RAP Energy solutions for a changing world

Widening Energy Regulators' Circles of Interest:

State Examples of Energy Regulations and Processes That Consider Environmental Impacts

Authors:
Brenda Hausauer & John Shenot

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1. Introduction

The years ahead will see many changes in the fields of energy and environmental regulation. In fact, some of these changes have already begun. As global warming has become an ever larger problem, federal and state policies on air emissions and a range of other issues have started to change. Meanwhile, certain energy technologies and processes have improved and become more affordable, including renewable technologies, shale gas extraction, and others. The electric generation fleet and distribution system have aged, and transmission systems require upgrades and expansion. In this shifting landscape, the economic viability and profitability of electricity sources is also changing.

Consider just a few changes that have occurred in the past two or three years. Natural gas prices fell by almost 50% – from $6.98 to $3.59 per thousand cubic feet – from January 2010 to August 2012.[1] Coal plant owners announced plans to retire about 30 GW of U.S. coal plant capacity (roughly 10% of total U.S. coal capacity) by 2016.[2] Budgets for electric and natural gas energy efficiency programs increased from $5.3 to $8.0 billion between 2009 and 2011.[3] And utility-scale photovoltaic (PV) capacity increased from 70 MW to 1,052 MW between 2008 and 2011, while wind capacity increased from 24.7 GW to 45.2 GW during the same period.[4]

Such changes are significant for the electric industry, and their impacts and influences are complex and far-reaching. With so many factors changing simultaneously, it can be extremely difficult for energy regulators to chart a secure path into the future. What is more, the stakes are high. Decisions that energy regulators make in the next several years on generation, distribution, and transmission involve investments that will remain for 30 or 40 years or longer. It falls to energy regulators to ensure that investments are made wisely during the next several years, with an understanding of the risks associated with each of their choices under possible future scenarios.[5] To understand the risks, energy regulators must understand the current and possible future environmental regulations, and the value of all energy and demand sources when environmental and public health benefits are included. Historically, energy regulators' circle of interest has been drawn around the reliability, adequacy, and affordability of our electric system. That circle now needs to widen to include air, water, and other environmental and public health impacts, and the agencies that deal with those issues.

In the past, state energy regulators often have not dealt deeply with environmental issues or interacted closely with their counterparts in state air and other environmental regulatory agencies. Air and energy regulators have important similarities, such as their common goal of serving the best interest of the public. But, there also are differences between the areas of concern and primary operating procedures of each, as summarized in Table 1.[6]

[1] USEIA, 2013.
[2] Brattle Group, 2012.
[3] Includes industrial, commercial, residential, low-income, load management, and other efficiency programs. Wallace & Forster, 2012.
[4] USEIA, 2012a, 2012b.

[5] For a fuller treatment of this topic, see Binz, et al, 2012.
[6] Both state energy and air regulators undertake additional processes and have more responsibilities than those listed in Table 1. For example, energy regulators provide licenses for projects, and both energy and air regulators undertake rulemakings. However, this table lists the primary responsibilities and processes of each.

For energy regulators, air and other environmental regulations are key determinants in the future viability and profitability of many energy resources. And, state air regulators' choices of policies to achieve compliance with federal regulations often impact energy use. For example, end-of-pipe emissions controls that may be implemented by air officials may have an "energy penalty," referred to as parasitic load, impacting the energy output of certain plants (i.e., because emissions controls themselves use energy to operate, their installation will reduce the efficiency of the generator on which they are installed). When energy regulators plan, approve utility investments, and make other regulatory decisions without incorporating environmental considerations, ultimately more costly supply options or solutions can be chosen, opportunities for less costly options can be passed by, and money, time, and resources lost. Once made, many such decisions are hard to redirect later and commit states, utilities, and ratepayers to specific outcomes for decades. To be effective, energy regulators now must find ways to regularly incorporate environmental issues into their processes, and to do so with the help of their counterparts in environmental agencies. When they do so, the result is better energy policy. Some states have started to proactively do this in various ways, providing a good learning opportunity for states which have not yet begun the process. This report describes the efforts of selected states that have:

- Institutionalized coordination between energy and air regulators;
- Considered forthcoming environmental regulations in Commission proceedings;
- Considered environmental issues and upcoming regulations in resource planning or procurement processes; and
- Incorporated environmental and public health benefits in cost-effectiveness tests when selecting energy efficiency programs and when conducting evaluation, measurement, and verification of energy efficiency programs.

Table 1: State energy and air regulators' primary authorities, responsibilities, and areas of intersection

Type of state regulator	Statutory authority	Main responsibility	Processes employed	Regulators overseen by	Areas of intersection
Energy Regulators	Largely state-specific authority	Electric system reliability, safety, and adequacy at fair prices	Hold quasi-judicial proceedings; determine decisions based on evidentiary record	Elected state officials (though regulators have much autonomy, and are sometimes themselves elected)	Air regulations can change the economics of power plants; air regulators set policies that impact energy use
Air Regulators	Largely federal Clean Air Act authority, delegated to states	Healthy air quality that complies with federal standards	Issue regulations to meet federal laws and maintain air quality; monitor air quality; ensure that regulations are met	Elected state officials and the U.S. Environmental Protection Agency	Energy generation can worsen air and water quality, land use, and create disposal issues; energy policy can worsen or improve air pollution compliance

For example, Massachusetts created one state agency overseeing environmental regulation, utility regulation, and energy policy. The Colorado General Assembly passed a law that required utility commission consideration of new and forthcoming EPA air pollution regulations. Delaware's principal regulated utility now is required to include environmental benefits in its resource planning process. And Wisconsin uses cost-effectiveness tests that include environmental benefits for screening energy efficiency programs and for conducting evaluations of those programs. These and other examples are described in more detail below.

2. Institutionalizing Communication and Coordination Between Energy Regulators and Environmental Regulators

If utility commissioners are not aware of current and expected future environmental regulations, they cannot fully account for environmental issues when they make decisions. Certainly, some of the information they need will be entered into the formal record under various cases before the Commission. However, the information that is entered into the record is often so specific to an adjudicated case before the Commission that all context is lost. Furthermore, the record will often reflect only the status quo of environmental regulations, without consideration of known or possible changes to those regulations in the future. The people who know the environmental regulations best – state environmental regulators – typically are not parties to the proceeding, and their expertise may never be reflected in the record. Thus, utility commissions occasionally make regulatory decisions that have profound environmental or economic impacts without adequately considering environmental regulatory risks, and environmental regulators too often learn of these decisions only after they are finalized.[7]

[7] In just the past few years, utility commissions in several states approved major capital investments in retrofits at coal-fired power plants. Today, some of these power plants are slated for retirement, in whole or in part due to new environmental regulations like the EPA's Mercury and Air Toxics Standard. The investments in these soon-to-be-retired power plants will almost certainly become stranded assets that cost ratepayers dearly, and they also represent a lost opportunity to invest in cleaner resources like energy efficiency. This suggests that the potential impacts of forthcoming mercury rules probably were not considered adequately when utility commissions approved those investments. Similarly, in many states utility commissions still treat the regulation of greenhouse gas emissions from power plants by the EPA as a future possibility rather than an inescapable outcome of current federal law as decided by the U.S. Supreme Court. Better communication with environmental regulators might help clarify this misunderstanding.

Environmental regulation is an incredibly dynamic field, one where even those directly involved struggle to stay abreast of the latest developments in federal and state laws, federal and state regulations, judicial decisions, local permitting decisions, and enforcement actions. It is unrealistic to expect that utility commissioners, in addition to managing all of their other responsibilities, will independently follow these developments and know enough about what's happening (or soon to happen) to contact the environmental regulators and ask the right questions on an "as needed" basis. Most utility commissioners could benefit from a process or structure that *institutionalizes* regular communication and coordination between themselves (or their staff) and environmental regulators. But before we discuss how to do that, it is necessary to understand why this kind of communication and coordination does not routinely happen. In most state governments, Governors exercise control over cabinet agencies and try their best to ensure coordinated policy approaches. However, most states have established their utility commissions as independent agencies led by Commissioners who, once appointed and confirmed to their positions, act independently of the Governor and Legislature. Furthermore, Commissions preside over utility cases as quasi-judicial bodies and, like judges, are generally prohibited from discussing the cases before them "off the record." The independence of utility commissions and these prohibitions against *ex parte* communications have created hurdles for interagency efforts that are sometimes perceived as absolute barriers.

To overcome these perceived barriers and ensure that utility regulators and environmental regulators keep the lines of communication open, some states have institutionalized communication and coordination between utility and

environmental regulators. This can be accomplished in a variety of ways that maintain the fundamental separation and independent authorities of the two types of regulators. In some cases, coordinated approaches to regulation are mandated through a statutory or administrative code requirement – usually for a limited, specific process like pre-construction permitting of new power plants or transmission lines. There are also examples where coordination is not a legal requirement, but the state environmental agency and the state utility commission have entered into a formal Memorandum of Understanding (MOU) or Memorandum of Agreement (MOA). Finally, some states have initiated regularly scheduled, executive-level interagency meetings to exchange information and discuss regulatory issues.

An alternative method to improve collaboration and communication between utility and environmental regulators is to organize state government in such a way that the two agencies are explicitly linked. At least two states (Massachusetts and Connecticut) have reorganized the structure of their governments to place these two agencies under common leadership. While this is perhaps the most straightforward way to ensure that the two agencies improve collaboration and communication, reorganizing state agency structures can be difficult.

A few specific examples of states that have institutionalized regular discussions between environmental regulators and utility regulators are described below.

2.1 Massachusetts

Massachusetts is an example of a state that created one office that oversees environmental regulation, utility regulation, and energy policy. This began in an informal way when Governor Mitt Romney signed an executive order in 2003 creating an Office of Commonwealth Development to oversee those and other functions. Then, in 2007, Governor Deval Patrick signed legislation that officially and formally consolidated six state agencies under a single cabinet secretariat, the Executive Office of Energy and Environmental Affairs. The Secretary of this Office oversees the Department of Public Utilities (DPU), the Department of Environmental Protection (DEP), the Department of Energy Resources (DOER, the designated state energy office), and three other agencies involved in agricultural and natural resource policy. The Secretary also chairs the state's Energy Facilities Siting Board. With this reorganization, Massachusetts explicitly recognized that its commitment to protecting the environment was inextricably linked to its goals for energy efficiency, renewable energy, reducing dependence on fossil fuels, diversifying energy sources, and promoting energy technology innovation.

This kind of government reorganization does not constitute a radical departure from previous practices. Although the Secretary of Energy and Environmental Affairs oversees all six state agencies, ultimate authority for regulating public utilities still rests with an independent utility commission, just as in other states. Massachusetts has a three-person commission, with each Commissioner appointed by the Governor to a four-year term. In adjudicated cases before the DPU, the Secretary of Energy and Environmental Affairs and everyone associated with the other five sister agencies are not afforded special privileges and are still subject to restrictions against *ex parte* communications with DPU Commissioners.

But despite *ex parte* restrictions, Massachusetts benefits from this reorganized structure because there are many opportunities for interagency communication and collaboration that fall completely outside of the context of adjudicated cases. The reorganized structure allows Massachusetts

to routinely recognize and efficiently capitalize on those opportunities. In fact, the law that created the Executive Office assigns to the Secretary the power *and duty* to coordinate and improve program activities involving two or more agencies. For example, the Chair of the DPU meets frequently with the Secretary and the leaders of the other agencies, with other DPU Commissioners or senior staff pulled in as necessary; the DPU and other agencies have collaborated on big multi-agency projects such as the *Massachusetts Clean Energy and Climate Plan for 2020*; and DEP and DOER both have appointments to an Energy Efficiency Advisory Council that reviews and votes on utility energy efficiency plans before the plans are submitted to DPU for approval. The DEP is also an active participant in an Environmental Advisory Group formed by the independent transmission system operator for New England (ISO-New England). This advisory group has facilitated ongoing collaboration between environmental regulators and energy planners (at a broader scale than the DPU's jurisdiction) for more than half a decade. A reorganized government is not a precondition for this kind of communication and collaboration, but it facilitates and institutionalizes the process.

2.2 Wisconsin

Wisconsin provides an example of a state that has not reorganized its government but has adopted several other approaches to institutionalizing communications between utility and environmental regulators.

Wisconsin law explicitly requires coordination between the Public Service Commission (PSC) and the Department of Natural Resources (DNR, the environmental regulator) on several matters. To begin with, coordination between these agencies is required on environmental impact statements.[8] With respect to mandatory ratepayer-funded public benefits programs, state law requires the PSC to cooperate with the DNR "to ensure coordination of energy efficiency and renewable resource programs with air quality programs and to maximize and document the air quality improvement benefits that can be realized from energy efficiency and renewable resource programs."[9] The PSC must also share drafts of each biennial Strategic Energy Assessment with the DNR, and other state agencies, before the document is finalized.[10] Finally, and perhaps most importantly, the statutes spell out a very detailed process and timeline for coordinated interagency review and approval of proposed large utility projects.[11]

In order to fulfill these duties, the DNR created an Office of Energy & Environmental Analysis that is responsible for coordinating the review of all proposed energy and utility projects in the state and serves as the PSC's main point of contact at DNR. The PSC, for its part, has a small number of staff focused exclusively on environmental issues. The PSC and the DNR developed a Cooperative Agreement (equivalent to an interagency MOA) that formalizes these relationships and provides details of how they will interact on environmental impact statements and preconstruction permitting reviews.[12] The agreement also provides for a certain amount of routine coordination on policy issues that are not specific to any one utility project. The PSC and DNR jointly developed application filing requirements for large utility projects to make the process easier for utility project developers.[13]

[8] Wisconsin Statutes, Section 196.025(2m).
[9] Wisconsin Statutes, Section 196.374(3)(a).
[10] Wisconsin Statutes, Section 196.491(2).
[11] Wisconsin Statutes, Section 196.491(3).
[12] Wisconsin Department Of Natural Resources & Public Service Commission Of Wisconsin (undated).
[13] Wisconsin Department Of Natural Resources & Public Service Commission Of Wisconsin, 2012.

In recent years, DNR and PSC staff members have collaborated on special joint investigations of topics of mutual interest, specifically: integrated gasification combined cycle power plants; carbon capture and sequestration; and offshore wind power in the Great Lakes.[14]

Finally, under a previous Governor, Wisconsin also briefly experimented with the idea of an informal "Energy Independence Cabinet." This idea manifested itself in the form of monthly meetings of the leaders of the PSC, the DNR, the state energy office, and several other state agencies with energy sector ties. Direction and oversight came from the Governor's office. These meetings provided a routine and institutionalized way for the agencies to exchange information, discuss concerns, and coordinate policy approaches where appropriate.

2.3 New York

Like Wisconsin, the State of New York has taken a number of steps to institutionalize coordination among energy and environmental regulators without changing organizational structures. But in this example, which is more typical of other states not detailed in this paper, the state agencies are not interacting on the basis of statutory requirements or an MOA or MOU. Rather, New York provides an example of how routine collaboration can happen in a structured but less formal manner.

The Department of Public Service (DPS), the Department of Environmental Conservation (DEC), and the New York State Energy Research and Development Authority (NYSERDA, the designated state energy office) collaborate and interact in several ways. The DPS convenes an Evaluation Advisory Group which meets on a monthly basis to discuss evaluation, measurement, and verification of the goals of programs developed under the state's Energy Efficiency Portfolio Standard (EEPS). NYSERDA is a member of this group, and the DEC also participates. These three agencies also jointly convened one of the working groups that developed the EEPS programs. DEC representatives meet with the New York State Reliability Council on a bimonthly basis to discuss upcoming regulatory agendas (both EPA and DEC) and the impacts new regulations may have on reliability; DPS staff attends some of these meetings. Representatives from all three agencies regularly attend meetings of the Electric System Planning Working Group at the New York Independent System Operator (NYISO). This is a stakeholder group that provides guidance to the NYISO with planning (e.g., reliability) studies. And as a final example of collaboration, DEC, DPS, NYSERDA and other state agencies are actively participating in the development of the 2013 State Energy Plan.[15]

[14] Wisconsin Department Of Natural Resources & Public Service Commission Of Wisconsin, 2007, 2010, undated; Off-Shore Wind Main Study Group, 2009.

[15] Robert Bielawa, New York State Department of Environmental Conservation, personal communication, November 29, 2012.

3. Consideration of Forthcoming Environmental Regulations in Commission Proceedings

In the next several years, the EPA will be issuing and implementing several far-reaching public health and environmental regulations for air and water pollution and solid waste management related to power plants.[16,17] While there is active debate about the effects of these regulations on the nation's generation mix, it is clear they will alter the planning processes, resource choices, and decisions regarding existing plants for many years to come.

Some state utility commissions have taken a proactive stance on preparing for forthcoming EPA regulations by considering and planning for them now, before all the regulations are final. States have done this in a variety of ways, including as a comprehensive, collaborative approach or as an aspect of a particular case. Other states incorporate considerations related to upcoming environmental regulations into their routine planning processes. Such forward-looking processes allow these state Commissions to prepare to deploy the best resource mixes that will meet the new regulations at the lowest cost, leading to decreased risk and increased reliability.

Examples of states that have held proceedings to consider new and forthcoming EPA air and water regulations are described below.

3.1 Colorado

The Colorado General Assembly passed a law in 2010 that required consideration of new and forthcoming EPA air pollution regulations.[18] The *Clean Air – Clean Jobs Act* anticipated new EPA regulations for NO_x, SO_2, particulate matter, mercury, and CO_2. It required rate-regulated utilities that own or operate coal-fired generating units in Colorado to submit an emissions reduction plan to the state by August 2010 that would meet current and reasonably foreseeable federal and state clean air act requirements.[19] The law was intended to ensure that utilities and the state would look ahead to future environmental regulations and make provisions in a comprehensive and coordinated fashion, instead of addressing each new regulation in a piecemeal approach.

The law gave unique joint responsibilities regarding the emissions reduction plans to the Public Utilities Commission (PUC), the Colorado Department of Public Health and Environment (CDPHE), and the Air Quality Control Commission (AQCC – a division of the CDPHE). Utilities were required to consult with CDPHE in the formation of their plans, and to submit them for approval to the PUC. The CDPHE was required to provide an evaluation of the plans to the PUC, including a determination of whether the plans were consistent with the current and reasonably foreseeable federal and state Clean Air Act requirements;[20] the PUC could not approve

[16] See Farnsworth, 2011 for a brief description of the EPA's forthcoming regulations.

[17] In addition to the forthcoming regulations, some existing regulations must be reviewed and updated on a regular basis, such as the National Ambient Air Quality Standards under the Clean Air Act.

[18] Colorado Revised Statutes 40-3.2-201 through 210.

[19] The emissions reductions plans were required to cover a minimum of 900 MW or 50% of the utility's coal-fired electric generating units in Colorado, whichever was smaller; and to include a schedule that would result in full implementation of the plan by the end of 2017.

[20] The CDPHE had the authority to determine which emissions requirements were reasonably foreseeable, and to determine the definition of "reasonably foreseeable." During the process, the CDPHE determined that "reasonably foreseeable" included requirements imposed after 2017; and that the following requirements were reasonably foreseeable:

plans unless the CDPHE determined this was so. The PUC's role was to ensure that the plans achieved emissions reductions in a reasonable and cost-effective manner. The law required the PUC to consider nine factors when evaluating the plans, including whether the CDPHE determined that the plans were likely to achieve at least a 70% reduction in NO_x emissions.[21]

The plans also were required to set forth associated costs. The utilities were allowed to fully recover the costs of implementing the emissions reduction plans, and the PUC evaluated the reasonableness of costs associated with the plans, as well as the mechanisms by which costs will be recovered.

As a result of this new law, Xcel Energy and Black Hills Corporation filed their initial emissions reduction plans in August 2010, and the PUC issued orders approving the plans in December 2010.[22] The approved Xcel plan will retire 550 MW of coal generation by the end of 2017, replacing the generation with natural gas fired plants, and will install additional emissions controls on some plants. The Black Hills plan will retire two coal generation units and replace them with a new natural gas fired unit.

After the plans were approved by the PUC, the AQCC undertook a proceeding to incorporate the air quality provisions of the plans into the State Implementation Plan (SIP) for reducing regional haze. When EPA approved Colorado's regional haze SIP in September 2012, state officials, utility spokespersons and a variety of other stakeholders described the approval as a ratification of the *Clean Air – Clean Jobs Act* approach.[23]

The *Clean Air - Clean Jobs Act* required a one-time emissions reduction plan from the affected utilities. The actions approved in the emissions reductions plans will be taken into account in the resource planning process that the utilities are required to undertake every four years.

3.2 Missouri

In Missouri, an investigation into the EPA's new and forthcoming regulations originated in the Public Service Commission rather than in the Legislature. In addition, Missouri requires utilities to consider upcoming environmental costs in their resource plans and cost-effectiveness tests, described later.

The Missouri Public Service Commission (the Commission), on its own initiative, opened an

1) the threshold requirement for NO_x emissions reduction of 70%, 80%, or greater as measured against 2008 actual NO_x emissions for applicable facilities; 2) the expected requirements of EPA's current Regional Haze regulation for "Best Available Retrofit Technology" emissions sources or "Reasonable Progress" emissions sources; 3) the revised National Ambient Air Quality Standards for ozone and other criteria pollutants; 4) sector specific requirements for hazardous air pollutants; and 5) greenhouse gas requirements. (Colorado Public Utility Commission, 2010a).

[21] The other requirements that the PUC had to consider were: 1) Whether the CDPHE determined whether any new or repowered electric generating unit proposed under the plan, other than a peaking facility utilized less than twenty percent on an annual basis or a facility that captures and sequesters more than seventy percent of emissions not subject to a national ambient air quality standard or a hazardous air pollutant standard, will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit; 2) The degree to which the plan will result in reductions in other air pollutant emissions; 3) The degree to which the plan will increase utilization of existing natural gas-fired generation; 4) The degree to which the plan enhances the utility's ability to meet state or federal clean energy requirements, relies on energy efficiency, or relies on other low-emitting resources; 5) Whether the plan promotes Colorado economic development; 6) Whether the plan preserves reliable electric service; 7) Whether the plan is likely to protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements; 8) Whether the cost of the plan results in reasonable rate impacts, particularly on low-income customers.

[22] Colorado Public Utility Commission, 2010b, 2010c.

[23] See Office of Governor John Hickenlooper, 2012.

investigation in August 2011 to determine the potential impact on electric system reliability and costs of the new and forthcoming regulations.[24] The Commission directed its staff to lead a working group to investigate and draft a report on these issues. The Commission stipulated that the working group would include the state Office of the Public Counsel; each of Missouri's four investor-owned electric utilities; and other consumer, industrial, and environmental groups that wished to be involved. The Commission staff was required to file its report by May 1, 2012.

The Missouri utilities, Midwest Independent System Operator (MISO), the Southwest Power Pool, the Sierra Club, and the owner of a natural gas fired generation plant made presentations during two workshop meetings or submitted written comments. The Commission staff also used other information sources in compiling the report, including utility filings under the Securities Exchange Act detailing environmental-related capital expenditure estimates, and documents filed under Missouri's resource planning requirements.

The final report from Commission staff was issued on April 2, 2012.[25] The report estimated that capital costs for complying with EPA rules that have been issued and those that are likely to be issued were in the range of approximately $1.981 to $3.276 billion between 2012 and 2021 (based on estimates by the utilities and the Sierra Club). The report concluded that four generating units in Missouri likely would not require many or any retrofits to comply with the regulations, but that the remaining units may face extensive capital improvements and increased operation and maintenance costs. Commission staff noted in the report that Missouri's investor-owned utilities will continue to plan for how to address the EPA regulations in their resource plans, and the expense of retrofitting plants to achieve compliance should always be weighed against other options such as energy efficiency, demand-side management, distributed generation, or other demand resources.

3.3 Other Models

Colorado and Missouri represent models in which a process to consider environmental regulations was initiated by the Legislature or the Commission, and the results of the process informed or fed into the states' resource planning processes. Resource planning thus is a useful complement to Commission proceedings, because it focuses and applies decisions concerning environmental regulations to decisions about supply and demand options. However, states without resource planning requirements could certainly undertake proceedings similar to those of Colorado or Missouri, with their outcomes feeding into particular utility and Commission decisions about supply procurement.

In some states, Commissions are considering the new and forthcoming environmental regulations in the context of individual cases regarding new supply or new environmental compliance plans on existing supply sources. For example, in two Indiana cases regarding "clean coal technology," new and forthcoming environmental regulations were discussed and considered by the Indiana Utility Regulatory Commission before it issued decisions.[26] In Arkansas, a docket is underway regarding environmental controls on a coal plant that are needed to comply with new environmental regulations; the docket also includes consideration of projected prices for future environmental compliance.[27] Such cases provide

[24] Missouri Public Service Commission, 2011.
[25] Missouri Public Service Commission, 2012a.
[26] Indiana Utility Regulatory Commission, 2011a, 2011b.
[27] Arkansas Public Service Commission, 2012.

opportunities to consider specific proposals regarding specific plants, but also to broaden the discussion to include the longer-term future of the plants and how they will address future environmental regulations.

All of these processes provide increased focus on new and upcoming environmental regulations and more prudent decisions for the future, whether the process is comprehensive across all supply sources in the state or is done on an individual basis with particular plants.

4. Consideration of Environmental Issues in Resource Planning Processes

Many states consider air pollution issues and requirements in their resource planning, portfolio management, or procurement planning processes. As mentioned in the previous section, some states specifically look at proposed EPA regulations related to power plants and incorporate compliance costs and risk assessments for those regulations into their resource plans. Other states incorporate environmental issues in a more general way within their resource plans, or within the context of their benefit-cost considerations used in the resource plans. Following are examples of states whose resource planning rules incorporate such environmental benefits in a variety of ways.

4.1 Delaware

The Delaware Public Service Commission (the Commission) issued rules governing the integrated resource planning (IRP) process for Delmarva Power, the principal regulated utility, in 2009.[28] Delmarva is required to file an integrated resource plan every two years and filed its first plan under the new rules in 2010. The rules stipulate, and Delmarva's IRP includes, a calculation for anticipated environmental benefits from 2010 to 2020.

The rules require Delmarva's IRP to show, when considering supply options, "all reasonable opportunities for a more diverse supply at the lowest reasonable cost, including consideration of environmental benefits and externalities."[29] "Environmental benefit" is defined as incorporating positive and negative impacts to wetlands, sea levels, fisheries, air quality, water quality and quantity, public health, climate impacts, land masses, and groundwater. "Externalities" are defined as encompassing social, health, environmental, and welfare costs or benefits.[30] Cost evaluations of resource options must include the economic and environmental value of each resource option. An integrated resource evaluation of the supply and demand scenarios must be included in the IRP, with consideration of environmental benefits and externalities.[31] The rules also require that Delmarva (in the plan development stage) and the Commission (in the review and comment phase) seek input from the Delaware Department of Natural Resources and Environmental Control on the issues of externalities and environmental benefits, including impacts due to emissions.[32]

To assess the externalities, Delmarva's 2010 IRP estimated changes in air emissions and public health benefits and costs associated with three alternative resource scenarios. The primary pollutants of interest in the assessment were particulate matter, ozone, sulfur dioxide, nitrogen dioxide, carbon dioxide, and mercury; however, particulate matter and ozone were determined to have the highest health impacts, so they were assessed through modeling, while carbon dioxide and mercury health impacts were estimated separately. Life-cycle assessments, including evaluations of the environmental and human health impacts, also were performed on the three resource scenarios. The externality calculations included the effects of fossil fuel use, renewable energy use, and efficiency measures. The calculations

[28] Delaware Administrative Code, Title 26, Chapter 3010.
[29] Delaware Administrative Code, Title 26, Chapter 3010, Section 5.2.
[30] Delaware Administrative Code, Title 26, Chapter 3010, Section 2.
[31] Delaware Administrative Code, Title 26, Chapter 3010, Section 6.1.4.
[32] Delaware Administrative Code, Title 26, Chapter 3010, Sections 6.2 and 9.2.

projected that the expected health benefits under the reference case in 2020 compared to 2010 were between $1.8 and $4.3 billion.[33]

Delaware also is in the process of developing an evaluation, measurement and verification framework that will include similar types of calculations.[34]

4.2 Nevada

Nevada's investor-owned utilities are required to perform IRPs every three years, including a plan for demand-side management. Under rules issued by the Public Utilities Commission of Nevada, supply plans and demand-side management plans in the IRP must quantify environmental costs for air emissions, water, and land use. "Environmental costs" are defined as costs, "wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[35] Nevada's demand-side plans also include an estimate of the reduction in emissions attributed to the annualized decrease in energy use created by the plan. The emissions include carbon dioxide, carbon monoxide, particulate matter, volatile organic compounds, nitrogen oxides, and heavy metals.[36] Net environmental costs to Nevada of any planned facilities, including facilities that are not located in-state, are required in the IRP as well.[37]

Nevada's rules require that when developing a supply plan, analyses of each supply option must include an examination of the environmental impact; in addition, options of low carbon intensity must be considered.[38] Nevada also requires that demand-side management plans include a life-cycle analysis of the efficiency programs using the Total Resource Cost Test as the primary measure of cost-effectiveness. Other tests also must be used as secondary tests, and when the Societal Test is used, a 10% "adder" is included as a proxy for the hard-to-quantify, non-energy, environmental benefits.[39]

4.3 New Mexico

New Mexico requires its electric utilities to undertake an IRP process every three years. The state's resource planning rules[40] require each utility to consider environmental factors in its resource planning process in several ways.

First, the statement of the objective of the resource planning rules stipulates that "For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts." In addition, the rules require that utilities put in their resource plan a description of existing supply resources, including, for each supply source, the emissions rates of criteria pollutants,[41] carbon dioxide, mercury, and the water consumption rate.

Finally, in determining the most cost-effective resource portfolio, utilities are required to take into consideration risk and uncertainty, including "anticipated environmental regulation." Utilities must discuss how "existing and anticipated environmental laws

[33] Delmarva Light and Power Company, 2010. See pages 22 and 113 et seq.
[34] Bahareh van Boekhold, DE Department of Natural Resources and Environmental Control, personal communication, April 13, 2012.
[35] Nevada Administrative Code 704.9359.
[36] Craig McDonnell, Public Utilities Commission of Nevada, personal communication, December 12, 2012.
[37] Nevada Administrative Code 704.9395 and 704.9063.
[38] Nevada Administrative Code 704.9355.
[39] Craig McDonnell, Public Utilities Commission of Nevada, personal communication, December 12, 2012.
[40] New Mexico Administrative Code, Title 17, Chapter 7, Part 3.
[41] Criteria pollutants are: carbon monoxide, sulfur oxides, nitrogen oxides, ozone, lead, and particulate matter.

and regulations, and, if determined by the Commission, the standardized cost of carbon emissions" were considered in or affected the development of the resource portfolios.[42]

The IRP submitted by Public Service of New Mexico in 2011 discussed several environmental factors, including the National Ambient Air Quality Standards, regional haze, hazardous air pollutants, coal ash, CO_2 emissions, and water issues.[43] Several of these factors were modeled in the 26 scenario analyses of the resource plan. Five levels of CO_2 costs were modeled, in addition to seven other potential impacts resulting from environmental factors.

4.4 Arizona

Arizona requires its load-serving entities to complete 15-year resource plans every two years. Requirements are laid out in Arizona's resource planning rules,[44] which were revised in 2010 and which incorporate environmental concerns.

Environmental issues are addressed in several places in Arizona's resource planning rules. Costs used in resource plans must include the costs associated with "mitigating any adverse environmental effects." Arizona's load-serving entities have yearly reporting requirements under the rules, which must include for each generation unit or purchased power contract the "environmental impacts, including air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt-hour) for carbon dioxide, nitrogen oxides, sulfur dioxide, mercury, particulates, and other air emissions subject to current or expected future environmental regulation; water consumption quantities and rates; and tons of coal ash produced per generating unit."

The resource plans themselves also must consider environmental impacts and water consumption. Cost and cost projections in the resource plans must include "the cost of compliance with existing and expected environmental regulations." The rules require that each demand-side management program described in the resource plan includes "the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure." In addition, each resource plan must have "a plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption." Load-serving entities also must submit analyses to identify and assess risk and uncertainty that include "the costs of compliance with existing and expected environmental regulations."

Arizona's resource planning rules also provide for load-serving entities or other interested parties to provide analyses and data relating to environmental impacts, including "monetized estimates of environmental impacts that are not included as costs for compliance." During other proceedings or stakeholder workshops, parties may present "values or factors for compliance costs, environmental impacts, or monetization of environmental impacts." Finally, in its review, the Arizona Corporation Commission must consider the environmental impacts of resource choices and alternatives.

The Integrated Resource Plan submitted by Arizona Public Service in 2012 includes discussion of many environmental factors.[45] The plan includes EPA-required emissions controls for SO_2 and other emissions into the report's prospective analyses, incorporates a

[42] New Mexico Administrative Code 17.7.3.9.G.
[43] Public Service of New Mexico, 2011.
[44] Arizona Administrative Code, Title 14, Chapter 2, Article 7.
[45] Arizona Public Service, 2012.

price for CO_2 of $12 per metric ton starting in 2019 and escalating at 5% above inflation thereafter, and incorporates a sensitivity analysis that values water using a marginal cost approach.

5. Incorporation of Avoided Environmental Costs in Cost-Effectiveness Tests and Evaluation, Measurement, and Verification of Energy Efficiency Programs

Many states use cost-effectiveness tests to decide whether to implement energy efficiency programs during resource planning or energy efficiency planning processes. Such cost-effectiveness tests (also called benefit-cost tests) compare the benefits of energy efficiency measures, programs, and/or portfolios against their costs, in order to determine overall cost-effectiveness and which measures, programs, or portfolios should be implemented. Five standard cost-effectiveness tests exist, three of which are predominately used by states.[46] The Total Resource Cost Test (TRC), used by many states,[47] is not traditionally defined as including environmental benefits; however, some states have modified the Total Resource Cost test to include some environmental benefits. The Societal Cost Test (SCT), used by several states, is defined as including environmental benefits.[48] In addition to environmental benefits, there are many "non-energy benefits" that may be included in the SCT or modified TRC.[49] Including environmental and other non-energy benefits in cost-effectiveness tests paints a truer picture of the value of energy efficiency programs and results in more resources with lower total costs being pursued. Cost-effectiveness tests that do not incorporate such benefits run the risk of skewing the test results against energy efficiency.

According to a recent report, 13 states include environmental impacts in their cost-effectiveness tests. Of those, according to the report, at least 8 states attempt to quantify a specific value for the environmental costs or benefits, while the others use a more general "environmental adder" to account for the benefits of energy efficiency. At least 10 states include the issue of carbon dioxide emissions in their rationale for quantifying environmental benefits, the report found.[50]

As part of evaluation, measurement, and verification (EM&V) of energy efficiency programs, many states also undertake a cost-effectiveness analysis after energy efficiency programs have been implemented. A cost-effectiveness analysis implemented as part of an EM&V process compares the outcomes of the energy efficiency programs with the costs incurred to achieve those benefits. The cost-effectiveness analysis helps program managers and Commissioners decide whether to retain the energy efficiency programs, or modify or replace them. Some states incorporate environmental benefits into these cost-effectiveness analyses as well.

Below are examples of states that have incorporated environmental benefits into their cost-effectiveness analyses for determining which energy efficiency programs to implement, or for determining whether the implemented programs were a good value during their EM&V process.

[46] The five standard cost-effectiveness tests are: Total Resource Cost Test, Societal Cost Test, Participant Cost Test, Utility/Program Administrator Cost Test, and Ratepayer Impact Measure Test.

[47] A recent report found that, of 41 states surveyed, 71% use the Total Resource Cost Test as the primary cost-effectiveness test and 15% use the Societal Cost Test. (See Kushler, et al, 2012.)

[48] Environmental compliance costs, which are actual costs that utilities incur, should be included in the TRC, SCT, Utility/Program Administrator Cost Test, and Ratepayer Impact Measure Test. Environmental externalities, by contrast, should be included in the SCT and are sometimes included in a modified TRC.

[49] For a full treatment of non-energy benefits, see Woolf, et al, 2012.

[50] Kushler, et al, 2012.

5.1 Missouri

Missouri requires its three largest electric utilities[51] to submit resource plans every three years and to use the TRC as the primary test to screen its energy efficiency programs as part of the resource planning process (with the Utility Cost Test as a secondary screening tool). The TRC test is defined as including avoided probable environmental costs.[52] "Probable environmental cost" is defined as "the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility decision-makers, may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates."[53] When quantifying probable environmental costs for supply and demand options, utilities must identify a list of environmental pollutants for which legal mandates may be imposed, specify a subjective probability of the likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point in the planning horizon, and calculate expected mitigation costs for each identified pollutant.[54] Utilities also must describe and document how they developed the avoided probable environmental costs.

There are several other ways in which probable environmental costs are incorporated into the resource planning process. When ranking supply resource options, utilities must rank options based on estimates of utility costs and also on utility costs plus probable environmental costs. Demand-side programs that pass the total resource cost test including probable environmental costs must be included as resource options in at least one alternative resource plan. Utilities must develop a set of quantitative measures for assessing the performance of alternative resource plans, and those must include the present worth of probable environmental costs. Graphs also are required for each alternative resource plan, showing the annual emissions of each environmental pollutant identified and annual probable environmental costs.

The state's resource planning regulations that contain these provisions were revised in 2011. One utility's plan was reviewed in 2012 (but the Commission has not yet determined whether it complies with the rules, pending a revision in 2013),[55] and another is due in April 2013.

5.2 Wisconsin

Wisconsin has well-developed energy efficiency programs that are implemented by an independent administrator. The state uses the same two cost-effectiveness tests to evaluate proposed energy efficiency programs as to evaluate already implemented energy efficiency programs.[56] Both of the state's tests incorporate some environmental benefits.

The two cost-effectiveness tests used in Wisconsin are: the "modified TRC test" or "simple benefit-cost test" which combines elements of the TRC and SCT approaches; and the "expanded benefit-cost test" which builds upon the previous test in several ways.[57] The modified TRC test includes avoided air emissions that are assumed to have been internalized, for example through trading markets or emissions caps, and are counted as an additional avoided cost per unit of

[51] Ameren Missouri, Kansas City Power & Light, and Empire District Electric Company.
[52] Missouri Code of State Regulations, 4 CSR 240-22.020(60).
[53] Missouri Code of State Regulations, 4 CSR 240-22.020(47).
[54] Missouri Code of State Regulations, 4 CSR 240-22.040(2)(B).
[55] See Missouri Public Service Commission, 2012b.
[56] Carol Stemrich, Wisconsin Public Service Commission, personal communication, April 9, 2012.
[57] Goldberg, et al, 2009.

energy saved. Avoided air emissions in the modified TRC test are SO_x and NO_x (using avoided emissions values based on current regulations and trading markets) and CO_2 (using avoided emissions values based on expected future regulations or externality costs) associated with reduced electricity use. In the expanded test, water savings and avoided emissions, such as mercury, are also included, both of which have values set by regulatory policy or public willingness-to-pay studies, but are not assumed by the Commission to translate into flows through the economy.[58]

The Commission uses the modified TRC test at the energy efficiency measure and program levels and the expanded benefit-cost test at the portfolio level.[59] During considerations of which energy efficiency measures to implement, measures that are not cost-effective using the modified TRC test, but which have substantial non-energy benefits, may be considered for implementation on a case-by-case basis using the expanded test.

5.3 Vermont

Since 1990, Vermont has required that its own version of the SCT be used to evaluate energy efficiency programs. Changes were approved to the cost-effectiveness screening process in 1999 and, most recently in 2012, by Vermont's Public Service Board.[60] In addition, Vermont statute requires that utilities examine environmental costs in least cost integrated planning.[61]

The cost-effectiveness screening process requires that environmental externalities associated with greenhouse gases, as well as several other types of non-energy benefits, be incorporated. The requirements are as follows:

- Environmental externalities associated with greenhouse gases must be accounted for by assuming a CO_2 allowance price of $80 per ton.[62]
- The non-energy benefits of energy efficiency resources must be accounted for by applying a 15% adder to the energy benefits.
- Water savings, operation and maintenance savings, and other fuel savings resulting from energy efficiency programs should be accounted for with quantified and monetized estimates.
- The reduced risk benefits of energy efficiency resources should be accounted for by applying a 10% discount to the costs of energy efficiency. This provision is intended to address a variety of possible risks, one of which might include the risk of uncertainty regarding future environmental regulations on fossil fuel generators.
- The widespread benefits of low-income energy efficiency programs should be accounted for by applying a 15% adder to the energy benefits associated with those programs.[63]

[58] Wisconsin Public Service Commission, 2010.
[59] Wisconsin also requires the Utility/Administrator Cost Test to be used at the program level.
[60] Vermont Public Service Board, 2012.
[61] Vermont Statutes Annotated, 30, 218c(a)(1).
[62] Vermont Public Service Board, 2011.
[63] Vermont Public Service Board, 2012. See also, Woolf, et al, 2012.

6. Conclusion

There are a variety of ways that energy regulators can start to collaborate more with environmental regulators, to include more environmental costs and benefits into resource planning and cost-effectiveness tests, and to consider environmental regulations in energy regulatory processes.

In order to ensure regular coordination between energy and environmental regulators, the best option is to institute the relationship formally through legislation, the re-organization of agencies, or similar means. However, a regular relationship also can be established informally, through regular meetings of the Public Utility Commission, state energy office, and environmental agency to discuss issues in common. With changing staff and leadership within state government, however, this type of informal relationship may result in a more short-lived practice.

As described above, some states have considered a broad set of forthcoming environmental regulations as a result of legislation or through a Commission proceeding. For optimal results, a process would be put in place to regularize such proceedings. New environmental regulations are regularly forthcoming, and some, such as the National Ambient Air Quality Standards, have a statutorily prescribed schedule for periodic review and update. Institutionalizing the consideration of environmental regulations on a regular basis can help states avoid costly surprises, and some evidence suggests that states benefit from getting ahead of revisions to federal environmental regulations.[64]

States that have a resource planning process can require utilities to consider upcoming environmental regulations in their resource plan scenarios. States without a resource planning process can still use an "IRP-like" process for individual decisions. For example, a Commission considering in a proceeding whether to close a coal plant or authorize pollution controls can require the utility to present multiple scenarios, testing the cost and risk of each scenario using environmental costs and benefits of possible future environmental regulations (among other factors).

Finally, energy regulators can incorporate environmental benefits in cost-effectiveness tests, either by adopting the Societal Cost Test, or modifying the Total Resource Cost Test. Several states have worthwhile experience in this practice. Practices and policies such as those described in this report that regularly incorporate environmental issues into regulatory processes, and that institutionalize collaboration between energy and environmental agencies can help state energy regulators to decrease risk and improve their long-term policy decisions.

[64] Hoppock, et al, 2012.

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