Units 3 and 4 would "jeopardize the reliable operation of the bulk power system and would result in violations of the criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), or ISO-NE." Id. at 5. FERC acknowledged that the ISO Tariff requires ISO-NE to "identify alternatives to resolve" the reliability need for a rejected de-list bid and identify "the time to implement those solutions" with the Reliability Committee "prior to the start of the New Capacity qualification period" for the next Forward Capacity Auction." Id. FERC ordered ISO-NE to submit a compliance filing "identifying alternatives to resolve the reliability need for Salem Harbor Units 3 and 4 and the time to implement those solutions," or to provide "an expedited timeline for identifying and implementing alternatives" Id. at 11.

162 Tezak at note 11.

Plant Retirements in Organized Markets and in Traditional Service Territories

In organized markets like PJM or the New England ISO, electric generation is made available through resource auctions and the establishment of economic merit order. For example, in New England's forward capacity market, in order to get paid, a generator needs to submit a bid for its unit, and that bid must clear through the auction. Once the bid is successful, i.e., the generator has a position and a price, the generator must deliver the resource for the time and the capacity bid. If the generator fails to deliver on its bid, it could face a penalty, and certainly would forego revenues for capacity it has failed to deliver.

In this context, retirement, in effect, is removing a unit from a current or future auction, and is referred to as "de-listing." In the New England ISO's Forward Capacity Market, existing resources are able to leave the market by submitting a "de-list" bid. All de-list bids are subject to a reliability review by the ISO. If the ISO concludes that the unit submitting the de-list bid is needed for reliability purposes, the bid is rejected and the resource is retained.[163a]

Retirement works differently in traditionally regulated markets, such as in Colorado like Public Service of Colorado's service territory. As part of its decision-making under the Clean Air Clean Jobs Act, for example, Public Service of Colorado the company relied on its own dispatch models and reviewed options across its system to "take action," i.e., either to retire, control, or fuel switch a unit to natural gas. This was generally the case across the country before organized wholesale markets were established in the mid-1990s. Companies might pool their resources in a less formal manner, but generally speaking, there was no affirmative obligation to offer any particular unit for service. Instead, companies would have what was referred to in New England as a "capacity responsibility" and would have had to make a demonstration that they had sufficient capacity to meet their responsibility in the pool. In traditionally regulated markets, if the company wants is relatively free to retire a unit and replace it with another, the company does so, subject to reliability demands, and to any additional constraints that might be included in a generator's certificate of public convenience granted by a state commission.[163b]

In Xcel's analysis of Public Service of Colorado's system, the company determined that the existing transmission system and the units targeted for replacement posed distinct challenges for the company and dictated Xcel's "feasible" capacity replacement options. The capacity that was most suited for retirement (approximately 700 MW) was located in the Denver metro area (a significant load pocket), and the 230 and 115 kV transmission system serving the area was, in many respects, built around this capacity. So it was critical, were these plants to be retired, to maintain appropriate voltage and frequency on the transmission grid.

It is this additional reliability analysis that must occur at the local level, and at a level of detail that recognizes specific plants — generation that is being retired or retrofitted or is being brought on by new market entrants. The key focus in this effort is the location on the transmission system of each of the resources that may be affected.[164] As noted by PJM economist Paul M. Sotkiewicz, resource adequacy in the "global sense" is one thing, but where and when actual units may retire and new entrants actually appear is important to determine.[165]

163a. See ISO New England Inc. 5th Rev. Sheet No. 7308, FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design Tariff at Section III.13.2.5.2.5. "The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules." Id.

163b In Vermont the certificate is a "certificate of public good." See, e.g., 30 V.S.A. Section 231(b). "A company subject to the general supervision of the public service board under section 203 of this title may not abandon or curtail any service subject to the jurisdiction of the board or abandon all or any part of its facilities if it would in doing so effect the abandonment, curtailment or impairment of the service, without first obtaining approval of the public service board, after notice and opportunity for hearing, and upon finding by the board that the abandonment or curtailment is consistent with the public interest.... provided, however, this section shall not apply to disconnection of service pursuant to valid tariffs or to rules adopted under section 209(b) and (c) of this title." Id.

164 This is a theme raised by PJM economist Paul M. Sotkiewicz in his presentation to the Biapartisan Policy Center on December 7, 2010. See "Thinking about Potential Reliability Consequences in PJM from Forthcoming EPA Rules" and comments of Paul M. Sotkiewicz, Ph.D., Chief Economist, PJM Interconnection, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multi-media/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a.

165 Id.

While the retirement of a small unit may not make much of a difference from a broader statistical perspective, from a transmission reliability point of view, it may make a significant difference.[166]

This again illustrates where demand response and energy efficiency may play a very important role. Both types of resources can be deployed quickly, and can be targeted geographically. If the economic decision is to retire a small, older generating unit, a premium value can be ascribed to distributed resources in the market and transmission area served by the retiring unit. So-called "efficiency power plants" have been developed in several regions of the world, and can often replace existing or new generation at considerable cost savings and emission reductions.[167]

Going forward then, as commissions assess the engagement of their utility companies on these issues, commissions will want to ensure that utilities develop and integrate relevant and current data regarding applicable health and environmental regulations, options regarding generation units that are candidates for action, emissions control strategies, replacement capacity, demand-side alternatives, and any specific transmission constraints or reliability challenges.

While state regulators have authority to affect rate-regulated utilities and their generation resource decisions, utility commissions do not have the same influence over decisions being made by merchant generators, especially vulnerable ones (for whatever reasons) whose retirement decisions could affect system reliability. As noted in the following section, the FERC and the EPA have indicated that they are attempting to work together to address, among other things, reliability implications of the EPA's forthcoming rules. The potential coordination between the EPA and the FERC was one of the subjects raised by recent inquiries of the FERC from Congress.[168] It is currently unclear what effect these inquiries will have on the possible development of a FERC/EPA relationship, joint agency solutions to reliability issues associated with merchant generation, and on the potential for producing least-cost solutions to the EPA's implementation of these public health and environmental regulations.

Developing Scenarios

After gathering current data on affected units, emissions control options and strategies, unit retirement and decommissioning alternatives, replacement generation, and transmission system reliability, companies can start to assemble scenarios for modeling that simulates future company actions.

In Colorado, the Act required Xcel to first examine a basic scenario referred to as the "benchmark" or "all controls" case that required the company to install NOx controls on all affected generation to achieve 70 to 80 percent reductions. This "starting point" scenario contained no flexibility to consider potentially less expensive options (e.g., fuel switching to natural gas).

The NERC Study, published in October 2010, relied upon a similar "all controls" approach for all the EPA rules: 316(b) (closed-cycle cooling), Mercury/Air Toxics (FGD/SCR/filter systems/activated charcoal injection), Clean Air Transport Rule (FGD/SCR), and Coal Combustion

166 Id. It should be noted that, on this topic M.J. Bradley wrote:

> [T]he retirement of some existing generating capacity will create room on the transmission grid to accommodate additional power flows, or new generating capacity, without requiring attendant upgrades in transmission, thus mitigating reliability concerns while reducing the cost of transitioning to a cleaner, more efficient generation fleet.
>
> M.J. Bradley at 5.

167 "Energy Efficiency Power Plants: A Policy Option for Climate-friendly Air Quality Management in China "Energy Efficiency Power Plants: A Policy Option for Climate-friendly Air Quality Management in China," http://www.raponline.org/docs/RAP_EPPandAirQualityinChina_2009_11_30.pdf; see also "China's Energy and Environmental Challenges, Committee on International Relations," Frederick Weston, NARUC Winter Meetings, 17 February 2008, http://www.google.com/search?q=weston+NARUC+china&ie=utf-8&oe=utf-8&aq=t&rls=org.mozilla:en-US:official&client=firefox-a.

168 On May 17, 2011, Senator Lisa Murkowski sent a letter to FERC Chairman Jon Wellinghoff expressing her concern over the possible effects of forthcoming EPA rules.

> http://murkowski.senate.gov/public/?a=Files.Serve&File_id=88bd8af0-a3e3-4f98-82fd-2af961f312b0. On May 9, 2011 Congressmen Fred Upton, Ed Whitfield, and Cliff Stearns sent a letter to Steven Chu, the Secretary of the Department of Energy (DOE) and to FERC's Chairman Wellinghoff seeking, among other things, information on EPA coordination with DOE and FERC. http://republicans.energycommerce.house.gov/Media/file/Letters/112th/050911ChuandWellinghoff.pdf.

Residuals (various types of containment systems). The NERC Study applied the "all controls" assumption to determine compliance costs and resulting retirement or retrofit choices for generators nationwide. It retired generation units if its assumptions about compliance costs, fixed current O&M costs, and variable O&M costs (including cost of fuel) exceeded replacement costs. It retrofitted a unit if its costs were less than the costs of replacement power.

Beyond this benchmark scenario, Xcel also developed numerous combination scenarios. These included varied mixes of retirement, NOx controls, and fuel switches, and also different amounts of renewable resources (e.g., wind and solar) and demand-side management. Within each scenario, they also developed various portfolios of replacement capacity for possible retirements, and estimated potential portfolio costs through modeling.

Figure 12

Compliance for Existing Resources

Regulation	Timing-Development	Timing-Compliance
316(b)	Proposal March 2011 Final July 2012	8 years to install screens, nets, or to reduce intake velocity; 10 years (fossil units requiring cooling towers); and 15 years (nuclear plants requiring cooling towers.)
Mercury Air Toxics	Proposal March 2011 Final November 2011	3 years from final rule with possible 1-year extension
CATR	Proposed August 2010 Final June 2011	*Annual* SO_2 and NOx, Phase I Jan 2012; Phase II Jan 2014 *Seasonal* NOx Phase I May 2012; Phase II May 2014
CCR	Proposed June 2010 *Final TBD [169]	TBD

Feasible versus Conceivable

Of the many variables that can contribute to the development of a scenario, regulatory compliance deadlines, transmission/reliability concerns, and construction scheduling play a significant role. In Colorado, these limitations prescribed by the Act caused Xcel to conclude that not all of its "conceivable scenarios" would be "feasible scenarios." For example, the December 31, 2017 NOx reduction deadline under the Act had to be factored into each scenario. Schedules for facilities removal and replacement and controls installation had to fit within the December 2017 time frame, or else the scenario was rejected.

Compliance timelines set by EPA regulations should have a similar effect on companies as they develop scenarios. As noted in Fig. 12 while dates for final CCR and 316(b) regulations are uncertain, CATR and the Mercury/Air Toxics Rule will be finalized in June and November of 2011, respectively. CATR compliance will be phased. For annual SO_2 and NOx, Phase I compliance is expected in January 2012, and Phase II in January 2014. For seasonal NOx, Phase I compliance is expected in May 2012, and Phase II in May 2014. Existing sources under the Mercury/Air Toxics Rule are required to meet standards within three years of the publication of a final rule, with the possibility of a one year extension.

The analysis of additional transmission needs will be a critical part of scenario development. For a scenario to be deemed feasible, it must first pass the reliability test. Questions that will need answers include: where are plants located relative to load; how will reliability needs be met during retirement and construction periods; and what specific impacts will retirements have on voltage and frequency support?

All scenarios considered by Xcel had to ensure that the company could maintain reliability. Of the various scenarios that it developed addressing reliability requirements, the

169 The final rule deadline is likely to be revisited: "EPA Administrator Lisa Jackson had originally sought to issue a final rule in 2011 but she told a March 3, 2010 House Appropriations Committee interior panel hearing that a final rule is unlikely in 2011 given the work involved in processing more than 450,000 public comments on the proposed rule." "Inside EPA," April 5, 2011. http://insideepa.com/201104052359945/EPA-Daily-News/Daily-News/industry-says-epa-risk-assessment-fails-to-justify-strict-coal-ash-rule/menu-id-95.html.

company ultimately identified nine feasible scenarios. For each of these, Xcel identified multiple generation portfolios to replace retired capacity, causing the number of scenarios to grow quickly.[170]

The ability to schedule construction necessary for installing environmental controls will be a project-specific inquiry. Companies will need to consider this as they develop compliance scenarios. There are differing views about how an increase in demand for controls installation will affect the construction industry or the amount of constraint that it should place on potential scenarios. In its October 2010 study, NERC made assumptions about industry practices and industry's ability to meet compliance deadlines, noting that, "considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort will occur…."[171] As noted, NERC had not seen either of the proposed Mercury/Air Toxics or 316(b) rules when it issued its study; the EPA would not issue them for another 5 months. So it is not clear what NERC would conclude about the construction timelines implicated by the actual rules that the EPA proposed.

The Institute of Clean Air Companies (ICAC), articulates a more optimistic message about the ability of industry to meet the construction demands raised by the EPA's proposed regulations. David C. Foerter, Executive Director of ICAC, is very encouraging in his response to Senator Thomas Carper's inquiry as to whether or not "the availability of labor might constrain the industry as it seeks to comply with interstate transport [i.e., CATR] and utility MACT rules."[172] Foerter is confident in "the ability of . . . industry to deliver and satisfy … the labor, materials and resources needed to meet the demand."[173] According to Foerter, this is due to (1) over a decade of industry experience, (2) the "extent of controls already installed at existing coal-fired power plants," and (3) the availability of "less capital intensive control technology options available to the industry that can be implemented in a shorter period of time." He adds that currently the air pollution control industry "is in a period of underutilization as compared to the NOx SIP Call and CAIR Phase I years" (i.e., 2000-2010).[174]

Regardless of the precise degree to which the industry around the country will be able to respond to the construction demands necessary for installing environmental controls, it is important to recognize the potential for challenges associated with construction scheduling.[175] Given the actual implementation and compliance schedules adopted by the EPA and the precise control technologies that are chosen by particular resources (and whatever relevant construction industry information is available), this will be an important issue for regulators to monitor and for companies to model.

Numerous factors will be considered and be weighed differently among various companies as they consider the merits of various resources, strategies, and develop

170 Of the combinations of these options, the company identified one of these as its preferred scenario. CO PUC Docket No. 10M-245E, Decision No. C10-1328, December 9, 2010, Finding 56 at 23.

171 See EPA Scenario at V. NERC further notes that "compliance costs are based on current average retrofit costs with existing technology," and that the "assessment does not evaluate the compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects." Id. at 6, 9, and 49. To reflect this concern, NERC performed an additional sensitivity comparison for the 2015 Strict Case for MACT that goes beyond the Strict Case assumption of a 25 percent increase in cost for third-party engineering services to reflect potential for "compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects." Id. at 6, 9, and 49. See Figure 6: "Sensitivity of Retirements Plus Derated Capacity as a Function of Higher Assumed Costs due to MACT Regulation." It should be noted that NERC does not include estimates of lower cost strategies as alternatives to back-end compliance technology or reduced costs associated with resulting economies of scale resulting from greater use of certain compliance technologies.

172 Letter of Senator Thomas Carper to David Foerter, Executive Director, Institute of Clean Air Companies, October 6, 2010 (ICAC Letter).

173 Id. at 1.

174 Id. at 2.

175 See, e.g., comments of Steve Fine, Vice President, ICF International, in regard to 2000-2004 post SIP-call SCR installation costs, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multimedia/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a. It is not unusual for models to include a "congestion" function that recognizes some level of increase in construction activity and the associated potential for increased costs. See comments of Howard Gruenspecht, Deputy Administrator of EIA, regarding capability of EIA's NIMS model. Id.

176 Lazar at 73.

scenarios. As mentioned earlier, an optimal mix of resources is one that will be "cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[176]

Modeling

Modeling allows a company to test the data it has developed and the various scenarios it has assembled. After putting together a set of feasible scenarios, companies can use their modeling capacity to determine costs of various scenarios implemented on their system. They can also develop a sense of how their system would react under various scenarios.

Relying on its own dispatch models, Xcel reviewed the company's ability to dispatch its own resources and purchased generation assets to meet its customer load. It used its models to represent both the existing system and least-cost generic resource techniques to represent what it considered would be the future system, including forecasts of energy, demand, fuel prices, and operations and maintenance costs

Xcel's modeling also looked at the economic dispatch implications of meeting load under each scenario. At the same time the modeling tracked numerous factors (e.g., fuel, O&M, capital, emissions costs, emissions levels, and total power supply system costs) and reported the present value of each of these costs within different time windows (e.g., 10 years, 20 years, 35 years).

Each scenario would report the present value of total power supply system costs. The shorter term (10 years) would be more certain and the longer terms (20 and 35 years) less so. These different views provide Xcel with a sense of the relationship between potential near-term and longer-term costs and benefits.

Sensitivities

In developing sensitivities, a modeler revisits certain assumptions already modeled and recasts them to see how sensitive the results are to changes in the specific assumptions. For example, one of Xcel's sensitivities assumed and modeled higher construction costs than originally considered. Xcel also revisited assumptions about fuel prices, CO_2 costs, replacement generation costs, and additional renewable resource and demand-side management investments.

Sensitivities can also be used to update assumptions based on the availability of more current information. For example, NERC's Study utilized used data from its own *2009 Long-Term Reliability Assessment* (2009 LTRA) rather than its *2010 Long-Term Reliability Assessment* (2010 LTRA). In the more recent NERC report, electricity generation capacity numbers were higher than those relied upon in its *EPA Scenario.* The 2010 LTRA's total U.S. "Existing Certain & Net Firm Transactions" (932,071 MW) exceed the same figures from the 2009 LTRA (925,336 MW) by 6,735 MW.[177]

Similarly, in the 2010 LTRA, NERC's more recent demand numbers are lower than those relied upon in the NERC Study. As demonstrated in Fig. 13 projected future summer loads, for example, are significantly lower than anticipated in earlier forecasts:

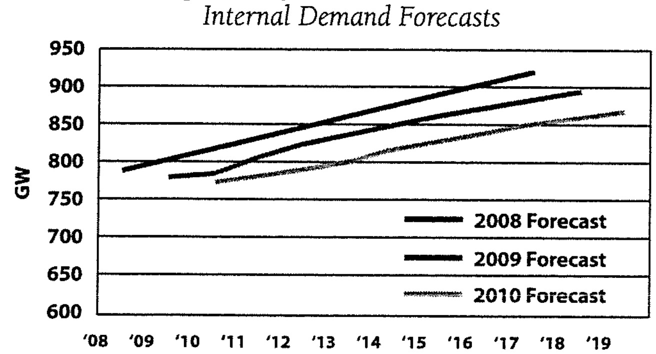
> *A comparison for 2018, the last common year of the two projections, shows that the summer peak demand for the United States is 36,400 MW (or about 4.1 percent) lower than last year's projection. Furthermore, when comparing this year's forecast with the 2008 forecast (pre-recession), the 2017 peak demand forecast is 71,400 MW (or 7.8 percent) less, representing a significant decrease over the past two years.*[178]

This is not to say that NERC should have used its newer data; NERC had to plan this study and conduct it with available (i.e., 2009) data. In both of these instances,

Figure 13

Forecast of Summer Peak Loads[179]

Comparison of U.S. Summer Peak Total Internal Demand Forecasts



177 NERC 2009 LTRA at 397; 2010 LTRA at 30.

178 2010 LTRA at 5; see also Fig. 3.

179 Id.

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however, the supply and demand numbers varied considerably and the effects that they have on the modeling assumptions can likewise be significant. Because Planning Reserve Margins are a measure of "the amount of generation capacity available to meet expected demand in the planning horizon," regulators should note that, all things being equal, had NERC used its own more recent supply and demand data in its *EPA Scenario,* the resulting reserve margins would have been greater and the potential resource adequacy challenge less pronounced.

Another value in conducting sensitivities lies in the ability to test how robust a given scenario is under various futures. For example, it is not clear what effects increased demand for gas will have on supply and demand for non-gas generation. Increased demand for gas could increase the difference between gas and coal prices, which might benefit remaining coal-fired generation and change the retirement economics. In order to test this, a company might revisit coal and gas prices and run sensitivities on them.

Part Three
Potential Next Steps for Commissions

In order to better understand forthcoming EPA regulations and the implications of implementation locally, utility commissions should take the opportunity to explore these and related issues with others, including utility companies, sister state energy and environmental agencies, and federal agencies like the EPA and the FERC.

In fact, commissions may want to consider explicit collaborations with their counterparts in state environmental agencies. These may be informal meetings between staff or commissioners that are general and introductory or more in-depth and topic-focused. For example, energy regulators and environmental regulators use significantly different terminology in their respective processes. An effort to clarify some of these differences (e.g., as a side event at other established meetings) might provide a simple starting point for the development of productive conversations between state energy and environmental regulators. This same approach might be useful with representatives from regional EPA offices and with representatives from commissions in adjacent states, particularly where multi-state utilities and jointly-owned power plants serve adjacent jurisdictions or where there are close inter-state interconnections in power markets.

Meetings might also attempt to go into more depth on the challenges associated with greater coordination between environmental and energy regulators. For example, a better understanding of "State Implementation Plans," (SIPs) a key regulatory tool used by state air regulators, or potential connections between SIPs and utility planning would be useful for utility commissions trying to understand effects of forthcoming EPA regulations.[180] There may be additional approaches for devising solutions across related emissions sources (e.g., "bubbling" of emissions sources under CATR) or possible regional solutions. While air regulators may only be able to address specific pollutant emissions from individual power plants, for instance, utility regulators can guide the expansion of energy efficiency and demand response programs that reduce emissions of multiple pollutants by reducing the underlying load that needs to be served.

In fact, such "multi-pollutant" strategies provide another constellation of issues that commissions could explore with environmental regulators. The general question would be whether there are opportunities for coordination between regulatory programs that might implicate cheaper overall compliance strategies for companies. For example, because certain compliance technologies address more than one pollutant, would it be worth examining the costs and benefits of Mercury/Air Toxics Rule compliance and their relationship with CATR compliance?[181] This type of inquiry could implicate existing regulatory timelines and judgments as to the reasonableness of company investment strategies.

Commissions and environmental regulators could

180 Key principles for air quality planning include:

- Long-term (10-15 years) planning period;
- Integrated air quality modeling and monitoring;
- Monitoring data are part of inputs to air quality models;
- Emissions reductions necessary to attain and maintain the air quality standard;
- Process consistency;
- Quantifiable, enforceable emissions reductions; and
- Effective program oversight.

181 Another example might call for the consideration of compliance issues in the long term and their implications on compliance investment today. For example, in modeling conducted for its recent study, "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT," Charles River Associates took a more stringent approach than NERC and others who have modeled CATR NOx requirements. Rather than adopting the relatively relaxed NOx standards from CATR, Charles River Associates chose to model effects of the current NOx standards in the Clean Air Interstate Rule as a proxy for the likely more stringent NOx standards that may be proposed under CATR II.

also jointly convene face-to-face meetings with key stakeholders, including utilities, independent generators, the energy efficiency industry, and others to gauge likely utility exposure to upcoming regulations and utility preparedness in light of these challenges. Many questions could be addressed as affected parties educate themselves about forthcoming federal/state requirements, as well as each other's expectations, needs, and constraints.

Such meetings could help regulators and companies identify the many general and local issues that are likely to present themselves in the near future. These meetings would also be an opportunity to signal utilities that proactive planning provides the potential for greater choice of compliance alternatives and the potential for lower cost compliance. This would also be an opportunity for companies to gain the support of their energy and environmental regulatory commissions as they move forward.

Commissions may also want to explore working with federal agencies whose programs may be of assistance to state commissions attempting to sort out these challenges. For example, in 2010 FERC released its "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities" Notice of Proposed Rulemaking (NOPR) in which it recognized that:

> *[G]reater regional coordination in transmission planning would expand opportunities for transmission providers, their transmission customers, and other stakeholders to identify and implement regional solutions to local and regional needs that are more cost-effective than those proposed in the transmission planning process of individual transmission providers.*[182]

In the NOPR, FERC proposed a requirement for a "regional transmission planning process [to] consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet … needs."[183] FERC proposed to require both individual transmission providers engaged in local planning as well as regional planning processes to consider "transmission facilities and non-transmission solutions" as part of planning processes.

In requiring the inclusion of "non-transmission solutions" in planning processes, FERC has opened the door for a broader review of alternatives in transmission planning, thereby creating the opportunity to include potentially less expensive measures and potentially cleaner resources that could help states with environmental compliance challenges.

In requiring the inclusion of "non-transmission solutions" in planning processes, FERC has opened the door for a broader review of alternatives in transmission planning, thereby creating the opportunity to include potentially less expensive measures, and potentially cleaner resources that could help states with environmental compliance challenges.

As states develop their understanding of the role of clean energy solutions in meeting the requirements of forthcoming EPA health and environmental regulations, they may want to explore the implications of FERC's interest in promoting non-transmission alternatives as part of regional system planning.

As noted earlier, States may also want to explore the possibility of FERC and EPA developing a joint response to potential reliability challenges associated with possible unit retirements due to the combination of market effects and the effects of EPA regulations on older, smaller, dirtier, and/or economically marginal generation. The EPA and FERC have indicated their intent to model potential effects on electric generation associated with the EPA's forthcoming regulations,[184] but part of that effort might include the development of a mechanism to enable early identification of threats to system reliability associated with potential retirements of generation units. State involvement could also help focus follow-up modeling efforts to optimally address such threats once identified.

Because FERC (through NERC) has authority over system reliability, it could develop a joint protocol with the EPA to address reliability concerns. Under such a protocol, if the EPA were to issue a rule affecting the power sector,

182 FERC NOPR RM10-23-000 (June 17, 2010) at Paras. 51-52.

183 Id. "Non-transmission solutions" include energy efficiency, demand response, distributed resources, fuel switching, and load-center generation.

184 See http://energywashington.com/ The data developed in this process could be valuable as the states go forward with their own inquiries.

utilities or RTOs might have a certain amount of time to indicate whether or not there were actual reliability concerns associated with the rule, and specifically, what aspects of the rule put which plants at risk. Once utilities and RTOs had identified the plants and regions or areas potentially affected and provided supporting information, then FERC could review and verify the claims.

In cases where FERC determines that there could be a genuine reliability issue, the RTO or utility would engage in a process to find substitutes that would address the reliability challenge within a reasonable time, but no later than the timeframe for implementation of the rule itself. The EPA's pending rules, driven by statutory deadlines and judicially derived settlement agreements, provide dates by which generators need to be in compliance. Such a process would be similar to the ones already in place around the country for granting "reliability-must-run" or "RMR" status to generators that would otherwise have to withdraw from the market due to economics.

Conclusions

The EPA's current development of public health and environmental rules will have a significant impact on the electric sector. Due to the extensive reach of environmental regulations, energy regulators will need to work more closely with environmental regulators as utility resource planning decisions are explored. Never before has building understanding between utility commissions and their sister regulatory agencies been so important. By engaging with utilities and with other regulators, utility commissions will be better suited to evaluate a wider array of potential futures, thereby identifying the most affordable compliance scenarios associated with various EPA public health and environmental regulations.

Appendix 1
Acronym Glossary

BACT	Best Available Control Technology
BTA	Best Technology Available
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
CCR	Coal Combustion Residuals
CDPHE	Colorado Department of Public Health and Environment
CEMS	Continuous Emissions Monitoring System
CHP	Combined Heat and Power
DR	Demand Response
DSI	Dry Sorbent Injection
EPA	US Environmental Protection Agency
ESP	Electrostatic Precipitator
FERC	US Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FIP	Federal Implementation Plan (see SIP)
GW	Gigawatt
GHG	Greenhouse Gases
HAP	Hazardous Air Pollutants
Hg	Mercury
IB	Illinois Basin
ICAC	Institute of Clean Air Companies
INGAA	Interstate Natural Gas Association of America
IPM	Integrated Planning Model
MACT	Maximum Achievable Control Technology
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NAP	Northern Appalachian
NARUC	National Association of Regulatory Utility Commissioners
NCEP	National Commission on Energy Policy
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operations and Maintenance
PM	Particulate Matter
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RCRA	Resource Conservation and Recovery Act
RMR	Reliability-Must-Run
SCR	Selected Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TL	Texas Lignite
UARG	Utility Air Regulatory Group
WB	Western Bituminous
ZLD	Zero Liquid Discharge

Appendix 2
Controls for Criteria and Toxic Air Pollutants[185]

While some emissions control technology is related to the pre-combustion phase of energy production, most control technology is directed at the combustion and post-combustion phases of energy production. Pre-combustion technologies include products referred to as "engineered fuels" that can have reduced sulfur dioxide (SO_2), spell out like the others (NOx), mercury, and carbon dioxide (CO_2) content and therefore, associated emissions. These fuels include coal "preparation" (cleaning), upgrading (dewatering with heat and/or microwaves), and treatment with additives to alter combustion characteristics. Combustion and post combustion technologies include scrubbers, selective catalytic and non-catalytic reduction, and electrostatic precipitators.

SO_2 and Acid Gas Removal

"Scrubber" is a general term that describes an "air pollution control device or system that uses absorption, both physical and chemical, to remove pollutants from the process gas stream." Scrubbers are also known as flue gas desulfurization or "FGD" systems. They rely upon a chemical reaction between pollutants such as SO_2, acid gases, and other air toxics from flue gases. These systems can be classified as either "wet" or "dry" but both systems employ significant amounts of water in their processes.

In a "wet" scrubber, a liquid sorbent (i.e., absorbing material) is sprayed into the flue gas. Wet scrubber technology can be used in absorbing gases and particulate matter. In the case of SO_2 removal, for example, calcium is used as a sorbent. This reacts with the SO_2, forming into a wet, solid waste by-product that can require additional treatment. New wet scrubbers can achieve SO_2 removal efficiencies of upwards of 90 percent. Scrubbers have been used on coal-fired boilers, significant sources of hydrochloric acid (HCl) and hydrofluoric acid (HF), with removal efficiencies for HCl in the 90 percent range, and HF by more than one-third. Wet scrubbers also help remove arsenic, beryllium, cadmium, chromium, lead, manganese, and mercury from flue gas.

In a "dry" scrubber or FGD process, sorbents are injected in flue gas, producing a dry solid by-product. There are various types of dry scrubbers, but all typically introduce an absorbing material at some point in the combustion process which reacts with the pollutant. The resulting materials, including fly ash, are generally collected downstream in particulate control devices, e.g., an electrostatic precipitator or fabric filter (discussed below).

NOx Removal

Selective Catalytic Reduction (SCR)

SCR is a process for controlling nitrogen oxide (NOx) emissions by reducing NOx to liquid nitrogen (N_2) and water (H_2O) by the reaction of NOx and ammonia (NH_3) in the presence of a catalyst. The process occurs at controlled temperatures within a "reactor" chamber made of certain types of metal, e.g., titanium or platinum. SCR technology can provide reductions in NOx emissions in the 90 percent range.

Selective Non-Catalytic Reduction (SNCR)

SNCR relies on a chemical process and high temperatures that changes NOx to N_2 similar to SCR, but

185 Based on information found at "Pre-Combustion Technologies: A Key Environmental Compliance Tool," Jason Hayes "Power," Februrary 1, 2011, http://www.powermag.com/coal/Pre-Combustion-Technologies-A-Key-Environmental-Compliance-Tool_3401_p2.html; "Acid Gas/SO2 Control Technologies," "NOx Controls Technologies," and Particulate Controls, ICAC, http://www.icac.com/i4a/pages/index.cfm?pageid=3398; Maxon Corporation, https://www.maxoncorp.com/Pages/product-Low-Nox-Burners; for additional information on cost of environmental controls, see "Environmental control costs and the WECC Fleet—Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls," Synapse Energy Economics, Inc. Jeremy Fisher, Bruce Biewald, January 23, 2011.

without the use of a catalyst. Typically, ammonia or another "reagent" is introduced into hot flue gas under controlled temperatures and converts the NOx into nitrogen gas and water vapor. The process is referred to as "selective" because it reacts with (i.e., "selects") NOx and does not react with other constituents of flue gas. SNCR is significantly less effective than SCR, but under optimal conditions can reduce NOx levels by as much as 75 percent.

Particulate Removal

Electrostatic Precipitators

An electrostatic precipitator (ESP) uses an electric field to remove particulate matter from flue gas. An ESP creates an electric field that charges particles negatively. These particles pass through "collecting electrodes" that attract them. Electrodes are periodically shaken, dislodging particulate matter that falls into disposal containers.

Fabric Filters

Fabric-filter collectors — also known as "baghouses" — work like sieves. Flue gas passes through tightly woven fabric which catches particulate matter. Fabric filters are capable of 90 percent removal efficiencies over a range of particle size.

Wet Scrubbers and Mechanical Collectors

Particulates can be removed with wet scrubbers and mechanical collectors. Wet scrubbers remove particles found in liquid droplets. Wet scrubbers have removal efficiencies in the 90 percent range for particles larger than 10 microns in diameter. Efficiencies are much lower for smaller particles. Mechanical force can also be used to collect particulate matter more effectively with larger particulates than with smaller (i.e., particles in the range of 2.5 microns in diameter or "PM2.5").

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DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 4

Dominion News

Dominion Sets Schedule to Close Salem Harbor Power Station

- Units 1 and 2 to cease operations by end of this year
- All Salem Harbor units and station to retire on June 1, 2014
- Pending environmental regulations, market conditions led to decision

SALEM, Mass., May 11, 2011 /PRNewswire/ -- Dominion (NYSE: D) will cease operating two of the four units at Salem Harbor Power Station by the end of the year and plans to retire all four units on June 1, 2014, because pending environmental regulations and market conditions are making the power station uneconomical to operate.

Company officials today told ISO-New England, the independent system operator for the region's electric grid, that it will not seek to negotiate an agreement that could keep the station operating beyond existing commitments.

"This was a decision we had to make given the significant costs required to keep the station in compliance with pending environmental regulations and the falling margins for coal stations selling electricity in New England," said David A. Christian, chief executive officer of Dominion Generation. "Salem Harbor employees are dedicated professionals who will continue to operate the station safely as we move toward retirement in 2014."

Dominion has operated Salem Harbor safely, economically and in compliance with existing environmental regulations since it purchased the power station in 2005.

Dominion said last year that it would not invest the funds needed to comply with new environmental regulations that would go into effect in 2014 and beyond. The company would have been required to spend millions of dollars on new controls at the power station to comply with new regulations from the U.S. Environmental Protection Agency.

Dominion last fall submitted a permanent delist bid for all four Salem Harbor units in the ISO-New England's Forward Capacity Auction 5, covering June 1, 2014 to May 31, 2015. ISO-New England rejected that bid and offered a mitigated price that did not guarantee full cost recovery of the environmental controls. In response, the company submitted a non-price retirement bid for all four units in February. On May 10, the ISO informed Dominion that it had accepted those bids for Units 1 and 2, but rejected the non-price retirement bids for Units 3 and 4 because they were needed for system reliability during the FCA5 commitment period.

"We would have been faced with spending millions to comply with new environmental regulations without assurance of full cost recovery before committing to support the ISO's reliability needs," said Christian. "We could not take that risk."

Dominion is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 27,600 megawatts of generation, 11,000 miles of natural gas transmission, gathering and storage pipeline and 6,200 miles of electric transmission lines. Dominion operates the nation's largest natural gas storage system with 947 billion cubic feet of storage capacity and serves retail energy customers in 15 states. For more information about Dominion, visit the company's website at www.dom.com.

SOURCE Dominion

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request TC-02

Dated: 04/29/2011
Q-TC-005
Page 1 of 15

Witness: **Richard L. Levitan**
Request from: **TransCanada**

Question:
Please provide a copy of any presentation made by Levitan related to the NEPOOL capacity market in 2009 and 2010.

Response:
LAI prepared three non-confidential presentations related to the NEPOOL capacity market in 2010, and none in 2009.

Please refer to the web link below for the May 13, 2010 pre-filed direct testimony of Ellen Cool, Boris Shapiro, and Richard Levitan on behalf of the Office of Consumer Counsel in the Connecticut Integrated Resource Plan Review Docket No. 10-02-07:

http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/e70a149570d7b3a9852577e3004ba6fe?OpenDocument

Please refer to the web link below to the Massachusetts DPU File Room, and navigate to Docket 10-132, Volume 1 of the Petition, Part 3 of 12, Attachment 2-1, for the June 1, 2010 LAI report, "Economic Assessment of NSTAR's Third 345kV Transmission Line from Carver to Cape Cod, prepared for NSTAR Electric Company.
http://db.state.ma.us/dpu/qorders/frmDocketList.asp

Please refer to the attached presentation for the November 17, 2010 presentation at the Northeast Energy and Commerce Association Power Markets Conference by Richard Levitan.

Economic Assessment of NSTAR's Third 345 kV Transmission Line from Carver to Cape Cod

Prepared for

NSTAR Electric Company

Westwood, MA

June 1, 2010

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2 EXECUTIVE SUMMARY

Reliability in the Tremont East load subzone has historically been furnished by the dual-unit, 1,095 MW Canal Station. Both units are very old STGs, with vintage dates of 1968 and 1976. The units take a long time to start up, ramp poorly, and cannot be committed in real time. Unit 1 was originally designed for baseload, while Unit 2 was originally designed as a load-following intermediate unit. While Unit 1 burns only RFO, Unit 2 can burn RFO and/or natural gas.

Canal's capacity factor averaged about 50% from 1999 through 2005. Since then, it has plummeted to below 20% in 2006 through 2008. During this period, the majority of Canal's generation was out-of-merit-order, at significant ratepayer cost. In 2008, Canal collected either all or the lion's share of ISO-NE's second contingency uplift payments of $143.4 million in SEMA. These costs have diminished since NSTAR completed its short-term transmission improvements in 2009. Canal was dispatched sparingly in the Day-Ahead Market (DAM), and its capacity factor in 2009 was below 6%.[2] Going forward, LAI forecasts that Canal Unit 2 will continue to operate at a low capacity factor, averaging about 3% in the summer for 2013 through 2022. The capacity factor for Unit 1 is and will continue to be virtually nil. We do not expect either unit to operate at all during the winter. Despite Canal's extremely low capacity factor over the planning horizon, *absent the Project* Canal will be required by ISO-NE to provide second contingency coverage for Tremont East.

For financial support, Canal depends on the Forward Capacity Market (FCM) administered by ISO-NE. Since the first Forward Capacity Auction (FCA), the FCM has cleared at the floor price, and these revenues are further reduced by pro rationing to reflect the surplus of cleared resources. The generation surplus in New England, the entry of renewables and DR, and the recessionary effects on load portend a continuation of the FCM clearing prices at the floor value through 2016. Over the next several years, Canal's financial challenges will be exacerbated by more stringent environmental restrictions, increasing its costs and requiring significant new capital investment. Specifically, we expect that Canal will need to either retrofit its cooling water intake structures with new screens or similar modifications, or it will be required to convert its once-through cooling water system with a capital-intensive, closed loop system and cooling towers.

Using a conservative estimation of Canal's fixed operation and maintenance (O&M) expenses to maintain plant availability, LAI expects that Canal will operate at a significant financial loss over the planning horizon. If we assume the need for minimal environmental upgrades, the present value of the cash operating loss is estimated to be $68 million. If we assume the need for more extensive upgrades, the present value of the cash operating loss is estimated to be $184 million.

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[2] Based upon NSTAR meter data.

Recognizing the units' poor financial performance, Canal could decide to submit a de-list bid. In our opinion, ISO-NE would accept the de-list bid for one unit (and thereby allow one unit to retire), but reject the de-list bid for the second unit needed for reliability, thereby providing Canal with much higher capacity prices than would otherwise be realized as a price taker in the FCM. A rejected de-list bid is equivalent to the formerly negotiated Reliability-Must-Run (RMR) agreements. Hence, throughout this report we refer to above-market compensation achieved through the de-list bid process as equivalent to RMR contracts, or "RMRe" for short.

Under the de-list bid protocol approved by the Federal Energy Regulatory Commission (FERC), a Canal de-list bid would cover Canal's out-of-pocket cash costs and could also include opportunity costs, including both the return of and on capital for any incremental investment to ensure environmental compliance. We estimate that a rejected de-list bid for Canal would result in RMRe payments of between $43 million and $99 million in 2016, depending on environmental requirements and Mirant's de-list bid strategy. Under RMRe, Canal would be entitled to enjoy above-market payments until such time that ISO-NE determines that Canal is no longer needed for reliability.

To meet the reliability criterion for Tremont East, the Project, Canal, or a new, alternative resource is required. We have added up the costs and benefits for a variety of options, summarized in present value form in Figure 1. LAI believes the key comparison here is between the first bar (the Project) and the second bar, with Canal receiving RMRe payments at a breakeven level, assuming retrofit of water intake screens to meet environmental requirements. This alternative would result in present value costs to load $22.9 million higher than those of the Project. Note that, if Mirant were forced to convert to closed-loop cooling, the incremental cost would escalate to $116.1 million, and if Mirant is able to maximize RMRe revenues over the study period, the cost to load could be as much as $247 million above that of the Project.

In reviewing the financial results, three caveats bear brief mention. First, by Project economics we mean net cost to load, that is, the net change in the total cost to serve load when we compare a case with the Project in service against either a reference case without the Project or against an alternative to the Project. Second, Project economics herein are on a region-wide basis. Third, Canal's decision to retire or submit a de-list bid for one or both units may be affected by other commercial and practical considerations associated with the cost of decommissioning the plant, salvage value, employment, and community relations.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 6

TVA TENNESSEE VALLEY AUTHORITY

HOME ABOUT TVA ENERGY ENVIRONMENT RIVER MANAGEMENT ECONOMIC DEVELOPMENT NEWS & ISSUES

TVA Board Sets Path for Environmental Future

April 14, 2011

Utility advances clean air strategy by retiring coal-fired generating units

CHATTANOOGA, Tenn. — The Tennessee Valley Authority announced plans Thursday to retire 18 older coal-fired generation units at three power plants as part of the federal utility's vision of being one of the nation's leading providers of low-cost and cleaner energy by 2020.

The retirements will help TVA reduce emissions of sulfur dioxide, a component of acid rain, by 97 percent from 1977 levels and help reduce emissions of nitrogen oxides, which contribute to smog, by 95 percent from 1995 levels. Previous TVA pollution-control programs already have reduced sulfur dioxide emissions by more than 90 percent and nitrogen oxide emissions by 86 percent.

The retirements, which include about 1,000 megawatts of coal-fired capacity previously slated for idling, mean TVA will have idled or retired about 2,700 megawatts of its 17,000 megawatts of coal-fired capacity by the end of 2017. The capacity will be replaced with low-emission or zero-emission electricity sources, including renewable energy, natural gas, nuclear power and energy efficiency.

President and CEO Tom Kilgore told the TVA board of directors, meeting in Chattanooga, that replacing older and less-economical generation with cleaner sources also is in alignment with recommendations in the utility's Integrated Resource Plan as well as the utility's vision for cleaner air.

The Integrated Resource Plan, which was formally presented to the board of directors at Thursday's meeting, was developed over two years, with extensive business, technical and economic analysis and public input. Kilgore

Fact Sheets

Clean Air Act agreements

Plans for coal-fired generation

Nuclear program updates

Presentation

Board meeting presentation slides

High-resolution photographs

John Sevier Fossil Plant

Johnsonville Fossil Plant

Widows Creek Fossil Plant

EPA Information

Settlement informaiton

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credited a Stakeholder Review Group, consisting of representatives of the political, business, consumer and environmental communities, for providing expertise and viewpoints "that added important perspectives as we formulated our Integrated Resource Plan."

The plan recommends a strategic direction focusing on a diverse mix of electricity generation sources, including nuclear power, renewable energy, natural gas and energy efficiency, as well as traditional coal and hydroelectric power.

"Diversity proved to be the most prudent course in meeting future energy needs in all the various future scenarios we studied," Kilgore said. "A variety of electricity sources, rather than heavy reliance on any single source, reduces long-term risks and helps keep costs steady and predictable."

Because coal constitutes more than half of TVA's current generation mix, Kilgore said replacing older and less-efficient coal units with cleaner sources of power follows the Integrated Resource Plan's advice to further diversify the utility's future power portfolio.

"In the longer term, these actions reinforce our vision to keep bills low, keep our service reliability high and further improve air quality as we modernize the TVA power system," Kilgore said.

The coal-unit retirements announced Thursday include two at John Sevier Fossil Plant in East Tennessee, six at Widows Creek Fossil Plant in northern Alabama and all 10 units at Johnsonville Fossil Plant in Middle Tennessee. TVA announced in 2010 that it would idle units at John Sevier and Widows Creek, as well as one of 10 units at Shawnee Fossil Plant near Paducah, Ky. Idling units shuts them down in stand-by status, while retirement permanently removes them from service under their current operating permits.

"These units are among the first built by TVA and have served us well over the years. But as times change, TVA must adapt to meet future challenges," Kilgore said, adding that installing the expensive emission-control equipment that new regulations would require at the smaller, older plants would not be economical. He explained that other coal-fired units without advanced emission controls also are under consideration for idling and possible retirement or for additional emission-control equipment.

Consistent with the coal-unit retirements, and in alignment with the Integrated Resource Plan and vision for cleaner air, the TVA board also authorized Kilgore to enter agreements with the U.S. Environmental Protection Agency; the states of Alabama, Kentucky, Tennessee and North Carolina; and three environmental advocacy groups to settle ongoing legal and regulatory issues related to Clean Air Act compliance.

TVA has invested more than $5.3 billion since 1977 to reduce coal-fired power plant emissions. With the EPA agreements and its own long-range plans, TVA estimates that it will invest an additional $3 billion to $5 billion in the next 10 years on new emission-control equipment and upgrades of existing equipment at its coal plants.

The agreements with EPA also call for TVA to provide $350 million to fund a number of environmental improvement projects over the next five years. Those include efficiency upgrades to the electric grid; support for energy efficiency enhancements in homes and businesses; assistance to the National Park Service and U.S. Forest Service in restoring and improving lands, watersheds and forests; and aiding reduction of greenhouse gas emissions through efforts such as waste-heat recovery, solar and landfill-gas energy installations.

Also under the EPA agreements, TVA has agreed to pay a $10 million civil penalty to end costly legal proceedings and reduce the risks of much higher costs in the future related to past and potential disputes over regulatory compliance.

TVA's chief operating officer, Bill McCollum, briefed the board on the utility's nuclear operations and on potential implications of last month's nuclear-plant problems in Japan. McCollum told directors that safety is TVA's top priority in designing and operating its plants and that its nuclear program will incorporate lessons learned from Japan into the operations, designs and features of its nuclear plants, including those under construction and projects that are under consideration.

The previously approved construction at Watts Bar Nuclear Plant Unit 2 in East Tennessee and engineering work at the Bellefonte site in northern Alabama are proceeding on schedule. McCollum said TVA staff will ask the board to make a decision on whether to move ahead with construction of a nuclear unit at the Bellefonte site "after TVA has a clear understanding of the Japanese nuclear situation and any potential impact on the project."

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Chief Financial Officer John Thomas told the board that colder weather has increased demand for TVA electricity and fuel expenses since the fiscal year began in October, but uncertainty resulting from the slow U.S. economic recovery and from the Japanese nuclear situation could increase the volatility of TVA's revenue for the remainder of the year. Thomas added that TVA has managed cash flows well and is on track to achieve its fiscal 2011 financial objectives, which include avoiding increases in the base wholesale rate for electricity during the fiscal year.

The board also voted to re-elect director Dennis Bottorff of Nashville as chairman. Bottorff became chairman last year, succeeding director Mike Duncan of Inez, Ky., who stepped down as chairman but remains on the board. The board also named Director William Sansom to serve as vice chairman.

In other business, the board of directors:

- Authorized the CEO to approve certain major contracts for electrical transformers;
- Approved a pilot program for additional customer participation in the Valley Investment Initiative economic development program; and
- Approved de-watering facilities for bottom ash at the Kingston Fossil Plant and for bottom ash and gypsum at the Bull Run Fossil Plant, part of ongoing efforts to convert coal byproducts to dry storage.

The Tennessee Valley Authority, a corporation owned by the U.S. government, provides electricity for utility and business customers in most of Tennessee and parts of Alabama, Mississippi, Kentucky, Georgia, North Carolina and Virginia – an area of 80,000 square miles with a population of 9 million. TVA operates 29 hydroelectric dams, 11 coal-fired power plants, three nuclear plants and 11 natural gas-fired power facilities that can produce about 34,000 megawatts of electricity, delivered over 16,000 miles of high-voltage power lines. TVA also provides flood control, navigation, land management and recreation for the Tennessee River system and works with local utilities and state and local governments to promote economic development across the region. TVA, which makes no profits and receives no taxpayer money, is funded by sales of electricity to its customers. Electricity prices in TVA's service territory are below the national average.

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TVA Newsroom

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request CLF-01

Dated: 02/25/2011
Q-CLF-002
Page 1 of 1

Witness: **Elizabeth H. Tillotson**
Request from: **Conservation Law Foundation**

Question:
Beyond the descriptive text in Sections IX and XII of the LCIRP, has the Company conducted any analysis of the requirements and costs associated with coming environmental regulations, including but not limited to, the following:

a) Clean air Act (CAA) - Best Available Retrofit Technology (BART) – Visibility
b) CAA - Clean Air Transport Rule (CATR) - Ozone and particulates
c) CAA - Maximum Available Control Technology (MACT) - Air Toxics
d) New CAA National Ambient Air Quality Standards (NAAQS)
e) Clean Water Act (CWA) - Cooling water intake structures under section 316(b)
f) CWA - Effluent limitations (NDPES permits)
g) Coal combustion residuals (CCR) rule - RCRA Subtitle "C" or "D" (hazardous or special waste)
h) Greenhouse Gases (GHGs) – CAA Tailoring rule
i) GHGs – CAA New Source Performance Standards (NSPS) for new / modified units under section 111

If not, why not? If so, please identify and provide all such analyses and related documents?

Response:
As part of its Least Cost Integrated Resource planning process, PSNH does not prepare analyses or scenarios based upon possible regulatory rules or outcomes. Since EPA has not issued or recently revised the standards referenced in the question, it is clearly premature for PSNH to have prepared examinations or studies of the new rules. As a result, PSNH has no information that is responsive to the question posed.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request CLF-01

Dated: 02/25/2011
Q-CLF-020
Page 1 of 1

Witness: William H. Smagula
Request from: Conservation Law Foundation

Question:
With regard to hypothetical future environmental requirements that could apply to the Schiller Station, what is the Company's best estimate for the capital costs and operating costs associated with SCR, FGD, cooling towers, and ash storage. Please provide any available documents for these estimates.

Response:
As part of its Least Cost Integrated Resource planning process, PSNH does not prepare analyses or scenarios based upon possible regulatory rules or outcomes.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-012
Page 1 of 1

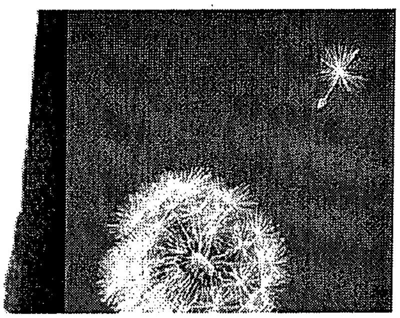
Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

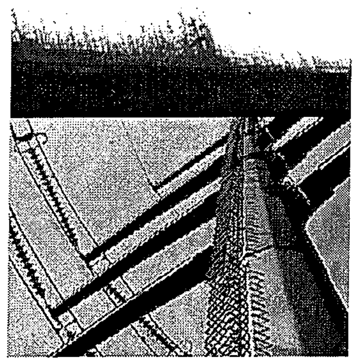
Question:
Referring to OCA 01-050, has PSNH developed estimates of incremental operating or capital costs for any of its generating units in order to comply with potential changes in environmental regulation over the next 5 years? If yes, please provide all such estimates.

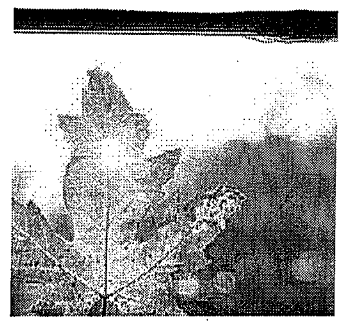
Response:
Potential environmental regulations go through a number of phases as they are proposed, drafted, released, reviewed, commented on and finalized, if they come to fruition. Environmental regulation changes also provide compliance timelines of years to allow utilities to develop a compliance plan, estimate costs, and if necessary, specify, procure, install, and put in service necessary technologies. This approach results in potential changes in environmental regulations having compliance dates and possible incremental costs in out years. PSNH does not prematurely estimate costs of potential changes in environmental regulations.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 10

a legacy of leadership. a promise of growth.







Northeast
Utilities

2010 ANNUAL REPORT

a legacy of leadership. a promise of growth.

Since Northeast Utilities (NU) and its companies were founded, we have built an enduring legacy of delivering reliable energy for our customers, leadership for our industry and value for our investors. We continue to build on that legacy with our support of the efficient use of energy and new clean energy technologies as a foundation for regional economic growth. With a steady hand dealing with today's economic landscape and an eye to the challenges that lie ahead, NU continued to deliver strong operational and financial performance in 2010. As we turned the final pages of the 2010 calendar, we did more than just say goodbye to a year of significant accomplishments for NU. We welcomed the start of a new era. We capped the year with an agreement to merge with Boston-based NSTAR to ensure our position as New England's leading regional energy company, poised to better serve our customers by delivering on a promise of future growth.

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believe is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability. We continue to evaluate the environmental impact of our former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on us for these practices. At December 31, 2010, the liability recorded by us for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $37.1 million, representing 58 sites. These costs could be significantly higher if remediation becomes necessary or when additional information as to the extent of contamination becomes available.

The most significant liabilities currently relate to future clean up costs at former MGP facilities. These facilities were owned and operated by our predecessor companies from the mid-1800's to mid-1900's. By-products from the manufacture of gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose risks to human health and the environment. We, through our subsidiaries, currently have partial or full ownership responsibilities at 28 former MGP sites.

HWP, a wholly-owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal electric utility, in 1902. HWP is at least partially responsible for this site and has already conducted substantial investigative and remediation activities. HWP's share of the remediation costs related to this site is not recoverable from customers.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from EMF associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Although weak health risk associations reported in some epidemiology studies remain unexplained, most researchers, as well as numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies, have concluded that the available body of scientific information does not support the conclusion that EMF affects human health.

We have closely monitored research and government policy developments for many years and will continue to do so. In accordance with recommendations of various regulatory bodies and public health organizations, we reduce EMF associated with new transmission lines by the use of designs that can be implemented without additional cost or at a modest cost. We do not believe that other capital expenditures are appropriate to minimize unsubstantiated risks.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government, particularly in recent years. The EPA has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector. The EPA has mandated GHG emission reporting beginning in 2012 for 2011 emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF-6 gas and methane.

We are continually evaluating the risks presented by climate change concerns and issues. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal "cap and trade" laws, or regulations requiring additional capital expenditures at our generating facilities. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers.

Global climate change could potentially impact weather patterns such as increasing the frequency and severity of storms or altering temperatures. These changes could affect our facilities and infrastructure and could also impact energy usage by our customers.

FERC Hydroelectric Project Licensing

Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, or (ii) the United States may take over the project or (iii) the FERC may issue a new license to a new licensee, upon payment to the existing licensee of the lesser of the fair value or the net investment in the project, plus severance damages, less certain amounts earned by the licensee in excess of a reasonable rate of return.

PSNH owns nine hydroelectric generating stations with a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act and related FERC regulations, including provisions related to the condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment and severance damages and other matters.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request CLF-01

Dated: 02/25/2011
Q-CLF-008
Page 1 of 1

Witness: Terrance J. Large
Request from: Conservation Law Foundation

Question:
Does the Company have a long-term forecast of the market price for energy and capacity in ISONE markets? If not, why not? If so, please identify and provide that forecast and related documents.

Response:
PSNH does not forecast long-term energy and capacity prices because there is no routine business need for such forecasts. In order to do the Newington CUO study, PSNH commissioned Levitan to develop assumptions and do the analysis.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request CLF-01

Dated: 02/25/2011
Q-CLF-009
Page 1 of 1

Witness: William H. Smagula
Request from: Conservation Law Foundation

Question:
Does the Company have forecast of SO2 prices that it used for planning purposes? If not, why not? If so, please identify and provide all such forecasts and related documents.

Response:
PSNH did not use a going forward SO2 price forecast. For planning purposes PSNH uses an indicative SO2 price that reflects purchased inventory and federal and state allocations.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-015
Page 1 of 1

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
The response to CLF 01-009 states: "For planning purposes PSNH uses an indicative SO2 price that reflects purchased inventory and federal and state allocations. What was the market price for SO2 allowances as of year-end 2010? What estimated prices were used for each year 2011-2015?

Response:
PSNH does not retain historical year-end SO2 market prices.

For planning purposes, PSNH used the following estimated SO2 price per ton for years 2011-2015:

Year	$/Ton
2011	235
2012	215
2013	110
2014	110
2015	110

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-068

Witness: Richard L. Levitan
Request from: Office of Consumer Advocate

Question:
Section F. Quantitative Analysis of the Economic Benefits of Newington Station, on page 216 of Appendix G, includes the language: "The starting point of the ROV analysis is a set of expected price forecasts for - oil, natural gas, and emission allowances, and both DAM and RTM energy prices on the product side." Please provide the expected price forecasts.

Response:
Please see the attached spreadsheet for the expected price forecasts for oil, natural gas, emission allowances, and on and off peak energy prices. The DAM and RTM energy price forecasts used in the Newington CUO analysis were created through a simulation model developed by Levitan & Associates for which historical hourly DAM and RTM shapes were randomly sampled instead of using a single expected shape. Hence there are no expected hourly price inputs that can be provided in response to this question. The simulation model uses historical Newington prices and hourly MassHub prices provided by ISO-NE to calculate hourly to monthly time-of-use block (on-peak, off-peak) ratios. The DAM and RTM simulated forecast used a random selection of a week of historical price ratios for all weeks in the same calendar month for that month of the forecast.

	Emission Allowance ($/ton)		
Year	SO_2	NO_x	CO_2
2010	7.00	52.00	1.92
2011	7.00	34.00	1.92
2012	6.00	34.00	1.92
2013	3.90	34.00	1.97
2014	2.90	34.00	2.02
2015	2.90	34.00	2.07
2016	2.90	34.00	2.12
2017	2.90	34.00	2.17
2018	2.90	34.00	2.23
2019	2.90	34.00	2.28
2020	2.70	34.00	2.34

SO_2 Based on CCFE SFI Futures Contracts from 8/27/10.
NO_x Based on CCFE NFI Futures Contracts from 8/27/10.
CO_2 Based on CCFE RGGI Futures Contracts from 8/27/10 through 2012. Forecast increases by 2.5% from 2013 to the end of the forecast period.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-036
Page 1 of 4

Witness: David A. Errichetti
Request from: New Hampshire Public Utilities Commission Staff

Question:
Ref. Appendix D-1. Please provide, in electronic format, the Excel spreadsheet (with all formulae intact) that underlies Appendix D-1. Please also explain how the output for each unit was determined. Is it, for example, based on historical capacity factors or is it the result of a model that dispatches each unit based on projected fuel and other variable costs?

Response:
The attached file is an electronic version of Appendix D Exhibits D-1, D-2 and D-3. The generation for each Schiller and Merrimack steam unit was calculated using the following formula: unit rating times hours in period times (hours in year minus hours of planned maintenance) times (1 minus the equivalent forced outage rate), where the equivalent forced outage rate reflects history. Output for Newington reflects a 3% capacity factor running during peak hours. Output for PSNH's hydro units reflects 20 year average output. Output for the IPPs reflects historical deliveries. The ICUs, which provide non-spinning reserve, are held in reserve and no assumption was made for Wyman.

As noted in the response to CLF-1, Q-CLF-016, while the process described in section C.2.4 at page 32 is used daily for dispatch decisions and in the ES rate setting process, it was not explicitly used in developing the generation schedule shown in this plan. The generation amounts were premised upon relative economics of various types of units, and historical output levels adjusted for maintenance and forced outage assumptions. Because the generation projection was not a rigorous analysis, there were no assumed dispatch prices nor a specific market price forecast.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-019
Page 1 of 1

Witness: David A. Errichetti
Request from: Office of Consumer Advocate

Question:
Section III-C.2.4: Forecasted Dispatch Patterns for Fossil Plants on page 32 includes the sentence: "In general, the coal-fired and wood-fired units (Merrimack and Schiller) are economic in all periods and, thus, are assumed to operate as baseload resources outside of planned maintenance periods." Please explain the basis of PSNH's determination that those units were economic in all periods, how that analysis will be revisited in the future, and how exceptions are determined.

Response:
This question refers to "Forecasted Dispatch Patterns for the Fossil Units." As noted, in the referenced sentence, "*In general*, the coal-fired and wood-fired units (Merrimack and Schiller) are economic in all periods and, thus, are assumed to operate as baseload resources outside of planned maintenance periods." This sentence does not state, nor should it be implied that, the referenced generating units were or will necessarily be economic "in all periods." If actual operations demonstrate that the units are not generally running as baseload units when they are otherwise available, then future generation projections will reflect lower outputs.

Also see the response to CLF-01, Q-CLF-016.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-003
Page 1 of 2

Witness: **David A. Errichetti,William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
Referencing OCA 01-020, please provide a Table stating the percent of time in each year from 2005 to 2010 that Merrimack Units 1 and 2, Schiller Units 4, 5, and 6, and Newington Stations were in "economic reserve." What are the comparable projections through 2016?

Response:
The table below provides the requested information for 2005 through 2010. As noted in responses to previous data requests, no assumption was made about economic reserves in the plan period that went through 2015.

ECONOMIC RESERVE

Unit	2005	2006	2007	2008	2009	2010
Merrimack 1	0.00%	0.00%	0.00%	0.00%	1.54%	9.89%
Merrimack 2	0.00%	0.00%	0.00%	0.09%	1.03%	9.76%
Schiller 4	0.00%	1.16%	0.00%	0.00%	8.67%	11.10%
Schiller 5	0.00%	0.00%	0.00%	0.00%	0.03%	0.00%
Schiller 6	0.00%	0.00%	0.00%	0.00%	8.01%	20.33%
Newington	28.12%	80.50%	79.47%	82.41%	83.63%	78.14%

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-020
Page 1 of 1

Witness: David A. Errichetti
Request from: Office of Consumer Advocate

Question:
Section III-C.3: Energy Service Requirement Forecast and Planning on page 33 refers to the option of placing Newington Station on "economic reserve." Please explain "economic reserve" and how PSNH would determine if such was the most economic option for Energy Service customers. If PSNH has made such an analysis in the past, please provide a copy of any such analysis.

Response:
Economic reserve simply means the resource is available but not being dispatched. It occurs whenever the cost to generate from the resource is greater than the cost of using an alternative resource. Reserve shutdowns occur in the normal course of serving ES load. No special periodic analysis is performed other than comparing the cost of the unit's output to the cost of an alternative source.

Public Service Company of New Hampshire
Docket No. 11-094

Data Request STAFF-01

Dated: 06/23/2011
Q-STAFF-004
Page 1 of 2

Witness: **Frederick White,William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Reference Mr. Cannata's testimony in Docket DE 10-121, Exhibit MDC-2, and page 46. Please update the upper table with 2010 information and the lower table with forecasted and actual 2010 information.

Response:
Below is a table of the average annual heat rates for Generation's six steam units updated to include 2010 information.

Units	Average Annual Heat Rate (BTU/kWh)					
	2005	2006	2007	2008	2009	2010
MK1	10,184	10,376	10,264	9,933	10,211	10,221
MK2	10,071	10,328	10,157	9,723	9,919	9,663
NT	11,522	12,270	11,723	11,690	12,382	13,517
SR4	12,558	12,832	13,405	12,244	13,019	13,073
SR5	12,871	9,398	15,565	16,689	17,122	17,131
SR6	12,379	12,460	12,528	12,072	12,644	12,588

Note: Newington Station's heat rate includes warming fuel for equipment and #6 oil, as necessary.

Please see the attached table for 2010 actual and projected capacity factor information (consistent with the lower table in Exhibit MDC-2, page 46) for PSNH's major units.

2010 - Actual and Projected Annual Capacity Factors for PSNH's Major Units
(Annual Generation/Winter Rating/8760)

	Capacity Factor	
Unit	Actual	Projected
Merrimack 1	67.2%	79.6%
Merrimack 2	67.5%	75.5%
Schiller 4	53.4%	68.8%
Schiller 5	79.0%	75.1%
Schiller 6	51.0%	78.7%
Newington	6.4%	3.0%

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 20

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 10-121

In The Matter of

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
2009 ENERGY SERVICE AND STRANDED COST RECOVERY CHARGE RECONCILIATION

DIRECT TESTIMONY

of

Michael D. Cannata, Jr., P. E.
Senior Consultant
ACCION GROUP, INC.

November 23, 2010

PSNH Major Unit Historical Unit Heat Rates [8]

Unit	Average Annual Heat Rate (BTU/kWh)					Full Load Heat Rate (BTU/kWh)
	2005	2006	2007	2008	2009	2009
Merrimack-1	10,184	10,376	10,264	9,933	10,211	9,900
Merrimack-2	10,071	10,328	10,157	9,723	9,919	9,520
Newington	11,522	12,270	11,723	11,690	12,382	10,900
Schiller-4	12,558	12,832	13,405	12,244	13,019	12,900
Schiller-5	12,871	9,398 (1)	15,565	16,689	17,122	15,800
Schiller-6	12,379	12,460	12,528	12,072	12,644	12,300

Historic Unit Capacity Factors

The table below shows the historical capacity factors and the projected capacity factors used for the 2008/2009 period.[9]

Actual and Projected Annual Capacity Factors for PSNH Major Units

(Annual Generation/Winter Rating/8760)

Unit	Actual Capacity Factor (Percent)									Forecasted
	2001	2002 (1)	2003 (2)	2004	2005	2006	2007	2008	2009	2009
Merrimack-1	81.6	74.7	93.3 (3)	86.8	90.6 (3)	80.6	95.7 (3)	79.8	84.1 (3)	88.3
Merrimack-2	72.7	75.7	73.9	80.3	79.1	84.1	82.9	72.8	56.1	55.7
Schiller-4	66.5	65.4	73.9	73.7	76.5	71.1	84.2	78.5	59.5 (6)	76.4
Schiller-5	59.3	68.2	73.5	74.0 (4)	72.4 (4)	42.0 (5)	76.7	79.8	79.6	75.7
Schiller-6	62.8	71.6	75.1	76.6	81.4	77.6	74.6	80.7	56.9 (6)	70.4
Newington	12.6	19.0	55.9	50.3	33.5	8.0	9.3	3.3	5,2	6.9

(1) - Seabrook removed from PSNH mix for November and December due to sale.
(2) - First full year Seabrook is not in PSNH mix.
(3) - No unit overhaul in this year.
(4) - Very minor outage this year due to wood conversion.
(5) - Coal to wood boiler conversion project.
(6) – Actuals reflect reserve shut down periods.

2009 Energy Market

Where much of PSNH generation is either base load or peaking generation, it is not expected that they will have significant interaction with the market. The remaining unit, Newington, is the unit

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[8] Coal to wood conversion took place in 2006.
[9] Calendar 2009 is in this period.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-067
Page 1 of 1

Witness: David A. Errichetti
Request from: Office of Consumer Advocate

Question:
Section E.2.2. Short-Term Hedge Value, on page 212 of Appendix G, includes the following language: "PSNH can purchase fuel forward contracts, which are generally recognized as having a lower market risk premium (as a percentage of the price) than on-peak power contracts." Please provide a copy of the cost/benefit analysis PSNH last conducted addressing the decision of whether or not to enter into purchasing fuel forward contracts.

Response:
PSNH has not done this particular kind of analysis.

Public Service Company of New Hampshire
Docket No. DE 10-160

Data Request STAFF-01
Dated: 08/13/2010
Q-STAFF-002
Page 1 of 1

Witness: David A. Errichetti
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Baumann testimony, page 4, lines 15-18. Please quantify the annual costs attributable to "purchase power arrangements that were entered into to minimize future market exposure risk" for the years 2006 - 2010. For 2010, please provide actual amounts up to the most recent date available and forecasted amounts for the remainder of the year. For each year, please also provide the above-market portion of the total costs.

Response:
Please see table below for the requested information. The analysis looked at firm bilateral energy purchases of one month or greater duration which were typically captured in the rate setting proceedings and were meant to lock in power supply costs so as to minimize future market exposure risk. The above market costs were calculated as the difference between the firm bilateral energy purchase price and the day-ahead energy market clearing price at the contract delivery point times the contract quantity.

Year	Purchase Costs	Above-Market Costs
2006	242,378,478	89,793,546
2007	158,399,248	24,381,473
2008	178,366,008	(21,331,297)
2009	226,684,750	127,277,461
2010 (actual thru July)	33,300,000	13,464,423
2010 (est. Aug thru Dec)	24,300,000	10,051,800

* August to December, 2010 market value estimates are based on 7/30/10 broker quotes.

While comparing the contract price to the day-ahead energy market clearing price reflects what the contracts would be paid in the ISO-NE energy market settlement system, it is not necessarily indicative of how a third party buying power for a customer's future needs would act. As an alternative the 2009 calculation was redone assuming the firm bilateral energy purchases were made on the last day the contract term was traded. For example a 2009 calendar year purchase was priced based on end of December 2008 prices and a June 2009 purchase was priced based on end of May 2009 pricing. The 2009 above-market cost using this alternative market value approach would then be calculated as $93.4 million.

The analysis did not consider any firm bilateral energy sales of one month or greater that may have been made during this period.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01
Dated: 03/04/2011
Q-STAFF-031
Page 1 of 1

Witness: Terrance J. Large
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please provide the number and kW capacity of distributed generation resources installed by PSNH or its customers in each of the last five years. Please also specify the number and kW capacity of generators directly connected to PSNH's distribution system each year.

Response:
The table below lists the number and total KW capacity of distributed generation resources that were completed in each year since 2005. The table also provides the total number and capacity of resources at year-end.

For purposes of this response, "distributed generation resources" includes all generation connected to distribution (i.e. voltages less than 115 KV), including behind-the-meter resources.

Note: the "KW Capacity" values were taken from PSNH's internal database of IPP and Net Metering installations. In most cases, the value represents the nameplate capacity of the generator or the inverter (for inverter-based net metering resources). The value does not represent the ISO-NE Forward Capacity Market supply obligation associated with the resource.

	New DG Installations		Total at Year End	
	# of Resources	KW Capacity	# of Resources	KW Capacity
2005	5	59	134	179,422
2006	13	9,373	147	188,795
2007	31	153	178	188,948
2008	40	26,284	218	215,232
2009	106	8,898	324	224,130
2010	127	2,872	451	227,002

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-021
Page 1 of 1

Witness: **Terrance J. Large**
Request from: **Office of Consumer Advocate**

Question:
Referring to the response to Staff 01-031, for the years 2011-2015, what number of DG installations and new KW Capacity did PSNH use in its forecast?

Response:
PSNH did not account for any DG installations in the kwh sales forecast used in this plan.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-014
Page 1 of 1

Witness: Terrance J. Large
Request from: Office of Consumer Advocate

Question:
The section on Weather on page 24 indicates that PSNH bases its forecasts on the 30 year average ending 2006. Why isn't a more current 30 year average used? How would the results change if a more current 30 year average was used?

Response:
PSNH has not utilized a more recent computation of the 30 year average (1977-2006) due to the fact that adding a small number of years to the average and removing older values will have little effect on the outcome. In addition, making these small changes year to year makes it more difficult to compare the impact of changes in economic variables, price of electricity, and usage patterns from one forecast to another.

In forecasts to be undertaken in the spring of 2011 and after, an updated 30 year average (1981-2010) will be used. This updated 30 year average shows that there are fewer heating degree days and fewer cooling degree days in the more recent 30 year average. Using this newer average and holding all other variables constant would lower the forecast for delivery energy sales.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-002
Page 1 of 1

Witness: **Terrance J. Large**
Request from: **Office of Consumer Advocate**

Question:
Please provide a copy of the 30-year weather average source data referenced in OCA 01-014.

Response:
The data follows:

Concord

	Heating Degree Days			Cooling Degree Days		
MONTH	1977-2006	1981-2010	Difference	1977-2006	1981-2010	Difference
1	1370	1348	-22	0	0	0
2	1148	1115	-33	0	0	0
3	974	975	1	0	0	0
4	594	585	-9	0	0	0
5	291	285	-6	20	18	-2
6	83	74	-9	89	88	-1
7	17	13	-4	185	177	-8
8	33	29	-4	153	140	-13
9	183	177	-6	36	32	-4
10	519	522	3	2	1	-1
11	789	794	5	0	0	0
12	1179	1166	-13	0	0	0
Total	7,180	7,083	-97	485	456	-29
Leap Year	37	36	-1			
Total	7,217	7,119	-98			

The source of this data is a paid subscription to MDA EarthStat Weather (http://weather.earthsat.com/)

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-038
Page 1 of 1

Witness: David A. Errichetti
Request from: Office of Consumer Advocate

Question:
Referring to Section V-B.2 Forecast of Energy Requirement and Supply Resources on page 93, please provide the base case forecast/scenario for migration per customer class for each of the next 5 years and explain the derivation of the forecast including assumptions.

Response:
The plan reflects no base case migration scenario. The range provided was intended to be illustrative of the overall PSNH ES energy balance under varying levels of migration. Exhibit III-15 shows the migration level assumptions for each customer class for each migration level. These levels of migration by customer class reflected the trends seen for these classes in 2009 and 2010.

Public Service of New Hampshire

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The Northeast Utilities System

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 28

July 12, 2011

JUL 12 2011
CONSUMER ADVOCATE

Debra A. Howland
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: 2nd Quarter 2011 Customer Migration Report

Dear Ms. Howland:

In its Order No. 24,714-Order Approving Energy Service Rate in Docket DE 06-125, the Commission directed PSNH to provide monthly data regarding the migration of its customers to the competitive market on a quarterly basis. Enclosed for filing with the Commission is a Customer Migration Report for the 2nd quarter of 2011. This report is being filed electronically with one paper copy being sent to the Commission.

We would be pleased to respond to any questions the Commission may have on this report.

Sincerely,

Heather M Arvanitis

Heather M. Arvanitis
Analyst

HMA:kd
Enclosures
cc: M.A.Hatfield, OCA

Public Service Company of New Hampshire
Migration of Customers To and From the Competitive Energy Supply Market
2011 Report
to the New Hampshire Public Utilities Commission

	Customers Receiving Energy Service From the Competitive Market			Retail Sales			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Number of Customers Not Billed for PSNH's Energy Service	Total Kilowatt-hours Delivered (KWH)	Estimated Demand at the Time of PSNH's System Peak Reported to the ISO-NE (KW)	Total Customers Taking Delivery Service	% of Customers Not Billed for PSNH's Energy Service as a % of Total Customers* Col (1) / Col (4)	Total KWH Delivered To All Customers (KWH)	%of Kilowatt-hours Not Billed for PSNH's Energy Service as a % of Total KWH Col (2) / Col (6)
April							
Residential	1,257	412,385		420,419	0.30%	249,383,657	0.17%
Small C&I Rate G	8,408	33,172,190		73,290	11.47%	135,925,275	24.40%
Medium C&I Rate GV	797	88,737,717		1,421	56.09%	137,359,104	64.60%
Large C&I Rate LG	89	95,200,504		114	78.07%	102,212,935	93.14%
Lighting	147	1,100,334	320,150	1,063	13.83%	3,047,600	36.10%
Total	**10,698**	**218,623,130**		**496,307**	**2.16%**	**627,928,571**	**34.82%**
May							
Residential	1,260	376,416		422,761	0.30%	211,501,362	0.18%
Small C&I Rate G	8,817	31,827,298		73,605	11.98%	123,923,433	25.68%
Medium C&I Rate GV	795	83,633,000		1,419	56.03%	129,451,256	64.61%
Large C&I Rate LG	88	85,146,701		112	78.57%	91,704,101	92.85%
Lighting	175	970,889		1,016	17.22%	2,578,129	37.66%
Total	**11,135**	**201,954,304**	**422,025**	**498,913**	**2.23%**	**559,158,281**	**36.12%**
June							
Residential	1,270	461,079		422,752	0.30%	239,405,235	0.19%
Small C&I Rate G	8,867	35,974,269		73,730	12.03%	139,666,610	25.76%
Medium C&I Rate GV	802	94,288,450		1,418	56.56%	144,153,593	65.41%
Large C&I Rate LG	91	111,975,377		116	78.45%	120,036,764	93.28%
Lighting	177	946,620	549,073	1,016	17.42%	2,508,425	37.74%
Total	**11,207**	**243,645,795**		**499,032**	**2.25%**	**645,770,627**	**37.73%**

*"Total Customers" refers to all customers taking Delivery Service.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-023

Witness: Terrance J. Large
Request from: Office of Consumer Advocate

Question:
Referring to Section III-D.3 Planning Use of the Engineering Forecast on page 36, please explain how PSNH incorporates targeted load-control and/or targeted energy efficiency into its decisions on whether or not a Planning Area requires additional capital investments due to projected load growth.

Response:
Until very recently, PSNH was prohibited by law from using SBC funds to target specific areas with load control and/or energy efficiency. PSNH has several voluntary programs which can be used to curtail load, but not in a focused manner. Regarding the planning for additional capital investments in a particular Planning Area, PSNH is relying on traditional solutions to keep the system reliable and secure. This is primarily done by adding infrastructure such as transformers and distribution lines when an part of area becomes overloaded. One way that we use load control on the system is to reduce the voltage temporarily by up to 5% across the system to reduce energy requirements when needed.

Public Service Company of New Hampshire
Docket No. DE 10-257

Data Request STAFF-01

Dated: 10/21/2010
Q-STAFF-001
Page 1 of 2

Witness: **Robert A. Baumann,Frederick White**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Reference Attachment RAB-1, page 1. Please provide, by generating unit, a) the total revenues listed by source and b) the total revenue requirements used in calculating the preliminary 2011 energy service rate. For purposes of this question, the hydro units and the combustion turbines can be shown as separate groups.

Response:
The tables shown on page 2 of 2 summarize by generating unit the estimate of forecasted revenue requirements and wholesale market revenues consistent with the preliminary 2011 energy service rate, in thousands of dollars. The revenue requirements are not typically tracked on a station or unit specific basis. In order to provide this detailed breakout, assumptions were made as to allocations to specific station or unit for items such as depreciation of common facilities, property taxes, payroll taxes, emissions allowances, material and supplies and allocation of PSNH's and NU's administrative and general expenses. Other column reflects certain Combustion Turbine costs, Wyman entitlement costs and certain intangible costs not allocated to specific stations along with the related revenues.

Data Request STAFF-01
Dated: 10/21/2010
Q-STAFF-001

TABLE 1

The following summarizes by generating unit the forecasted costs for 2011 in thousands of dollars.

	Merrimack	Schiller #4,	Schiller # 5	Newington	Hydros	Other (5)	Total
Fuel Costs	$ 110,948	$ 21,571	$ 8,467	$ 4,703	$ -	$ -	$ 145,689
O&M costs (1) (2)	58,561	22,988	11,492	10,391	12,629	-	116,061
Depreciation (1) (3)	3,738	2,291	4,330	8,808	2,401	1,035	22,603
Property Tax (1) (4)	3,955	849	1,329	960	2,617	1,232	10,942
Payroll Tax (1)	1,063	437	219	170	248	-	2,137
ARO Amortization (1)	283	165	82	19	18	30	597
Return on Rate Base	17,291	5,040	7,224	8,256	4,920	456	43,187
Total Cost	$ 195,839	$ 53,341	$ 33,143	$ 33,307	$ 22,833	$ 2,753	$ 341,216

TABLE 2

The following summarizes by generating unit the forecasted revenues for 2011 in thousands of dollars. The energy revenues were calculated by multiplying forecasted MWH output by the forecasted market LMP, and does not include all fo the value that might be realized from actual operation during 2011.

	Merrimack	Schiller #4,	Schiller # 5	Newington	Hydros	Other (5)	Total
Capacity revenues	$ 19,219	$ 4,629	$ 1,796	$ 16,459	$ 2,351	$ 1,288	$ 45,742
Energy revenues (6)	130,412	24,334	12,618	5,181	15,089	-	187,634
Loc Fwd Reserve Mkt	478	231	-	-	-	458	1,167
Total Revenue	$ 150,109	$ 29,194	$ 14,414	$ 21,640	$ 17,440	$ 1,746	$ 234,543

(1) See Staff Set-01, Q-STAFF-003 for the O&M, Depreciation, Property Tax, Payroll Tax and ARO Amortization detail and assumptions.
(2) Schiller Station O&M allocated one-third to each unit.
(3) Schiller Station #5 depreciation allocated to unit based on net plant.
(4) Schiller Station #5 property tax allocated to unit based on property tax analysis from 2009 tax data.
(5) Includes Combustion Turbine, Wyman, and Intangibles not allocated to specific units.
(6) Calculated using forecasted MWH output times the forecasted market LMP.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 31

Public Service Company of New Hampshire	**Technical Session TS-01**
Docket No. DE 10-261	**Dated: 03/30/2011**
	Q-TECH-001-SP01
	Page 1 of 2

Witness: **Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Re: Staff 1-91 attachment, page 4: Why does the average fuel expense appearing on the fourth line decline from 2011 to 2019?

Response:
Review of the simulation model results revealed a problem in the calculation of energy prices, which in turn caused the expected value of average variable expenses (fuel and emission allowances) to decline over time. The revisions to the Newington CUO filed April 26, 2011 show expected value annual results for average fuel costs that are higher and upward-trending, in line with the upward-trending forward curves for Dracut natural gas prices and NYH residual fuel oil prices. Average variable cost increases from about $59/MWh in 2011 to $74/MWh in 2019, as shown in the table attached. The revised Newington CUO also included a revision in the model reflecting slightly higher heat rates, which resulted in average energy costs being higher by a few percent across all years, as shown in the table attached.

Revenue Requirement Details

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Original shown in Staff 1-91:										
Avg fuel expense ($/MWh)	$50.87	$51.57	$51.01	$49.30	$47.57	$44.55	$43.04	$42.28	$43.10	$42.21
Capacity Factor	16.71%	14.75%	15.25%	16.95%	16.60%	16.56%	16.92%	17.89%	18.47%	18.01%
Energy Production (MWh)	585,943	516,967	534,802	594,103	581,993	580,725	593,190	627,342	647,343	631,423
Energy Cost ($)	$29,809,742	$26,659,654	$27,282,203	$29,291,022	$27,686,915	$25,870,153	$25,529,387	$26,522,489	$27,902,062	$26,651,529
Revised per April 26, 2011 update:										
Avg fuel expense, $/MWh	$58.98	$65.59	$70.15	$71.76	$72.91	$71.97	$72.75	$73.14	$74.09	$72.82
Capacity Factor	7.98%	6.96%	7.08%	8.15%	9.18%	9.49%	9.66%	9.49%	9.84%	10.72%
Generation (MWh) [Note 1]	279,775	244,015	248,256	285,846	321,757	332,734	338,487	332,553	344,899	375,824
Energy Cost ($) [Note 2]	$16,501,014	$16,004,594	$17,415,617	$20,511,101	$23,460,589	$23,945,291	$24,626,365	$24,322,802	$25,552,848	$27,368,814

Notes:
1. Expected generation, shown in Exhibit G.17 (in GWh).
2. Expected energy cost, shown in Exhibit G.17 (in $000). Expected energy cost equals the sum of fuel and fuel-related O&M expenses and emissions allowance expense, shown in Exhibit G.12 (in $000).

Public Service
of New Hampshire

Public Service Company of New Hampshire
P.O. Box 330
Manchester, NH 03105-0330
(603) 669-4000
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The Northeast Utilities System

July 12, 2011

Mr. Alexander Speidel
Hearings Examiner
State of New Hampshire
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

Re: Docket No. DE 10-261 - PSNH 2010 Least Cost Integrated Resource Plan

Dear Mr. Speidel:

This letter provides the response to requests for the information listed below.

Response to TS-02 Technical Sessions dated 06/22/2011
TECH-007

Very truly yours,

Stephen R Hall KB

Stephen R. Hall
Manager
Rate & Regulatory Services

cc: Service List

Witness: Richard L. Levitan
Request from: New Hampshire Public Utilities Commission Staff

Question:

Re-run the Levitan Newington CUO Study model with the following data input changes:

a) Apply a premium to the Dracut natural gas price of 80 cents in Jan-Feb and 84 cents in all other months.
b) Include the revision to the start up costs to reflect adjustment made by Levitan in 2010 Backcast analysis.
c) Change the natural gas/ #6 residual oil parity ratio to reflect oil being 4.0 times higher than natural gas in 2011 and narrowing down on a linear basis to 3.5 times higher than natural gas in 2020. Also adjust #2 fuel oil parity ratio to reflect oil being 5.0 times higher than natural gas in 2011 and narrowing down on a linear basis to 4.5 times higher than natural gas in 2020.
d) Add warming fuel as a separate line item in the financial result when reporting the final results.

Response:

Implementation details of the data input changes in the requested model run are as follows:

a) As in the CUO Study run, the Dracut premium inputs are in 2010 dollars and escalated at 2.4% annually over the 2011 to 2020 period.

b) As in the 2010 Backcast run with higher start costs, no energy generation or revenue was credited for dispatch while ramping from the 20 MW online load to the 60 MW stable minimum operating load.

c) RFO prices don't vary by month and 2FO prices have very little seasonal shape, so the requested oil to gas price ratios were applied to annual average natural gas prices at Dracut. The RFO oil to gas price ratios were applied to both 1% S RFO, used through 2017, and 0.5% S RFO, used from 2018 to 2020.

d) Annual warming fuel of 72.9 BBtu of 2FO, per the calculation reported in TS-02, Q-TECH-006(b), was multiplied by the annual average 2FO prices for the respective scenarios and years. Warming fuel is fired in the auxiliary boilers. Almost all modeled emission allowance costs are for CO2 allowances, which are only required for the main boiler, so no additional emission allowance costs were calculated.

   Expected value revenue requirements results are presented in Attachment 1, in the same basic format as Exhibit G.12, with the addition of "Warming" and "Operation" sub items under "Fuel and Fuel Related O&M" expenses. The PV of net revenue requirements is still a negative number, indicating that continued operation of Newington Station is expected to produce customer benefits.

   Operational performance results are presented in Attachment 2, in the same basic format as Exhibit G.17 of the CUO Study, with additional row items under the "With Warming Fuel" heading in each of the three panels (for expected value, median, and P25 results). Warming fuel is modeled as a constant 72.9 BBtu, regardless of how much the plant ran during the winter. The warming cost is the 72.9 BBtu times the price of the 2FO for the scenario (or all scenarios for the expected value panel). The warming fuel cost is added as an after-the-fact adjustment to the financial results reported by the model.

A complication resulting from insufficient time to include the warming fuel costs within the dispatch model is that the percentile-based results in the P50 and P25 panels are reported on the basis of energy net revenue <u>without</u> warming cost. This means that because the warming costs were added outside the model, the bottom line net revenue results, with warming costs, do <u>not</u> represent the indicated percentile levels. For example, in 2011, the P50 net revenue with warming cost included is smaller (more negative) than the P25 result. If the percentile results were ranked with the warming fuel costs included, the P50 and P25 cases would vary slightly. Also, the year-to-year fluctuations in the net revenue results with warming cost are larger than if that measure had been used for the percentile ranking since the (e.g.) P25 scenario, without inclusion of warming costs in the net revenue ranking, may in one year have high 2FO prices, but the P25 scenario for the next year may have low 2FO prices, resulting in overly wide warming cost fluctuation.

Attachment 1

Expected Values of Incremental Revenue Requirements
Case: Higher Start Cost and Warming Fuel Cost; PUC Staff Requested Natural Gas Premiums and Oil Prices

	Present	Calendar Year									
	Value EOY	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenses ($000)											
Non-Fuel O&M with Indirects											
Other than Emission Allowances	$57,236	$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances	$1,415	$179	$170	$181	$212	$225	$207	$212	$243	$244	$248
Total O&M Expense	$58,651	$7,677	$7,876	$8,101	$8,351	$8,591	$8,807	$9,053	$9,331	$9,587	$9,853
Fuel and Fuel Related O&M	$98,035	$10,981	$11,772	$12,875	$14,954	$15,926	$15,019	$15,476	$16,923	$16,709	$16,756
Warming		$1,885	$2,133	$2,263	$2,332	$2,389	$2,431	$2,450	$2,457	$2,455	$2,463
Operation		$9,096	$9,639	$10,612	$12,622	$13,537	$12,589	$13,025	$14,466	$14,253	$14,293
Property Tax	$9,057	$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879	$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses	**$168,621**	**$19,666**	**$20,789**	**$22,261**	**$24,751**	**$26,142**	**$25,656**	**$26,596**	**$28,610**	**$29,033**	**$29,988**
Rate Base ($000)											
Incremental Gross Plant Value		$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation		$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value		$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital		$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes		$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory		$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base		$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base		*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
Return on Rate Base ($000)	**$11,271**	**$1,540**	**$1,586**	**$1,626**	**$1,660**	**$1,688**	**$1,707**	**$1,717**	**$1,715**	**$1,695**	**$1,641**
Expenses Plus Return on Rate Base	**$179,892**	**$21,206**	**$22,374**	**$23,887**	**$26,411**	**$27,830**	**$27,363**	**$28,313**	**$30,325**	**$30,728**	**$31,628**
Revenues ($000)											
Energy	$104,104	$11,549	$12,088	$13,431	$15,958	$17,116	$15,813	$16,483	$18,216	$18,172	$18,114
Capacity	$111,205	$17,250	$13,343	$12,121	$12,779	$13,791	$14,903	$16,420	$17,830	$22,106	$29,026
Ancillary	$1,367	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue	**$216,676**	**$28,999**	**$25,631**	**$25,752**	**$28,937**	**$31,107**	**$30,916**	**$33,103**	**$36,246**	**$40,477**	**$47,340**
NET REVENUE REQUIREMENT	**($36,785)**	**($7,793)**	**($3,257)**	**($1,864)**	**($2,526)**	**($3,277)**	**($3,553)**	**($4,789)**	**($5,921)**	**($9,749)**	**($15,712)**

Attachment 2

Operational Performance at Selected Annual Energy Net Revenue Probability Levels
Case: Higher Start Cost and Warming Fuel Cost; PUC Staff Requested Natural Gas Premiums and Oil Prices

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expected Value										
DAM Dispatch Hours	451	429	445	508	525	470	471	526	514	506
RT Dispatch Hours	19	17	17	22	23	21	22	23	25	26
Generation (GWh)	137.0	130.0	134.7	154.3	159.9	143.1	143.5	160.2	157.2	155.6
Number of Starts	22	22	22	25	24	22	22	23	23	23
2FO Consumption (BBtu)	13	13	13	15	15	14	14	15	15	14
RFO Consumption (BBtu)	3	3	2	2	3	4	4	5	9	19
Gas Consumption (BBtu)	1,544	1,468	1,521	1,743	1,805	1,616	1,619	1,806	1,768	1,740
CO2 Emitted (1000 ton)	92	87	90	103	107	96	96	107	105	105
SO2 Emitted (ton)	15	14	15	17	17	16	16	16	17	19
NOx Emitted (ton)	92	87	91	104	107	96	97	108	106	105
Capacity Factor (%)	3.9%	3.7%	3.8%	4.4%	4.6%	4.1%	4.1%	4.6%	4.5%	4.4%
Service Factor (%)	5.4%	5.1%	5.3%	6.0%	6.3%	5.6%	5.6%	6.3%	6.2%	6.1%
Energy Revenue ($1000)	11,549	12,088	13,431	15,958	17,116	15,813	16,483	18,216	18,172	18,114
Energy Cost ($1000)	9,276	9,809	10,793	12,834	13,762	12,795	13,237	14,708	14,498	14,541
Net Revenue ($1000)	2,273	2,279	2,638	3,124	3,354	3,018	3,245	3,508	3,674	3,573
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	1,885	2,133	2,263	2,332	2,389	2,431	2,450	2,457	2,455	2,463
Energy Cost with Warming Fuel ($1000)	11,160	11,943	13,056	15,166	16,150	15,226	15,688	17,166	16,953	17,004
Net Revenue with Warming Fuel ($1000)	389	146	375	792	965	587	795	1,050	1,219	1,110
P50 (Median)										
DAM Dispatch Hours	287	328	328	756	595	389	537	469	604	545
RT Dispatch Hours	5	13	5	48	21	16	6	29	31	36
Generation (GWh)	85	97	97	234	183	116	158	144	186	166
Number of Starts	12	22	21	39	19	25	23	20	25	34
2FO Consumption (BBtu)	9	14	11	23	13	15	15	13	14	19
RFO Consumption (BBtu)	0	0	0	0	3	14	0	0	1	0
Gas Consumption (BBtu)	972	1,113	1,099	2,629	2,018	1,318	1,785	1,626	2,091	1,875
CO2 Emitted (1000 ton)	58	66	65	156	119	80	106	96	124	111
SO2 Emitted (ton)	6	13	13	27	12	22	16	13	15	20
NOx Emitted (ton)	58	66	65	156	121	80	106	96	124	111
Capacity Factor (%)	2.4%	2.8%	2.8%	6.7%	5.2%	3.3%	4.5%	4.1%	5.3%	4.7%
Service Factor (%)	3.3%	3.9%	3.8%	9.2%	7.0%	4.6%	6.2%	5.7%	7.2%	6.6%
Energy Revenue ($1000)	8,817	10,148	13,959	19,980	14,369	13,263	14,220	11,801	15,383	23,460
Energy Cost ($1000)	6,718	8,208	11,804	17,172	11,544	10,731	11,735	8,800	12,535	20,466
Net Revenue ($1000)	2,099	1,940	2,155	2,808	2,825	2,531	2,485	3,001	2,848	2,994
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	2,306	2,207	3,479	2,500	1,228	2,223	1,092	1,754	1,397	3,736
Energy Cost with Warming Fuel ($1000)	9,023	10,415	15,283	19,672	12,772	12,954	12,826	10,554	13,932	24,202
Net Revenue with Warming Fuel ($1000)	-206	-267	-1,324	308	1,597	309	1,394	1,247	1,450	-742
P25										
DAM Dispatch Hours	391	311	294	489	302	481	600	502	477	512
RT Dispatch Hours	24	15	23	34	24	16	30	30	23	40
Generation (GWh)	120.7	95.8	90.8	149.3	94.5	145.6	181.2	157.8	145.0	159.6
Number of Starts	22	21	17	22	22	14	38	14	29	20
2FO Consumption (BBtu)	14	11	11	15	13	9	21	11	18	12
RFO Consumption (BBtu)	15	12	0	0	12	0	0	4	11	0
Gas Consumption (BBtu)	1,360	1,074	1,025	1,692	1,068	1,633	2,059	1,767	1,644	1,787
CO2 Emitted (1000 ton)	82	65	61	100	65	96	122	105	98	105
SO2 Emitted (ton)	21	19	11	15	18	9	23	9	21	13
NOx Emitted (ton)	82	66	60	100	65	97	122	105	99	106
Capacity Factor (%)	3.4%	2.7%	2.6%	4.3%	2.7%	4.2%	5.2%	4.5%	4.1%	4.6%
Service Factor (%)	4.7%	3.7%	3.6%	6.0%	3.7%	5.7%	7.2%	6.1%	5.7%	6.3%
Energy Revenue ($1000)	9,037	8,501	7,881	9,767	9,429	9,965	10,329	9,643	16,023	10,242
Energy Cost ($1000)	7,695	7,247	6,439	7,903	7,801	8,210	8,912	7,721	14,167	8,460
Net Revenue ($1000)	1,343	1,253	1,443	1,864	1,627	1,755	1,417	1,921	1,856	1,782
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	1,495	2,221	1,840	1,612	2,171	1,563	1,163	1,428	1,666	1,300
Energy Cost with Warming Fuel ($1000)	9,189	9,468	8,279	9,515	9,972	9,773	10,076	9,149	15,833	9,760
Net Revenue with Warming Fuel ($1000)	-152	-967	-397	252	-544	192	253	494	190	482

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-023
Page 1 of 5

Witness: Terrance J. Large
Request from: Office of Consumer Advocate

Question:
Referring to Staff 01-047, please provide a copy of the initial RFP that PSNH issued seeking a consultant to conduct a CUO Study for Newington. How many entities received the RFP, and how many provided bids?

Response:
Please see the attached file for the RFP issued seeking a consultant to conduct a CUO study for Newington Station. Four entities received the RFP and three entities submitted bids.

Scoping Document for Newington Station Hedge Valuation

Introduction/Objective

Public Service of New Hampshire ("PSNH") is a regulated utility that owns and operates several fossil/hydro power generating assets to meet a portion of its customers' load requirements. PSNH is undertaking a Continuing Unit Operation Study to evaluate one of its oil/natural gas burning generating plants, Newington Station. This study will be incorporated into PSNH's Least Cost Integrated Resource Plan which is due to be filed with the New Hampshire Public Utilities Commission ("NHPUC") on September 30, 2010.

PSNH is requesting assistance with assessing the long-term value of continued operation of an existing rate-based thermal power plant to PSNH customers, including but not limited to its option values in the capacity, energy, and ancillary services markets.

Characteristics of Newington Station

Newington Station is a 400 MW, dual-fuel unit, with the ability to operate on residual oil or natural gas with a heat rate of about 11,000. Newington is located in Portsmouth, NH and is interconnected at the 345 kilovolt level to the regional transmission system which is operated by the Independent System Operator – New England ("ISO-NE"). Because of the unit's operational flexibility it serves as PSNH's intermediate load facility. Newington Station can operate between a low output level of 60 MW up to full capability (400 MW) and shut down overnight. Due to current market conditions, Newington Station's capacity factor has declined from a high of 55.9% in 2003 to its current level of 5%. Newington's declining capacity factor has brought into question its value to PSNH's customers by the NHPUC.

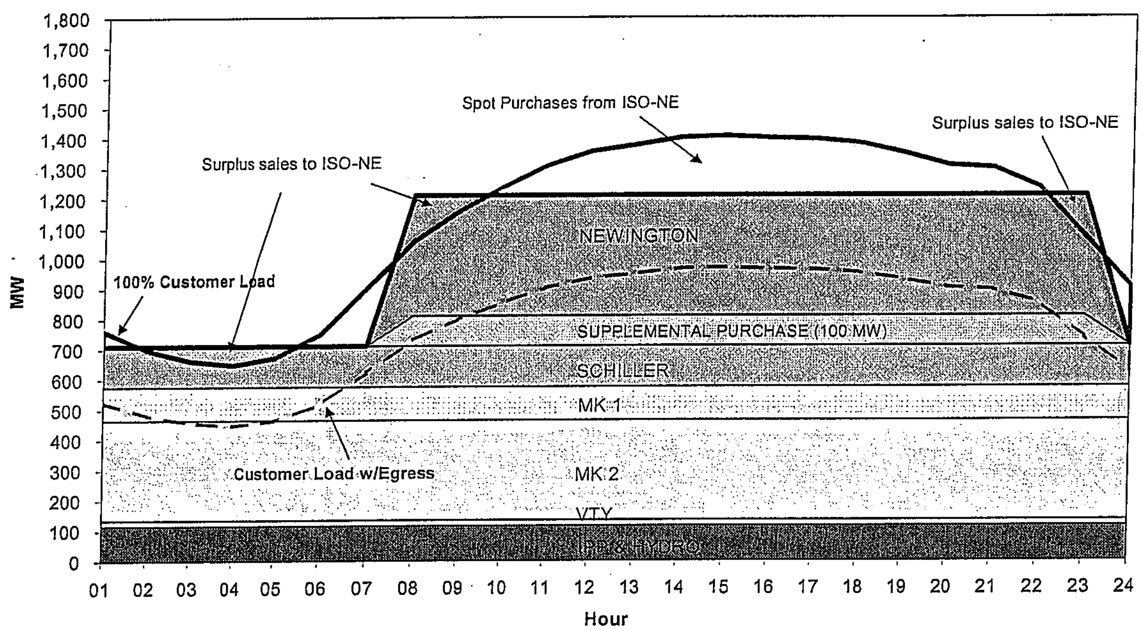
Use of Newington Station under Long-Term and Short-Term Planning

Each year during PSNH's Energy Service rate filing, PSNH develops a plan to economically meet the customers' forecasted energy requirements for the coming year. PSNH is required to supply the energy needs of customers who do not choose to utilize a retail competitive supplier. The Energy Service plan accounts for the utilization of the PSNH fossil/hydro generation. To the extent that customer energy needs can not be met by economic PSNH generation, a supplemental purchase forecast is developed. This purchase forecast changes hourly and can range from zero to a significant portion of total requirements, depending on the availability of PSNH's resources, the level of customer demand, the migration of PSNH Energy Service taking customers to competitive energy service options, and the relative economics of PSNH's generation versus purchase alternatives.

Annual energy supply planning is further refined and/or supplemented by monthly, weekly, and daily planning. PSNH reviews market conditions, current load forecasts (including the impacts of customer migration to/from competitive supply) and any known changes to planned generation maintenance schedules. Given the particular flexibility and fuel diversity of Newington Station, the economics of this unit are closely monitored to ensure that the unit is operated in a manner that optimizes the fuel usage and incorporates operational consideration such as emission control, minimum down times, minimum run times, ramp rates, etc. For example, if replacement power contracts can be executed at a price that is less than the dispatch price of Newington, it may be possible to place the unit on economic reserve. A similar type of review is conducted on a daily or weekly basis depending on the time of year.

On a daily basis, PSNH forecasts the hourly load and supply resource distribution for the following day. This process incorporates updated information on weather and load patterns, fossil unit availability, Newington status, hydroelectric and IPP production forecasts and existing power purchases. The daily forecast determines the anticipated level of energy obligation that is not being served at a known price, i.e. the ISO-New England spot purchase exposure. PSNH reviews this exposure and, if required, executes additional bilateral purchases. Typically, and by necessity, a small portion of PSNH's energy obligation is procured via the ISO-New England spot market. Also, each day normally includes a number of hours in which PSNH has surplus supply that is sold into the ISO-New England spot market. To illustrate this interaction with the ISO-New England spot market, Exhibit 1 depicts PSNH's 2011 typical summer weekday energy position.

Exhibit 1: PSNH 2011 Typical Summer Weekday Energy Position



Request for Proposal

PSNH is seeking assistance to value the flexibility that Newington Station provides to PSNH's customers and ISO-NE markets 1) as a hedge against future market uncertainty, 2) as an asset which is bundled within a managed portfolio of generation resources and optimized for use to meet customer needs in meeting long-term Energy Service rate planning needs and 3) in the short term market to meet customer energy needs and ISO-NE reliability needs. This assessment will study the period of time from 2011 thru 2020.

PSNH views the work product being requested as three separate pieces and is asking the bidders to respond to each item separately.

1. Identify, describe, and summarize the opportunities where a unit such as Newington Station would provide value in the ISO-NE market to PSNH customers, and to the reliability of the local and regional power system. Define key short-term and long-term market products which Newington supplies and uncertainty drivers.

2. Provide a description of the approach to be used and an estimate of the expected effort level to quantify the selected opportunities where Newington Station provides a physical and/or market hedge/option value to customers and New England. The assessment would include a forecast of expected plant utilization and net revenues under base case assumptions and should include a calculation of the long-term physical hedge/option value using stochastic simulation, in terms of (i) expected economic value and the distribution of benefits and (ii) local and system reliability benefits.

3. Provide expert witness testimony and support as the filing progresses through the regulatory process. PSNH expects to file the study on September 30, 2010 and expects the regulatory process to begin in mid-2011, extending into late 2011 and potentially into 2012.

In your return bids, please describe the data inputs required and timeframe for completion. Also, if there are other methods to approach the analysis, please inform PSNH of alternate approaches.

Timeline for Deliverables

PSNH anticipates the final deliverable to be a white paper containing the qualitative and quantitative analyses.

The expected timeline is as follows:

April 26, 2010: Bids received from vendors
May 3, 2010: Vendor selected and contract awarded
June 18, 2010: First draft working versions received for review by PSNH/NU
August 1, 2010: Comments delivered to vendor for incorporation in next version
September 1, 2010: Final document delivered to PSNH/NU for incorporation into final filing
September 30, 2010: Document filed with NH Public Utilities Commission

Minimum Bidding Requirements

- Familiarity with ISO-New England wholesale power markets.
- Chronological commitment and dispatch simulation modeling expertise for quantitative power plant asset valuation taking into account various market uncertainty conditions
- Expertise in stochastic simulation of multiple correlated sources of short-term and long-term power system uncertainty.
- Prior experience with presenting testimony to state utility commissions on plant valuation.

Please return bid information to:

Clifford Akerley
Sourcing Consultant
Northeast Utilities
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-6346
Email: akerlcs@nu.com

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-049
Page 1 of 1

Witness: Terrance J. Large
Request from: New Hampshire Public Utilities Commission Staff

Question:
Ref. Appendix G at page 1. LAI states that "In order to determine the benefit of PSNH's continued ownership and operation of Newington Station to its customers, the economic value of Newington Station must be determined under market conditions that are uncertain." Did LAI also determine the benefits of retiring, mothballing or selling the unit? If so, please identify where in the study those benefits are presented. If not, please explain why not.

Response:
LAI did not determine the benefits or costs of retiring, mothballing or selling the unit as those alternatives are outside of the scope of a continuing unit operations analysis.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-036
Page 1 of 1

Witness: Richard L. Levitan
Request from: Office of Consumer Advocate

Question:
Please provide copies of (or electronic links to) the 5 most recent CUO Studies conducted by Levitan.

Response:
LAI has not conducted other CUO studies. However, the knowledge and modeling methods applied to a CUO study do not differ much from those which LAI has applied in performing numerous asset valuation studies of new and existing generation units.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-066

Witness: Terrance J. Large
Request from: Office of Consumer Advocate

Question:
Please provide all information in the possession of PSNH or Levitan containing a projection of the market value of Newington Station if PSNH were to divest it?

Response:
PSNH has not performed a divestiture analysis for Newington Station nor are we in the possession of any projections of the market value of Newington Station if PSNH were to divest Newington Station.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 37

Public Service Company of New Hampshire
Docket No. DE 10-257

Data Request OCA-02
Dated: 05/16/2011
Q-OCA-016

Witness: Frederick White
Request from: Office of Consumer Advocate

Question:
Please explain any changes made during 2011 regarding how PSNH's generating plants are dispatched.

Response:

The approach for the dispatch of PSNH's generating plants has not changed during 2011. PSNH continues to optimize utilization of the generating plants for the benefit of ES customers.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-030
Page 1 of 1

Witness: David A. Errichetti
Request from: Office of Consumer Advocate

Question:
Referring to the response to Staff 01-068, please explain why for 2010 the Newington Average Energy Revenue in $/MWh is almost twice the Average On Peak Day Ahead Price for Newington in $/MWh.

Response:
Fundamentally, Newington's average energy revenue would only approach the Newington node average on peak day ahead energy price if Newington cleared a constant MW amount in the the day-ahead market in every hour of the year. This did not happen in 2010. In 2010 Newington ran in approximately 1,600 hours at an average level of 140 MWh/hr mostly in the real time energy market, and for a significant portion of this time it was dispatched for operating reserves. Furthermore, when dispatched to provide operating reserves Newington generally received net commitment period compensation which means its energy revenues equaled its offer costs and not its nodal location marginal price.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-02

Dated: 04/29/2011
Q-STAFF-026
Page 1 of 1

Witness: **Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. PSNH response to Tech 1-SP01. PSNH reports a revised average fuel expense for Newington for 2011 of $58.98/MWh. For 2010, fuel expense was reported at $19,787,000 and emissions allowance expense at $1,969,000 (see Staff 1-61) for a total of $21,756,000. With total 2010 generation at 224,667 MWh (see Staff 1-60), the average fuel expense for 2010 is calculated at $96.83/MWh. Please explain the reduction in average fuel expense from $96.83/MWh actual in 2010 to $58.98/MWh projected in 2011.

Response:
The revised 2011 results reflect economic operations over a range of possible states of fuel and energy prices, but did not include potential ISO-NE dispatch for operating reserves. These two differences account for most of the spread in average generation cost.

First, Newington Station 2010 operation reflected a unique solution that included a great deal of operation to provide operating reserves. When providing operating reserves the unit was not being dispatched on economics and as noted in other data request responses was paid for all its dispatch costs, not just the nodal LMP. Thus the 2010 costs are higher than 2011 in large measure because the unit was run out of merit to provide operating reserves.

Second, the stochastic simulation of fuel prices assumed a lognormal distribution, which means that more than half of the scenarios will have lower fuel prices than their expected (mean) value. Because we only observe one historical scenario, but the simulation model accounts for the distribution of fuel prices and energy prices, a direct comparison of an historical period with the average value over the set of scenarios is not an apples-to-apples comparison. While not exact, a more fair comparison would be with the median cost of generation instead of the mean cost.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-03
Dated: 06/03/2011
Q-OCA-002
Page 1 of 1

Witness: Richard L. Levitan
Request from: Office of Consumer Advocate

Question:
The first sentence in the response to Staff 02-026 reads:

The revised 2011 results reflect economic operations over a range of possible states of fuel and energy prices, but did not include potential ISO-NE dispatch for operating reserves.

For the years 2012 through 2020, is it also the case that the Levitan model did not include potential ISO-NE dispatch for operating reserves? If that is not the case, please explain how they were included.

Response:
According to the Secretarial letter dated May 9, 2011 in this proceeding, the third round of data requests to be served on June 3, 2011 was limited to questions derived from New Levitan Data supplied to the parties on April 26, 2011. PSNH therefore objects to this data response as not timely.

Notwithstanding this objection, PSNH states the following:

Yes, it is also the case that for the years 2012 through 2020 included in the Levitan model, the potential ISO-NE dispatch for operating reserves was not included. The scope of the model did not include operation of the ISO-NE system so it did not simulate decisions by ISO-NE for Newington Station to provide operating reserves.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request TC-02

Dated: 04/29/2011
Q-TC-013
Page 1 of 1

Witness: **Richard L. Levitan**
Request from: **TransCanada**

Question:
With reference to PSNH's response to Q-TC-013, please have Levitan explain why PSNH's historic negative net energy margins are not useful in informing Levitan's assessment of the forward looking, continuing operation of Newington.

Response:
The dispatch simulation model used by LAI, as is standard practice, assumes that a generating unit that has the flexibility to shut down will shut down when the spark spread is negative. The simulation analysis did not attempt to incorporate certain minor real-world constraints on that flexibility, such as the need to generate at times in order to provide test data. Models necessarily simplify some aspects of reality. In situations where there are a multiplicity of reasons for why a unit may be run despite providing a negative energy margin, it is preferable to examine the reasons qualitatively rather than simulate the factors within a quantitative model.

Also, as the CUO study discussed, it may be desirable from a risk management perspective to run Newington Station during some high-risk periods in order to protect load against the possibility of very high real time prices for market purchases. However, the simulation model, which was not a portfolio-based model, did not incorporate this aspect of PSNH decision-making. During such times, the recorded financial losses represent an insurance-like cost to prevent possible larger spot market costs.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-03
Dated: 06/03/2011
Q-OCA-007
Page 1 of 1

Witness: Richard L. Levitan, William H. Smagula
Request from: Office of Consumer Advocate

Question:
The response to TC 02-013 reads in part:

The simulation analysis did not attempt to incorporate certain minor real-world constraints on that flexibility, such as the need to generate at times in order to provide test data. Models necessarily simplify some aspects of reality. In situations where there are a multiplicity of reasons for why a unit maybe run despite providing a negative energy margin, it is preferable to examine the reasons qualitatively rather than simulate the factor's within a quantitative model.

a. Please provide a complete list of the "multiplicity of reasons" for why Newington ran in 2009 or 2010 despite providing negative net energy margins.
b. For each of the reasons listed in .(a), please provide the number of hours Newington ran in 2009 and 2010.
c. For each of the "multiplicity of reasons" provided in response to (a) above, please explain which of those situations are incorporated in the Revised Levitan model.

Response:
According to the Secretarial letter dated May 9, 2011 in this proceeding, the third round of data requests to be served on June 3, 2011 was limited to questions derived from New Levitan Data supplied to the parties on April 26, 2011. PSNH therefore objects to this data response as not timely.

Notwithstanding this objection, PSNH states the following:

a. In 2009, testing was done outside of economic operation for controls optimization testing, gas operational testing, post arc flash mitigation performance testing, particulate matter stack testing, winter claim capability testing and gas valve tuning. In 2010 Newington was dispatched outside of economic operation for ICR required stack testing and RATA testing. Operation during these periods likely resulted in negative energy margins in one or more hours.

b. Below is the number of hours associated with the reasons list in item a..
1/26/09 - Controls Optimization Testing = 12 hrs
1/28/09 - Controls Optimization Testing = 9 hrs
6/25/09 - Gas Testing = 19 hrs
6/26/09 - Gas Testing = 10 hrs
7/29/09 - Gas Testing = 11 hrs
10/13/09 - Post Arc Flash Mitigation Performance Testing = 9hrs
11/4/09-11/6/09 - PM testing on oil, winter audit = 44.2 hrs
11/9/09-11/18/09 - Gas valve tuning = 83.5 hrs
2/15/10-2/19/10 - ICR environmental testing = 66.75 hrs
7/15/10-7/16/10 - RATA testing = 30 hours

c. None of the reasons listed in part a were incorporated in the revised Levitan model.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 43

Public Service of New Hampshire

Manchester, NH 03105-0330
(603) 634-2701
Fax (603) 634-2449

The Northeast Utilities System

Stephen R. Hall
Rate & Regulatory Services Manager

E-Mail: hallsr@psnh.com

RECEIVED
MAY 02 2011
NH PUBLIC UTILITIES COMMISSION

May 2, 2011

Debra A. Howland
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: Reconciliation of PSNH's Energy Service and Stranded Cost for Calendar Year 2010
Docket No. DE 11-XXX

Dear Secretary Howland:

Enclosed please find the original and six copies of Public Service Company of New Hampshire's ("PSNH") testimony and exhibits supporting the reconciliation of revenues and expenses for PSNH's Default Energy Service Charge and Stranded Cost Recovery Charge for the calendar year 2010. As previously stipulated and approved by the Commission, PSNH's annual reconciliation filing is due on May 1.

This filing contains the testimony and exhibits of Robert A. Baumann, Frederick B. White and William H. Smagula.

Electronic copies have been sent to the Office of Consumer Advocate.

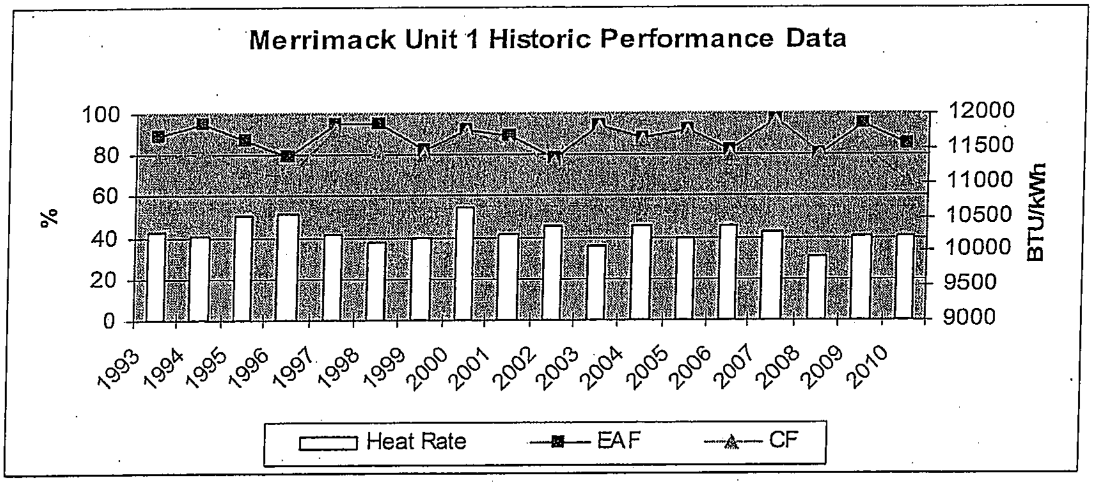
Sincerely,

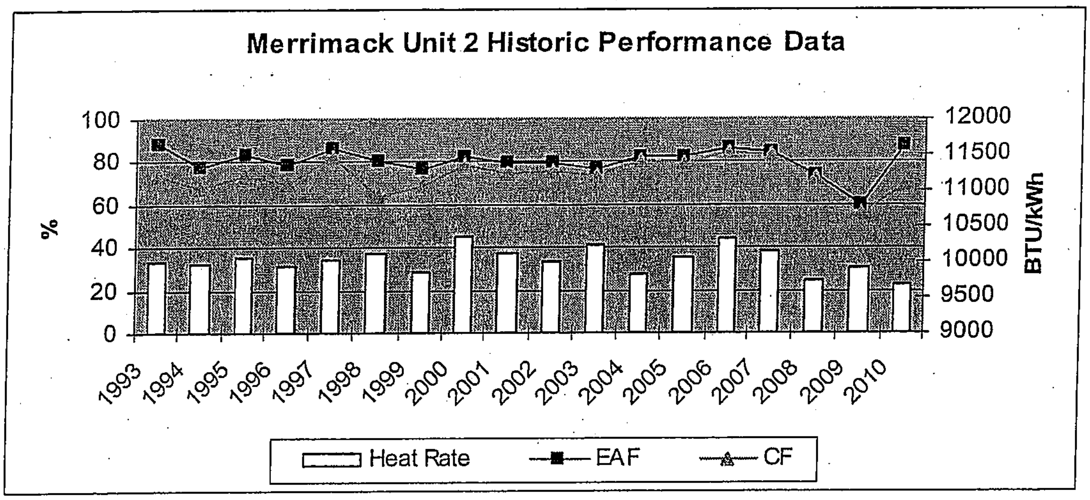
Stephen R. Hall

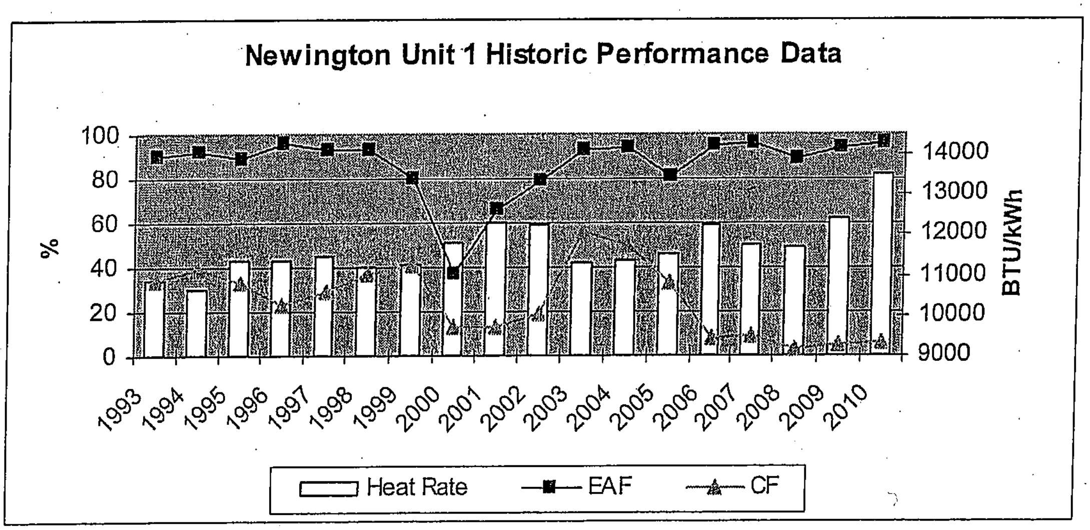
Stephen R. Hall
Rate & Regulatory Services Manager

SRH:kd
Enclosures

Fossil Plant Graphs – Planned Outages Included







Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-03

Dated: 06/10/2011
Q-STAFF-001
Page 1 of 1

Witness: **William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:

Ref. Staff 1-54. The response included quantities of fuel burned by fuel type at Newington Station in 2010. Please respond to the following questions:

a. Please confirm that the quantities shown in the third column, titled "Units Burned," are expressed in the units shown in the second column, titled "Unit;"

b. If the answer to part a. is in the affirmative, provide by fuel type the corresponding quantities burned in Btus. If it is negative, please clarify.

c. In Docket DE 11-094, PSNH provided a chart which appears to show that the actual average heat rate for Newington in 2010 was approximately 13,500 Btu/kWh. If the Btu data provided in response to part b. together with 2010 generation data provided in response to Staff 1-38 do not support a heat rate of 13,500 Btu/kWh, please explain the discrepancy.

Response:

a. PSNH confirms that the quantities burned by fuel type as shown in the third column for Newington are expressed in the units shown in the second column as BBLs., Gals., and MCF.

b. The information below provides by fuel type the quantities burned in BTUs for 2010.

#6 Oil MMBTU	#2 Oil MMBTU	Gas MMBTU	Total MMBTU
489,033.5	134,408.7	2,397,895.5	3,021,337.7

c The data above references the same core data as used in the filing in Docket DE 11-094.

Total 2010 generation	224,667.0
Heat Rate (BTU/KWH)	13,448

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-068
Page 1 of 2

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Ref. Appendix G at page 21. Please update Exhibit G.3 by including full year 2010 data.

Response:
Please see the attached table.

Data Request STAFF-01
Dated: 03/04/2011
Q-STAFF-068
Page 2 of 2

Newington Station Recent Operating Performance, 2000-2010

Year	Capacity Factor (%)	Service Factor (%)	Avail-ability (%)	Starts	RFO Use Share (%)	#2 Oil Use Share (%)	Natural Gas Use Share (%)	Newington Average RFO Cost ($/MMbtu)	Newington Average Natural Gas Cost ($MMbtu)	Newington Average Energy Revenue ($/MWh)	Average 1% S RFO Spot Price, NYH ($/MMbtu)	Average Natural Gas Spot Price, Dracut ($MMbtu)	Average On Peak DA Price, Newington ($/MWh)
2000	13.0	22.8	37.2	116	83.2	2.0	14.8	3.31	3.51		3.99		
2001	12.8	24.0	65.6	62	87.4	2.3	10.3	3.57	2.39		3.29		
2002	19.0	31.7	79.0	135	83.3	2.1	14.5	3.59	3.86		3.58	3.69	
2003	55.9	75.4	92.8	94	99.6	0.4	0.0	4.29	N/A		4.37	6.44	
2004	50.2	71.7	93.7	122	99.5	0.5	0.0	4.25	N/A	54.42	4.44	6.76	55.83
2005	33.6	47.0	80.5	117	98.9	1.0	0.1	5.30	7.50	75.84	6.63	9.83	80.34
2006	8.0	14.6	95.4	85	72.3	3.3	24.4	6.16	7.07	75.14	7.30	7.15	65.04
2007	9.4	15.7	95.7	39	92.0	2.4	5.6	10.17	7.82	84.81	8.57	8.01	72.19
2008	3.3	6.2	88.9	23	89.0	6.3	4.7	10.60	12.68	124.16	12.14	9.73	87.16
2009	5.2	10.4	94.2	39	74.1	3.5	22.4	7.42	5.87	74.27	8.92	5.05	44.75
2010	6.4	17.5	96.2	123	15.7	4.6	79.6	7.71	5.90	101.60	11.49	5.25	53.56

Notes
1 Average oil and gas cost and average energy revenue = total cost or revenue / total energy
2 Average oil and gas price and average on-peak price are time-weighted averages of NYH or Dracut prices
3 Residual oil price is 1% at New York Harbor
4 Natural gas price is at Dracut
5 On-peak DA power price is at Newington

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-033-SP01
Page 1 of 4

Witness: **William H. Smagula**
Request from: **Office of Consumer Advocate**

Question:
Referring to pages 3 and 4 of 34 of the work papers included with the response to Staff 01-091, please replace the numbers in the 2010 column with actuals for the year.

Response:
As was the case with Staff-01-061 and addressed in Staff-01-061-SP01, the original response to OCA-02-033 included renewable portfolio standard costs in emission allowance costs and some generation in August and September 2010 was valued in both the day ahead and real time energy markets. Also, in the original response the Expenses Plus Return on Rate Base calculation was incorrect and has been revised in this response. In addition, the original fuel BTU conversion factors have been updated to reflect the actual 2010 fuel factors calculated by PSNH. This last modification has no impact on the financial model or the results, it was updated for accuracy purposes only. The attached table corrects these items. The impacted lines are shown in bold type and highlighted.

Revenue Requirement Details (from Staff 01, Q-Staff-091 and Staff 01, Q-Staff-091-SP01)

Calendar Year		2010
Capacity Factor		6.41%
Expenses		
Non-Fuel O&M	$	6,945
Direct O&M		
Indirects		
Emission Allowances	**$**	**176**
Total O&M Expense	**$**	**7,121**
Fuel and Fuel Related O&M	$	19,787
Property Tax	$	654
Depreciation Expense	$	8,926
Total Expenses	**$**	**36,488**
Plant Values		
Gross Plant Value	$	144,158
Accum. Depreciation	$	102,758
Net Plant Value	$	41,400
Working Capital	$	856
Accumulated Deferred Taxes	$	(4,075)
Fuel Inventory (year end)	$	22,339
NOx, SO2, CO2 Allowance Inventory	$	454
Material & Supply Inventory	$	3,670
Total Rate Base	$	64,644
Average Return on Rate Base		11.21%
Return on Rate Base	$	7,244
Expenses Plus Return on Rate Base	**$**	**43,732**
Revenues/Benefits		
Energy	**$**	**21,459**
Capacity	$	18,688
Ancillary	$	254
10 MW Unitil Entitlement	$	-
Total Revenue	**$**	**40,401**
NET REVENUE REQUIREMENT	**$**	**3,331**

bold type in "2010" column denotes value change
emission allowance cost reduced $1,793 k
energy revenues reduced $1,370 k

Public Service Company of New Hampshire
Docket No. DE 10-257

Data Request OCA-02
Dated: 05/16/2011
Q-OCA-017
Page 1 of 1

Witness: Frederick White, Robert A. Baumann
Request from: Office of Consumer Advocate

Question:
Please update the response to Staff 01-001 dated October 21, 2010 in this docket

Response:

The requested data is not readily available, and it would require a significant amount of effort to update the calculation using January - March, 2011 actual data and re-forecasted data for April - December, 2011. However, since the cost and revenue data has not materially changed since PSNH responded to Staff 01-001, the undertaking of such an effort would not produce materially different results.

Public Service Company of New Hampshire
Docket No. DE 10-257

Data Request STAFF-01

Dated: 10/21/2010
Q-STAFF-001

Witness: Robert A. Baumann, Frederick White
Request from: New Hampshire Public Utilities Commission Staff

Question:
Reference Attachment RAB-1, page 1. Please provide, by generating unit, a) the total revenues listed by source and b) the total revenue requirements used in calculating the preliminary 2011 energy service rate. For purposes of this question, the hydro units and the combustion turbines can be shown as separate groups.

Response:
The tables shown on page 2 of 2 summarize by generating unit the estimate of forecasted revenue requirements and wholesale market revenues consistent with the preliminary 2011 energy service rate, in thousands of dollars. The revenue requirements are not typically tracked on a station or unit specific basis. In order to provide this detailed breakout, assumptions were made as to allocations to specific station or unit for items such as depreciation of common facilities, property taxes, payroll taxes, emissions allowances, material and supplies and allocation of PSNH's and NU's administrative and general expenses. Other column reflects certain Combustion Turbine costs, Wyman entitlement costs and certain intangible costs not allocated to specific stations along with the related revenues.

TABLE 1

The following summarizes by generating unit the forecasted costs for 2011 in thousands of dollars.

	Merrimack	Schiller #4,	Schiller # 5	Newington	Hydros	Other (5)	Total
Fuel Costs	$ 110,948	$ 21,571	$ 8,467	$ 4,703	$ -	$ -	$ 145,689
O&M costs (1) (2)	58,561	22,988	11,492	10,391	12,629	-	116,061
Depreciation (1) (3)	3,738	2,291	4,330	8,808	2,401	1,035	22,603
Property Tax (1) (4)	3,955	849	1,329	960	2,617	1,232	10,942
Payroll Tax (1)	1,063	437	219	170	248	-	2,137
ARO Amortization (1)	283	165	82	19	18	30	597
Return on Rate Base	17,291	5,040	7,224	8,256	4,920	456	43,187
Total Cost	$ 195,839	$ 53,341	$ 33,143	$ 33,307	$ 22,833	$ 2,753	$ 341,216

TABLE 2

The following summarizes by generating unit the forecasted revenues for 2011 in thousands of dollars. The energy revenues were calculated by multiplying forecasted MWH output by the forecasted market LMP, and does not include all fo the value that might be realized from actual operation during 2011.

	Merrimack	Schiller #4,	Schiller # 5	Newington	Hydros	Other (5)	Total
Capacity revenues	$ 19,219	$ 4,629	$ 1,796	$ 16,459	$ 2,351	$ 1,288	$ 45,742
Energy revenues (6)	130,412	24,334	12,618	5,181	15,089	-	187,634
Loc Fwd Reserve Mkt	478	231	-	-	-	458	1,167
Total Revenue	$ 150,109	$ 29,194	$ 14,414	$ 21,640	$ 17,440	$ 1,746	$ 234,543

(1) See Staff Set-01, Q-STAFF-003 for the O&M, Depreciation, Property Tax, Payroll Tax and ARO Amortization detail and assumptions.
(2) Schiller Station O&M allocated one-third to each unit.
(3) Schiller Station #5 depreciation allocated to unit based on net plant.
(4) Schiller Station #5 property tax allocated to unit based on property tax analysis from 2009 tax data.
(5) Includes Combustion Turbine, Wyman, and Intangibles not allocated to specific units.
(6) Calculated using forecasted MWH output times the forecasted market LMP.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-03

Dated: 06/10/2011
Q-STAFF-009
Page 1 of 1

Witness: **Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Page 8 of the Modeling System Overview appears to indicate that the natural gas fuel expenses for Newington were modeled based on a forecast of natural gas prices at Dracut plus summer and winter premiums. If correct, specify the size of the applied premiums by month and by year. Also explain how the premiums were incorporated in LAI's modeling of fuel expenses. Finally, clarify whether the same premiums were added to the Dracut natural gas prices that were used to calculate the energy market clearing prices.

Response:
Please refer to the confidential PSNH document "Levitan Data Requests for NT Station CUO.doc" provided on CD in response to OCA-1-062. The natural gas adders provided to LAI were premiums over the Dracut daily price posting on Platts Gas Daily of $0.50-$1.00/Dth in January and February and $0.10-$0.25/Dth in other months. LAI modeled the natural gas basis spread as the averages of the Jan.-Feb. range ($0.75/Dth) and March-Dec. range ($0.175/Dth) for the escalation base year 2010 and assumed a 2.4% annual escalation rate over the 2011 to 2010 study period.

The premiums were added to the cost of fuel used by Newington Station. The premiums were not included in the Monte Carlo modeling of daily stochastic natural gas prices. The premiums were not included in the calculation of Newington node energy prices by time-of-use block as a function of the Dracut gas price.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-02

Dated: 04/29/2011
Q-STAFF-008
Page 1 of 2

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
For each year during the period 2006 through 2010, please provide the five-year capital budget estimates for Newington Station.

Response:
Attached is Newington Station's 5 - year capital budget forecasts for the years 2006 through 2010.

Staff Request
Set 2, Q2-8
Docket No. DE 10-261
Staff Request 8

Newington Station

5 year Capital Budget Forecast

	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	1,748	1,080	1,442	3,570	2,170				
2007		1,080	1,567	3,570	2,618	4,860			
2008			2,050	1,361	2,218	4,400	2,270		
2009				1,860	1,210	2,848	1,770	4,900	
2010					500	500	500	500	500

183-A

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request TC-02

Dated: 04/29/2011
Q-TC-006
Page 1 of 2

Witness: **Richard L. Levitan,David A. Errichetti**
Request from: **TransCanada**

Question:
Relative to generating units listed in footnote 26 on page 38, please provide the following:

a. A list of unit retirements announced publicly by the resource owner;
b. Estimates of SCR installation capital costs assumed by Levitan to support the statement "owners will opt for retirement by 2016 rather than commit to the capital expenditure associated with SCR installation";
c. A list of the units that have in any way indicated their desire to not incur a capacity obligation in any NEPOOL Forward Capacity Auction through FCA 6;
d. A list of the units Levitan believes are not required for any local or zonal reliability need.

Response:

(a.) PSNH is unaware of any press releases by resource owners stating forthcoming retirements. PSNH is aware that a number of non-price retirements have been requested and ISO-NE maintains a status report which can be found using the following link: http://www.iso-ne.com/genrtion_resrcs/reports/sts_non_retrmnt_rqst/NPR_Tracking_External_03-21-2011.pdf.

The largest non-price retirement is Salem Harbor units 1 – 4. On May 9, 2011 the ISO-NE Reliability Committee approved the non-price retirement request for Salem Harbor 1 and 2, but rejected the non-price retirement request for Salem Harbor 3 and 4. ISO also reported that the preliminary preferred transmission solution to allow Salem Harbor 3 and 4 to retire is the reconductoring of some 115 kV transmission circuits. Details are CEII and can not be provided. Furthermore, PSNH is aware of units that have delisted in the Forward Capacity Auction per the links provided in response to part c.

(b.) In order to develop the projection of unit retirements that resulted from required capital expenditures on environmental compliance equipment, LAI relied on the Integrated Resource Plan for Connecticut dated January 1, 2010. http://www.brattle.com/_documents/UploadLibrary/Upload830.pdf That document provides a forecast of unit retirements as well as the underlying economics that support those retirement decisions, including SCR capital cost assumptions. The discussion of plant retirements begins at p. 1-14 of that document.

(c.) The following links provide what is readily available with respect to identifying resources that have sought to avoid capacity supply obligations other than the non-price retirements noted above. The result links get you to the answer quicker.

FCA 1 delist bids results:
http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/ferc_filing_b.xls

FCA2 delist bids results filing:
http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/fca_2_delist_bids.xls

FCA 3 after auction delist bids:
http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/fca3_after_auction_delist_bids.xls

FCA 4 after auction delist bids:
http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/fca4_after_auction_delist_bids%20(2).xlsx

FCA 5 informational filing:
http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-3034-000_03-08-11_fca_5_info_filing.pdf

(d.) LAI does not expect any generating units listed in footnote 26 on page 38 to be needed for reliability reasons (and would thus have their de-list bids rejected by ISO-NE) over the forecast period.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 52

Integrated Resource Plan for Connecticut

January 1, 2010

Prepared by:

The Brattle Group

Connecticut Light & Power
The Northeast Utilities System

The United Illuminating Company

The Brattle Group

Samuel Newell
Dean Murphy
Marc Chupka
Judy Chang
Mariko Geronimo

Connecticut Light & Power

The Northeast Utilities System

The United Illuminating Company

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SECTION 4: TRANSMISSION

SECTION 5: NUCLEAR POWER

SECTION 6: COMBINED HEAT AND POWER

SECTION 7: ENVIRONMENTAL REGULATIONS AFFECTING ELECTRICITY long-term decisions (invest in environmental controls versus retire). The assumptions and interdependent components of this multi-period analysis are described below, followed by an explanation of results and sensitivity analyses.

1.F.1 Assumptions

Potential Environmental Regulations Requiring Major Capital Expenditure

All units are assumed to be required to meet region-wide NO_X emission rate limits of 0.125 lbs/MMBtu by 2013 and 0.07 lbs/MMBtu by 2017 to facilitate region-wide Federal National Ambient Air Quality Standards (NAAQS) compliance, including Connecticut compliance under Clean Air Interstate Rule (CAIR). These rate limits were developed in consultation from the Connecticut Department of Environmental Protection (CT DEP, or DEP), and are based on Ozone Transport Commission (OTC) studies and recommendations on achievable NO_X rate targets. Non-compliant units with NO_X emission rates of 0.25 lbs/MMBtu or below are assumed to be able to meet the 2013 limit with temporary measures at relatively little cost, such as with a selective non-catalytic reducer (SNCR) or through adjustments to fuel or operations. These units must install a selective catalytic reducer (SCR) to meet the 2017 emission rate limit. All other non-compliant units must install a SCR to meet the 2013 and 2017 emission rate limits. To meet these emission rate requirements we also assume the following:

- **SCR capital costs:** Estimates of the overnight capital cost of SCR installation at Middletown 4, Montville 6, and Norwalk Harbor 1 & 2 have been provided by DEP staff. At Middletown 4 a SCR is assumed to cost \$113/kW, \$110/kW at Montville 6, \$123/kW at Norwalk Harbor 1, and \$119 at Norwalk Harbor 2. A capacity-weighted average of these values, \$114/kW, is assumed for all other units.
- **SCR revenue requirement:** The SCR capital cost is expressed in terms of a 10-year annuitized revenue requirement. This is derived using a capital charge rate of 22.5 percent, assuming 50/50 debt-to-equity ratio, a debt rate of 7 percent, and a 15 percent return on equity reflecting risk associated with merchant generation. There are also relatively small fixed O&M costs.
- **SCR emission rate reduction:** 90 percent.
- **Newington 1 exemption:** Newington 1, a 400 MW steam oil/gas unit in New Hampshire, is supported through Public Service New Hampshire's (PSNH) Energy Service (ES) rate, and is assumed to provide sufficient value to ES customers to warrant investing in an SCR in 2017 and operate in all year.

Fixed O&M While Operating or Mothballed

Data on unit-specific Fixed O&M (FOM) are based on reliability agreements with the ISO and data compiled by Ventyx. If either (1) unit-specific data are unavailable, or (2) the unit-specific FOM value is inconsistent with FCA de-list bids or lack thereof, then we assume generic FOM values of \$30-34/kW-year. Rather than retiring permanently, a unit may choose to temporarily go offline ("mothball") during poor market conditions, and then return online when market prices are more favorable. The annual cost to mothball a unit is assumed to be one-half of FOM

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-033
Page 1 of 4

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Referring to pages 3 and 4 of 34 of the work papers included with the response to Staff 01-091, please replace the numbers in the 2010 column with actuals for the year.

Response:
Attached is PSNH's attempt to replicate LAI's worksheet with 2010 actual data. As discussed during the technical session on March 30, 2011 these work papers are un-audited intermediate/transitory artifacts of a long term analytical process. The data in question was not used for the CUO analysis.

Revenue Requirement Details (from Staff 01, Q-Staff-091 and Staff 01, Q-Staff-091-SP01)

Calendar Year		2010
Capacity Factor		6.41%
Expenses		
Non-Fuel O&M	$	6,945
Direct O&M		
Indirects		
Emission Allowances	$	1,969
Total O&M Expense	$	8,914
Fuel and Fuel Related O&M	$	19,787
Property Tax	$	654
Depreciation Expense	$	8,926
Total Expenses	$	38,281
Plant Values		
Gross Plant Value	$	144,158
Accum. Depreciation	$	102,758
Net Plant Value	$	41,400
Working Capital	$	856
Accumulated Deferred Taxes	$	(4,075)
Fuel Inventory (year end)	$	22,339
NOx, SO2, CO2 Allowance Inventory	$	454
Material & Supply Inventory	$	3,670
Total Rate Base	$	64,644
Average Return on Rate Base		11.21%
Return on Rate Base	$	7,244
Expenses Plus Return on Rate Base	$	35,699
Revenues/Benefits		
Energy	$	22,829
Capacity	$	18,688
Ancillary	$	254
10 MW Unitil Entitlement	$	-
Total Revenue	$	41,771
NET REVENUE REQUIREMENT	$	(6,072)

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-039
Page 1 of 2

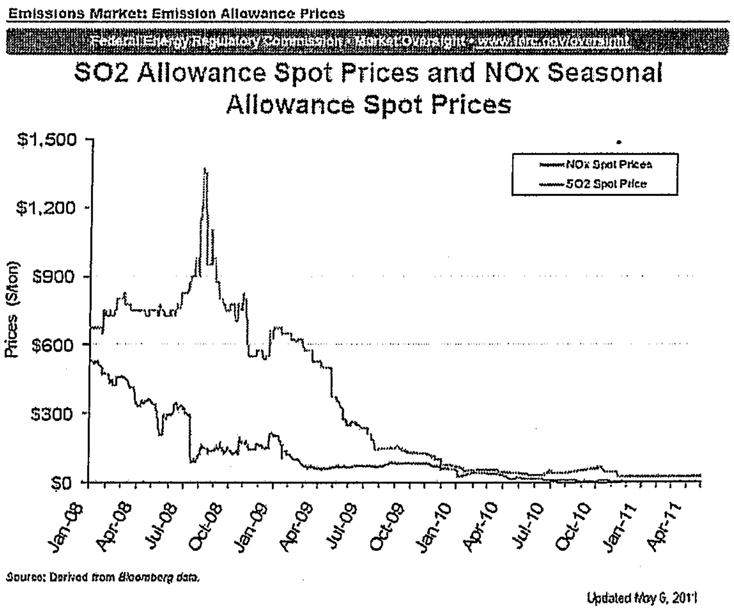
Witness: Richard L. Levitan
Request from: Office of Consumer Advocate

Question:
The annual Emissions Allowance expenses shown in the revised Exhibit G.12 on Bates page 227 range from $300-500,000 annually. Exhibit G.1, Bates page 196, which wasn't revised, shows the annual Emission Allowance expenses in 2008-2009, in the range of $2 million. Why has the annual forecasted level declined so much from prior actual expense levels?

Response:
Annual emission allowance expenses are the product of emission allowance prices and the number of emission allowances used. In turn, the number of emission allowances used is a function of energy generation and the natural gas versus oil shares of fuel consumption. RFO emits SO2 while natural gas does not, and RFO emits nearly twice as much NOx and about 50% more CO2 as natural gas.

In 2008, the natural gas share of fuel use was 4.7% in 2008 and 22.4% in 2009. Due to forward market natural gas prices per MMBtu much lower than RFO prices in the 2011-2020 period, lower-emitting natural gas was simulated to be 99% of the fuel mix in 2011 and very high shares in all following years.

Emission allowance prices, particularly for SO2 and NOx, have fallen dramatically since 2008 as the following chart from FERC based on Bloomberg data shows. The study used forward market SO2 allowances prices of $7/ton in 2011 falling to $2.70/ton in 2020, and NOx allowance prices of $34/ton for in all years, 2011 to 2020 (see the response to Staff-01, Q-Staff-079, Attachment 5). Annual emission allowance cost in 2008 and 2009 reflect the actual inventory cost of allowances expensed for compliance.



RGGI CO2 allowance expenses began in 2009. The average price of current period allowances in auctions 1-6, held from 9/25/2008 to 12/2/2009, was $2.91/ton, and the average price in auctions 7-10, held from 3/10/2010 to 12/1/2010, was $1.92/ton. The clearing price of the 11th auction, held 3/9/2011, was $1.89/ton, similar to the forward price LAI used for 2011 of $1.92/ton (see the response to Staff-01, Q-Staff-079, Attachment 5).

The substantial declines in SO2 and NOx allowance prices from 2008 to 2011 and the decline in CO2 allowance prices from 2009 to 2011 and the projected very high share of natural gas usage explain the reduction in annual emission expenses, despite an increase in generation expected during the forecast period.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-01
Dated: 02/25/2011
Q-OCA-041
Page 1 of 1

Witness: William H. Smagula
Request from: Office of Consumer Advocate

Question:
Section B.5.1 Fuel Inventory Management on page 100 states: "Ten to twenty days of full-burn equivalent of residual oil is maintained in-inventory on-site at Newington Station." Please provide:

a. A chart showing the average monthly inventory levels of residual oil at Newington Station from January, 2009 to date and forecasted for the next 5 years.
b. What has been the average daily full-burn amount of residual oil for Newington Station for 2009 and 2010?
c. Any and all studies PSNH has conducted regarding selling off some of the residual oil inventory.

Response:
a. PSNH maintains end of month inventories for fuel at its generating stations. Below lists the end of month inventories in gallons from January 2009 through February 2011. PSNH does not forecast Newington's oil use on a monthly basis over the next 5 years.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	End of Month Inventory											
2009 (actual)	21623904	24634570	24530475	24434300	24377378	24296146	23873475	23330400	23262573	23028178	21748222	20975626
2010 (actual)	20523906	20103181	20068901	19837293	19833093	19659154	18595691	17993393	17819159	18018553	17926437	17431644
2011 (actual)	14850535	14290786										

b. Newington Station's daily full-burn residual oil amount has not changed. However, in 2009 Newington used 95% oil and 5% natural gas to generate with a 5.2% capacity factor and a 10.4% service factor. Conversely, in 2010 Newington used 17% oil and 83% natural gas to generate at a 6.4% capacity factor and a 17.2% service factor.

c. PSNH is continuing to investigate the viability, logistics and risks of moving oil at Newington to the dock and on to a barge for sale. The station is working with an engineering firm to determine a design and system modification. Once complete a procedure for moving the oil must also be developed. Newington Station personnel have discussed this potential effort with the Coast Guard, who at this point have no specific objections. Finally, the station is identifying any other agencies that need to be contacted.

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 56

Witness: Jody J. TenBrock
Request from: Office of Consumer Advocate

Question:
Comparing Attachments RAB-2, page 6 of the December 16, 2010 filing with the May 4, 2011 filing, the average Fossil Fuel Inventory has increased by over $10 million. Please explain why, as well as what steps PSNH is taking to control fossil fuel inventory levels, including at Newington Station.

Response:
Coal inventories have risen from near-minimum targeted levels to higher levels, but not excessively high, due to increased coal deliveries and lower capacity factors of the coal-fired units, while the Merrimack Station units have been in planned outages. It is expected that inventories will decrease during the the course of the summer months as the unit capacity factors increase. Following a study of selling a portion of Newington Station's residual fuel oil in order to lower its inventory level, it was decided to retain the oil as it is priced at approximately half the current market price and it is expected that Newington Station will run on residual oil during periods when natural gas prices in New England spike high.

Public Service Company of New Hampshire
Docket No. DE 10-257

Data Request OCA-02
Dated: 05/16/2011
Q-OCA-003
Page 1 of 1

Witness: Jody J. TenBrock
Request from: Office of Consumer Advocate

Question:
What is the current oil inventory in both gallons and dollars at Newington Station? What are the forecasted amounts as of December 31, 2011?

Response:
The oil inventory at Newington Station is currently at 14,251,594 gallons (339,324 barrels) with a value of $19 million. The forecasted amount of residual fuel oil in inventory on December 31, 2011 is 13,915,594 gallons (331,324 barrels) with a value of $18.5 million.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request OCA-02

Dated: 04/29/2011
Q-OCA-024
Page 1 of 28

Witness: **Terrance J. Large**
Request from: **Office of Consumer Advocate**

Question:
Attached to the Response to Staff 01-047 is a "Proposed Addendum to Determine the Real Option Value of the Newington Station" from Levitan to PSNH dated June 23, 2010.

a. The letter references an Original Proposal dated April 26, 2010 and a second proposal of June 20, 2010. Please provide copies of those 2 proposals.

b In the second paragraph of the letter is the statement: "Notably, we will not make any structural modifications to the valuation technique that addresses the potential impact of the proposed HQ HDVC transmission line to southern New Hampshire, nor will we consider PSNH's portfolio attributable to interaction effects between Newington and other generation assets." Please provide copies of all documents Leviton provided to PSNH or that PSNH provided to Leviton related to these issues that are dated prior to June 23, 2010.

c. On page 3 of that document under Task 1-Qualitative Analysis of Economic and Reliability Value is a bullet under "We will review and evaluate" which reads: "Potential repowering of Newington in order to take advantage of existing electrical and natural gas interconnections, oil tankage and conversion capability to low sulfur diesel, community support, and other infrastructure capability." Please provide copies of all analyses Levitan conducted regarding potential repowering.

d. Page 8 of that document under Data Inputs Required contains a bullet which reads: "Any prior short-term or long-term studies that have been conducted for Newington." Please provide copies of all such documents which were provided to Levitan.

Response:
a. Please see attached files.

b. Please see attached email communication between PSNH and Levitan.

c. Levitan did not conduct any analyses related to potential repowering of Newington Station.

d. Please see the response to OCA-01, Q-OCA-062 and TS-01, Q-TECH-004.

RE: PSNH Meeting on Wednesday, June 16
From: David W. Packard < PURCHASING PSNH > < 720-2299 > 06/18/2010 10:39 AM
To: rll
Cc: '"Ellen Cool'", Erica L. Menard, '"Jack Elder'", '"Rich Carlson'", sgp, Erica L. Menard

History: This message has been forwarded.

Good Morning Richard -

As promised, here are the additional outstanding issues that we want Levitan to consider and/or include in your revised scope of services (supplemental proposal) for this project. Please address these items along with the items in my 6.15.10 email below. As with the supplemental proposal, if these prompt any further questions that require clarification, please address them to both Erica and me.
****

1) Analysis Timeframe
Regarding the question as to whether to extend the analysis beyond the original 2020 timeframe requested. PSNH would like to keep the end date at 2020. Also, PSNH requests that Levitan indicate whether they are expecting to provide a cumulative NPV by year as an output.

2) Hydro Quebec
Do not include the proposed Hydro Quebec HVDC transmission line in the analysis as it is currently only a proposal

3) Relevance of PSNH's generation asset portfolio as opposed to only the Newington Station

PSNH would like the analysis to be performed for Newington Station only and not the portfolio. Referencing page 9 of the proposal submitted, PSNH is interested in performing the analysis for Newington Station in isolation without the use of MarketSym. Page 9 of the proposal indicated that LAI would be developing a customized model to quantify the sources of NT's physical or real option value.

As a supplement to what was provided in our initial scoping document and our discussions on June 16th, we've tried to be a little more clear about what we are asking for.

If one were to take a static view of forward energy prices and NT's expected variable costs to generate, the benefits derived from energy markets would be minimal (given currently expected market conditions). If one were to then recognize in that analysis the uncertainty surrounding expected market conditions, the benefits would be greater than in the static analysis. (It seems that Newington is much like a daily peak option, the value of which would be roughly equivalent to this gross value.) The positive delta between this greater value and the static analysis value would quantify PSNH's view of the hedge value, consistent with the manner in which it has been described to regulators.

Regarding insurance value, it is the value of NT providing a cost ceiling within PSNH's resource & load portfolio. There are many ways to close a gap between PSNH's other (baseload) resources and an expected load curve (subject to customer ingress & egress). Primarily, the insurance notion is that to the extent this gap is not fulfilled in its entirety, NT provides a cost ceiling which mitigates risk (allows us to sleep at night) and avoids other potentially expensive means of closing the gap (strips/options/etc). Insurance is the flexibility the resource provides in this portfolio management context. And it's possible that the insurance value is subsumed in the hedge value described above.

Also, with respect to the hedge, insurance and capacity price forecast we want to be sure that Levitan will recognize the capacity market "peak energy rent" provision. This doesn't have to be written in the proposal and can be discussed in more detail once the work begins.

We believe that through the proposal and discussions you have a general understanding of what we're looking for, but would like to understand more about the approach in the supplemental proposal.

4) Outputs
PSNH requests that Levitan provide PSNH with energy, capacity, emission allowance, CO2, etc. price forecasts that are being used in the analysis for use in other parts of the IRP

5) Report Format / Level of Reporting
PSNH requests a report, on the 30 page side rather than a power point presentation or a lengthy report. In terms of the report content, here is a rough approach to use:
25% education as to what a CUO study is, what is included and what is not included
25% qualitative
50% quantitative

6) Data Inputs
PSNH requests that Levitan include a list of data inputs that PSNH will need to provide in its supplemental proposal

Thanks in advance for your quick turnaround,

DWP

David W. Packard
Senior Sourcing Consultant
Purchasing Division
Northeast Utilities
P: 603-634-2299
F: 603-634-2449

David Thank you for your time and that of your c... 06/17/2010 01:51:42 PM

From: <rll@levitan.com>
To: David W. Packard/NUS@NU
Cc: Erica L. Menard/NUS@NU, "'Rich Carlson'" <rlc@levitan.com>, "'Ellen Cool'" <egc@levitan.com>, <sgp@levitan.com>, "'Jack Elder'" <jje@levitan.com>
Date: 06/17/2010 01:51 PM
Subject: RE: PSNH Meeting on Wednesday, June 16

David
Thank you for your time and that of your colleagues yesterday. It was a constructive session and we look forward to the privilege of this engagement. The conflict resolution process before the CT DPUC will commence this afternoon. The request will necessarily disclose PSNH (not NU). In prior COI requests, we have not copied the potential client. I am therefore hesitant to do so here but will accommodate your request if you insist. I should be able to forward you their response for your file, however.

We will be working on the revised proposal today and tomorrow. I am hopeful it will be ready for release tomorrow aft. LAI team is particularly interested in: (i) the relevance of the HQ project w/ respect to the simulation economics and probabilistic modeling (ii) the relevance of PSNH's generation asset portfolio as opposed to only the Newington Station (iii) your preference re formal documentation and statistical heft. Re (ii), a portfolio approach will be much more expensive than the NTE discussed to date and will necessarily intensify both the work load and the level of interaction w/ PSNH team.

Pls advise at your earliest convenience.
Richard

From: packadw@nu.com [mailto:packadw@nu.com]
Sent: Thursday, June 17, 2010 1:11 PM
To: rll@levitan.com; rlc@levitan.com; Jack Elder
Cc: menarel@nu.com
Subject: Fw: PSNH Meeting on Wednesday, June 16

Gentlemen -
I wanted to extend our thanks for the time you spent with us yesterday; particularly since it was on somewhat short notice.

In response to your questions after I left:

a. If you would, please proceed with the process of notification to the CT DPUC of the potential engagement for this PSNH study. If you need to disclose PSNH or NU by name, could you provide us with a copy?

b. There were several technical questions concerning the size of the report, timeframe, etc. that you asked of Erica and her team. We are formulating our responses and expect to get back to you promptly (most likely tomorrow).

Please provide your revised proposal, or addendum, based on our discussions as soon as practical.

Best regards, DWP

David W. Packard
Senior Sourcing Consultant
Purchasing Division
Northeast Utilities
P: 603-634-2299
F: 603-634-2449

----- Forwarded by David W. Packard/NUS on 06/17/2010 01:01 PM -----

From: David W. Packard/NUS
To: rll@levitan.com, rlc@levitan.com
Cc: Erica L. Menard/NUS@NU
Date: 06/15/2010 11:20 AM
Subject: PSNH Meeting on Wednesday, June 16

Good Morning Gentlemen -
After a discussion with Erica Menard, we would like to assure that, in addition to the technical presentation, you will also be fully prepared to discuss the following items:

1. Proposal: "LAI will be able to meet the overall time objective of delivering a final report and testimony or affidavit by September 1, 2010. The current expected schedule has seven weeks to prepare a first working draft and another six weeks for PSNH to return comments to us. We suggest that we keep PSNH abreast of our progress throughout the assignment, so that we can safely extend the seven week draft deadline to nine weeks and still have a full month for PSNH to return comments."

Comment: Please discuss LAI's current proposed schedule. In particular, discuss if LAI has any other commitments that will impact upon the timely completion of this study and follow-on testimony.

2. Proposal: "LAI has provided lump sum pricing for the three tasks as required. We have budgeted a reasonable number of hours to fully value the real option benefits that Newington Station provides, work closely with PSNH staff, and incorporate changes to our report based on your comments. Our prices are not-to-exceed, and could be less if our work progresses easier than envisioned."

Comment: Please discuss the estimated cost breakdown of the three separate tasks, including the estimated hours and the individuals who would be performing the work. Please discuss the method of tracking and reporting hours as a method to minimize the costs as expressed in your last sentence.

3. Comment: Please discuss LAI's potential conflicts in meeting this scope as it may pertain to other work performed, or other LAI clients. Additionally, please be prepared to give details if LAI has performed any other studies that discuss Newington Station directly or indirectly.

4. Comment: Please discuss how LAI will support a potential audit by the NHPUC of the methods and/or software utilized by LAI to create the report.

We look forward to meeting you tomorrow.

Thanks, DWP

David W. Packard
Senior Sourcing Consultant
Purchasing Division
Northeast Utilities
P: 603-634-2299
F: 603-634-2449

DE 10-261 PSNH IRP
Testimony of Traum
Attachment KET - 59

1. INTRODUCTION AND SUMMARY

1.1. Purpose and Overview of analysis

Northeast Utilities ("NU") and NSTAR subsidiaries have entered into a joint venture, Northern Pass Transmission LLC ("NPT"), to develop the Northern Pass Transmission Line ("NPT Line" or the "NPT Project"). On October 4, 2010, NPT entered into a forty year transmission service agreement with H.Q. Hydro Renewable Energy, Inc. ("HQHRE"), to facilitate delivery of power generated in Québec to the New England transmission system. The NPT Line will provide capacity to deliver up to 1,200 MW of power to New Hampshire, allowing a significant amount of power generated by plants burning fossil fuels to be replaced with imported power generated predominantly by hydroelectric facilities in Québec. The additional deliveries of power from Québec to New England will supplement imports on the current ties between the systems, which are fully utilized in most peak hours throughout the year. The capacity provided by the NPT Line will therefore relieve congestion on the transmission interface between Québec and ISO New England Inc. ("ISO-NE") by allowing more competitively priced power from low incremental cost resources in Québec to be delivered in the hours when New England prices are highest but existing transfer capacity is exhausted.

At the request of NPT, CRA has prepared an assessment of the congestion mitigation impacts of the NPT Line and resulting price reductions in New England. This report summarizes CRA's analysis of the ISO-NE electricity market and power system under scenarios with and without the NPT Line in service. Specifically, CRA has estimated the hourly operations of the ISO-NE system for each scenario and compared electricity prices, wholesale power costs, and power plant operations between the two scenarios to quantify the impact of the congestion mitigation and increased supply provided by the NPT Line.

Section 1.2 provides a summary of the principal results of CRA's study. Section 2 follows with background information about the NPT Project, the Hydro Québec system, the ISO-NE market, and the expected impact of the Line. Section 3 describes the analytical methodology and key assumptions utilized in the study. Section 4 presents the quantitative results regarding the impact of the NPT Line and Section 5 provides a summary of key conclusions.

1.2. Principal Results

The principal results of CRA's analysis include:

- The NPT Line will reduce congestion between Québec and ISO-NE by:
  - (i) allowing more competitively priced energy to be imported in ISO-NE, displacing higher cost generation on the ISO-NE system, and
  - (ii) allowing more of the energy imported from Québec to be delivered during peak hours when marginal generation costs and prices in New England are highest.

  This reduced congestion will lower New England power prices and reduce costs for wholesale load customers. CRA's base case estimate of the cost reduction to wholesale load customers is $1.58/MWh, or $206 million in 2015 and $2.30/MWh, or $327 million in 2024. These wholesale cost savings should be passed on to retail customers through lower electricity rates driven by lower prices in standard offer procurements and lower costs to competitive retail suppliers.

- Without the NPT Line, existing ties are expected to be fully utilized in 99.8 percent of peak hours. The capacity of the NPT Line allows energy delivered in other, lower-priced hours, or delivered to lower-priced locations in New York and Ontario, to be reallocated to deliveries in New England during these peak hours, when (and where) the power is most valuable.
- Based on the quantity of energy expected to be available for Hydro Québec (referred to as either "Hydro Québec" or "HQ" herein), the parent company of HQHRE, to export from Québec to neighboring markets, CRA's analysis shows that as much as 7.7 TWh of energy would be delivered to ISO-NE via the NPT Line in 2015, the first year the Line is expected to be operational. By 2024, imports on the Line are expected to grow to 8.9 TWh, with the increased utilization driven by expansion of the hydroelectric generating capacity in Québec. Accounting for reductions in the net imports of power into ISO-NE on other AC and DC ties with neighboring markets, the analysis shows that total net imports to New England will increase by 5.3 TWh in 2015 and 6.4 TWh in 2024. This modeled level of exports from Québec is based on projected export capability for the Hydro Québec system. Under open access provisions in the TSA, other competitive power marketers may also have access to unused transmission capability on the Line from time-to-time, potentially allowing for additional utilization.
- In order to provide a conservative estimate of the reduction in congestion and wholesale power costs in New England, CRA's analysis has examined a base case with assumptions that represent conservative expectations for market conditions. The likely range of actual market conditions also includes scenarios under which the reduction in congestion, displacement of thermal generation, and wholesale cost reductions would be greater. In particular, higher natural gas prices, more limited renewable capacity additions, and unit retirements would all tend to increase the benefits of the project. Moreover, CRA has conservatively assumed that currently projected growth in exports from Québec will occur whether or not the NPT Line is built. However, absent the NPT Line, these additional exports would be delivered during lower value periods with lower net revenues to Hydro Québec, which could result in delaying the development of the resources that will allow growth in total exports. If more projects supporting exports were developed as a result of the NPT Line, the impact of the line on imports, reduction in fossil-fueled generation in New England, and wholesale cost reductions would be greater.
- Under the base case scenario modeled, the increased net imports to New England would lead to the displacement of generation from fossil-fueled generators totaling 5.3 TWh in 2015, most of which will be from gas-fired generating units. If, as a result of their ongoing build of new hydro-electric facilities, Hydro Québec has more surplus energy than modeled, exports could increase to a level that would support additional deliveries on the NPT line, up to 10.5 TWh. For every additional TWh of imports that displaces gas-fired generation, carbon emissions would be reduced by approximately 0.44 million tons, up to 5 million tons total.