Integrated Portfolio Management in a Restructured Supply Market

A Report to the
Office of the Ohio Consumers' Counsel

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Executive Summary

Ohio has faced exceptional challenges in implementing a competitive electricity market since the 2005 end of the statutory Market Development Period. The Public Utilities Commission of Ohio (PUCO), realizing that very little residential choice activity had occurred, implemented such interim measures as utility-designed rate stabilization plans. Some of those plans have been found unlawful by the Ohio Supreme Court, which remanded them to the PUCO for further consideration.

In this restructured power market, Ohio faces the task of minimizing costs and risks for ratepayers while creating a reasonable degree of certainty as to short- and long-term power prices and an opportunity for a competitive market to develop after the expiration of the interim rate stabilization plans (mostly after 2008).

Achieving those objectives will require the following steps:

- Fixing the wholesale procurement process, so that customers who continue to receive power supply through the utility as the Standard Service Offer (SSO) pay prices that reflect prudent acquisitions from the competitive market.
- Ensuring that supply costs are fully recovered through the SSO and that the SSO charges are fully bypassable by customers who switch to alternative retail suppliers.
- Diversifying the SSO supply, to minimize short- and long-term costs and risks for SSO customers.
- Planning, to ensure adequate, low-cost, reliable and stable regional power supply and the availability of those supplies for Ohio consumers.

The proposed tools for regulators to meet this goal include the following:

- A series of competitive generation procurements of SSO power supplies, for varying purchase dates, contract lengths (from less than a year to more than a decade), and pricing terms, including fixed prices and potentially formulae tied to market fuel prices or other indices.
- Acquisitions of specific types of resources—new coal capacity, renewables, and energy efficiency—to supplement the generic full-requirements supplies in the SSO.
- Portfolio standards to ensure that all power suppliers are contributing to the development of clean and efficient resources that will provide environmental benefits, reliability, price stability and lower bills to all customers.

- A statewide planning process to determine needs for capacity and energy supply statewide and regionally, and establish priorities for SSO acquisitions.

The diversified mix of supplies for SSO, like a diversified investment portfolio, will protect customers from excessive swings in future market prices, as well as providing opportunities for the least-cost development of resources needed for reliability, price stability, and/or bill reduction.

The SSO portfolio should be divided between long-term supply contracts of five to twenty years and short-term contracts of up to three years. As discussed in Chapter I, a mix of 60% of energy supply from long-term contracts and 40% of energy (plus a majority of capacity and ancillary services) may be a reasonable mix of resources.

The long-term supply contracts would comprise the following:

- existing supplies for fixed blocks of power,
- new clean baseload supply (such as integrated gasification combined-cycle),
- renewables,
- energy efficiency, and
- existing supplies for fixed percentages of the remaining SSO load.

The short-term contracts would cover fixed percentages of the SSO load not served by long-term supplies.

The long-term supply contracts would both stabilize prices and allow developers to build new capital-intensive resources, preferably in Ohio, which are difficult to finance based only on projected revenues from short-term markets.

Figure 1 illustrates the assembly of SSO contracts over time.[1] The top section represents a series of short-term full-requirements contracts, starting with a one-year contract serving 2009, a two-year contract for 2009–2010, and a three-year contract for 2009–2011. As each of these contracts expires, it is replaced by a new three-year contract. After 2011, each year is served by three short-term contracts, procured one, two and three years earlier.[2] Below the short-term contracts is a

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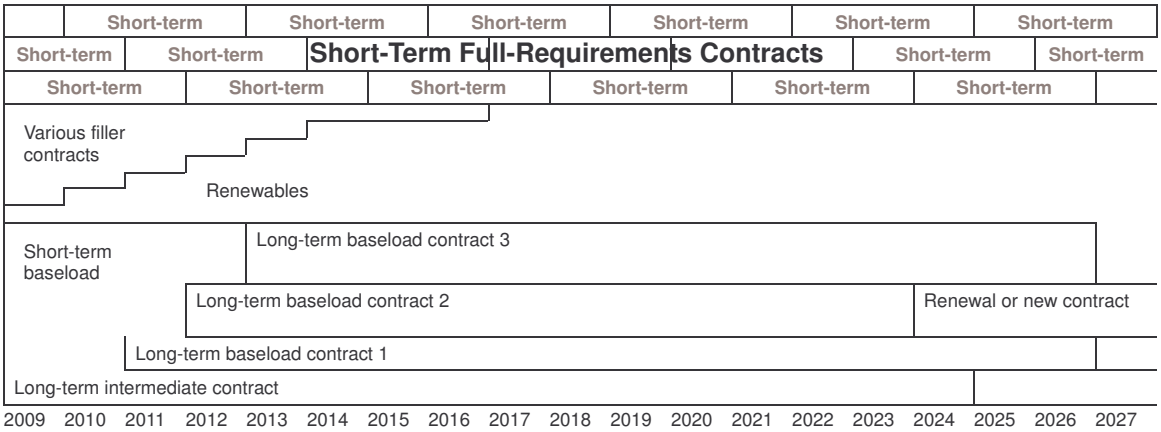
[1] The specific values and timing of the resources in the integrated portfolio would be developed over time, reflecting market conditions and regulatory decisions regarding risk and other objectives. The values in Figure 1 are simply illustrative.

[2] Each of the contract blocks shown could be divided into several smaller slices, to allow for multiple providers and multiple procurement dates. Each slice, regardless of megawatt size, would be for three years.

block of contracts for new renewable or other preferred new resources, which are acquired over time, and a variety of short-term contracts to fill in the supply requirements until the later renewable contracts enter service. Below the renewables is a group of baseload contracts, starting with short-term contracts for baseload power from existing plants or firm system supply, followed by contracts with new plants to ensure development of adequate capacity. The bottom block represents one or more long-term contracts for intermediate supply, similar to the baseload contracts.

Figure 1: Example Contracts Over Time



Both the SSO portfolio and competitive suppliers should be required to supply a portion of their loads from renewables and energy efficiency. These portfolio standards would grow over time. For illustrative purposes, as described in Chapters V and VI of this report, the standard might be set at the following percentages of energy delivered:

Table 1: Portfolio Standard Targets

	Energy-Efficiency Portfolio Standard	Renewable Portfolio Standard
2008	0.3	2%
2009	0.8	4%
2010	1.5	6%
2011	2.3	8%
2012	3.2	10%
2013	4.2	12%
2014	5.2	14%
2015	6.2	16%
2016	7.2	18%
2017	8.2	20%
2018	9.2	20%
2019	10.2	20%
2020	11.2	20%

The Renewable Portfolio Standard (RPS) for the SSO could be satisfied by some combination of the renewable portions of the long-term SSO portfolio and requiring the suppliers of short-term full-requirements SSO to include renewable energy (or equivalent credits) in their supply. Competitive retailers would probably meet their RPS obligation via market purchases of renewables (or credits). The Energy Efficiency Portfolio Standard, for both SSO and competitive retail suppliers, would be satisfied by purchase of energy efficiency credits from a program administrator, such as the Ohio Office of Energy Efficiency.

I. Introduction

Background

Evolution of Utility Generation

In the first part of the 20th century, a substantial portion of the nation's electric generation was in the form of what we would now call self-generation or combined heat and power. Industrial operations often ran large boilers that could readily be adapted to produce electricity for the factory's own needs and much more besides for sale to utilities. Others, originally located near water power for their own use, began to sell electricity at wholesale. Some even provided electricity to worker housing. This self-generation sector became much less important as generating technology advanced, non-industrial demand for power grew, and the economies of scale of central-station generation began to dominate the electric industry.

For about a century, consumers have relied on utilities with monopoly franchises to provide them with electricity; the rates of those utilities were generally set based on their cost of service plus an allowed rate of return on the capital they invested, but that situation began to change in the 1970s. Up to that time, investor-owned, municipal, or cooperative utilities owned and operated most of the electric generation needed, and construction of generators was financed on the basis of reasonably assured revenue streams from retail monopolies and, for some companies, expected wholesale sales.[3] Declining real prices for fossil fuels and increasing economies of scale for capital-intensive steam-generating plants kept retail rates acceptable, while making entry into the wholesale generation business difficult.

Between the mid 1970s and the late 1980s, several trends led to a drive for better planning and resource choices by utilities. Among those trends were higher prices for fossil fuel, slower sales growth, stagnation in economies of scale, increased inflation and cost of money, and extraordinary cost overruns for some very large power-plant projects. Greater public demands for environmental protection also led to a greater level of scrutiny of generation and transmission siting. Many states, including Ohio, implemented policies requiring some kind of long-term (often referred to as "least-cost" or "integrated resource") planning policy. Those policies usually mandated a long-term view of the cost of various alternatives and

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3 The transmission and distribution systems were funded in the same way.

equal consideration of power purchases, renewable energy and energy efficiency.[4] Many planning policies incorporated environmental impacts or costs, allowed greater public involvement, and raised standards for permit approval. While the breadth, depth, and formality of these planning requirements varied widely among the states, most states developed some sort of long term planning function, at least for their larger electric utilities. We refer to this form of utility planning procedures as integrated resource planning or IRP.

The Rise of Wholesale Competition

Along side this trend, changes in technology made small generation units relatively cheaper and more competitive with large units. Technological progress also made long-distance transmission of bulk power cheaper and more practical. Utility territories and power pools became less isolated. Successful operations by non-utility generators—the so-called qualifying facilities—under the 1978 federal law called PURPA (the Public Utility Regulatory Policies Act) and apparently successful deregulation of the airline and telecommunications industries led to calls for deregulation of wholesale and eventually retail electric sales.

After 1988, the Federal Energy Regulatory Commission (FERC) began to further promote competitive wholesale electricity markets, using both rulemakings and case-by-case orders to advance that idea. FERC established various mechanisms to allow generators to charge market (that is, non-cost-based) rates and to provide transmission access to independent power producers, power marketers, and others. A key part of this evolution was a set of new FERC rules allowing generators to gain non-discriminatory access to bulk transmission. To further promote this kind of access, Congress enacted the Energy Policy Act of 1992. The Act also created a whole new class of "exempt wholesale generators" who did not need to comply with cost-based ratemaking at all and eliminated certain legal barriers faced by utility-affiliated and nonaffiliated power producers. For the same reason, FERC encouraged formation of independent system operators (ISOs) and regional transmission operators (FERC Orders 888; 888-a; 889; 2000). The Energy Policy Act of 2005 has further enhanced federal law supporting competitive mechanisms in the wholesale power industry.

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[4] In Ohio, the IRP process led to development of some energy efficiency, but little or no renewables.

The Appearance of Retail Competition

During the 1990s, interest in opening retail electric service to competition began to grow, especially in states with high retail electricity rates. It was argued that retail competition would reduce such rate disparities.

California, as well as many New England and mid-Atlantic states, and a few others adopted retail competition. As of July 2000, 24 states and the District of Columbia had moved to restructure retail electric service, with 18 others either considering or moving towards restructuring. However, since the 2000–2001 electricity crisis in the Western markets, no further action has taken place, and a few states have suspended, scaled back, or cancelled retail competition.

Retail choice exists in 16 states and the District of Columbia; however, nearly ten years into the restructuring of some of those states, only a small fraction of residential customers rely on competitive power suppliers. Large commercial and industrial customers "shop" much more frequently and have more choices and options than residential customers, but many are still seeing price increases.

The States Provide for Standard Service

Most retail-choice states provide customers the option of taking power supply from a standard service offer at a regulated price to ensure universal access to generation. In some states, the price was determined by competitive wholesale bidding from the time of restructuring. In many cases, however, the initial SSO was discounted below previous regulated rates or capped for a period of years. As a consequence, many retail-choice states now face steep rate increases for the SSO as generation rates transition to full dependence on the wholesale generation market. In many retail choice states, utilities providing SSO service have sold their generation assets or transferred them to unregulated affiliates.[5]

More recently, a series of events have led some states to reconsider their approach to retail choice and standard service. During 2000–2001, California saw wholesale prices jump above levels that could be supported under its fixed SSO rates. Ultimately, one large investor-owned utility filed for bankruptcy protection, and the State had to intervene to acquire wholesale electricity supply on behalf of two utilities, locking in very high supply prices for some time. Subsequently, California suspended retail competition for most customers.

Most SSO procurement falls into one of two categories. Many states (e.g., Massachusetts, Pennsylvania, and Maryland) provided that standard service was

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5 The transfers were often at prices below current market value for such assets.

delivered by the incumbent utility at fixed prices, often set so that total rates were discounted from the pre-restructuring retail rate, for a set number of years. The discounted fixed rates were sometimes mandated by state law. In other cases, the incumbent utility agreed to the discounted rates for a transition period as part of a settlement that included collection of so-called stranded costs. In many cases, the utility guaranteed the availability of the discounted rate by requiring a contract at that price as a condition for the purchase of its generation assets. Advocates of restructuring generally expressed confidence that retail competitors would be able to beat the fixed price by the end of the transition period. Consumer advocates were often reassured that consumers would get some savings in power-supply prices for some period of time.

Other restructured states (e.g., New York, Connecticut, California) focused on using wholesale competitive forces to set the SSO rate early in the restructuring process. As the initial transition contracts end, additional states (or in some cases, individual utilities within states) have started to acquire SSO supply from the competitive market, by variations on the following approaches:

- Short-term purchases from the short-term market, largely through the ISO (California, prior to the Western power crisis of 2000–2001).
- Purchases of standard products from the wholesale market, such as fixed blocks of around-the-clock energy, peak-period energy, and capacity, supplemented by transactions with the short-term market (e.g., New Jersey until mid-2002).
- Purchases of full-requirements service for the entire SSO load in forward contracts ranging from a few months to a few years, selecting the low-cost bidder in response to a Requests for Proposals (RFP) or similar solicitation (e.g., United Illuminating).[6]
- Full-requirements purchases for slices (tranches) of the SSO load through RFPs (Maryland, DC, Delaware, Massachusetts, Maine, Rhode Island, Connecticut Light and Power, Duquesne).
- Full-requirements purchases for tranches of SSO load through fast-paced, multi-round, declining-clock auctions (New Jersey).

Rules for these auctions or RFPs and the rules for converting the resulting wholesale power costs into retail SSO rates were debated at length, with the

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6 These full-requirements contracts shifted many risks (price, load, migration to and from SSO) to the utility's supplier for the period of the contract.

regulators trading off minimizing the costs to SSO customers against encouraging retail competition.

One important aspect of these competitive SSO procurements was the period for which power as procured at one time. One approach was to make SSO a minimal short-term transitional product, for customers who had not yet selected a competitive supplier or were between suppliers. This view leads to short-term acquisitions (from California's monthly ISO prices to the procurements of three to six months in Massachusetts, to New Jersey's and Duquesne's real-time pricing for large customers at ISO energy prices), with the expectation that volatile SSO prices would encourage more customers to move to competitive suppliers. If customers were likely to leave SSO in large numbers, longer-term SSO contracts might well be very risky to the supplier, and hence considerably more expensive than short-term contracts. Other states (e.g., Maine, Maryland and New Jersey for small customers, Connecticut) chose to procure SSO load in contracts lasting a year or more.

Regulators (and in many cases legislators) assumed that SSO consumers were best served or, at least, adequately served by short-term procurement that followed the wholesale market, and that retail competitors would offer more stably priced products as a value-added service. In fact, it seems that neither of those assumptions was valid, at least for small consumers. Instead, retail suppliers have largely withdrawn from serving small customers, leaving SSO consumers have been exposed to considerable price volatility, as power prices have followed the rapid rise in natural-gas prices and responded to congestion and market manipulation.

Even where retail suppliers have been willing to serve small consumers, they have not offered much variety of products. Few small consumers have been presented with competitive choices other than rates structured similar to that of the utility's standard offer or offers of so-called green supply at higher prices.

A number of retail-choice states have begun to diversify their SSO procurements slightly, such as acquiring power in multiple solicitations within a year and purchasing supplies for overlapping periods. This kind of diversification, however, addresses only the timing of the procurement, which still depends on one kind of purchased product—all-requirements, fixed-price contracts with similar term lengths—and ultimately on wholesale markets driven by one fuel price. The cost and risks of SSO procurement from the short-term market are no longer minor problems and cannot be ignored. For the wholesale *and* retail power markets to work for all customers, significant changes in SSO planning and procurement are needed.

A few states (e.g., California and Delaware) have recently mandated a return to some sort of deliberate resource planning for procurement of SSO supply. In this report, we consider the strategies adopted in those jurisdictions and the latest types of integrated resource planning in use in non-restructured states. We also discuss additional tools that could be used to address better the need of SSO consumers for reasonably and stably priced power while improving wholesale competition and maintaining the opportunity for effective retail competition in electric power supply.

Advancing Generation Service for Ohio Consumers

As discussed in more detail in Chapter II, Ohio faces a difficult situation at both the retail and wholesale levels of the electric industry. Most Ohio electricity consumers now receive their generation service through the SSO and are likely to continue to do so. Further, the way SSO supplies have been acquired and priced through the rate stabilization plans has not contributed to the development of either competitive wholesale markets or competitive retail supply. The uncertainty of how Ohio will frame its post-2008 SSO regime does not help move those markets in constructive directions.

Unless a new approach is taken to procuring power for SSO service, small consumers will continue to suffer multiple losses. First, they have lost access to traditional, cost-based power in the transition to SSO service. Second, very few have been offered competitive retail supply. Third, SSO prices have been set at the prices that the incumbent utility has been willing to offer, rather than at competitive wholesale market prices. Fourth, the utilities have been allowed to make large parts of the SSO supply cost non-bypassable, and to adjust upward SSO rates for a variety of cost charges (including non-market prices, such as environmental-compliance costs at the utility's power plants), further discouraging competition.[7] Fifth, even these flawed transition-service offerings are likely to be replaced by more volatile market-priced rates.

Moreover, in the post-transition regime, consumers will likely face prices based on *market clearing prices*, that is, all their power would be priced by reference to the cost of the *most expensive source* in any given hour. That clearing price is likely to be set much of the time by natural-gas prices that are at very high levels now and are likely to remain so for some time to come. To the extent that those markets are

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[7] The Ohio Supreme Court has recently remanded to the PUCO two of the cases implementing rate stabilization plans. The specific item mentioned by the Court that must be addressed is the Competitive Bidding Process (4928.14(B)).

not completely competitive or have any other structural problems, the problem would be even more serious.

As discussed in Chapter II, long-term purchases of SSO supply from new resources can contribute to ensuring the adequacy of regional power supply. In the current Ohio regulatory structure, no entity has responsibility for ensuring regional supply adequacy. The utilities are no longer responsible for power-supply planning, the generation owners (including utility affiliates) have no long-term responsibility to customers (and actually benefit from supply shortages), neither PUCO or the Ohio Power Siting Board (OPSB) is legally required to take on this function, and the ISOs only do transmission planning and occasionally offering incentives to keep existing power plants on-line.[8] Even if a shortage of power supply were emerging, it is not clear how Ohio could ensure construction of new generation, under current arrangements.

Ohio can best minimize costs and risks for ratepayers while creating an opportunity for a competitive retail market to develop, by pursuing the following steps:

- Revising the wholesale procurement process, so that customers who continue to receive SSO power pay prices that reflect the prudent procurement from the competitive market.
- Ensuring that the SSO rate recovers all categories of costs paid by competitive suppliers, and that all such costs are recovered in SSO charges bypassable by shopping customers, so that each customer pays for either SSO or competitive supply, but not both.
- Diversifying the SSO supply, to minimize costs and risks for SSO customers and competitive customers as well.
- Developing long-term planning, to ensure an adequate, low-cost, and stable regional power supply and the availability of those supplies for Ohio consumers.

In order to achieve those goals, Ohio must take the following steps:

- *Encourage wholesale competition* by reforming SSO procurement.
- *Level the playing field* for retail competition by pricing SSO to be consistent with the wholesale market on which retail competitors depend.

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8 PJM's Reliability Pricing Model and MISO's Scarcity Pricing Model are attempts to grapple with this issue, but would rely on raising prices to all generators to encourage construction when and where it is needed.

- *Encourage clean energy and energy efficiency* in a manner consistent with the further development of retail competition by (1) renewable-portfolio and energy-efficiency-resource standards and (2) additional procurement of clean and renewable energy for SSO supply but with costs shared by all consumers.
- *Promote wholesale-market stability* and reduced retail volatility for all consumers by (1) using SSO load as an "anchor tenant" for development of new clean baseload generation and (2) serving SSO with a managed portfolio of short- and long-term purchases of new clean or renewable generation.

Currently, most residential and small commercial consumers lack options for shopping and there is little reason to think this will change in the near future. Residential consumers in other states, with only a few exceptions (largely temporary), have not seen significantly better opportunities to save money or control volatility through retail competition. Blumsack, Apt, and Lave (2005, 12) sum up the situation as follows:

> With a few exceptions, residential switching activity in the competitive retail market has been minimal at best. Even if residential consumers wanted to switch, many service areas simply don't have any competitors to the incumbent utility. Nineteen states currently offer some form of retail competition to at least some of its consumers, but in some areas (such as most of Pennsylvania) there are no alternatives to the incumbent utility. Residential activity in competitive retail markets has been low, with the exception of some traditionally high-cost urban areas.

As of mid 2005, among those states that had implemented retail choice, only Texas and the FirstEnergy companies in Ohio reported residential switching greater than 10%.[9] In Ohio, residential switching was driven primarily by a statewide opt-out aggregation program.[10] In Texas, the "price to beat" was set administratively but, despite the "price to beat" being adjusted upward an average of 43% in two years, only approximately 20% of residential customers had switched to competitive retail suppliers (Rose and Meeusen 2005, 36). Meaningful retail competition for residential consumers is rare and shrinking. Increases in default service prices are not simply a reflection of natural-gas prices, but also strongly reflect structural difficulties with the relevant markets.

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[9] Rose and Meeusen (2005, 2). Ohio's opt-out program no longer contains a large number of residential shoppers.

[10] Ohio residential aggregation has declined dramatically since late 2005, due to the below-market bypassable generation rates in the FirstEnergy utilities' rate-stabilization plan.

Residential switching has been very low all along and there is no reason to suspect that residential consumers' behavior will change, given the high transaction costs required to acquire customers, the uncertainties and risks involved, and the small annual consumption of each customer. As Blumsack, Apt, and Lave (2005, 13) observe, default service providers and competitive retail suppliers "face the same market price for bulk power.... Particularly in the case of the residential sector, there is little room for efficiency gains (and therefore vigorous price competition)."

The problem of securing the power needed for adequate and reasonably and stably priced SSO service can be addressed through careful resource planning, updating traditional IRP with a more-extensive use of the financial portfolio management techniques that have been adopted in SSO procurement in many states. By adopting this approach, Ohio can develop adequate power resources, obtain lower, more stable prices, and reduce consumer risk, while continuing its progress towards competitive wholesale and retail electricity markets. We will call that combination of portfolio management and IRP integrated portfolio management, or IPM.[11]

Traditional IRP evaluates a wide variety of supply- and demand-side resources to identify the combination of resources expected to meet current and future needs at the least cost. Integrated resource plans typically looked at planning periods of twenty years and were updated every two to three years.

Financial portfolio management comprises the guidelines that sophisticated investors and commodity purchasers utilize for determining their product mix. An investment manager must select the appropriate mix of cash, stocks of various kinds (large cap, small cap, foreign, etc.), bonds of various maturities and issuers (corporate, municipal, federal, foreign), futures and hedges, mutual funds, and so on. State-of-the-art portfolio management uses detailed quantitative analysis, to assess how different combinations of investments with varied kinds of uncertainty affect the return and risk profile of the total portfolio.

Similarly, the managers of power portfolios have multiple options, including buying power under various contractual arrangements (short- and long-term, full-requirements or baseload, firm or unit-specific), building and running generation and of reducing need through demand-side management (DSM). Traditional vertically integrated utilities used portfolio-management approaches for some fuel

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[11] Chapters II through IV explain in detail how the IPM approach can integrate with continued competitive retail marketing. Chapters V and VI detail the energy-efficiency and renewable-energy implementation part of the IPM approach recommended for Ohio.

and short-term power transactions, but did not generally see portfolio management as relevant to their major efforts, focused on building or buying generation and on DSM. Two recent changes have made portfolio management techniques more relevant to power-supply planning. First, the growth of market trading of futures and options for power, natural gas, weather, and emission permits, has expanded utility choices in resource planning, in a manner that resembles the financial and commodity markets in which portfolio management is commonplace. Second, utilities that have divested their generation and must procure power for SSO service have begun to use elements of portfolio management, such as contract laddering.

Debates about how to structure electricity markets and retail SSO procurement often become very theoretical. Ohio does not face an exercise in theory; the problem of ensuring adequate, reasonably and stably priced SSO will affect real people with real problems. Failure to do careful, integrated resource planning on how to meet that need *is* a planning decision, but not a very sound one! Failure to carefully choose and actively manage an appropriate portfolio of resources for that purpose *is* a portfolio management decision, but not a well thought out one.

II. Power Supply for the Standard Service Offer

Prior to restructuring, Ohio utilities provided generation services under full regulation. The utilities owned power plants and purchased power from other generators. Retail rates were set to cover the return on investment (as well as depreciation and taxes) for the plants, their fuel and operating expenses, and purchased power. Some utilities also operated energy-efficiency programs, recovering their costs through retail rates.[12]

In general, utilities were allowed to recover their prudently incurred costs through rate cases. Utility choices in generation planning were subject to the following restraints:

- the possibility of disallowances of imprudently incurred costs;
- specific legislative requirements, such as PURPA, which required utilities to purchase power from qualifying facilities at avoided cost;
- the requirement of obtaining a certificate of environmental compatibility and public need for generating stations, transmission lines, and transmission substations; and
- the requirement for PUCO approval of the utility's Long-Term Forecast Reports, which included generation-expansion plans.

With restructuring, generation service was no longer regulated on a cost-of-service basis, and the generation-planning function was eliminated from the Forecast Reports. The utilities retained a responsibility to provide the SSO, but most customers were expected to be served by electric suppliers, either directly or through governmental aggregation.

The actual situation has worked out differently from those initial expectations. Most Ohio electricity consumers still receive their generation service through the SSO. This situation is likely to continue: No restructured state to date has shifted a majority of its customers or load to direct competitive supply.

In addition to the absence of a real competitive retail market, the current situation in Ohio has been disappointing in other ways. The SSO supplies in the rate-stabilization plans have not been acquired or priced through competitive bidding in the wholesale markets, and the division of costs between SSO and delivery rates

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[12] During the 1990s, as part of their IRP activities, some Ohio utilities implemented DSM programs with stakeholder participation through collaboratives.

does not correspond to the operation of the wholesale markets or the requirements on competitive suppliers.

The current regulatory framework for the SSO and competitive power supply runs mostly through 2008. The implementation of that framework is in flux. However various pending legal and regulatory proceedings turn out, Ohio must address the structure of the market after 2008.

The Legislature has a number of options, ranging from reintegration of the existing generation into the utilities and return to full cost-of-service regulation, to continuing to serve most customers through the SSO, to assigning slices of load by means of short-term bidding, to randomly assigning customers to retail electric suppliers and hoping that the competitive market will sort itself out.

This report examines options for making the SSO alternative work for customers in the short- and long-terms. This approach uses the principles of integrated portfolio management, discussed in detail in Chapter III, to determine an appropriate mix of resources for the SSO portfolio.

Building a Standard-Service Portfolio

This section describes conceptually the types of resources that may be appropriate for a SSO portfolio, and how those resources could be acquired over time. The actual mix would be determined through integrated portfolio management, as described in Chapter III.

An effective SSO portfolio should comprise both short- and long- term resources. The short-term resources would provide flexibility in responding to changes in load, as well as providing the mix of services that are required to make up full-requirements service. The long-term resources would provide price stability and contribute to long-term resource adequacy.

While the mix of short- and long-term resources would vary over time, and would be determined as part of the IPM process, two types of resources should contribute about equally to the typical SSO portfolio. Increasing the long-term portion of the portfolio would increase the stability of prices, the reliability of regional supply adequacy, and the ability of Ohio to direct capacity expansion in desired directions. On the other hand, increasing the short-term portion of the portfolio would spread out the responsibility for balancing load and supply over a larger share of the portfolio. It also would reduce the likelihood that the SSO portfolio will become a net seller into the short-term market, if the market share of SSO falls. As a starting point, the long-term resources are assumed to average about 60% of the portfolio energy requirements.

The short-term resources will (1) provide more than their proportional share of ancillary services, and probably of capacity as well; (2) provide more-expensive load-following energy; and (3) assume all the risks of load growth, weather and migration between SSO and competitive supply. Hence, the cost of the short-term and the long-term portions of the portfolio may be approximately equal over time.

Long-Term Resources

Some types of resources that may be appropriate for long-term resource acquisition in the SSO are as follows:

- Contracts of five years or longer from existing power plants, owned by utility affiliates or independent generators. These contracts could either be for specific products (e.g., energy) or for every service the plant produces (energy, capacity, operating reserves, regulation, black-start capability). The energy prices should be fixed.
- Contracts for five years or longer for power, without any linkage to specific power plants. These contracts could be for combinations of: (1) flat around-the-clock energy supplies; (2) peak-period energy supplies; (3) shaped energy supplies, either to follow typical SSO load shapes or to follow the specific daily shape; and (4) capacity.
- Contracts specifically for power to be provided from new plants meeting particular requirements, which could include location (to avoid or relieve transmission constraints), fuel type (to mitigate price risks), technology (to diversify supply and demonstrate improved technology), and emissions (to reduce costs of compliance statewide). Integrated gasification combined-cycle plants would be one candidate technology for this treatment. Minimizing the costs of these resources may require long-term contracts, on the order of 10 to 20 years.[13]

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[13] Another approach to minimizing costs would be for the legislature to allow, and the PUCO to approve, the securitization of some project debt through utility rates. The principal and interest on the securitized debt would be paid directly to the lenders through a charge on utility bills, essentially eliminating all the risks to the lenders. The problem with securitized costs is that they must be paid, regardless of performance, while normal power-supply contracts would reduce payments if the power plant produced less than the contracted power supply and terminate payments entirely if the plant ceased operation. Hence, securitization might slightly reduce the price of capital-intensive generation, but at the cost of shifting risk to consumers.

Such contracts have been used elsewhere to ensure the construction of new generation of required type and location.[14] For example, Consolidated Edison issued an RFP for additional generation to be built in (or electrically connected to) the constrained New York City transmission pocket, and signed a ten-year contract for the output of a new 500-MW combined-cycle plant. Consolidated Edison will use the output to serve its equivalent of standard service and sell any excess into the competitive market. Any difference between the cost of the contract and the market prices for energy and capacity will be spread over all Consolidated Edison customers. Customers served by competitive suppliers would benefit both from the effect of the plant in pushing down local energy and capacity prices, and from the credits that would flow to them whenever market prices rise above the contract cost. After the ten-year contract, the existence of the plant will continue to increase wholesale competition and reduce market prices.

Xcel Energy and other utilities have similarly used RFPs in recent years to acquire new capacity contracts.

The recent $16-billion Repowering America initiative by NRG Energy, a major independent generation owner, involving new integrated-gasification combined-cycle and nuclear plants, as well as peakers and gas combined-cycle plants, emphasizes the importance to that generation company of long-term power-purchase agreements with credit-worthy entities, such as utilities.[15] NRG expects to have contracts for about 70% of the output of its new and repowered plants output prior to construction. Specifically, "NRG expects to contract substantially all of its development projects in the Northeast through state administered processes. The contracts will range up to 20 years in length."[16]

- Contracts for power from new renewable plants. This is really a part of the previous point, which are separated here to emphasize the importance of developing the markets for renewable energy. These contracts can be used to meet any renewable portfolio standards implemented in Ohio. The RPS

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14 Similar long-term contracts with utilities allowed the construction of the qualifying facilities and independent power producers that supplied a large percentage of new capacity nationally in the 1980s and 1990s.

15 Repowering America with NRG, June 2006 (slides for June 21, 2006 analyst and investor conference call)

16 "NRG Announces Comprehensive Repowering Initiative," NRG Energy, Inc. Press Release, 6/21/2006

would be a floor, not a ceiling, on the amount of renewable energy in the SSO portfolio.

- Energy efficiency and other DSM resources, to reduce usage and allow the utility to meet the SSO requirements with less generation energy and capacity, as well as avoiding or deferring transmission and distribution investments in constrained areas.[17]

For both energy efficiency and renewables, legislatively mandated portfolio standards are desirable to ensure that all power suppliers participate in the development of these important resources. If either the EERS and the RPS are not enacted, the importance of incorporating these resources in the IPM process will be increased.

Short-Term Resources

Short-term resources will supply all the services that are not provided by the long-term resources. While the long-term resources would probably provide large fractions of the installed capacity requirements and the average hourly energy requirement, short-term resources will be needed to provide the following:

- The remaining daily installed capacity requirement.
- The residual energy load for each hour: customer load plus losses, minus the energy actually generated by the long-term resources (which may be lower than their capacity due to outages and economic dispatch).
- Ancillary services. Some of the long-term resources tied to particular plants may provide some ancillary services, but most such services will probably be obtained from the spot market.
- Any transmission or other services provided by load-serving entities under ISO rules.[18]

The Short-Term Supply Contracts for Standard Service

In most restructured states in which the SSO service is procured from the competitive markets (New Jersey, Maryland, Delaware, the District of Columbia, Maine, Massachusetts, Rhode Island, Connecticut), the short-term resources are

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17 This subject is discussed in more detail below in Section V.

18 For PJM, this category would include PJM Scheduling, System Control and Dispatch Service charges; Transmission Owner Scheduling, System Control and Dispatch Service charges; Network Integration Transmission Service charges; and Other Supporting Facilities charges.

contracts to provide slices (often called tranches) of the SSO service.[19] Each tranche is typically a contract to provide full-requirements service for a percentage of the utility's SSO load, including hourly energy, capacity, operating reserves and other ancillary services, and any transmission services that would be provided by competitive suppliers serving retail customers directly.[20] For example, if a utility with 5,000 MW of SSO load procures supply in 50 tranches of 100 MW each, a supplier who contracts to supply one tranche is obligated for:

- one hundred MW of capacity plus reserves;
- two percent of the energy required for the SSO load (100 MWh in the peak hour, 60 MWh when SSO load is 3,000 MW, etc.);
- two percent of all ancillary services required for the SSO load in each hour; and
- two percent of the transmission services required for the SSO load.

The contracts may range from a few months to about three years in length, with deliveries typically starting in one to four months from contract signing. The supplier takes (or hedges) the risks of varying market prices, load effects of weather and the economy, and migration between the SSO and competitive supply.[21]

To varying degrees, most of the utilities that purchase full-requirements SSO have some remaining non-utility contracts, power plants, or other long-term supply resources that must be integrated with the full-requirements supply. In the

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[19] In New York, the SSO service is acquired by each utility as a set of purchases of firm bilateral energy and capacity from generators and marketers, with balancing and ancillary services supplied by the ISO. In New Jersey, JCP&L and Atlantic Electric initially supplied the SSO service from a combination of their remaining generation resources and bilateral and ISO purchases similar to those used in New York. In 2002, New Jersey converted to its current practice of supplying the SSO primarily with full-requirements tranches. Pennsylvania utilities are mostly supplying the SSO at prices set under their restructuring plans; Duquesne Lighting supplies the SSO for some large customers from full-requirements RFPs.

[20] Various utilities have modified this approach in various ways. For 2004–2006, for example, Connecticut Light & Power procured full-requirements service for energy delivered to the ISO-NE Hub, plus all ancillary services, but purchased for capacity and congestion charges from the Hub to Connecticut in separate bilateral contracts and the ISO markets.

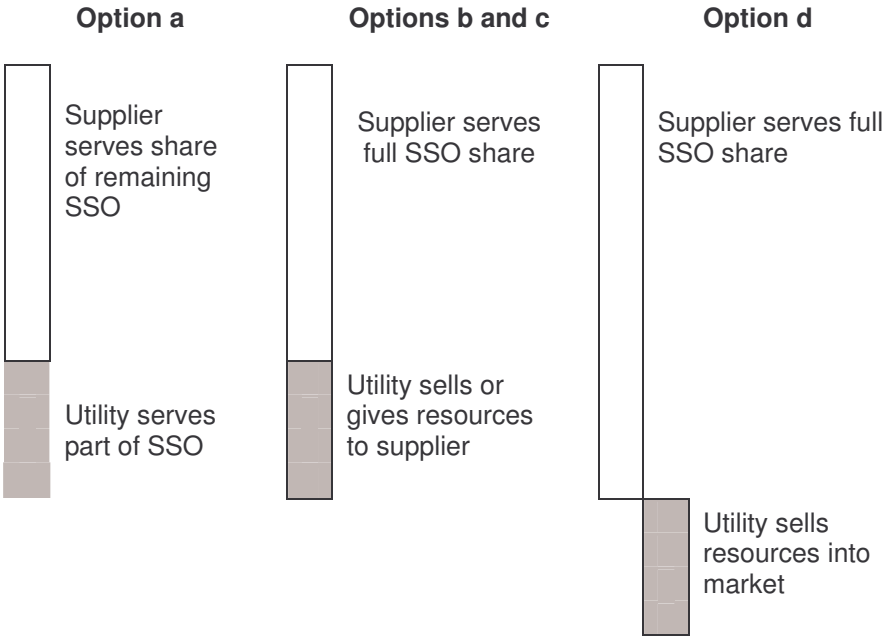
[21] Migration is often limited by tariff conditions so that, for example, customers returning to the SSO cannot leave for competitive supply for six months or a year.

approach proposed in this report, each utility would have a large long-term component of its SSO supply to integrate with the shorter-term full-requirements contracts. To allow for this coordination, the short-term contracts can be structured in at least four ways:

- For each product required by the ISO, each supplier provides its proportional share of the difference between (1) the amount of the product required to meet SSO load and (2) the amount of the product provided by the long-term resources. In other words, if the slice is 5% of the utility's SSO load, suppliers would be bidding to provide 5% of the difference between the hourly SSO load and the output of the long-term resources.
- Each supplier provides its proportional share of the amount of the product required to meet the SSO load, and the utility makes the long-term resources available on pro rata basis to the suppliers, at no cost, as dispatched by the ISO.
- Each supplier provides its proportional share of the amount of the product required to meet the SSO load, and the utility makes the long-term resources available on pro rata basis to the suppliers at their dispatch price. Each supplier is free to enter into bilateral contracts to sell the output of its share of the long-term resources (for the length of the supplier's contract to provide the SSO). To the extent such transactions reduce the supplier's costs or risks, this arrangement would allow the suppliers to reduce their bids for providing the SSO.
- Each supplier provides its proportional share of the amount of the product required to meet the SSO load. The utility sells the products of the long-term resources into the market, and credits the proceeds against the costs of the resources.

The differences among these approaches are illustrated in Figure 2, where the outlined block is the total requirement and the gray area is the part supplied by the long-term resources. Options b and c differ only in whether the supplier is charged for the resources.

Figure 2: Options for Coordinating Utility Resources and Supplier Service



Various combinations of these approaches have been used by utilities in other jurisdictions. It is not clear how suppliers would react to each of these options, and which would produce the least net cost. Option d is the most simple for suppliers to price out, since it does not depend on the characteristics, availability, or dispatch of the long-term resources. It is thus likely to be the least costly overall. However, the PUCO should probably be allowed to review market conditions and take comments from potential bidders before determining whether another of the options might be preferable for a particular procurement period.

Pricing of the Short-Term Contracts

Short-term purchases of the SSO supply are invariably priced in cents per kWh, priced either at the ISO transmission level (without losses) or at the meter (with losses added in). The SSO tranches can be for a percentage of all of the SSO load, or for the SSO load of a particular rate class or customer class. In various procurements, utilities in other jurisdictions have acquired SSO supply in the following ways:

- for all of the SSO load, and priced all of the SSO load at the same dollars-per-MWh price (or added class-specific line losses to the generation-level SSO price), such as obtaining a wholesale supply at $60/MWh and charging all customers $63/MWh to cover losses;
- for all of the SSO load, and administratively derived the SSO prices for each rate schedule, such as obtaining a wholesale supply at $60/MWh and

charging industrial customers $50/MWh and $10/kW-month, residential customers $7/MWh, and so on;

- in separate tranches for each of several rate classes (e.g., residential, small commercial and industrial, large commercial and industrial), and priced all of the SSO load within each class at the same dollars-per-MWh price, such as obtaining a $50/MWh wholesale supply for industrial customers, a $70/MWh supply for residential customers; and
- in separate tranches for each of several rate classes, and administratively derived the SSO prices for each rate schedule (and sometimes separate energy blocks and demand charges) within the class, such as (starting from the previous example) differentiating the $70/MWh residential contract into $75/MWh in the summer, $70/MWh in the winter, and $65/MWh for off-peak water heating.

The best practice in this regard would usually include procurement of separate tranches for each major rate class, and some administrative disaggregation of costs among rate schedules within a class, where they have significantly different load shapes. In general, the SSO costs should be recovered through flat energy charges, rather than block rates or demand charges, since the wholesale contracts are priced in terms of total monthly energy. Wholesale costs do not vary with the distribution of energy among customers in a class, or with customers' non-coincident billing demands.

Similar variety exists in the treatment of seasonal and time-of-use variation in price in past acquisitions. Some utilities have acquired supply at a single price for six months or a year, and charged that price for all months in the period. Others have acquired supply at a single price and administratively determined prices by season.

The best pricing approach is to obtain prices on a monthly, or at least seasonal, basis and charge customers the market prices. This approach has four advantages: bid prices should be lower since the suppliers do not bear the risk of variation in the mix of sales across months (or seasons); the utility can select different bidders for different months; the monthly cost variations reflect market valuation and do not require regulatory determinations; and the SSO revenues are likely to track closely the SSO charges from suppliers, minimizing over- and under-collections.[22]

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[22] Since power delivered by suppliers in one month may be billed to customers in the next month, there may be some differences between SSO bills and revenues. This problem can be reduced by reflecting the billing cycle in setting the monthly retail rate, or

For existing and new time-of-use rates, the utility should acquire SSO supply at separate rates for the various time-of-use pricing periods. Again, this approach has the advantages of matching prices to the market, reducing bidder risk, reducing regulatory burden, and matching SSO costs and revenues.

Timing and Duration of Short-Term Resources

A utility can obtain SSO supply for a particular period (a month or a year) in a single acquisition or in a number of separate acquisitions at different times. The market prices for a given future period will vary over time; for example, the market price for power to be delivered in the summer of 2009 may be 7¢/kWh in December 2007, 8¢/kWh in June 2008, and 6¢/kWh in December 2008. If the utility or the PUCO knew when the price would be at its lowest, that would be the time to acquire all of the SSO supply. Unfortunately, optimal timing of forward purchases from a competitive market is no easier than optimal timing of purchases in the stock market. Just as investors are advised to purchase stocks on an even basis from month to month, rather than trying to pick the optimal day in each year, utilities should purchase SSO supply at a number of different dates.[23] Once all auction mechanisms have been developed and the suppliers educated on the process (and the contract requirements), the costs of issuing another RFP and opening and selecting another round of bids should be trivial. The resulting average price will not be the lowest possible price, but it will not be the highest price either.

A number of utilities have diversified their acquisition dates by purchasing power for any year (or other period) in two or three acquisitions in earlier years. The following discussions consider these procurements in four groups: straight three-year laddering; flexible three-year laddering; mixes of one-, two- and three-year contracts; and overlapping semi-annual contracts.

Straight three-year laddering: New Jersey and Maine purchase one-third of their supply each, in three-year contracts, to replace an equal fraction that expire each year. New Jersey and Maine have used this approach since 2003 and 2004,

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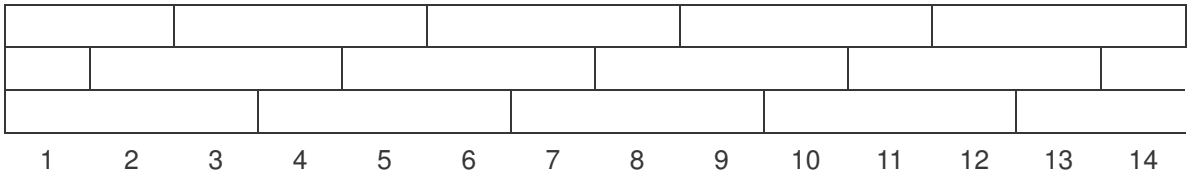
charging each customer a SSO rate based on a weighted average of the wholesale prices in effect during that customer's billing cycle.

[23] For stock purchases, investors can use an approach called "dollar-weighted averaging," in which they invest the same amount of dollars each month. Not only does that strategy avoid the risk of investing all one's funds on the worst day, but it also results in more shares being purchased on days when it the price is lower than average. Since the utility needs to acquire a fixed amount of supply, rather than invest a fixed amount of capital, this approach cannot be applied directly to the SSO acquisition.

respectively.[24] Both states procure power for all their utilities simultaneously; New Jersey uses a complex declining-clock multi-round auction conducted by the four utilities with oversight by a contractor for the regulator, while the Maine PUC directly conducts the RFP for power supply for its utilities.[25]

Figure 3 shows the pattern of contracts with three-year laddering. Prior to the first year, the utility obtains contracts for one, two, and three years. As each contract expires, it is replaced by a new three-year contract. The supply for each year comes from three contracts—after the second year, those contracts are obtained one, two, and three years earlier.

Figure 3: Three-Year Laddering of Power-Supply Contracts



Flexible three-year laddering: Connecticut requires that a portfolio of service contracts be procured in an overlapping pattern of fixed periods and that the portfolio of contracts procured under such plan shall be for terms of not less than six months (Conn. Gen. Stat. 16-244c(c)(3)). The Connecticut Department of Public Utility Control, with the support of the utilities and the state's consumers counsel, has decided that power should be acquired through "a laddering approach, in which a portion of the total power requirements are contracted over a three year cycle, to create a blended portfolio. Staggering the contracts in this manner generally mitigates price fluctuations and provides greater rate stability for customers" (DPUC 06-01-08, Phase 1, June 21 2006, 12). Specifically, the DPUC approved one utility's plan to seek supply through semi-annual RFPs, with

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[24] New Jersey held its first basic generation service auction in 2002, but that first year, it only utilized one year contracts. It began phasing in three year contracts starting in 2003. The New Jersey firm-price purchases are for power years from June to the next May. The Illinois Commerce Commission has ordered a process similar to New Jersey's, although there are appeals from that order pending in state courts. Maine held its first residential standard-offer procurement RFP in 2004, which set prices for March 2005 to February 2006.

[25] PPL Electric recommended a similar three-year laddering strategy in the Pennsylvania PUC's generic investigation of options for power supply at the end of the rate caps for that state's utilities in 2011. "PPL Electric Utilities Offers Strategy for Completing Transition to Competitive Electricity Markets in Pennsylvania," PPL press release (06/22/06).

contracts terms of up to three years, and the other's plan to use three annual procurements (ibid., 13). The Department clarified that these schedules should be a plan, not a straitjacket, so that utilities "retain the ability to reject bids and return to the market at any time for further solicitations. The Department will also allow shorter contract durations and more-frequent solicitations in response to market conditions or if specific bidding results are not favorable."

Mix of one-, two-, and three-year contracts: Maryland, the District of Columbia, and Delaware purchase power for residential customers so that the power for each year is provided in equal amounts from one-, two- and three-year contracts.[26] In some years, this results in all the supply coming from new contracts; in others, one-third of the power supply is new, one-third was purchased a year earlier, and one-third was purchased two years earlier, just as in the straight laddering approach.[27]

Figure 4 illustrates the mixed-laddering approach. In each year, the utility obtains a one-year contract for a part of the next year's load. Before year 1, and in years 2, 4, 6, and 8, the utility obtains a two-year contract for the next two years. Before year 1, and in years 3, 6 and 9, the utility obtains a three-year contract for the next three years. The diversity in the procurements varies from year to year: year 6 is served with contracts obtained in year 5 (for one year), year 4 (for two years) and year 3 (for three years), but year 7 is served entirely with contracts obtained in year 6.

Figure 4: Mixed Laddering of Supply Contracts

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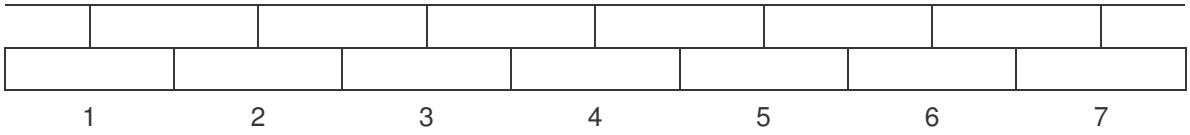
26 In Maryland, this approach is applied by BG&E, PEPCo and Delmarva. Small commercial loads are acquired in one- and two-year contracts. Allegheny is still providing power at rates fixed in the restructuring settlement.

27 The Connecticut utilities used a similar approach in acquiring power for calendar years 2004–2006. In October 2003, Connecticut Light & Power purchased 100% of its supply for 2004 and about 25% of its supply for 2005 and 2006. (The details of the acquisitions have been kept confidential.) In October 2004, CL&P acquired the rest of its supply requirements for 2005 and about half its remaining requirements for 2006. The remaining 50% of requirements for 2006 were purchased in October 2005. Meanwhile, United Illuminating purchased all of its 2004–2006 requirements in October 2004.

These three jurisdictions also spread out their procurement dates for each of the contract lengths being acquired that year among three separate RFP bid rounds, spaced approximately three weeks apart. Such a process may have advantages or disadvantages for both the buyers and suppliers. However, there is not enough data available to be conclusive in this regard. One advantage of the multiple procurements is that, if the bid prices are anomalously high in an early round, the utility can defer acquisition to a later round. All three Maryland utilities purchase their power on the same days.[28]

Overlapping semi-annual contracts: Massachusetts has been using a shorter-term procurement ladder for its residential and small-commercial SSO contracts. Every six months, each utility has procured one-year contracts to cover half of its load.[29] The Massachusetts Department of Telecommunications and Energy settled on this standard after a few years in which various utilities procured their SSO supplies for different periods, but without overlap or laddering. The supply for each half-year has been acquired in two procurements, in the two preceding half-years (DTE 02-40-B, April 24, 2003). This approach is illustrated in Figure 5. For example, in year 3, the first half is supplied by the end of a contract obtained early in year 2 and the beginning of a contract obtained late in year 2; the second half of year 3 is supplied by the end of that latter contract, and the beginning of a contract obtain early in year 3.

Figure 5: Massachusetts Annual Ladders



Recently, NStar has committed to acquire supply for residential customers through a "laddered approach,… such that: (1) 50 percent of supply will be procured under one-year contracts; (2) 25 percent of supply will be procured under two-year contracts; and (3) 25 percent of supply will be procured under three-year contracts." (DTE 05-85, December 30 2005, 9). This language sounds like the Maryland approach, but the parties agreed to "develop a staggered schedule to implement this provision...potentially include[ing] longer-term contracts" (ibid.),

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28 Delaware and the District of Columbia have only one investor-owned utility each.

29 Each utility or holding company has procured power on a separate schedule, through separate RFPs.

suggesting that NStar may move toward a laddered approach like that in New Jersey and Maine.[30]

Empirical comparison of the results of these procurement methods is limited by the short period of experience and the effects of major increases in market prices in that period. The experience is thus anecdotal, but nonetheless instructive. The utilities that have been purchasing power in three-year laddered procurements have fared much better than those with shorter-term purchases in the price spikes of 2005 and 2006. For example,

- The New Jersey utilities procured a third of their 2006–2007 supplies in 2005 at 10.2¢/kWh, about 55% more than power procured in 2005. Since two-thirds of the 2006 supply was procured in 2004 and 2005, JCP&L's residential power rates rose only about 20% from 2005–2006.[31]
- The same pattern occurred in Maine. Central Maine Power, for example, went into the 2005 procurements with two-thirds of the 2006 supply locked in at 6.654¢/kWh from 2004 and 2005 procurements. The power procured in 2005 for 2006 cost 11.844¢/kWh, resulting in a blended price of 8.38¢/kWh, about 21% higher than the 2005 blended rate (Order in Mane PUC Dockets No. 2005-553 and 2005-521, December 20, 2005).
- In November 2005, Western Massachusetts Electric purchased power for the first half of 2006 at 13.8¢/kWh, 93% more than WMECo charged for the same period in 2005. Since these supply contracts were averaged with 8.5¢/kWh supply contracts from May 2005, the average wholesale price for the first half of 2006 was 11.1¢/kWh, still 55% higher than 2005.
- NStar's procurement in October 2005 to supply half of its supply for its constrained northeastern Massachusetts territory for the first half of 2006 cost 14.9¢/kWh, over twice the price for the first half of 2005. Averaged with the 8.3¢/kWh from the May 2005 procurement, the early-2006 price was 11.6¢/kWh, 66% higher than the early-2005 rate.
- Connecticut Light and Power's procurements for 2006 cost 6¢/kWh for contracts signed in 2003, 7.2¢/kWh for contracts signed in 2004, and 14.5¢/kWh for contracts signed in 2006 (McCarthy 2006a; 2006b).

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30 The settlement and the DTE's order both specify that "the laddered approach aims to reduce price volatility for small customers" (ibid.).

31 This description applies to the fixed-price supply contracts for small-customer loads. Large commercial and industrial customers receive SSO as real-time ISO prices.

- In Maryland, PEPCo and Delmarva were in the third year of their three-year cycle, and in early 2006 purchased new one-year and two-year contracts, totaling 75% of their load. PEPCo's average supply for 2006–2007 averaged 9.6¢/kWh, 60% more than in 2005–2006.[32]

The results in 2006 were residential SSO price increases of 60% for Maryland, 50%–60% in Massachusetts, about 20% for Maine, CL&P and New Jersey, and a small decrease for UI. Some of these differences in price increases are due to location, load shape, or the effect of retained generation resources, but the differing procurement schedules is by far the most important factor.

Of course, in years in which forward generation prices fall, utilities with longer-term procurements may miss some of the savings. The main lesson of 2005–2006 is that a well-designed laddering policy reduces the effect of any one year's auction prices on customer bills.

Acquisition Method

The two basic approaches that have been used extensively for competitive acquisition of short-term power supply are both auction methods. Since bidders will generally guarantee price bids for only a day or so, it is important that all the terms of the procurement (the nature of the product to be delivered, payment schedules, dispute resolution, and all other contract terms) be determined prior to the bid.

The simpler and more common method is a request for proposals (RFP), essentially a sealed-bid auction. This approach allows the utility to permit some narrow variations in the bid terms, and allows for some brief post-bid negotiations to fine-tune the supply.

The other approach, which has been used in five annual acquisitions in New Jersey, attempted in one Ohio auction, and has been proposed for use in Illinois, is a simultaneous, multi-round, declining-clock auction. Declining-clock auctions have been used for the sale of communications (e.g., cell-phone) licenses, where the value of any one license depends on whether the bidder will be able to purchase compatible licenses in other markets. Similar auctions have been proposed for ISO-wide pricing of locational capacity in New England. For most acquisition of the SSO supply, there are no combinatorial complications comparable to those of building a communications system. Furthermore,

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[32] Since 2006–2007 was BG&E's first year of competitive procurement for residential load, it acquired all of its SSO requirements, at an average costs of 10.6¢/kWh, well over twice the 4.6¢/kWh it was charging in 2004–2006.

declining-clock auctions are more expensive to operate than the sealed-bid approach.

We therefore recommend that the short-term power supply be acquired through sealed-bid RFPs, subject to continuing review of the cost and effectiveness of alternative auction types.

Best Practices

While no one procurement scheme has been demonstrated to be clearly superior, the following guidelines appear to be consistent with current best practices:

- Short-term power supply should be acquired over the three years preceding the year in which the power will be delivered.
- Acquisitions should occur at least twice a year.
- Procurement dates should be staggered, so not all utilities are acquiring power on the same date.
- The acquisitions should be planned to be approximately equal in magnitude (e.g., one-third each year, or one-sixth every six months), although planned acquisitions may vary by 50% or so upward or downward from the average.
- Utilities, with regulatory oversight, should be allowed to increase or decrease the amount of acquisition in response to the magnitude and pricing of any particular offer. If the share of supply procured is less than planned, future procurements can be increased, or additional acquisitions may be scheduled.

Transition Resources

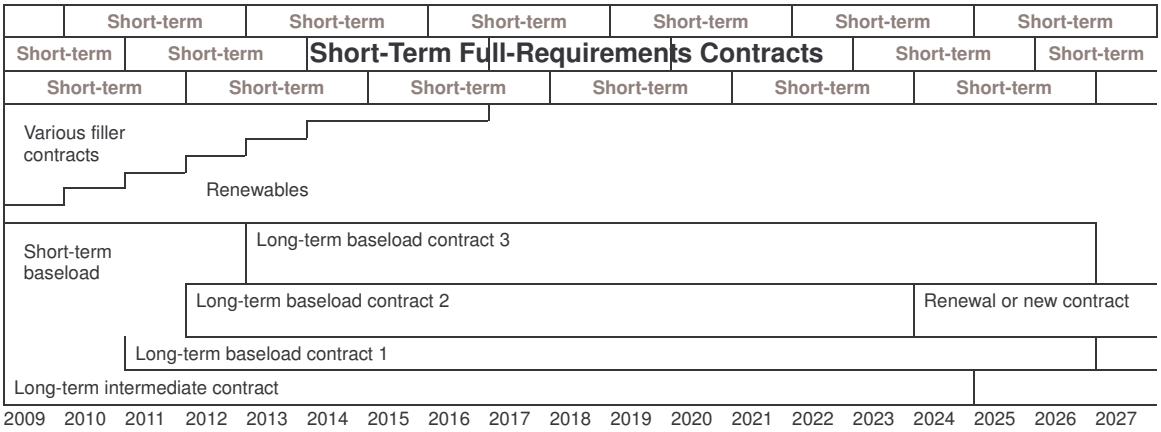
Accumulating the long-term resources that will be a part of the SSO portfolio will require some time to allow for development of the IPM process discussed in Chapter III, issuance of RFPs, and construction of new resources. In the meantime, the utility will need bridge resources. Those resources may be plant-specific or firm purchases from utility affiliates or other suppliers, for periods of a few to several years.

The utility may also need to acquire short-term resources for the first year or so using shorter lead times and fewer procurements than will be used for later years. Using the guideline suggested above—that short-term resources be acquired over the three years prior to the delivery year—power for 2009 should be acquired starting in 2006. Since the legislative and regulatory processes for guiding post-2008 procurement are unlikely to be completed in 2006, the procurement for 2009 will start somewhat later than the guideline proposes.

Summary of Standard-Service-Offer Resource Mix

Figure 6 summarizes the conceptual construction of the SSO resource, with hypothetical resources and quantities. The vertical axis represents the amount of supply, as annual megawatt-hours or a percentage of SSO load, while the horizontal axis represents time. The top portion of the figure is a series of short-term contracts to supply full-requirements service. Those purchases are shown as three-year contracts. The short-term supply for 2011 is shown as composed of equal contributions from procurements in 2008, 2009, and 2010; the actual pattern of procurements may differ from this strict equality.

Figure 6: Illustrative SSO portfolio



Recovery of Standard-Service-Offer Costs

Long-term fixed-price power contracts for SSO supply complicates the coordination of cost recovery with facilitation of the competitive market. Competitive suppliers are likely to offer customers power priced to reflect the wholesale market prices over the next quarter, year, or whatever period the customer is likely to stay with the supplier. If SSO is priced on a mix of short-term market prices and longer-term contracts, the SSO price will sometimes be higher than the competitive offers and sometimes lower. When the SSO price is below the prevailing market price, customers would tend to stay with, or switch back to, SSO service. If the contract prices result in a SSO price that is higher than the market price, customers would tend to leave the SSO for lower retail offers.

The possibility of the SSO deviating widely from the market prices creates the following four potential problems:

Stability of the SSO: If the market price goes down (compared to earlier expectations), the SSO price may be higher than the price competitive bidders would offer, resulting in migration from SSO to competitors. The short-term full-requirements purchases would automatically shrink as the

SSO requirements decline, and the utility could let some mid-term contracts expire without replacement, so the SSO would not be burdened with excessive supplies of power. But as SSO sales fall, the above-market costs of the longer-term contracts would be spread over smaller volumes of sales, requiring higher prices and promoting more migration. Unless customers are prohibited from leaving SSO, the entire mechanism for paying the SSO contracts may be undermined.

Stability of competition: On the other hand, if the market price goes up more than expected, the stable prices of the mid- and long-term contracts in the SSO portfolio will tend to keep the SSO price well below market. Competitive suppliers would not be able to match those prices, and retail competition would be limited until market prices came back into line with the portfolio.

Higher prices for full-requirements supply: If the bidders on the short-term full-requirements supplies know that the SSO price may diverge significantly from the market, they may build into their prices the risks of (1) dumping large amounts of power into a weak market, if market prices fall and load migrates to competitive suppliers and (2) buying large amounts of power from an expensive market, if market prices rise and load returns to SSO. That risk premium could raise SSO prices.

Gaming by large customers: As SSO prices rise above competitive offers, large customers will quickly migrate to the competitors. As SSO prices become economic, the large customers will return. Small customers are likely to respond more slowly, due to higher transaction costs. So small customers may bear more of the costs of any periods that SSO is above market, while getting less of the benefits when SSO is below market. Further limiting the rights of customers to switch would moderate this problem, but also interfere with competition.

There are at least two ways of dealing with these potential problems. First, SSO could be set to reflect market conditions, and any difference between the market-based price and the SSO portfolio cost could flow through to all customers.[33] If the market prices are high in a particular year, the portfolio differential would be a net credit to all customers, whether they are supplied by SSO or a competitive supplier. If market prices are low, the portfolio differential would be a charge to

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[33] Market prices for retail service could be determined by directly bidding out a small part of the SSO load, by surveying competitive-supplier prices, or by estimating retail market prices from wholesale forward prices, retail load data and ISO charges for ancillary services.

customers. Thus, the long-term portfolio would have the direct effect of stabilizing total rates for all customers. In addition, the new resources brought on-line as part of the SSO portfolio would ensure adequate supply, and help avoid price spikes due to capacity shortages and excessive reliance on natural gas or any other fuel.

Alternatively, the SSO could be structured to recover all portfolio costs from SSO customers. The diversity of supplies, contracts and pricing terms would tend to reduce the risk of the average SSO cost diverging far from the market price. The utility would also be acquiring a portion of the short-term SSO supply every year, as well as new contracts to replace expiring contracts. Some of the continuing contracts may also be indexed to fuel prices or other factors that move with the market. Hence, the cost of the SSO supply will tend to move in the direction of the market, if more slowly. Those changes in SSO costs will require that the SSO price be reset annually, which would provide the opportunity to ensure recovery of long-term contract costs through price adjustments. In the event that SSO rates move very far from market prices, in either direction, the PUCO could be authorized to either temporarily limit migration or allow a cost or credit to be spread over all customers so that the SSO can approximate the market price.

As noted in the next section, energy efficiency would be dealt with somewhat differently from other long-term resources.

Demand-Side Management in the Standard-Service Portfolio

Unlike supply resources, which can be efficiently acquired piecemeal from various providers, efficient DSM programs require a coordinated approach. Only a finite amount of DSM resources exist, in the equipment and buildings of the utility's customers. Working with a customer and visiting a building to install one measure without comprehensively addressing other efficiency opportunities can waste a lot of money in the form of additional visits. Even worse, equipment installed in one measure may need to be removed, and even discarded, to install a later measure.

For example, a poorly design DSM process can result in the installation of high-efficiency fluorescent lamps in a building, followed by removal and replacement of the lamps so that the ballasts can be upgraded to higher efficiency, followed by removal and replacement of both the ballast and the lamps so that the fixture can be upgraded, followed by removal of all that equipment so that the nearly-new ballasts can be replaced by dimmable ballasts allowing for load reductions in response to daylight levels and market prices, and so on. A comprehensive program would install the lamps, ballasts, fixtures and dimming capacity simultaneously, greatly reducing costs. Hence, while other resources can be

selected based on a simple dollars-per-MWh cost test, DSM must be acquired in a comprehensive fashion.

As discussed in Chapter V, Ohio should establish an energy-efficiency resource standard (EERS), which would require all electric suppliers to obtain energy-efficiency credits from the administrator of statewide DSM programs. The Office of Energy Efficiency might be a good choice for that administrator role, hiring contractors to implement particular programs. Similar approaches are used in New York State, through the New York State Energy Research and Development Administration, and Oregon, through the non-profit Energy Trust of Oregon, Inc., formed for that purpose. In Vermont, similar statewide administration is provided by Efficiency Vermont, which has twice won competitive three-year contracts to provide that service.

The EERS should be a floor on the amount of energy efficiency in the SSO portfolio. The utility should acquire additional DSM resources as determined to be appropriate through the IPM process, or as may be cost-effective to relieve transmission or distribution constraints and defer specific investments. These additional efficiency resources may be acquired through the statewide administrator, or if the administrator is not able to provide the necessary services, directly by contractors hired by the utility.

To avoid any adverse effects on the competitive market and improve the efficiency of the programs, all DSM programs should be available to both SSO customers and shopping customers. The effects of the DSM programs will reduce the loads of all participating customers, and hence the costs of all major power suppliers. Since all customers will be eligible for and benefit from the programs, and costs to all power suppliers will be reduced, it seems equitable to charge the costs of energy-efficiency resources to all customers eligible to participate in the particular programs. In other words, the costs of residential programs would be recovered from all residential customers, whether they are served by the SSO or an aggregator; the costs of industrial programs would be recovered from all industrial customers, whether they are served by SSO or a competitive supplier.

All DSM programs should be designed to be comprehensive and cost-effective under the Total Resource Cost Test.

III. Portfolio Management and Integrated Resource Planning

Reliable SSO service can be acquired at reasonable and stable prices through integrated portfolio management (IPM), combining the thoughtful planning of traditional utility IRP and the diversification approaches used in financial portfolio management. This approach can reduce consumer risk while continuing progress towards competitive wholesale and retail electricity markets.[34]

Basic Concepts in Integrated Resource Planning and Portfolio Management

Integrated Resource Planning

Traditionally, utilities did Integrated Resource Planning (IRP) by evaluating a wide variety of supply-side and demand-side resources available (or expected to become available) to meet current and future needs.[35] They usually emphasize finding the combination of demand-side management (DSM) resources, power-supply alternatives, and transmission upgrades that, when added gradually over a planning period, is expected to meet the need at the least cost to the utility and its ratepayers. Integrated Resource Plans (IRPs) typically looked at planning periods of 20 years and were updated every two to three years.[36]

The outcome of an IRP process depends on many planning assumptions and forecasts that are subject to uncertainty. These uncertainties are often addressed by choosing a few alternative scenarios with different assumptions. The selected

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34 Section A of this chapter describes these separate ideas conceptually. Section B provides more detail on the implementation of IRP and portfolio management. Section C describes the need for SSO planning and management. Section D discusses how they can be combined quite naturally into a unified approach under IPM for selecting the types and amounts of resources that may be appropriate for SSO and how those resources should be acquired over time.

35 *Supply-side* resources are those that generate or deliver electricity to the consumer's meter. *Demand-side* resources are those that modify or reduce the consumer's need for electricity. Depending on the jurisdiction, generation on the customer's side of the meter may be referred to and treated as a demand-side resource or treated as part of a special third category of integrated resource planning.

36 States that currently have IRP requirements include California, Colorado, Delaware, Georgia, Hawaii, Idaho, Iowa (for DSM only), Indiana, Kentucky, Minnesota, Missouri, Montana, Nevada, North Carolina, Oregon, South Carolina, South Dakota, Utah, Vermont, and Washington.

resource plan and a few competitors are re-evaluated using those new assumptions to ensure that the selected resource plan is not too brittle. Additionally, revisiting IRPs every few years makes mid-course corrections possible.

While the general IRP process is similar from state to state, the detailed requirements vary. These differences included details for treatment of energy efficiency programs, whether and how to include environmental and societal costs, mechanisms for public input, and the way risk and uncertainty are treated. The legal implications of utility-commission review of IRPs also vary.

Portfolio Management

Few investors would put 100% of their available funds in one investment product. Certainly, no investment manager making decisions in trust for others would consider doing so. Similarly, a purchasing agent for a manufacturer that needs a regular supply of certain commodities would not normally want to make only one type of purchase on one single day for a whole year's worth of production. Rather, wise investors and commodity purchasers use some kind of portfolio management (PM) and procurement process to choose from the huge variety of products, vendors, contract lengths and starting dates, options and hedging products, and other possible strategies.

An example would be investing a fund of money, say the assets of a retirement fund or an individual investor. Here, some of the available choices are cash, stocks of various kinds, bonds of various lengths and maturities from various issues (companies, governments, special purpose entities, etc.), interest rate futures, mutual funds, and so on. An example from the world of commodity purchasing might be the job of buying raw materials needed for a manufacturing process. In this case, one type of choice available is long contracts, but even that one concept includes the possibilities of buying contracts for varying amounts on varying dates and those long-term contracts can also have a variety of delivery dates, i.e., purchases could be for delivery a month ahead, a year ahead, or several years out. Other alternatives would include options to buy or sell on certain dates at a given price (the "strike price"), hedges for related commodities or other economic drivers, and reliance on spot markets. Some regulated utilities practiced this type of PM when buying generating fuel, and many retail natural gas utilities do so, as well.

State-of-the-art PM uses detailed quantitative analysis of the uncertainty of different investment choices. The goal of this quantitative analysis is to assess and manage how different combinations of investments with varied kinds of uncertainty affect the return and risk profile of the portfolio as a whole.

Standard service is procured in some retail-choice states using a few, relatively superficial PM tools, such as laddered multi-year contracts from multiple vendors. However, even in those states little attention has been paid to truly diversified portfolios or to quantitative assessment of the costs and risks of the various possible options. Rather, there has usually been a subjective choice to procure one or a very small number of products in subjectively chosen amounts.[37]

A few state regulators now require utilities to conduct portfolio management so as to provide least-cost and stable electric service to customers over the long term, either as an enhancement to IRP for vertically integrated service or as part of SSO procurement.[38]

Specific Steps in Integrated Resource Planning and Portfolio Management

In an IRP process, the utility evaluates various candidate supply-side and demand-side resources that could be used to meet current and future needs and selects the resources that will do that job at the lowest (present value) cost to its ratepayers. Some state commissions require regulated vertically integrated utilities to prepare an integrated resource plan every two or three years as a way to provide least-cost electric service to customers and to minimize or manage risks faced by ratepayers.[39] The IRP process generally involves the following steps:

1. Forecast load, fuel and market power prices, and other key factors, such as likely environmental regulations or market changes;
2. Document costs and benefits of existing supply- and demand-side resources including existing generation and transmission facilities, purchase contracts,

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37 To cite one example, New Jersey's Basic Generation Service was initially purchased using (roughly) one year contracts that all expired at once. Later, a system of three-year laddered purchases was adopted. Recently, the Illinois Commerce Commission adopted a variant of that approach, splitting purchases between three-year contracts and one-year contracts. However, the choice of those term lengths and the split between them was not based on quantitative analysis of their relative costs and variability.

38 States that currently have instituted some form of portfolio management requirements include Delaware, Montana, Maine, Maryland, Massachusetts, New Jersey, Illinois, and the District of Columbia.

39 States that currently have IRP requirements include California, Colorado, Delaware, Hawaii, Idaho, Indiana, Minnesota, Missouri, Montana, Oregon, Vermont, and Washington.

demand-side-management programs, and market purchases of power; study their strengths and weakness, challenges and opportunities;

3. Identify and characterize new supply- and demand-side resources that could be acquired over the life of the IRP, including technologies not yet commercial;
4. Develop different resource plans that could meet future load requirements, and screen them based on cost;
5. Select the best resource plans and test their sensitivity to risk factors such as load uncertainty, fuel price volatility, and regulatory uncertainty;
6. Select a preferred plan, usually based on a combination of lowest present value life cycle cost (under one or another definition of cost) and risk profile;
7. Develop an action plan for the near term, often three to five years, depending on the construction lead-time of the selected resources.

Integrated resource plans are usually submitted to the state commission for review and, in some states, approval. Approval usually does *not* imply any guarantee of cost recovery; new construction continues to be governed by any existing siting laws and usually requires additional approvals. It is sound practice to review the progress of an IRP at least annually, checking for major shifts in planning assumptions or resources that are performing especially well or poorly, and to completely revisit the IRP every three years or so.

While the general IRP process is similar from state to state, the requirements specified by PUCs vary. IRP states usually require that DSM programs be given equal treatment with generation resources. Some require special consideration of peak shaving measures, opportunities to reduce transmission and distribution line losses, or certain renewable technologies.

A key issue in specifying an IRP process is the definition of the costs that may or may not be included. At a minimum, resource plans are ranked according to the present value revenue requirement (PVRR). The resources in a resource plan will have certain projected annual expenses for capital, interest, return on equity, fuel, operation and maintenance, etc., over the planning period. If those annual costs are discounted (for inflation and the cost of money to the utility) and added up over the planning period, you get the PVRR for that resource plan. The costs counted here include all cash expenses of the utility for implementing the resource plan, including the utility's share of the cost of DSM programs. A resource plan with a smaller PVRR would be preferred over one with a larger PVRR.

Some states also require counting cash costs incurred by someone other than the utility. For example, in some DSM programs the utility pays part of the cost of a measure, such as discount coupons for efficient light bulbs, while the participating consumer pays the rest. Another example of a non-revenue requirement cost is the value of research grants that might be used to pay for part of a new type of renewable generator or transmission device. If those costs are added to the PVRR of a resource plan, the result is the resource plan's Total Resource Cost (TRC). The TRC is a more-comprehensive measure for comparing resource plans and is usually preferable to the utility PVRR. Some states also require that planning take account of the cost of environmental impacts from resources used in the plan. If those external societal costs are included, the TRC becomes the Societal Test. States also vary in whether they require planning to take account of expected costs of future environmental regulation, such as potential carbon dioxide emissions regulation.[40]

Integrated resource planning procedures should provide appropriate opportunities for public participation. They should also specify how uncertainty and risk should be considered in choosing among candidate plans, whether and how plans will be reviewed by regulators, the time horizon for plans, and the time cycle for submitting and updating IRPs. The IRP practice of other states is summarized in Appendix I.

Portfolio management (PM) refers to a planning and procurement process that meets a purchaser's requirements through consideration of a variety of products, ranging from direct purchases of various lengths and starting dates, options to purchase or sell, other hedging products, and the possibilities of producing one's own product (now or in the future) or of reducing ones need for the product. (When applied to electric power procurement, "producing one's own product" equates to building and running generation, while "reducing one's need for the

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[40] Environmental regulations will likely impose more costs on Ohio's energy producers in the future, so investing in energy efficiency provides a good hedge against future price increases. Cinergy expects to spend between $1.7 and $2.2 billion through the next decade to comply with EPA's new NOx-, SO_2- and mercury-control regulations (Leahy, McElfresh, and Stowell 2004, 10). American Electric Power (2004, 10) projects costs of about $3.5 billion through 2010. Compliance with greenhouse gas provisions for AEP range from $0.5 billion to $6.4 billion depending on future Federal legislation (ibid., 10). FirstEnergy (2005, iii) expects to spend between $1.65 and $2.15 billion on pollution controls for new controls for NOx, SO_2, and mercury. The utilities estimate the cost of complying with CO_2 legislation at less than a cent per kWh to over 2.5¢/kwh, depending on the legislation adopted (FirstEnergy 2005, 36; Leahy, McElfresh, and Stowell 2004, 41).

product" translates into any of the available DSM resources.) For many traditional vertically integrated utilities, especially those outside the northeast, those were the main possibilities, and PM would have been very similar to IRP, perhaps differing mainly in emphasis. With the introduction of more intensive market trading of electricity and the beginnings of hedging products for power, natural gas, weather, and emission permits, utility resource planning begins to look more like the type of PM seen in financial and commodity markets, although crucial differences remain.[41] And, as some states began to engage in retail competition and competitive procurement of default service supply (with or without divestiture of utility power plants), some aspects of power supply more closely approached a state where purely financial players could participate and utility ownership of physical generation is sometimes not an option.

Portfolio management has emerged in recent years in states that have restructured their electric utilities and is becoming particularly important with respect to utilities that provide default service in states where retail choice is available. In IRP, vertically integrated utilities can weigh various utility-owned resource options including new generation, transmission expansion, and DSM programs as well as power purchase contracts. With electric industry restructuring, many utilities were required to divest generation and transmission resources and are now required to serve load from contracts with generators, energy marketers, or other utilities, or purchases from the spot market. Some state PUCs require utilities to conduct portfolio management as a way to provide least-cost and stable electric service to customers over the long term.[42]

Action Needed to Ensure Appropriate Standard Service

It might be argued that recent run ups in SSO auction prices are just due to natural gas prices and would have flowed through to consumers even under traditional regulation. This is not correct. Blumsack, Apt, and Lave (2005, 13) find that the

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41 Many of these differences stem from the fact that electricity cannot be stored except by a few specialized and expensive facilities. Therefore, electricity markets differ from commodity markets. Rules require maintaining reserves of several kinds at every moment to deal with the instantaneous nature of power consumption. Also, flows in the power grid are depend on changing patters of load and generation moment by moment and power may not flow over transmission lines that were not contracted for by the buyer and seller. These differences, among others, require specialized market mechanisms and products.

42 States that currently have instituted portfolio management requirements include Delaware, Montana, Maine, Maryland, Massachusetts, New Jersey, Illinois, and District of Columbia.

increases many states have seen in default service rates are *not* simply a reflection of high natural-gas prices, but also strongly reflect the structure of the relevant markets. These authors observe, default service providers and competitive retail suppliers "face the same market price for bulk power....particularly in the case of the residential sector, there is little room for efficiency gains (and therefore vigorous price competition)." So, at this point, those reasons, plus the high transaction costs, uncertainties and risks involved in shopping by small customers and the small annual consumption of each customer, suggest new procedures are needed to ensure adequate, stable and reasonably priced SSO service.

It is likely that reasonable and stable electricity prices for residential consumers, dependent as they are on default service, will be obtained more successfully if default service is delivered from a carefully planned and managed portfolio of resources of varied types and durations, procured from varied types of entities, than if it is delivered solely from standardized power purchase contracts of a few selected durations, obtained from one type of procurement at one time each year. Essentially, this amounts to acknowledging that default service needs long term planning in addition to efficient procurement, and that certain aspects of IRP can be judiciously applied to default service procurement to achieve that end.

Such enhanced SSO procurement and the related policies explained in Chapter II are not incompatible with the development of a vibrant competitive generation industry. In fact, by providing a stable demand for long-term power products, portfolio management for default service can enhance the health of the currently distressed generation industry by alleviating its dependence on an unfriendly project financing market. SSO procurement also needs to be more competitive and to use more sophisticated PM approaches.

Integrated Portfolio Management: Merging Integrated Resource Planning and Portfolio Management

Portfolio management and integrated resource planning are not really different concepts. Rather, they are labels that emphasize different aspects of resource planning, all of which should be included in an ideal resource planning process.

Integrated resource planning tries to put together a portfolio of existing and new resources of all types that help achieve the lowest cost for consumers over the life of the plan. Each time an integrated resource plan is revised, an essentially new plan is created, treating resources acquired since the previous update as committed and seeking the best selection of additions to form its new plan. Risks are usually assessed qualitatively or via scenario analysis, trying to find the resource plan that combines a low cost with a reasonable degree of robustness against uncertainties. While some IRPs include fixed term purchased power contracts or consider

disposing of committed resources, the emphasis is usually on permanent acquisition of resources.

On the other hand, PM emphasizes assembling and managing a collection of resources, often entirely fixed-term purchase contracts. Diversification of expiration dates, vendors and, sometimes, term lengths is a typical tool in PM. Carefully designed competitive procurements are often the centerpiece of a PM approach, especially in when over-the-counter-type markets are less fully developed.

Versions of PM with modest degrees of diversification are common in states with retail choice and default service programs. Some states (New Jersey, Maryland, Delaware) limit procurement for default service generation to laddered two- or three-year slice-of-load contracts obtained via a once-a-year auction or RFP.[43] California initially mandated that 100% of purchases come from spot markets. While such selections are a sort of resource plan, they arbitrarily exclude a wide array of alternatives and limit the degree of risk mitigation that can be provided to retail consumers. Conversely, choosing to focus the least-cost mix of permanent generation acquisitions in IRP without measuring their riskiness leads to a very limited kind of portfolio management—one with few choice points, limited diversification, and few market effects. IRPs often fail to make use of competitive forces.

Clearly, IRP can be improved by harnessing competition and by treating the resource plan as a portfolio judged on quantitative measures of risk and subject to active management. And, likewise, the procurement and management of procurement for default service (or other needs) should embrace a broad range of resource alternatives, strive for least cost service over time, and focus on the risks borne by consumers.

Prior to the 1980s, utilities typically made procurement when and as they wished. The only checks on their procurement activities were subsequent rate review for prudence, adequacy, and used-and-useful status. At that time, a trend began towards greater regulatory oversight, either by establishing planning standards or by review and/or approval of the utility's plans, themselves. Most vertically integrated utilities continue to follow some sort of state procurement policy or guidelines of some sort.

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43 Maryland and Delaware RFPs are conducted in three steps spaced over a few months. This reduces the risk of market price flukes, but does not eliminate it, and all the contracts start and stop on the same dates each year (aside from the laddering).

Since the advent of wholesale and retail restructuring, some utilities have completely exited the generation business or spun that business off to unregulated subsidiaries. Retail choice states generally have had a transition period during which the incumbent utility provided (or provides) default service using its own resources, often at a fixed price established in legislation, settlements or regulators' orders. Most states have instituted some type of competitive procurement for generation service needed to provide default service after that transition period. A few states have recently reinstituted utility responsibility for the generation component of default service and have mandated some sort of long term planning; examples of these include California, Maine, and Delaware.

Applying aspects of portfolio management to the development and implementation of IRPs should be viewed as a challenging but natural enhancement of IRP for vertically integrated utilities. Several states have begun to consider such a move, especially with regard to risk management.[44]

Much more controversial is the suggestion that IRP-like policies have a place in restructured states, especially when utilities have divested generation resources. One approach to pricing default service would be to deliberately make it unattractive (by, for example, changing rates frequently to follow market prices), to promote switching to retail suppliers. The public interest will be better served by providing SSO consumers stable, reasonably priced service, especially so long as retail competition for residential consumers is very limited.

The descriptions of IRP and PM given above are generalizations based on typical practice among the states and may not be identically implemented in every jurisdiction. In fact, various practices can be *called* IRP or PM and include some beneficial features of IRP or PM, but not fully realize either concept, much less an integration of the two. In principle, they are two ways of looking at the same problem. Ideally, resources would be planned, procured and managed in ways that are both integrated and reflect portfolio management.

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[44] The Delaware legislation quoted in Appendix I.G.0 is one clear example of this trend.

IV. Coordinating Regional Planning with Integrated Portfolio Management

Two independent system operators (ISOs) manage the markets and transmission systems in various parts of Ohio: PJM in the AEP and Dayton P&L service territories, and the Midwest ISO (MISO) in the Cinergy and FirstEnergy territories. Both the operation of markets and the planning of transmission by the ISOs can be included in and enhanced by integrated portfolio management.

Markets

The ISOs can facilitate DSM and distributed generation by including those resources in their markets as follows:

- The ISO can structure its operating-reserve markets to allow the participation of such customer-side resources as load management, demand response, and distributed generation.
- The ISO can include all customer-side resources, including energy efficiency, in capacity markets, as FERC has approved for ISO-New England's new forward capacity markets.[45]

Both of these features would improve the cost-effectiveness and cash flow of customer-side resources selected under Ohio's IPM process.

Parties to PJM proceedings are currently negotiating the future structure of the capacity markets in that ISO. Ohio parties have an opportunity to press for better treatment of demand-side measures in those proceedings.

Planning

In the planning area, the ISOs' roles are quite limited. They do not involve themselves in the planning for generation, other than comparing forecasted load with existing capacity and (often unreliable) projections of future capacity, and ensuring that new generation does not destabilize or overstress the transmission system. Nor are the ISOs involved in planning for energy-efficiency or load-management programs. The ISOs' major planning activities concern transmission.

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[45] The settlement (Order Accepting Proposed Settlement Agreement, Docket Nos. ER03-563-030 and ER03-563-055, June 16, 2006) provides, "For the Forward Capacity Market, a distinct method shall be developed to allow energy efficiency and demand response resources (other than Real Time Demand Response) to be fully integrated as Qualified Capacity in the Forward Capacity Market" (§11, Part II.E.2.b).

In transmission planning, the utilities identify constraints that may reduce reliability or (for MISO) increase energy costs. The ISO examines two sets of technical solutions: building new transmission equipment or limiting generation dispatch to reduce transmission loads.[46] This planning process ignores the option of resolving or relieving transmission constraints by demand-side measures, including energy efficiency, distributed generation, and load management (including demand response).[47] In PJM, the transmission planning process includes a one-year period in which other parties may propose to build generation or reduce loads in the relevant planning areas. While PJM apparently considers this respite to be an opportunity for the deployment of lower-cost solutions to the transmission constraint, the ISO does not offer either the generation or demand-side measures any of the savings from avoiding the transmission upgrade or generation redispatch.

The ISOs could seek to identify the least-cost alternative to relieve transmission constraints, which may be some combination of the following:

- transmission additions,
- targeted additions of supply-side generation,
- additions of distributed generation on the customer side of the meter,
- energy-efficiency investments,
- load management and demand response,
- generation redispatch.

The ISO should be willing to financially support alternatives, to the extent that alternatives avoid the embedded costs of transmission additions or the congestion costs of generation redispatch. Those costs should be recovered through transmission rates in the same manner as the avoided investments or congestion costs. Ohio government agencies should push for this even-handed treatment of all

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46 See, for example, the Midwest ISO's 2005 Transmission Expansion Plan, (Midwest ISO 2005, 32 (Figure 2.7-3)). In some cases, where the transmission issue arises from plans to retire a generating facility, the ISO may also examine the option of paying the generator to remain available.

47 In Southwest Connecticut, ISO-New England has purchased short-term emergency distributed generation and load-management resources. These are stopgap measures, rather than part of an integrated plan. We are not aware of any similar acquisitions of locational distributed resources by either PJM or MISO, even on a temporary basis.

resources before the relevant ISO committees, at FERC, and through its congressional delegation.

If one or both of the ISOs continue to resist the incorporation of least-cost principles in its transmission-planning process, Ohio can make siting approval for new transmission facilities contingent on exhaustion of lower-cost demand-side and central-generation options. It appears that this standard could be established through a policy change at the Ohio Power Siting Board (2005, 42) in the interpretation of the statutory criteria of need, "minimum adverse environmental impact, considering the technology that is available and the nature and economics of alternatives," serving "the interests of electric system economy and reliability," and serving "the public interest, convenience, and necessity."

Direct adoption by the ISOs of an IRP approach to resolving transmission constraints would be greatly preferable to attempting to achieve the same goal through limitations on transmission siting, for a number of reasons. First, the ISOs have mechanisms for recovery of costs from all users of the transmission system, while the Ohio Power Siting Board (OPSB) has no explicit power to recover costs of resources from anyone. Second, the ISOs have the capability to plan well into the future, allowing time for study and implementation of demand-side resources, while the OPSB has only a few months to act on siting applications. Third, transmission constraints may involve loads and facilities in other states, beyond the jurisdiction of the OPSB and the Ohio utilities likely to file applications before it. If the ISOs do not assume responsibility for least-cost planning of the transmission system, the Ohio legislature may need to consider additional funding, staffing and authority for the OPSB (and/or the Office of Energy Efficiency and OCC), so that Ohio can monitor emerging transmission issues, develop plans for non-transmission solutions to transmission constraints and start the process of implementing solutions even before the filing of an application for the transmission project.

V. Energy-Efficiency-Resource Standards

The Benefits of Energy Efficiency

Many efficiency measures cost significantly less than generating, transmitting, and distributing electricity. Thus, energy-efficiency programs offer a huge potential for lowering systemwide electricity costs and reducing customers' electricity bills.[48]

In addition to lowering electricity costs and customers' bills, energy efficiency offers the following benefits to utilities, their customers, and society in general.[49]

- Energy efficiency can help *reduce the risks associated with fossil fuels* and their inherently unstable price and supply characteristics, and avoid the costs of unanticipated increases in future fuel prices.
- Energy efficiency can *reduce the risks associated with environmental regulation*. By reducing a utility's environmental impacts, energy efficiency programs can help utilities and their ratepayers avoid the hard-to-predict costs of complying with potential future environmental regulations, such as CO_2 regulation.
- In addition, energy efficiency can *result in significant benefits to the environment and to the health and quality of life of Ohio residents*. Every kWh saved through efficiency results in less electricity generation and, thus, less pollution.[50] Energy efficiency can delay or avoid the need for new power plants or transmission lines, thereby reducing the environmental impacts associated with power plant or transmission line siting.
- Energy efficiency can *improve the overall reliability* of the electricity system. First, efficiency programs can have a substantial impact on peak demand, during those times when reliability is most at risk (Nadel, Gordon, and Neme 2000, iii–v). Second, by slowing the rate of growth of electricity peak and

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48 While the potential benefits are probably much smaller than those of efficiency, demand response and load management can also be helpful in avoiding costs and controlling volatile markets. Those resources should be included in the IPM process.

49 The importance of energy efficiency was recognized by the Ohio Energy Strategy Interagency Task Force (1993, 39–70).

50 Unlike other pollution-control measures, such as scrubbers or selective catalytic reduction, energy efficiency measures can reduce air emissions with a *net reduction* in costs. Thus, energy efficiency programs should be considered as one of the top priorities when investigating options for reducing air emissions and other environmental impacts from power plants.

energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions, while moderating the boom-and-bust effect of competitive market forces on generation supply (Cowart 2001, iv–v).

- Since efficiency programs have a substantial impact on peak demand, they help *reduce the stress on local transmission and distribution* systems, potentially deferring expensive T&D upgrades or mitigating local transmission-congestion problems.
- Energy efficiency can also *promote local economic development* and job creation by increasing the disposable income of citizens and making businesses and industries more competitive compared to importation of power plant equipment, fuel, or purchased power from outside the utility service territory. Kushler, York and Witte (2005, 36), found that energy efficiency targeted at natural gas use (for both gas end-uses and gas used for electric generation) could create a total of 12,430 jobs and employee compensation of $290 million by 2020.
- Energy efficiency can *help a utility, state and region increase its energy independence* by reducing the amount of fuels (coal, gas, oil, nuclear) and electricity that are imported from other regions or even from other countries.
- Energy efficiency *offers a variety of societal benefits for low-income* electricity customers.

The Rationale for Energy-Efficiency Policies and Programs

If energy efficiency is so plentiful and cost-effective, why should there be public policies to support it, and why should utilities and others implement energy efficiency programs? In particular, why not rely on market forces to deliver energy efficiency services? It is sometimes argued that fully functional markets cause the economically efficient amount of a good to be delivered to consumers without intervention, and by the most cost-effective means.

The reason for public policy in support of energy efficiency is the many *market barriers* that hinder electric customers from adopting energy efficiency measures on their own. That is, the markets for energy and for energy efficiency are imperfect, meaning that markets free of public intervention are not able to maximize use of cost-effective energy efficiency. The following examples illustrate some of the ways in which markets for energy-efficiency services are imperfect:

- *Institutional and regulatory barriers*. Rate-of-return regulation rewards electric utilities for increased sales and penalizes them for improvements in end-use energy efficiency. Hence, utilities that could be an influential promoter of energy efficiency instead have powerful financial incentives to oppose it. This point holds true both under traditional regulation and under electricity restructuring.
- *Lack of awareness.* Electricity customers do not often consider energy-efficiency measures as an alternative to electricity generation. Even in those states where customers are provided "choice" of electricity suppliers, they rarely consider that they have a choice between energy efficiency and historic levels of generation.
- *Lack of information and training.* Customers, businesses, industries, and contractors are often not aware of energy efficiency options, or lack information on the economic, productivity, and environmental benefits of efficiency measures.
- *Limited product availability.* Many energy-efficiency measures are produced and distributed on a limited scale and are not readily available to customers, builders, contractors or industries.
- *Lack of money or financing.* Customers, businesses, and industries may lack the up-front capital for an energy efficiency product.
- *High transaction costs.* An investment of time, money, and patience may be required to obtain information and make an informed purchase and installation of energy efficiency measures. This is a particular problem when construction, renovation, and replacement require that decisions be made and products obtained quickly. Many small consumers, both residences and businesses, lack the physical ability to put time into these activities due to work and family commitments.
- *Split incentives.* The financial interests of those in a position to implement energy efficiency measures are often not aligned with electricity customers who would benefit from the measures. For example, landlords and building owners make capital purchases and maintain buildings, while tenants frequently pay the energy bills. Similarly, at the time of new construction the builder has incentive to minimize short-term costs, while it is the new owner who would benefit from lower electricity bills over the long term.
- *Purchasing procedures and habits*. Many buildings are constructed, products purchased, and facilities renovated on the basis of minimizing short-term

costs, not on minimizing long-term life-cycle costs, including electricity costs.

- *Bounded rationality*. For many customers, electricity costs represent a small portion of the total costs of maintaining a home, running a business or operating a factory, so little or no attention is paid to opportunities to reduce these costs.
- *Unaccounted-for societal benefits.* The societal benefits of energy efficiency—particularly the environmental and economic-development benefits—are often not considered by customers and producers seeking to minimize their own costs.
- *Uncertainty and risk avoidance.* Customers may be skeptical of potential energy-efficiency savings, or may have doubts about whether an unfamiliar energy-efficiency measure will work properly.

As a consequence: (a) regulatory policies are necessary to overcome these barriers to truly efficient choices, and (b) energy-efficiency programs should be explicitly designed to overcome these barriers.

Even when retail electricity markets are opened up to competition it is still necessary to maintain public policy support of efficiency and renewable resources. The market barriers and market failures described above apply in a competitive electricity market, just as much as they have in the past applied in a regulated market.

System-Benefits Charges and Energy-Efficiency-Resource Standards

A system-benefits charge (or public benefits fund) is generally a monthly charge to a utility's customers that funds system-wide energy-efficiency projects. The charge is almost always mandated by the legislature and may ramp up over a period of years or remain static.

An energy efficiency resource standard (EERS) is a mandate to help end-use customers, as a group, achieve a designated level of energy savings from energy efficiency. It is similar to a renewable-portfolio standard in that energy-efficiency providers can bank and trade energy-efficiency savings in the form of credits (commonly called "White Tags"). Because of the trading scheme, non-utility participants can supply energy efficiency to end-use customers, thus creating competition in the market for energy-efficiency savings. Another advantage of an EERS is that, like a renewable-portfolio standard, the tradable nature of energy savings credits would tend to result in the least-cost savings being achieved first.

However, the use of a system-benefits charge does not preclude an energy-efficiency standard or vice versa. Both can be used as complementary policies to move towards the same goal: maximizing the utilization of cost-effective energy efficiency.

Both methods have disadvantages, however. Poorly designed, a system-benefits charge can make little headway in achieving energy efficiency. For example, a charge set at a low level like that in Ohio will yield little savings. Or if there are no limitations on what the funds are spent, a utility may use the funds on programs which result in little energy savings, such as consumer education or web-site energy audits.

Energy efficiency resource standards have their own disadvantages. In a state such as Ohio, that offers retail competition, applying an EERS to all load-serving entities would tend to result in a greater division of program administrators than one that simply applies to distribution companies. A greater number of program administrators raises the average cost of energy efficiency since program administration and implementation, monitoring and verification of program savings and regulatory oversight would be duplicated across all the load-serving entities and distribution companies.

Recent Experience with Energy-Efficiency-Resource Standards

This section and parts of the next are based in large part on the work of Steve Nadel in his March 2006 report, "Energy Efficiency Resource Standards: Experience and Recommendations" (Nadel 2006).

Table 2 is a summary of current and proposed energy-efficiency-resource standards in the U.S. All of the standards apply to electric end-use. Some of the standards are incorporated as part of an RPS. California's also has goals for the reduction of natural-gas use.

Table 2: Current and Proposed Energy Efficiency Standards in the U.S.

EERS Description	Applies to	Savings Target	Timeframe
California			
Sets specific energy and demand savings goals	Investor-owned utilities	Savings goals set for each program year from 2004 to 2013 The savings target for program year 2013 is as follows • 23,183 GWh • 4,885 MW peak • 444 million therms gas	2004–2013 Annual MWh, MW, and therm savings adopted for each of these years.

EERS Description	Applies to	Savings Target	Timeframe
Colorado			
Settlement agreement approved by PUC includes specific targets utility will make “best efforts” to achieve	Public Service of Colorado (the major utility in the state)	320 MW and 800 Gwh (40 MW and 100 GWh each year)	2006–2013
Connecticut			
Energy efficiency at commercial and financial facilities eligible under Distributed Resources Portfolio Standard , along with combined heat and power and load management	Investor-owned utilities	DRPS goals set for each program year:	
		1%	2007
		2%	2008
		3%	2009
		4%	2010 and thereafter
Hawaii			
Allows efficiency to qualify as a resource under RPS requirements	Investor-owned utilities	20 % of kWh sales (overall RPS target, EE portion not specified)	2020
Illinois			
Setting goals as percentage of forecast load growth	Investor-owned utilities	10%	2006–2008
		15%	2009–2011
		20%	2012–2014
		25%	2015–2017
New Jersey			
Two initiatives:			
1. Setting energy and demand goals for overall PBF program.	PBF program administrators (selected competitively)	1,814 GWh (four-year total)	2005–2008
2. Setting goals for savings as a percent of sales.	Investor-owned utilities	Conceptual draft calls for 1% per year for a total of 12% in 2016	2005–2016 in conceptual draft
Nevada			
Redefines portfolio standard to include energy efficiency as well as renewable energy	Investor-owned utilities	Energy efficiency can meet up to 25% of combined EE/RE portfolio standard of:	
		6%	2005–2006
		9%	2007–2008
		12%	2009–2010
		15%	2011–2012
		18%	2013–2014
		20%	2015 and thereafter
Pennsylvania			
Includes energy efficiency as part of a two-tier energy portfolio standard	Investor-owned utilities	Tier 2 goals (including EE):	
		4.2%	Years 1–4
		6.2%	Years 5–9
		8.2%	Years 10–14
		10.0%	Years 15 and thereafter
Texas			
Sets goals as percentage of forecast load growth	Investor-owned utilities	10%	2004 and thereafter

EERS Description	Applies to	Savings Target	Timeframe
Vermont			
Sets energy and demand goals for overall PBF program	Program administrator	83,766 MWh 119,490 MWh 204,000 MWh	2000–2002 2003–2005 2006–2008

Source: Nadel (2006, 21)

Design Issues for Energy-Efficiency-Resource Standards

Administrator

The Ohio Office of Energy Efficiency (OEE) is a logical choice of program administrator since it is already somewhat familiar with energy efficiency programs and their evaluation through its administration of the Home Weatherization Assistance Program. The Public Utilities Commission of Ohio may have a role in approving the efficiency programs that distribution companies implement since it already has jurisdiction over those companies. However, the legislature may need to give the OEE authority to assess compliance with the EERS and impose penalties for non-compliance. Alternatively, the OEE could be legally assigned the responsibilities of EERS administrator but outsource the task to a third party such as is done in Vermont.

Neither OEE nor PUCO regulate cooperative or municipal utilities in any form. If regulation of cooperative or municipal utilities for the purposes of an EERS is not politically acceptable in Ohio, one alternative is to follow Vermont's example and allow the OEE to begin regulating cooperative and municipal utilities for purposes of the EERS if they do not meet the goals of the EERS on their own.[51] The less-desirable alternative is to exclude cooperatives and municipal utilities from the EERS requirements altogether, which would create lost opportunities and result in less economic, environmental, and other benefits to the people of Ohio.

Eligibility of Measures

Measure eligibility is a question of both politics and priorities. End-use efficiency is the obvious target of an EERS, but other types of efficiency or related energy-savings measures may be included to increase support and acceptance of the EERS. These measures include (a) efficiency improvements to the distribution system, and (b) combined-heat-and-power facilities. Nadel (2006, 27) notes, "including these measures makes an EERS more complicated as special rules will be needed for each of these resources." Our recommended target, set out below, assumes that only end-use efficiency is eligible. If Ohio wishes to include distribution enhancements or combined heat and power, the target should be

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51 One of Vermont's municipal utilities is subject to such a provision.

revised upward, or different targets should be established for each type of measure, to ensure that the separate efficiency goals are met.

Target Sectors

Ohio may also consider whether the savings achieved under the EERS come from different consumer sectors. According to ACEEE, the cost of energy efficiency is, on average, lower in the commercial and industrial sectors than in the residential sectors. To ensure that each sector is not neglected under the standard, Ohio might consider requiring a percentage of savings from residential and/or low-income customers. For example, Nevada requires that half of all savings come from the residential sector.

Monitoring and Verification

Monitoring and verification (M&V) is key to the success of an EERS. In order for an EERS to work, monitoring and verification efforts must yield results that are credible and transparent. Typically, the entities administering the programs would contract with an outside party to evaluate the savings achieved from efficiency programs. To make the job of all parties simpler, the OEE should establish clear, detailed rules governing how monitoring and verification is performed. Other states like Pennsylvania and Nevada serve as examples of such rules.

Monitoring-and-verification reports would then be submitted to the EERS administrator, in this case, the OEE, for review by its staff. M&V certainly adds a cost to energy efficiency which must be weighed when setting the frequency with which it is performed. Initially, Ohioans will be best served by yearly M&V of utility efficiency programs. The investor-owned utilities currently offer little in the area of efficiency programs. Hence, yearly evaluations will be more likely to catch flaws in analysis or program implementation early on. The growth of our proposed EERS for Ohio tapers off in later years, at which time it may be appropriate to allow M&V efforts every two years.[52]

Size of the Energy-Efficiency Targets

The size of the energy-efficiency target is obviously one of the more important aspects of designing the EERS. Table 2 above shows the amounts that are required by the EERS that are currently in place.

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[52] The ACEEE report upon which this section is based (Nadel 2006) contains more-detailed information concerning M&V efforts if measures besides end-use efficiency are included. It also discusses alternatives to program-specific M&V reports in the case of common efficiency measures.

For comparison purposes, Table 3 (below) shows the cumulative energy savings achieved by the 50 U.S. states and their spending levels. The level of spending and savings on electric energy efficiency varies widely across the states.[53]

Table 3: 2004 Electric Energy-Efficiency Spending and Savings by State

	Total Spending			Cumulative Savings	
	$1000s	*Per Capita*	**Revenues**	*GWh*	*Sales*
Alabama	438	$0.10	0.0%	382	0.4%
Alaska	103	$0.16	0.0%	3	0.1%
Arizona	4,000	$0.70	0.1%	106	0.2%
Arkansas	231	$0.08	0.0%	32	0.1%
California	380,009	$10.60	1.3%	19,590	7.8%
Colorado	13,715	$2.98	0.4%	687	1.5%
Connecticut	58,098	$16.60	1.8%	2,651	8.3%
Delaware	NA	NA	NA	0	0.0%
District of Columbia	2,200	$3.97	0.3%	251	2.3%
Florida	72,014	$4.14	0.4%	5,951	2.7%
Georgia	1,356	$0.15	0.0%	291	0.2%
Hawaii	9,190	$7.28	0.5%	85	0.8%
Idaho	7,023	$5.03	0.6%	813	3.7%
Illinois	3,000	$0.24	0.0%	130	0.1%
Indiana	2,062	$0.33	0.0%	812	0.8%
Iowa	28,833	$9.76	1.1%	1,310	3.2%
Kansas	0	$0.00	0.0%	0	0.0%
Kentucky	4,146	$1.00	0.1%	161	0.2%
Louisiana	324	$0.07	0.0%	25	0.0%
Maine	13,118	$9.98	1.1%	33	0.3%
Maryland	50	$0.01	0.0%	2,221	3.3%
Massachusetts	133,326	$20.81	2.2%	3,514	6.3%
Michigan	8,000	$0.79	0.1%	1	0.0%
Minnesota	55,784	$10.95	1.4%	4,791	7.6%
Mississippi	497	$0.17	0.0%	83	0.2%
Missouri	928	$0.16	0.0%	22	0.0%
Montana	8,002	$8.63	1.0%	560	4.3%
Nebraska	4,348	$2.49	0.3%	56	0.2%
Nevada	8,473	$3.63	0.3%	75	0.2%
New Hampshire	15,120	$11.64	1.2%	340	3.1%
New Jersey	92,753	$10.68	1.2%	3,234	4.2%
New Mexico	2,000	$1.05	0.1%	26	0.1%
New York	147,193	$7.63	0.8%	4,772	3.4%
North Carolina	3,722	$0.44	0.0%	12	0.0%
North Dakota	465	$0.73	0.1%	0	0.0%
Ohio	16,195	$1.41	0.2%	394	0.3%
Oklahoma	316	$0.09	0.0%	91	0.2%
Oregon	62,888	$17.51	2.2%	2,940	6.4%
Pennsylvania	3,446	$0.28	0.0%	16	0.0%
Rhode Island	13,990	$12.95	1.6%	492	6.2%
South Carolina	4,920	$1.17	0.1%	107	0.1%
South Dakota	542	$0.70	0.1%	0	0.0%
Tennessee	10,937	$1.86	0.2%	441	0.4%
Texas	80,000	$3.56	0.3%	6,229	1.9%
Utah	16,450	$6.80	1.2%	762	3.1%

53 Note the table below reflects utility spending only, not energy efficiency implemented by other organizations.

	Total Spending			Cumulative Savings	
	$1000s	*Per Capita*	**Revenues**	*GWh*	*Sales*
Vermont	14,000	$22.54	2.2%	400	7.1%
Virginia	0	$0.00	0.0%	166	0.2%
Washington	88,522	$14.26	1.9%	5,974	7.5%
West Virginia	992	$0.55	0.1%	23	0.1%
Wisconsin	53,734	$9.76	1.1%	3,233	4.8%
Wyoming	0	$0.00	0.0%	0	0.0%
USA TOTAL	1,447,453	$4.93	0.5%	74,286	2.1%

Source: York and Kushler (2006, 5)

Ohio spends very little on energy efficiency (see Table 3 above). While per-capita spending is as high as $22.54 in Vermont; Ohio spends just $1.41 per person. The range of cumulative efficiency savings across states is 0.0% to 8.3%; Ohio achieves 0.3%. It is important to keep in mind, however, that a higher level of cumulative savings is likely to result not just from increased spending levels but also a longer period of time over which efficiency programs have been offered.

Compatibility with the Renewable Portfolio Standard

Energy efficiency resource standards and renewable portfolio standards have similar goals; to encourage the development of desirable resources up to a specified percentage of retail sales. As such, they can be compatible. Indeed, a number of states have a combined RPS and EERS. One concern, however, is that energy efficiency is generally less expensive than renewable energy and therefore may overwhelm renewable energy in meeting the standard. If Ohio wishes to motivate the development of renewable energy as well as the provision of energy efficiency, it should keep the two standards separate.

Alternative Compliance and Compliance Penalties

Other states allow utilities to minimize their costs of compliance with the EERS by paying an alternative compliance payment. The payment is set at a level that represents a reasonable cap on the cost but that also encourages compliance with the standard. If the costs of energy efficiency to any company exceed the alternative compliance payment, that company can choose to pay the alternative compliance payment instead. However, the alternative compliance payment should be set high enough so that it encourages the implementation of all energy efficiency that is truly cost-effective.

Ideally, the alternative compliance payment would equal the true unit costs avoided by efficiency for each utility. In practice, it would be administratively difficult to set such a standard. We recommend using a rough proxy which is high enough to encourage compliance with the EERS, but low enough to represent a reasonable cost cap on the EERS. Accordingly, a reasonable alternative compliance payment would be 5¢/kWh (i.e., $50/MWh).

Policy Options and Recommendations for Ohio

Structure of the Energy-Efficiency-Resource Standard

Ohio should promote an EERS that (1) allows for trading of credits, (2) is administered by OEE, (3) applies to all retail providers including public power utilities, (4) requires monitoring and verification of all programs annually from 2008 through 2011 and then biannually thereafter, and (5) establishes an alternative-compliance payment of $50/MWh. We also recommend that Ohio keep EERS separate from the RPS.

The budgeting, planning, and overall administration of the EERS should be the responsibility of the OEE. The OEE could perform these functions itself, or could conduct periodic competitive bidding processes to hire a third-party contractor to perform these functions. If the latter approach is taken, the third-party contractor should have a minimum term (e.g., three years), with the option for renewal, in order to ensure stability, consistency and long-term perspectives in the energy efficiency planning process.

The distribution companies should be required to purchase all necessary credits from the OEE in order to cover their EERS obligation. This requirement would provide the OEE with a predictable and stable source of revenue with which to operate. The other load-serving entities, which will make a much smaller portion of electric sales, should be allowed to implement their own programs or purchase credits from the OEE.

Energy-Efficiency Targets

Energy-efficiency programs, like other electric resources, require some lead time, so an EERS should ramp up over time rather than attempting to achieve a high level of savings in the first year of implementation.

Ohio's investor-owned utilities currently do not offer any efficiency programs (outside of low-income weatherization programs). Unfortunately, that means that there are many lost opportunities for cost-effective energy efficiency.[54] That also means that Ohio should be able to make early, rapid gains in annual energy savings by initially taking advantage of energy efficiency. For example, residential and commercial lighting programs are normally very cost-effective. There is no

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54 A least-cost energy-efficiency opportunity is lost whenever an efficiency measure is not installed when most cost-effective (e.g., when a customer purchases a new refrigerator that is less efficient than is cost-effective).

reason to think that the highest level of savings in experienced by other states (see Table 3 above) would not eventually be achievable in Ohio.

A recent energy-efficiency-potential study by the Midwest Energy Efficiency Alliance is evidence that an Ohio EERS can go much higher than the maximum level of savings achieved in Table 3. The report concluded that Ohio's achievable energy-efficiency potential in only the residential sector was 10.1% of base case energy consumption after 20 years. (MEEA 2006, 64) There are likely to be significant additional achievable energy savings from the commercial and industrial sectors as well.

For Ohio, we recommend an energy-efficiency target that starts out more modestly and whose rate of savings increases over time. This reflects the fact that Ohio utilities can achieve greater amounts of efficiency savings per year once they have ramped up their DSM programs.

The target should include cumulative annual savings from efficiency programs that were implemented after the commencement of the EERS. Table 2 below presents the EERS target in terms of the cumulative annual savings targets, as well as the incremental annual savings that would be necessary to reach the cumulative amounts.

The EERS target in the first year (2008) should be 0.3% of retail electric sales,[55] and should increase each year as the efficiency programs ramp up. After the fifth year (2012) the EERS target should increase by 1.0 % per year, which represents an aggressive but achievable amount of energy-efficiency activity.

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[55] This is comparable to the level of savings Duke is proposing in its current DSM filing (Case No. 06-91-EL-UNC) combined with its existing $2.2-million low-income weatherization program.

Table 4: Proposed Ohio Energy-Efficiency Resource Standard

	Incremental Annual Savings (% of Sales)	Cumulative Annual Savings (% of Sales)
2008	0.3	0.3
2009	0.5	0.8
2010	0.7	1.5
2011	0.8	2.3
2012	0.9	3.2
2013	1.0	4.2
2014	1.0	5.2
2015	1.0	6.2
2016	1.0	7.2
2017	1.0	8.2

In the eighth year of implementation, the legislature should review the progress made by the EERS and decide what the EERS targets should be after the tenth year. The legislature should consider whether to hold the EERS target level after the tenth year, to continue to increase the savings target by 0.8% per year, or to increase the savings target by a different amount each year. Reasons to continue to increase the savings target include (1) a desire to leverage more of Ohio's cost-effective energy efficiency, (2) an increase in avoided costs which raises the level of energy efficiency that is cost-effective or (3) concerns that supply side resources that are more expensive than energy efficiency will be proposed (39% of the Midwest's achievable residential electric efficiency potential comes at a cost of 6¢/kWh or less).

The EERS target should be considered a floor, not ceiling, for energy efficiency savings. Electric distribution companies should evaluate the potential for implementing cost-effective energy-efficiency programs when conducting their portfolio management and integrated resource planning processes. If they find that there are additional cost-effective energy-efficiency resources, beyond those required by the EERS, then they should investigate opportunities to implement such resources. This evaluation of additional energy-efficiency resources should be done in coordination with the OEE. If there is potential for additional cost-effective energy-efficiency resources, the distribution companies should purchase efficiency credits from the OEE.

VI. Renewable Portfolio Standards

Renewable-Portfolio Standards

A renewable-portfolio standard (RPS) is a market-based policy mechanism to promote renewable resources in both regulated and restructured electricity markets. An RPS requires retail sellers of electricity (or load-serving entities or LSEs) to include a certain amount of renewable resources in their total portfolio of electricity supply mix. It also encourages competition among renewable energy developers for contracts with LSEs. The amount of renewable energy requirements typically increase over time.

A properly designed RPS will provide LSEs with strong incentives to reduce the costs of meeting the requirement. An LSEs should be allowed to satisfy its RPS obligation by some combination of (1) owning a renewable energy facility and generating its own power, (2) purchasing renewable energy from a generator or power marketer, or (3) purchasing tradable renewable energy credits (RECs) that represent the generation of electricity from a renewable energy facility. Other advantages of an RPS are that (1) it maintains a competitive neutrality among suppliers when applied to all suppliers, (2) regulators can set the quantities of renewable energy required over time so as to minimize overall impacts on customer bills,[56] (3) preset long-term RPS targets can ensure stability and development of future renewable-energy markets, and (4) administrative costs of renewable energy procurement can be relatively low because an RPS gives LSEs the burden of contracting with renewable-energy developers (Wiser, Porter, and Grace 2004, 4).

One of the disadvantages to an RPS is that it is a complex policy. Thus establishing a RPS suitable for a specific region and policy objectives takes significant time and efforts. An ill-designed RPS does not create a market where developers can have long-term contracts. Further, the requirement to promote the least-cost renewable-energy resources is sometimes at odds with the goal of promoting diverse sources of renewable energy. However, these disadvantages can be resolved by designing an RPS carefully.

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56 Numerous RPS cost studies found that projected rate impacts by RPS policies are modest, with the median retail rate increase being 0.7% or 0.04¢/kWh among 28 studies. The majority of studies showed the rate increase of less than 0.25¢/kWh while four studies showed rate decreases (Chen, Wiser, and Bolinger 2006, 13–14).

By increasing renewable energy sources in the generation mix, the RPS offers the following benefits to the electricity system and to society in general:[57]

- The RPS significantly reduces the environmental impacts of electricity generation and improves the environment (e.g., air-pollution reduction, climate-change mitigation, water and other natural-resource conservation) because Ohio is overly dependent on coal-fired power generation.
- It increases the diversity of fuel sources and reduces electricity price volatility caused by changes in the price and availability of fossil fuels.
- It has the potential of reducing peak wholesale electricity prices by displacing more expensive peaking generation that often sets wholesale market prices.
- It improves energy supply security by lessening our reliance on imported fuels
- By promoting the use of local renewable energy resources, it brings jobs and revenues to local areas and spurs local economic development.

Ohio Senate Bill No. 69 would require all retail electric sellers (excluding municipal utilities, cooperative utilities and governmental aggregators) to include a certain percentage of eligible renewable generation resources in their supply mixes. The requirement starts at 3% by 2007 and increases to 8% by 2010 and to 20% by 2021 and thereafter (See Table 5).

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57 An enumeration of the extensive benefits of renewable energy in Ohio can be found in the Biofuel and Renewable Energy Task Force Report (Sharp 2004). The importance of renewable energy was also recognized by the Ohio Energy Interagency Task Force (2004) in particular, initiatives numbers 32–34.

Table 5: Ohio Renewable-Portfolio Standards Targets Under S.B. No. 69

Year	Target
2007	3%
2008	5%
2009	6%
2010	8%
2011	10%
2012	11%
2013	12%
2014	13%
2015	14%
2016	15%
2017	16%
2018	17%
2019	18%
2020	19%
2021 and each subsequent year	20%

The bill would define eligible renewable generation as follows:

> biomass that is available on a renewable basis; geothermal energy; energy produced by a photovoltaic technology system; wind energy; or energy from a hydroelectric facility that produces less than twenty megawatts of electricity and is certified on or after two years following the effective date of this section as a low-impact hydropower facility by the low-impact hydro institute. "Renewable energy" excludes nuclear energy and energy produced from coal, natural gas, oil, propane, or any other fossil fuel. SB 69, Sec. 4905.88(A)(3)

Customer-sited photovoltaic facilities and any net-metered system using renewable energy would also be eligible for meeting the RPS requirements.[58]

While SB 69 would give the Public Utilities Commission of Ohio permission to establish a system of generation and trading renewable energy credits, only in-state renewable energy facilities are eligible for the RPS. It also directs the Commission to adopt rules requiring the filing of an annual report by each retail service provider. Further, the proposal directs the Commission to establish just and

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[58] As part of the requirement of the Energy Policy Act of 2005, the PUCO opened an investigation into net-metering, smart metering, cogeneration and small power, and interconnection in 2005 (Case No. 05-1500). Four technical conferences were held and many comments were submitted. A PUCO staff report is expected by September 30 2006.

reasonable penalties for non-compliance with the requirements by retail electricity suppliers.

The Economic Impact of Renewables in Ohio

The development of renewable resources in Ohio and the surrounding region will create economic development and new jobs for Ohio. Developing new renewable resources requires manufacturing, installation, and operation and maintenance activities that can be provided by local businesses.

A recent study of the potential for developing energy efficiency and renewables in 10 Midwestern states (including Ohio) found that an aggressive investment in renewable resources would create 68,400 new jobs in the region and an associated increase in annual economic output of $6.7 billion by 2020. Of this total, Ohio would experience 13,500 new jobs and $1 billion increase in annual economic output. (REAL 2003, 8)

Sterzinger and Svrcek (2004) look in more detail at the potential for increased wind energy development to promote economic development. The authors note that, as a rule of thumb, every 1,000 MW of wind energy requires roughly $1 billion investment in rotors, generators, towers and other related equipment. This investment will in turn create a potential for 3,000 jobs in manufacturing, 700 jobs in installation, and 600 jobs in operations and maintenance (Sterzinger and Svrcek 2004, 4).

These authors investigate the existing U.S. companies that would be likely to produce these new jobs in response to an aggressive nationwide investment in new wind power. They find (2004, 5–6) that many of these companies are located in Ohio, which they expect to be second to only California in the potential for new jobs as a result of increased investment in wind turbines.

Sterzinger and Svrcek (2004, 5–6) find that from a nationwide program to develop 50,000 MW of wind power from an investment of $50 billion, Ohio businesses could be expected to receive roughly $3.9 billion in investments, which would lead to new jobs in Ohio of 11,688. While there may not be such an aggressive nationwide program planned today, clearly state policies to promote renewable resources in Ohio and the region will yield significant economic-development benefits for the state.

Recent Experience with Renewable-Portfolio Standards

Numerical Renewable-Portfolio Standards Targets

As of May 2006, 22 states and Washington D.C. have adopted RPS policies, while another 15 states are considering adopting RPS. Most of RPS policies are applied to investor-owned utilities or retail energy suppliers, while some apply to other type of utilities such as municipal and cooperative utilities. Table 6 summarizes the magnitude of the RPS targets that have been adopted to date.

Table 6: Renewable Energy Portfolio Targets by State

	All-Resource Target	Set-Aside Target
Az.	1.1% by 2007	0.66% solar by 2007
Cal.	20% by 2010	
Col.	10% by 2015	0.4% solar by 2015
Conn.	10% by 2010	
D.C.	11% by 2022	0.386% solar by 2022
Del	10% by 2019	
Hawaii	20% by 2020	
Iowa	105 MW	
Mass.	4% by 2009 (+ 1% annual increase)	
Md.	7.5% by 2019	
Maine	30% by 2000	
Minn.	10% by 2015 goal	
Mont.	15% by 2015	
N.J.	22.5% by 2021	2.12% solar by 2021
N.M.	10% by 2011	
Nev.	20% by 2015	1% solar and maximum 5% efficiency by 2015
N.Y.	24% by 2013	0.1542% customer-sited gen. by 2013
Penn.	18% by 2020 (8% is RE)	0.5% solar by 2015
R.I.	15% by 2020	
Tex.	5,880 MW by 2015 (about 5%)	
Vt.	Load growth between 2005 and 2012 (about 9%)	
Wisc.	10% by 2015	

Source: DSIRE 2006

These RPS policies will support the development of significant amount of renewable energy facilities in the U.S. Nogee (2005, 4) estimates that 19 RPS

policies will support 25,700 MW of renewable generation by 2017 assuming RPS goals set by 18 states and Washington D.C. are met.[59]

It is not certain that all of these goals will be met because more than half of the states have limited experience with renewable portfolio standards. Eight states began implementing their policies within the past five years and at least six states have made major revisions in the same period (Nogee 2005, 9). However, several RPS policies have shown notable successes to date.

For example, the Texas RPS has led to approximately 1,600–1,900 MW of renewable energy projects (mainly wind power) since 2001, which exceeded the state's annual RPS requirements.[60] Iowa has installed 250 MW of wind. Minnesota has installed at least 700 MW of wind and 125 MW of biomass. California's RPS has generated contracts by investor-owned utilities for 1,853–3,275 MW of new, re-powered, or reactivated facilities which 241 MW is already online (the contract spread is due to the fact that renewable contracts often provide the possibility of expanding the capacity of the projects in the future). Wind (730–970 MW) and solar thermal (800–1,750 MW) projects comprise most of these renewable energy projects in California. Geothermal projects in the pipeline also expect to provide significant capacity (500–625 MW), half of which are from new facilities. See Table 7 for more examples.

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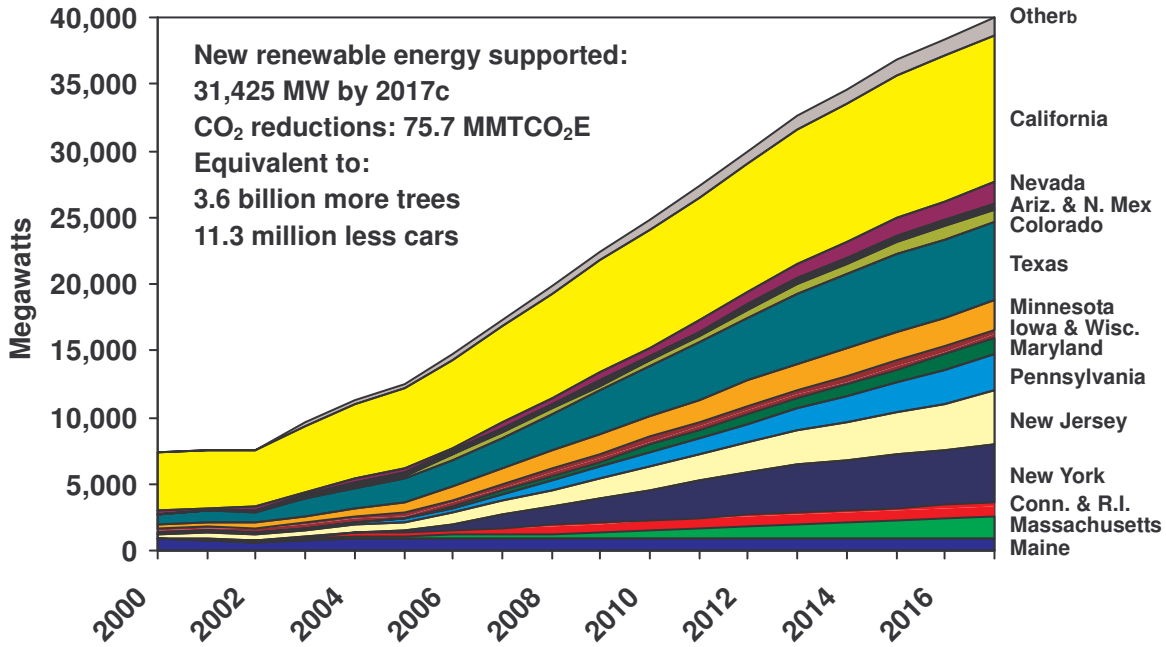
59 Nogee (2005) estimated renewable generation capacity by converting state generation output goals (MWh) to capacity (MW) using typical expected capacity factors.

60 O'Grady (2006) reports that wind has become the cheapest electricity source in Austin, the capital of the largest U.S. gas-producing state, after costs for gas and other generator fuels soared. The Austin City Council voted to hold a drawing to determine which municipal utility customers will be allowed to switch to wind power. More customers are expected to request wind power than the utility has available because the pollution-free option, which used to cost extra, will save a typical resident about $16 a year.

Figure 7: Projected Renewable Energy Capacity from RPS Policies[a]



Source: Nogee (2005, 4).

[a]Projected development assuming states achieve annual RES targets.

[b]Includes Delaware, Hawaii, Illinois, Montana, Ohio, Oregon, and Washington D.C.

[c]If achieved, goals for Iowa, Illinois, and Minnesota would support an additional 5,300 MW by 2017.

Table 7: Recent Renewable Energy Development Supported by RPS Policies

Texas—915 MW in 2001, 204 MW in 2003, and additional 700 MW in 2005.
Iowa—250 MW of wind. MidAmerican plans to add 310 MW of new wind without raising rates.
Minnesota—705 MW wind and 33 MW of biomass.
California—IOUs contracted for 1,853–3,275 MW of new, repowered, or restarted facilities, of which 241 MW is online.
Wisconsin—140 MW, mostly wind; and more than 500 MW of new wind proposed.
Nevada—130 MW of wind, 97 MW of geothermal, and 50 MW of solar.
Arizona—7 MW of solar, 10 MW of landfill gas and biomass, 15 MW of wind, 20 MW of geothermal.
New Mexico—260 MW of wind in 2003–2004.

Source: LBNL (2004, 9); Nogee (2005, 10); California Energy Commission 2006 web site; American Wind Energy Association (2006) and web site

Some RPS policies have failed to promote new projects. The most notable example is Maine. Although Maine's RPS has a 30% renewable-energy requirement, the highest in the nation, it is not leading to the development of new facilities because (1) existing facilities that have been serving more than 30 percent of energy supply in Maine are eligible to meet the requirement and (2) large hydro and cogeneration are included as eligible fuel and technologies.

The example of Maine's RPS suggests that the success and failure of an RPS depends on various aspects of its design. Below, this report highlights several key RPS design criteria along with state experiences.

Eligible Fuels and Technologies

There are various kinds of fuels and technologies eligible under different RPS policies. Table 8, reproduced from EPA (2006, 5–7), summarizes eligible fuels and technologies for all RPS policies except Washington D.C. and Illinois. All of these states qualify photovoltaic (PV), wind, and biomass for the RPS. A few states qualify energy efficiency, cogeneration, and waste tires. Policies that qualify energy efficiency and cogeneration in the RPS tend to have relatively high renewable-energy requirements because such resources are less expensive than most renewable energy resources.

States that allow hydro facilities to qualify for an RPS frequently limit the type of hydro to small hydro (5–30 MW capacity) or low-impact hydro, since large hydro power is a conventional energy source and has some negative environmental impacts. (In contrast, Maine qualifies existing hydro plants up to 100 MW. This loose eligibility standard is one of the major reasons why its RPS did not engender more renewable energy.) Biomass can be another controversial resource for the states with plenty of existing biomass power plant facilities. For example, the eligibility rule for Connecticut Class I RPS category has been recently modified by allowing existing biomass facilities with adequate emission controls to qualify. This had the effect of flooding the Connecticut Class I market with existing biomass projects, which reduced REC prices dramatically. This in turn became an obstacle to new renewable generation in Connecticut.

Table 8: Eligibility of Resources for Renewable Portfolio

	AZ	CA	CO	CT	DE	HI	IA	MA	MD	ME	MN	MT	NJ	NM	NV	NY	PA	RI	TX	VT	WI
Biomass	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Cogeneration				●		●				●					●		●				
Energy Efficiency						●									●		●				
Fuel Cells				●						●	●		●	●			●				
Geothermal	●	●	●		●	●			●	●		●	●	●		●	●	●	●		●
Hydro		●	●	●	●	●	●		●	●	●	●	●	●	●	●	●	●	●	●	●
Landfill Gas	●	●	●	●	●	●		●	●	●		●	●	●	●	●	●	●	●	●	●
Municipal Waste	●		●		●	●			●	●	●	●	●		●		●			●	
Ocean Thermal		●		●	●	●		●	●							●		●	●		
PV	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Solar Thermal Electric	●	●		●	●	●		●	●	●	●	●		●	●		●		●	●	●
Tidal		●		●	●			●	●	●			●			●		●	●		●
Transportation Fuels						●															
Waste Tire		●								●											
Wave		●		●	●	●		●	●				●					●	●		●
Wind	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●

Source: EPA (2006, 5)

Resource Class and Preference

Several RPS policies have created more than one category for different eligible resources in terms of types of resources or online date for resources. Some states such as Connecticut, Maryland, and New Jersey created one resource class (often called class I or tier I) for new, environmentally sustainable or low impact renewable energy resources and another class (class II or tier II) for existing or new other types of resources. Class II usually includes existing resources, biomass resources not qualified to be in class I, trash-to-energy facilities, and hydro. Rhode Island placed a 2% cap on the amount of existing resources for its Class II RPS requirements. The target for the class-II or existing resources in these states do not often increase over time.

There are also other states that design their RPSs to promote specific kinds of resource and technologies such as PV, biomass, distributed generation and energy efficiency. Further, some states value certain resources higher than other resources by giving more RPS credits for such resources. These policies are likely to be driven by such state-specific policy objectives as (1) increasing renewable-energy resource diversity, (2) maximizing in-state resources such as solar and biomass, and (3) reducing emission while minimizing transmission and distribution constraints (by promoting on-site generation). Details of these features in state RPS rules are provided in Table 9.

Table 9: Resource and Technology Specific Targets and Credits

Separate Targets
AZ: 60% from solar electric power in 2004-2012; 30% of the renewables from distributed generation resources under a recently modified RPS (called EPS in Arizona) approved by the Commission and currently under review by the Attorney General's Office.
CO: 4% from solar-electric generation technologies; half of the 4% from customer-sited generation facilities
DC: 0.386% from solar by 2022
MN: At least 0.5% from biomass by 2005 and 1% from biomass by 2010
NJ: By 2021 2.12% from solar
NY: 0.1542% from customer-sited generation
PA: 0.5% from PV by 2020
NV: Minimum 5% of the annual requirements from solar energy system and maximum 25% of the annual requirements from energy efficiency measures
VT: electric growth between 2005 and 2012 from energy efficiency and renewable-energy resources
Different Values
DE: 300% credit for solar-electric systems and fuel cells using renewable fuels, and 150% credit for wind turbines sited in Delaware on or before December 31, 2012.
MD: 200% credit for solar; 110%—120% credit for wind; and 110% credit for methane
NM: Two kWh value for one kWh of generation from biomass, geothermal, landfill gas or a fuel cell is worth two kWh toward the RPS; and three kWh value from one kWh of generation from solar resources
NV: 240% credit for solar and a multiplier of 1.05 to a customer-sited PV system

Source: DSIRE (2006)

Trading Renewable Energy Credits and Geographic Eligibility

As mentioned above, a renewable energy credit (REC) trading scheme provides LSEs flexibility to meet their requirements and minimize compliance costs. In general, the wider the geographic area where LSEs can purchase RECs, the more cost-effective resources will become available for the LSEs. On the other hand, states placing high value on local environmental and economic benefits tend to limit imports of RECs from out-of-state facilities.

States with the RPS in the Independent System Operator New England (ISO-NE) territory are currently trading RECs using a regional Generation Information System that tracks RECs and power-purchase contracts. Likewise, RPS states in the PJM region can use a REC-tracking system called the Generation Attribute Tracking System or GATS. Among the states and the district in these regions, the eligible geographic areas under Connecticut, Maryland, and the District of Columbia appears to be overly broad. This broad out-of-state eligibility could reduce the cost of renewable development but obstruct the development of in-state renewable energy resources and reduce intended local benefits (Nogee 2005, 14).

Western RPSs tend to restrict the trading of RECs. For example, California, New Mexico, and Montana RPSs allow for out-of-state facilities provided that such facilities deliver RECs bundled with the energy they generate. Currently, Arizona only accepts out-of-state bundled RECs from solar projects, but its proposed RPS would allow bundled RECs from other out-of-state facilities. Nevada's RPS rules exclude most renewable energy projects outside of the state. It is possible that any of these restrictive locational rules for renewable energy may be challenged on the ground of Interstate Commerce Clause.

The Western Governors' Associations and the California Energy Commission are developing a REC-tracing system in the West for operation by late 2006 or early 2007. Since several western states in the region are weighing participation, the locational restrictions may be loosened in the near future.

Contracting Standards

Long-term contracts for power and RECs can be crucial for demonstrating a reliable cash flow and allowing renewable energy projects to obtain financing. In several states, especially in the East, utilities acquire standard-service supply through short-term full-requirements contracts, and there few potential purchasers of long-term contracts for renewable energy. This condition plus uncertainty in RPS policies or REC markets for LSEs have created a difficult condition for developers to enter into long-term contracts for both power and RECs. Some states have addressed this problem to some extent.

- In 2003, the Massachusetts Renewable Energy Trust, a quasi-public agency, established a program to use funds from the renewables charge on all retail bills to purchase RECs from eligible renewable energy projects under a long-term contract of up to 10 years. The trust then auctions the RECs to LSEs that want to buy RECs (Katofsky and Frantzis 2005, 2).
- In New York, NYSERDA has become the central procurement agent that collects a RPS specific fund from ratepayers and buys RECs from all eligible renewable energy projects (Cory 2005, 12).
- Connecticut mandates that LSE enter into a long term contract for 100 MW of class-I renewable energy projects by 2007 for "a period of time sufficient to provide financing for such projects, but not less than ten years" (Connecticut Public Act No. 03-135, Sec. 4(j)(2)). Connecticut uses its Renewable Energy Investment Fund (funded by a charge on retail consumers) to support long-term contracts.
- Montana requires LSEs to enter into long-term contracts for RECs with or without power contracts of at least 10 years (MCA 69-8-1001 et seq.).

Long-term contracting is generally more straightforward for vertically integrated utilities than for restructured one. Many states that require an RPS for regulated generation supply simply require utilities to enter into long-term contracts for power and/or RECs, ensuring renewable generators a dependable cash flow. This approach has been applied in California, Colorado and Nevada. California requires 10-year minimum contracts for renewable energy projects; Colorado requires 20-year minimums; Nevada requires 10-year contracts (Nogee 2005, 18). In these states, especially in Nevada, one remaining issue is utility's credit worthiness. Developers are hesitant to enter into long-term contracts with Nevada utilities, which suffer from reduced creditworthiness since the California energy crisis. Nevada addressed this issue by creating the Temporary Renewable Energy Development Fund that is used to support utility contracts until credit ratings for the utilities improve (Cory 2005, 13–14).

Enforcement and Compliance

Enforcement is another key element of RPS, especially in deregulated states. Wiser, Porter, and Grace (2004, 16) find that the lack of compliance penalties in Arizona's RPS has led to significant under-compliance. In contrast, states that have relatively high compliance penalties or payments are Connecticut (5.25¢/kWh), Montana (10¢/kWh), and Massachusetts (around 5.3¢/kWh).

Massachusetts has established a mechanism for alternative compliance payments (ACP), under which LSEs can pay an ACP if they cannot, or choose not to, procure RECs. The ACP was initially set around $50/MWh and is adjusted for inflation annually. The ACP is also a cap on REC prices, which are unlikely to rise above the ACP. The ACP is collected by the Massachusetts Technology Collaborative and used to fund renewable energy development in the state.

Policy Options and Recommendations for Ohio

Eligible Resources

To be eligible for the RPS, renewable generation should meet three criteria. First, the renewable generator should be new. Second, the technology used to generate the energy must meet environmental standards. Third, the renewable generator must be located in a region where it will result in benefits to the electricity customers and citizens of Ohio.

New Renewable Resources

Only new renewable generation facilities should be eligible for the RPS. In this context, "new" should be defined as those renewable generation facilities that have begun commercial operation after a clearly defined date (e.g., January 1, 2007). In

addition, existing renewable generators that make substantial increases in capacity output should be considered a new renewable resource. It is crucial to qualify only the incremental renewable generation over historical generation levels. If it is important to use the RPS to support existing renewables, then this goal can be achieved through a separate RPS target (i.e., a separate tier) which should be set a certain level and not increase over time.

Qualifying Resources

The Ohio RPS bill (S.B. 69) includes an appropriate set of definitions for what types of generation sources should be considered renewable. However, we recommend that the definition for biomass be clarified to include only those biomass resources that meet high environmental standards in terms of power plant emissions and sustainability of the biomass supply. We recommend the following definitions for the types of renewable generation that will be eligible for the OH RPS:

- wind energy,
- energy produced by direct solar radiation,
- geothermal energy,
- energy from a hydro facility that produces less than twenty MW of electricity and is certified as a low-impact hydropower facility by the Low Impact Hydropower Institute,
- energy produced from eligible biomass fuels.

Eligible biomass fuels should include the following sources:

- brush, stumps, lumber ends and trimmings, wood pallets, bark, wood chips, shavings, slash, yard trimmings, site clearing waste, wood packaging and other clean wood that is not mixed with other unsorted solid wastes;
- agricultural waste, food and vegetative material, energy crops; and landfill methane and biogas generated from materials that would be eligible as biomass fuels.[61]

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[61] The intent here is that the gas be provided directly to the generating unit, without being mingled with natural gas in pipelines or utility mains. Some separate mechanism might be more appropriate to support the production of pipeline-quality biogas, without requiring that such gas be burned for generation.

The following generation sources should not be considered renewable or eligible for the Ohio RPS: energy produced from any fossil fuel, and waste-to-energy technologies.

If the legislature wishes to include the generation of energy from waste coal in the RPS then it could propose a separate tier in the RPS target for this purpose. A separate tier is necessary to ensure that generation from waste coal does not preclude or limit the development of other renewable resources through the RPS. In order to be eligible for the Ohio RPS, the waste coal should be from a source located in Ohio, to ensure that the environmental benefits of this generation source are enjoyed by Ohio citizens.[62] Also in order to be eligible for the Ohio RPS, the waste coal should come from sources that are no longer producing coal for the purpose of electricity generation, in order to prevent creating a subsidy for coal generation. The waste-coal RPS target should be set for five years duration, and after four years the legislature should review the progress made in cleaning up waste coal sites, and determine whether and to what extent the waste-coal RPS tier should continue after the fifth year.

Geographic Location

Renewable resources located within Ohio will clearly provide direct benefits to the state, both in terms of environmental benefits and economic development benefits. Any such renewable source should automatically be eligible for the RPS.

While the Ohio RPS bill (S.B. 69) would not qualify renewable resources located in neighboring electricity systems, such resources will also provide benefits to Ohio by displacing generation from non-renewable resources. We recommend that renewable sources located in neighboring states be eligible for the RPS–as long as there is a mechanism in place to demonstrate that the renewable generation was sold in one of the power pools to which Ohio electric utilities belong.

Renewable resources located in neighboring electricity systems that do not necessarily sell power into Ohio may also provide environmental benefits to Ohio, by reducing pollutants of regional, continental and global significance (e.g., NOx, mercury, CO_2), reducing pressure on Ohio to reduce local emissions, as well as reducing some emissions that would otherwise blow into Ohio. Due to the interconnection of utility systems, a renewable project in New Jersey may reduce energy output and emissions from plants in Ohio, and even upwind in Indiana, Illinois and beyond. Because a significant portion of Ohio utilities participate in

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62 The Legislature should consider commissioning a study to investigate the environmental impacts of waste coal, and identify the tradeoffs between alternative disposal options.

both the PJM and MISO power pools, PJM's Generation Attributes Tracking System (GATS) and MISO's Renewable Energy Tracking System (M-RETS) could be used to track the environmental and emissions attributes for ensuring compliance with the Ohio RPS.[63]

Allowing out-of-state generators to qualify for the Ohio RPS may significantly reduce the cost of RPS compliance. While Ohio does have considerable renewable generation potential within its borders, the potential for low-cost renewables is significantly expanded if other states in the region are included in the RPS. Including out-of-state renewables would also avoid any possible constitutional problems with violation of the Interstate Commerce Clause. To capture the economic development benefits of Ohio based renewable energy development, Ohio can enact additional incentives such as a state production tax credit.

Applying the Renewable-Portfolio-Standard Requirements to Retail Sellers.

The RPS should apply to all entities that sell electricity to retail customers. The RPS should also apply to all retail electricity sales made by such entities. The RPS should apply to all SSO service, as well as to all retail sales to contestable electricity customers. In this way, all electricity customers will contribute their fair portion of support to the new renewable resources, regardless of where they purchase their generation services.

Some retail electric sellers may decide to offer several different electricity products. For example, a seller may decide to offer one green product and one simple low-cost electricity service. The RPS should be applied to each individual product offered by each retail electricity seller; the sellers should not be allowed to comply with the RPS on an average, companywide basis. This approach will ensure that all electricity customers contribute to their fair portion of the RPS, regardless of which electricity product they buy.

Customers that self-generate a large amount of electricity should also be required to comply with the RPS. This measure is necessary to ensure that large customers do not bypass the RPS requirement by installing their own generation systems.

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63 The Generation Attributes Tracking System tracks environmental and emissions attributes for electric generation in the PJM Interconnection region which covers all or parts of thirteen states (Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. MISO's tracking system is expected to be ready in early 2007.

Mechanisms for Demonstrating Renewable-Portfolio-Standard Compliance.

Renewable Energy Credits (RECs) should be used for demonstrating compliance with the RPS. Under this approach, each qualifying renewable generator would receive a REC for every kWh of renewable generation. These generators would then have two products to sell separately: generation would be sold into the power market, and the RECs would be sold to retail electricity sellers for their compliance with the RPS. This means that retail electricity sellers would not have to actually purchase renewable generation to comply with the RPS, the purchase of a REC would serve the same purpose. It also means that there is no need for a central administrator to track the flows of power and the associated renewable attributes.

One benefit of the tradable-credit approach is that it significantly increases the ability to buy and sell the renewable attributes and increases the flexibility of the retail electricity suppliers for compliance with the RPS. This should help reduce some of the barriers and transaction costs associated with RPS compliance. The tradable credit approach also helps to promote a more-competitive market in renewable resources, by increasing the number and types of players that can participate in the REC market, intensifying competition for renewable attributes, and facilitating forward markets, price hedging, and project financing.

One of the key issues to work out with any RPS compliance-demonstration mechanism is how to deal with power sales and purchases from other regions. It is important to ensure that power used to comply with the Ohio RPS is indeed generated from RPS-qualified facilities, that the power was somehow delivered to a power pool that includes Ohio electric utilities, and that the power is used to comply with only one RPS requirement and only once.

One way to achieve this goal is to require that power purchases from other states or regions will only be eligible for the RPS if that state or region has an RPS-compliance-demonstration mechanism that is consistent with Ohio's. In other words, if Ohio adopts a tradable credit approach, then power from a neighboring region would qualify for the Ohio RPS as long as that region (a) also has some form of tradable credit approach, and (b) the approach has a similar design and requirements.

Currently, New Jersey, Maryland, and Pennsylvania are using GATS for their RPSs, and Washington D.C. is considering using GATS. This means that renewable-energy facilities in Ohio can sell RECs into these RPS markets if the facilities meet the requirements of the RPSs. Participating in GATS and M-RETS would reduce the cost of complying with the Ohio RPS by increasing the pool of

eligible renewable resources, or allow for a larger RPS goal for the same amount of cost.[64]

Renewable-Energy Targets

We recommend that the Ohio RPS target be set at 2% of Ohio retail sales in the first year of implementation, increasing by 2% per year until it reaches 20% after 10 years. In the eighth year of implementation, the legislature should review the progress made by the RPS and the renewable energy market in the region and decide whether the RPS target should be held constant at 20% or should increase after the tenth year.

A comprehensive assessment of the cost and potential for renewable resources in Ohio and the region is beyond the scope of this study. The RPS target proposed above is based upon our attempt to strike a balance between achieving the benefits of renewable energy and mitigating the costs to Ohio electricity customers. The target accounts for the fact that renewable generation located outside of Ohio will be eligible to meet the target, which will greatly increase the renewable potential and reduce the cost of complying with the RPS.

Our recommended target is also based on our general understanding of the potential for renewable generation in the state and region. A recent study prepared by Synapse Energy Economics and others identified significant amounts of renewable energy potential in Ohio and other states in the Midwest. (Synapse 2001). The study found that Ohio could provide eight percent of the state's electricity from renewables by 2010 and 22 percent by 2020.[65]

Our recommendation is also based on studies of the costs of RPS targets in other states. Several RPS cost studies found a modest bill increase or decrease associated with renewable portfolio standards proposed in other states (Chen Wiser, and Bolinger 2006). Among 28 studies, the median rate increase caused by an RPS is 0.7%. or 0.04¢/kWh. Further cost studies for California and New Mexico, two of the most aggressive RPS states, found very modest cost impact from their policies, of less than 1.5% or 0.15¢/kWh (Chen, Wiser, and Bolinger 2006, 13–14).

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64 The cost of compliance with the RPS will first fall upon the retail electricity suppliers, but it is expected that these costs will eventually be passed on to retail customers.

65 These percentages pertain only to the renewable generation located within Ohio. If the renewable potential in the surrounding region is included, the percentages would be significantly higher.

Supporting Long-Term Contracts for Renewables

As discussed above, long-term contracts for power and/or RECs are often crucial to obtain private financing for renewable energy projects. To support stability and long-term development of the renewable energy industry as well as to enjoy various types of long-term economic and environmental benefits from renewable energy, the Ohio RPS should require retail sellers to enter into long-term contracts of at least 10–15 years with renewable-energy projects unless developers prefer short-term contracts. These contracts could be evaluated and established in conjunction with the portfolio management and integrated resource planning approaches described above in Chapter III

Additionally, Ohio could use a retail renewables charge, like those in Massachusetts and Connecticut, to collect funds to support a part or all of the long-term contracts. A central agency could collect the funds and purchase all RECs on a long term basis from developers. This approach might provide more comfort to lenders to lend money to renewable energy projects if credit ratings of retail sellers are not sufficient enough for lenders.

Mechanisms for Enforcing the Standard.

Some form of penalty should be established to ensure that retail electric suppliers will comply with the RPS, preferably in the form of a dollars-per-MWh charge for the difference between the supplier's renewable purchases and the RPS requirement. The size of the penalty should significantly exceed the expected cost of compliance, in order to encourage retail electric suppliers to comply and to minimize the administrative cost of applying the penalties.

A monetary penalty of this type also can act as a cap on the compliance costs incurred by retail electric suppliers. If compliance costs turn out to exceed the monetary penalty, then suppliers will simply choose to pay the penalty instead of complying with the RPS. For this reason, the penalty is sometimes referred to as an alternative compliance payment.

We recommend that the Ohio RPS include an alternative compliance payment of $50/MWh, similar to those in Massachusetts and Connecticut. This is enough to encourage retail suppliers to comply with the RPS target and stimulate the market for renewables, while also being low enough to serve as a reasonable cap on the costs of the RPS.

Any revenues that are generated by the alternative compliance payment should be used to support the development of renewable resources in Ohio. In this way, the goal of the RPS can still be pursued even if some of the retail electricity suppliers are not in compliance.

Procurement Plans and Auctions

The Ohio RPS should require distribution companies to file annual procurement plans with the Public Utilities Commission, including a detailed description of how each utility intends to comply with the RPS in the following year.

The Ohio RPS could also require distribution companies to conduct periodic auctions to identify the best sources of renewable energy and RECs. Auctions could help identify the lowest-cost source of RECs for the compliance year, as well as the lowest-cost sources of RECs for the 10- or 15-year contracts discussed above. The auctions for renewable energy should be conducted in conjunction with the acquisition of other resources under the portfolio management and integrated resource planning approaches described above in Chapter III.

Separate Resource Targets for Energy Efficiency and Renewable Resources

In the previous chapter, it was recommended that Ohio adopt an energy efficiency resource standard. It is important that the EERS target be kept separate from the RPS target. Otherwise, low-cost energy efficiency resources could be used to comply with the RPS target and renewable resources would not receive the intended support from the RPS.

Appendix I: Integrated Resource Planning and Portfolio Management in Selected States

This appendix summarizes the IRP and portfolio management approaches in eight states: Montana, Oregon, Maine, Maryland, New Jersey, California, Delaware and Vermont. Of these, Montana, Maine, Maryland, New Jersey and Delaware are entirely restructured, with customers free to purchase from competitive suppliers and the utility's standard service option priced by the market. California was fully restructured, but has largely retreated to a regulated power supply. Oregon came close to restructuring prior to the western market crisis of 2000-2001, and has continued to explore options for competitive supply for large customers. Vermont does not have any form of competitive retail supply, but the utilities purchase incremental power supply (beyond that supplied by pre-2000 generating units and power purchase contracts) in the competitive wholesale market.

Montana

Background

The Montana Public Service Commission enacted IRP guidelines in 1992 that encourage electric utilities to develop and implement least-cost planning in accordance with state guidelines. In 1997, the Montana Legislature passed the Montana Electricity Utility Industry Restructuring and Consumer Choice Act. The act led to the establishment of customer choice and the functional break up of Montana's largest vertically integrated investor-owned utility, Montana Power Company (MPC). PacifiCorp was also affected by restructuring, and PacifiCorp sold its Montana service territory to the Flathead Electric Cooperative. Rural electric cooperatives, however, opted not to open their territories to competition. The other major investor-owned utility, Montana-Dakota Utilities (MDU), which provides power in eastern Montana, was exempted from restructuring and remained a vertically integrated utility.[66]

Shortly after the passage of the restructuring bill, MPC sold off its power-generating assets and, after a failed venture in telecommunications, ended in

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[66] Pursuant to Title 69, chapter 8, MCA which states that certain utilities are not required to restructure. Section 201(9)(a) states, "a public utility currently doing business in Montana as part of a single integrated multistate operation, no portion of which lies within the basin of the Columbia River, may defer compliance with this chapter until a time that the public utility can reasonably implement customer choice in the state of the public utility's primary service territory." Montana-Dakota Utilities' primary service territory is in North Dakota.

bankruptcy. The company sold its electric and gas distribution territories in Montana to NorthWestern Energy Corporation of Sioux Falls, South Dakota. NorthWestern Energy (NWE) became the state's default electric supplier in most of the state. In 2003, the PSC enacted default electric supplier procurement guidelines that provide policy guidance to default supply utilities on long-term default electricity supply resource planning and procurement.

Currently, there are two separate planning processes applying to the two major service territories: traditional (applicable to MDU) and restructured (applicable to NWE). Thus, the state's one vertically integrated utility (MDU) practices traditional integrated resource planning under those guidelines, while the state's one restructured utility (NorthWestern Energy) practices portfolio planning, management, and resource procurement for electricity supply for default customers under the guidelines for restructured entities. In NorthWestern Energy's territory, there is currently no competitive supply available for residential and small business customers. However, a 2005 statutory change will allow entities to aggregate residential and small business customers, subject to regulatory approval. The law states that these entities will be required to supply service that is consistent with the default supply. The Commission has not yet determined precisely how to interpret this language. Currently, the Commission does not require aggregators to submit resource plans and is not in the process of developing rules to require such plans—the Commission's existing resource-planning and portfolio-management rules do not apply to aggregators.

Current Planning Practices

Montana's IRP guidelines provide a fairly comprehensive framework for conducting least-cost planning, addressing a variety of costs and risk factors. As described above, the IRP guidelines apply to MDU. The guidelines place strong emphasis on managing and reducing risks associated with resource choices in a manner that addresses environmental, societal, and ratepayer risks in addition to shareholder risks. Montana's guidelines require that utilities consider all available resource options, including DSM, and evaluate these options based on a broad range of resource attributes. This includes explicit evaluation of the uncertainty and risk associated with future environmental regulations and of environmental externalities including uncertainty regarding the size and importance of external environmental costs and environmental costs associated with continued operation of existing resources. Existing and potential resources are to be weighed and ranked, in part, on the basis of their environmental impacts, and in evaluating potential resource options utilities should recognize protected areas and any areas inhabited by protected wildlife.

Integrated-Resource-Planning Guidelines for Montana

The Montana IRP guidelines state that utilities should determine the sources of risk using their own techniques and judgment but suggest a list of potential sources of risk that includes the following:

- resource lead-time,
- water availability,
- future load growth,
- shortcomings of various forecasting methods,
- performance and useful lives of existing resources,
- costs and performance of future demand- and supply-side resources,
- the rate of technological change,
- future fuel availability and price,
- the existence and social evaluation of environmental externalities, and
- the future sociopolitical and regulatory environment.

The IRP guidelines also present a list of potential planning techniques for utilities to consider that manage risks associated with the above sources.

The screening process in Montana's IRP guidelines requires that the cost assigned to each resource reflects all relevant attributes including attributes that influence utility cost as well as attributes that influence societal cost. Some of these attributes are as follows:

- environmental externalities,
- the overall efficiency with which the resource produces energy services,
- the administrative costs of acquisition programs,
- the cost effectiveness of the resource, determined in the context of the utility system,
- risk and uncertainty,
- reliability,
- associated transmission costs.

The IRP guidelines also include provisions on sizing and evaluating demand-side resource options. The impact of price-induced conservation (i.e. conservation undertaken by customers in the absence of any utility-sponsored program) should be accounted for either in the load forecast or as part of the total available

resource. The revenue impacts of decreased sales resulting from demand-side resources are not added to cost of acquiring such resources. Also, in considering demand-side resources, until a point at which there are no market barriers or market failures that may interfere with investment in demand-side resources as opposed to supply-side resources, demand-side resources are considered cost-effective up to 115% of the utility's long-term avoided cost.

When evaluating alternative supply resource strategies, the utility must quantify the costs associated with transmission and distribution and any T&D savings that may be associated with distributed generation. Transmission costs, positive and negative, associated with a resource must be imputed based on long-run avoidable costs that reflect the utility's best estimate of the opportunity cost of new or existing transmission capacity that would be consumed if a particular resource were acquired.[67]

Montana's IRP guidelines also require the utility to provide ample opportunity for public involvement in the planning process, including the establishment of a broad-based advisory body to review, evaluate, and comment on the planning process, resource plans, the acquisition process, and efficiency programs. The guidelines also require that the utility clearly and thoroughly document the decision process for choosing resource options.

The guidelines also recognize the importance of rate design in the IRP process and the ability of rate design to create opportunities for demand-side resources. Montana also recognizes that a planning process that is consistent with the IRP guidelines will ensure that the objectives and goals of rate design efforts are consistent with goals of the IRP process.

Default Service Procurement Guidelines for Montana

Montana's default electric supplier procurement guidelines were developed with the following stated objectives:

- Provision of adequate, reliable default supply services, stably and reasonably priced, at the lowest long-term total cost
- Pricing that is both equitable and promotes rational, economically efficient consumption and retail choice decisions
- A balanced, environmentally responsible portfolio of power supply and demand-side management resources, coordinated with economically efficient cost allocation and rate design

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67 The guidelines for Montana's IRP process do not specify how this opportunity cost is measured or defined.

- Diversity with respect to resource types and contract durations
- Dissemination of information to customers regarding the mix of resources in the supply portfolio and corresponding level of emissions and other environmental impacts

In order to comply with these objectives, restructured utilities are required to develop portfolio management plans based on a comprehensive resource needs assessment that considers all aspects of customer load, resource availability, product type availability, an assessment of the resource diversity and flexibility of the existing portfolio, and an assessment of the effect of cost allocation and rate design on future needs. The utility is required to incorporate rigorous computer modeling and analysis into the portfolio management and resource procurement process to evaluate the previously stated factors and to develop least cost scenarios and risk sensitivity analyses for various options. Risk factors that utilities are required to consider include:

- Fuel prices and price volatility
- Environmental regulations & taxes (including carbon regulation)
- Default supply rates
- Competitive suppliers' prices
- Transmission constraints
- Weather
- Supplier capabilities
- Supplier creditworthiness
- Contract terms and conditions

Restructured utilities are directed to apply cost-effective resource planning and acquisition techniques to manage and mitigate risks associated with these risk factors. In addition to computer modeling and analysis, such techniques also include contingency planning, portfolio diversification and conducting a transparent planning and procurement process. Restructured utilities must balance environmental responsibility with other portfolio objectives including lowest- long term total cost, reliability and price stability. This is done by developing methods for weighting resource attributes and ranking bid offers in the competitive bid solicitation process for resource procurement. The procurement process guidelines emphasize transparency and require the input of a stakeholder advisory body.

As a requirement of providing default electric supply service, a default supplier is required to also provide customers with the option of choosing a "green" product.

The guidelines specify that this product shall be composed of or support power from certified environmentally preferred resources such as wind, biomass, solar or geothermal resources.

The Montana PSC is not required to explicitly "approve" resource plans filed by restructured or traditional utilities, therefore, recoverable costs associated with an implemented plan are not guaranteed in rate cases.

The Montana PSC recently adopted a rule establishing a Renewable Energy Resource Standard. The rule was adopted to comply with the Montana Renewable Power Production and Rural Economic Development Act of 2005 (68-6-1001 MCA) which established a renewable-energy-resource standard. From January 1, 2008, through December 31, 2009, each public utility is required to procure 5% of retail electricity sales from eligible renewable resources. The standard increases to 10% for the period January 1, 2010, through December 31, 2014, and to 15% beyond January 1, 2015. Eligible renewable resources include facilities in Montana or delivering electricity into Montana from wind, solar, geothermal, small-scale hydro (less than 10 MW), landfill or farm methane, wastewater treatment waste gas, and fuel cells powered by renewable-derived hydrogen. Renewable resources must be tracked and verified through the Western Renewable Energy Generation Information System. With the exception of this rule, the resource planning guidelines in Montana do not mandate the outcome of the planning process.

Noteworthy Practices and Conclusions

Montana's planning guidelines, both for regulated and deregulated utilities, provide a framework for assessing resource alternatives that incorporates environmental externalities and a wide array of risk factors. One drawback of these guidelines, however, is that they do not provide much guidance regarding how to assess environmental externalities and which externalities should be incorporated into the planning process. The guidelines leave the determination of how to assess environmental externalities and risk factors to the utility based on "documented judgment."

Montana's planning guidelines provide ample opportunity for public input into the planning process through all stages of the process.

Oregon

Background

Since 1989, Oregon has required investor-owned gas and electric utilities to file individual integrated resource plans with the PUC every two years.[68] The primary goal of Oregon's IRP process is to acquire resources at the least cost to the utility and ratepayers in a manner consistent with the public interest. These resource plans must consider risk and cost/risk tradeoffs. Utilities have employed risk factors such as price volatility, weather, and the costs of current and potential federal regulations, including regulations that address CO_2 emission standards.[69,70] The Environmental Protection Agency (2006) finds that in recent years, utilities have considered non-quantifiable issues that impact planning, such as potential changes in market structure, the establishment of renewable portfolio standards, changes in transmission operation and control, and the effect of PacifiCorp's multi-state process on regulation and cost-recovery.

Current Planning Practices

The OPUC is currently considering changes to its IRP requirements.[71] The most recent proposal, put forth by the Commission Staff in docket UM10-56 (Staff's Reply Comments, September 30 2005) and edited by the Staff in this proceeding based on comments by other parties, includes the following requirements:

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68 The original IRP order, No. 89-507, was modified in 1993 in Order No. 93-695, which required utilities to quantify external societal costs. Although the court ruled that mandating consideration of these costs was outside of the OPUC's jurisdiction, it also found that the Commission can order utilities to consider policies that are likely to arise on federal level. Order No. 93-695 was superseded by another (No. 94-590), which dealt with the cost-effectiveness of conservation.

69 In its most recent IRP, PacifiCorp looks at five primary risks: load variation; natural gas, electric, and hydro price variation; and forced outage rates. It also conducts scenario analysis for some "what if?" risks. For example, CO_2 risk was considered in a scenario analysis, which employs simpler models than are used for analysis of the primary risks. (Phone interview, Maury Galbraith, OPUC Resource Planning Department. Feb. 3, 2006)

70 Although Oregon is covered by the federally mandated Northwest Power and Conservation Council plan, Oregon only considers this analytically sophisticated plan peripherally in the IRPs. Northwest electric power and conservation plans are available at http://www.nwcouncil.org/library/Default.htm

71 A parallel docket, UM1182, is considering competitive bidding guidelines for resources above a certain size, how bids should be evaluated, and how bidding should mesh with IRP processes and criteria.

- *Utilities should evaluate all supply- and demand-side resources on a consistent and comparable basis,* using consistent, clearly defined assumptions and methods for evaluation of all resources. Utilities should provide a comparison of resource fuel types, technologies, lead times, in-service dates, durations, and locations in portfolio risk modeling. Demand-side resources should be evaluated on par with supply side resources, and any potential savings in distribution system costs from these resources should be identified.
- *Uncertainty and risk must be considered in the IRP.* At a minimum, utilities should address uncertainty due to load requirements, hydroelectric generation, plant forced outages, natural gas prices and electricity prices. Utilities should identify in the plan any additional sources of uncertainty. The analysis should recognize the historical variability of these factors as well as future scenarios. Discussions on specific risk evaluation metrics are ongoing.[72]
- The primary goal is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its ratepayers. To this end, *utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.* The plan should include analysis of current and estimated future costs for all long-lived resources (such as power plants) as well as short-lived resources (such as short-term power purchases) for a planning horizon of at least 20 years. Utilities are required to address risk by analyzing resource alternatives using measures of cost-variability and the severity of bad outcomes, and by evaluating portfolios for a range of discount rates. These plans must analyze the effect of potential compliance costs related to global warming on costs and risks for the resource portfolios under consideration, by including CO_2 allowances costs ranging from $0–40/ton. The plans should also consider how costs and risks are affected by the use of physical and financial hedges.

Additionally, the staff's proposal requires that the public be allowed adequate involvement in development of the plan.

Currently, the Commission reviews submitted IRPs and either acknowledges them or sends it back to the utility for modification and resubmission. Although the OPUC does consider IRPs in future rate-case proceedings, a formal

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72 Phone interview, Maury Galbraith, OPUC Resource Planning Department. Feb. 3 2006.

Acknowledgment of an IRP does not pre-approve costs associated with resource acquisition for recovery by the utility. The significance of acknowledgment for future prudence review has been raised in the current docket; the OPUC has yet to respond to this issue (Staff's Reply Comments, filed Sept. 30, 2005 in docket UM 1056 (Public Utility Commission of Oregon)).

Noteworthy Practices and Conclusions

The explicit requirement that utilities incorporate a range of CO_2 allowance costs as well as a variety of other risk factors helps the utilities develop resource plans that balance the goal of least cost with mitigation of risks, resulting in plans that provide customers with lower and more stable rates over the long term. The treatment of DSM resources accounts for all the benefits of DSM including the effects on transmission and distribution costs relative to supply-side resource options.

Maine

Background

Under Maine's retail electric access rules, the Maine Public Utilities Commission (Maine PUC) ensures that standard offer service is available to all customers in the state. The Maine PUC has the statutory authority to issue RFPs for Standard Offer Service (SOS) pursuant to Chapter 301 of the Commission's Rules.[73] The Maine PUC is required to solicit suppliers to provide standard offer service through a competitive bid process. The Commission staff prepares the RFP package for supply contracts to serve all customer classes. Solicitations are issued twice a year for medium and large customer classes and annually for residential and small commercial customer classes.

Current Planning Practices

Chapter 301 is a comprehensive rule that identifies specific criteria that must be met when requesting and approving bids for SOS for all classes of customers, in all service territories in Maine. The rule prohibits bids that are variable or indexed, prohibits time or load dependent rates for residential or small commercial customers, requires rates that are the same throughout each utility service territory, and requires compliance with Maine's renewable portfolio standard. Bids must be accompanied by a performance bond.

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[73] Maine Public Utilities Commission Chapter 301—Standard Offer Service. Available on the Internet: http://mainegov-images.informe.org/mpuc/doing_business/rules/part_3/ch-301.pdf

The bid evaluation process occurs in two phases. In Phase 1, bidders provide all non-price portions of their proposals, and the Commission reviews these proposals and determines whether all applicable requirements are satisfied. In Phase 2, eligible bidders provide prices at which they propose to supply SOS. (Maine PUC, 2001b)[74]

Beyond this, price is the key criterion for evaluating bids, except that the Maine PUC will preferentially select at least three providers in each service territory, providing this does not increase the overall cost by more than a set threshold. However, in selecting bids, the Commission "shall select the standard offer provider or combination of providers" based on obtaining the "lowest price" for each class, the "lowest cost for standard offer service overall," and "the stability of standard offer prices." Chapter 301 Sec. 8(B)(2).

Although the solicitation is run by the PUC, which is independent of any market participant, a representative from the Maine Office of Public Advocate reviews all bids and participates in the selection process.

As the RFP process has evolved, the Maine PUC has received an appropriate response for SOS solicitations, but in the earlier years, bids were rejected. In fact, in 1999 the Commission rejected all bids and terminated the processes for medium and large classes in the Central Maine Power (CMP) territory and for all three classes in the Bangor Hydro Electric Company (BHE) territory, because there were no qualifying bids for some classes and unacceptably high bids for other classes. When this happened, the Commission directed CMP and BHE to provide SOS for those classes.[75]

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[74] Maine Public Utilities Commission. Standard Offer Bidding Procedure. Docket No. 2000-808. Available on the Internet: http://mainegov-images.informe.org/mpuc/orders/2000/2000-808sob.pdf

[75] The Maine PUC did so based on the following clause in Chapter 301 of the SOS Terms and Conditions Maine Public Utilities Commission (Maine PUC). 2000. Public Utilities Commission Amendments to Standard Offer Service Rule (Chapter 301). Docket No. 2000-489. Available on the Internet: http://mainegov-images.informe.org/mpuc/orders/2000/2000-489oar.pdf) :

> The Commission may reject standard offer bids for any standard offer class if it finds that the bids are unreasonably high and acceptance would not be in the public interest. In the event the Commission rejects standard offer bids, it will either select a standard offer provider for the applicable standard offer class(es) through alternative means or issue an order directing the transmission and distribution utility to provide standard offer service to the applicable standard offer class(es) through purchases from the regional wholesale bulk power markets, contracts with wholesale suppliers or other appropriate arrangements, as specified by the Commission, until the selection of a standard offer provider is made through a new bid process. We add provisions stating that, in the event the Commission receives no

Noteworthy Practices and Conclusions

In general, there have been no complaints regarding the fairness and impartiality of the supplier selection process, either from market participants or from regulators. However, Competitive suppliers have complained that the Maine PUC's focusing simply on price has impeded competition, and that the State should not play such a central role in the procurement process. In addition, after an early procurement cycle, some stakeholders complained about the resulting electric prices, asserting that the initial one-year contract framework was too sensitive to short-term fuel price increases. To counteract this, the Maine PUC implemented a three-year ladder of contracts.

Maine's example demonstrates that it is possible to reject all RFP results if bids are unreasonably high. It also shows that rejection of bids in one year does not negatively impact supplier participation in future solicitations.

In April of 2006, the Maine Legislature passed an Act to Enhance Maine's Energy Independence and Security. The stated policy goals of the act are as follows:

- To increase the share of new renewable capacity as a percentage of total capacity resources in the state as of December 31, 2007 by 10% by 2017;
- To reduce electric prices and price volatility for electric customers and to reduce the emissions of greenhouse gases from the electricity generation sector;
- To develop new capacity resources that reduce demand or increase capacity thereby mitigating the effects of any regional or federal capacity mandates.

The act directs the Public Utilities Commission to conduct major substantive rulemakings, provide legislative reports, develop certain plans and strategies and consider a variety of issues related to electric resource adequacy, long-term contracting, standard offer supply, and the cost of electricity.

The important differences resulting from the new law with regards to resource procurement and planning have to do with contracting for capacity resources, standard offer contract lengths and terms, and renewable energy and DSM

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bids for a class or finds that all bids for a class must be rejected, it may negotiate with individual providers or direct the utility to provide the service. The existing rule provides the Commission with only the option of requiring the utility to be the standard offer provider. We add the option of individual negotiations with potential suppliers because we prefer standard offer service to be provided by competitive suppliers rather than utilities, as contemplated in the Restructuring Act. In addition, we note that this change makes the provision more consistent with the provisions regarding a default by a standard offer provider. In such a case, section 9 of the rule allows the Commission to negotiate with potential replacement suppliers in addition to directing utilities to provide the service.

mandates. The act states that in its solicitation process the Commission shall develop a method for selecting bids for capacity that account for any accompanying energy. The act also provides an "order of priority" for selecting capacity resources as follows:

1. New interruptible demand response or energy efficiency resources located in Maine;
2. New renewable capacity resources located in Maine;
3. New capacity resources with no net greenhouse gas emissions;
4. New non-renewable capacity resources located in Maine with preference given to resources with no net emissions of greenhouse gases;
5. Capacity resources that enhance the reliability of Maine's electric grid with preference given to resources with no net emissions of greenhouse gases; and,
6. Other capacity resources.

The Act gives the Commission discretion to require and accept DSM bids for standard offer service and to secure long-term contracts (10 years or more in duration) when price stability or grid reliability considerations justify. The long-term contracting aspects of the new law are designed to improve rate stability and capacity adequacy for T & D ratepayers, and these costs will be paid for in T & D rates and not standard offer charges. As a result of the provisions of this act, bid evaluation for standard offer service will necessarily be more complex, and the Commission issued a Notice of Inquiry on June 7, 2006 seeking comments on the various provisions of this Act, as Docket No. 2006-314.

Maryland

Background

In 1999, Maryland adopted its Electric Customer Choice and Competition Act, which allowed customers to select their own electricity provider beginning in the summer of 2000. However, the number of competitive retail suppliers to choose from remained limited through 2003, and the majority of Maryland residents continued to purchase power from their traditional electricity utility under the Standard Offer Service (SOS) rate plan. In response to the clear lack of customer switching, in its Order No. 78400, the Maryland Public Service Commission (Maryland PSC) approved a settlement on April 29, 2003, under which the distribution utilities would continue to provide SOS service to residential and small commercial service customers. On September 30, 2003, in Order No. 78710,

the Maryland PSC approved the mechanics to be used by the utilities to procure generation for their SOS customers.[76]

Current Planning Practices

In contrast to the Maine solicitation process which is run by the Public Utilities Commission, the Maryland SOS RFPs are issued by each individual utility. Each utility's RFP must provide the following information:

- Lists of the customer classes, the total load, the number of load blocks and approximate size of each load block for each solicitation;
- The bidding timeline and deadlines for key activities in each bidding tranche;
- A general description of customer class and pricing characteristics;
- Bid form spreadsheets to be used for an applicant's offer for load blocks for each service and each tranche (Maryland PSC Case No. 8908, Order No. 78710 x pages?).

Bidders submit bids in the form of an offered price for each rate element in the existing tariffs of the utility. Bidders may submit multiple bids with different prices and different numbers of blocks offered, but no bid can be contingent on another bid. Affiliates are allowed to participate without restrictions, and there are no load caps.[77]

Instead of single, annual procurement cycles, Maryland conducts its RFP solicitation process in three sealed-bid rounds that occur within weeks of one another. Additional rounds are conducted if less than 100% of the required service was awarded in the first three rounds. Such sequencing allows for repositioning of unsuccessful bids by suppliers. Utilities' requirements for their service territories are split among the three tranches (rounds) in accordance with each utility's specific bid plan (e.g., 50%, 30%, 20%). Bids are solicited by service type, including Residential, Type I Non-Residential SOS, Type II Non-Residential SOS, and Type III Large Customer Service.

Bidding is conducted at the same time for all four Maryland utilities. This is intended to ensure the most equitable opportunities are afforded to each utility in terms of getting its load served at a reasonable, market-based price (Maryland PSC

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[76] Maryland PSC Case No. 8908, Order No. 78710, September 30, 2003 x pages?. See also, Maryland PSC, 2004 Request for Proposals for Full Requirements Wholesale Electric Power Supply.

[77] The term bid cap refers to a limit on the amount of the supply being bid out that any one bidder may win.

Case No. 8908, Order No. 78710 x pages?). After the RFPs are posted by each utility, bidders are asked to respond with an expression of interest, followed by a pre-bid conference. Interested bidders must meet certain pre-qualification requirements proving their eligibility to participate in the PJM energy market at market-based rates, and their creditworthiness.[78] They are also required to post bid assurance collateral in proportion to the bid quantity, which is returned to the bidder subsequent to contract execution or the rejection of its bid(s). However, suppliers in poor credit standing must provide additional collateral upon being awarded a bid.

After the RFP is posted by the utility, bidders are asked to respond with an expression of interest. Following, there is a pre-bid conference. Interested bidders must then meet the pre-qualification requirements for market status, credit worthiness, and provision of collateral.

Because of the prequalification requirements and the standardized bid worksheets used in the process, cost is the sole criterion for awarding contracts to qualified bidders. Bids once submitted represent firm commitments and cannot be changed or withdrawn. Because this is an RFP process and not an auction, successful bidders are paid their bid price instead of a clearing price, despite the simultaneous awarding of contracts in each round.

While the utilities prepare their own RFPs, oversight is provided by the Maryland PSC, which hires an independent monitor. The monitor participates in the entire procurement and bid process. Each round of bids is either approved or denied by the Maryland PSC within two business days of receiving the offers. Thereafter, the transactions are contingent only upon any necessary FERC approvals.

Winning bidders each receive the exact payments to which they individually bid. This differs from other regions, wherein all bidders are paid the same price for their load. Bids represent firm commitments and cannot be changed or withdrawn.

Thus far, three multi-round RFPs have been conducted. The first was finalized in April 2004, the second in March 2005, and the third in March 2006.

Noteworthy Practices and Conclusions

The Maryland PSC has found the SOS RFP process to be appealing in the following ways:

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[78] Maryland PSC Case No. 8908, Order No. 78710, September 30, 2003; Maryland PSC, 2004 Request for Proposals for Full Requirements Wholesale Electric Power Supply.

- Transparent, competitive procurement approach
- Objective, fully pre-specified bid selection process
- Streamlined, non-contentious regulatory process
- Consistent with FERC affiliate sales policies
- Efficient allocation of risks and responsibilities
- Distribution company manages procurement process and provides distribution service
- Suppliers take on all generation-related responsibilities, including portfolio/risk management
- Does not require regulated entity to duplicate portfolio/risk management function readily available in wholesale market

The Maryland process has the benefits of transparency and objectivity in the sense that qualified bidders are compared based on a single, well-defined price criterion, in a process monitored by the PSC and an independent monitor. This clearly meets the FERC competitiveness criteria, while retaining a leading role for the state regulatory body in designing and overseeing the process. Also, multiple rounds of procurement reduce the risk of an unfavorable outcome due to temporary disruptions in markets or prices fluctuations. In addition, using a mixture of 1, 2, and 3-year contracts offers greater rate stability than using only very short term contracts. One drawback may be that non-price criteria are given limited review, beyond that required to assure creditworthiness. While this does not appear to have been a problem for procurement of SOS in Maryland thus far, it may be an important drawback for the procurement of other services, such as generation capacity, or in other markets.

New Jersey

Background

Starting in 2002, the State of New Jersey has held an auction each year for the procurement of fixed-price, basic electric generation service (BGS-FP), analogous to SOS in Maryland and Maine. BGS rates are set yearly based on the results of a competitive auction. These auctions have attracted a variety of participants—utility affiliates, non-affiliated generators, and intermediaries, who offer their supply bids to the four electric distribution companies (EDCs) that provide BGS service to customers. The four EDCs are: Public Service Electric and Gas Company (PSE&G), Jersey Central Power & Light (JCP&L), Rockland Electric Company (RECO), and Atlantic City Electric Company (ACECO).

Thus far, the yearly NJ BGS-FP auctions have had a variety of participants–utility affiliates, non-affiliated generators, and intermediaries. The auction process is run as a declining clock auction, wherein bid prices continue to decline until there are only enough bids from suppliers to serve the number of tranches of electricity load being procured.[79]

Though NJ holds its auctions yearly, it does not procure 100% of its contracts each year. Instead, a three-year laddered approach is used for the procurement of BGS-FP electric service. One-third of the total necessary electricity is procured in any given year, and one-third of the existing contracts expire each year. NJ phased in its ladder of generation contracts. Specifically, in 2002, when New Jersey started its auction process, it only offered BGS-FP tranche contracts of one-year in duration. Then, in an effort to build up to a three-year ladder of contracts, in both 2003 and 2004, New Jersey held auctions for the provision of both one-year and three-year contracts for BGS-FP service. As of 2005, only three-year contracts were necessary to continue the laddering concept. This year and going forward, NJ will procure a total of 33% of its electricity each year, all through three-year contracts.

Current Planning Practices

The auction process is run on-line as a declining clock auction, in which prices "tick down" throughout the auction, starting high and being reduced gradually until the supply bid is just sufficient to meet the load to be procured. Bidders holding the final bids when the auction closes are the winners, and all winners are paid the same final clearing price (unlike the Maryland RFP process).

Each year, the BGS auction design is proposed by the four utilities, published for public comment, and then submitted for approval to the New Jersey Board of Public Utilities (BPU). Bidders are then qualified and registered for the auctions through a two-part application process. Part I is a prequalification based on creditworthiness. Part II involves certifications regarding associations, to ensure that each bidder is independent of other parties in the auction and to ensure the confidentiality of information. With their Part II Application, qualified bidders are required to submit an indicative offer and to submit a financial guarantee in proportion to their indicative offer. In the Part 2 Application, qualified bidders must make a number of certifications regarding associations to ensure that they are

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79 A BGS-FP tranche represents approximately 100 MW of load. There are 50 total tranches offered in the BGS-FP auction.

bidding independently of other parties and to ensure the confidentiality of information regarding the Auction.[80]

If the Part II Application is accepted, the bidder becomes a "registered bidder." The Auction Manager (discussed below) will send, simultaneously, to each registered bidder, a list of registered bidders in the BGS auction and the total initial eligibility in the auction. Neither the list of registered bidders nor the total initial eligibility in the auction is released publicly.

Once the auctions are concluded, the Board renders a decision on the results within two business days. If the Board approves the results, winning bidders have three business days to execute the standard statewide BGS Supplier Master Agreement and to post any required security. Supply years are synchronized with the planning year of PJM, the regional ISO, so that power flows from June 1 through May 31 of the following year.[81]

To further promote competitiveness, a load cap limits the amount of load that any single bidder can serve. Each utility sets its own load cap. The amount is reviewed and approved by the BPU Staff and the Consultant. The 2005 BGS load caps differed for each service territory, as follows:

PSE&G..... 36%

JCP&L..... 33%

ACECO 38%

RECO 100%

Winning bids for each tranche are those that remain after the "clock" has stopped, that is when there are just enough tranche bids remaining to satisfy the load. Winners are required to provide all services required by PJM for a load serving entity (LSE) including capacity, energy, ancillary services, transmission and any other services required by PJM. Winning suppliers must also comply with the state's renewable portfolio standard.

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80 A qualified bidder is associated with another qualified bidder if the two bidders have ties that could allow them to act in concert or that could prevent them from competing actively against each other in the Auction. Since the competitiveness of the Auction and the ability of the Auction Process to deliver competitive prices may be harmed by the coordinated or collusive behavior that associations facilitate, such associations among bidders is prohibited.

81 New Jersey State Wide Basic Generation Service (BGS) Auction Overview. Available on the Internet: http://www.bgs-auction.com/bgs.auction.overview.asp

As in Maryland, the solicitation is run by an independent third party (called the Auction Manager in New Jersey) chosen by the utilities with oversight from the BPU. In addition, there is an independent Auction Advisor, who is chosen by and accountable to the BPU. The Auction Advisor's role is as follows:

- Observe of all activities leading up to the auction itself, including software development and testing, bidder education and communications, bidder qualification;
- Observe preparatory steps such as establishment of the opening prices and number of tranches;
- Monitor in real-time all aspects of the auction;
- Review and analyze auction data and documents as needed;
- Brief the commission staff on all of the above;
- Form an assessment of the auction process and results;
- Make recommendations to the Board about acceptance or rejection of the auction results.

The Auction Manager and Auction Advisor are each responsible for reporting to the BPU on the results and process of the auction. This report's process evaluation consists of answering a list of 28 pre-specified questions after the auction ends that help the BPU determine whether the auction process was properly conducted. The Board has the final say in terms of whether or not to approve the auction results. If the Board approves the Auction results, winning bidders have three business days to execute the standard statewide BGS Supplier Master Agreement and to post any required security.

Noteworthy Practices and Conclusions

The New Jersey auction process has operated successfully five times in the sense that the full required amount of load was procured in each cycle since the auction process began in February 2002. The New Jersey auctions have had a variety of participants—utility affiliates, non-affiliated generators, and intermediaries, and a significant amount of competition (25 suppliers participated in 2006).

New Jersey was the first state to adopt an auction style process, as opposed to the more traditional RFP process, for procuring the equivalent of standard offer service. It was also one of the first deregulated regions to successfully solicit bids

for greater than one-year terms through implementation of a three-year ladder.[82] This process seems to have run very smoothly and efficiently, and has attracted broad participation from a variety of participants each year. There have been some arguments for procedural changes to further prevent dominance of the procurement by affiliates of Exelon. Some adjustments have been made over the various iterations to respond to these complaints.

One highly important characteristic of the New Jersey auction process is that as long as the auction process has no apparent flaws, the results of the declining clock auction are accepted. In other words, the Auction Manager and Auction Advisor watch to make sure that the process is properly monitored. Unlike in Maine, there is no party designated to monitor the auction results to determine that the prices are fair; and results are not rejected unless there is clear fault in the auction process. One further characteristic of the New Jersey auction process that makes this a particular concern is that the Auction Manager intentionally sets the starting price at multiples of expected competitive market price, so that auction results could be deemed to be competitive even though the clock stops at well above reasonable price levels. This appeared to be the case the first time the auction was run.

Perhaps the most important conclusion here is that New Jersey has proved that an auction process can successfully be used in lieu of an RFP process. The state's annual auction and use of a three-year ladder of contracts has succeeded in meeting the state's needs so far with relatively little criticism. However, it is also clear that the success of the auction process depends on painstaking groundwork and a strictly limited palette of highly standardized products being sought. While the New Jersey auction process is well developed and has proven to be successful in managing price risk for New Jersey customers, the process does not allow DSM programs to compete with generation in the auction process. There is no weighting or ranking process that rates bids based on attributes other than price.

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82 In this report, we use the term "ladder" to mean a system of power procurement contracts of multiple years, with only a portion of the contracts expiring each year. This analogous to a laddered portfolio of bonds for an investor. The usual purpose is to mitigate the risk of undesirable outcomes due to price volatility. For further discussion of this concept, see Biewald et al (2003); Roschelle et al. (2004); Roschelle and Steinhurst (2004).

California

Background

California was the first state in the country to move to retail electric competition, but the market structure and pricing mechanism used there was not copied by other states. When full scale retail competition began in March of 1998, utilities were required to purchase all of their power for default service from the Power Exchange utilizing the spot market until the end of the stranded cost recovery transition period that ended in April 2002.

In 2000, a variety of circumstances led to the infamous California energy crisis which caused extremely high utility bills, energy shortages, rolling blackouts, and an overall distrust of the electric industry and the deregulation process. High wholesale prices led to financial instability for California utilities and as a result, power suppliers were not willing to enter into power supply contracts with utilities for fear of not getting paid. In January of 2001, in an effort to mitigate the energy shortages created by this situation, Governor Gray Davis authorized the California Department of Water Resources to enter into contracts and arrangements for power purchase and supply under the provisions of the California Emergency Services Act. The deregulation process was suspended on September 20, 2001, but the state is still considering alternative free competitive market models for future consideration.

In the beginning of 2003, the California Public Utilities Commission (CPUC) ordered the three California utilities–SDG&E, Pacific Gas & Electric, and Southern California Edison–to resume the role of planning for and buying electricity to meet customer needs. In Decision 04-01-050, the PUC adopted the long-term regulatory framework under which utilities would plan for and procure energy resources and demand-side investments with Long Term Procurement Plans (LTPPs). The plans are designed to meet the energy needs of a growing California economy with adequate and reliable resources while implementing the best possible measures to ensure low rates and reduce environmental impact.

Current Planning Requirements

The California LTPP process is very new, having begun only in 2004; it involves California's three major electric investor-owned utilities (IOUs). The three IOUs, PG&E, SCE, and SDG&E, were asked to submit LTPPs on July 9, 2004, for review and approval. The IOUs are required to submit a 10-year procurement plan biennially, detailing its demand forecasts and showing how it plans to meet that demand. Each utility's LTTP must show that it has the ability to meet the following requirements (among others):

- Resource adequacy—IOUs must have 15-17% reserve margins by July 2006.
- Renewable Portfolio Standard (RPS)—Renewable energy must be 20% of each IOU's portfolio by 2010, and must increase by at least 1% each year toward that goal.
- Energy Efficiency (EE)—Each IOU must meet specific MW and GWh/year goals, mandated by the CPUC and based on requirements in the state's Energy Action Plan, with annual increases through 2013.
- Demand Response (DR)—Each IOU must meet 3% of its annual system peak demand for 2005 through DR programs, increasing 1% annually through 2007; these goals are translated into quantifiable MW savings for each IOU.

The California Public Utilities Commission directed the utilities to prioritize their resource procurements and to follow the priorities, or "Loading Order," established in the state's Energy Action Plan (EAP). The EAP identifies certain demand-side resources as preferred because California believes that they work toward optimizing energy conservation and resource efficiency while reducing per capita demand. The EAP also identifies certain preferred supply-side resources. The EAP established the following priority list:

- Energy efficiency (EE) and demand response (DR).
- Renewable energy (including renewable distributed generation).
- Clean fossil-fueled distributed generation (DG) and clean fossil-fueled central-station generation.

Currently, the three IOUs are still operating under previous purchase contracts for energy. As these expire, and as new procurement is needed, the EAP loading order must be followed. When EE, DR, and DG resources have been exhausted, then the utilities are required to issue Requests for Offers (RFOs) for supply-side resources. The RFOs are to be issued in an open, competitive process. These resources are compared using the least-cost/best-fit test. Before issuing an RFO, the burden of proof is on the utility to show that the priority options following the EAP loading order have been exhausted, and use of fossil fuels over renewable resources must be justified.

When the utility anticipates needing fossil fuel sources, it must initiate a competitive process designed to ensure that it compares renewable and fossil fuel energy sources. CPUC has directed the utilities to include the costs of carbon dioxide emissions in their long- term procurement plans and resource evaluation. Utilities must file monthly risk assessments and quarterly reports on the implementation of their plans.

The CPUC's review of the plans is guided by the prior Commission decisions and the Energy Action Plan (EAP) adopted in 2003. In addition, D.04-01-050 (the order establishing procurement guidelines) provided guidance on the parameters of the plans, e.g., load scenarios, portfolio choice issues, cost issues, etc. In response to the LTPPs filed by utilities, intervenors representing consumer groups, municipalities, energy producers, environmental groups, and others may make formal comments on various portions of the plans through CPUC's litigation process. The CPUC analyzes each plan and the parties' positions and may approve the plans, in whole or in part. IOUs may be required to submit compliance filings to resolve any deficiencies in the plans. Once approved, the plans become the guidelines for IOU resource procurement. Each utility files a quarterly report which is used by the CPUC for monitoring purposes.

The process is utility-specific, involving the three main electric IOUs. The CPUC has set statewide goals (e.g., 20% renewable energy by 2010) that have been defined and quantified for each utility. The utilities then formulate individual plans, which are required to meet those goals.

Inclusion of certain resource options in the LTPP does not guarantee pre-approval for rate treatment. The IOUs are required to file separate applications to get authorization to sign contracts with a duration of five years or longer. A similar procedure is used for turn-key or IOU-built projects. Requirements for all-source solicitations are listed in D.04-12-048. If the CPUC finds all or a portion of a plan to be non-compliant, they may ask the utility to modify and file the updated plan via compliance filing. The implementation process is monitored by the utilities' quarterly reports and other applications and reporting requirements, and the process is enforced through its impact on the utilities' cost recovery. Cost recovery may not be allowed for expenses that are not in compliance with the plans.

Conclusions and Noteworthy Practices

Based on its first comprehensive review of the implementation of the Loading Order, California Energy Commission staff found different success rates for different resources. For example, the state and its utilities are currently ahead of their goals for energy efficiency, but are having a harder time meeting their goals for demand response and renewables. The state continues to work on reducing barriers to distributed generation, and to take steps to meet the goals of the Loading Order policy (Jones, Smith, and Korosec 2005).

Southern California Edison's request to meet an anticipated energy shortfall during Summer 2005 with an additional $38 million in efficiency programs demonstrates that the utility is following the EAP's priorities.

Like Oregon, California specifically requires utilities to include an adder for carbon dioxide for evaluating the costs of fossil fuel resource options. Instead of a range, however, utilities in California are required to use an adder of $8/ton of carbon dioxide emissions.

Delaware

Background

At the request of the Governor, the Cabinet Committee on Energy (2006) has recommended a return to IRP, and requiring Delmarva to sign long-term contracts, own and operate generation facilities and diversify fuel sources to meet a percentage of its retail load, and to implement DSM programs. The below is excerpted from the Committee report (21–23):

> **Take Long-Term Steps to Ensure More Stabilized Prices and Supply**
>
> The Executive Order asked the Public Service Commission if it would be feasible to order Delmarva Power to build or buy "to meet up to 100 percent of supply options under traditional rate base, rate-of-return regulation."
>
> From a technical standpoint the approach is feasible. Whether such procurement would be financially feasible (i.e., "bankable") at a reasonable cost of capital would depend on the particulars of the regulatory and statutory regime that exists or was put in place. A suitable regulatory and statutory regime could be established that would make such procurement financially feasible, while remaining fair to consumers and investors.
>
> After all, traditional rate base, rate-of-return regulation was bankable for over a century, and it remains so in many states today. Given the contractual commitments made during the recent RFP process, it is likely that utility procurement would need to be phased in over a period of years, but this would make the job easier, not harder.
>
> **More comprehensive planning required**
>
> If this concept were pursued, Delmarva Power would be conducting procurement starting from a position of zero assets (supply- or demand-side, physical or financial) with the sole exception of its recently acquired contracts from the Standard Offer Service RFP. For this reason, if no other, it would be unwise to mandate a return to utility procurement under traditional rate making without clear procurement conduct guidance to the utility. Any such mandate should be required to follow modern Integrated Resource Planning ("IRP") guidelines, and take place under PSC oversight.

That oversight should be especially close during the initial planning and procurement, since Delmarva Power would need to be procuring virtually all post- 2008 resources. This stands in contrast to the incremental procurement process that is generally seen under traditional ratemaking regimes.

A mandate to Delmarva Power for building or buying new generation resources should be considered only as part of IRP practices, regardless of who ultimately builds or owns the resources. The feasibility of implementing either utility procurement under traditional rate making, IRP, or both further depends on the availability and quality of certain technical planning and implementation resources. The knowledge and skill requirements are especially large if the portfolio can include physical or financial hedging instruments. Those resources include software for forecasting, power cost estimation, and portfolio management requirements. However, the primary resource is experienced staff to carry out the planning and to acquire and manage the selected resources.

Take steps to manage demand

Under prior regulatory arrangements, these resources were common in the utility world, although certain utilities did not field resources in certain areas such as demand-side management (DSM). DSM initiatives attempt to reduce customer energy demand, especially during peak usage periods. Ultimately these efforts can reduce the need to build new generating capacity and lessen environmental and rate impacts, because dirtier and more expensive peaking units may run less due to such programs.

After passage of the Restructuring Act, it is likely that Delmarva Power divested the necessary resources to the extent it did have them, as the utility's functions no longer required these skills. However, there is reason they could not be reacquired within a reasonable period of time.

In fact, Delmarva Power affiliates may already have many of those resources available. Providing IRP support and portfolio management support to utilities and other entities is also a lively consulting field.

More of a challenge would be the policy process of deciding how and under what rules to "unwind" the divestiture process that followed the Act. However, certain aspects of the challenges to be faced can be anticipated. These include the significant time that would be required to carry out and approve the first round of planning and resource plans; implementing any resource plan would take additional time, especially if it included novel components such as DSM hedging instruments. Also, natural-gas and

power-market prices are likely to remain high relative to historic levels for some time, and this will affect power procurement strategy.

Regardless of the options pursued or how quickly they are implemented, it is likely to take some time to improve Delaware's current situation. None of this is an argument against the feasibility of IRP. Rather, it is a cautionary note against the notion that Delaware can significantly reduce power procurement costs finding an alternative means of serving retail load. IRP remains a viable option for optimizing resource selection, especially if demand side and renewable resource options are given due consideration in mix of possible resource options.

Traditional rate-making stabilizes prices

How could implementing utility procurement under traditional rate making, IRP, or both help Delaware its current predicament? First, building or buying long-term new generation resources may provide opportunity to gradually reduce customer power rates, especially if those acquisitions are within areas constrained by transmission and distribution, while providing greater economic stimulus to the local economy than external purchases of power.

Second, procuring power under traditional ratemaking provides a different, potentially more favorable, favorable, risk allocation. Under current market-based procurement, ratepayers see market clearing prices driven by the most expensive resource in use. In contrast, under traditional rate making, ratepayers are charged based on the actual cost for all resources.

Third, choices can be made to procure long-term, non-fossil resources (including DSM) and pass through to ratepayers the resulting price stability, rather than leaving ratepayers exposed to market fluctuations. Fourth, if coal gasification is an option in Delaware, coal may have lower, more stable prices than other fossil fuels, although the risk from possible future carbon-control requirements remains significant. In addition, this is a relatively new technology that has only seen limited use in the United States.

In order to step into this process, the PSC recognizes that it should modify its recent approval of the default service RFP process to reflect the current market condition. Specifically, if implementing either utility procurement under traditional rate making, IRP–or both–is being considered, Delmarva Power should not implement RFP procurement without first modifying the products and process so that they would not constrain the PSC's opportunity to shift to either of those approaches. For example, it may be

that instead of replacing the first set of tranches that will expire with new three-year contracts, shorter contracts or no contracts should be procured.

Renewable power as an option under IRP

The PSC should consider whether long-term renewable power should be procured in lieu of some or all of any expiring tranches as part of the IRP process.

For the medium to long term, it is essential that a proper IRP process be established in order to examine the state's resource options in a systematic and comprehensive manner. In order to implement the longer term strategies, legislation would be necessary to provide the PSC with the flexibility to stage a process that would ultimately lead to the integration of all or part of the procurement process under traditional ratemaking depending on the results of a regular and detailed IRP Process.

The IRP process will examine the need for the utility to obtain long-term contracts, build its own generation or to continue to buy on the open market or any combination of these activities. Each presents its own level of risk. Currently, market prices are very high because of the economic dispatch issue, whereby bids are reflected at the highest priced bid dispatched. Long-term contracts contain their own set of issues. First, in the current marketplace they are difficult to find. Second, they are by nature a lengthy commitment that may appear to be a reasonable option under today's market conditions, but later end up being higher than market conditions.

Having the utility construct its generation must be investigated on a case-by-case basis to ensure that customers end up benefiting from such activity. Providing the Commission flexibility to utilize any of these methodologies is critical for this longer term approach.

Recommendations—EO 82 Task 1b, c, d

- Propose immediate legislation authorizing the State to require Delmarva to sign long-term contracts, own and operate generation facilities and diversify their fuel sources in order to meet a percentage of its retail load, provided the Public Service Commission determines that doing so will stabilize and improve the long-term outlook for electric prices. Such legislation would require Delmarva to develop and the Public Service Commission to approve an Integrated Resource Plan (IRP) for Delaware every two years; and

- Propose legislation requiring regulated utilities to develop Demand Side Management programs that are subject to regulatory approval to reduce electricity consumption.
- Coordinate efforts with regional regulators and our federal and state elected officials to effect changes in certain PJM Interconnection market rules and proposals that are adversely affecting wholesale electric pricing throughout the Northeast and Mid-Atlantic States.

Current Planning Practices

Introduced in the Delaware General Assembly on March 30, 2006, and passed by both houses and signed by the Governor on April 4, 2006, House Bill 6 amended the electric utility restructuring law (Title 26, Ch. 10, § 1007) and provides as follows:

> Subject to the approval of the Commission, the standard offer service provider to meet its electric supply requirements shall have the ability to:
>
> 1. Enter into short- and long-term contracts for the procurement of power necessary to serve its customers;
> 2. Own and operate facilities for the generation of electric power;
> 3. Build generation and transmission facilities (subject to any other requirements in any other section of the Delaware Code regarding siting, etc.);
> 4. Make investments in demand-side resources; and
> 5. Take any other Commission-approved action to diversify their retail load.
>
> In order to take such action, DP&L as a standard offer service supplier must file an application with the Commission or have had such action approved as part of its integrated resource plan.... Costs from these projects which have been approved by the Commission shall be included in standard offer service rates.

The law also requires integrated resource planning:

(1) DP&L is required to conduct integrated resource planning. On December 1, 2006, and on the anniversary date of the first filing date of every other year thereafter (i.e., 2008, 2010 et seq.), DP&L shall file with the Commission, the Controller General, the Director of the Office of Management and Budget and the Energy Office an integrated resource plan ("IRP"). In its IRP, DP&L shall systematically evaluate all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost. The IRP shall set forth DP&L's supply and demand forecast for the next 10-year period, and shall set forth the resource mix with which DP&L

proposes to meet its supply obligations for that 10-year period (i.e., demand-side management programs, long-term purchased power contracts, short-term purchased power contracts, self generation, procurement through wholesale market by RFP, spot market purchases, etc.).

a. As part of its IRP process, DP&L shall not rely exclusively on any particular resource or purchase procurement process. In its IRP, DP&L shall explore in detail all reasonable short- and long-term procurement or demand-side management strategies, even if a particular strategy is ultimately not recommended by the company. At least 30 percent of the resource mix of DP&L shall be purchases made through the regional wholesale market via a bid procurement or auction process held by DP&L. Such process shall be overseen by the Commission subject to the procurement process approved in PSC Docket #04-391 as may be modified by future Commission action.

b. In developing the IRP, DP&L may consider the economic and environmental value of:

1. Resources that utilize new or innovative baseload technologies (such as coal gasification);
2. Resources that provide short- or long-term environmental benefits to the citizens of this State (such as renewable resources like wind and solar power);
3. Facilities that have existing fuel and transmission infrastructure;
4. Facilities that utilize existing brownfield or industrial sites;
5. Resources that promote fuel diversity;
6. Resources or facilities that support or improve reliability; or
7. Resources that encourage price stability.

The IRP must investigate all potential opportunities for a more diverse supply at the lowest reasonable cost.

The legislature also requires an initial RFP for new local power supply, to deal with the fact that the Delmarva peninsula is a transmission-constrained load pocket with higher market prices than in neighboring parts of PJM.

As part of the initial IRP process, to immediately attempt to stabilize the long-term outlook for standard offer supply in the DP&L service territory, DP&L shall file on or before August 1, 2006, a proposal to obtain long-term contracts. The application shall contain a proposed form of request for proposals ("RFP") for the construction of new generation resources within Delaware for the purpose of serving its customers taking standard offer service. Such proposed RFP shall

include a proposed form of output contract which shall include capacity and energy and may include ancillary electric products and environmental attributes between the electric distribution company and developers of new generation facilities, which contract shall have a term of no less than 10 years and no more than 25 years. Such RFP shall also set forth proposed selection criteria based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities.

(1) The Commission and Energy Office may approve or modify the elements of the RFP prior to its issuance. The Commission and Energy Office shall ensure that each RFP elicits and recognizes the value of:

a. Proposals that utilize new or innovative baseload technologies;

b. Proposals that provide long-term environmental benefits to the state;

c. Proposals that have existing fuel and transmission infrastructure;

d. Proposals that promote fuel diversity;

e. Proposals that support or improve reliability; and

f. Proposals that utilize existing brownfield or industrial sites.

Noteworthy Practices and Conclusions

Of all the restructured states, Delaware has taken the lead in reinstituting IRP and putting the distribution utility and the Commission back in the position of assuring adequate and reasonably priced supply for customers. Perhaps most noteworthy is the state's decision to mandate a combination of planned portfolio management by the SOS provider (Delmarva) for part of the SOS need and a competitive procurement for a minimum fraction of the SOS need. Proceedings are under way now to determine how wholesale competitive procurement should be altered to accommodate these factors, as well calls for greater transparency and flexibility in SOS procurement.

Vermont

Background

Vermont began movement towards long range utility planning in 1981. The Public Service Board's advocacy staff was separated into an executive branch department, the Department of Public Service. The department included the existing Division of Public Advocacy which was joined by a planning division. The planning division was initially charged with drawing up a 20-year electric plan for the state. The first edition of that plan, issued in 1983, called for the state's electric utilities to review a menu of demand-side management options and

implement them unless demonstrated not to be cost-effective using the PVRR test (the Utility Test in current language). That first plan also called for reduction in T&D line losses and for supply-side options to be compared using the same test and for various strategic transmission and generation options to be explored.

Current Planning Practices

The second edition of the state electric plan, issued in 1989, explicitly called for all electric utilities to undertake integrated least cost planning using the Societal Test. A lengthy Public Service Board proceeding (Vt. PSB Docket 5270) reviewed the options for utility planning and resulted in an Order requiring all electric utilities to prepare IRPs, submit them for public review and Board approval, and update them at least every three years. The Board provided for a 10% downward risk adjustment to the cost of all DSM options in recognition of their greater flexibility and reduced exposure to environmental risks. A 5% adder was also applied to the cost of all non-DSM resources as a rebuttable presumption for the environmental externality costs. While specific dollar per ton adders for air pollutants were proposed, they were not adopted. In the mid- to late-1990s, as retail choice and wholesale competition came to be debated in Vermont and around the region, the requirement to submit IRPs was suspended. Retail choice was debated in the Legislature each year for three years running and, ultimately, rejected conclusively. The IRP requirement was reinstated shortly after 2000 with a greater emphasis on finding “robust” portfolios, but without any specific analytical requirements.

Noteworthy Practices and Conclusions

Also in the mid-1990s, the Vermont Department of Public Service and each of the retail electric utilities joined in a settlement that moved responsibility for system wide DSM away from the retail utilities and to a new “Efficiency Utility.” The Efficiency Utility was to be an entity charged with providing statewide, uniform DSM programs to all customer classes. The Efficiency Utility was to be independent of all electricity market participants and selected by the Board, based on competitive proposals. Its work was to be funded by a negotiated per kWh charge on the bills of all retail electricity consumers. The Department was charged with evaluating the work of the Efficiency Utility every three years and recommending changed or additional programs and savings targets. The Public Service Board approved the settlement in its Order in Docket 5980, and the Legislature later enacted its provisions into statute.

The term system wide DSM means energy efficiency programs that were not targeted to alleviate a transmission or distribution problem in a particular location or to defer a specific transmission or distribution upgrade. When the Efficiency

Utility was created, retail utilities were left with responsibility for implementing all cost effective DSM and distributed generation projects that could defer such upgrades. In a later proceeding (Docket 6290), settlements were again reached providing the details for how such opportunities were to be identified, especially how they were to be identified early enough to be usefully addressed by DSM and distributed generation. The settlement also defined the methods for studying the alternatives.

Appendix II: Ohio Action Plan

A. Portfolio Management and Power Procurement

The legislature should establish a set of standards for procurement of SSO supply, including:

- SSO should be supplied from a mix of resource-specific long-term contracts, firm supply contracts for fixed quantities of energy and capacity, full-requirements supply contracts and DSM resources.
- At least one-third of the SSO supply should be from full-requirements supply contracts.
- In the long term, at least one-third of the SSO supply should be from contracts of more than five years.
- The long-term contracts should be as long a necessary to permit the financing of new desirable generation, including IGCC and renewables.
- The long-term contracts should be diversified by fuel source and pricing terms.
- The full-requirements supply contracts should be for periods not to exceed four years, unless the PUCO finds longer periods to be in the public interest.
- The full-requirements supply contracts should be laddered, so that any one year's full-requirements supply would be procured from multiple procurements in multiple years.

Each utility should be directed to procure a SSO supply mix that would be expected to minimize the cost of SSO service, while maintaining diversification and moderating price risk.

Energy Efficiency Resource Standard

The legislature should establish a set of electric energy-efficiency targets that each load-serving entity would be required to meet. The EERS targets should be equal to a percentage of each LSE's total retail electric sales.

The EERS targets should include cumulative annual savings from efficiency programs that were implemented after the commencement of the EERS. The table below presents the EERS target in terms of the cumulative annual savings targets, as well as the incremental annual savings that would be necessary to reach the cumulative amounts.

Ohio Energy-Efficiency-Resource-Standard Targets

	Incremental Annual Savings (% of Sales)	Cumulative Annual Savings (% of Sales)
2008	0.3	0.3
2009	0.5	0.8
2010	0.7	1.5
2011	0.8	2.3
2012	0.9	3.2
2013	1.0	4.2
2014	1.0	5.2
2015	1.0	6.2
2016	1.0	7.2
2017	1.0	8.2

In the eighth year of implementation, the legislature should review the progress made by the EERS and decide what the EERS targets should be after the tenth year.

The Ohio Department of Development Office of Energy Efficiency (OEE) would be charged with administering a comprehensive set of efficiency programs, and would generate efficiency credits that would be sold to the LSEs for the purpose of complying with the EERS. The revenues from the sales of the efficiency credits would be used to cover the costs incurred by OEE.

The OEE would be responsible for the budgeting, planning and overall administration of the EERS. The OEE could perform these functions itself, or could conduct periodic competitive bidding processes to hire a third party contractor to perform these functions. If the latter approach is taken, the third party contractor should have a minimum term (e.g., three years), with the option for renewal, in order to ensure stability, consistency and long-term perspectives in the energy efficiency planning process.

The distribution companies should be required to purchase from the OEE all efficiency credits necessary to cover their EERS obligation. The other load serving entities should be allowed to implement their own programs or purchase efficiency credits from the OEE.

The EERS should include an alternative compliance payment of $50/MWh.

The EERS target should not be considered a ceiling for energy efficiency savings, it should instead be considered a floor. Electric distribution companies should evaluate the potential for implementing additional cost-effective energy efficiency

programs when conducting their portfolio management and integrated resource planning processes.

The energy efficiency resource standard should be kept separate from the renewable portfolio standard.

Renewable Portfolio Standard

The legislature should establish a set of electric renewable portfolio standard targets that each load serving entity would be required to meet. The RPS targets should be equal to a percentage of each LSE's total retail electric sales.

The Ohio RPS target should be set at 2% of Ohio retail sales in the first year of implementation, and should increase by 2% per year until it reaches 20% after ten years. In the eighth year of implementation, the legislature should review the progress made by the RPS and the renewable energy market in the region and decide whether the RPS target should be held constant at 20% or should increase after the tenth year.

Only new renewable generation sources should be eligible for complying with the Ohio RPS, where new resources are defined as having a commercial operation date after a clearly defined date, such as January 1, 2007.

The following types of renewable generation should be considered eligible for complying with the Ohio RPS:

- Wind energy,
- Energy produced by direct solar radiation.
- Geothermal energy.
- Energy produced from eligible biomass fuels. Eligible biomass fuels are defined in Chapter V.
- Energy from a hydro facility that produces less than twenty MW of electricity and is certified as a low-impact hydropower facility by the low-impact hydro institute.

The following generation sources should not be considered renewable or eligible for the Ohio RPS: nuclear energy, energy produced from any fossil fuel, and waste-to-energy technologies.

If the legislature wishes to include the generation of energy from waste coal or IGCC in the RPS then it could create a separate tier in the RPS target for these purposes. In order to be eligible for the Ohio RPS, the waste coal should be from sources located in Ohio that are no longer producing coal commercially. The waste-coal RPS target should be set for five years duration, and after four years the

legislature should review the progress made in cleaning up waste-coal sites, and determine whether and to what extent the waste-coal RPS tier should continue after the fifth year.

In order to be eligible for the Ohio RPS, any IGCC plant should meet emissions targets set by the PUCO (as well as any applicable environmental regulations) and have provisions for carbon sequestration.

Load-serving entities should be allowed to use renewable energy credits for the purpose of complying with the RPS.

Renewable generation sources located in neighboring states should be eligible for the Ohio RPS–as long as there is a mechanism in place to demonstrate that the renewable generation was sold in one of the power pools that Ohio electric utilities are members of.

The RPS should apply to all entities that sell electricity to retail customers. The RPS should apply to all SSO service, as well as to all retail sales to contestable electricity customers. The RPS should also apply separately to all products sold by each load-serving entity.

Load serving entities should be required to enter into long-term contracts of at least 10-15 years with renewable energy developers for a portion of their RPS requirement.

The RPS should include an alternative compliance payment of $50/MWh.

The RPS target should not be considered a ceiling for renewable resources, it should instead be considered a floor. Electric distribution companies should evaluate the potential for developing additional cost-effective renewable resources when conducting their portfolio management and integrated resource planning processes.

The RPS should require distribution companies to file annual procurement plans with the Public Utilities Commission. These plans should include a detailed description of how each utility intends to comply with the RPS for the forthcoming year.

The RPS should require distribution companies to conduct periodic auctions to identify the best sources of renewable energy and RECs. These auctions should be conducted in conjunction with the portfolio management and integrated resource planning approaches described elsewhere in this report.

The renewable portfolio standard should be kept separate from the energy efficiency resource standard.

Resource Adequacy Planning

The Legislature should give the PUCO the authority and responsibility to determine whether resources will be adequate, on a regional, statewide or utility basis, and in particular transmission-constrained areas, and to take appropriate actions to ensure adequacy, including:

- Increasing utility funding of DSM programs.
- Encouraging distributed generation.
- Ordering utilities to solicit contracts for new supply.

The PUCO and other state agencies should attempt to ensure that the ISOs establish least-cost planning for the relief of transmission constraints, including offering the dollar amounts that would be spent on congestion or transmission investments for other resources that would have the same energy, capacity and/or reliability benefits, including DSM, distributed generation and centralized generation in the constrained area.

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