Strategies for Procuring Residential and Small Commercial Standard Offer Supply in Maine

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Executive Summary

In procuring standard offer electric service, the Maine Public Utilities Commission should strive to strike the appropriate balance between reducing costs and risks, while guaranteeing customers reliable, efficient electric service. This report discusses numerous strategies that could be employed to balance those costs and risks under the general heading of "portfolio management". Most of the strategies could be implemented pursuant to the Commission's current statutory authority; a few may require legislative changes.

Overall, we recommend that the Commission adopt some form of a segmented RFP process for standard offer service for residential and small commercial customers. This is in contrast to the current RFP process that consists of a single point in time bid for the entire residential and small commercial customer class for a particular distribution utility service territory. Other key specific recommendations and findings are as follows:

- The Commission should consider a laddered approach for standard offer supply bids. It should establish a 5 segment ladder with annual maturations for most of the load. The remainder should be reserved for efficiency and long-term contracts with renewables. To begin a 5 segment annual maturation ladder, one needs to start with contracts that mature in 1, 2, 3, 4 and 5 years for segments of the ladder. In subsequent years, one would procure additional contracts with a five year maturation date. Thus, every year, 20% of the ladder expires and 20% of the ladder is newly purchased. Although the transaction costs increase with a laddered approach, the risk management advantages greatly outweigh the higher transaction costs.

- Reducing the current potential for price volatility in standard offer supply bids through portfolio management is unlikely to affect retail competition in the residential and small commercial customer classes. Evidence in Maine and other retail competition states shows that the residential and small commercial customer classes are the least likely to select a competitive supplier, for a variety of reasons. These customer classes are likely to remain on standard offer service for a considerable period of time, and reasonable improvements to the standard offer are unlikely to alter the situation.

- The Commission should consider targeting a portion of standard offer supply through energy efficiency programs and long-term contracts for renewable energy resources. This is a highly desirable portfolio management tool that will help balance the risk inherent in more traditional supply resources (coal, oil, and gas) that are subject to fuel price volatility. Energy efficiency and renewable resources also provide some protection against future environmental compliance costs associated with fossil fuel resources.

- The Commission should evaluate the benefits of separating the RFP processes for standard offer supply and entitlement energy resources. There should also be further evaluation of the statutory prohibition of indexed standard offer bids; allowing a portion of the standard offer supply to fluctuate based on some fuel index may provide significant price benefits to customers. And the Commission should evaluate requiring bidders to adopt hedging instruments.

- The Commission has considerable flexibility under current Maine statutes and Commission Rules to implement most of the portfolio management strategies discussed in this report. One exception is the requirement that standard offer bids must be for a fixed price and a specific prohibition on any “indexing” of standard offer bids. If the Commission were to open a new rulemaking proceeding as a result of the enactment of LD 1929 (see attachment),[1] this prohibition could be revisited.

Additional recommendations and suggestions are contained in the body of this report. Appendix B summarizes our responses to the specific questions contained in the Commissions Notice of Inquiry and Request for Comments issued on March 17, 2004.

[1] The final attachment to this report is the LD 1929 draft amendment that was presented to the Utilities and Energy Committee of the Maine Legislature on April 7. The Committee made several changes to the amendment and unanimously voted out LD 1929 “Ought to Pass as Amended.” As soon as the final amendment is printed, it will be provided as a supplement to this report.

1.0 Introduction to Maine's Standard Offer Procurement Issues

Currently in Maine, residential and small commercial standard offer service for electricity is provided through a three-year contract within both the Central Maine Power Company (CMP) and Bangor Hydro-Electric Company (BHE) service territories. These contracts expire in February 2005. Customers automatically receive standard offer service if they do not otherwise have a retail electric supplier. Standard offer service is the only type of default service in Maine. The process by which standard offer service is procured is determined by Maine's Public Utilities Commission (PUC, Commission). To date, each solicitation the Commission has issued provided for the purchase all of the standard offer power in a single contract expiring on a single day. This single day bid contract approach has resulted in reasonably affordable and generally stable rates. However, such a future result is not guaranteed. And occasional price shocks are a likely result of continued procurement by this method.

In this report, we discuss the principles behind portfolio management practice and offer recommendations on how the State of Maine might procure residential and small commercial standard offer supply in a way that reduces price volatility for customers over the long-run. After this Introduction, Section 2 of the report reviews the benefits of portfolio management. Section 3 is broken down into six subdivisions that discuss:

1. ways that states are currently managing their standard offer and default service programs;
2. portfolio management concepts, including contract types and durations;
3. types of resources used to serve standard offer, including a discussion on all-requirements service, the role of renewables, and fixed price versus price-indexed contracts;
4. Maine's efficiency initiatives and how Maine can reduce customer exposure to risk through efficiency programs;
5. the pros and cons of hedging strategies;
6. the Commission's legal authorities for procuring standard offer electric service for residential and small commercial customers as it relates to portfolio management.

Appendices provide details of how laddering works for one type of portfolio and a question by question response to the Commission's Notice of Inquiry.

Overall, our main conclusion is that those procuring standard offer services should strive to strike the appropriate balance between reducing costs and risks, while guaranteeing customers reliable electric service, through the use of a diversified portfolio of resources.

2.0 Why a Portfolio Management Approach Works

Retail electric competition is currently available in over a dozen states across the US. Originally, legislators and regulators expected that, over time, most customers residing in locations with deregulated electricity markets would switch to competitive generation providers, and that the default services would only be needed as a transitional mechanism, or to serve only a small number of customers. Hence, insufficient attention was paid to the requirements for acquiring resources to provide default services, and the policies associated with default service providers. However, in most states that allow retail competition, the vast majority of customers continue to be served by the default service provider. This is particularly true for residential and small commercial customers. (Alexander 2003) Factors thought to have contributed to this outcome include limited offerings, lack of customer information and customer interest, uncertainties associated with restructured electricity markets, press coverage of poor results of retail competition in some jurisdictions, unclear details of the unbundling of the regulated prices, marketing and business costs for competitive retail suppliers, and transaction costs associated with switching.

It is quite likely that the majority of customers, especially residential, and small commercial customers, will continue to require default services well into the foreseeable future. Portfolio management provides a means for these customers to enjoy some of the benefits offered by the competitive wholesale markets, through the efforts of the portfolio manager who essentially acts as their "broker." Legislators and regulators can play a key role in ensuring that these customers are provided with reliable, low-cost electricity services at stable prices in the near-term and over the long run. (Harrington, et al. 2002) Portfolio management offers the tools and techniques to achieve this important goal.

For example, recent procurement practices, particularly in areas with retail choice, overemphasize relatively short-term contracts. Many default service providers simply establish new generation contracts for short-term power every six or twelve months. This exposes customers (or providers, depending on how each jurisdiction allocates market risk) to costs based on whatever happens to be the state of the market on a particular date each year or half-year, with the forward cost of power very strongly influenced by the level of spot market prices at the time.

If done well, portfolio management will result in lower electricity costs, lower electricity bills, and more stable electricity prices. If, instead, default service providers simply pass through the costs of short-term generation contracts, customers will be subject to higher electricity prices, greater volatility in prices, and greater risks of future cost increases. (Biewald, et al., 2003)

In business and finance, portfolio management is the art of balancing all management skills and resources to achieve optimum strategic, financial, and operational impact across time. As applied to the electricity industry, portfolio management rests on the simple notion that that active participation in electricity markets and careful choices among a variety of electricity products and resources will provide more stable service to customers over both the short- and long-term future. The key benefits of portfolio management include:

- Portfolio management, if done well, will result in lower electricity costs, lower electricity bills, and more stable electricity prices, not only by purchasing more wisely for consumers' needs, but by injecting valuable discipline into wholesale markets.
- Portfolio management offers a way to shift the focus of electric utilities' or default service providers from short-term, market-driven prices to long-term customer costs and customer bills. This shift allows regulators to maintain (or reintroduce) key public policy goals into the critical function of power procurement for the large majority of electricity customers.
- Portfolio management offers regulators a mechanism to promote energy efficiency, build markets for renewable generation, encourage fuel and technology diversity, and achieve environmental objectives.

In sum, portfolio management is not only consistent with competitive markets; it is, in fact, necessary to ensure that competitive wholesale markets are robust. These benefits can and should be delivered to standard offer service customers, but are now being foregone in many jurisdictions, both restructured and traditional.

How to implement a portfolio management approach

Portfolio management requires several key steps on the part of electric utilities or default service providers. Portfolio management begins with the regulators, utilities and other stakeholders identifying the primary objectives that should use in obtaining electricity resources to meet customers' needs. Portfolio managers must prepare load forecasts that represent the best assessment of customer demands for generation, transmission and distribution services for the long-term future.[2] They will then, ideally, assess all the opportunities available for meeting customer demand through cost-effective energy efficiency resources. The next step includes assessing the wide variety of generation-related opportunities, including building power plants, purchasing from the wholesale spot market, purchasing short-term and long-term forward contracts, purchasing derivatives to hedge against risk, developing distributed generation options, building or purchasing renewable resources, and expanding transmission and distribution facilities. Following, one must determine the optimal mix of these resources that will best achieve the defined objectives. A sound portfolio management approach will seek to adopt a variety of resource types to lower costs, reduce risk, and achieve other key objectives. Finally, utilities and default service providers must regularly upgrade and modify their resource portfolios and acquisition plans in order to respond to industry changes over time.

[2] As discussed further below, load forecasting is less important for default service providers and regulators in power procurement if all or a portion of "all requirements" are being bid out, as the bidder assumes the load forecasting risk. However, it can still be important to have a reasonable load expectation if efficiency and long term contracts are to be included in the portfolio.

The remainder of this report focuses on the specific procurement topics that the Maine Commission has set out to be addressed in its inquiry concerning portfolio management residential and small commercial standard offer electricity service.

3.0 Considerations in Implementing a Portfolio Management Strategy

3.1 What Other States Have Tried

Default Service Procurement Processes

The purpose of default service under retail choice is to ensure that if a customer does not choose a specific energy provider or loses that provider, the customer will automatically receive electricity from the default service provider. Default service has various names in various states, including standard offer service, provider of last resort service, default service, etc. Under any name, it is a challenging task to provide good retail electric service in a deregulated market due the following: volatile wholesale market prices, fuel supply risks, market power risks, uncertainty about environmental impacts and regulations, bankruptcy filings by major players, and the possibility of customer switching between default and competitive suppliers.

States have gone about procuring electricity for their default customers using several different methods. In some retail choice states, default service is procured under contracts with competitive providers who bid for the job using an RFP type process. In other states, former incumbents are mandated to provide default service from their owned resources or competitively acquired contracts. The durations of such contracts vary between states. Other contract variables include length and price of the contract, fuel (e.g., renewable vs. coal.), compensation, and cost recovery arrangements. For example, in Rhode Island, default service is competitively bid in 6-month increments, while in New Jersey, auctions are held annually. See Table 3.1.1.

Table 3.1.1: Default Term in Various States. (Besser 2003) (Alexander 2002) (Alexander 2003)

State	Default Term End Date	Procurement Rules for Default Service	Renewable Rules
Connecticut	2007	Contracts procured in overlapping pattern of fixed periods. The contracts must be for terms of not less than 6 months, unless shorter terms are justified.	Renewable energy portfolio requirement is applicable to the Standard Offer, but the timetable for the minimum % renewables is extended.
Maryland	Various	Utilities must attempt to obtain 1, 2, and 3 year contracts with 50% of load served through a 1-year contract.	
New Jersey	2006	Fixed price lasting 34 months for 1/3 of supply; Fixed price lasting 10 months for 2/3 of load. Single annual auction date.	
Rhode Island	2009	6 month increments	
Massachusetts	2005	50% of load is procured semiannually for 12-month terms.	No minimum standards; no requirement to enter into long-term contracts with renewable resources.
Pennsylvania	Various		20% of customers assigned to suppliers offering service with a renewable energy component of at least 5%.
Washington, DC	2006	Recommended to utilities that contract mix should include contracts of at least 3 years for no less than 40% of the total load	None

Because electricity prices have been regulated for most of the last century, price risk management is relatively new for this market. Recent procurement practices, particularly in areas with retail choice, overemphasize relatively short-term contracts. This exposes customers (or providers, depending on how each jurisdiction allocates market risk) to costs based on whatever happens to be the state of the market on a particular date each year or half-year when contracts are renegotiated. The result is that the forward cost of power that forms the basis for the price of default service is highly influenced by the spot market prices at the somewhat arbitrary negotiation date.

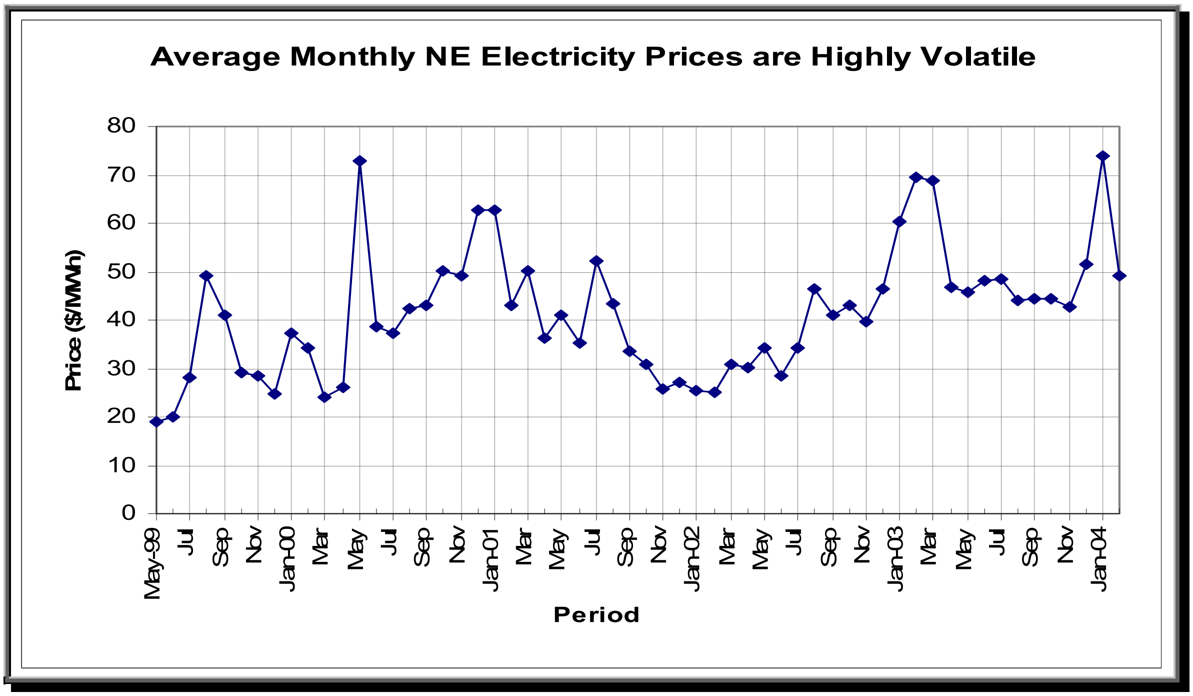

Figure 3.1.1: Wholesale Electricity Prices in New England. (ISO-NE 2004)

For example, the wholesale electricity prices in New England have fluctuated dramatically in recent years, as indicated in Figure 3.1.1. If a default service provider in Maine were to purchase all of its generation through a short-term contract at the time of one of the peaks in wholesale prices, then its customers would end up paying considerably more for electricity than necessary. While the opposite outcome is also possible, the resulting volatility is undesirable from the consumer's perspective. In addition, the price risk may be asymmetric in that the potential for price increases and the consequences of large increases can be greater than the potential for and consequences of price decreases. Consider for example, the experience the last few years in the Western power markets, with its prolonged period of greatly inflated prices and the associated economic consequences to the region.

In recent years, it has been shown that those states relying upon short-term wholesale market prices for default services have experienced higher costs and greater price volatility than other states that have used a competitive bid approach to procuring default services. Some states, like Maine, have been lucky – having procured contracts at points in time when wholesale electricity prices were relatively low. But luck is never guaranteed. Portfolio management, including a mix of contract types and durations, offers a technique to hedge against uncertain costs and price volatility in restructured markets.

IRP Practices

For those states that have yet to undergo competitive restructuring of retail service, portfolio management practices are still prevalent. Many states have developed Integrated Resource Plan (IRP) requirements to protect market participants from spot market price volatility (among many other purposes). IRPs are used to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes.

Montana, though restructured, utilizes an IRP-type approach for default service that may have some relevance to Maine's situation. Montana follows rules that require the default supply utilities to "plan and manage its resource portfolio in order to provide adequate, reliable and efficient annual and long-term default electricity supply services at the lowest total cost." [Rule V (38.5.8209)] While green or renewable energy products can be offered, Montana does not make this a requirement. The default supply utilities are, however, required to use a portfolio approach to acquiring supply. This includes negotiating contracts of at least 10 years. In addition, demand-side management must be considered as part of the portfolio. Most interesting, perhaps, is that in Montana default supply service must be provided for a lengthy transition period that does not end until July 1, 2027, thus ensuring a long planning and acquisition horizon. To the extent that Maine can incorporate elements of this approach to default service provision, there will be opportunities to manage cost and risk for default service customers.

Table 3.1.2: Sample of IRP Programs.[3]

State	Initiation of IRP (year)	Filed how often?
Georgia	1991	Must file every 3 years
Oregon	1989	Must file every 2-3 years
Utah	1992	Must file every 2 years
Idaho		Must file every 2 years
Montana	1992	Must file every 2 years for traditional utilities. Restructured utilities must file three-year action plans on an annual basis. PSC has not yet established frequency for filing comprehensive long-term plans.
Vermont	1991	Must file every 3 years

[3] http://www.nwppc.org/energy/powersupply/adequacyforum/2003_0528/irprequirements.pdf

Best Practices in Default Service Procurement

In short, states have been exploring and experimenting with how to procure electricity for default service customers. We have identified certain best practices that, in combination, may be expected to produce a well-balanced portfolio:

- Use of laddered contracts, such as in Connecticut.
- Inclusion of a reasonable percentage of long-term contracts, such as in Washington, DC.
- Use of demand side management programs to reduce exposure to market risks, such as in Montana
- Inclusion of long term, fixed price contracts for renewables to reduce exposure to fossil fuel prices and environmental risks, such as in Pennsylvania
- Establishment of a long transition period to ensure a long planning and acquisition horizon, such as in Montana.

A number of states have adopted or are moving towards adopting a portfolio management approach, either for integrated utility service or default service. In the following sections, we explore why those responsible for default service procurement should consider a range of contracts and resource types.

3.2 Varied Types of Contracts and Varied Contract Durations

Diversification

A basic tenet of financial management is that a diverse portfolio is less risky than any single investment. The same is true for commitments for commodity supply, such as electricity. Because prices of different investments are not perfectly correlated, a decline in the value of one investment is often offset by a rise in the price of the other. By applying this notion to power supply and efficiency alternatives, we can take advantage of similar variations. Each technology and resource options has its own cost structure and economic drivers. Gas generation has moderate capital costs, but significant fuel costs driven by natural gas prices. Wind energy has high capital costs, but is insensitive to fuel prices. By combining generation options and technologies in appropriate proportions, we can get a mix with a lower, more stable cost than by relying on anyone type alone. (Awerbuch 2000)

Perhaps more important for Maine is a similar rationale that applies to diversifying contractual instruments used when soliciting and approving bids for power. A strategy that relies on market price bids at a single point in time may be diversified by laddering, a technique discussed below. But a strategy that relies solely on market-based bids, even if laddered, remains vulnerable to systematic risks that affect the market clearing price and the ability of market participants to physically deliver and to withstand financially adverse market fluctuations. Selecting some portion of a power portfolio from resources that are not tied to those uncertainties, such as long-term renewable unit contracts, energy efficiency, or derivatives in non-electric markets (e.g., weather or natural gas derivatives) can materially limit the long-term risk of the strategy as a whole. After reviewing some key concepts in diversification, we will explore these particular types of diversification further.

Each individual asset, whether an investment or a generation alternative, has two main sources of risk. The first is *unique risk*, which results from events that are specific to an individual investment or resource. For common stocks, unique factors are those that affect a particular company or sector, such as a mistake or a disaster affecting the company's production or a broader disaster affecting supply of a particular commodity essential to the sector. For generation resources, unique risks include a failure at a specific plant and unexpected regulatory costs affecting a technology. For wholesale power contracts, counter-party risk is an example of unique risk.

The other type of risk is *systematic risk*, such as risks due to macroeconomic factors that threaten all investments or power supplies equally. (Culp 2001, 26) With respect to the stock market, these risks include changes in interest rates, exchange rates, real gross national product, inflation, and so on, which affect the price of stock for all companies or all sectors in roughly the same manner. For generation assets, oil and gas shortages or price spikes are examples; recessions or booms that change the demand-supply balance are also types of systematic or market risks. Forward contracts for electricity are, individually and on their face, not exposed to the same systematic risks as specific generation assets, but they do face default risk if those same factors suffer extreme excursions. In addition, the entire strategy of relying on wholesale contracts exposes the portfolio to those same uncertainties, since forward contracts must be renewed at regular intervals.

Equity portfolio managers maintain diversity by investing in a wide range of different companies in different industries. While there are sector-specific investment funds, these are recognized as riskier than broad-market funds that eliminate unique industry risks through diversification. The manager of an electric resource portfolio can diversify by relying on a variety of different power plants using different fuels and technologies, by using firm power contracts of varying durations and starting dates, and by acquiring a mix of supply- and demand-side resources.

The "take-home message" from the financial markets is that diversification reduces undesirable risks or volatility in prices. The unique part of the uncertainty in any individual investment is diversified away when that investment is grouped with others into a portfolio of different investment types and durations. The systematic part of the uncertainty in a given type of investment may be diversified away when investments of totally different types are combined, such as a combined portfolio of efficiency, unit shares in renewables, and forward contracts for commodity power. Overall, diversification gives the portfolio manager more flexibility and protection from unknowns. A well-managed portfolio will draw from both demand- and supply-side resources, as well as a mix of short-term, medium-term, and long-term contracts to ensure price protection over time. In addition, if there is owned generation in the portfolio, risk protection will be further enhanced by applying the same portfolio management approaches to fuel acquisition, a technique long practiced in that part of the utility industry.

Procurement Options

A well-managed commodity portfolio is usually a combination of a variety of traditional procurement contracts, such as long-term contracts, options and flexibility contracts, and some reliance on spot markets. Each of these resources, listed below, has its own pluses and minuses, but in combination they can greatly reduce risk.

- *Spot purchases* involve paying market price on the day that the commodity is needed. Spot market pricing can be quite volatile, but requires no commitments. Spot market reliance protects against both falling demand and falling prices, but exposes the portfolio to risks from rising demand or prices. Spot purchases for electricity are commonplace.
- *Forward contracts* are agreements between buyers and suppliers to trade a specific amount of a commodity at a pre-agreed upon price at a given time or times.[4] Payment is on the delivery date. Forward contracts avoid exposure to spot market volatility, but accept the risk that market prices may fall, that the counter-party may default, and that demand may fall. Forward contracts for electricity are common.
- In an *option contract*, the buyer prepays a (relatively) small *option fee* up front in return for a commitment from the supplier to reserve a certain quantity of the good for the buyer at a pre-negotiated price called the "strike price." The cost of the option may increase the total price compared to the price (offered at *that time*) of a long-term contract, but one does not need to commit to buying a specific quantity. Typically, the option is *exercised* only when the spot price (on the date of need) exceeds the strike price of the option. Option contracts for electricity remain uncommon.
- A *flexibility contract* is like a forward contract, but the amount to be delivered and paid for can differ based on a formula, but by no more than a given percentage determined upon signing the contract. Flexibility contracts are equivalent to a combination of a long-term contract plus an option contract. (Simchi-Leve 2002).
- Any contract may be *indexed*, although most commonly this applies to forward contracts. An indexed contract has fixed quantities, but the price is determined in whole or in part by a formula involving some agreed on outside factor, such as the market price of a fuel or an inflation index. They pass some or all of the price volatility through from the seller to the buyer.

Procurement managers need to find the optimal trade-off between price and flexibility by an appropriate mix of low price, low flexibility (long-term contracts,) reasonable price but better flexibility (option contracts) or unknown price and supply but no commitment (the spot market.) Varying durations as well as contract types can help.

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[4] The term or time period of a forward contract can be of whatever length the parties choose and often begins sometime in the future. For example, power contract can be for one month, one year or for the life of a generator and may start immediately on signature, the next month, or one or more years into the future. Forward contracts for less than one year are often called "short-term" contracts, but they are still referred to as "long," as opposed to "spot" purchases.

Laddering Theory

Forward contracts have been the norm for default service procurement. A portfolio made up of only forward contracts can be diversified to reduce risk using a laddering approach. Like a board of directors whose terms are staggered so that a certain fraction expire each year to ensure turnover yet benefit from continuity of management, a portfolio of power supply contracts can be structured so that a modest fraction of the portfolio turns over each year. This laddered approach eliminates both the risk that one will choose a "bad" time to lock in a price for one's entire portfolio and the risk of having to go to market for all of that portfolio in a less than ideal economic environment when a single contract expires. This technique is similar to laddering of bond portfolios for investors; a detailed example of that method can be found in the Appendix to this report. As explained below, it is possible to ladder acquisitions of power for a fluctuating load, such as default service loads, in several ways.

Laddering Recommendations for Standard Offer Electric Service

As discussed above, acquiring needed supplies of power in laddered segments reduces volatility and risk exposure in the absence of foreknowledge of future price trends. While there is no *a priori* rule for determining the "best" approach to segmentation and laddering, practical considerations may be taken into account, and virtually any degree of diversification via laddering will be beneficial.

Planning the segmenting of resource acquisitions for laddering involves selecting the *duration of segment contracts* to be acquired, the *number of segment contracts* in the ladder (that is, the fraction of expected need to be acquired each time a segment from the ladder matures), and the *frequency of segment maturation*, i.e., the time interval between acquiring segments. Note that for a simple, uniform ladder, picking any two of these determines the third. If a ladder is being established from scratch, all but one of the segments initially acquired will be shorter than the target duration. Each of these traits needs to be established in a reasonable manner, but they may also be altered over time as circumstances change, another advantage of laddering.

While the following discussion treats the load to be served as if it were constant over the year, it will be necessary for the Commission to address the seasonal and diurnal variations and fluctuations of default service. For example, if bids are solicited for segments that are to serve specified fractions of the "all requirements" standard offer load (whatever it turns out to be), the vendors assume the task of managing those fluctuations, and the following discussion applies as is. If bids are to be considered for set amounts of energy or capacity, the Commission will need to address the issue of load fluctuation by designing its acquisitions to include appropriate amounts of peak and off-peak power in each month, a more complex task. Even then, some load-following resource will be needed. Therefore, except for whatever portion of the need the Commission considers meeting through efficiency and long-term renewable purchases, it would seem most reasonable to solicit bids for segments that represent certain fractions of the "all requirements" load. Alternatively, it *may* be possible to address fluctuating load directly. For example, if the Commission decided there should be five segments in its ladder, it could acquire four that are for fixed amounts and one contract to serve the residual that fluctuates. Or the Commission could approve acquisition of five fixed segments and address fluctuating load through the spot market purchases and sales (the norm in most industries) or a combination of option purchase and sale contracts.

Frequency of Adding to the Ladder

Laddered segments can be spaced annually, semi-annually, quarterly, monthly or at multi-year intervals. Transaction costs increase substantially for shorter intervals, but laddering with fewer, longer intervals provides less risk diversification. Current electricity commodity markets enable ladder segments to be spaced as closely as monthly, but given the procedures for solicitations by the Commission, it would be reasonable to ladder the Commission's acquisitions at annual intervals.

The duration of segments in a laddered portfolio influences the price paid for each segment. Wholesale electricity markets are relatively immature, with fewer derivatives available for hedging positions, so commodity market purchases will likely need to be of no more than modest length, at least for a while. Longer forward contracts are often available bilaterally or in bid solicitations, but are usually indexed unless tied to underlying renewable generators. To the extent acquisitions will be from commodity markets or from bilateral contracts with traders backed by such markets, a ladder composed of contracts between one and five years in length would be a reasonable starting position.

Fixed Price versus Indexed Ladder

As discussed above, it is reasonable to expect that the term structure (premium charged for longer term contracts) would be smaller for resource contracts indexed to fuel prices, inflation or some other indicator or indicators than for fixed price contracts, especially at longer terms. Whether continuing past practices or engaging in diversification through, say, laddering, the Commission should expect to receive bids that would result in lower *expected* prices for standard offer service than without indexing. This would come at the expense of retaining for standard offer customers some degree of price volatility. If only a portion of the portfolio were selected from indexed contracts, that volatility would be less, as would the expected savings.

The expected price-volatility trade off is inherently a question of preferences that are hard to measure for someone else, but it should be possible to monetize the increased risk by determining the market cost of hedges against some or all of that volatility. If the offer were indexed to natural gas prices at Henry Hub (a common choice), the appropriate hedge would be the corresponding derivative. To set benchmark volatility, it might be reasonable to try to keep standard offer price volatility at or below the level of historic volatility in Maine's retail electric prices during the twenty years preceding retail competition in Maine. If that were deemed suitable, any indexed contracts could be evaluated by adding to the offered price the cost of the derivatives necessary to collar the contract price inside a band of the same width as the historical retail electric price volatility. Naturally, if this approach is adopted, it would make sense to adjust the price of fixed price offers by the revenue that could be obtained by selling the opposite hedges. (If the auction market encountered is efficient, the difference should be mainly transaction costs. If not, the Commission would have strong guidance about the best offers before it!)

By Commission Rule, Maine requires that default service be priced at a fixed level for customers during "the standard offer period" and provides that the default service price may not, itself, be indexed. Ch. 301, Sec. 7(A)(2). Therefore, if any indexed source contracts or spot market resources are to be considered for inclusion in the default service portfolio, that uncertainty must be fully hedged.[5] It may be possible to do so using appropriate derivatives and option contracts. However, if major portions of the default service supply portfolio were to be indexed, the cost of purchasing hedges sufficiently tight to assure *no* fluctuation in default service would likely be prohibitive.

Ladder Segment Size

For a given load to be served, a larger number of segments in the ladder may also affect the prices offered due to economies of scale and institutional factors. It would probably be wise to ensure that segments are at least the size of standard commodity market products, as dealing with such fractional products can be expensive. In addition, some bidders may prefer very large lots, but any apparent savings would bring with it a reduction in diversity and increased risk. Also, concentrating purchases with only one or two vendors increases counter-party risks. Since the standard offer load in Maine is about 9% of the total New England market, it seems reasonable for the Commission to proceed with acquisition of a laddered portfolio with a reasonable number of segments. (If, as is likely, bids are in the form of bilateral contracts from generation owners, this will be even less of an issue.) If actual bids received seem out of line with expectations or comparable market or bilateral transactions, the Commission could reconsider the number of segments.

Ladder Segment Duration

Thus, even if soliciting only from commodity markets or vendors relying on those markets, it would be reasonable for the Commission to seek bids for a five segment ladder with annual maturations, each segment for 20% of the current load. (If this results in segment sizes that are "odd," the percentages could be changed; there is no magic in having them be identical fractions of the load.) One segment would be for a one-year term, one for a two-year term, and so on up to a five-year term. If load grows during the first year, the segment expiring after that year (the one with a term of one year), could be replaced by a larger five year segment expiring at the end of year six. Or, if shopping percentages begin to rise during the first year, a smaller segment could replace the first segment. If load uncertainty increases materially, expiring segments could be replaced by a complete "sub"-ladder to further mitigate risk. As discussed earlier, segments that are

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[5] The Commission may consider revising these restrictions in order to enhance the opportunities for portfolio management of default service. It could do so in the context of any major and substantive rulemaking proceeding necessitated by enactment of LD 1929, which appears to require the Commission to consider "an effective hedging strategy" in conjunction with incorporation of renewable resources in the Standard Offer.

for a fraction of the "all requirements load" make this simpler, while segments of fixed size would require some supplementary mechanism to address fluctuations in load.[6] For a diagram and example of this approach, see the Appendix on laddering.

It would be helpful if the Commission had and retained the discretion to alter acquisition dates for replenishing a segment in its laddered portfolio, perhaps by briefly relying on short term purchases, if it found at some maturation dates that longer term contracts are more expensive than short term ones by unusual amounts. Or the Commission might receive an especially attractive offer for an odd period or starting at a date other than its intended or usual maturation date. This might occur if a vendor has resources that will come on line at certain dates, for example.

The above suggestions (a five segment, five year initial ladder with flexibility at each maturation date) are reasonable, but the final decision on ladder structure should be reserved until bids are received. At that time the term structure of the bids actually received, information from futures markets, current load forecasts, the state of switching, and other factors should be considered in making final choices. Furthermore, the Commission should solicit and seriously consider longer term bids from renewable generators and efficiency providers. While these resources may entail some business or technology risks, they avoid fuel price risk, enabling vendors to make offers for longer, fixed price contracts. The Commission should retain the discretion to acquire a reasonable fraction of its expected needs from such resources rather than from commodity markets and commodity vendors.

Laddering and Competition

In theory, the more default service is managed to eliminate risk, the less customers are going to be exposed to spikes in electricity prices over time. Again, in theory, this might discourage customers from switching to competitive retailers. However, switching statistics provided by the Maine Office of Public Advocate show that switching in Maine is insignificant in the residential/small commercial sector. The exception has been in Northern Maine, in Maine Public Service's territory, where there appears to be some meaningful competition between Energy Atlantic and WPS Energy Services.

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[6] The Commission has specifically inquired about how to handle “all requirements” service with respect to standard offer procurement. We understand “all requirements” service to mean one of two possible requirements. First, “all requirements” offers might mean bids to supply a specific fraction of the standard offer load, whatever that may turn out to be. Under such a requirement, bidders assume the risk of load changes. This version of “all requirements” service was discussed above.

Second, “all requirements” might mean a requirement to provide not only energy and capacity, but ancillary services as well. Ancillary services are typically a small fraction of the cost of energy and capacity, should remain so or even shrink as the markets for them mature, and could be quite complicated for some other bidder to manage separately. We recommend the Commission require bidders to provide all ancillary services necessary to meet whatever standard offer load the bidder is serving.

Table 3.2.1: Switching in Maine in the Residential/Small Commercial sector is insignificant. (Maine Public Advocate Office 2004)

Percentage of Customer Load (kWh) served by a provider other than the Standard Offer Provider (as of 02/29/04)				
	Residential/Small Commercial	**Medium Commercial**	**Large Commercial**	**Total**
Central Maine Power	**0.29**	**34.92**	**85.95**	**35.48**
Bangor Hydro-Electric	**0.61**	**25.51**	**49.43**	**14.21**
Maine Public Service	**13.2**	**76.8**	**98.8**	**49.7**

It is difficult to anticipate and assess all the possible effects that portfolio management of Maine's standard offer resources would actually have on the prospects for retail competition in Maine's residential and commercial sectors. However, on balance, we believe that the effects are likely to be positive. It might be argued that retail competition may best be encouraged by making standard offer service unattractive—costly and volatile. While it seems unlikely that this was the intent of establishing standard offer service in Maine, this is a shortsighted argument. But whatever the price or volatility of the standard offer service, overseen by the full power of the Commission, consumers are unlikely to trust competitive suppliers unless they provide a substantially better combination of price and security. Competitive suppliers will provide the best price and service only if they must do so to win customers from standard offer service. Setting a reasonable standard of price and stability for standard offer service will encourage competitive suppliers to be more attractive. (No one should think that a properly managed resource portfolio of standard offer service would grossly undercut well-managed competitive suppliers, especially those who operate on a national scale.) In addition, as Maine and, we hope, other states establish reasonable portfolio management for standard offer service (and its counterparts in other states), markets will be come more stable, enabling competitive suppliers to function with less risk and lower costs. Also, if states create a demand for more flexible trading instruments to enhance their portfolios, competitive suppliers will benefit from those developments.

Contracts and Energy Entitlements:

The Commission is concerned about how to treat bids to purchase utility legacy capacity and energy entitlements if it solicits a diversified portfolio of resources for standard offer service. It is our understanding that pursuant to Maine law, CMP and Maine's other investor-owned electric utilities have divested much of their generation assets and must sell by periodic auction any remaining contractual entitlements to capacity and energy they hold, for example, with Qualifying Facilities. We also understand that, to date, those periodic auctions of legacy entitlements have actually taken the form of a linked or bundled transaction where the standard offer bidders condition their standard offer bid on Commission acceptance of their legacy entitlements bid.

If the Commission decides to solicit diversified portfolio components, such as a portfolio of laddered segments, *and* wishes to continue to allow linked disposal of legacy entitlements, it would be reasonable and convenient to specify that bidders must quote a price for segments that reflects taking a corresponding pro rata share of the legacy entitlements. The most important advantage of that approach is that potential bidders would know with specificity what their obligation is regarding legacy entitlements. However, a wider variety of beneficial bids may be elicited if this linkage is dissolved. The main reason for this is that it could bring in an entire new class of bidders—entities with power to offer, but without the ability or interest to acquire additional must take, non-dispatchable power. Conversely, there may be entities with a need for power, such as Load Serving Entities (LSEs), who do not have power to offer the Commission; unlinking procurement and disposal of legacy entitlements would allow such entities to compete for the legacy entitlements. To open up its solicitation to these potential new entities, the Commission should consider soliciting bids to *take* legacy entitlement power entirely separately from soliciting bids to *deliver* standard offer power. In addition, separating these sales and purchases would make their respective values more transparent, potentially improving the Commission's ability to make sound decisions.

In connection with offering legacy entitlements for sale, it is worth noting that selling, like buying, entails uncertainties. For example, there are potential counter-party risks and price volatility risks. If a sale takes place at a time of low market prices, the Commission would be worse off selling all the power at once, and vice versa. The good news is that sales may be treated as a portfolio, just like purchases. The Commission could, for instance, set a laddered portfolio of legacy entitlement sale contracts, keep a portion to sell on the spot market (statute permitting), and so on. The Commission should consider these possibilities, especially if it is going to consider unlinking the sale of legacy entitlements from the purchase of standard offer power.

3.3 Sources of Supply should be Diverse

Supply Sources should address Fuel Supply Risks

The Commission, in considering approaches to portfolio management for standard offer service, should take into account not only risk mitigation obtainable by diversifying commodity contract types and durations, but also diversification of the ultimate physical underpinnings of the contracts it acquires. Commodity contracts and spot prices in New England are largely determined by (1) supply/demand balance and (2) fossil fuel prices on the margin, typically natural gas prices. Laddering generic commodity purchases, as discussed above, can manage random fluctuations of these two factors, but underlying trends can best be addressed by considering placing some of the portfolio in resources whose prices do not depend on fossil fuel prices.[7] To maximize these benefits and to begin addressing long-term uncertainties in those factors, the Commission should seek to acquire very long term, probably life of unit contracts, for a portion of the portfolio that is devoted to renewable resources.

To explain further, note that different types of fuels are subject to different risks in terms of both price and availability. For example, while coal is a domestic and abundant fuel, it has in the past been subject to regional disruptions due to labor disputes, which drove prices upward. Similarly, certain technologies can be subject to industry-wide reliability issues. For instance, after the Three Mile Island nuclear accident, most nuclear power plants in the country were shut down for extended periods for safety upgrades. And then of course, there are supply shortage issues, such as those forecasted for natural gas.

> Average U.S. peak electricity prices are expected to rise 48 percent in 2003 from the previous year, mostly the result of a surge in natural gas prices… We do not forecast a return to normal supply- demand balance… before 2008. (UBS 2003)

A state and region's reliance on a given supply resource should be examined with respect to the larger picture of demand forecasts. Increasingly, many regions of the U.S. are relying on natural gas to generate electricity. As a result, wholesale electricity prices are directly linked to natural gas prices, which have been highly volatile in recent years relative to other fuels. While the resource base for natural gas remains large, increased production will require massive investments and time. For instance, in Atlantic Canada, major new supply is unlikely to materialize before the end of 2008. It is anticipated that such investments will be linked to higher commodity prices, increased price volatility, and larger trading volumes. Thus, it seems gas price volatility and, hence, electricity price volatility are here to stay, at least until new gas supplies are commercialized in future years. (Levitan & Associates, Inc. 2003)

In the New England region, use of gas as a fuel source for electricity has been increasing markedly. In 1999, gas-fired generation represented 16% of all electricity in the region. In 2003, this number increased to 41%. It is expected that use of natural gas to generate electricity will total 49% in New England by 2010. Other than the state of Texas, New England is the most gas-dependent region in North America for power generation. Interestingly, gas-fired units set over 50% of all electricity prices in New England. (ISO-NE 2003) As indicated in Figure 3.1.1 natural gas prices have been highly volatile in recent years, and are have been much more volatile than other fuels such as coal or fuel oil.

[7] In theory, similar protection could be obtained by purchasing fossil fuel price derivatives. However, the lifetimes of those derivatives in today's markets are not much longer than those of fixed price electricity contracts and the ability of brokers to deliver on them under extreme conditions may be questioned.

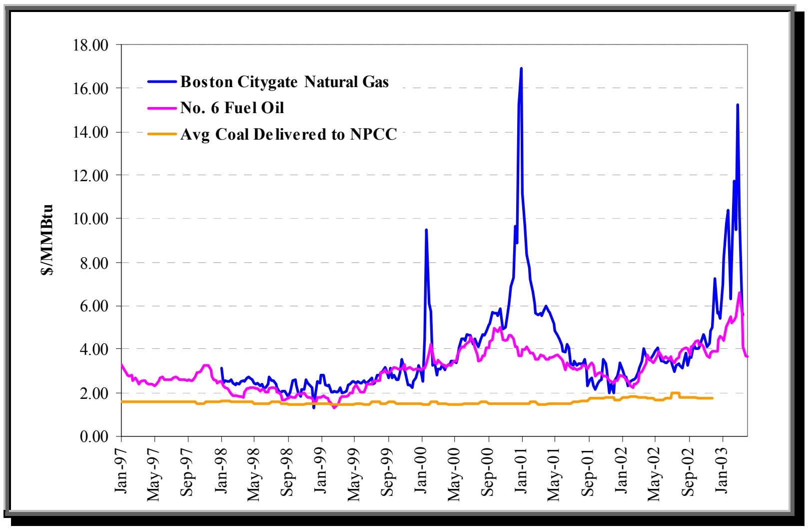

Figure 3.3.1 Comparative Fuel Costs Delivered to New England.
Source: ISO New England, 2003

This illustrates the fact that heavy reliance on one or two supply resource fuels or technologies is risky both from a reliability and price perspective and can only be mitigated so far by laddering. One way to mitigate this risk is to incorporate renewables into default service supply procurement rules. This does not imply that it is necessary to procure a green-only product. It does mean, however, that renewable resources should be utilized across all default service products to hedge against wholesale price and fuel related volatility.

Maine's default service already includes the nation's largest renewable portfolio standard (RPS), requiring no less than 30% of an electric provider's supply sources to be from renewable resources. Commission Rules Ch. 311, Sec. 3(B)(3). This requirement helps ensure an adequate and reliable supply of electricity and encourages use of renewable and indigenous resources.[8] Thus, Maine has a large amount of renewable use already and is only 10% reliant on natural gas in terms of its direct entitlements. However, this does not eliminate the issue for Maine default service provision. Under the current approach to acquiring default service contracts, those renewables are effectively repriced at levels determined by market rates each time a solicitation is held, because vendors can easily sell to the market. So, while the fact that Maine's RPS applies to default service supports the renewable industry, Maine's default service customers have lost much or all of the relevant risk mitigation benefits. The default service providers have their risks mitigated, instead. Thus, the Commission should consider allocating a portion of the default service portfolio to long-term, physical resource-based renewable contracts over and above the RPS to recapture those risk mitigation benefits for default service customers.

In addition, further increases to the renewable generation fleet in the region will benefit

[8] Maine also currently derives approximately 50% of its electricity from renewables: 17% from hydropower, 25% from biomass, and the rest from municipal waste-to-energy plants.

default service customers and, indeed, all electricity consumers. In particular, those renewables that operate during peak demand periods are especially powerful at reducing price and reliability risks for both recipients of the power, for the market as a whole, and for all end-users.

For example, photovoltaics will generate the most electricity during midday in the summer season - just when electric load and price is highest for most regions. The importance of peak load shaving is well known, but the value of photovoltaics in reducing load in peak electricity demand periods is frequently overlooked. A recent study analyzed the market price of electricity in the PJM region in order to determine the value of generic load reduction. (Marcus and Ruszovan 2002) The estimated value of PV load reduction during the on-peak hours during that summer season was over 27 cents/kWh in the PJM (4.8 times the corresponding market price estimate) and roughly 8.1 cents/kWh during summer mid-peak hours. PV's summer on-peak load reduction value may very well be equal to or exceed the levelized cost of electricity from the panel. This effect is thought to be especially pronounced in unhedged markets.

Wind power is another interesting example. It is, of course, intermittent, but does add to system reliability, particularly when pooled across a control region with diverse wind regimes. Simulations applying traditional measurement techniques to wind (30% availability) show that they add as much to system reliability as their capacity factor multiplied by their capacity (i.e., 100 MW of wind, with a 30% capacity factor makes the same contribution to system reliability as 33 MW of combustion turbine with a 10% forced outage rate). (Lazar 1993; Bernow, et al., 1994)

Supply Sources Should Address Environmental Regulatory Risks

Yet another reason to incorporate renewables into a supply portfolio is to hedge against future environmental regulatory costs. Compliance with federal and state environmental regulations can be costly. And there is considerable uncertainty about the type and extent of environmental regulations that may be imposed in the near- to long-term future. While it is difficult for utilities and default service providers to predict the full impact of future environmental regulations, planning for such uncertainties and hedging against those risks is feasible and vital.

Quantifying Risks of Environmental Regulation

PacifiCorp has estimated that the cost of meeting present, pending and future SO_2, NO_x, and Hg regulations will be substantial, with related after-tax O&M, A&G and capital expenditures through 2025 ranging between $500 million to $1.7 billion (NPV). The lower figure represents an SO_2 scrubber and low NO_x burners scenario. The higher amount represents full controls (SO_2 scrubbers, Selective Catalytic Reduction controls for NO_x, and bag houses with activated carbon injection for mercury). (PacifiCorp 2003)

Utilities and wholesale vendors of electricity already must comply with sulfur dioxide (SO_2) and nitrous oxides (NO_x) emission requirements; most recognize that CO_2 regulation in some form is highly likely. Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level, the most important being President Bush's Clear Skies Act/Global Climate Change Initiatives.

To protect themselves against the risk of such future regulations, sellers can diversify by investing in generating assets with a mix of emissions profiles. For example, they might acquire or build wind farms or convert from coal to gas-fired plants, rounding out their portfolio to include more environmental- and regulation-friendly assets. Portfolio management offers regulators, utilities and default service providers the tools necessary to develop a diverse set of electricity resources that would benefit default service customers in the same manner.

Recommendations for Maine

Maine should require a diverse resource and technology supply set for procuring electric default service.

3.4 Efficiency is a Risk Management Tool

Energy efficiency and demand-side management programs, like renewables, provide significant hedging value against environmental cost and reliability risks. Demand-side hedging programs are by no means unique to the electric industry. Liability insurers not only hedge their payout risks by re-insuring those risks, but engage in both customer specific education and technical assistance and generic programs (such as establishing the Underwriters' Laboratory) to reduce those payouts. Airlines and cellular communications companies engage in peak shaving rate designs, as do many restaurants (in the guise of early bird discounts).

Energy efficiency measures reduce customer demand and can cost, over their lifetimes, significantly less than generating, transmitting and distributing electricity. Energy efficiency programs offer enormous opportunities for lowering system-wide electricity costs and reducing customers' electricity bills. They also offer other important benefits in terms of reducing risk, improving reliability, mitigating peak demands, mitigating environmental impacts, and promoting economic development. Despite widespread scaling back of utility energy efficiency programs during the 1990s, the primary rationale for implementing energy efficiency programs – to reduce electricity costs and lower customer bills – is just as relevant in today's electricity industry as it has been in the past. Consequently, energy efficiency is an important resource, because it can (a) lower electricity costs and customers' bill, and (b) reduce the amount of generation needed to be obtained from the market.

Some states have established a system benefits charge (SBC). A fixed charge is collected from all distribution customers to provide stable base funding for energy efficiency activities and to address some of the concerns created by restructuring. However, SBCs in place today fall far short of capturing the full potential for cost-effective energy efficiency to meet the future needs of the system and consumers. Consequently, portfolio management should be used to identify and implement additional energy efficiency beyond that which is implemented through SBCs. In general, efficiency programs should be implemented if their total life-cycle costs are lower than those of comparable generation, transmission and distribution facilities.

Maine does have energy efficiency funding through system benefits charges. The program is called Efficiency Maine, and it is funded by electricity consumers and administered by the Maine PUC. These initiatives do help reduce customer's exposure to electric price volatility. Currently, the SBC funding for energy efficiency in Maine is equal to 1.5 mils per kWh and 1.5% of revenue or $17.2 million per year. Other states, such as Massachusetts, have been able to do more. There, the SBC funding for energy efficiency represents 2.5% of revenue. (ACEEE 2003)

Maine can and should be doing more demand-reduction initiatives – above and beyond what the current system benefits charge (SBC) allows it to do. Additional efficiency could be implemented either (a) through Efficiency Maine, or (b) through energy service companies that provide bids for efficiency services and savings. It would not make sense to set up another entity to implement additional efficiency programs. In Maine, the simplest source of funding for such programs would be an additional charge on the distribution companies' bill, i.e., a temporary supplement to the SBC to finance targeted increases in efficiency investments identified by Efficiency Maine or energy services companies. Such initiatives would help reduce price volatility for Maine consumers year after year.

3.5 Hedging Pros and Cons

Financial Derivatives

A *hedge* is an investment made in order to reduce the risk of adverse price movements by taking an offsetting position in a related security or commodity. In simpler terms, hedging is a side bet on the unknown. Types of hedging in the utility industry include laddering of contracts, diversity of fuel resources, and use of fuel efficiency and demand side management. These types of hedging tools should be considered for regular use by portfolio managers in the electric industry.

Financial derivatives represent another type of risk management tool that can have definite advantages as part of a portfolio.

Like insurance, use of such "hedges" reduces the effect of unknown events in return for a fee. Derivatives should be viewed as financial insurance instruments that protect the buyer from spikes (and the seller from dips) in commodity pricing. The intent is to stabilize prices, not to lower them.

The most common derivatives are futures contracts and swaps.

- *Futures contracts* are advance orders to buy or sell an asset. Like forward physical contracts, the price is fixed at the time of execution, and payment occurs on the delivery day. Unlike forward contracts, futures contracts are highly standardized and traded in huge volumes on futures exchanges, often by speculators as well as physical buyers and sellers. They are readily traded, as profits and losses from these derivative instruments are realized daily under exchange rules.

- A *swap* is a contract that guarantees a fixed price for a commodity over a predetermined period. At the end of each month, the prevailing market settlement price of the commodity is compared to the swap price. If the settlement price is greater than the swap price, the supplier pays the buyer the difference between the settlement price and the swap price. Similarly, if the settlement price is less than the swap price, the buyer pays the supplier the difference. Swaps give price certainty at a cost that is lower than the cost of options, with no physical commodity actually transferred between the buyer and seller.

New types of derivatives and variations on currently used instruments are constantly offered in order to suit a range of investor interests. These include weather derivatives, and a form of swap known as a contract-for-difference.

One advantage of derivatives is that in many markets they are more liquid and have lower transaction costs than physical contracts.[9]

Financial derivatives in the Electric Industry: Pros and Cons

Industry participants have agreed that the use of derivatives could help to limit market risk in a deregulated electricity industry, as it has been shown by many studies that use of derivatives either reduces or has no adverse effect on overall market volatility. For instance, overall market volatility has actually declined significantly with use of derivatives in the commodity markets for cotton, wheat, onions, and pork bellies. (EIA 2002) Derivative instruments are most successful in commodity markets with large numbers of informed buyers and sellers and in those markets where there is timely, public, and accurate information on prices and quantities traded. And thus, the prospect for an active electricity derivatives market is directly linked to wholesale electric industry restructuring; until electricity spot markets work well, the successful use of electricity derivatives will be limited. (EIA 2002)

Hedging however can still be effective in the meantime. One means to do this is through creative derivatives that do not rely solely on the underlying spot price of electricity. For example, weather hedges exist whereby some power producers have climate adjustments built into their fuel supply contracts. (EIA 2002) In addition, power plant owners can purchase or trade SO2 and NOx allowances, as established by the Clean Air Act, to manage their permit price risk. Similarly, companies can buy insurance against certain improbable events. One example is the use of multiple trigger derivatives. For instance, a power plant might be paid money if it experiences a forced outage during a period when the spot price also exceeds an agreed upon spot price.

There is evidence from other energy sectors that hedging through the use of financial derivatives in the electricity market has great potential for mitigating risk. Gas futures, for example, are now highly standardized, even though the New York Mercantile Exchange (NYMEX) only first offered them in April 1990. After a slow start, natural gas market participants now make extensive use of the futures market. For example, futures markets now allow marketers to offer a range of pricing options to their customers. In addition, some gas utilities have recently begun hedging as a tool as a way to offer their customers gas at fixed prices. During 1999, natural gas market futures trading on the NYMEX exceeded $534 billion. As such, gas futures are now much more liquid and, therefore, more easily traded than forward, fixed-price gas contracts. In addition, gas derivatives generally have lower transaction costs than forward contracts due to their liquidity. Also, exchange traded gas futures and options pose little credit risk to the buyer. This would be important in an industry like electricity where credit risk is pervasive. All of this suggests a good eventual outlook for the electricity markets, which are currently only thinly traded beyond a few years. (Costello 2001) Portfolio management in electricity will really take off when such instruments mature.

Recommendation to Maine on Hedging

It might be a little too soon for the Maine PUC to actively participate in financial derivative hedging practices. In the meantime, the Maine PUC might take the time to focus on understanding how financial derivative hedging works. However, it is not too soon for the PUC to engage in the following hedging practices: laddering of contracts, diversity of fuel resources, use of fuel efficiency and demand side management. These practices are in general well understood should be considered best in practice hedging tools for the electric industry. The Commission should examine any proposed hedging by bidders to ensure that speculative risks will not impair the viability of the utilities implementing default service.

3.6 Maine PUC Legal Authorities

The Maine Public Utilities Commission (Commission) has the statutory authority to issue RFPs for Standard Offer Service pursuant to Chapter 301 of the Commission's Rules. Chapter 301 is a comprehensive rule that identifies specific criteria that must be met when requesting and approving bids for standard offer service for all classes of customers in all service territories in Maine.

The rule specifies that bids to provide standard offer service must "specify prices or a set of prices for the entire standard offer period" and that prices "may not be defined by a formula or reference to market or economic indices". Sec. 7(A)(2)

For residential and small commercial customers, the standard offer rate "shall be an amount per kWh that does not vary by level of usage, or by time of year or day". No demand charges or fixed charges are allowed. Sec. 2(A)(3). In addition, rates, terms, and conditions shall not vary based on a customer's location within a single service territory. Sec. 2(A)(5).

Each standard offer provider shall comply with the renewable resource portfolio requirements established by the Commission pursuant to Chapter 311 of the Commission's Rules. Chapter 311 Sec. 3(B)(3) currently requires that 30 percent of a customer's energy be purchased form qualifying renewable resources. In addition, each standard offer provider must provide a bond or guarantee equal to $0.01 per kWh multiplied by the billing units and the number of years of service. The bonding requirement will be allowed to decrease as the years of remaining service decrease. Chapter 301 Sec. 3(A)(2)(a).

The Commission retains a significant amount of discretion under Chapter 301. For standard offer periods beyond March 1, 2001, the Commission "may establish different durations for standard offer bids." Sec. 7(A)(1). The Commission "shall establish the process and procedures to solicit and evaluate bids to provide standard offer service." Sec. 8(A)(1). And, 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." Sec. 8(B)(2).

The Commission may reject bids for standard offer service if it finds that the bids "are unreasonably high and acceptance would not be in the public interest." Sec. 8(D)(2). If the Commission makes such a determination, or if no bids are offered, the Commission is authorized to "establish the standard offer rates for the applicable standard offer class(es)" in a manner that ensures that the transmission and distribution utility that procures and delivers the standard offer service shall recover all its costs. Sec. 8(D)(3).

In summary, the rules governing standard offer service solicitations do not appear to limit the Commission's ability to adopt any of the provisions discussed in the earlier sections of this report with the exception of a market-index based standard offer bid. Such a bid would be out of compliance with the specific language of Sec. 7(A)(2). Nor has our review of Commission Orders specifying the terms and requirements of standard offer bids revealed any prohibitions against segmenting standard offer supply into multiple arrangements of differing durations.

As to the specific question of whether the Commission can engage in its own hedging strategies, separate and apart from the bid process for standard offer supplies, Chapter 301 provides no guidance. The ability of bidders to engage in hedging mechanisms may be limited by the requirements in Chapter 301 that require "fixed price" bids on a per kWh basis and prohibit any market indexing, but, as discussed earlier in this section, it may be possible to manage hedging in ways that do not require variable prices for default service.

4.0 Conclusions

In short, to reduce price volatility risks, environmental regulatory and fuel price risks, the Maine PUC should diversify its standard offer supply procurement process, using sound portfolio management techniques. The Commission should acquire part of the default service need using fixed price, forward contracts of varied durations over time using a laddering approach. The Commission should favor energy efficiency, demand side management, and use of varied supply sources, including renewables, to serve standard offer service customers. In addition, for the time being, the Commission should leave hedging to the individual bidders with which they negotiate standard offer service contracts.

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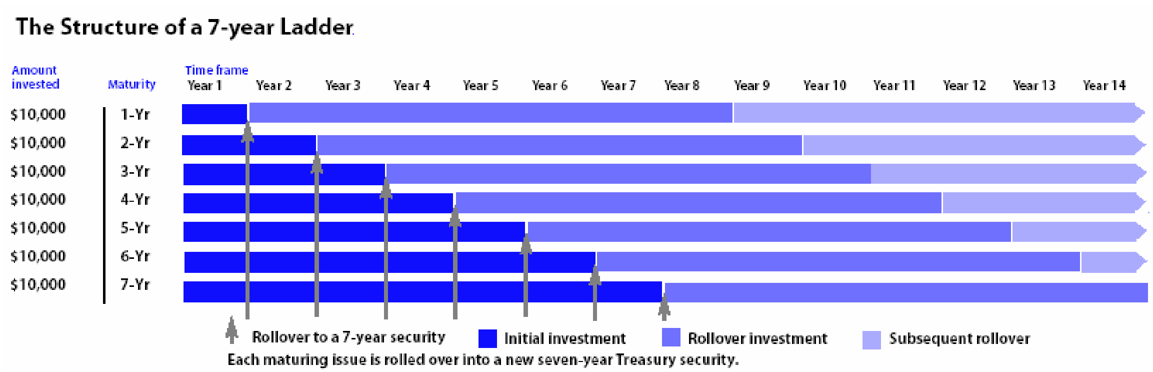
Appendix A: Laddering Example

Bond Laddering Example

Bond laddering is an investment strategy where the portfolio manager invests monies in bonds with a range of maturity dates. For the purposes of this example, we will choose a bond laddering range of 7 years, a beginning balance of $70,000 to be managed, and US treasuries as our financial instrument. Using this strategy, on day one, the portfolio manager divides up the monies into $10,000 portions and buys 7 Treasuries with durations of 1, 2, 3, 4, 5, 6, and 7 years respectively. As each bond matures, the portfolio manger reinvests the proceeds in Treasuries that will mature seven years from that date and, in effect, continues to build the ladder into perpetuity, as illustrated in Fig. A-1, below. (Engle 2002)

Figure A-1. Bond Laddering Example



There are several benefits from adopting this strategy. First, laddering reduces risks associated with market timing. Instead of trying to predict the best time at which one should lock in an interest rate, laddering provides both a range of current interest returns (capturing variation in the current term structure of interest rates) and, more importantly, a range of future investment opportunity time frames. Laddering also achieves immediate positive returns regardless of current economic conditions, unlike simply hiding the money under the mattress until economic conditions improve.

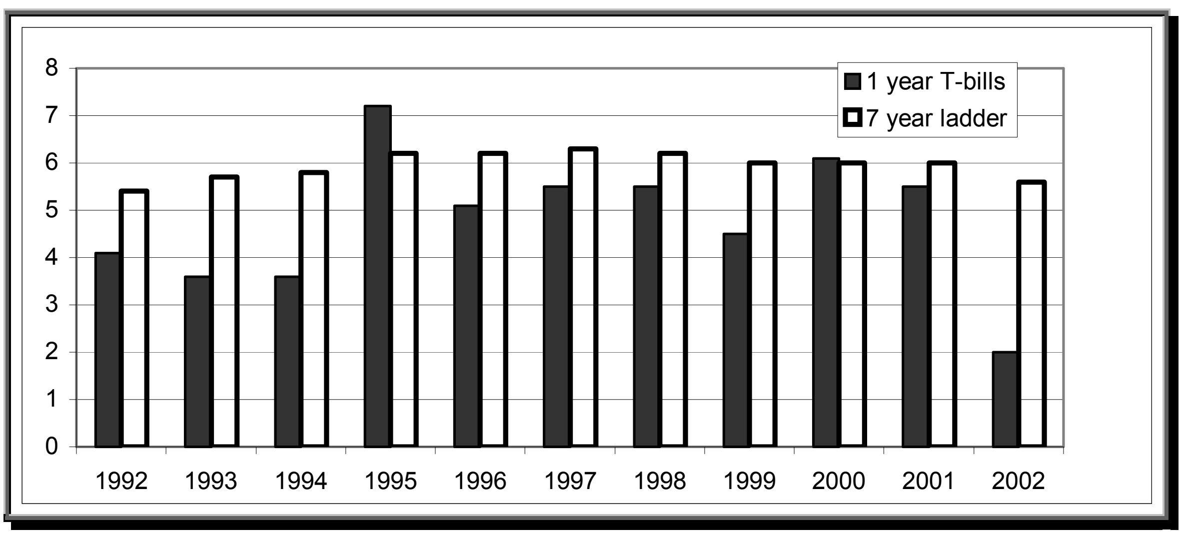
The second major benefit of a bond laddering strategy is that it provides some of the benefits of a longer-term investment, while retaining some of the benefits of a short-term investment strategy. In other words, in the laddering strategy, an investor commits funds neither to just the short-term nor just the long-term. Because a portion of the portfolio expires each year, laddering simulates a short-term liquidity risk approach. However, because funds are invested in a range of durations--averaging 3.5 years for the initial investments and increasing to 7 years over time--the returns on the portfolio are similar to those of longer-term investments, which typically yield higher returns, as described below, while avoiding the risk of locking all of the assets into a single long term investment at what may turn out to have been a time when the yield was lower than average.

Table A-1. Term Structure of US Treasury Yields September 25, 2003.

Maturity	Yield (%)
3 Month	0.83
6 Month	0.95
2 Year	1.62
3 Year	2.04
5 Year	3.01
10 Year	4.09
20 Year	5.00

In Table A-1, we see US treasury yields as of September 25, 2003. (Yahoo 2003) The data represents the available yields for bonds with various durations. Usually, the longer one commits monies to a particular investment fixed interest rate instrument, the greater the yield that is available. Thus, the fact the bond ladder returns rates of an average 3.5-7 year duration, while freeing up 1/7th of the portfolio yearly, is far better than simply investing in 1 year treasuries alone. This is illustrated in Fig. A-2. Here, we see that, over the10 year period from 1992-2002, 1-year treasuries returned 4.8% on average, while a 7-year ladder returned 5.9% annually on average over the same time period.

Figure A-2. Yearly Returns on the Bond Ladder Relative to Treasury Bills



So, investing in a laddered approach is superior to investing in 1-year treasuries, in terms of returns. However, one might ask, what would happen if one were to invest one's funds all at once into a 10-year treasury instead of annually into 1-year treasuries? According to our chart, 10-year treasuries currently yield 4.09%, which is lower than both the historical return on 1-year treasuries and on our ladder. Now, of course, 10-year yields in the past have oscillated, sometimes yielding higher than our laddered strategy and sometimes yielding lower returns. But again, the laddered approach eliminates both the risk that one will choose a "bad" time to lock in a rate for one's entire portfolio and the risk of having to reinvest all of that portfolio in a less than ideal economic environment upon maturity of the bond.

In short, a laddered investment strategy is both simple to set up and to manage. Through diversification, this strategy both reduces volatility of returns and drives up average returns.

Appendix B: Answers to the Commission's Questions

<u>Varied Term Lengths</u>

1. The Commission should segment residential and small commercial standard offer supply into multiple contracts with multiple contract durations. The advantage to this approach is that it minimizes the influence of the underlying volatile wholesale spot market prices on the somewhat arbitrary procurement date. The main disadvantage to this approach relates to the transaction costs associated with negotiating and managing more than one contract. However, the advantages in terms of risk management greatly outweigh the costs. (For full discussion, see sections 3.1 and 3.2.)

2. We recommend that the standard offer supply should be broken down into multiple contracts using a laddered approach. Laddered segments can be spaced annually, semi-annually, quarterly, monthly or at multi-year intervals. Transaction costs increase substantially for shorter intervals, but laddering with fewer, longer intervals provides less risk diversification. Current electricity commodity markets enable ladder segments to be spaced as closely as monthly, but given the procedures for solicitations by the Commission, it would be reasonable to ladder the Commission's acquisitions at annual intervals. We recommend that the Commission seek bids for laddered segments, such as a five-segment ladder (each segment should constitute about 20% of the current load.) The initial contracts would mature in about one, two, three, four and five years. (For full discussion, see section 3.2)

3. We note that for a given load to be served, a larger number of segments in the ladder may affect the prices offered due to economies of scale and institutional factors. It would probably be wise to ensure that segments are at least the size of standard commodity market products, as dealing with such fractional products can be expensive. In addition, some bidders may prefer very large lots, but any apparent savings would bring with it a reduction in diversity and increased risk. Also, concentrating purchases with only one or two vendors increases counter-party risks.

4. We believe that a laddered contract approach would not be expected to negatively effect the prospects for retail competition in the residential and small commercial sectors. Switching statistics show that switching in Maine is insignificant in the residential/small commercial sector. It is difficult to anticipate and assess all the possible effects that portfolio management of Maine's standard offer resources would actually have on the prospects for retail competition in Maine's residential and commercial sectors. However, on balance, the effects are likely to be positive. (For full discussion, see section 3.2)

5. If the Commission decides to solicit diversified portfolio components, such as a portfolio of laddered segments, *and* wishes to continue to allow linked disposal of

legacy entitlements, we recommend that it would be reasonable and convenient to specify that bidders must quote a price for segments that reflects taking a corresponding pro rata share of the legacy entitlements. The most important advantage of that approach is that potential bidders would know with specificity what their obligation is regarding legacy entitlements. However, a wider variety of beneficial bids may be elicited if this linkage is dissolved. (For full discussion, see section 3.2)

6. We note that other states, such as Connecticut, Maryland, New Jersey, and others, have split their standard offer supply into multiple contracts to protect against price volatility. (For full discussion, see section 3.1)

7. Our review of Commission Orders specifying the terms and requirements of standard offer bids does not reveal any prohibitions against segmenting standard offer supply into multiple arrangements of differing durations. The exception is that of a market-index based standard offer bid. Such a bid would not be in compliance with the specific language of Chapter 301 of the Commission's Rules, Sec. 7(A)(2). (For full discussion, see section 3.6)

<u>Varied Supply Components</u>

8. Setting aside whatever portion of customer demand that the Commission considers meeting through efficiency and long-term renewable purchases, we believe that it is most reasonable to solicit bids for segments that represent certain fractions of the "all requirements" load. Alternatively, it *may* be possible to address fluctuating load directly. For example, if the Commission decided there should be five segments in its ladder, it could acquire four that are for fixed amounts and one contract to serve the residual that fluctuates. Or the Commission could approve acquisition of five fixed segments and address fluctuating load through the spot market purchases and sales. (For full discussion, see section 3.2)

9. The Commission should seek to acquire very long term contracts (as long as ten years) for a portion of the portfolio devoted specifically to renewable resources. Renewables act as a hedge against fuel supply risk and environmental regulatory risks. Some renewables also help counter peak loads. (For full discussion, see section 3.3)

10. We believe that it is reasonable to expect that the premium charged for longer term contracts would be smaller for contracts indexed to fuel prices, inflation or some other indicator or indicators than for fixed price contracts, especially at longer terms. Whether continuing past practices or engaging in diversification through, say, laddering, the Commission should expect indexed bids would result in lower *expected* prices for standard offer service than without using price-indexing. This would come at the expense of retaining for standard offer customers some degree of price volatility. If only a portion of the portfolio were selected from indexed contracts, that volatility would be less, as would the expected savings.

Maine law requires that default service be priced at a fixed level for customers during "the standard offer period" and provides that the default service price may not, itself, be indexed. Ch. 301, Sec. 7(A)(2). Therefore, if any indexed source contracts or spot market resources are to be considered for inclusion in the default service portfolio, that uncertainty must be fully hedged

(For full discussion, see section 3.2)

Hedging

11. Because the practice is not commonplace throughout the electric industry, we suggest that it would be premature for the Maine PUC to directly participate in financial derivative hedging practices. However, it is not too soon for the PUC to engage in the following hedging practices: laddering of contracts, diversity of fuel resources, and use of fuel efficiency and demand side management. These practices are in general well understood and should be considered best in practice hedging tools for the electric industry. (For full discussion, see section 3.5)

12. The Commission should consider acquiring standard offer supply from suppliers who hedge their own risks. (For full discussion, see section 3.5)

13. We do not believe that a managed portfolio will likely create stranded costs. We understand stranded costs to mean the cost of firm purchase commitments in excess of market cost for that fraction of the default service load that leaves default service rather than continue purchasing at the established default service price. First, considering just laddered approaches to forward contract bids, there is no possibility for stranded costs if the Commission uses one of the "all requirements" fraction of load approaches discussed above. Second, to the extent that a portion of the expected default service requirement is obtained through long term contracts for renewable supplies, it will simply be important to keep those contracts to a reasonable fraction of the total load so that it cannot exceed the actual experienced load.

14. We note that other states, including New Jersey, Connecticut, Maryland, the District of Columbia, and Montana have engaged in a “portfolio” approach that entails entering into a variety of long-term and short-term contracts and the purchasing of a variety of hedging instruments. (For full discussion, see section 3.1)

15. As to the specific question of whether the Commission can engage in its own hedging strategies, separate and apart from the bid process for standard offer supplies, we have not found any specific prohibitions regarding such activity in either the Commission’s Rules or the Maine statutes. (For full discussion, see section 3.6)

Efficiency Maine

16. In order to reduce customer exposure to price volatility, we recommend that the distribution companies in Maine should pursue additional demand-reduction initiatives – above and beyond what the system benefits charge (SBC) funds.

Additional efficiency could be implemented either (a) through Efficiency Maine, or (b) through energy service companies that provide bids for efficiency services and savings. It would not make sense to set up another entity to implement additional efficiency programs. In Maine, the simplest source of funding for such programs would be an additional charge on the distribution companies' bill, i.e., a temporary supplement to the SBC to cover increases in efficiency investments. (For full discussion, see section 3.4)