Comments on the Procurement of Default Service Power Supply for Residential, Small Commercial, and Industrial Customers in the Commonwealth of Massachusetts

Prepared by:
Amy Roschelle, William Steinhurst
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

Prepared for:
Office of Massachusetts Attorney General

January 10, 2005

Table of Contents

1. Most customers remain on default service.

As in the past, the vast majority of retail electric customers in the US continue to be served by their default service provider. This trend is likely to continue well into the foreseeable future due to the many barriers that limit most customers' ability to switch to alternative generation companies.

Behavior in the Commonwealth of Massachusetts is no exception. As shown in Figure 1, evidence in Massachusetts shows that residential and small commercial and industrial (C&I) customers are the least likely to select a competitive supplier. Non-switching customers (known as standard offer customers in Massachusetts) represent a significant portion of overall electricity requirements - 43% of total electricity load and 94% of total customers.[1] Similar results are seen in each state that allows electric competition. In fact, no state currently has greater than 15% residential switching, and there has been no indication that small customers will begin to migrate en masse in either the near or medium-term. In other words, residential and small C&I customers are likely to remain on default service for a considerable period. Such a non-switching reality need not be considered problematic. The real problem lies in how to provide stable, low-cost electric service for those who choose not to shop.

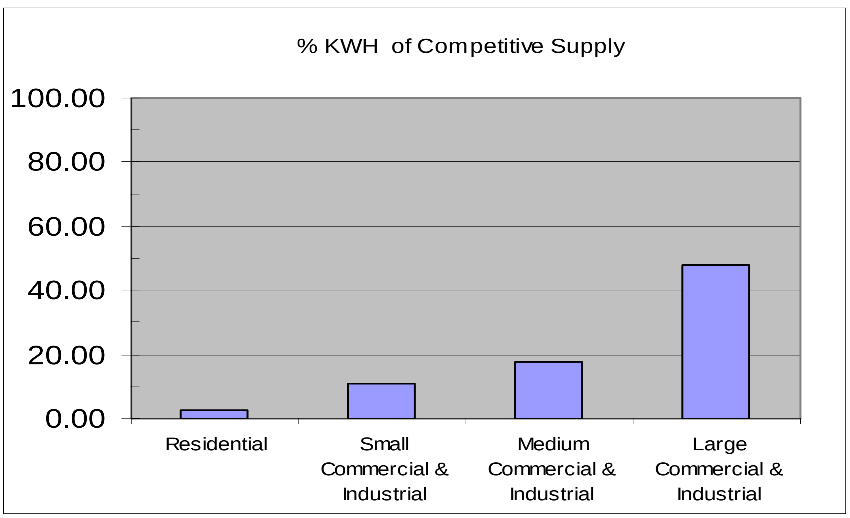

Figure 1: Switching statistics in Massachusetts show that Residential and Small Commercial and Industrial Customers are least likely to switch to a competitive supplier. These results are representative of most all US states that allow competition. Source: mass.gov (March 04)

Several states have adopted strategies for the procurement of electricity that incorporate portfolio management techniques. There is a simple reason for this growing trend: a portfolio management approach is in the ratepayers' best interest, as it ensures reasonable and stable

[1] Massachusetts Division of Energy Resources (DOER), *2003 & 2004 Electric Power Customer Migration Data*, March 2004, at http://www.mass.gov/doer/pub_info/migrate.htm

prices for default electric service. As an added benefit, a portfolio management approach decreases customers' exposure to a long list of risks, including, but not limited to risks associated with:

- Fluctuating wholesale market prices
- Future environmental regulations
- Fuel price and supply fluctuations
- Price spikes due to extreme weather and other sources of demand fluctuation
- System reliability and security
- Market power

In addition, there are reasons to believe that such an approach can lead to lower power costs, overall.

Illinois, Maine, Delaware, New Jersey, the District of Columbia, Connecticut, Ohio, and others, have begun to define processes for ensuring reasonable and stable generation rates for small customers. In the remainder of this report, we answer questions specifically posed by the Commonwealth of Massachusetts Department of Telecommunications and Energy (DTE) regarding procurement of default service power supply for residential, small commercial, and industrial customers.[2] The background on the DTE's inquiry is that, for several years, Massachusetts's electric customers have been in a so-called transition period, which was established under the 1997 Electric Restructuring Act. During this transition period, most customers were on the "standard offer" rate plan. However, on February 28, 2005, the transition period will officially end. Thereafter, all remaining standard offer service customers will become "default service customers." Our goal in answering the DTE questions is to recommend policies that will ensure that electric service is available to residential and small C&I customers at a reasonable and stable price.

[2] MA DTE Docket 04-115

2. A Portfolio of more than two solicitations is advantageous, but costly.

Question: Would smaller customers be better served if power supply for default service is procured using a portfolio of more than two solicitations? Please discuss the advantages and disadvantages of increasing the number of solicitations used to procure default service supply.

Currently, the DTE requires distribution companies to procure 50% of their residential and small C&I supply requirements semi-annually for twelve-month terms. This question asks us to explore whether a system of more than two solicitations would provide further diversification benefits. We believe it most certainly would. Procuring power supply for default service load in only two segments does not sufficiently mitigate the huge wholesale market price volatility that exists. Figure 2 illustrates our point. Here, we see data for the New England region, which is representative of markets throughout the US. We see large month-to-month variability in regional electric rates. What this tells us is that it is risky to contract 100% or even 50% of one's needs at any given time, as one might lock-in at an unfavorable price points. On the flip side, however, the more often one solicits contracts, the higher the transaction costs -- administration of the contract process is not cost free. With this in mind, we recommend a laddered procurement approach that can increase portfolio diversity while actually lowering administrative costs.

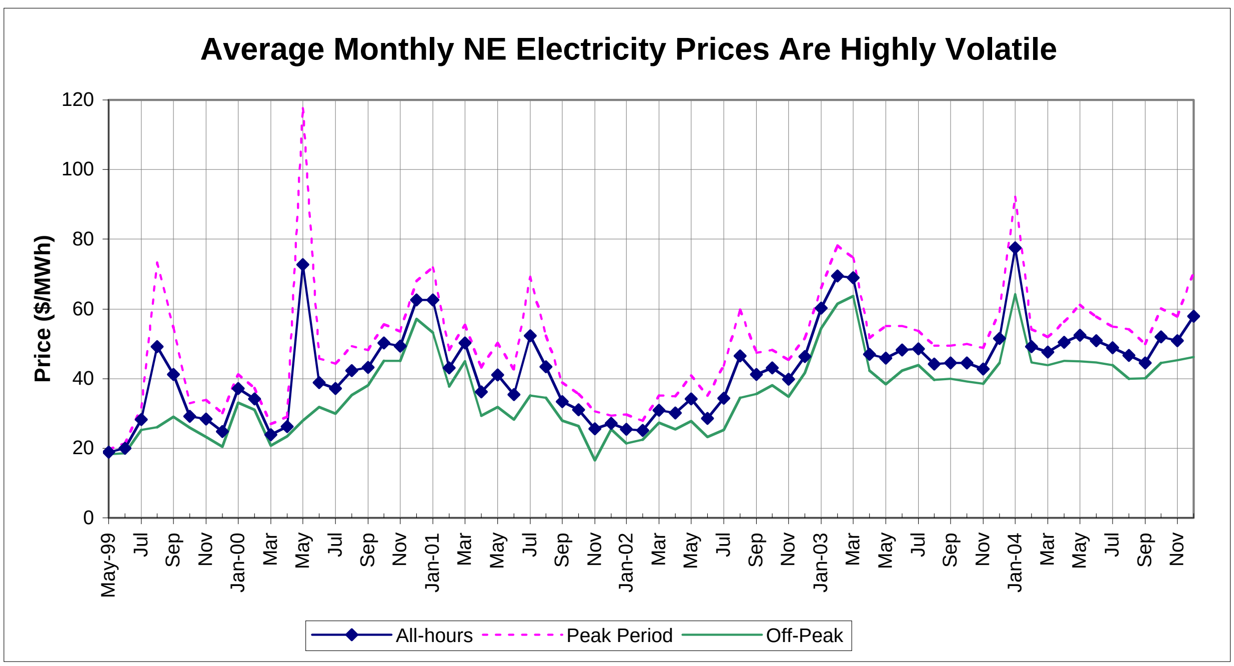

Figure 2: Contracting a large portion of supply at one or two points in time increases exposure to price volatility.

A Laddering Approach Reduces Both Risk and Administrative Cost

Specifically, we recommend a contract laddering approach, wherein default service providers divide their load into smaller, (generally) equal-sized segments, which are procured individually over time. Administrative costs are reduced by instituting only one procurement cycle per year, but diversity is increased by gradually phasing in a portfolio with longer terms and more than two load segments or tranches.

Figure 3 shows an illustrative example of a 5-year ladder. In Year 1, this sample portfolio starts with five contracts that mature in 1,2,3,4 and 5 years to establish the segments in the ladder. In each subsequent year, the default provider replaces the expiring segment with an additional contract or contracts that have a 5-year term. The result is that every year, 20% of the ladder expires and 20% of the ladder is newly acquired. By Year 6, the entire portfolio is made up of overlapping five-year contracts.

The strategic advantage of this approach is that only a fraction of the portfolio is exposed to the volatile wholesale market at any given time, and procurement fees are kept at a minimum, as contracts need be negotiated only on an annual basis. The result is a more stable and, on average, lower electricity rate for customers.

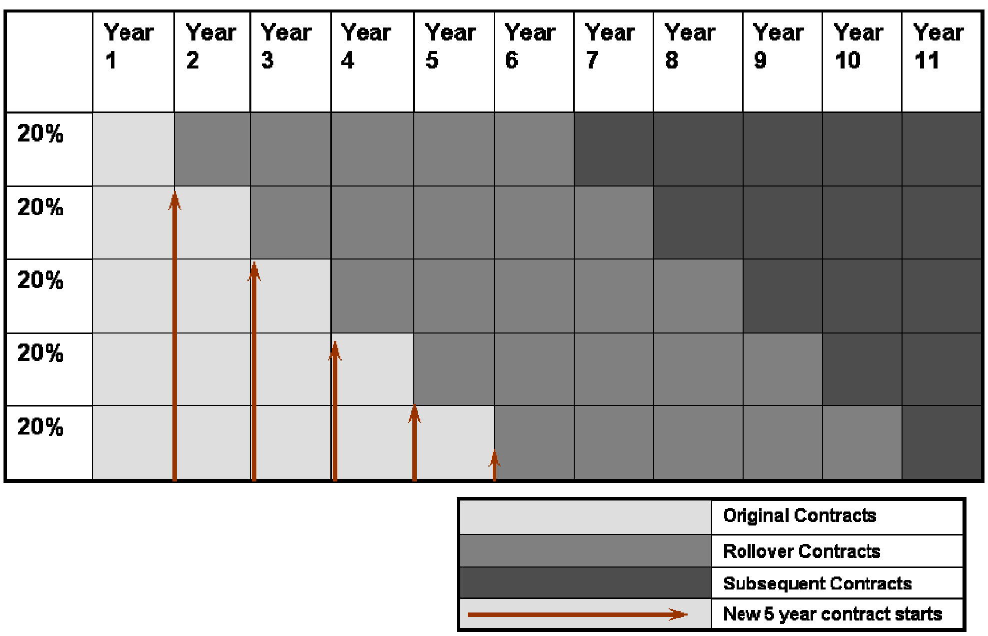

Figure 3: A five-year contract laddering approach. Such a method results in lower and more stable prices.

Several states have already had experience with such a laddered approach, including New Jersey, which uses a 3-year ladder. Although considered quite successful and innovative, this approach remains limited in certain ways and does not maximize all diversification benefits. An enhanced version of New Jersey's laddered portfolio approach might include a mix of spot market, 1-year, 3-year, 5-year, and some long-term contracts. Such an approach would yield even greater benefits for customers. Some of the rationale behind these ideas is discussed in section 3.

3. Longer-term contracts offer price stability.

Question: Would smaller customers be better served if power supply for default service was procured for a term longer than twelve months? Please discuss the advantages and disadvantages of using supply terms greater than twelve months.

Yes. Smaller customers would be substantially better off if the majority of contracts for default service were greater than 1 year in duration. The overriding benefit of longer-term contracts is simple: small customers see less variation in their bills month-to-month and year-to-year with long-term contracts. For these customers, budgeting and planning matters, especially for an essential good like electricity. Using only short-term contracts is an invitation to unnecessary price volatility and can actually induce greater wholesale market volatility.

Several issues are commonly cited by utilities as reasons for limiting default service portfolios to short-term procurement. Among these are: (1) generation owners and markets are unable to deliver financially viable, long-term, fixed price contracts; (2) excessive price premiums are required to obtain long-term fixed price contracts; and (3) migration risk.[3] In the remainder of this section, as we discuss various features of our smart portfolio management recommendation, we will show that (1) it is reasonable to expect mid-term (three to five year terms) fixed-price contracts to be available at reasonable market rates and to expect long-term fixed-price contracts to be available from renewable generation vendors; (2) that price premiums are likely to be small or non-existent; and (3) that suitable smart portfolio management can include features that appropriately address migration risk.

Specifically, for the reasons set out below, we recommend that the Department adopt a smart portfolio approach for procurement of default service power supply. We recommend that this portfolio be composed primarily of a multi-year ladder of wholesale power supply contracts, as well as a portion of short-term wholesale power supply contracts and an initially small, gradually increasing segment of long-term (preferably life-of-unit) renewable contracts. Each element would be procured competitively once a year, although each year's additional procurement of renewable power could (and probably should) be procured separately in advance of the generic wholesale power procurements. Below we discuss the importance of including renewables in the mix of power sources for serving default service electric customers.

Renewables should be included in the mix.

Long-term contracts can provide incentives for the delivery to market of additional renewable generation. Some argue that the issue of encouraging renewable generation should be ignored in default service procurement or that the issue should be addressed in default service procurement by simply applying existing renewable portfolio standards (RPSs) that can be met through annual

[3] Migration risk refers to the uncertainty in default service loads because customers will have the option to leave default service for competitive service, potentially leaving wholesale vendors or default service providers with surplus power, potentially in a "down market."

purchases of renewable energy certificates (RECs). However, explicit inclusion of long-term or, life-of-unit, contracts for renewable generation in default service portfolios can protect customers against future environmental regulation risk, fuel price and availability risk, as well as risk of high peak cost due to extreme weather and system reliability risk. All of this can be accomplished at little or no additional cost through the use of long-term contracts. We describe the reasons for each of these conclusions below.

Renewables can reduce peak energy costs and mitigate pressure on fossil fuels.

There is the well-understood relationship between extreme weather and electricity demand; the hotter the summer or colder the winter, the more electricity we use and the more generation costs. As a counter to this effect, some renewables, such as photovoltaics, generate the most electricity at peak load hours, such as at midday during the summer season. This is exactly when electric load and price is highest for most regions. Thus, photovoltaics can be a powerful resource for reducing peak energy costs and mitigating pressure on fossil fuel prices.

Second, the costs and output of wind and photovoltaic technologies do not depend on fossil fuel prices. This is especially important in many regions of the country that increasingly rely on natural gas to generate electricity. As of June 2004, for example, natural gas prices rose to an all-time US high. Electricity production and wholesale market prices are directly affected by these kinds of natural gas peaks and volatility. In order to minimize exposure to fuel supply disruptions and price increases and in order to keep ratepayer's costs low, alternative fuels for serving default service load, such as wind and photovoltaic technologies, should be included in the portfolio mix.

Renewables act as a hedge against environmental regulation risk.

Third, there is considerable uncertainty about the type and extent of environmental regulations that may be imposed in the near- to long-term future. Currently, utilities and wholesale vendors of electricity must comply with sulfur dioxide (SO2) and nitrous oxides (NOx) emission requirements. It is now clear that some form of federal regulation of carbon dioxide (CO2) is highly likely in the near to mid-term. Several states have already adopted CO2 requirements and climate change action plans. In addition, 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. 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 price risks is feasible, vital, and prudent. This can be accomplished by establishing a default service portfolio with a mix of emission profiles.

Renewables can be a reality with long-term contracts.

So, why is it that even with so many good reasons to include them, many states do not include renewables in their generation mix or limit inclusion to minimum requirements set out in state renewable portfolio standards? Renewables are capital intensive. In fact, developers usually require project financing in order to buy, install and operate wind farms or large-scale photovoltaic sites. Such financing is generally not available when developers have only one- to three-year power sales contracts or when they must depend on spot market prices for renewable energy credits.

One way to bring together renewable energy developers and the financing they need would be for regulators and default service procurement to devote a segment of the default service portfolio specifically to longer contracts and renewable generation. As an example, a default provider might consider devoting a 10-15% segment of the portfolio specifically to longer-term durations of 10-12 years or to life-of-unit contracts (preferably for a diverse fleet of units). This approach would assure renewable generation developers a reliable revenue stream that covers both costs and a reasonable return on investment, reducing their financing costs. Default service customers would then share the resulting lower financing costs, electric peak-shaving savings, and diversification benefits with consumers, as would be expected in a competitive request for proposal (RFP) process. The consequence: everybody wins. Default providers build more renewable generation assets, and buyers get reduced prices.

A renewables tranche would not be in conflict with Massachusetts's RPS

While there would be interactions between the Massachusetts Renewable Portfolio Standard (RPS) and our proposed renewable tranche for default service, it would be straightforward to define the proposed renewable tranche in a way that the two concepts mesh smoothly and even support each other.

The first point to note is that the RPS would apply equally to all retail sales - both competitive and default. The difference would be that competitive retail providers would be able to comply with the RPS using only RECs produced by generators eligible under the Commonwealth's definition for the RPS.

The second step is to distinguish the proposed renewables tranche from the RPS by requiring that it be composed of long-term contracts for certain renewables acquired for the default service portfolio through a competitive solicitation, most likely an RFP or auction. The renewable solicitation should be held in advance of the generic procurement so that the generic bidders will know that they are bidding on the residual load and will know (or can estimate) what that residual load is. Each year (including the first year,) a small increment of such renewable power would be procured for the default service portfolio, perhaps 1% to 3% more power each year until an appropriate target quantity is reached. The target quantity should be driven by risk analysis of the portfolio and its components and could be adjusted as appropriate. A reasonable initial target would be around 15% within ten years. The annual increment actually procured should be flexible and respond to the prices that are offered, expectations for cost trends in technologies, quality of the bids, etc. That flexibility could be exercised by the Department in a "charge" to each year's procurement manager or by the procurement manager in accordance with an approved risk management strategy.

In order to achieve the purposes of the renewable tranche in the default service portfolio, eligible technologies should additionally be defined as sustainable, not subject to material environmental regulation risks, having both fixed and variable costs that do not depend in a material way on fossil fuel prices, and not requiring material amounts of fossil fuel.[4] As a practical matter, then, the tranche should be reserved for certain renewables.[5] For the rest of this discussion, we make that assumption.

It is important to emphasize that mere purchase of RECs should not qualify. Only long-term contracts for actual delivery of renewable output should be eligible. Contracts may be for energy only, but must include delivery of all RECs associated with the energy. Contracts that deliver all products produced by the units, not just energy and RECs should be preferred, as they maximize risk mitigation.

Contracts must be long-term, but life-of-unit contracts should be preferred to maximize both risk benefits to default consumers and support for renewable development. The appropriate minimum length for eligible long-term contracts has not been determined, but it should likely be at least ten years and should be comparable to the length of financing available to renewable developers.

If the target quantity of renewable power in the tranche is less than the state RPS, the balance of the RPS requirement associated with the default energy sales should be met by purchase of RECs. If, in a given year, the target quantity of renewable energy in the tranche is greater than the RPS requirement, the portfolio manager should sell off surplus RECs to reduce the cost of service to default customers.

Contracts selected for this tranche could be for specific units or assembled by brokers from a diverse fleet of eligible units. In any case, they should be for the actual power from specific units and require delivery of power to the same grid locations as other default power. The Department may wish to require units to be within the RTO or even within the state to maximize economic development benefits.

Empirical evidence in electricity markets fails to demonstrate the existence of a significant and validly comparable price premium for longer-term contracts for default service.

The State of New Jersey has been quite proactive in moving towards a laddered approach for the procurement of its default service–basic generation service (BGS). To achieve this, New Jersey has phased in longer-term contracts. In 2002, when New Jersey started its auction process, it procured only 1-year contracts for electricity for basic generation service for residential and small commercial customers. Then, in both 2003 and 2004, New Jersey held auctions for the

[4] Examples of fossil fuel requirements that should not considered material include (1) biomass generators that require 1 or 2% of their energy from oil or gas for startup and other engineering requirements; (2) biomass fuel cultivation, harvesting or transportation that requires fossil fuel; and (3) O&M for renewable units that requires transportation dependent on fossil fuel.) MSW combustion should be considered to have material environmental regulation risks and not be eligible.

[5] Excluding fossil fuels from the long-term contract tranche follows from its risk mitigation goal: dependable, long-term, fixed-price purchases. Options such as mine-mouth coal or dedicated oil well generation with the fuel source and the generator both owned or controlled by the bidder could provide part of this purpose (should bidders wish to a specific reserve fossil fuel resource for sale at a fixed price), but would not fully meet risk goal because they do not eliminate environmental regulation and non-sustainability risks.

provision of both 1-year and 3-year contracts for default service.[6] The auction design and results are shown below.

[6] The 2003 auction contract lengths were 10-months and 34-months to permit synchronization with PJM's power planning periods.

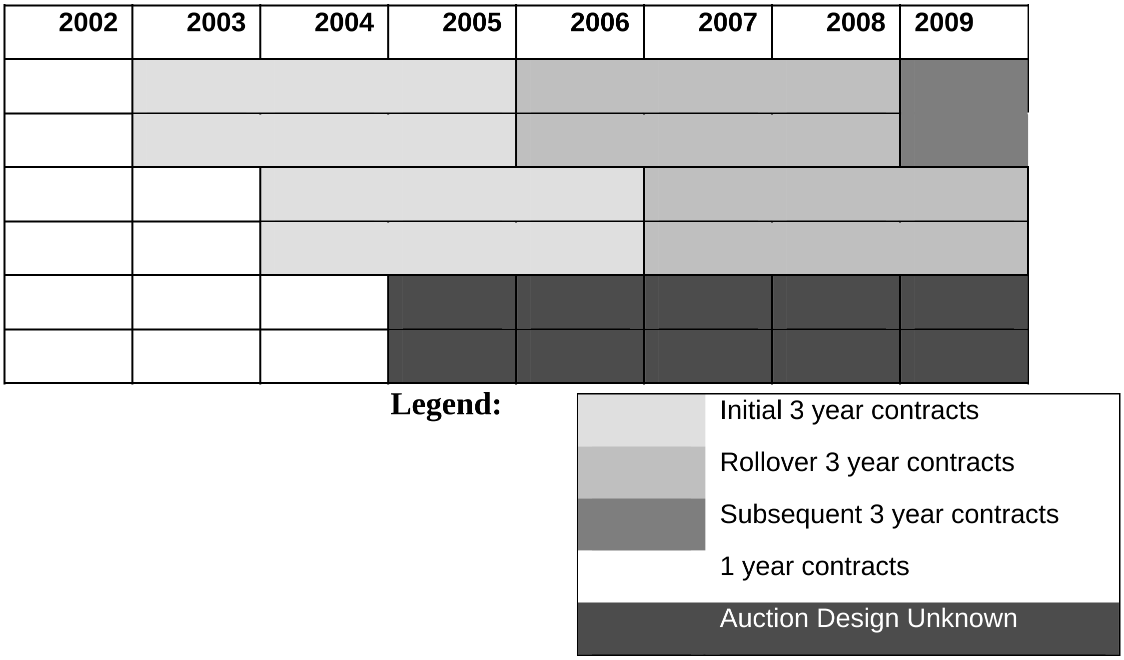

Figure 4: NJ BGS Auction design. NJ is phasing in long-term contracts and a laddering approach.

Table 1 shows that there were price differences between the 1 and 3-year contracts. The 3-year contracts were indeed more expensive than the 1-year contracts. However, those difference were modest in the first year and considerably smaller in the second year.

Table 1: NJ BGS auction for fixed price basic generation service contracts. There is an apparent price difference between the 1 and 3-year contracts. But comparing the two directly is like comparing apples to oranges.

		10 month or 1 year contract price (cents/kWh)	34 or 36 month contract price (cents/kWh)	% difference between 1 and 3 year contract
2003	PSEG	5.386	5.56	3.23
	JCPL	5.042	5.587	10.81
	ACECO	5.26	5.529	5.11
	RECO	5.557	5.601	0.79
2004	PSEG	5.479	5.515	0.66
	JCPL	5.325	5.478	2.87
	Conectiv	5.473	5.513	0.73
	RECO	5.566	5.597	0.56

But can one really compare a 1-year contract directly to a 3-year contract and conclude that the use of the longer contracts for default service will carry a premium over time compared to the use of one-year contracts? Not necessarily. What one should really be looking at is the price difference between a series of one-year contracts and 1 three-year contract for the same time period. In Figure 5, we present an illustrative, hypothetical example of such a comparison.

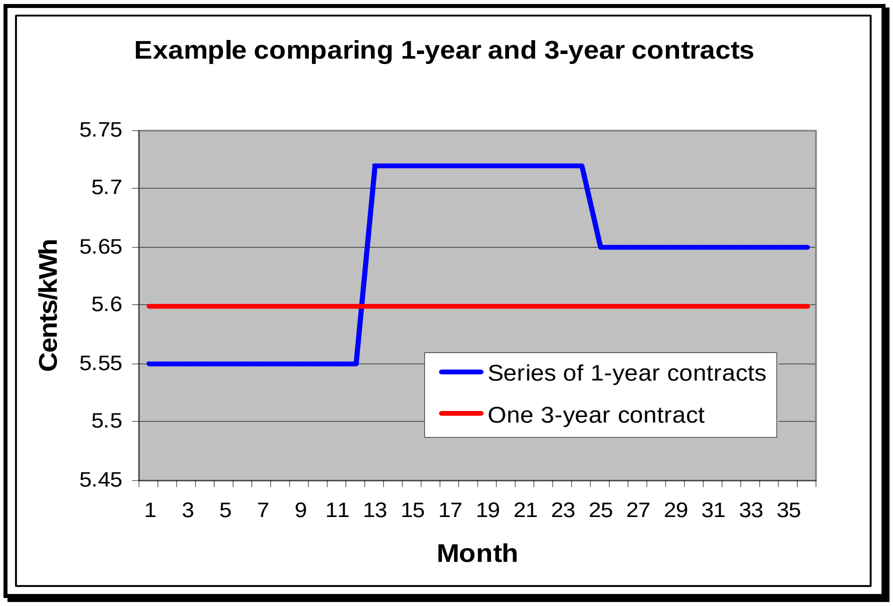

Figure 5: Hypothetical prices for a 3-year contract signed in Year 1 and for one-year contracts signed in Years 1, 2, and 3.

Suppose, for example, we had started up a 3-year laddering strategy and the available prices for one-year and three-year contracts in Year 1 were as shown in Figure 5. And suppose, further, that the one-year contract prices in Years 2 and 3 happen to have moved as shown in Figure 5, as well. In Year 1, we might have been tempted to choose a strategy of meeting 100% of need with one-year contracts, since their price was less than the three-year contract price. However, this did not mean that there was necessarily a price premium for the three-year contract. For example, if the one-year contracts had followed the hypothetical track shown in Figure 5, their average price over Years 1, 2, and 3 would have been higher than for the 3-year contract signed in Year 1. In other words, just because Year 1 showed a price difference between the two options that does not imply that over the three-year time frame there is a price premium. One cannot simply look at the current 1-year contract in isolation and conclude that it is more advantageous than a 3-year contract. In order to determine if a price premium exists, one has to compare the two scenarios over a similar time horizon.

It is also interesting to note (Table 1) that even if there is a price premium for the longer-term default service contracts in New Jersey, the premium seems to have diminished in the second auction to a relatively small amount. One might expect this amount to be offset by the financial benefits (price stability) that consumers receive from longer-term contracts.

A ladder of longer-term contracts can be tailored to accommodate customer migration to competitive supply.

Any laddering approach allows the default providers to vary the quantity purchased in each annual contract segments, as load expectations vary, say, due to migration to competitive service or changes in the economy. For example, if the total required load for default service decreases over time, then each segment of the ladder can be reduced when it comes up for renewal to reflect such change. Our smart portfolio management recommendation enhances this flexibility by incorporating a small tranche of short-term contracts procured annually. This offers two ways to adjust for load expectations or migration, depending on whether the load change is expected to be temporary or not.

Longer-term contracts stabilize prices and may even lower them.

For many commodities, we see a trend in the futures markets: the further away the delivery date, the lower is the current contract price.

In the graph below, we see that for the Euro dollar and pork, prices decline as a function of contract start date. What does this indicate? While there may be unique circumstances for each of these individual commodities and industries that might explain the declining prices, a general explanation might be that by locking-in to contracts now, both the suppliers and buyers are forging an agreement for the future. This agreement can reduce risks for both sides. Suppliers are assured that somebody is going to purchase the commodity at an acceptable price, and buyers are assured that demand can be met on the date that it is needed at an affordable price. For both parties, risk is therefore reduced and prices can be lower.

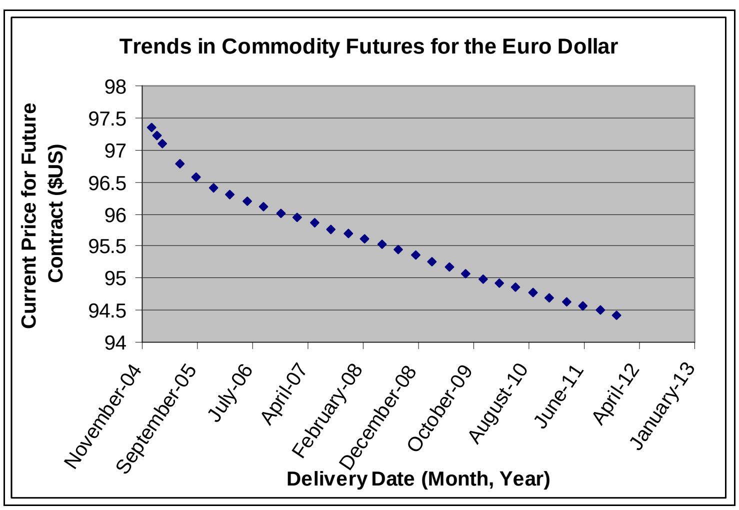

Figure 7: Trends in Commodity Futures Prices for the Euro. Source: Chicago Mercantile Exchange. Settlement prices as of 01/03/05.

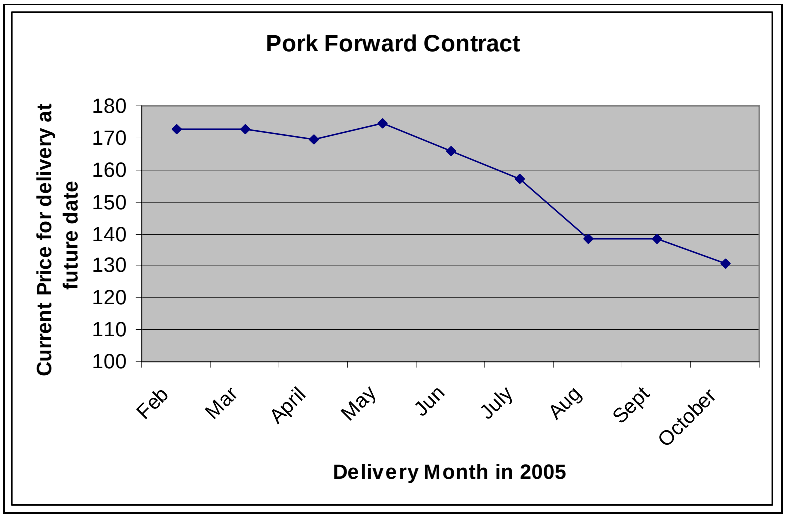

Figure 8: Trends in Commodity Futures Prices for Pork. Source: Ontario Pork. Settlement prices as of 01/03/05.

There are, however, some commodities that, at least at times, show a pattern of increasing contract prices into the future. For example, both coffee and cocoa are currently priced higher for contracts farther out into the future. For coffee, this is based on the current expectation of lesser crop volume in top-grower Brazil, slower exports from Central America, and consumption growth forecasts.[7] When looking at such a result, it is important to consider the following: coffee only grows in a limited number of regions, there is no substitute, and crop success is highly sensitive to weather conditions.

When current events indicate a less favorable future, prices that rise with delivery date are to be expected. In such an instance, it might temporarily be better to rely on shorter duration contracts. However, this does not invalidate the general proposition; it still holds that those suppliers who have a long-term contract in hand will be in the best position to take action to moderate shortages and any resulting price swings.

[7] story.news.yahoo.com/news?tmpl=story&cid=568&ncid=749&e=4&u=/nm/20040412/bs_nm/markets_coffee_prices_dc

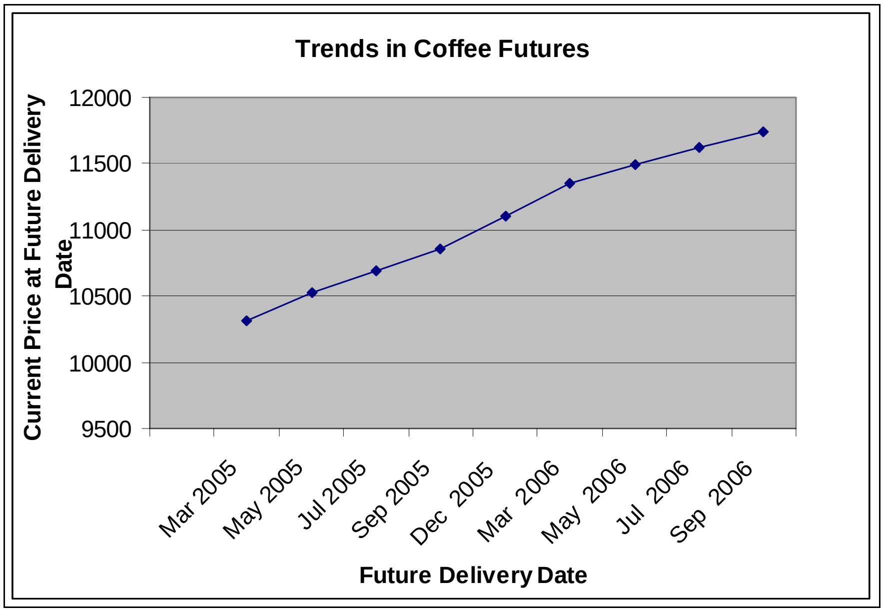

Figure 9: Trends in Commodity Futures Prices for Coffee. Source: New York Board of Trade. Settlement prices as of 01/03/05.

So, what do electricity futures look like? Unfortunately, sources of equivalent information on electricity futures are few and far between. The electricity futures market, though growing, is currently only thinly traded. However, since natural gas prices currently drive electricity prices, it makes sense to look at natural gas price futures, which are actively traded.

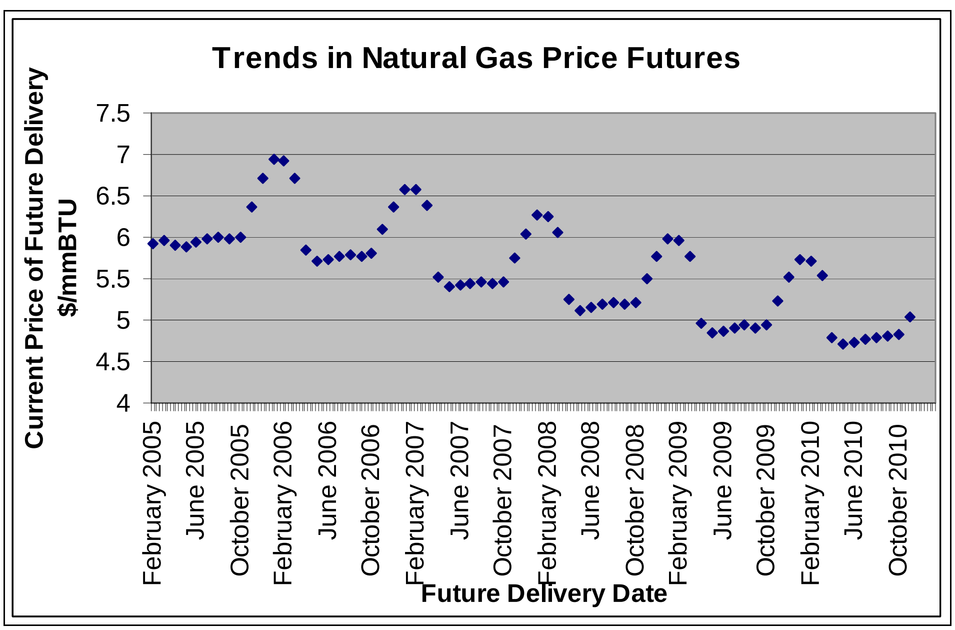

Figure 10: Trends in Commodity Futures Prices for Natural Gas. Source: New York Mercantile Exchange. Settlement prices as of 01/03/05.

Here, we see that natural gas price futures, though exhibiting an annual cyclical variation, currently decline in price as a function of lead-time. From this, we conclude that longer-term contracts for gas, and presumably for electricity as well, should not result in higher prices than shorter-term contracts. At times, expected *future* supply or demand imbalances may overshadow these effects, but the general finding should hold.

As mentioned above, recent run-ups in oil and natural gas prices may create a price premium for longer-term electricity contracts, as has occurred in the past when fossil fuel markets were under pressure. This phenomenon is not expected to be long-lived. One possibility is that fossil fuel prices may retreat. Alternatively, fossil fuel and electricity contracts may stabilize at new, higher prices. In this situation, it would be expected that any large upward slope in the term structure for electricity contracts would be replaced by declining or nearly level slopes.

Some use of spot markets and short-term contracts offers flexibility.

Another enhancement to a "plain vanilla" medium term laddering approach is to leave a small portion of load open to the spot market or short-term contracts, say up to one year in length. There are several reasons to consider this portfolio addition. First, if there is significant uncertainty in the quantity of product needed, it may be wise to keep part of the portfolio in shorter-term assets, perhaps a share about equal to the size of that uncertainty. This would involve a balancing of the risks due to uncertainty in market conditions with risks due to uncertainty in the portfolio manager's needs. In addition, devoting a portion of the portfolio to shorter-term assets allows managers flexibility to participate in new projects or to take advantage of new offers or products as they appear on the market. In sum, just as it is unwise to devote an entire portfolio to short-term contracts or spot purchases, it is generally unwise to tie up the entire portfolio with long-term assets, even if they are laddered.

Putting it all together

Figure 11 shows an illustrative version of a smart portfolio strategy for the procurement of default electric service. This approach takes advantage of both longer-term renewable and spot/short-term market options, as well as the standard laddering approach. It includes a mix of short, medium, and long-term contracts that take advantage of a diversity of generating options. The result is low costs in addition to reduced wholesale market, future environmental regulation, fuel supply, and peak cost risk.

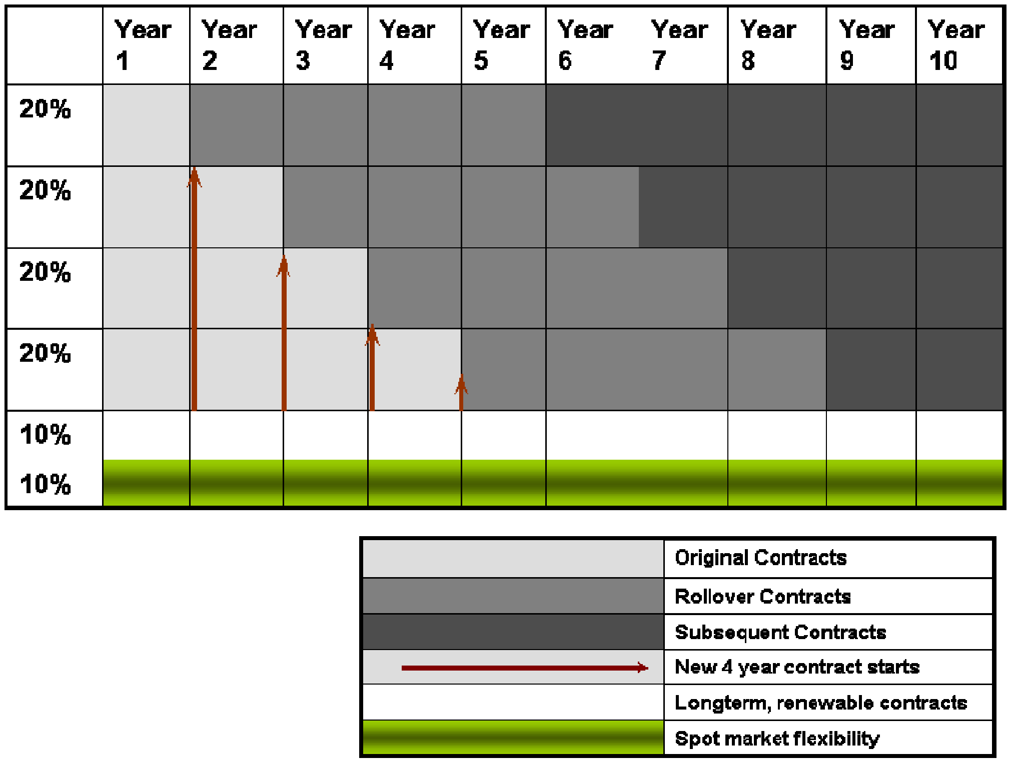

Figure 11: A smart portfolio laddering strategy uses a combination of short, medium and longer-term contracts to take advantage of the benefits of renewables, the flexibility of the spot market, and the systematic nature of the ladder approach.

In addition to the advantages discussed above, a laddering approach to default service procurement also offers significant reliability benefits due to its basic diversification principles. Diversification can take the form of varied fuels, technologies, and a mix of generation resources. Additionally, diversification should include a mix of transmission, demand-side resources, energy efficiency, and demand response. On average, with diversification, each resource represents a relatively smaller proportion of the total required load to serve customers. This decreases unique risks. It is important to keep in mind that these potential reliability benefits flow not from diversifying paper contract types in a portfolio, but from the fact that smart portfolio management practices, as described above, would influence the physical make up of the resources by incorporating various technologies, energy efficiency, as well as demand response options.

Diversification through laddering also effectively reduces the risk of market power, as there is less exposure to any short-term market manipulations and more feasible entry by small and medium sized generators.

Moreover, this approach to default electric service offers a way to shift the electric utilities' focus 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. Overall, our approach, as outlined, is not only consistent with competitive markets; it is, in fact, necessary to ensure low prices for customers and to ensure that competitive wholesale markets are robust.

In sum, default service providers will continue to service the majority of residential and small C&I customers. These providers have an obligation to provide low cost, reliable electric service. Portfolio management can help ensure this result. A smart portfolio management strategy includes a laddered contract approach, with inclusion of longer-term contracts, renewables, and some use of the spot market and/or short-term contracts.

4. A statewide procurement process has both advantages and disadvantages.

Question: Would smaller customers be better served if power supply for default service was procured on a statewide basis? Please discuss the advantages and disadvantages of using a statewide approach to default service procurement.

Currently Massachusetts, like Delaware, procures default service electricity supply through a distribution company-specific request for proposal process. This approach differs from states such as Maine or New Jersey, which uses statewide solicitations to procure default service supply. From the consumer's perspective, the disadvantages of a company specific RFP include the potential for gaming opportunities and favoritism by the individual utilities. Having a statewide approach may seem "more fair." By offering a larger marketplace, it may also encourage greater price competition. The advantage, however, of a company specific RFP is that each distribution company can be very specific about its needs, which may differ from the needs of other distribution companies in the State. This may, in the long run, offer some advantages.

The Department may wish to consider following the New Jersey approach. There, prices and amounts bid are allowed to vary between retail utilities. However, all bids for all default service providers are made simultaneously in one auction. This approach could reap the advantages of scale and competitiveness offered by a single procurement, while allowing for appropriate pricing differences due to load shape, transmission access, and other economic and engineering factors.

5. Small customers can benefit from either an RFP or Auction Process, as long as each is properly designed

Question: Would smaller customers be better served if power supply for default service was procured using an auction process (e.g. descending clock) rather than through requests for proposals (RFP?) Please discuss the advantages and disadvantages of using an auction process to procure default service. In particular, please discuss whether using an auction is likely to produce lower default service prices.

Recently, we conducted a series of interviews to better understand the advantages and disadvantages from various parties' perspectives of an auction process versus an RFP process for the procurement of default electric service. Our findings suggest the following:

1. Parties associate shorter time durations between bid offer and acceptance for an auction format relative to an RFP format.
2. Financial players (bidders who are not generation owners) prefer shorter durations between bids and decisions, since any waiting period adds risk to their bid offer. Thus, more financial players will likely participate in an auction format, than in an RFP process. Having more players is usually considered advantageous in terms of competition and driving down the default service price that is passed on to consumers.
3. However, financial players, who prefer the auction, are also hesitant to bid on a product for which there is insufficient futures data. Currently, there is insufficient futures data for electricity contracts beyond 3-5 years. Thus, the auction, by definition, will be less successful on longer-term contracts. In other words, long-term (10 year) contracts are more suitable to an RFP-type process.

Thus, some, if not all, default procurement should be achieved through an RFP type process to ensure the inclusion of an appropriate amount of long-term contracts. (See Section 3 on the benefits of long-term contracts.)

Another benefit of the RFP process is that each year, RFP solicitations can be custom tailored to the specific needs of the region. The auction process seems to require more standardization year-to-year.

However, despite these RFP benefits, many parties seem to prefer an auction-type process, similar to that used in New Jersey. Both generators and financial players cite auction format transparency and speed as key advantages. However, concerns about the auction process from the customer perspective follow:

1. The auction format lacks transparency for any party that is not actually there to witness the auction process. Should Massachusetts choose an auction style format, a consumer advocate representative should be present to observe the actual goings-on of the auction process. Otherwise, this process occurs in a "black box" from the perspective of all consumers.

2. The auction results, as currently presented by NJ, provide little meaningful insight into market power. It is not clear from the list of winners who is actually providing the underlying generation nor how much generation they are providing, since financial players have confidential third party contracts with unidentified generators. If Massachusetts were to choose an auction style format, reports on the auction should be made available that include, at a minimum, how much generation the physical players are providing, whether for themselves or for a financial players.

In addition, if there were to be an auction format in Massachusetts for the procurement of default service, it would need some degree of flexibility to react to changes in market trends. For instance, relative to contracts in the 1970's or 1980's, currently, there seems to be a trend towards shorter-term contracts. But that trend might change or need to be changed in the future. The auction parameters need to be flexible over time.

These are our main observations on the RFP versus auction format debate. As long as each of the processes is well defined, either could potentially be used quite successfully for the procurement of default service electricity in Massachusetts.

6. “Basic Generation Service” is preferable to “Default Service.”

Question: Although the term “default service” is statutory, G.L. C.164, paragraph1, it has confused some customers because of its unintended suggestion of nonfeasance in performing a legal or contractual obligation. Is there some better or more descriptive term that ought to be used by the distribution companies on and after March 2005.

States have come up with a variety of names for the service offered to those customers who choose not to switch to a competitive supplier. Many states have tended toward the term “default service.” New Jersey, however, uses the term “basic generation service” or BGS to represent those customers who have chosen not to switch to a competitive electricity supplier. Perhaps the name “basic generation service” is a bit more descriptive than the term “default service.” The term “generation” in the BGS moniker explains that one is paying for generation service, as opposed to some other component of the electricity bill. The term “basic” is advantageous in that it reflects the notion that one has more than just one option; it implies that there are other alternatives out there for those who wish to pursue them. It is our recommendation that Massachusetts adopt the BGS label as a replacement for the term “default service” post February 28, 2004.