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INV 2023-001 – DOE Energy Procurement Investigation – Final Report

On May 24, 2023, the New Hampshire Department of Energy (Department) issued an Order of Notice commencing DOE Docket INV 2023-001, an investigative proceeding relative to energy service procurement in New Hampshire. At the outset of this proceeding the Department engaged the services of Exeter Associates, Inc. (Exeter), a leading energy, economics, and regulatory consulting firm providing economic and financial consulting services in the areas of public utility regulation and energy economics. Enclosed is the final report prepared by Exeter on behalf of the Department.

As described in the report, the recommendations provided herein are based on Exeter's assessment of the New Hampshire power industry; statutes and regulations relevant to default service; historical and current default service arrangements; recent market conditions; stakeholder comments in DOE INV 2023-001, New Hampshire Public Utilities Commission Docket IR 22-053, and in response to Exeter and DOE inquiries; and observed practice in other retail choice jurisdictions. Exeter also considered a variety of criteria when developing recommendations, including policy objectives, adaptability to changing market conditions, implementation requirements, and potential market impacts for customers, electric distribution utilities, retail suppliers, and wholesale suppliers.

The Department would like to express its gratitude to Exeter for its diligence in preparing this report and looks forward to the next steps in addressing the future of energy procurement in New Hampshire.

Jared S. Chicoine
Commissioner

Solicitation and Procurement of Default Electric Service in New Hampshire

March 28, 2024

Prepared for:

New Hampshire Department of Energy

in Response to INV 2023-001

Prepared by:

EXETER

ASSOCIATES, INC.

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Any errors remaining in this report are the sole responsibility of the authors.

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LIST OF ACRONYMS

C&I	Commercial and industrial
CEP	Competitive electricity provider
Commission	New Hampshire Public Utilities Commission
Coop	Customer-owned cooperative utility
COS	Cost of Service
CY	Calendar year
D.C.	District of Columbia
DASI	Day Ahead Ancillary Services Initiative
DOE	New Hampshire Department of Energy
EDU	Electric distribution utility
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRC	Full-requirements, load-following contract
GSE	Granite State Electric
IEP	Inventoried Energy Program
IOU	Investor-owned utility
IPA	Illinois Power Agency
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
kW	Kilowatt
kWh	Kilowatt-hour
LMP	Locational marginal price
MISO	Midcontinent Independent System Operator
Mystic	Mystic Power Plant
Muni	Municipally owned utility
MW	Megawatt
MWh	Megawatt-hour
NEPOOL	New England Power Pool
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
P.L.	Public Law
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PSNH	Public Service Company of New Hampshire
PUC	New Hampshire Public Utilities Commission
REC	Renewable energy credit
RFP	Request for proposal
RPS	Renewable Portfolio Standard
RTC	‘Round-the-clock
RTO	Regional transmission organization
TOU	Time-of-use

EXECUTIVE SUMMARY

This report was prepared on behalf of the New Hampshire Department of Energy (Department or DOE) as part of DOE's Investigative Proceeding Relative to Energy Service Procurement (INV 2023-001). The report focuses on potential improvements to default electric service available to New Hampshire's electric utility customers who do not participate in the competitive retail electricity market.

The recommendations provided herein are based on Exeter Associates, Inc.'s (Exeter's) assessment of the New Hampshire power industry; statutes and regulations relevant to default service; historical and current default service arrangements; recent market conditions; stakeholder comments in DOE INV 2023-001, New Hampshire Public Utilities Commission (PUC or Commission) Docket IR 22-053, and in response to Exeter and DOE inquiries; and observed best practice in other retail choice jurisdictions. Exeter also considered a variety of criteria when developing recommendations, including policy objectives, adaptability to changing market conditions, implementation requirements, and potential market impacts for customers, electric distribution utilities (EDUs), retail suppliers, and wholesale suppliers.

Summary of Recommendations

This report contains 35 recommendations regarding the default service attributes adopted in New Hampshire. These recommendations include both suggested changes and also recommendations *against* adopting certain strategies proposed by other stakeholders (i.e., maintaining the status quo). The report also identifies seven other topics related to default service that require further study or separate assessment, and provides four initial recommendations pertaining to these topics.

Default Service Attributes

1. Default Service Provider and Procurement Entity

1.1 Do not deviate from the current practice of assigning default service provider and procurement responsibilities to the EDUs.

1.2 Do not adopt a single, statewide procurement process overseen by a centralized procurement entity.

1.3 Consider introducing a limited capacity independent advisor (contracted through DOE) to specifically support the assessment and approval of default service bids.

2. Product Types

2.1 Continue to assign the responsibility of meeting hourly load obligations and all accompanying energy market requirements to wholesale suppliers via full-requirements, load-following contracts (FRCs).

2.2 Exclude long-term (i.e., greater than five years) contracts from default service FRCs.

2.3 Adopt monthly, variable price contracts for all large customers. These contracts should pass-through energy costs.

2.4 Do not change the current approach of procuring fixed-price FRCs for all small customers.

3. Laddering

All else equal, pricing for utilities with laddered contracts adjusts more slowly to changes in market conditions. This applies to both decreases and increases in market costs. Stakeholders presented mixed views of laddering in response to DOE INV 2023-001 and PUC Docket IR 22-053. Commission and Legislative preference for market-reflective rates versus stable rates has also varied over time. Most retail restructured states employ laddering, at least for residential and small customers. The appropriate path forward for laddering in New Hampshire requires careful consideration of the state's objectives for default service, and likely varies by customer class. As such, Exeter's recommendations regarding laddering are sensitive to the assumptions applied.

If key stakeholders value market reflectiveness higher than rate stability, Exeter recommends that New Hampshire maintain the current procurement approach (subject to the other recommendations discussed in the report).

If key stakeholders value rate stability higher than market reflectiveness, Exeter recommends that New Hampshire consider the following:

3.1 Implement laddering for residential and small customers both in terms of delivery period (i.e., overhanging contracts) and products (i.e., multiple, stacked procurements for each period).

3.2 To implement laddered contracts, use two sets of contracts. During the initial procurement, each utility should procure one set of contracts totaling 50% of the Small Customer Group load for six months, and a second set of contracts totaling 50% of load for one year. Then, in the subsequent procurement, when the six-month contracts expire, a new set of contracts should be solicited for an additional 50% of the load during the next year. That same arrangement would be in place for all subsequent years such that half of the total Small Customer Group load for each utility would be repriced every six months.

3.3 Use one-year overlapping contracts in place of shorter- or longer-term contracts in order to balance rate stability with administrative cost and potential risk premium.

3.4 Delay implementation of stacked contracts until after implementing overhanging contracts.

Related to Exeter's laddering recommendations, but applicable irrespective of the laddering approach that New Hampshire adopts, Exeter also recommends that the Commission and utilities:

3.5 Reclassify Unitil's current Medium Customer Group, inclusive of Rate G2 and Rate OL customers, as part of Unitil's Small Customer Group, and move Liberty's Rate G-2 customer class from Liberty's Large Customer Group into the Small Customer Group.

3.6 Maintain eight tranches (each equal to 12.5% of load) for Eversource, and implement two tranches (each equal to 50% of load) for Liberty and Unitil for each utility's Small Customer Group.

3.7 Do not change the tranche sizes for the Large Customer Groups.

4. Timing

4-1. Should New Hampshire adopt longer-duration (i.e., greater than six months) contracts, approve contract durations of no longer than 24 months on account of uncertainties characteristic of the Independent System Operator of New England (ISO-NE) market. Contract durations equal to or less than 12 months are appropriate in the near term due to uncertainty related to community power aggregation.

4-2. Maintain the current biannual procurement schedule.

4-3. Continue to mitigate seasonal price volatility by either splitting up January and February or, for small customers, procuring longer-duration contracts that smooth out fixed costs over at least 12 months.

4-4. Extend the period of time between final bid approval and contract maturity to at least 2.5 months (from less than two months, typically) in order to support contingency planning, but not more than seven months to manage uncertainty related risk premium.

5. Oversight

5.1 Do not change the level of Commission oversight of default service procurement, such as by adopting a managed portfolio approach.

5.2 Continue indefinite-term procurement strategies, subject to revision at the Commission's discretion.

6. Procurement Method

6.1 Do not adopt reverse auctions or other alternative procurement methods at this time.

7. Supplier Eligibility

7.1 Do not adjust existing wholesale supplier eligibility requirements.

7.2 Do not deviate from the existing bid evaluation approach that prioritizes the selection of least-cost providers, regardless of the amount of load they serve.

8. Anti-Gaming and Migration Control

8.1 Restrict the frequency of switching for large customers to the extent that the Commission does not require pass-through pricing for large customers.

8.2 Do not introduce additional anti-gaming limitations for small customers at this time.

8.3 Implement regulation providing additional community power aggregation process and timing clarity rather than adjusting existing FRCs on account of migration risk.

9. Default Service Cost Components

9.1 Evaluate potential costs for pass-through based on a three-pronged assessment of whether the cost is large, variable, and un-hedgeable, and consider treatment on an *ad hoc* basis.

10. Reconciliation

10.1 Minimize reconciliation costs to the maximum extent possible and, when such costs apply, pass them on to customers as close to their occurrence as feasible.

10.2 Address unique reconciliation circumstances, such as those related to mass migration, on an *ad hoc* basis.

11. Contingency Provisions (Failed Solicitation)

11.1 Develop preemptive contingency plans that include multiple, ranked contingency strategies as well as thresholds to determine when contingency strategies are required.

11.2 Prioritize issuance of a replacement request for proposal (RFP) as part of contingency plans for Small Customer Groups.

11.3 Confidentially standardize the proxy prices developed by EDUs and establish general boundaries for application of these prices to the extent that the DOE does not implement an independent advisor to support bid evaluation.

Standardization efforts should not eliminate flexibility to account for market circumstance as part of bid evaluation.

12. Self-Supply

12.1 Do not adopt self-supply procurement methods except in contingency circumstances.

12.2 To the extent that real-time pricing is a preferred part of the default service portfolio, incorporate these pricing components into default service FRCs (rather than adopt self-supply).

12.3 Fix all costs (e.g., capacity, ancillary services, etc.) with the exception of energy when incorporating real-time pricing components into default service.

Other Topics

13.1 Do not conduct separate default service procurements for low-income customers.

13.2 Do not reassign default service customers' Renewable Portfolio Standard (RPS) requirements to wholesale suppliers (in place of EDUs) due to recent Renewable Energy Credit (REC) price uncertainty.

13.3 To the extent New Hampshire incorporates time-of-use (TOU) elements into default supply service, align applicable TOU rates with those that apply to distribution rates. Do not conduct separate default service procurements for TOU-rate customers but, instead, derive a TOU default supply rate administratively.

13.4 Address default-service-specific aggregation implementation issues as part of a separate aggregation proceeding. Future aggregation regulations should increase certainty regarding the timeline from aggregation approval to implementation.

Additional topics identified as relevant to default service but outside the scope of this assessment include Independent System Operator/Regional Transmission Organization (ISO/RTO) participation, categories of restructured utilities, and net metering policies.

I. INTRODUCTION

A. Background

New Hampshire, like other currently restructured jurisdictions, enacted legislation in the late 1990s to separate electricity service into competitive and non-competitive segments.[1] Incumbent utilities retained exclusive monopoly franchise over non-competitive segments, such as transmission and distribution services (i.e., the "wires" business) thought to have natural monopoly characteristics. Competitive segments, including generation and retail services, were opened to new market entrants. Following the restructuring of its generation sector, New Hampshire also became one of 14 jurisdictions to give retail electric customers the right to "shop," meaning pick an electricity supplier among competing providers.

Most customers in New Hampshire have electric power delivered by one of three investor-owned utilities (IOUs). Public Service Company of New Hampshire (PSNH), doing business as Eversource Energy (Eversource), is the largest of the three utilities and serves much of the southern and northern portions of New Hampshire. Eversource accounts for approximately 72% of total electricity sales in New Hampshire. The next largest electric utility, accounting for 11% of total electricity sales in the state, is Unitil Energy Systems (Unitil), formerly Concord Electric Company and Exeter and Hampton Electric Company. Unitil serves the City of Concord and a portion of southeast New Hampshire. Granite State Electric (GSE), doing business as Liberty Utilities (Liberty), is the smallest of the three IOUs, serving approximately 8% of the retail customers in New Hampshire in the western and southern areas of the state. The remaining customers in the state are served by either electric cooperatives (coops) or municipal utilities (munis) which are owned by customers or local governments, respectively, rather than by shareholders. New Hampshire Electric Cooperative, Inc. (NHEC) is the largest coop in New Hampshire, serving approximately 7% of the total load with much of it located in the central portion of the state.[2,3]

Prior to electric restructuring (also referred to as electric deregulation), New Hampshire's IOUs were required to generate (or procure through the wholesale market) electric power sufficient to meet the requirements of their retail customers. The obligation to serve and to ensure the availability of adequate power supplies was coupled with the recognition of franchised monopoly service areas in which the licensed utility maintained the sole right to

[1] The electric power industry in New Hampshire and elsewhere, both historically and currently, is complex and entails regulated and competitive components, regulation at both the state and federal levels, and utility participation in multi-state organizations to facilitate the availability of reliable and lower-cost power. The simplified description presented here will be expanded upon later in this report, as needed, to address particular aspects of service or institutional arrangements related to energy service procurement.

[2] Load data sourced from the U.S. Energy Information Administration (EIA) (2022). Form EIA-861.

[3] Approximately 2% of total load is served by smaller coops and munis, including Ashland Electric, Littleton Light, Wolfeboro Electric, and Woodsville Light.

provide service to retail customers. Prices for IOU service were set by the New Hampshire Public Utilities Commission (PUC or Commission) in a rate case or other similar proceeding in accordance with cost-of-service regulatory principles.

New Hampshire enacted RSA 374-F, Electric Utility Restructuring, in May 1996, and the law took effect January 1998 following legal intervention. In order to restructure, New Hampshire required its IOUs to divest themselves of generation assets and functionally separate competitive and non-competitive business segments. The utilities divested in waves, with Liberty divesting its resources in the late 1990s and Unitil divesting in the early 2000s, following the merger of its predecessors, Concord Electric Company and Exeter and Hampton Electric Company. Although Eversource began restructuring and allowing customers to seek competitive energy supply in the early 2000s, it did not complete the restructuring process and fully divest from its generation assets until 2018.[4]

With the commencement of restructuring and retail choice, New Hampshire relieved the IOUs of their obligation to originate the power supply component of electric service, and designated the incumbent IOUs as primarily responsible for the delivery of electric power to retail customers (including fulfillment of certain related functions). In place of the traditional monopoly service model, customers could obtain supply in one of two new ways: through competitive electricity providers (CEPs) or from a default service alternative (also known as Standard Offer Service [SOS] or basic service) managed by the incumbent IOU. The PUC made the latter option available to customers who chose not to, or could not, shop for power, and approved utility-specific plans to competitively procure default service at market rates as part of utility-specific proceedings.

Over the course of the more than 20 years since the introduction of electric utility restructuring in New Hampshire, some unanticipated challenges have emerged for wholesale markets, retail competition, and, most directly relevant to this report, default service procurement. These circumstances are not unique to New Hampshire; they have also been experienced, to varying degrees, in other jurisdictions that have restructured their retail electric power industries. Problems related to default service have included: high degrees of rate instability; high price levels; new load and price risks in wholesale markets; the introduction of difficult-to-hedge, out-of-market supply costs; and declining levels of wholesale supplier participation in procurements.

Exeter prepared the following report on behalf of the New Hampshire Department of Energy (Department or DOE) as part of DOE's *Investigative Proceeding Relative to Energy Service Procurement* (Investigation or INV 2023-001). DOE initiated this proceeding in response to

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[4] Following the initial restructuring plan issued by the PUC, Eversource filed a lawsuit regarding the constitutionality of the 1997 Restructuring Act. As a result of the lawsuit, Eversource was allowed to keep its generation assets for a period of 10 years to recover the costs of the Seabrook Nuclear Facility and other fossil/hydro generation plants. Further delays in divestiture following the end of the 10-year period resulted in Eversource not finishing the restructuring process until 2018.

the Commission's *Report On New Hampshire Energy Commodity Procurement* and the issues raised in PUC Docket IR 22-053, *Investigation of Energy Commodity Procurement (Renewable Portfolio Standard; Default Service Electric Power; Cost of Gas Methodology and Process).* The Department filed comments in the Commission's proceeding stating its intent to open an investigation in which it would further examine specific topics and unresolved questions relevant to default service.

Pursuant to the Department's Order of Notice and further guidance from the Department, this report presents Exeter's review of the method by which default service is provided in New Hampshire and the important factors relevant to the success of default service procurement in the state. Exeter also provides discussion and analysis of the components of default service in restructured jurisdictions as they relate to important factors of New Hampshire's default service. The analysis presented herein, along with the requisite background material needed to fully understand the issues being addressed, informs a series of conclusions and recommendations intended to (1) help improve the functioning of electric service procurement in New Hampshire; and (2) help mitigate some of the adverse impacts that have accompanied changing market conditions in New Hampshire and the broader electric power industry.

B. NH DOE INV 2023-01

On May 24, 2023, DOE issued an Order of Notice opening INV 2023-001. As part of this Order, DOE specified the intent of the Investigation as addressing the following questions and issues:

1. Are current energy service procurement methodologies adequately addressing the restructuring policy principles identified in RSA 374-F:3 or would an alternative method provide a better opportunity to accomplish the policy principles?
2. More analysis of the methodologies used by other restructured states that provide default/provider of last resort energy service.
3. The potential benefits and risks of using self-supply for default service as a replacement for the current, six-month competitive procurement method.
4. Whether the current procurement methodologies are providing sufficiently market-based pricing for energy service by accurately representing risks that market participants face when responding to energy service requests for proposals issued by New Hampshire's regulated utilities.
5. Whether an alternative procurement methodology might provide a more robust approach at delivering prices with lower risk premium amounts under a variety of market conditions.
6. Would a change to an alternative energy service procurement method create market disturbances resulting in undesired market outcomes?

DOE also identified its intent to prepare and disseminate a comprehensive report that explores and provides recommendations regarding the above questions, among other topics relevant to default service. DOE issued three data requests as part of INV 2023-001. The first data request sought feedback from utilities and suppliers on procurement methods and processes, solicitation contingency provisions, bidder participation, and barriers to participation. The second data request asked utilities to expand upon their previous comments about interactions with wholesale suppliers, the solicitation process, bids received in recent procurements, community power aggregation, and self-supply. The third data request, directed at wholesale suppliers, asked for further information on decisions to participate in solicitations, the effect of solicitation timing and consistency on participation and bids, and the effect of state policies or practices on participation and bids. DOE did not receive written comments in response to the third data request. Following the data requests, DOE held additional interviews with several stakeholders to seek further clarification on topics addressed in the data requests. Table 1 lists the dates and stakeholders involved in these additional interviews.

Table 1. Interview Schedule

Stakeholder	Interview Date(s)
Dr. Margarita Patria, Charles River Associates	October 6, 2023
Eversource	October 5, 2023 October 12, 2023 October 20, 2023
Liberty	October 12, 2023
Unitil	October 27, 2023

Interview discussions supplemented DOE's data requests and addressed topics including wholesale supplier interactions and participation in solicitations, customer migration, procurement methods and processes, and procurement risk factors. DOE also facilitated interviews to discuss community power aggregation implementation procedures from the perspective of the utility, the trade-offs between different procurement auction strategies, and how utilities derive proxy prices for use during procurement evaluation.

II. NEW HAMPSHIRE ELECTRIC POWER INDUSTRY

A. Pre-Restructuring

Prior to restructuring, New Hampshire's electric utility industry primarily relied on vertically integrated IOUs to oversee all stages of electricity service, including power generation, transmission, delivery, and retail services. This approach reflected the widely held belief that the network characteristics and high fixed costs of electricity service gave rise to natural monopolies. IOUs accepted an obligation to provide safe, reliable service in exchange for exclusive franchise over a designated service territory and an opportunity—but not a guarantee—to earn a reasonable rate of return on prudent investments.[5]

Electric utility restructuring emerged from several market and policy changes that caused policymakers and regulators to reconsider the above assumptions. The origins of these changes trace back to the 1973 oil crisis. Subsequent volatility in oil prices exposed vulnerabilities inherent to New England's reliance on oil as an input for electricity generation and introduced significant price inflation for the first time in nearly two decades. Retail prices remained elevated over the next two decades as a result of slower-than-forecast electricity demand growth and soaring utility costs stemming from cancellations, abandonments, and cost overruns of several nuclear plants, among other factors. In the midst of these conditions, federal policymakers and regulators created conditions conducive to wholesale market competition. This includes the passage of the Public Utility Regulatory Policies Act of 1978, the Energy Policy Act of 1992, and implementation of several Federal Energy Regulatory Commission (FERC) orders requiring utilities to implement non-discriminatory open access transmission tariffs. These conditions encouraged consideration of alternative approaches to utility service and regulation.[6]

B. Restructuring Goals

In 1996, New Hampshire became the first state to pass legislation enabling electric utility restructuring. The state legislature specified its main motivation for passing the enabling statute as the high electricity rates in New Hampshire, which ranked among the highest in the nation (see Figure 1).[7] The legislature also expressed concern that electric rates would likely continue to rise, with corresponding negative impacts on consumers and economic

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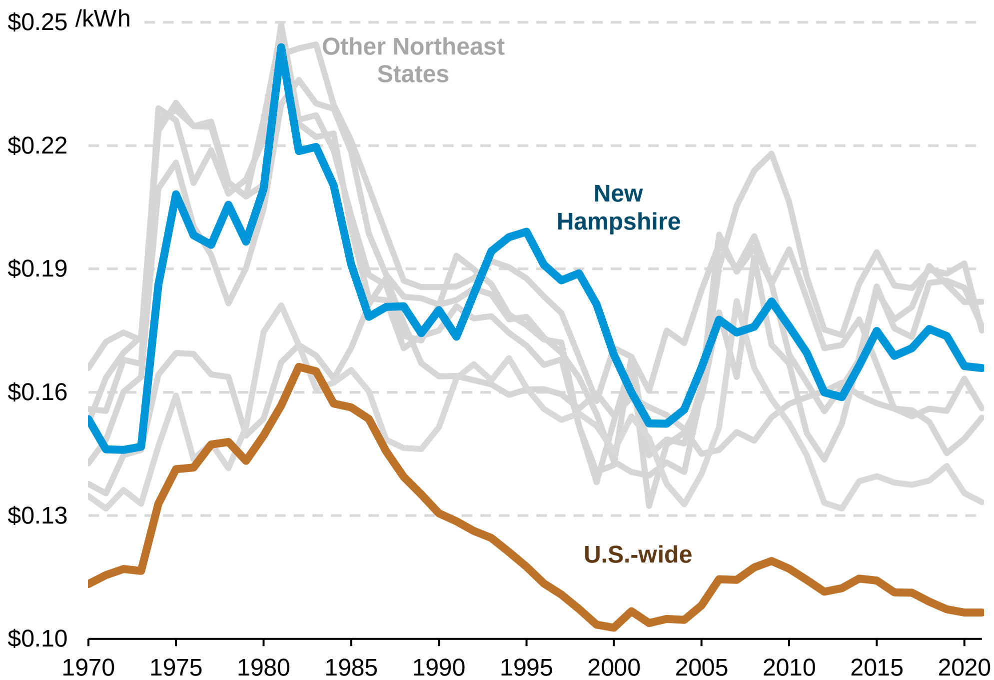
[5] This agreement is commonly referred to as the regulatory compact. As is still the case today for non-competitive portions of electric service (i.e., distribution service), the New Hampshire PUC sets service rates in accordance with well-established cost of service ratemaking principles. That is, the PUC determines an overall revenue requirement sufficient for the utility to recover its costs (including a reasonable return on investment) and allocates this requirement across customer classes via rates set in relation to costs incurred.

[6] New Hampshire PUC (1997). Docket DR 96-150. Order 22,514. *Statewide Electric Utility Restructuring Plan*.

[7] New Hampshire Legislature (1996). House Bill (HB) 1392. *An Act restructuring the electric utility industry in New Hampshire and establishing a legislative oversight committee.*

growth. To address these concerns, the legislature called for New Hampshire to "aggressively pursue restructuring and increased customer choice" with the goal to "develop a more efficient industry structure and regulatory framework […] while maintaining safe and reliable electric service."[8]

Figure 1. Historical All-Sector Average Electricity Prices (2020$)



Note: Adjusted to 2020$ using the Bureau of Labor Statistics' national Consumer Price Index (CPI) (through 1978) and CPI-U (1979-2020).

Source: U.S. Energy Information Administration (EIA) (2022). "Coal and Electricity Retail Sales Price and Expenditure Estimates, 1970-2021." State Energy Data System. eia.gov/state/seds/sep_sum/html/xls/pr_ex_cl_es.xlsx.

Chapter 374-F, Electric Utility Restructuring, of the New Hampshire Public Utilities Code (Pub. Util. Code) called for the New Hampshire PUC to implement restructuring no later than July 1, 1998, and provided the Commission with guidelines on both restructuring and the development of a default service product. According to this legislation, restructuring would:

1. Provide incentives to electric suppliers to operate efficiently and cleanly;
2. Open markets for innovation;
3. Provide buyers and sellers with appropriate price signals; and
4. Improve public confidence in the electric utility industry.

[8] Id.

Other major restructuring policy principles included: maintaining reliable service; promoting customer choice and setting the expectation that customers are "responsible for the consequences of their choices"; providing "clear price information" for each of the unbundled service cost components; and ensuring that restructuring "benefits all customers equitably."[9] The restructuring statute called for default service to be designed "to provide a safety net and to assure universal access and system integrity."[10] Due to the unique circumstances of each jurisdictional utility, the statute does not outline specific rules regarding default service. Instead, it directed the Commission to develop default service arrangements as appropriate for each utility. The statute also gave the Commission authority to "implement measures to discourage misuse, or long-term use, of default service" if in the public interest.[11]

In 1997, the Commission issued its Statewide Electric Utility Restructuring Plan (Restructuring Plan), which directed each utility to unbundle their transmission, distribution, and generation rates and divest their generation assets within two years following the onset of competition.[12] In the Restructuring Plan, the PUC stated that default service would be procured competitively through either competitive bids or spot market purchases that would provide customers an opportunity to realize the benefits of competition even if they did not directly participate in the market. The Restructuring Plan also designated the electric distribution utilities (EDUs) as default service providers to all residential and small commercial customers. Initially, policymakers envisioned default service as remaining available to large commercial and industrial (C&I) customers for only a six-month transition period. Following the transition period, these customers would have been precluded from taking default service except for when they were temporarily between suppliers, and only then for a period of no longer than 60 days. In the Restructuring Plan, the Commission cautioned against long-term power contracts for default service, fearing they would create stranded costs. The PUC opined that "default service, in our view, should be made up of suppliers of a short contractual duration which will not create stranded costs regardless of the number of customers that may choose to acquire their own supplies."[13]

Although legislation directed that restructuring begin by 1998, this process was significantly delayed by utility appeals to the PUC and lawsuits regarding different parts of the restructuring plan, most significantly the recovery of stranded costs. Eversource became the last utility to complete its restructuring process in 2018 when it fully divested from its generation assets.

[9] New Hampshire Legislature (1996). Public Utilities Electric Utility Restructuring. [Chapter 374-F ELECTRIC UTILITY RESTRUCTURING (state.nh.us)](state.nh.us).

[10] Id.

[11] Id.

[12] New Hampshire PUC (1997). Docket DR 96-150. Order 22,514. *Statewide Electric Utility Restructuring Plan*.

[13] Id.

C. Historical Procurement Approach

New Hampshire Pub. Util. Code RSA 374-F requires default service to be tailored to the particular circumstances of each jurisdictional utility. This provision, and the fact that each utility deregulated and began offering default service at different times, has resulted in the absence of a unified procurement strategy for all the utilities. Instead, the rules for procurement have been developed in individual dockets for each utility and have been modified in a similar fashion over the years. What follows is a brief overview of the historical approaches used by New Hampshire utilities to procure default service, as well as brief discussion of the justifications in support of changes.[14]

1. Liberty

Granite State Electric (GSE), currently known as Liberty Utilities, filed an initial proposal for the implementation of default service on December 27, 1999, and became the first utility in the state to offer default service. In its first Request for Proposal (RFP), GSE received bids for a short-term supply agreement to provide default service through April 20, 2000.[15] For the first several solicitations, GSE had no default customers.[16] To foster competitive bidding, GSE combined its procurements with the procurements of its Massachusetts affiliates (Massachusetts Electric Company and Nantucket Electric Company), which had several thousand customers.[17,18] GSE greatly varied its procurement strategy over the first few years of default service. The company issued solicitations for several different time periods, ranging from four months to a year, and switched between having fixed prices for the entire term and variable prices that changed each month. After testing these different strategies, GSE filed a plan in 2005 to revise its default service approach and account for the upcoming expiration of transition service on April 30, 2006.[19] Following approval of this plan, GSE split its customers into small and large groups (in place of uniform pricing across all customers). For small customers, GSE conducted solicitations every six months for fixed-price, full-requirements, load-following contracts (FRCs). For large customers, GSE held solicitations every three months for monthly, variable price FRCs.[20]

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[14] For additional description and definition of default service elements discussed in this section, see Section III, "ELECTRIC POWER INDUSTRIES IN OTHER RESTRUCTURED Jurisdictions."

[15] New Hampshire PUC (2000). Docket DE 99-205. Order 23,393.

[16] Customers who had not selected a CEP instead received transition service from the utility.

[17] In a 2003 solicitation, a bidder was chosen that did not offer the lowest rate for GSE customers but did offer the lowest rate for Massachusetts customers. When asked about this decision, GSE stated that the GSE bidder with the least-cost offer for New Hampshire declined to service only the New Hampshire portion of load. Since Massachusetts had significantly more customers than GSE, GSE selected the bidder that offered the lowest rate for Massachusetts.

[18] New Hampshire PUC (2003). Docket DE 03-079. Order 24,163.

[19] New Hampshire PUC (2006). Docket DE 05-126. Order 24,577.

[20] Id.

In 2012, Liberty Utilities acquired GSE and began doing business as Liberty Utilities in New Hampshire. Shortly after acquiring GSE, Liberty filed for a change in its default service process. Instead of soliciting quarterly products for large customers, Liberty began issuing two (2) consecutive, 3-month solicitations during biannual procurement processes. As justification for this change, Liberty cited administrative efficiencies of less frequent procurements and likely reductions in price volatility.[21]

In 2015, Liberty petitioned to alter the timing of all its solicitations to procure service for six-month periods beginning February 1 and August 1 of each year, in place of the existing timeline of periods beginning November 1 and May 1. The company argued that by splitting up the two highest-cost months of January and February, customers that take default service would experience less seasonal rate volatility. Some wholesale suppliers raised concerns about this plan, claiming it would be hard to obtain separate monthly pricing for these products because wholesale markets generally transact products that include December through February together. One supplier indicated that, if the PUC adopted this change, it would no longer submit bids for the Small Customer Group due to uncertainty regarding incremental costs associated with Winter Reliability Programs.[22] Additionally, suppliers raised concerns that the inclusion of a high-cost winter period in two of the three-month solicitations would lead to increased migration risk in the Large Customer Group.

Despite the above contentions, the Commission approved the change on the basis that splitting January and February might reduce price volatility and provide more rate stability for the Small Customer Group. The Commission cited New Hampshire's restructuring statute in its order, finding that "RSA 374-F:3, V(e) authorizes the Commission to approve alternative means of providing default service which are designed to minimize customer risk, not unduly harm the development of competitive markets, and mitigate against price volatility without creating new deferred costs, provided that the Commission finds such means to be in the public interest." [23] In the decision, the Commission also mentioned that all customers are still able to obtain competitive energy supply as a substitute.

2. Unitil

Unitil was the second New Hampshire utility to restructure and began providing transition and default energy service in May 2003.[24,25] During this early period, Unitil supplied default service to large (i.e., Rate G1) customers by soliciting FRCs on a quarterly basis. Large

[21] New Hampshire PUC (2013). Docket DE 13-018. Order 25,601.

[22] New Hampshire PUC (2015). Docket DE 15-010. Order 25,806.

[23] Id.

[24] On May 1, 2006, the transition period ended, and all customers receiving transition service were switched to default energy service. New Hampshire PUC. Docket DE 04-197. Order 24,420.

[25] New Hampshire PUC (2003). Docket DE 01-247. Order 24,139. *Order Approving Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement by and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing LP*.

customers were charged a variable monthly rate set during the quarterly procurements. For non-large, residential, and small business customers, Unitil solicited default service using a portfolio, or laddering, approach. This portfolio included four tranches, each representing 25% of the load; two tranches were purchased for 1-year terms, and two tranches were purchased for 3-year terms. Under this structure, Unitil procured a new 1-year tranche every six months and a new 3-year tranche every 18 months, and blended the four products into a single fixed price using the weighted average price of each tranche.[26]

In 2012, Unitil petitioned the PUC to change its default service solicitation approach. Unitil requested to phase-out laddering for non-large customers and instead solicit 100% of the load every six months. Unitil claimed that the proposed approach was preferable because wholesale suppliers viewed longer-term obligations as riskier. Phasing out the 12- and 24-month contracts in favor of 6-month terms, therefore, could reduce wholesale supplier risk premium and increase wholesale supplier competition. These changes, in turn, could result in lower prices for customers. In addition, Unitil requested to split its non-large customer solicitations into two groups, small and medium, to better represent the distinct load and risk factors for each group. The Commission approved this new approach and stated that the shorter terms would provide more accurate price signals to customers as well as encourage small retail customers to avail themselves of competitive third-party supply, which is consistent with the goals of restructuring.[27]

In the same 2012 petition to change its solicitation approach, Unitil requested to change its large customer solicitation term from quarterly solicitations to biannual procurements. Additionally, Unitil requested to apply variable prices with a fixed monthly adder to large customers. Unitil believed this approach would discourage customers from strategically switching between competitive supply and fixed-rate default service. The Commission agreed and approved these changes.[28]

3. Eversource

Eversource, previously known as the Public Service Company of New Hampshire (PSNH), was the last New Hampshire utility to restructure and offer default service through a competitive bidding process. The company partially restructured in 2001 by unbundling its vertically integrated services. Eversource did not, however, begin offering competitively procured default service until 2018, over 20 years after New Hampshire initiated restructuring. This delay was caused in part by court cases surrounding the recovery of stranded costs for the Seabrook Nuclear Facility and other fossil/hydro generation facilities, as well as the constitutionality of the 1997 Restructuring Act. In March 1997, the Federal

[26] New Hampshire PUC (2005). Petition for Approval of a Default Service Supply Proposal for G1 and Non-G1 Customers and Approval of Solicitation Process. Docket 24,511.

[27] New Hampshire PUC (2012). Docket DE 12-003. Order 25,397.

[28] Id.

District Court granted a temporary restraining order that stayed the Commission from implementing its restructuring plan.[29] In 2000, Commission Staff, PSNH, and other government officials reached a settlement agreement that allowed PSNH to keep its generation resources but also establish retail electric choice and transition/default service.[30] During the period that Eversource still owned generation resources, the default service rate was set equal to Eversource's actual costs of providing power, as approved by the Commission on a calendar year basis.[31]

In 2015, Eversource entered into another settlement agreement and began divesting itself of its generation resources consistent with New Hampshire's restructuring objectives. This agreement stated that, no later than six months after the closing of its expected divestiture, Eversource would begin using a competitive procurement process.[32] In 2017, Eversource submitted a proposal for its default service procurement process to the Commission. As a part of this plan, Eversource proposed that it solicit FRCs twice a year for two sets of customers. For small customer classes, Eversource favored laddering and recommended the solicitation of fixed prices for one-year blocks of energy every six months, with each block representing 50% of load. Eversource noted that this approach was similar to the approach used by its affiliates in Massachusetts and Connecticut.

For large customer classes, Eversource recommended soliciting variable monthly prices for one tranche of 100% of load every six months. In the settlement agreement for the case, Eversource agreed to procure service for 100% of the load every six months for both large and small customers. For the small customer class, Eversource stated it would procure tranches of around 100 megawatts (MW). Additionally, Eversource set up its procurement periods to split up the two most expensive months of the year, January and February, following Liberty's lead. Eversource's first solicitation took place in January 2018 and had four tranches for residential customers, each equal to 25% of the load, and one tranche for large customers equal to 100% of the load.[33]

[29] New Hampshire PUC (2013). Docket IR 12-020. *Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market.*

[30] In April 2001, the state legislature passed HB 489 into law, amending existing legislation (RSA369-B:3-a) and granting Eversource the authority to offer transition supply service until at least 2006. After 2006, the statute stated that "PSNH may divest its generation assets if the Commission finds that it is in the economic interest of retail customers of PSNH to do so and provides for the cost recovery of such divestiture." See: New Hampshire PUC (2013). Docket IR 12-020. *Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market.*

[31] New Hampshire PUC (2013). Docket IR 12-020. *Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market.*

[32] New Hampshire PUC (2017). Docket DE 17-113. Order 26,092.

[33] Id.

D. Recent Market Conditions

Since 2020, prevailing market conditions have created a series of challenges for default service procurement in New Hampshire. First, as a consequence of the COVID-19 pandemic, electricity usage patterns for all customer classes changed in 2020, with varying degrees of persistence since that time, on account of public health interventions (e.g., stay-at-home orders leading to increased residential demand and reduced commercial demand).

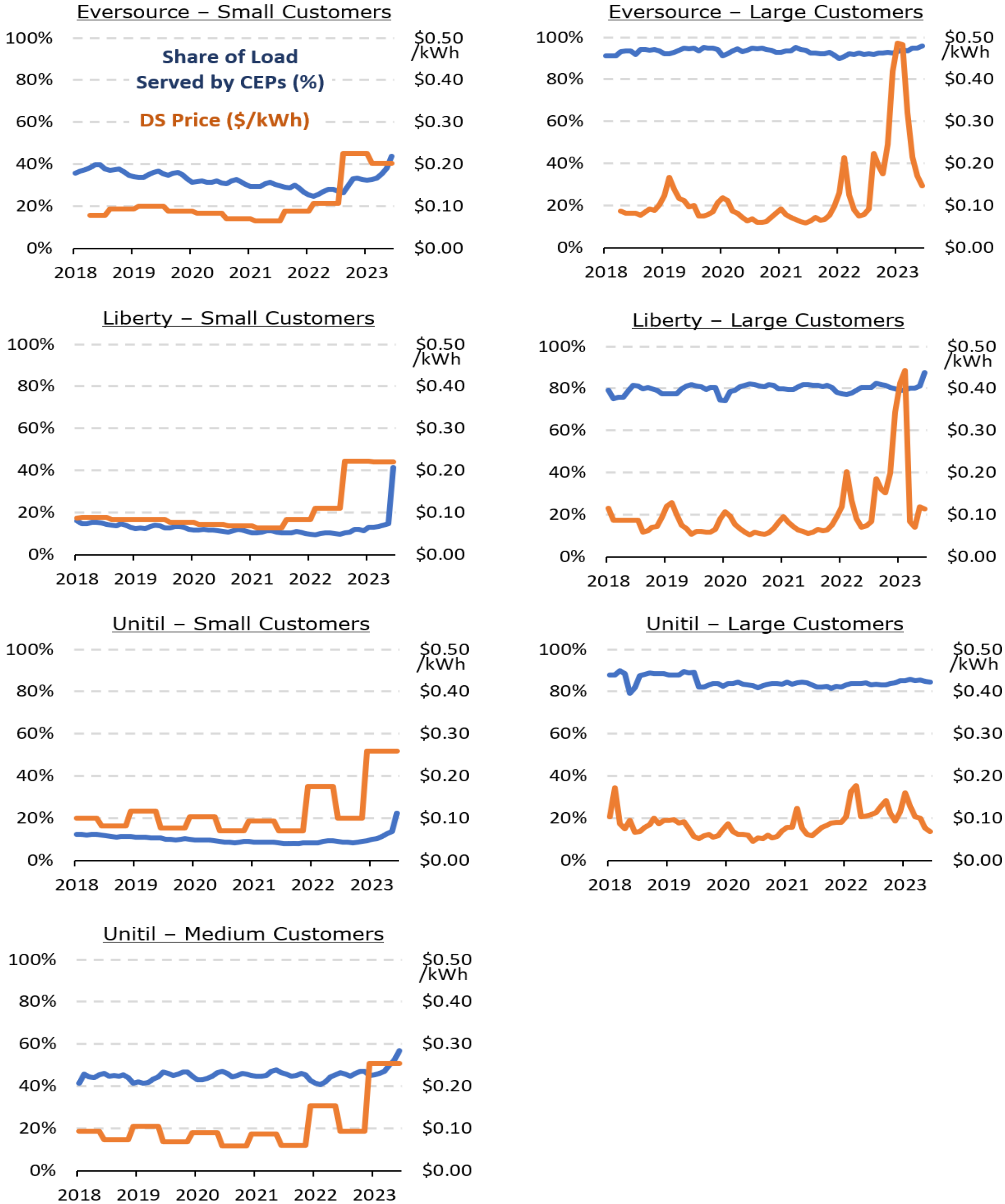
Second, as economic activity rebounded in late 2021 and early 2022, global events, most notably Russia's invasion of Ukraine and subsequent international response, introduced turmoil into energy markets. This turmoil included substantial increases in international demand for liquefied natural gas, with downstream impacts on U.S. natural gas prices and, therefore, electricity prices. These impacts were particularly acute in the Northeast.

Third, the Independent System Operator of New England (ISO-NE) has taken a variety of steps to address resource adequacy challenges related to the energy transition in the last few years, both at the behest of state and federal regulators and in response to stakeholders. These steps include various market design reforms as well as non-market interventions (e.g., the Mystic Power Plant [Mystic] reliability-must-run determination and associated Cost of Service [COS] agreement).[34] Confounding the various challenges outlined above, New Hampshire introduced new energy policies, including allowing community power aggregation, that impact customer participation in competitive retail electric markets.

What follows is a brief description of recent default service solicitations and procurement outcomes for New Hampshire's three IOUs since 2020. These results illustrate the challenges stemming from the above market changes (among others) and identify key limitations and uncertainties that this report aims to address. Figure 2 shows the recent increases in default service prices that correspond with the below procurement descriptions, by utility and customer group. Although prices increased for all groups, they increased the most for the Large Customer Group with the notable exception of Unitil, which passes through wholesale energy costs for large customers. Additionally, Figure 2 highlights recent changes in customer shopping activity (i.e., adoption of CEP supply). In general, large customers shop at much higher rates than small or medium-sized customers. Recent increases in small customers switching reflect the implementation of several community power aggregations. A brief description of New Hampshire's community power aggregation policies concludes the description of recent market conditions.

[34] The Mystic COS agreement results in additional out-of-market capacity charges to all customers that are tied to prevailing wholesale market prices. These payments are intended to retain Mystic service for fuel security purposes.

Figure 2. Share of Utility Customer Load Served by CEPs and Default Service Price



Source: Data from migration reports provided by each utility in Docket INV 2023-001 in response to DR DOE 2-12.

1. Liberty

Liberty first observed an uptick in default service prices in 2020 after the bids for its Large Customer Group for the August 2020 – January 2021 solicitation were higher than the company forecast. Liberty attributed this change to market uncertainty.[35] However, in the following two default service periods (i.e., service from February – July 2021 and August 2021 – January 2022), prices returned to pre-2020 levels and Liberty did not identify any notable change in auction participation or bid level. This stability dissipated in 2022 as markets became more volatile. Both the Small and Large Customer Groups experienced an increase in rates for the August 2022 – January 2023 service period following an auction with decreased participation.[36] Subsequently, the solicitations for the February – April 2023 service period did not attract any bids for the Large Customer Group. In response, Liberty, with approval from the PUC, issued a second RFP that, again, did not receive acceptable bids. [37] After the second failed solicitation, Liberty procured power on the day-ahead and real-time market for large customers. The Commission, in its approval of Liberty's contingency plan, noted that the high rates resulting from the above procurements reflected market conditions.[38]

Participation remained low (compared to historical levels) during Liberty's most recent solicitation (August 2023 – January 2024). Liberty attributed this sustained decline to ongoing volatility in the ISO-NE wholesale energy market and uncertainties related both to the Mystic COS agreement and community power aggregation.[39] However, as compared to the February – July 2023 period, the August 2023 – January 2024 load-weighted average rate decreased.[40]

2. Unitil

Unitil customers did not experience notable increases in rates until the December 2021 – May 2022 service period, when prices spiked by 164% for residential customers and 179% for medium customers. Additionally, the large customers' adder spiked by approximately 69% from the prior 6-month period.[41] In the accompanying PUC filing requesting approval, Unitil attributed this change to increases in natural gas prices.[42] During the subsequent solicitation period (June – November 2022), Unitil attracted more participants and received

[35] New Hampshire PUC (2020). Docket DE 20-053. Order 26,372, p. 5.

[36] New Hampshire PUC (2022). Docket DE 22-024. Order 26,643, p. 4.

[37] New Hampshire PUC (2023). Docket DE 22-024. Order 26,758, pp. 2-3.

[38] New Hampshire PUC (2022). Docket DE 22-024. Order 26,752, pp. 6-7.

[39] New Hampshire PUC (2023). Docket DE 23-044. Testimony of Warshaw & Green (June 23, 2023), p. 9.

[40] Id., p. 14.

[41] New Hampshire PUC (2020 & 2021). Dockets DE 20-039 and DE 21-041. Tariff Filings. The adder is an approximation based on the average 6-month rate for each period. Notably, Unitil only expected a 3.5% increase in the adder for large customers.

[42] New Hampshire PUC (2021). Docket DE 21-041. Order 26,532, p. 3.

lower bids, but still at elevated rates compared to the same time period the year before.[43] The number of bidders also remained historically low for the Large Customer Group due to the small load size and migration risk. Subsequently, Unitil, with Commission approval, held an eight-month default service supply period, from December 2022 – July 2023, to align its procurement schedule with Liberty's and Eversource's.[44] Rates for this eight-month period more than doubled for the residential and small commercial groups from the previous period and bidder participation was, again, low due to market volatility.[45]

Unitil's most recent solicitation, for August 2023 – January 2024, attracted "significantly higher" bidder participation compared to the previous solicitation and, while some previous suppliers continued to not participate due to market volatility, Unitil approved a new supplier.[46] The resulting rates were still higher than the same months in the previous year, but decreased from the price spike observed during the eight-month solicitation.

3. Eversource

Rates increased moderately across the procurements obtaining default service supply for the period August 2020 – July 2022. The PUC did not remark on these changes in the corresponding dockets.[47] However, following price spikes during the August 2022 – January 2023 solicitation, the Commission ordered a proceeding to review Eversource's solicitation procedure (as the Commission also ordered for Liberty and Unitil) in response to, among other reasons, residential power rates increasing by 112% and large customer rates increasing by 157% from the previous 6-month period.[48,49] Eversource cited increases in natural gas prices, a common marginal fuel source for power generation, as a reason for the price spike.[50]

Prior to the next solicitation period, for service during February – July 2023, Eversource petitioned to modify its procurement schedule to pre-authorize the company to self-supply on the day-ahead market if the solicitation failed.[51] Eversource also proposed an additional step in which the Commission, Office of Consumer Advocate, DOE, and the utility met to

[43] New Hampshire PUC (2022). Docket DE 22-017. Order 26,601, p. 1.; and Testimony of Pentz (March 25, 2022), p. 8.

[44] New Hampshire PUC (2022). Docket DE 22-017. Order 26,679, p. 1.

[45] New Hampshire PUC (2022). Docket DE 22-017. Order 26,694, pp. 1 and 6; Docket DE 22-017. Testimony of Pentz (September 23, 2022), pp. 9-10.

[46] New Hampshire PUC (2023). Docket DE 23-054. Testimony of Pentz (June 9, 2023), p. 8.

[47] New Hampshire PUC (2020). Docket DE 20-054. Orders 26,368 and 26,438; New Hampshire PUC (2021). Docket DE 21-077. Orders 26,491 and 26,557.

[48] New Hampshire PUC (2022). Docket DE 22-021. Order 26,645, pp. 1-2.

[49] Id., p. 5.

[50] Id., p. 6.

[51] New Hampshire PUC (2022). Docket DE 22-021. Testimony of Shuckerow and Littlehale (November 15, 2022), pp. 9 and 15.

review the bids to determine whether the solicitation failed.[52] As basis for this request, Eversource cited high risk of a failed solicitation or higher-than-historical bids based on its recent experiences in its affiliates' default service auctions.[53]

The Commission denied Eversource's motion, stating, "We interpret the terms of RSA Chapter 374-F to already enable the Company to go to the ISO-New England market to directly purchase energy to serve its [default supply] customers if conditions warrant. However, we strongly encourage Eversource to engage in a second 'lightning' RFP round in the event of a 'failed' first RFP process, as consistent with past practice."[54] Eversource subsequently revised its tranche sizes, utilizing an increased number of smaller tranches for both the Large and Small Customer Groups, as described below.

Eversource ultimately attracted only one bidder for its Large Customer Group solicitation that offered to serve one tranche (50%) for the class.[55] Following the partial failure of the first solicitation, Eversource issued a second RFP for this group and received an additional bid, allowing the company to meet the entire load obligation.[56] Eversource noted that the bid price secured in the second solicitation was 20% lower than the successful bid for the first tranche in the first RFP. The same wholesale supplier won both bids.[57] The Small Customer Group solicitation had normal participation, and a winning supplier was chosen from the first solicitation. However, small customer rates were well above those during the same months in the previous year.[58]

In Eversource's most recent solicitation, for August 2023 – January 2024, participation increased and bid prices declined.[59] Small Customer Group default service rates were well below the rates from the same months the previous year but higher than historical rates. Similarly, the Large Customer Group's highest cost month of the solicitation, January, is well above the rates for January 2021 and 2020, but below the prior year's peak.

4. Bidder Participation

While rates have somewhat recovered from the price spikes in 2022 and early 2023, participation in solicitations has generally not increased. In the last three years, Liberty

[52] Id., p. 15.

[53] Id., pp. 7-8.

[54] New Hampshire PUC (2022). Docket DE 22-021. Order 26,733, p. 5.

[55] It is unclear whether, under counterfactual circumstances, Eversource would have received any bids had it requested service for 100% of load. It stands to reason, however, that the bidder specifically bid to service only one 50% product, and not both, because it found the smaller product size more attractive.

[56] New Hampshire PUC (2022). Docket DE 22-021. Order 26,747, pp. 5-6.

[57] New Hampshire PUC (2023). Docket DE 22-021. Testimony of Lamontagne, Shuckerow, and Littlehale (January 12, 2023), p. 8.

[58] New Hampshire PUC (2022). Docket DE 22-021. Attachment MBP-1 (December 8, 2022).

[59] New Hampshire PUC (2023). Docket DE 23-043. Testimony of L. Lamontagne and P. Littlehale (June 16, 2023), p. 6.

experienced a failed solicitation that resulted in the utility self-supplying power for a portion of its Large Customer Group, and Eversource experienced a failed solicitation that required a contingency procurement. Along with the failed solicitations, the utilities have experienced lower participation and fewer bids. In testimony, utilities' witnesses described community power aggregation-related load risk, Mystic COS agreement costs, and market volatility as reasons for lower bidder participation.[60]

5. Aggregation

New Hampshire became the most recent state to authorize widescale community power aggregation when it passed NH RSA 53-E, Aggregation of Electric Customers by Municipalities and Counties, in 2019. The legislation established opt-aggregation for municipalities with the intent of allowing more opportunities for small customers to obtain "lower electric costs, reliable service, and secure energy supplies" through retail electricity markets.[61] Community power aggregation allows local governments to enter into retail supply agreements or otherwise procure power on behalf of community members, akin to customers adopting competitive energy supply but at a larger scale and at the behest of a local government.

PUC rules regarding community power aggregation are outlined in Pub. Util. Code 2200 – Municipal and County Aggregation Rules, effective October 12, 2022.[62,63] The Commission's administrative rules expand upon the enabling statute, stating that any municipality, meaning city, town, or county, can act as its constituents' aggregator. The rules also establish a timeline for approval of a community power aggregation application and set various notification requirements for community members, local utilities, and regulators.

As it relates to default service, if the start of aggregation service is set to begin within the first two months of a utility's default supply period, notice to the Commission and local utility must be provided not less than 90 calendar days before the commencement of service. If the start of service is set to occur after the first two months of a utility's default service period, or if there are no known fixed default service rates for a period of six months or more, the notice must be provided no less than 45 calendar days before the commencement of service.[64]

[60] See above cited testimony, specifically Dockets DE 23-044, DE 21-041, DE 22-017, and DE 22-021.

[61] New Hampshire Statutes. Chapter 53-E: Aggregation of Electric Customers by Municipalities and Counties. NH RSA 53-E, https://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-III-53-E.htm.

[62] See New Hampshire PUC Docket DRM 21-142, the Community Power Coalition of New Hampshire Petition for Rulemaking to Implement RSA 53-E for Community Power Aggregations by Stakeholders.

[63] New Hampshire PUC (2022). Docket DRM 21-142. *Chairman Daniel Goldner Filing Adopted PUC 2200 Rules.*

[64] *New Hampshire Code of Administrative Rules.* Chapter PUC 2200 Municipal and County Aggregation Rules. https://www.puc.nh.gov/regulatory/Rules/PUC2200.pdf.

The first municipalities to complete the implementation process began providing aggregated service in April 2023. As of October 2023, there are 16 active aggregations with approximately 83,700 customers and over 650,000 megawatt-hours (MWh) of estimated annual load across all utilities.[65] Table 2 lists the active community power aggregations and the approval stage of each. All have received approval from both the Commission and the applicable governing body. The four aggregations that have not provided notice of commencement of service received approval in 2022, indicating that there are likely further issues that are blocking the start of service. The active aggregations in each service territory, combined, represent 6-8% of each utility's total delivered energy.

Table 2. Community Power Aggregations in Progress

Municipality	Commission Approval	Governing Body Approval	Commencement of Service	Estimated Annual Load (MWh)[1]
Canterbury	X	X	X	7,325[2]
Enfield	X	X	X	6,617
Exeter	X	X	X	59,106[3]
Hanover	X	X	X	10,991
Harrisville	X	X	X	5,881
Keene	X	X		79,372
Lebanon	X	X	X	42,404
Marlborough	X	X		9,068
Nashua	X	X	X	276,048
Peterborough	X	X	X	28,529
Plainfield	X	X	X	5,483
Portsmouth	X	X	X	105,980
Rye	X	X	X	22,850
Swanzey	X	X		26,247
Walpole	X	X	X	11,720
Wilton	X	X		14,145

[1] Utilities' response to DOE Data Request 2-13.

[2] The data provided is from two utilities. One of the utilities provided five months of actual load. This estimation is calculated based on estimated annual load from one utility and three months of provided data from the other utility.

[3] This is an estimation based on three months of provided data.

There are 38 other community power aggregation plans in progress. Of those plans, 21 have either filed a plan with the Commission, formed a committee, or requested aggregated usage information but have not received Commission approval. There are 24 aggregations that have undergone the same steps but have not received approval from their governing body. Six of the 24 aggregations that have not received government approval have received

[65] The following aggregation stage information was derived from an internal DOE tracking workbook. The information may not reflect the most recent data.

Commission approval. Of the 27 community power aggregations that have received both Commission and governing body approval, there are eleven that are not active.[66]

E. Response to Recent Conditions

1. Utility Response

New Hampshire utilities recently made several changes to their default service procurement strategies in response to market conditions. First, Eversource, in advance of the February – July 2023 procurement, doubled the number of tranches it solicits, resulting in eight tranches equal to 12.5% of the load for residential customers and two tranches equal to 50% of the load for large customers. The primary goal of this change, according to Eversource, was to increase wholesale supplier participation in solicitations.[67] Notably, Eversource received only one bid for 50% of Large Customer Group load in the procurement for February – July 2023 service. It is conceivable that Eversource would not have received any bids for the Large Customer Group if it had maintained its previous 100% tranche size, given that the sole bidder retained the option to bid two (2) 50% tranches equaling 100% and chose not to do so.[68]

Second, Unitil revised its procurement schedules to align with Liberty and Eversource,[69] who have procured 6-month contracts running from February to July and August to January since September 2015 and December 2017, respectively.[70] Unitil's new schedule, implemented after an eight-month transition period, is meant to split two high-cost months, January and February, so that there is less volatility between product periods.

2. Commission Response

PUC Docket IR 22-053 addressed a variety of default service issues in light of recent market conditions. The record from this proceeding, therefore, informs many of the key questions also under consideration as part of DOE INV 2023-01. What follows is a brief overview of key comments provided and positions taken by participants in PUC Docket IR 22-053.

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[66] These communities are Allentown, Dover, Durham, Hampton, Jaffrey, Lee, Lincoln, New Boston, New Market, Waterville Valley, and Westmoreland.

[67] New Hampshire PUC (2022). Docket DE 22-021. Testimony of Shuckerow, Littlehale and Lamontagne (December 8, 2022), p. 5.

[68] New Hampshire PUC (2022). Docket DE 22-021.

[69] New Hampshire PUC (2015). Docket DE 15-010. Order 25,806 (Liberty); New Hampshire PUC (2017). Docket DE 17-113. Order 26,092 (Eversource).

[70] Unitil (2022). Order *Nisi* Approving petition for Modifications to Default Service Procurement Timeline. Order 26,679. PUC Docket DE 22-017.

Centralized Procurement

In response to related questions from the Commission, several parties commented about the potential for centralized, consolidated procurement of default supply. Under this model, the State of New Hampshire or a similarly situated entity would administer RFPs and handle default service procurement on behalf of the IOUs, in place of separate procurements conducted by each IOU. Liberty noted several potential benefits of centralized procurement, including greater bidder participation and lower costs arising from consolidated obligations. Unitil similarly commented that centralized procurement could result in administrative efficiencies and reduced procedural work.[71] The Office of the Consumer Advocate (OCA) also stated that it would support a statewide procurement approach for default service, similar to the current approach in Maine.[72]

Eversource, by comparison, stated that while there appear to be no legal barriers to the creation of a centralized procurement, there would be no discernable benefits to default service customers. Additionally, Eversource claimed that creating a centralized procurement entity would not lead to increased efficiency due to logistical barriers and the need for standardization across utilities, which Eversource believes would require a great deal of time and effort.[73] The Department also commented that it did not believe that a state-run procurement process would be the most efficient process for New Hampshire, in part due to increased administrative costs.[74]

Laddering

Parties to the Investigation also addressed questions regarding the introduction of laddering.[75] Liberty commented that there have been no observed, quantifiable benefits of laddering in terms of reducing price volatility in states where it has been implemented. The company also stated that, due to the small size of Liberty's load, laddering could reduce the number of bidders participating in procurements. This would occur as a result of subdividing the 100% default service load product in order to facilitate laddering.

Unitil, like Liberty, expressed the view that there is no clear benefit to laddering contracts compared to procuring 100% of requirements for a given time period. Unitil did note, however, that laddering could help moderate prices and reduce price volatility. This benefit would potentially be at the expense of prices reflecting the market. Unitil pointed to the

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[71] New Hampshire PUC (2023). Docket IR 22-053. *Report on New Hampshire Energy Commodity Procurement*.

[72] Id.

[73] Eversource (2022). *Response to DR PUC 1-001*. PUC Docket IR 22-053.

[74] New Hampshire DOE (2023). *Department of Energy Comments.* PUC Docket IR 22-053.

[75] Laddering entails meeting 100% of a company's default service load through two or more partial procurements with overlapping periods. The prices of the different procurements are then blended together. For additional description, see related discussion in Section III, "ELECTRIC POWER INDUSTRIES IN OTHER RESTRUCTURED Jurisdicitons."

Massachusetts procurement approach as an appropriate balance between price volatility and market price signals. Eversource made comments similar to Unitil's regarding laddering reducing volatility at the cost of prices reflecting prevailing market conditions. However, the company did not take a stance regarding whether New Hampshire should implement laddering.[76]

Two stakeholders, NRG Retail Companies (NRG) and Retail Energy Supply Association (RESA), filed joint comments recommending that laddering not be implemented for default service solicitations because it will distort price signals.[77] OCA took the opposite position, stating that laddering should be implemented because it reduces volatility and that the goal of providing low-cost service at stable prices should be the priority of default service.[78] DOE commented that it generally does not support the implementation of a laddering framework because laddering is designed to mitigate market volatility, and the Department feels that there is more value in utilizing current market signals to develop energy pricing.

Self-Supply

Self-supply through purchases on the ISO-NE spot market was discussed as a backup to default service procurement. All three IOUs commented that they could serve their load through spot purchases if an RFP failed. Liberty commented that it would be in the best interest of customers for the utility to immediately make purchases from the ISO-NE spot market if an RFP fails, because a second RFP could result in even higher bid prices if bidders factored into their offers the lack of competition during the first solicitation. Unitil offered a similar opinion and recommended that, in the case of a failed RFP, the company immediately implement self-supply. Eversource commented that self-supply should only ever be used as a last resort.[79] DOE expressed a similar view as Eversource, stating that self-supply should only serve as a contingency strategy.[80] No parties recommended self-supply as a substitute for existing procurement approaches. Additionally, several parties commented that ISO-NE day-ahead and real-time energy prices cannot be compared with monthly bid prices secured through RFP processes.

Timing

Regarding the schedule of default service procurement, all three utilities filed a joint statement highlighting the fact that bids are submitted approximately two months in advance of the default service period, resulting in inherent risk premiums related to market volatility, weather, fuel availability, and load migration, Mystic COS, and geopolitical

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[76] Eversource (2023). *Eversource Energy Response Regarding Commission Staff Report.* PUC Docket IR 22-053.

[77] RESA and NRG (2023). *Joint Comments.* PUC Docket IR 22-053.

[78] OCA (2023). *Position Statement*. PUC Docket IR 22-053.

[79] Eversource (2022). *Response to DR PUC 1-001*. PUC Docket IR 22-053.

[80] New Hampshire DOE (2023). *Department of Energy Comments.* PUC Docket IR 22-053.

events.[81] Eversource expanded on this in their response to the commission, stating that shortened RFP timelines (i.e., time from final bid to Commission approval), similar to processes used in Massachusetts and Connecticut, could lower default service prices by reducing wholesale supplier risk premiums.[82] In their joint comments to the Commission, NRG and RESA recommended that RFP solicitations be staggered and held closer to the time of service to offer more accurate prices and lower risk premiums.[83] DOE also supported staggered RFPs (separated by 3-5 days).[84]

Other Comments

Several other topics and recommendations were touched on by stakeholders in different parts of this docket. Comments relevant to the issues raised in this investigation include:

- DOE and OCA encouraged the exploration of different procurement methods, including descending-price-clock auctions.[85,86,87]
- Liberty mentioned that the development of a pre-approved hedging program could help reduce the volatility of default service rates. As a part of this program, each EDU would enter into transactions to cover a portion of its default service load and recover costs from its customers, similar to hedging programs implemented by NH natural gas distribution companies. Although this program could help reduce volatility, Liberty noted some drawbacks, including the potential for costs to be above market, hedged fixed prices competing with CEP offers, and increased gaming/switching.[88]
- Colonial Power Group, an energy consulting group in NH, MA, and RI that supports community power aggregation, advocated against over-emphasis on rate stability and in favor of transparent default service procurement processes that produce market reflective price signals.[89]
- Granite State Hydropower Association (GSHA) and OCA recommended that the PUC consider allowing the EDUs to blend in medium- or long-term Power Purchase Agreements (PPA) to meet default service load obligations as a way to reduce price volatility.[90]

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[81] New Hampshire PUC (2023). Docket IR 22-053. *Report on New Hampshire Energy Commodity Procurement*.

[82] Eversource (2023). *Eversource Energy Response Regarding Commission Staff Report.* PUC Docket IR 22-053.

[83] New Hampshire PUC (2023). Docket IR 22-053. *Report on New Hampshire Energy Commodity Procurement*.

[84] New Hampshire DOE (2023). *Department of Energy Comments.* PUC Docket IR 22-053.

[85] DOE did not recommend the implementation of descending-price-clock auctions but, rather, commented that this procurement method was worth further investigating and weighing the costs and benefits.

[86] New Hampshire PUC (2023). Docket IR 22-053. *Report on New Hampshire Energy Commodity Procurement*.

[87] OCA (2023). *Position Statement*. PUC Docket IR 22-053.

[88] Liberty (2023). *Technical Statement of Liberty Utilities.* PUC Docket IR 22-053.

[89] New Hampshire PUC (2023). Docket IR 22-053. *Report on New Hampshire Energy Commodity Procurement*.

[90] Id.

3. Additional Response

Several parties expanded or clarified their comments from PUC Docket IR 22-053 as part of the DOE INV 2023-01 proceeding. These comments, as summarized below, provide further detail and opinion relevant to the key questions under consideration in this Investigation.

Alternative Procurement Methods

Utilities were asked about the merits of alternative procurement methods (e.g., reverse auctions) as opposed to sealed bids. Liberty and Unitil noted that reverse auctions, as a substitute for sealed-bid procurement, could attract more competitive offers by providing better price signals to bidders during the auction process. Likewise, Vitol, Inc., a wholesale supplier, indicated a preference for descending-price-clock auctions specifically, as the auctions can provide greater pricing transparency. However, Liberty and Unitil also noted that the sealed-bid method results in a low price that reflects the market. Eversource, meanwhile, stated that there is no evidence that alternative methods would provide the desired benefits.

Procurement Manager

Eversource indicated that the adoption of a designated, independent Procurement Manager may be appropriate in New Hampshire if the state implements a procurement process similar to that of Connecticut. In Connecticut, a procurement manager evaluates and approves bids on behalf of the Connecticut Public Utilities Regulatory Authority, usually on the same day as bid receipt. As part of the approval process, several stakeholders independently calculate proxy prices, review received bids, and collaborate with the procurement manager during their assessment of bid reasonableness. Neither Liberty nor Unitil have experience with procurement managers.

Contingency Provisions

Eversource considers a procurement unsuccessful if bid prices are well above a predetermined proxy price, prices are not clustered, there is little to no bidder participation, or the winning bids do not cover 100% of the load requirement. Unitil and Liberty also apply similar criteria. In the event of an unsuccessful procurement, Eversource indicated its first preference would be to reissue the RFP and, if the second attempt fails, then serve load through self-supply. In case of a failed auction, Unitil similarly stated that it, as typical practice, it would reissue an RFP before reverting to self-supply. Unitil also indicated a preference to shorten the time period of the reissued RFP as a way to potentially reduce load risk and induce greater participation. Liberty would prefer to self-supply rather than reissuing an RFP in the event of a failed auction.

Permanent Self-Supply

Regarding permanent self-supply, Eversource noted that, to provide such service on an ongoing basis, it would need to increase its working capital requirements and incur additional interest expenses in order to meet ISO-NE's more frequent settlement obligations for wholesale suppliers. Unitil similarly noted a likely increase in working capital requirements under permanent self-supply, as well as the need to reevaluate ratemaking and reconciliation. Liberty commented that this process would require appropriate staffing and would result in more frequent reconciliation.

Load Risk

Both Constellation Energy Generation, LLC (Constellation) and Vitol expressed that migration risk is a concern as it relates to customer switching and community power aggregation. Constellation cautioned that certain switching regulations (i.e., limits on who can switch to and from competitive energy supply, and when) may increase wholesale supplier risk if suppliers cannot easily and accurately account for the effect of these regulations in their offer process. Vitol expressed support for clear switching regulations. Both parties articulated a desire for further transparency and clarity regarding migration and regulations related to community power aggregation.

Laddering and Tranche Size

Vitol commented that laddering does not impact bidders unless it results in tranche sizes that are too small. The company further specified that tranches sizes between 5 MW and 50 MW are reasonable. Specifically, Vitol commented:

> Tranches should be of a large enough size to be transactable with available market products, but not so large as to cause distortions in the market at the time of execution. Tranches that average in the 5-50 MW range are comfortably sized for the market. If an auction/RFP in New England seeks supply of more than approximately 250MW-300MW for one period (for example, average total load up for bid for a 6-month period in one RFP), it can impact the dynamics of the bilaterally traded markets, as this is a large quantity to trade at once in the relatively small New England energy market. Utilizing a laddered procurement strategy will likely help in procuring large quantities of default service supply without distorting the bilateral markets.[91]

Other parties did not provide new comments on laddering or tranche sizes.

[91] Vitol Inc. response to DR 1, INV 2023-001.

F. Current Procurement Approach

Unitil, Liberty, and Eversource issued default service RFPs on October 31, November 1, and November 2, 2023, respectively. All three solicitations requested service spanning the period of February 1 – July 31, 2024. The ensuing section outlines additional key details pertinent to these recent procurement processes and the guidelines employed by each utility.

1. Timing

All three utilities currently procure default service through sealed bids by issuing a semi-annual RFP for default service power supply. As of 2023, all three utilities procure default service on the same semi-annual timeline encompassing six-month delivery periods from August 1 to January 31 and from February 1 to July 31. All products are also structured to last six months with the exception of Liberty's Large Customer Group, for which Liberty procures service for two consecutive three-month periods.

The RFPs for these solicitations are generally issued within a few days of each other, approximately three months in advance of the service start period, with final bids due approximately two months before contract maturity (i.e., the beginning of service). All three utilities require that suppliers submit final bids by 10:00 a.m. the day that final bids are due. Following the submission of final bids, the utilities select a winning bidder (or bidders); Unitil selects suppliers by 1:00 p.m., Liberty selects by 2:00 p.m., and Eversource selects by 3:00 p.m. Within three business days of selecting a winning bidder, each utility prepares the requisite Commission filings to seek bid approval and then submits the filing to the PUC.[92] The PUC must then review and approve or deny the selection within five business days.[93] Therefore, each bid may take up to eight business days from final submission until the wholesale supplier receives approval.

2. Customer Groups

For procurement purposes, each utility clusters its customers into groups based on distribution rate schedules. For Liberty and Eversource, there are two distinct customer groups: small customers and large customers. The Large Customer Group is considered as those customers whose average demand is ≥20 kW in the case of Liberty, or ≥100 kW in

[92] See responses to DOE DR 2-05, INV 2023-01.

[93] Although the PUC has never rejected a winning bidder submitted by the utilities, it is in the Commission's right to do so if it believes that the bid is unreasonable or was not procured competitively.

the case of Eversource. The Small Customer Group includes all remaining customers, including residential households.[94,95,96]

Unitil splits its customers into three groups: small, medium, and large customers.[97] For Unitil, the Medium Customer Group includes any all outdoor lighting accounts and customers that, on average, uses less than 100,000 kWh/month or 200 kilovolt-amperes (kVA). Unitil's Large Customer Group includes any customer that, on average, uses greater than 100,000 kWh/month or 200 kVA. Again, all remaining customers, including the residential class, are assigned to the Small Customer Group. See Appendix A, Table 3 for a summary of the size designations by utility and customer group, as well as a breakdown of which retail rates are included in each customer group.

3. Product Type, Tranches, and Responsibilities

All three utilities procure 100% full-requirements, load-following service. Under this arrangement, wholesale suppliers are obliged to pay costs associated with ISO-NE energy, ancillary services, and capacity requirements, among other market and administrative costs. Suppliers are responsible for forecasting their load obligations on an hourly, daily, and monthly basis, and may not limit the amount of supply that must be purchased by the utility in each tranche.

The utilities retain all billing and customer service functions, including reconciling uncollectable expenses. They also retain delivery functions, including ISO-NE Regional Network Service (i.e., transmission) and distribution obligations, as well as Renewable Portfolio Standard (RPS) compliance responsibilities. Both Unitil and Liberty seek bids for a single tranche covering 100% of load for each separate customer class. Eversource, the largest utility in New Hampshire, seeks bids for a total of eight tranches (each 12.5% of load) for small customers and two tranches (each 50% of load) for large customers.

Each of the eight winning bidders for Eversource small customer load is responsible for approximately 217,000 MWh (August-January) or 191,000 MWh (February-July) of total delivered energy, or 44 to 50 MW on average. Similarly, the winning bidder for Unitil's small customer load is responsible for around 234,000 MWh (August-January) or 204,000 MWh (February-July) of total delivered energy, or between 47 to 53 MW on average. The winning bidder of Liberty's small customer load has a slightly smaller load responsibility of approximately 170,000 MWh (August-January) or 154,000 MWh (February-July), equal to

[94] Streetlighting is included in Liberty's Small Customer Group. Eversource states that municipal lighting is part of its Small Customer Group but outdoor lighting (Rate OL) is procured under the same group as its associated accounts.

[95] Public Service Company of New Hampshire d/b/a Eversource Energy (2023). *Request for Proposals for Power Supply for Energy Service.*

[96] Liberty Utilities (2023). *Request for Power Supply Proposals to Provide Default Service*.

[97] Unitil Energy Systems (2023). *Default Service Request for Proposals.*

between 35 to 39 MW on average. Unitil's Medium Customer Group winner is responsible for around 85,000 MWh (August-January) or 77,000 MWh (February-July) of total energy deliveries, or around 18 to 19 MW on average.

The winning bidders of Unitil's and Liberty's large customer load have load responsibilities of between 19,000 and 26,000 MWh, depending on the delivery period, or between 4 to 11 MW on average. Eversource's large customer load winning bidders have a load responsibility of approximately 38,000 MWh (February-July) or 52,000 MWh (August-January), or between 9 to 12 MW on average. See Appendix B, Table 4, for the data supporting these ranges, which is based on recent historical usage.

4. Bid Structure and End-Customer Rates

For residential customers, all three utilities ask suppliers to submit bids for fixed monthly prices for a period of six months. Those monthly prices are then converted into a single, load-weighted average price for comparison purposes using evaluation loads provided as part of the bid package. This weighted-average price serves as the basis for customer billing rates. A similar bid comparison approach is used for Eversource's and Liberty's Large Customer Groups, as well as Liberty's Medium Customer Group. However, for Medium and Large Customer Groups, the prices observed by customers vary by month in accordance with the winning bidder's submission.

Unitil, by contrast, asks suppliers to submit bids for fixed monthly adders that cover all monthly non-energy costs for large customers. Unitil establishes the default service rate on a monthly basis using load and real-time pricing data from the preceding month (i.e., one-month lag) to create a weighted average rate. Subsequent month prices true-up the differences between the derived cost (i.e., set during the month ahead) and actual costs to serve load (i.e., incurred settlement).

In addition to the above prices, all utilities pass through Renewable Portfolio Standard (RPS) costs and other collection-related reconciliation costs as part of the final default service rate. These pass-through costs are subject to Commission review.

5. Switching and Gaming

There are no restrictions on how often customers can switch between CEP and default service supply. Customers have the right to change their CEP at any time and with no advance notice, subject to payment of any termination fees described in the terms of service.[98] Small customers served by Unitil that switch from CEP to default service supply during the course of a default service term are assigned variable monthly rates until the

[98] *New Hampshire Code of Administrative Rules.* Chapter PUC 2000 Competitive Electric Power Supplier and Aggregator Rules. https://www.puc.nh.gov/Regulatory/Rules/Puc2000.pdf.

beginning of the next default service term. These variable rates are published in advance. This approach, although not restrictive, may deter gaming in some circumstances.

6. Supplier Eligibility

To issue a bid to supply default service, suppliers must have an executed Master Power Supply Agreement filed with the utility. New Hampshire's default service providers are required to showcase their financial capacity to fulfill their obligations throughout the agreement period by providing an irrevocable letter of credit or another form of financial security. New Hampshire does not limit the amount of load that any particular wholesale provider can serve at one time.

7. Contingency Provisions

New Hampshire has no formal contingency plan in place for when a failed solicitation occurs. Rather, if a solicitation fails, the utility must file with the PUC to propose a plan and determine its next steps. After recent failed solicitations, the Commission has considered proposals both to issue a second "lightning" RFP and to go directly to self-supply through spot market purchases.

8. Bid Evaluation Criteria and Proxy Price

The evaluation criteria used by the utilities when evaluating bids include, but are not limited to:

1. Price of bid;
2. Bidder's ability to meet credit requirements;
3. Firmness of proposed delivery; and
4. Supplier's past experience providing similar services.[99]

All suppliers further evaluate the reasonableness of the bid prices they receive using indicative estimates prepared in advance of bid receipt. How each utility derives its "proxy," or benchmark, varies. Eversource calculates its proxy price using a general slope formula: ($y=mx+b$); where (y) is the calculated proxy price. The value for (m) is calculated using the load-weighted forward energy price, and the value for (b) is the load-weighted capacity price. The final value, (x), is a multiplier that represents other wholesale cost elements, including ancillary services, ISO-NE administrative costs, uplift charges, supplier margins, and risk premiums.[100]

[99] See, for example, Liberty Utilities (2023). *Request for Power Supply Proposals to Provide Default Service*

[100] Eversource DR responses 2-11 and TS-002. INV 2023-001.

Unitil uses historical ratio analysis to assess the reasonableness of bids. To conduct this analysis, Unitil averages together the monthly bid prices of the winning bid for the Small and Medium Customer Groups and uses them to calculate a weighted average six-month bid price. The company then calculates on-/off-peak monthly average future prices based on New York Mercantile Exchange (NYMEX) forwards and uses that value to create a six-month weighted average. The six-month weighted average bid price is then divided by the six-month weighted average NYMEX forward price to calculate a ratio to compare the price of the winning bid to NYMEX forwards.[101] A reasonable ratio accounts for other wholesale cost elements, including supplier margins and risk premiums, gauged using confidential methods.

Liberty factors power forwards, capacity market costs, ancillary costs, on-/off-peak load, installed capacity load factors, Mystic COS, and premium bid factor calculations into its proxy price calculations.[102] In all of the above cases, the utilities keep the calculated proxy price (or equivalent ratio analysis) confidential to prevent strategic bidding behavior by auction participants. Likewise, none of the utilities publicize the methods by which they utilize their respective evaluation prices.

[101] Unitil DR response 2-11. INV 2023-001.

[102] Liberty DR response 2-11. INV 2023-001.

III. ELECTRIC POWER INDUSTRIES IN OTHER RESTRUCTURED JURISDICTIONS

A. Key Characteristics

The following subsections outline key design and market characteristics of default service and retail choice in the 14 restructured jurisdictions with electricity market structures comparable to New Hampshire. Among other topics, this overview includes characteristics that are particularly important to the issues raised by the PUC and DOE in response to recent market conditions, including procurement method, procurement timing, community power aggregation rules, and contingency provisions. Appendix C presents the major characteristics by jurisdiction within a summary table.

1. ISOs/RTOs

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) are private entities that oversee the operation of the regional electric grid; administer spot energy, capacity, and ancillary services markets; provide certain ancillary services; monitor transmission reliability; and dispatch generation resources to ensure reliability and minimize costs. There are seven ISOs/RTOs that oversee activity on regional electric grids in the U.S.[103] All jurisdictions with restructured retail electric utility industries also require utilities and suppliers to maintain membership in an applicable ISO/RTO. Areas that offer retail choice are located in five of the ISOs/RTOs: ISO-NE, New York ISO (NYISO), Midcontinent ISO (MISO), PJM Interconnection (PJM), and Electric Reliability Council of Texas (ERCOT). Suppliers and utilities in retail choice jurisdictions procure power, ancillary services, and capacity (except Texas), among other services, from wholesale markets administered by these regional authorities.

2. Types of Restructured Utilities

Jurisdictions with unbundled electric supply either require local utilities to offer retail choice or make implementation voluntary. The approach chosen can also vary among IOUs, municipally owned utilities (munis), and electric cooperatives (coops). In general, state regulatory commissions have more limited jurisdiction over munis and coops than over IOUs. As a result, most jurisdictions do not require customer-owned or municipally owned utilities to implement restructuring-related regulations.

[103] The ISOs/RTOs evolved from regional power pools (for example, the New England Power Pool, or NEPOOL) following the implementation of FERC Order 888 and Order 2000 in the late 1990s/early 2000s.

3. Default Service Provider & Procurement Entity

The default service provider is the entity that maintains responsibility for the overall fulfillment of default customers' requirements and pieces together the product that is ultimately provided to default service customers. That is, the default service provider acts as the load-serving entity.[104] The default service provider can be the regulated utility, which is the most common arrangement, a state agency, or an unregulated third-party supplier. The default service provider often serves as the backstop supplier when other wholesale suppliers are unavailable or contracted wholesale suppliers cannot meet their obligations.

The procurement function may be at least partially separate from the function of providing default service. The entity responsible for the procurement of default service supplies is typically responsible for overseeing the development of supply specifications, preparation of bid documents, solicitation of offers to meet those specifications, post-selection contracting, and ongoing monitoring of contracted obligations. These responsibilities are generally conducted in accordance with specific rules set forth by law or regulation, subject to oversight by the jurisdiction's regulatory commission.

In 12 of the 14 jurisdictions that have restructured their retail electric utility industries, default service is provided by the EDU. The remaining two states, Maine and Texas, select third-party default service suppliers and rely on competitive suppliers to meet default service obligations. Illinois utilizes both the EDU and its procurement agency, the Illinois Power Agency (IPA), as its default service provider. In 11 of the 14 jurisdictions with retail restructuring, the procurement entity is the EDU. In Illinois and Maine, a state agency is responsible for procurement. Texas assigns procurement responsibilities to third-party default service suppliers.

If both supply procurement and fulfillment are handled by the EDU, jurisdictions generally require close oversight by their respective regulatory commission to ensure that consumer interests are protected. Such oversight often includes requiring an independent monitor to administer the procurement process and/or subjecting procurement to commission review and authorization.

4. Product Types

The most common wholesale product types relied upon by default service providers include fixed-price FRCs; fixed-price, fixed-volume energy blocks; long-term, unit-contingent power purchase agreements with developers; and spot market purchases (and sales). The weight of each product type in the default service portfolio determines the allocation of price and

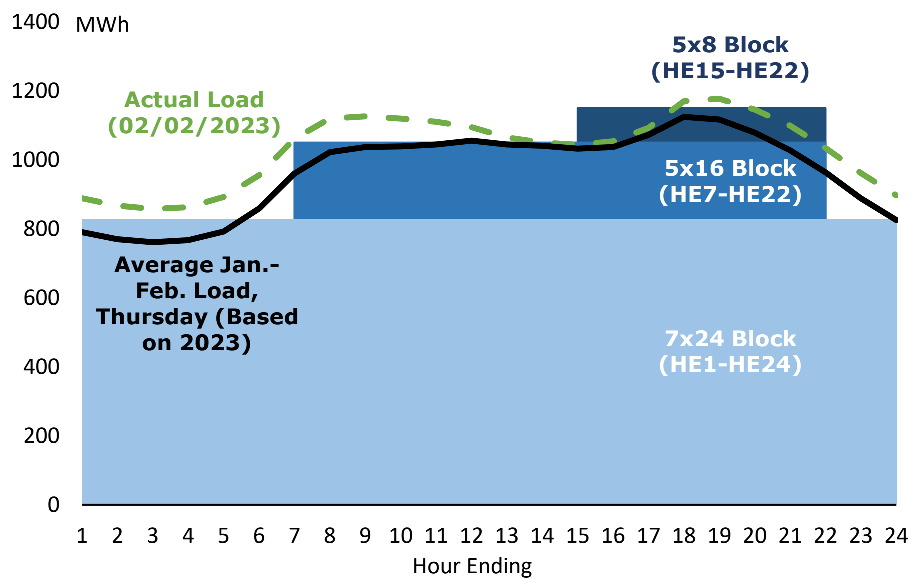
[104] When default service supply is sourced from wholesale markets, the default service provider owns the supply contract(s).

volume risk between wholesale suppliers of these products and the default service customers.

FRCs are products in which the wholesale supplier is responsible for a portion, or all, of the default service provider's load, including all related responsibilities such as capacity, at an agreed-upon unit price. A block is a fixed quantity of power at a fixed price. All of the retail restructured jurisdictions, with the exception of Illinois,[105] Texas, New York,[106] and certain utilities in Pennsylvania,[107] rely on FRCs to meet the loads of their residential and small non-residential customers.

Figure 3 and Figure 4 provide examples of how stacked block purchases can roughly meet load obligations for a specified period of time. Figure 3 and Figure 4 show a hypothetical Thursday in January or February and a typical week in June, respectively, of Eversource's combined default service load obligations. The black line in each chart represents anticipated demand based on average load requirements during the corresponding period in 2023. Each stacked block is labeled with a description of the product type. For example, the first block (7x24) includes supply provided seven days a week, 24 hours a day. To fill out the load curve, the default service provider might buy two smaller blocks of energy to complement this first base block, such as a 5x16 block (Monday-Friday, 6:00 am to 10:00 pm each day) and a 5x8 block (Monday-Friday, 2:00 pm to 10:00 pm each day).

Figure 3. Example of Block-and-Spot Structure to Serve Eversource Default Load in January and February



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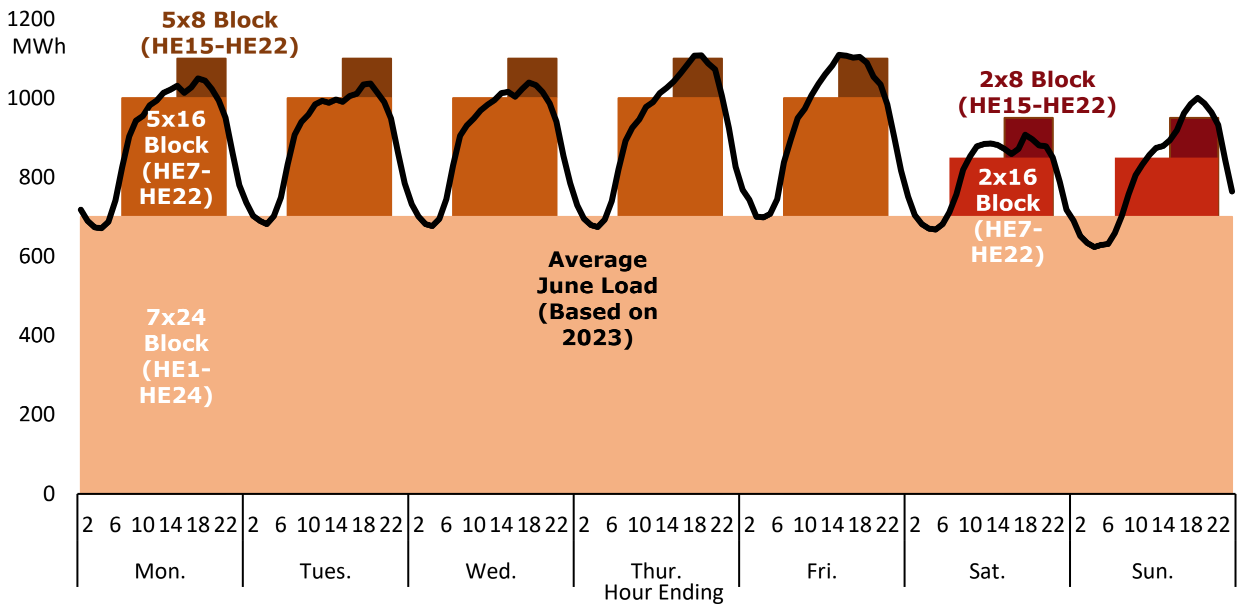
[105] In Illinois, the IPA conducts block procurements twice per year. The local utility then balances the blocks and actual demand by using spot transactions.

[106] Information about New York utilities' procurement practices are not publicly available.

[107] Pennsylvania utilities UGI and Pike Company use block-and-spot as a substitute for full-requirements, in part because of their small size.

Figure 4. Example of Block-and-Spot Structure to Serve Eversource Default Load in June



Block purchases are eventually reconciled with actual load; when load is above the blocks (e.g., green line in Figure 3, representing actual load on February 2, 2023), the default service supplier must procure additional power in the spot market. When the block is larger than the load, the default service supplier must sell block power in the spot market. The spot costs incurred to balance blocks with demand are reconciled through monthly adjustments. Blocks are a standard product bought and sold in wholesale markets and are typically easier to transact compared to full-service requirements.

5. Laddering

Laddering entails the procurement of wholesale products that are temporally diversified. These contracts can be stacked, overhanging, or some combination thereof. Stacked contracts are purchased during different solicitations but for the same duration and same period of service. This approach is designed to achieve some degree of procurement timing (i.e., when the solicitation takes place) diversification. Overhanging contracts are purchased during one or more solicitations but for overlapping, non-aligned periods of service. This means that when one contract, or set of contracts, for wholesale power expires and is replaced with another at prevailing market prices, other contracts in the portfolio remain unaffected. Hence, the change in the weighted average price of the portfolio is only affected by the portion of the portfolio being repriced. Overhanging contracts support service term (i.e., contract maturity period) and procurement timing diversification.

Both stacked and overhanging contracts can help moderate wholesale market price swings, and can also involve additional elements of contract duration and size diversity. For all laddering approaches, care must be taken to balance temporal risk mitigation with least-cost procurement of supply; fixed-price contracts entered further in advance of the delivery period place greater market risk on the supplier and, therefore, result in a price premium, all else equal. On a spectrum from spot-market pass-through to long-term contracts, laddering represents a reasonable compromise between price stability, risk mitigation, and having the portfolio embody then-current market conditions.

Laddering is used by most of the 14 jurisdictions that have restructured their retail electric utility industries; 11 of these jurisdictions employ laddered products as a means of mitigating the variability in the default service price for residential and small non-residential customers. The precise character of the laddered products—for example, the duration of the contracts, the month designating the start of service, and the amount of time between procurement and the beginning of performance—differs from state to state and often from utility to utility within a state. Thus, while there does not appear to be consensus with respect to the optimal arrangements, there is wide agreement regarding the value of laddered contracts.

Figure 5 and Figure 6 provide examples of laddered contract approaches relying on fixed-price FRCs. The colored rectangles represent the active contract period. The percentages represent the share of load procured (i.e., tranches) in each respective group of contracts. In both figures, the initial contracts are assumed to begin in Year 1, which designates the start of service, with stacked transition contracts that eventually give way to a consistent, "steady state" schedule of overhanging contracts.

Figure 5. Example of Three-Year, Equal Load Portion FRCs

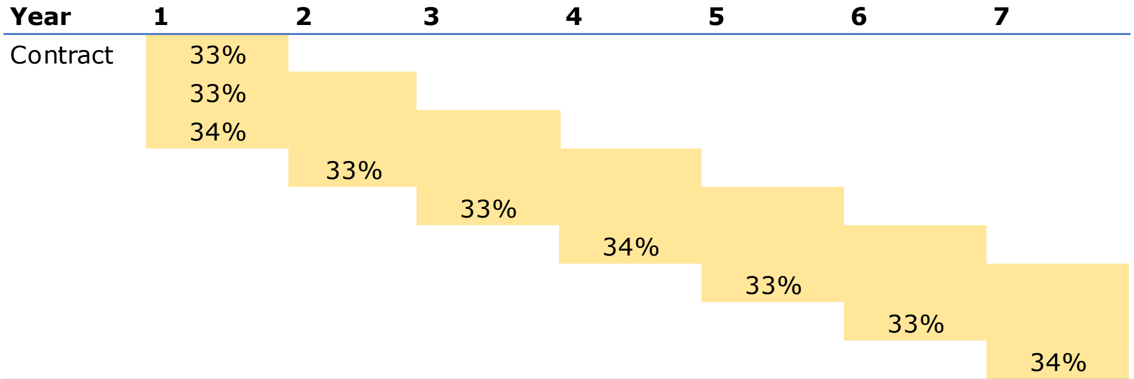
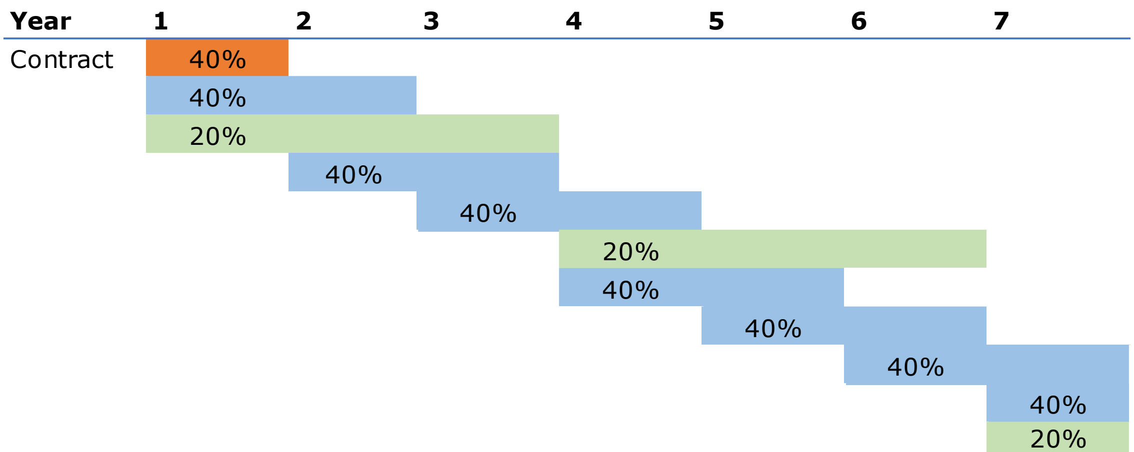


Figure 6. Example of FRCs of Varied Duration



As seen in Figure 5, approximately one-third of the supply requirement each year is met by a new three-year contract. This contract comes into effect just as an older-vintage contract expires. The default supply price, therefore, would change to reflect the new pricing for only the portion of the portfolio (one-third) that is made up of newly awarded FRCs. The remaining portion of the portfolio (two-thirds) is not subject to cost change, and hence the overall change in the price of the retail supply is only one-third as large as applicable with turnover of the entire portfolio at the same time; that is, the magnitude of the default supply price change is tempered.

The various contracts used to provide full-requirements service need not all be of the same size and duration. Pennsylvania, for example, requires a mix of short-term, long-term, and spot market purchases for the utilities' default supply portfolios with the goal of achieving the minimum reasonable cost of service over time.[108] Additionally, not all the contracts of a

[108] See 66 Pa. C.S. § 2807(e)(3.2). The utilities in Pennsylvania have generally interpreted this liberally, with the understanding that FRCs, upon which the Pennsylvania utilities almost exclusively rely, must necessarily incorporate a spot market component to allow load following. This permits the utilities to omit the explicit inclusion

specific duration, e.g., two years, need to be solicited and procured at the same time. Figure 6 (above) shows how a default supply portfolio made up of different duration FRCs could operate relying on a combination of one-year, two-year, and three-year FRCs.

Laddered wholesale supply procurement is also utilized in block-and-spot methods. For example, a load with a maximum demand of 100 MW and an off-peak average demand of 50 MW might be served with the purchase of:

- A two-year, 25-MW block of 'round-the-clock (RTC) energy;
- A one-year, 20-MW RTC block;
- A three-year, 15-MW RTC block;
- A two-year; 20-MW block of on-peak energy; and
- A one-year, 15-MW block of on-peak energy.

During off- and on-peak periods, the default service provider would likely sell energy into, and purchase energy from, the spot market, respectively. This arrangement places a greater degree of risk on the default service customer since reliance on the spot market necessarily entails market risk. The default service customer also absorbs load risk due to the correlation of load and price. Because the suppliers are not incurring this risk, overall power supply prices can be expected to be lower than under an FRC-type arrangement.

6. Timing

Duration of Product Delivery

The length of time, that is, the duration, of the delivery period for a default service product can vary from a one-time spot market purchase to multi-month and multi-year contracts. FRCs typically have a term of between three months and three years. Energy blocks can be procured for as short as a single month, or as long as multiple years. Long-term contracts with specific generation projects typically have terms of between five and 30 years. Spot market purchases and sales are hourly products that are transacted either in the day-ahead or real-time market. Important design elements in constructing a portfolio using these products include whether these products should be laddered and whether they should have overlapping delivery periods (discussed below).

Of the 11 jurisdictions that utilize FRCs, four predominantly use six-month products (New Hampshire, Connecticut, Massachusetts, Rhode Island); one exclusively uses 12-month products (Maine); one exclusively uses 24-month products (Delaware); two exclusively use 36-month products (D.C., New Jersey), and the three remaining states (Maryland, Ohio, Pennsylvania) mix together contracts of varying length ranging from three to 36 months.

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of a spot market component in the residential, small commercial, and medium commercial portfolios. Default supply for large customers in Pennsylvania is generally provided exclusively through spot market purchases.

Illinois utilizes three-year block contracts, with some other longer-term contracts and spot purchases. Many jurisdictions that use FRCs also rely on hourly spot products to meet the loads of large, non-residential customers.

Frequency and Consistency of Procurement

The frequency at which each jurisdiction conducts auctions or issues solicitations varies. Procurement events can take place sporadically, seasonally, or occur during the same month(s) annually. For example, Connecticut holds quarterly procurements, in January, April, July, and October; Massachusetts issues solicitations biannually; and New Jersey conducts auctions annually in February. The timing of both the procurement and the commencement of deliveries affects the level of price volatility observed by customers, the ability of default service providers or suppliers to hedge, whether bids reflect then-current market prices, and ease by which customers and suppliers can evaluate and compare competing offers. Default service procurers typically rely on the same procurement timing, products, and method of procurement every year but this is not necessarily always the case. For example, Ohio utilities have adopted several procurement schedules in recent history, including adjusted schedules on account of market conditions.

Timing of Product Periods

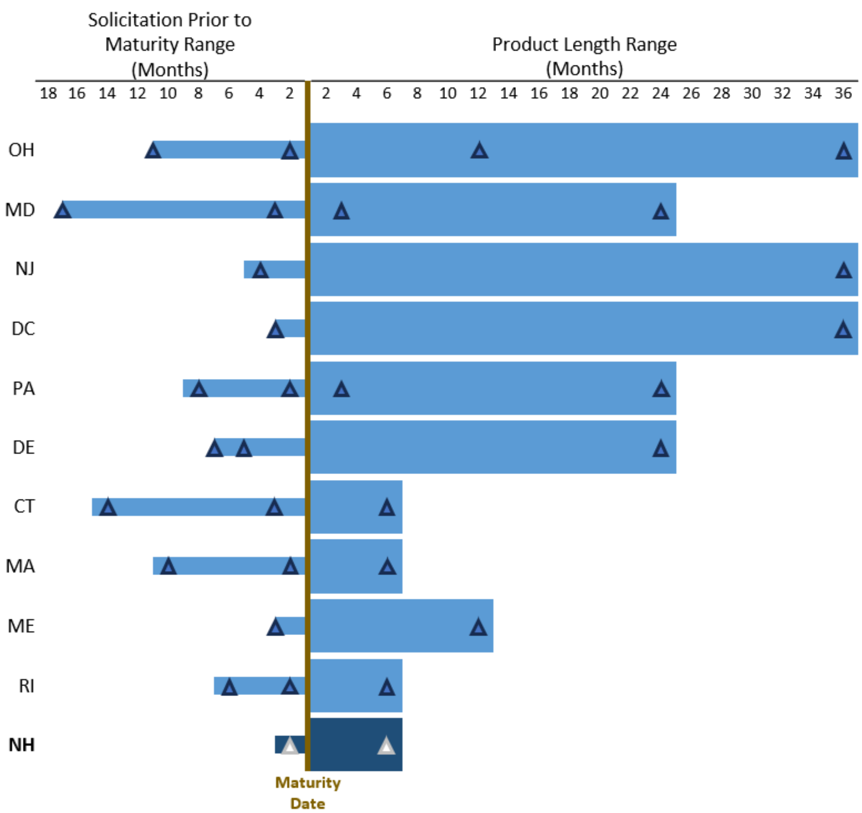
Another product timing consideration is when product delivery begins and ends. The initiation of a contract period can be aligned with specific seasons, a market delivery year, a calendar year, or can be variable. Jurisdictions may want to time solicitations so that they correlate with their ISO's/RTO's delivery year, do not overlap with major auctions in other states or utilities within the same state, and/or to break up high price periods. The majority of retail restructured PJM jurisdictions align their product periods with the PJM market delivery year (June 1-May 31) so that prices can more easily incorporate RTO specific costs (e.g., capacity). Two ISO-NE states, New Hampshire and Massachusetts, have utilities with product periods that run from February to July and August to January in order to split January and February, two high-cost months, into different product periods. Splitting January and February, in this case, reduces price differences between product periods.

Timing of Solicitation and Approval

The length of time between the contract procurement and contract maturity, that is, between when the contract obligation begins and commencement of the delivery period, is an additional timing consideration. The delivery period could commence shortly after the procurement or entail a lag between procurement and the beginning of delivery. A longer lag can support diversification goals or allow stakeholders adequate time to review potential products and bids. Both FRC and block contracts can be entered into as little as a couple of months before the start of their respective delivery periods, or as long as multiple years before.

The amount of time between contract approval and the completion of product delivery also varies, ranging from eight months (New Hampshire) to 46 months (Ohio). In general, ISO-NE states have shorter periods both between contract approval and contract maturity, and between contract approval and contract termination. There is a great deal of variation in how much time other jurisdictions generally provide between each of these stages, as also shown in Figure 7 for residential and small commercial procurements. The gold line in this figure shows when a default service product begins, i.e., its maturity. The bars to the left show how many months in advance products are procured, ranging from approximately two months in several jurisdictions to as much as 17 months in Maryland. The typical "first" procurement price approval occurs nine months prior to maturity and the "second" or "final" procurement price approval occurs three months prior to contract maturity. The price approval timing is shown as triangles in Figure 7. The bars to the right show the length of product procured, ranging from three months for some Maryland utilities to 36 months for D.C., New Jersey, and Ohio utilities. Minimum and maximum product lengths are again indicated in Figure 7 using triangles.

Figure 7. Residential and Small Commercial Procurement Solicitation and Approval Timing, by Jurisdiction



Note: Excludes states that do not use FRCs for small customers (Illinois, New York, Texas).

Sources: Utility and state procurement websites, utility solicitations and RFPs, and state regulatory commission websites.

7. Oversight

The degree of regulatory commission oversight over the default service procurement approach can vary, as can the frequency of review. Procurement plans can be approved in advance for a fixed term (e.g., four years in Pennsylvania), be left fully at the discretion of the utility subject to periodic prudency review by the commission (e.g., New York), or be preapproved for an indefinite term subject to revision at the discretion of the state's commission (e.g., New Hampshire). Most jurisdictions are similar to New Hampshire in that their default service plan is not regularly revisited on a predetermined schedule.

8. Procurement Method

There are several commonly used methods by which default service is procured. The two main approaches used are:

1. Reverse auctions, in which participants bid successively lower prices during the auction period until either no additional bids are made or the specified time period for the auction expires; and
2. Sealed bid, in which suppliers submit confidential bids in response to an RFP issued by the procurement entity.

There are multiple variants of both common approaches. The descending-price-clock auction (also known as clock auctions) is a version of a reverse auction where the auctioneer proposes a price for multiple products simultaneously and participants bid in load quantities. Each auction round, the product price decreases until the necessary load is reached. Other auction approaches include sequential auction, in which products are auctioned one after the other with pricing revealed after each round, and simultaneous, multiple-round auctions, where bidders propose load quantities and prices in multi-round bids for multiple products simultaneously.

The sealed-bid method may use a "one-shot" approach, in which bidders must submit their best and final bid in one round, or a two-step approach, in which in the first-round bidders submit a non-binding bid followed by a second round, often only for select bidders, in which bidders must submit their best and final bid. Finally, there is a combination, called the Anglo-Dutch hybrid approach, in which the procurer starts with a descending-price-clock auction and then, when close to a final price, requests that bidders submit their best and final price as well as load quantities via sealed bid.[109]

The procurement method used is a relevant consideration when assessing the competitiveness of default service offers. Certain approaches are also more or less favorable depending on market circumstances. Reverse auctions and related auction variants are less

[109] Descriptions of alternative auctions based on discussion and related notes from Charles River Associates.

effective for procurements with very few or one bidder as compared to the sealed-bid approach. This is the case because the additional transparency of reverse auctions can enable collusion and strategic bidding behavior. Nine of the 14 retail restructured jurisdictions rely on sealed-bid auctions (Connecticut, D.C., Illinois, Maine, Maryland, Massachusetts, New Hampshire, Pennsylvania, Rhode Island) and four states use a reverse or descending-price-clock auction (Delaware, New Jersey, Ohio, Pennsylvania).[110]

9. Supplier Eligibility

For all retail choice jurisdictions with default electric service, the bidders planning to participate are required to submit certain information to the procurement entity prior to the date of the auction or sealed bid. This information is intended to demonstrate the prospective supplier's ability to fulfill the terms of the contract and, as a result, reduce the default service provider's counterparty risk. Required details can include: evidence of financial capability, financial security, or a binding financial commitment sufficient to protect customers in the event of default during the term of the contract; evidence of membership in the applicable ISO/RTO; and agreement with the default service provider's terms of engagement. These documents are reviewed in advance of the date of procurement to eliminate those potential suppliers that do not meet specified threshold criteria.

Some states also take steps to foster a competitive ecosystem of participating wholesale suppliers. Maine, for example, applies a "three supplier test" that targets (but does not require) at least three winning bidders as a measure of market competitiveness.[111] Several states cap the maximum amount of load a particular supplier can serve. For example, Ohio utilities apply both credit-based tranche caps tied to bidder or guarantor credit rating, and an overall load cap.[112] Service caps are common for large utilities that employ reserve auction procurement methods.

10. Low-Income Customer Rules

There may be specific rules regarding default service procurement and/or participation for low-income customers. How state regulators define low-income customers varies, but is often tied to participation in specific assistance programs which, in turn, often base eligibility to an index of the federal poverty level. States pay special attention to low-income customers to protect them from possible exploitation and to ensure that assistance program funds are being wisely spent. Eight of the 14 retail restructured jurisdictions (D.C., Delaware, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island, Texas) have

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[110] Pennsylvania employs both approaches, depending on the utility in question.

[111] As required by 35-A M.R.S. § 3212(2) and Chapter 301, Section 8(C)(4) of the Maine Public Utility Commission's rules.

[112] See, for example, https://www.aepohiocbp.com/assets/files/AEP%20Nov%202023%20Auction%20Webcast_05%20OCT%202023%20(posted).pdf and https://www.firstenergycbp.com/Portals/0/InfoSessions/FEOU_CBP_Information_Session_March_2023.pdf.

no low-income customer provisions regarding their participation in retail choice. Connecticut, Maryland, and New York allow low-income customers to participate in retail choice; however, retail choice suppliers must guarantee savings relative to the default service price in order to serve these customers. Uniquely, Ohio is the only retail restructured state that has a separate procurement process for low-income customers.[113]

11. Anti-Gaming and Migration Control

Jurisdictions may have rules in place to prevent customers from switching between default and retail supply services to minimize “gaming,” meaning taking advantage of temporary differences in prices in a manner that may disadvantage other customers. These rules exist to reduce load risk that can adversely affect other default service customers by causing wholesale suppliers to include additional risk premium in their bids. Similarly, jurisdictions may have other migration controls in place to discourage mass migration of customers either toward or away from default service. Like anti-gaming rules, these provisions are meant to reduce load risk. The rules may vary between small and large customer classes because of differences in the opportunities to benefit from strategic switching.

States establish anti-gaming provisions in statute, in commission rules, or in utility and supplier tariffs (which are subject to commission review and authorization). Six of the 14 jurisdictions (Connecticut, D.C., Illinois, Maine, Massachusetts, New Jersey) have some limit on customers’ ability to switch. These rules can include a switching moratorium or the imposition of switching fees for a certain period of time.[114] Of the six jurisdictions that have anti-gaming rules, four (D.C., Maine, Massachusetts, New Jersey) only have rules specific to large customers. Aside from formal anti-gaming rules, most utilities in all retail choice jurisdictions have limits on the number of switches per month (e.g., no more than two switches and two drops per month) and make exceptions to these limits if a retail choice supplier defaults on its obligations.

Another approach to address load risk is to benchmark tranche sizes using volumetric caps. In this case, a jurisdiction may set an expected level of load that each full-requirements tranche represents. Then, if actual load exceeds the expected tranche size by a pre-established margin, potentially 10-15%, additional requirements are met by the EDU. This could be described as a sort of “swing” or “bandwidth” arrangement. To reduce load risk from large customer migration, Delaware has load bandwidth arrangements. Delaware defines each tranche as an approximately 50-MW block. Large customer loads that exceed this size by 10%, or 5 MW, are considered incremental and therefore served by the local utility.

[113] In place of descending-price-clock auctions with multiple winners, Ohio utilities issue a separate sealed-bid RFP and selects one supplier to serve 100% of low-income customer load.

[114] For example, Maine’s switching restrictions take the effect of an “opt-out fee” that is based on the number of months a customer has received basic service. It is equal to two times the amount of the highest basic service bill during the period of basic service.

12. Rate Design

The design of default service rates has the primary purpose of fully recovering the cost of providing service. However, the rate design may also be used to influence how much energy customers consume and/or to incentivize certain consumption patterns. Most default service rates are based on one of several standard rate structures:

1. Flat fixed prices: Rates that are invariant over seasons and the time of day. Another version of flat fixed prices is a block-price arrangement, where an initial amount of usage is priced at one per-unit level and all additional kWh are priced at a different level.
2. Seasonal fixed prices: Rates that vary by month or by season to reflect the differences in the cost of generation over the course of the year.
3. Time-of-use (TOU) pricing: Rates that differ by time of day to promote modification of usage patterns, usually to off-peak periods from on-peak or shoulder-peak periods. In general, peak period rates are in effect during weekday morning, daytime, and early evening hours, with timing that may vary by season. All remaining hours are either off-peak or shoulder-peak.
4. Real-time pricing: Rates change as wholesale market prices change and typically adjust for each settlement period, for example, each hour.

The applicable default service rate design, like the default service product, generally varies by customer class. Residential and small non-residential customers typically received fixed-price rates, with six jurisdictions offering 6-month, fixed-price rates, five offering seasonal fixed-price rates, and two offering other fixed-price rates.[115] Larger C&I customers are offered TOU pricing in five jurisdictions, variable or hourly pricing in seven jurisdictions, and either flat or seasonal fixed pricing in 12 jurisdictions.[116] Real-time prices are sometimes the default industrial default service rate under the notion that large C&I customers are in the best position to participate in the competitive retail market. If the only default service rate available to large C&I customers is a real-time rate, those customers have a strong incentive to shift load away from high-cost periods or move to the competitive market to avoid the price volatility inherent in real-time prices.[117] In New York and Pennsylvania, offerings are utility-dependent. Texas is unique in that all customers are offered variable pricing.

[115] Some jurisdictions offer a 6-month or seasonal fixed-price rate as well as an alternative fixed-price option.

[116] Most jurisdictions offer multiple pricing options. The fixed-price rate ranges from monthly, 3-month, 6-month and 12-month options.

[117] That is, these customers are considered more capable of responding to (e.g., shifting load during high-price periods) or avoiding (e.g., contracting with a CEP) volatile pricing.

It should be noted that TOU pricing is sometimes available to residential customers, either as a default rate or as an optional rate. Maryland and New Jersey offer TOU pricing to residential and small non-residential customers, and certain utilities in Massachusetts and New Hampshire offer TOU pricing to residential customers on a pilot basis. In these cases, the TOU pricing is derived from a flat, fixed default service price using price ratios designed to mirror wholesale costs or incentivize changes in consumption.

13. Default Service Cost Components

Default service can include various cost components in addition to energy and, as such, the price that default service customers pay may encompass multiple cost categories. These cost categories typically include:

1. Ancillary service – a broad range of costs that are necessary for the proper functioning of the grid, such as voltage regulation.
2. Network transmission – the costs associated with high-voltage transmission from trading hubs to the utility service area.
3. Capacity – the costs of making generating capacity available.
4. Administrative – the auction, RFP, and other related service costs needed to procure the power supply to meet default service obligations.
5. Certain ISO/RTO charges and fees.
6. Uncollectibles – charges to make up the difference between billed charges and payment receipts.

Default service charges can also include the cost of Renewable Energy Credits (RECs) to meet a jurisdiction's RPS and administrative costs associated with the procurement of RECs, as well as be subject to an adjustment or reconciliation rider. Both of these charges are described further below.

The obligation to secure and pay for the various charge components differs among jurisdictions. These costs can be the responsibility of the default service provider and recovered through distribution rates, or the default service provider may pass on the responsibility to the supplier. In the latter scenario, the costs are included in the price bid by the supplier to the default service provider. Many states, like New Hampshire, require that costs incurred by default service customers be recovered from these same customers based on the cost causation principle. Certain costs to administer or maintain default service, for example, are typically allocated only to default service recipients. These costs, however, do not typically track individual customers as they migrate between CEPs and default service. Thus, in certain circumstances (e.g., a period of very high migration), it may be appropriate to allocate default service costs to all customers.[118] The five ISO-NE restructured states include various ancillary, capacity, and ISO-NE related costs in the default service rate.

14. Reconciliation

Reconciliation costs emerge from the difference between the costs to procure default service and the revenue generated from the sale of default service to consumers. Reconciliation requirements may be either positive (i.e., credit owed to the default service customers) or negative (i.e., incremental costs owed to the default service provider). Where all the wholesale supply contracts are fixed-price FRCs, reconciliation charges/credits tend to be modest. If, however, there is a spot market resource in the default service supply portfolio, or if there are TOU rates that are supplied through fixed-price contracts, the reconciliation charges/credits can be larger. Typically, jurisdictions apply reconciliation refunds or costs to default service customers only, meaning customers served by a third-party supplier are not affected.

15. Renewable Portfolio Standard Fulfillment

RPS requirements for default service supply can be the responsibility of the local utility and satisfied through its regular procurement methods, or through separate auctions to meet the RPS requirements of default service customers. The RPS requirements may also be the obligation of other entities entirely, such as a state agency, a third-party load-serving entity, wholesale suppliers of default service, or multiple parties. RPS costs are included in the default service rate if the default service provider includes the obligation in its bid. When RPS costs are not included in the bid rate, they are procured separately, typically in a separate procurement, and included in the overall supply rate charged to customers on a pass-through basis.

Of the 14 retail restructured jurisdictions, six (Delaware, Illinois, Massachusetts, New Hampshire, New York, Ohio) have the utility as one of the responsible parties for RPS requirements. The wholesale or retail supplier is responsible for RPS requirements in the remaining eight jurisdictions. In Illinois, the IPA is responsible for procurement of the RPS requirement, but the utility has financial obligation for associated costs. In New York, utilities procure certain RPS credits by auction, but the New York State Energy Research and Development Authority (NYSERDA) procures other RPS credits. In the vast majority of

[118] The Massachusetts Department of Public Utilities (DPU) recently adopted similar reasoning in its order approving the allocation of certain default service costs to all customers, including those taking CEP service, in the face of very high costs. These costs were due, in part, to a high degree of load uncertainty related to community power aggregation activity. See: DPU 21-BSF-A4: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of Basic Service rates for December 1, 2021, through May 31, 2022, for its Small and Medium Customer Groups.

cases, RPS requirements are met by the responsible party through their demonstration of adequate RECs representative of generation from qualified resources.

16. Net Metering

Customers may meet some of their energy requirements through customer-owned, behind-the-meter resources or community-owned generation (in which case individuals are effectively allocated a share of production). Where net metering policies exist, energy from these resources can displace energy requirements from the default service provider or a CEP. Typically, the customer's energy consumption over the course of the billing period is netted against self-generation (or community generation) over the same period. If there is excess generation during the billing period, that is, self-generation by the customer exceeds the amount of energy consumed in the month, the utility may buy (i.e., cash-out) the excess at a retail or market rate, or carry forward the generation. Residual generation or cash-out credits are subsequently netted against consumption or costs in future months. These credits may be carried forward indefinitely or be subject to a periodic reset, at which time credits expire or are paid-out to customers in some form.

In net metering arrangements, some entity must be responsible for the physical and financial transaction of reconciling the energy used and generated by the customer. All the restructured ISO-NE states have one or more net metering programs. At least four of these states (Connecticut, Maine, Massachusetts, Rhode Island) allow excess generation dollar credits to roll over from month to month and have an annual reconciliation thereafter; however, specifics of the programs are utility-dependent. In Maine, as an example, production and consumption are netted monthly, with excess energy carried over to the customer's next bill. At the end of a 12-month period, any remaining energy credits are either cashed out or expire. States may also dictate at what rate customers are paid for their excess generation. Both Rhode Island and New Hampshire use an Avoided Cost Rate to calculate the applicable credit rate, while one of Connecticut's programs uses a retail rate. Another Connecticut program and Massachusetts use a commission-determined rate to calculate energy credits. These various approaches affect default supplier responsibilities and, in some cases, impose additional risk.

17. Community Power Aggregation

Customer aggregation is the formation of customer-side buying groups for the purposes of obtaining negotiation leverage, obtaining bulk-buying discounts, and reducing the friction of individual customers switching suppliers. Aggregators, in this circumstance, act as energy brokers. Some states allow community power aggregation (also referred to as community choice aggregation and municipal aggregation), meaning customer aggregation overseen by a government entity, such as a county, town, city, or other municipality. Under community power aggregation, the municipality procures energy on behalf of its residents and local businesses. Opt-in aggregation means that residents are given the option to be served by the third-party supplier selected by their municipality, but must take affirmative action to be served by that supplier. Opt-out aggregation means that residents are automatically served by the third-party supplier selected by their municipality unless they make the deliberate decision to not to participate.

Of the 14 retail restructured jurisdictions, four do not allow any type of community power aggregation (Connecticut, Delaware, Maine, Pennsylvania). Two of those states, Connecticut and Pennsylvania, have considered community power aggregation before their state legislature in recent years. Two jurisdictions, D.C. and Texas, only allow opt-in aggregation. The remaining states allow opt-out community power aggregation. At least six states (Illinois, Massachusetts, New Hampshire, New Jersey, Ohio, Rhode Island) specify that the community council or constituents must vote in favor of a community power aggregation provision in order for the locality to go forward with opt-out aggregation. New Jersey and Massachusetts both have the additional restriction that, for a community power aggregation to award a contract to a wholesale supplier, the rate must be lower than the default service rate or, for New Jersey, the energy resources must have a higher proportion of renewable energy. Switching provisions are also in place for community power aggregation. At least two opt-out programs (Ohio, Rhode Island) have rules related to switching fees if a customer leaves their community power aggregation.

18. Contingency Provisions (Failed Solicitation)

In case of a failed solicitation, default service providers or the regulatory authority may have a process in place to determine how the providers will procure default service. These processes may be reactionary, meaning the regulatory authority will determine contingency plans if or when a solicitation fails, or there may be a formal process set prior to the failed procurement. Of the five restructured states in ISO-NE, at least two, Massachusetts and New Hampshire, have recently experienced failed solicitations. In both cases, there was no formal process in place. Rather, the procurement entity informed the regulatory body and stakeholders of the failure and parties then submitted comments proposing or responding to potential contingency strategies. In Connecticut, if the procurement manager and utilities believe that bids should be rejected or procurement canceled, the procurement manager can authorize the utility to self-supply above its authorized amount based on prior permission from the regulatory authority. However, the procurement manager must immediately notify the regulatory authority following the authorization. In Maine, EDUs can be directed to take one of three actions in response to a failed solicitation to select a default service provider: pick a new retail supplier from an existing pool, conduct a new bid process, or order the EDU to supply default service.

19. Self-Supply

An alternative way in which the default service provider can procure energy for its customers is through self-supply. When self-supplying, the default service provider purchases energy to fulfill all or a portion of necessary load in the retail market as opposed to contracting with a wholesale supplier. Self-supply can be utilized as a way for a provider to purchase a portion of the load, or as a means of backup if the provider is unable to procure all load from a wholesale supplier. Self-supply is typically utilized for customer groups with greater risk premiums—either due to market circumstances or the nature of the customer group—which make it cost-prohibitive to provide them with full-requirements, load-following default service. In three of the five ISO-NE restructured states (Connecticut, Massachusetts, Rhode Island), self-supply is utilized as part of regular procurement for one or more utilities. In Massachusetts, one utility can utilize self-supply for only the large C&I customers. Rhode Island, the utilities can self-supply up to 10% of Last Resort Service (i.e., large C&I default service) load.

B. Summary of Other Approaches to Default Service

This subsection identifies prevalent default service implementation approaches and characteristics among the 14 jurisdictions with comparable retail electricity markets. Often, prevalent characteristics represent best practice employed to help achieve shared policy goals, such as minimizing rate volatility experienced by residential and small commercial customers or encouraging large customers to participate in competitive retail markets. These features and strategies are compared to those used in New Hampshire for informational purposes.

1. Predominant Approaches

Of the characteristics described above, several approaches stand out for being widely adopted:

- *Default Service Provider:* The EDU serves as default service provider in 12 of the 14 retail restructured jurisdictions. The exceptions are Maine and Texas.
- *Product Types:* Eleven of the retail restructured jurisdictions utilize FRCs when procuring default service for at least some customers. The exceptions are Illinois, New York, and Texas.
- *Number of Solicitations:* Eight of the retail restructured jurisdictions hold more than one solicitation for the same product period. The exceptions are D.C., Maine, New Hampshire, New Jersey, New York, and Texas.[119]
- *Timing:* Six of the jurisdictions secure final bid prices at least three months prior to contract maturity.

[119] New York may utilize more than one solicitation, but this is unclear due to the confidentiality of procurements in the state.

- *Product Lengths:* Four retail restructured jurisdictions utilize only six-month FRC products. Six jurisdictions utilize 12-month FRC products.
- *Laddering:* Laddering is used for residential and small non-residential customers in 11 of the retail restructured jurisdictions. The exceptions are New Hampshire, Maine, and Texas.
- *Procurement Method:* Nine of the retail restructured jurisdictions rely on sealed-bid auctions and the four remaining states use reverse or descending-price-clock auctions.
- *Low-Income Customer Rules:* Eight jurisdictions do not have provisions regarding low-income customer participation in retail choice.
- *Small Customer Rate Design:* Thirteen jurisdictions offer fixed-price rates for residential and small non-residential customers. Six of these jurisdictions offer 6-month, fixed-price rates (i.e., rates change no more frequently than once per year).
- *Large Customer Rate Design:* Large customers have more than one rate design option in ten jurisdictions. In 12 jurisdictions these options include either flat or seasonal fixed pricing, and in seven jurisdictions these options include variable or hourly pricing.
- *Non-Energy Costs:* The five ISO-NE restructured states include various ancillary, transmission, capacity, and ISO-NE related costs in the default service rate.
- *Community Power Aggregation:* Nine jurisdictions allow opt-out aggregation. The exceptions are Connecticut, D.C., Delaware, Pennsylvania, and Texas. Voting is necessary for approval of opt-in aggregation in at least six states.
- *Contingency Provisions:* Of the five ISO-NE restructured states, two have a formal contingency process in place, while the other three have a reactive approach to addressing failed solicitations.
- *Self-Supply:* In three of the five ISO-NE restructured states, self-supply is utilized as part of regular procurement for one or more utilities. Two of these states only allow self-supply for large customers. New Hampshire and Maine do not use self-supply except in contingency situations.

Notably, there does not appear to be a consensus approach to default service procurement entity, anti-gaming and migration controls, and rate design.

2. How New Hampshire Differs

There are two main ways in which New Hampshire differs from the above predominant approaches to default service. First, New Hampshire is one the three retail restructured markets that does not employ laddered contracts for residential and/or small commercial customers. As a result, these customers are exposed to the full impact of wholesale market changes that have taken place since the prior procurement. Maine is another state with broad default service adoption that does not use laddering. Maine is currently in the process of re-evaluating this approach.[120] Texas also does not ladder, as default service, known as Last Resort Service, is exclusively met through month-to-month variable price service provided by retail electric providers. This service is not widely adopted and is intended to encourage maximum participation in the competitive retail market.

The second way New Hampshire differs from other jurisdictions is in the timing of its auctions. There is a very short amount of time between when final bids are due and contract maturity (two months). Most jurisdictions with similar timing have more than one procurement that is held well before contract maturity. Connecticut, Maryland, Ohio, Pennsylvania, and Rhode Island have one procurement with bid prices accepted two to three months prior to contract maturity, but also have at least one other procurement with bid prices accepted between six and 17 months prior to contract maturity. As a consequence, New Hampshire allows minimal time for contingency while also exposing all load to market conditions at the time of the procurement. New Hampshire also has the shortest time between price acceptance and end of the contract (eight months total) of the 11 jurisdictions that utilize FRCs. This owes to the use of short-term contracts and absence of contract laddering.

C. Key Features and Their Impact on Different Stakeholders

Default service characteristics, or combinations of characteristics, shape how various parties interact with the service. What follows is a non-exhaustive overview of some of the major impacts of different default service approaches for important stakeholders.

1. Customers

Default service features can influence customer outcomes in a variety of ways, most notably through changes in actual costs. Depending on the approach adopted, nominal default supply rates may be higher or lower, more or less stable, and more or less uncertain. Default service rate design and regulations can also influence a customer’s ability to switch suppliers, their usage behavior, and their adoption of other energy technologies (e.g., electrification of household appliances), among other impacts.

[120] In the Maine PUC’s Inquiry Regarding Standard Offer Service Procurement Strategy, Docket 2023-00258, it specifies, “the Commission is opening this inquiry to gather information on what procurement strategies, including varying contract lengths and terms, could improve rate stability for residential customers taking standard offer service.”

Small Customers

The default service product type (e.g., FRCs, block and spot), hedging strategy (e.g., laddering with overhanging or stacked contracts), and timing (e.g., grouping or separation of high-cost winter months, procurement further in advance of contract maturity), among other features, all have an impact on both the prices faced and risk absorbed by customers. For smaller customers, these impacts can be magnified due to greater price inelasticity,[121] switching friction,[122] and relative financial exposure.[123] For example, when using a block-and-spot product, default service customers bear the market risk for the spot purchases needed to balance load and supply. Fluctuating costs from these purchases can be challenging for small customers to bear. Because of this (among other reasons), FRCs are the predominant approach to serve residential and small non-residential default service load in retail restructured jurisdictions; most policymakers and regulators prefer to shift risk to wholesale suppliers, which are thought to be better suited to manage and mitigate such risks.

Other product types, such as longer-term contracts, can provide more stable (and sometimes lower) rates, at least for the length of the contract. However, at the end of the contract, customers will be exposed to new market conditions, which could result in a large price change. Thus, the benefits of long-term contracts for customers are context dependent. Consequently, policymakers and regulators generally avoid long-term contracts in favor of other policy objectives, such as exposing customers to market price signals.

Default service timing considerations are also meaningful to small customers. Some examples of timing effects include:

- Shorter-duration products can cause greater changes in price over shorter time frames. Residential customers that lack the ability to quickly adjust usage to accommodate such changes can experience adverse effects.

- Bid approval timing can alter the risk profile of wholesale suppliers (discussed below) and result in additional risk premium. Schedules that cause excessive risk premiums are detrimental to consumers due to higher costs.

- Prices fluctuate between time of year and month. Seasonality of product periods can cause differences when transitioning from one product period to the next, which impacts consumer cost and rate stability.

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[121] Meaning, less ability or willingness to behave differently (e.g., consume less) in response to higher prices.

[122] Meaning, more barriers to the customer seeking and/or obtaining alternative service arrangements that better meet their risk preferences.

[123] Meaning, greater cost implications, both due to necessity of energy for many everyday activities (with few ready substitutes) and the relative cost burden of energy compared to other household expenses.

- Laddering ensures that only a portion of the overall supply portfolio is subject to a change in costs at any particular time, thus providing for increased price stability. Customers receiving laddered default service, however, are also precluded from experiencing the full extent of changes in market price, whether detrimental or beneficial.

Policy matters, including low-income customer rules, anti-gaming rules, net metering, and community power aggregation, also change customers' ability to control how they receive energy. For example, low-income customer rules can limit the ability of certain hardship customers to participate in retail choice and increase the number of customers taking default service. Community power aggregation, by contrast, can cause residential customers to migrate away from default service at higher levels than in the absence of aggregation policies.

Large Customers

Large customers are able to respond to price instability and higher costs in ways that residential or small commercial customers cannot. Thus, although the above characteristics also affect large customers, the impact can be quite different. For example:

- Block-and-spot or hourly pass-through products may be appropriate for large customers that are very responsive to price changes. In other words, it may be appropriate to assign greater risk to these customers (with corresponding reductions in price premium) due to these customers' ability to absorb and manage such risk.

- Timing considerations that increase volatility do not have the same effect on large customers because they are more capable of responding to pricing changes, either by shifting load or adopting alternative supply arrangements from a CEP.

- Fixed-price rate designs give large customers less incentive to react to price changes when these customers could otherwise relieve system constraints by reducing load.

Large customers have both the incentive and capability to strategically switch between default and retail supply. Thus, rules limiting switching frequency have a direct impact on large customers' market activity. Other approaches to default service that increase costs, however, have less impact because of this customer group's willingness to seek out alternatives.

2. Electric Distribution Utilities

EDUs, as the typical default service provider, are affected by default service policy and design in two main ways: (1) administrative cost to oversee procurement and service; and (2) working capital and expertise requirements. EDUs that are default service providers have different responsibilities and costs for different procurement products and approaches.

When using block-and-spot contracts, for example, the EDU will, at a minimum, have greater reconciliation requirements on account of adjusting costs monthly to reflect lagging costs from spot market transactions. If the default service provider is also responsible for managing block-and-spot construction (e.g., determining the appropriate blocks) and making associated transactions (e.g., buying products on a regular basis), the EDU may further require additional working capital to transact in wholesale markets. The EDU would also likely require additional in-house experts to support the load and price forecasting required to meet this responsibility. FRCs, by comparison, require less from EDUs in terms of portfolio management.

The relative complexity of default service procurement, even when using FRCs, can alter an EDU's administrative obligations. For example, more frequent procurements for laddering purposes imposes additional administrative costs. From a mechanical perspective, the use of sealed-bid RFPs is more straightforward and therefore minimizes administrative costs relative to more complex descending-price-clock auctions. Consequently, sealed-bid auction approaches are typically relied on for smaller auctions due to the lower administrative overhead.

Pre-determined price evaluation methodologies, such as proxy prices or price thresholds, facilitate bid approval by both the EDU and other regulatory entities. However, strict thresholds may result in rejecting reasonable offers and too readily triggering contingency circumstances. Contingency plans, like self-supply and EDU-managed block-and-spot, can be costly to implement and administer.

3. Retail Suppliers

Default service, by definition, serves as a substitute for competitive retail supply. Thus, third-party retail suppliers (and, in many respects, community aggregators) are directly affected by default design features that make competitive retail service more or less attractive compared to the default alternative. It is important to retail suppliers that they can compete against default service based on rate savings and/or product attributes. If default rates are not on an "even playing ground," it may disadvantage CEPs. For example, if Mystic COS costs are a pass-through expense for default supply but part of CEPs' obligations, the CEPs may be required to include risk premium that is not comparable. This may make third-party supply prices less attractive compared to default service.

The timing of default service products can also change the comparability of default service and competitive market products. For example, long-term default service contracts can create discrepancies between competitive rates and default service rates that persist over time. Depending on how the market has changed, this may or may not be advantageous to CEPs. Likewise, customer migration policies can either work for or against CEPs; policies that prevent customers from adopting default service (from CEP service) can also prevent customers from leaving default service.

Some default service characteristics encourage shopping and therefore favorably impact CEPs. For example, if rate designs are difficult to understand (e.g., complex TOU rates) or limit customers' options to control their costs (e.g., exposing customers to frequent price changes), then third-party supply may become more appealing as an alternative. This is especially true for large customers receiving variable, hourly-priced default service.

4. Wholesale Suppliers

Wholesale suppliers, as the principal counterparty to most default service arrangements, are attuned to default service features that affect their eligibility to participate in procurements as well as the level of risk they face when bidding. How the default service product addresses risk can directly influence wholesale suppliers' levels of interest in serving default service load. For FRCs, the wholesale suppliers bear all risks associated with changes in load or market prices. Policies that allow significant changes in load, such as community power aggregation, can therefore discourage wholesale supplier participation. Inclusion of costs in FRCs that are large, variable, and not hedgeable can also make bidding less attractive. As another example, very large tranches can create liquidity problems that limit suppliers' ability to hedge, while very small tranches may not present much of a revenue opportunity. In both cases, wholesale suppliers may be less likely to submit bids.

When suppliers do participate, their bidding strategies, including pricing and the amount of load they offer to serve, also take into account default service design. For example, long wait times between bid submission and acceptance can increase risk since the supplier may need to hold an open, unhedged position. If the default service provider is not able to commit to a relatively quick selection, then bidders may add substantial risk premium to account for market fluctuation while the bid position remains open. Likewise, procurement dates that are clustered with other major procurements may create hedging and liquidity problems that make it difficult for the wholesale supplier to participate in all procurements.

Wholesale suppliers must meet certain qualifications to bid on default service products. If these qualifications are strict, they may limit suppliers' ability to enter the market. Additionally, risk mitigation measures, such as limits on the amount of load any one wholesale supplier can meet, can alter the magnitude of the opportunity and change the incentives for a supplier to participate.

5. Public Utility Commissions

PUCs are impacted by the administrative costs associated with the regulation and oversight of default service. If the commission (or an equivalent public body) functions as the default service provider, it is also subject to many of the same potential impacts outlined above for EDUs.

Default service features and policies that are intended to protect small customers, such as low-income customer requirements and migration limits, can, when effective, promote better customer outcomes. This, in turn, can reduce both formal and informal customer complaints that a commission might otherwise field. Avoiding volatile or higher rates as a result of the default service design can also have the same effect of reducing customer issues and therefore decreasing administrative burden.

PUCs may be involved in the procurement and approval of default service rates to varying degrees. This includes establishing the procurement process (e.g., product type, procurement method, timing), overseeing procurements (e.g., supplier certification, bid evaluation, rate approval), and administering service (e.g., overseeing reconciliation, addressing complaints). Reverse auction methods are typically more administratively involved than sealed-bid procurements. Further, use of constrained timelines for bid review and approval can limit the amount of time available for the commission to review and, if needed, implement contingency plans. All these factors increase administrative burden (e.g., more staff hours). Alternatively, use of a third-party procurement manager or procurement entity can relieve the Commission of some of the day-to-day responsibilities related to default service. This approach, however, can incur additional contracting costs which may be shared with various other parties.

D. Issues Raised in Other Jurisdictions

Other retail restructured jurisdictions are confronting or have confronted many of the same default service challenges faced by New Hampshire in recent history, including volatile and high wholesale market costs. How these other jurisdictions have responded provides some guidance into potential strategies and improvements that New Hampshire might adopt going forward. What follows is a brief overview of other New England states and their response to date, including ongoing proceedings and proposals under consideration.

- In Maine, the legislature first directed the state's consumer advocate, the Maine Office of the Public Advocate, to develop a report regarding the state's default service in 2022. The purpose of the report was to recommend potential improvements to default service that would "provide greater competition among retail electricity supply providers and more options and protections for customers."[124] The report was provided to stakeholders and the legislature in early 2023. Subsequently, on June 12, 2023, the legislature directed the Maine Public Utilities Commission to consider procurement strategies and other measures, including varied contract lengths and terms, which could increase rate stability for residential SOS customers.[125] The associated proceeding is ongoing.[126]

[124] Maine 2021 P.L. Ch. 164 (LD 318).

[125] Maine Resolves 2023, Ch. 39 (SP 406-LD 887).

[126] Maine PUC. Docket 2023-00258.

- The Massachusetts Department of Public Utilities (DPU) opened a proceeding in January 2023 to investigate the state's default service and, specifically, potential changes to pricing and procurements capable of "(1) alleviating the burdensome regulatory process that has resulted from recent failed basic service solicitations and (2) lessening the differences in basic service rates between fixed-rate periods and across the EDUs."[127] Following a technical session and a comment period, the DPU ordered the local EDUs to modify their procurement of default service to separate the January and February service periods into separate contracts, similar to the approach used by New Hampshire utilities. Additional issues, such as strategies to respond to failed solicitations, reconciliation of over- and under-recovery of default service costs, and modifications to default service procurement and pricing policies that improve the accuracy of the price signals, have not yet been addressed or were set aside for a forthcoming, second phase of the proceeding.[128]

- The Connecticut Public Utilities Regulatory Authority (PURA) opened a proceeding in July 2023 to address legislative changes to Public Act 23-102 allowing PURA to open a docket to investigate "appropriate limitations" of retail supplier contracts with customers. Through this proceeding, the PURA sought to determine whether metrics, such as rate caps tied to default service rates, should be imposed on retail supplier contracts. A working group report was filed on October 18, 2023, and the proceeding is ongoing.

- In June 2023, the Connecticut procurement manager filed a request to revise the default service requirements effective as of the July and October 2023 procurement periods. In this request, the procurement manager asked that bidders be able to submit bids including and excluding Mystic COS agreement costs. If the accepted bids do not include Mystic COS agreement costs, then costs would be recovered through bypassable charges to default service customers only. This request was made in an attempt to lower risk premiums in bids.

- Rhode Island Energy's default service rate proceeding for the period starting October 1, 2022, attracted considerable attention on account of large price increases. Topics addressed in the proceeding included ways to mitigate expected price increases and manage risk premium related to new community power aggregations in the state. Parties to the proceeding proposed methods to defer costs or use other funding to offset costs and lessen the rate impacts to customers. The Rhode Island Public Utilities Commission ultimately approved the deferral of certain costs.[129]

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[127] Massachusetts D.P.U. 23-50, Vote and Order Opening Investigation (January 3, 2023), p. 27.

[128] Massachusetts D.P.U. 23-50, Order on Basic Service Fixed-Rate and Procurement Periods (September 1, 2023).

[129] Rhode Island PUC. Docket 4978.

Default service issues relevant to New Hampshire have also emerged outside of the New England region. For example, a large community power aggregation in Ohio returned approximately 500,000 customers back to default service in 2022 in response to default service prices that were well below the community aggregator's projected prices. The aggregator's move was unprecedented in the state, and raised significant issues regarding aggregation load risk. In an attempt to reduce uncertainty around large migration to and from default service, the Public Utilities Commission of Ohio implemented additional provisions as to how often large aggregators can transition customers.[130] As another example, the District of Columbia ordered its EDU to fulfill a portion of default service load using long-term contracts, with a target of procuring 5% of load from a 15- to 20-year power purchase agreement. This approach was intended both to support the jurisdiction's renewable energy mandates and add a stable price component to default service, all while minimizing price risk associated with an uneconomical long-term contract.[131]

In all of the above cases, price volatility and, similarly, increased electricity prices, highlighted to state regulators and policymakers that existing default service methods and processes did not support certain policy objectives. In response, key stakeholders revisited default service features such as product timing, including duration of product length and timing of solicitations; the non-energy costs included in default service, especially those related to the Mystic COS agreement; and migration policies, especially related to community power aggregation policies.

[130] PUC of Ohio. Case 22-1129. Finding & Order (March 8, 2023).

[131] District of Columbia PSC. Docket FC 1017.

IV. MARKET CONSIDERATIONS

A. Self-Supply Option

New Hampshire EDUs, in their roles as default service providers, assume responsibility for assembling a portfolio of default service supply products from the wholesale markets. As discussed above, EDUs can meet this obligation by procuring FRCs, block products, long-term contracts, or by making spot market purchases. "Self-supply" refers to any procurement approaches that rely on the EDU to directly participate in wholesale markets. Thus, self-supply includes all of the above options except for FRCs. For practical purposes, most long-term contracts can also be distinguished from self-supply. That leaves spot purchases and procurement of blocks as the primary vehicles for self-supplying default service. In default service provision settings, self-supply is usually associated with contingency planning, often due to a failed FRC solicitation. However, the mechanics of self-supply are identical regardless of whether a default service provider employs this approach by design or out of necessity.

There are many cost (and credit) line items that, together, make up the cost of providing default service. Foremost, self-supply requires procurement of energy, which is represented by ISO-NE locational marginal prices. Additional line items assessed by ISO-NE to the load-serving entity include capacity, certain transmission costs, various market-based and non-market-based ancillary services, uplift charges, and Auction Revenue Rights credits.[132] Default service providers are required to procure sufficient energy and associated services to meet customer requirements after accounting for distribution system losses (as established by each EDU), transmission system losses, and other "unaccounted for energy" factored into load settlement.

In the event of self-supply, the load-serving entity, as the default service provider, incurs the above ISO-NE charges (and assumes responsibility for paying them) based on the quantity of load served.[133] ISO-NE performs twice-weekly billing for the majority of the billing line items making up the total cost of serving load, including day-ahead and real-time energy, forward capacity, certain ancillary services, and uplift charges. Most remaining costs are subject to monthly settlement.[134] Given the lag between when wholesale costs are

[132] These components are further discussed in Section III, above. Although ISO-NE costs comprise the bulk of default service costs, the final default service rate also passes through RPS compliance costs (typically represented as the cost of RECs), various reconciliation adjustments that account for typically small settlement discrepancies for energy service and RPS compliance costs, and administrative costs associated with default service provision.

[133] These same line items are included in the fixed price of the FRC when a default service provider procures default service from wholesale suppliers via FRCs. That is, ISO-NE costs are borne by default service providers and passed on to default service customers through FRC bid prices, generally with a premium to account for load and price risk.

[134] See Exhibit ID, ISO New England Billing Policy, Section 1.3, available at: https://www.iso-ne.com/static-assets/documents/2017/09/sect_i_ex_id.pdf.

incurred and settled, ISO-NE requires financial assurances from market participants. This can include minimum capitalization, creditworthiness, and collateral requirements, or other guarantees. EDUs providing self-supply must maintain sufficient working capital to manage these regular settlement cycles.

Regulated utilities are typically unwilling to assume the above responsibilities unless the PUC first relieves the utility of risks associated with providing supply service. Thus, self-supply requires allowing the EDU to recover all reasonably incurred direct or indirect costs, obligations, expenses, or damages associated with procuring wholesale power. Cost recovery can be conducted through tracking riders, deferred as regulatory assets, or folded into base rates, among other common recovery mechanisms. In all cases, self-supply potentially incurs carrying costs that are passed on to customers. These carrying costs can include a rate of return when the EDU deploys capital in a prudent manner to support self-supply.

Additionally, the PUC must approve retail rates that facilitate the EDU's recovery of its self-supply costs. These rates can be fixed even as wholesale market energy costs change hourly. However, the longer the length of time that the rate is fixed, the greater the potential imbalance between collected revenues and actual wholesale costs. This under- or over-recovery necessitates reconciliation of such balances in a subsequent recovery period.[135,136] To reduce reconciliation, the utility can reset prices periodically to account for revised forecasts. Such reconciliation is not necessary when the default service provider procures FRCs because the risk of under-recovery (and the benefit of over-recovery) accrues to the wholesale suppliers of the FRCs.

The most variable component of total cost to self-supply load is energy. In order to mitigate large imbalances due to variable energy costs and take some of the energy price risk off the table, a default service supplier may purchase fixed-price, fixed-quantity blocks for part or all of its obligation during an upcoming rate period. While block purchases do not eliminate the price or load risk in the way FRCs do for the default service provider and customers, they lock in an energy price for some part of the default service load. This brings the projected and realized costs closer together, reduces the magnitude of under- or over-collection balances, and lowers the reconciliation rate that would apply to a subsequent rate period. Relying purely on the spot market can be viewed as a special case of block-and-spot where the default service provider makes the deliberate choice of not purchasing any block energy products.

[135] That is, when there is a large amount of under-collection (i.e., rates end up being too low to recover the total cost of serving load) or over-collection (i.e., rates end up being much higher than necessary to recover the total cost of serving load) during a rate period, such shortfall or excess is collected or credited back, respectively, in a subsequent rate period.

[136] To facilitate reconciliation, the PUC can require each EDU to submit sufficient detail to verify the amounts (and any applicable computations) used to derive their self-supply revenue requirement. Stakeholders would have an opportunity to scrutinize the EDUs' procurement practices and reconciliation processes as part of associated proceedings.

The chief drawback of self-supply (spot-only or block-and-spot) is that it places market price risks and load risks onto default service customers. Because of the highly volatile nature of ISO-NE spot markets, default service rates resulting from electric utility self-supply can be expected to be highly variable from one rate period to the next. However, in return for assuming the price risk and load risk (which includes customer switching risk as well as weather-related load risks), default service suppliers and customers greatly reduce the risk premium inherent in FRC prices. In the case of block-and-spot, block products are standard market products and are therefore relatively straightforward to buy (and sell) in the wholesale market. Major exchanges such as the Chicago Mercantile Exchange and the Intercontinental Exchange (as well as other subscription-based forward power index pricing providers) publish index prices at the close of each trading day. This information makes it easier to determine whether offers received for block products are in line with prevailing market prices.

Faced with the above trade-offs, most retail restructured jurisdictions have opted for FRCs since wholesale suppliers are thought to be better suited to assess and manage the risks associated with retail service, among other reasons. Wholesale suppliers have the same obligations as an EDU under self-supply, but typically must establish a price for a specific service period at a designated point in time (e.g., on the date of a solicitation). This causes prices for FRCs to diverge from self-supply, even when each approach provides service for the same period. FRC prices reflect forward pricing and best estimates of costs at the time of the procurement. Fixed-price FRC bids may also reflect the costs of options and other hedging products that a wholesale supplier can enter into in support of its future obligations. Wholesale suppliers also add risk premium to account for various uncertainties around future price and load conditions. Self-supply arrangements, by comparison, absorb and pass through costs associated with changes in price and load, as described above.

Recent volatility and high pricing, as discussed above, has caused the PUC to consider self-supply as an alternative for a portion or all of existing full-requirements service arrangements. In December 2023, the Commission directed Liberty, Unitil, and Eversource to develop proposals to use market-based pricing for 10-20% of small customer group default service beginning August 2024.[137] These proposals, once released, remain subject to PUC review. As justification for the requirement, the PUC cited persistent risk premiums under full-requirements service. For example, in the Unitil proceeding, the Commission noted that Unitil has "submitted, as part of the ordering requirements of Order No. 26,850, data for the months of August and September 2023 showing that the Company's requirements-contract prices for energy service were higher than the ISO-New England market prices for each month by a factor of approximately 1.5 to 2."[138] The Commission also noted previous data filed in Docket IR 22-053 showing substantial differences between

[137] New Hampshire PUC. Dockets DE 23-044 (Liberty), DE 23-054 (Unitil), and DE 23-043 (Eversource).

[138] New Hampshire PUC. Docket DE 23-054. *Order No. 26,910 Approving Petition for February 1, 2024 to July 31, 2024 Rates*, p. 7.

real-time energy prices and default service prices. The real-time energy prices presented in Docket IR 22-053 did not incorporate all non-energy components of wholesale costs.

To facilitate additional comparison on a historical basis, Exeter constructed a representative assessment of estimated wholesale, pass-through default service costs since 2018. Figure 8 visualizes these after-the-fact, realized costs for small customers by utility and compares them to the full-requirements default service costs observed during the same period. The wholesale costs in this graph are based on ISO-NE's monthly wholesale load cost report and represent, by month, average New Hampshire costs for energy at real-time locational marginal prices (LMPs) (which include transmission loss and transmission congestion costs); forward capacity; net commitment period compensation; ancillary services, including regulation, forward reserves, real-time reserves, and inadvertent energy; wholesale market service charges; and several other small credits and charges.[139] Additionally, the estimated wholesale costs incorporate Mystic COS supplemental capacity payments,[140] EDU RPS costs, RPS reconciliation amounts, and other reconciliation totals.[141]

ISO-NE revised its forward capacity market methodology in June 2022.[142] To account for this change, reported forward capacity costs before this time are adjusted based on class- and utility-specific load factor estimates.[143] Applicable energy and ancillary service costs are adjusted to account for distribution losses.[144] Notably, the estimated wholesale supply rates exclude some very small charges incorporated into the actual default service rate, such as the Energy Service Adjustment Factor and Energy Service Cost Reclassification Adjustment Factor. They also exclude administrative costs, working capital costs (including rate of

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[139] See: ISO-NE, 2023 Wholesale Load Cost Data Series, https://www.iso-ne.com/static-assets/documents/2023/02/lcm_jan2023_13feb23.csv.

[140] See: ISO-NE, *Monthly Market Operations Report November 2023*, https://www.iso-ne.com/static-assets/documents/100006/2023_11_mnthly_market_rpt.pdf.

[141] Costs sourced from default service filings or responses to DOE data requests in INV 2023-01. Some costs may not be reflected if not readily available or provided.

[142] Prior to June 2022, ISO-NE's monthly wholesale load cost report represented the capacity price as the net regional clearing price divided by the number of hours in the month. Beginning June 2022, the rate represents the cost allocation charge divided by the number of hours in the month. For additional information, see supporting documents before the change (e.g., https://www.iso-ne.com/static-assets/documents/2021/09/2021_08_wlc.pdf) and after the change (e.g., https://www.iso-ne.com/static-assets/documents/100006/2023_11_wlc.pdf)

[143] Eversource's load factor is estimated using installed capacity default values and hourly load profiles by rate class, grouped together by default service class. For applicable data, see: https://www.eversource.com/content/residential/about/doing-business-with-us/energy-suppliers/new-hampshire-electric-suppliers and https://www.eversource.com/content/docs/default-source/energy-supply/generic-rate-icap-tags-psnh.xlsx?sfvrsn=588e1cf9_1. Unitil's load factor is estimated using average installed capacity tags and indicative hourly load profiles by class. For applicable data, see: https://unitil.com/suppliers/energy-supplier-resources. Liberty's load factor is identified using monthly default service customer group data provided in the "Liberty 2022-08 Premium Bid Factor for Proxy Price" spreadsheet, part of Confidential Attachment INV 2023-001 RR 1.1.

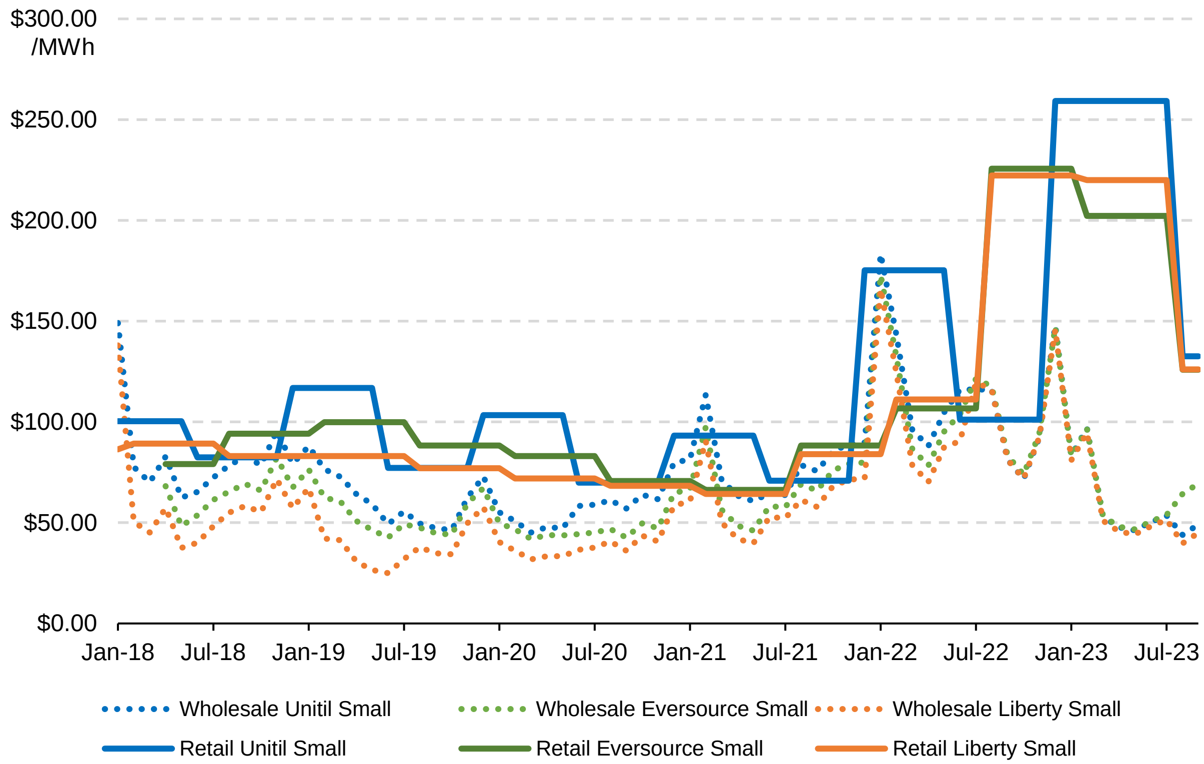
[144] Eversource loss factor: https://www.eversource.com/content/residential/about/doing-business-with-us/energy-suppliers/new-hampshire-electric-suppliers.

Liberty loss factor: https://new-hampshire.libertyutilities.com/uploads/LU_CurrentLineLosses.pdf, average primary metering and non-primary metering for each group.

Unitil loss factor: https://unitil.com/suppliers/energy-supplier-resources.

return on capital deployed), and unaccounted for energy, estimates for which were not readily available at the time Exeter compiled this analysis.

Figure 8. Wholesale, Pass-Through Compared to Retail, Full-Requirements Default Service Costs for Small Customer Groups, by Utility



From January 2018 – September 2023, actual default service rates were generally higher than the proxy wholesale rate. Some of this differential can be explained by additional costs not incorporated into the estimated wholesale rate, especially potential working capital costs. The difference also reflects timing variation and risk premium, as discussed above.[145] Over this full period, estimated wholesale costs were 32% lower per month, on average, than the actual default service rates across all three utilities.[146] Excluding August 2022 onwards, when retail default service rates spiked, reduces the average difference to 25%.[147] The biggest monthly differences ranged from estimated wholesale costs exceeding actual default service rates by as much as 99% (Eversource, January 2022) to actual default

[145] The results are also sensitive to some of the simplifying assumptions adopted by Exeter (e.g., using recent load data as a proxy for historical load factors when adjusting forward capacity prices prior to June 2022).

[146] Calculated using the simple average of the monthly percentage difference for all three utilities, combined. Using this approach instead of the average of dollar differences ensures that each value is given equal weight, regardless of its absolute size in dollars. This approach prevents larger dollar amounts from disproportionately influencing the overall average. Based on the simple (non-weighted average) rates, the average retail rate ($112.16/MWh) is higher than the average wholesale rate ($68.16/MWh) by 39.2%, or $43.99/MWh.

[147] Based on the simple (non-weighted average) rates, the average retail rate ($88.93/MWh) is higher than the average wholesale rate ($66.56/MWh) by 25.2%, or $22.37/MWh.

service rates exceeding wholesale costs by 82% (Unitil, May 2023). The mean and median monthly differences are close for all three utilities and exhibit a normal statistical distribution.[148] The large standard deviation (ranging from 28-30% difference per month) for all three utilities suggests a high level of variation within the relatively small sample of 69 months. This large variance suggests caution before reaching conclusions about the overall favorability of alternative wholesale procurement strategies versus existing approaches.

B. Future Market Conditions

Potential changes to New Hampshire default service should not only account for recent and historical conditions, but also for reasonably anticipated future conditions. What follows is an overview of select conditions that have the potential to materially impact future default service procurement outcomes.

1. Full-Requirements Contract Components

ISO-NE is exploring several changes to its capacity auctions and ancillary services that have the potential to alter the costs incorporated into full-requirements obligations. Most prominently, the Mystic COS agreement is set to end in May 2024. These costs were typically volatile and difficult to account for in default service bids. Therefore, the expiration of this agreement eliminates some cost uncertainty for wholesale suppliers. The last procurement period that Mystic arrangements will affect is from February – July 2024.

The end of the Mystic COS agreement, however, may coincide with the introduction of new programs intended to support winter reliability. For example, ISO-NE has proposed revisions to the Inventoried Energy Program (IEP). This program is intended to address energy shortages in winter and extreme weather periods by incentivizing generators to maintain additional fuel. There is disagreement regarding what resource should and can receive IEP incentives, as well as the expected cost incurred to customers for the program. As this discussion is still ongoing, there is uncertainty regarding associated winter costs.

More broadly, ISO-NE's Forward Capacity Auction was recently delayed. These delays make it challenging to estimate future capacity costs. The New England Power Pool (NEPOOL) also recently approved a new Day Ahead Ancillary Services Initiative (DASI). This program is intended to provide further price transparency into ancillary services, address gaps between

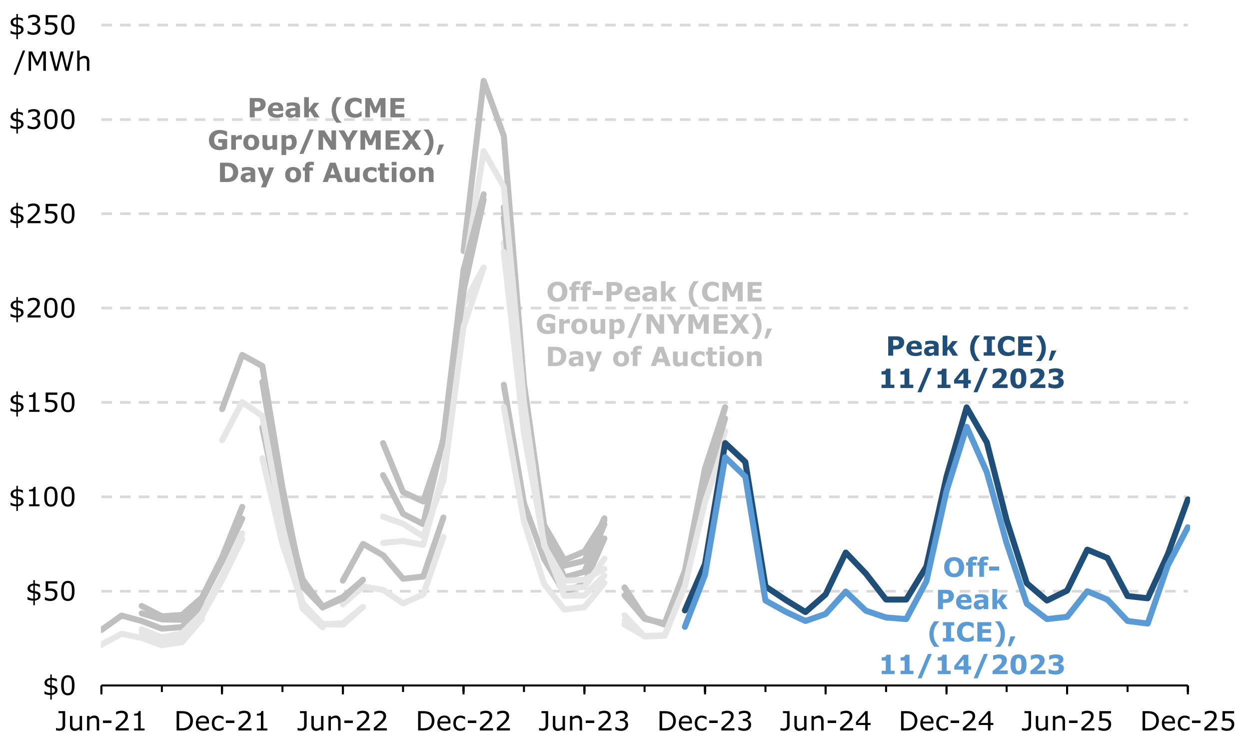
[148] Based on a normal distribution, it appears that the true average monthly percentage difference between estimated wholesale costs and actual retail costs is between -98.9% (i.e., wholesale costs would be 98.9% lower, meaning more favorable, on average) and 22.9% (i.e., wholesale costs would be 22.9% higher, meaning less favorable, on average) for Liberty, between -83.5% and 29.9% for Unitil, and between -89.2% and 26.1% for Eversource. These ranges represent 95% confidence intervals. In other words, if we assume the differences between estimated wholesale costs and actual retail rates are randomly distributed based on the distribution observed in the review period (sample size of 66-69 months), then 95% of the time we would expect the average difference to fall somewhere between each above range.

the day-ahead market energy supply pricing and forecasted load, and procure day-ahead services to respond to unexpected changes in load. DASI takes effect in March 2025. Both of the above issues create market price uncertainty over longer time horizons.

2. Forward Prices

As observed in recent history, wholesale energy price uncertainty results in undesirable outcomes, not the least of which is higher wholesale supplier bid premiums and resultant default service prices. Recent price forecasts, as compared to historical six-month futures, show a return to less volatile pricing as compared to the 2022/2023 winter period. This shift should have a positive impact on wholesale suppliers' ability and willingness to participate in solicitations. Lower forward energy costs, all else equal, should also facilitate lower bids. Figure 9 shows peak and off-peak energy futures (blue lines) for the New Hampshire Hub as of mid-November. These futures are compared to similar monthly prices in the last two years (gray lines) compiled for the date that final bids were due for each utility. Note that historical energy price trends for all three EDUs aligned, even across varied bidding periods and divergent delivery periods.

Figure 9. Monthly Energy Futures on Day of Auction (Historical) and Going Forward



Source: ICE Futures Daily Market Report for Financial Power 13-Nov-2023; S&P Capital IQ Day Ahead Market Data.

3. Aggregation

Aggregation has been a major recent policy change in New Hampshire. There are several active community power aggregations, with more forthcoming. Utilities have also experienced data and technical issues that create uncertainty regarding the implementation timing for upcoming community power aggregations. On June 14, 2023, three utilities filed the Joint Utilities' Petition for Waiver of Certain Provisions of the Pub. Util. Code 2200 Rules (DE 23-063). The petition highlighted issues related to billing mechanisms for community power aggregation and associated costs. The utilities' petition notes four main issues:

1. The utilities' metering export data does not support the functionality, namely negative usage numbers, as requested by community power aggregations.
2. The utilities' billing systems currently support utility-ready billing, but the rules state that community power aggregations can request bill-ready billing.
3. Bill-ready billing requires a delay because the utility must report usage data to a third party for it to calculate the charges and report it back to the utility for the bill.
4. There are costs associated with implementing changes to the utilities' billing and data systems that the utilities wish to recover.

In their petition, the utilities also propose changes to their billing system to accommodate bill-ready billing, but request that information needed for bills from third parties be ready within a certain number of days. Additionally, the utilities propose that the Electronic Business Transaction Working Group meet to discuss the appropriate incremental cost recovery mechanism for recovery of costs related to changing utilities' billing. Delays in activating community power aggregations due to data and billing issues could create further uncertainty surrounding default service customer load migration.

V. RECOMMENDATIONS

A. Criteria and Market Impact Considerations

Based on the above assessment, Exeter identified a series of recommendations regarding the future of default electric service procurement in New Hampshire. These recommendations reflect Exeter's consideration of a variety of criteria, including how each potential default service strategy or requirement:

- Complies with the policy objectives of RSA 374-F:3 and existing New Hampshire PUC rules and regulations;
- Reflects current and best practice observed in other states;
- Addresses stakeholder feedback provided in response to DOE INV 2023-001 and PUC Docket IR 22-053;
- Displays adaptability to a variety of current and future market conditions;
- Aligns with current and historical default service practice in New Hampshire; and
- Minimizes implementation requirements or costs.

Exeter also accounted for a range of potential market impacts when developing recommendations, as discussed in Section III. These include the influence of default service characteristics on:

- Default service customers (e.g., price stability, actual costs);
- Current and prospective default service auction participants (e.g., decision-making about how to bid and when to participate);
- Electric distribution utilities (e.g., reconciliation requirements and carrying costs);
- Competitive energy providers (e.g., customer interest in third-party supply); and
- Regulators (e.g., administrative burden or cost).

The various criteria and/or market impacts sometimes come into conflict. For example, shifting risk away from default service auction participants may induce greater bidding interest but may also reduce price certainty and stability for customers. Thus, the subsequent overview of recommendations includes brief discussion of which criteria or market impacts are emphasized as they relate to each recommendation.

B. Recommendations by Default Service Attribute

Exeter offers the following recommendations to help maintain or improve the functioning of default electric service procurement in New Hampshire. These recommendations are subdivided by attribute, with particular attention directed towards the questions and issues raised in DOE's Order of Notice opening INV 2023-001. Potential changes to some "key characteristics" (see Section III) exceed the scope of this report. These topics are addressed in brief as part of Subsection C. "Other Topics" that concludes Section IV.

1. Default Service Provider and Procurement Entity

Both DOE INV 2023-001 and PUC Docket IR 22-053 elicited comments regarding changes to the default service provider and procurement entity, including discussion of centralized, consolidated procurement of default supply and the adoption of a designated, independent Procurement Manager. Based on stakeholder feedback and comparative analysis of practices in other jurisdictions, **Exeter does not recommend deviating from the current practice of assigning default service provider and procurement responsibilities to the EDUs.** This recommendation is consistent with the predominant default service model across most retail restructured jurisdictions.[149] It also reflects several clear advantages of assigning default service provider responsibilities to local utilities versus CEPs or other parties.

First, local utilities are generally seen as more stable and less risky entities compared to CEPs, which may face higher financial and operational volatility. This stability is crucial for default service, which serves as a "safety net" for consumers who do not choose a competitive supplier per RSA 374-F:3. Additionally, utilities typically have better access to capital and stronger credit ratings than most CEPs. This financial robustness is essential for securing energy supplies in volatile markets.

Second, local utilities already own and manage the infrastructure needed to deliver electricity (like transmission and distribution lines). They also have established operational systems for billing, customer service, and outage response. Leveraging these existing capabilities for default service is often more efficient and less disruptive than setting up parallel systems with CEPs. Third, local utilities can more directly accommodate existing state policy and regulation, especially as compared to CEPs. This includes efforts to reflect state policy goals across both supply and distribution services and avoid potentially conflicting incentives. Further, local utilities are easier for states and regulatory bodies to effectively monitor given their existing regulated business relationships.

Finally, most local utilities have longstanding experience supporting customers in their service area. This experience equips them with an understanding of the local energy market, customer needs, and regional challenges that influence procurement outcomes. Establishing similar institutional capacity at a state level (e.g., implementing an entity akin

[149] Twelve of 14 retail restructured jurisdictions assign default service provider responsibilities to the EDU (exceptions are Maine, Texas), and 11 of 14 also assign procurement entity responsibilities (exceptions are Maine, Texas, Illinois).

to the Illinois Power Agency) is likely to be administratively intensive. It is also uncertain to provide measurable benefits in terms of procurement outcomes unless coupled with other changes, such as the consolidation of all default service requirements into a single statewide procurement of identical products. This approach has the potential to achieve scale economies and attract additional wholesale supplier participation. It also, however, introduces cost causation concerns insofar as a consolidated procurement does not inherently account for unequal costs to serve different default service customers. There may also be additional administrative burdens required to coordinate differentiated services to each EDU. **Exeter does not recommend adoption of a single, statewide procurement process overseen by a centralized procurement entity.**

Despite the above advantages, EDUs do not necessarily have expertise in energy procurement and bid evaluation as they relate to default service. Thus, it may be appropriate to integrate an independent administrator or advisor to manage elements of default service procurement. Independent administrators are most common in jurisdictions with complex procurement methods, such as descending-clock auctions. In their oversight capacity, these parties support development of procurement plans and oversee certain auction processes. Specific responsibilities of the administrator can include issuance of RFPs or bid specifications, establishment of proxy prices, review of received bids, and approval of winning bidders. An independent advisor might support similar responsibilities but do so in an advisory, rather than governance, capacity.

The existing, sealed-bid solicitation process is relatively straightforward and, as such, does not require the involvement of a third-party administrator with associated expense. However, Exeter, as part of the DOE INV 2023-001 assessment, observed inconsistent development and application of proxy prices by the EDUs in the last five years. Additionally, several parties identified concerns regarding the amount of time required for the Commission to review and approve winning default service bids. **Exeter recommends introducing a limited capacity independent advisor (contracted through DOE) to specifically support the assessment and approval of default service bids.** This entity would not assume each EDU's existing responsibility to develop and conduct default service procurements, or to contract with winning bidders. This entity would also not absorb the Commission's responsibility to approve contracts, establish default service procurement methods, or address contingency circumstances. The independent advisor would, however, take part in the solicitation process. The limited role of this entity, under DOE authority, would be to independently calculate a proxy price, review received bids, and assess the acceptability of received bids. The independent advisor would then compile a brief report for issuance to the Commission as part of the existing approval process.

The introduction of an advisor with these responsibilities would increase the Department's role in the initial, critical approval window that occurs immediately after receipt of bids. Involvement of state-sanctioned parties like DOE earlier in the default service process reduces some timing risk for wholesale suppliers (see Subsection 3. "Timing" below). It also relieves EDUs of their responsibility for evaluating bid acceptability, though they may continue developing their own proxy price as a point of comparison (akin to the process in Connecticut). The independent advisor would be granted the authority to request information from the EDUs that could inform proxy price development and bid approval not just for a specific EDU, but for all EDUs. Thus, an independent advisor may be able to better assess bids than individual EDUs by incorporating more information into its decision-making process. This is especially true for utilities like Liberty that do not have access to information for comparable Northeast affiliates. All assessment efforts conducted by the independent advisor would be subject to strict confidentiality standards.

2. Product Types

The choice of product type for default electric service procurement is critical to assigning risk. Under FRCs, the wholesale supplier for a particular FRC bears the risk associated with market changes during the time that the FRC is in place. For example, market price changes related to severe weather or unanticipated fuel price changes fall on the wholesale supplier and not default service customers. Further, default service suppliers under this arrangement have a strong incentive to optimize wholesale supply procurement, including hedges, to manage this risk while meeting their default service obligations. By contrast, under a block-and-spot approach, default service customers bear the market risk for the spot portion of the portfolio (either spot market sales or spot market purchases) that is needed to balance load and supply.

For most jurisdictions, policymakers and regulators prefer to shift price and volume risk to wholesale suppliers, who are thought to be best suited to manage these risks, even at the expense of supplier risk premium. Additionally, FRCs reduce certain administrative requirements and can promote price stability. While standardized block contracts are simpler to procure compared to FRCs, they require the default service provider to engage with wholesale markets on an hourly basis to balance supply with demand. This level of involvement requires additional administrative resources both to conduct actual market transactions and manage settlements. Hourly transactions also increase price risk for customers and introduce reconciliation costs, thereby reducing price certainty and stability. **Exeter recommends continuing to assign the responsibility of meeting hourly load obligations and all accompanying energy market requirements to wholesale suppliers via FRCs.** This approach ensures consistent risk management and aligns with best practices in 11 of 14 retail choice jurisdictions.

Several jurisdictions, including Maine and D.C., allow default service providers to layer long-term contracts into default service alongside FRCs. Common long-term contract arrangements specify a price per MWh which can escalate over time, sometimes in direct connection to a generating resource (i.e., a PPA). Eversource's default service rates prior to 2018 (when the utility instituted competitive default supply procurement) incorporated PPA costs. When relatively small, these contracts serve as a hedge against changing market costs. They can also introduce new risks, especially when supporting a large portion of load.

First, any long-term contract potentially creates large and long-lived differentials between the default service rate and the competitive market. Second, layered long-term contracts change the composition and load profile of the FRCs that are stacked on top. It may be more challenging, for example, for a wholesale supplier to hedge FRC obligations that complement solar production (i.e., increase requirements in the evening as solar production decreases), as compared to all-hours in the day. This challenge is passed through to customers in the form of higher risk premium. Third, if customers migrate away from default service, long-term contract costs have the potential to become stranded. The PUC's Statewide Electric Utility Restructuring Plan specifically cautions against long-term power contracts as a potential source of stranded costs, and the PUC has historically discouraged their use. **Exeter recommends excluding long-term (i.e., greater than five years) contracts from default service FRCs.**

FRCs can offer fixed prices for varying lengths of time, ranging from monthly fixed prices to prices that change annually. FRCs can also pass-through certain costs, with pass-through reconciliation occurring as often as each hour or on the same timescale as changes in fixed price. All 11 retail restructured jurisdictions that employ FRCs do so using fixed-price contracts for small customers. This approach is consistent with rate stability objectives discussed in further detail below (see Subsection 3. "Laddering" below). For non-residential customers, the landscape is more varied. Nine retail choice jurisdictions provide a monthly price option, while seven offer variable or hourly pricing options.

The availability of more variable pricing options for large customers reflects the greater responsiveness of this class to price changes (i.e., higher price elasticity) as well as its higher proclivity to shop for CEP service. Additionally, FRCs for large customers often include higher load risk than products for other classes. This heightened risk stems from both the limited number of larger customers utilizing default service (such that the entry or exit of even a single customer can significantly alter the requirement) and increased risk of gaming. These factors can increase the complexity of hedging for large customers, especially as it applies to energy costs which can be large and variable. In these conditions, pass-through of certain costs can help mitigate the substantial risk premiums otherwise imposed by wholesale suppliers. See Subsection 9. "Default Service Cost Components" below for additional discussion of costs that are appropriate for pass-through.

Exeter recommends adopting monthly, variable price contracts for all large customers. These contracts should pass-through energy costs. This recommendation mirrors the procurement strategy currently employed by Unitil. During recent periods of market volatility, Unitil's default service bids have remained relatively stable, partly because suppliers were not burdened with absorbing wholesale market risk. Moreover, Unitil consistently attracted enough bidders to select a winning wholesale supplier in recent auctions, therefore avoiding self-supply. Implementing monthly variable price contracts for the large customers of all utilities would enhance market price signals to this class of customers, encourage their continued participation in the competitive retail market, and avoid significant risk premiums for those customers taking default service. This strategy would not, however, ensure low or stable prices. This outcome is consistent with RSA 374-F:3 and the historical default service objective that large customers only take default service as a transition arrangement. These changes should be coupled with revisions to what customers comprise the Large Customer Group, as discussed below (see Subsection 3. "Laddering" below). **Exeter does not recommend changing the current approach of procuring fixed-price FRCs for all small customers.**

3. Laddering

All else equal, pricing for utilities with laddered contracts adjusts more slowly to changes in market conditions. This applies to both decreases and increases in market costs. Stakeholders presented mixed views of laddering in DOE INV 2023-001 and PUC Docket IR 22-053, with comments ranging from skepticism regarding laddering's benefits (Liberty, Unitil, NRG, RESA), optimism about its ability to reduce price volatility (Eversource, Unitil), and endorsement (OCA). Commission and Legislative preference for market-reflective rates versus stable rates has also varied over time, as discussed in Section II. The appropriate path forward for laddering in New Hampshire requires careful consideration of the state's objectives for default service, and likely varies by customer class. Additionally, Exeter's recommendations regarding laddering are sensitive to the assumptions applied.

A variety of practical and theoretical reasons explain why rate stability could be a preferred policy objective for residential and small commercial customers. First, as a practical matter, stable rates aid consumers in budgeting and reduce the risk of financial hardship due to sudden rate spikes. These practical matters are among the reasons cited by researchers in a diverse set of academic studies documenting both revealed (i.e., observed through customer action) and stated (i.e., observed through customer statement) consumer preference for stable retail electric rates.[150] These findings are also complemented by survey results showing similar preferences nationwide.[151,152]

[150] For example, see: Goett, A. A., Hudson, K., & Train, K. E. (2000). "Customers' choice among retail energy suppliers: The willingness-to-pay for service attributes." *The Energy Journal*, *21*(4); Kaenzig, J., Heinzle, S. L., & Wüstenhagen, R. (2013). "Whatever the customer wants, the customer gets? Exploring the gap between consumer preferences and default electricity products in Germany." *Energy Policy*, *53*, 311-322; Cardella, E., Ewing, B. T., & Williams, R. B. (2017). "Price volatility and residential electricity decisions: Experimental evidence on the convergence of energy generating source." *Energy Economics*, *62*, 428-437.

[151] For national survey evidence, see: Wimberly, J. (2011). EcoPinion: Resurgence for retail electricity choice and competition? *EcoAlign*. Survey Report Issue 11; J.D. Power (2015). Retail electric provider residential customer satisfaction survey. https://www.jdpower.com/business/press-releases/2015-retail-electric-provider-residential-customer-satisfaction-study.

[152] For example, a Maine PUC survey in 2002 specifically assessed the question of default service rate stability:

Second, as another practical matter, there is a longstanding historical precedent for treating rate stability as a default service procurement strategy and rate design objective in New Hampshire. Until 2012, Unitil utilized laddered procurements that included both overhanging and stacked contract components to meet its default service obligations. Eversource expressed a preference for laddered contracts when implementing default service in 2017. Laddering is also consistent with New Hampshire's RSA 374-F:3, which indicates that default service should be designed "to minimize customer risk, not unduly harm the development of competitive markets, and mitigate against price volatility without creating new deferred costs, provided that the Commission finds such means to be in the public interest."[153] Additionally, the Commission cited rate stability objectives when it approved Liberty's proposal to split up the January and February service months.

Third, laddering is employed by all retail restructured jurisdictions besides New Hampshire, Maine, and Texas. Maine, meanwhile, is currently considering ways to adopt laddering for residential and small customers. Finally, increased rate stability addresses the serial issue of limited small customer participation in the retail market. That is, more stable, laddered rates reduce volatility for customers that do not shop and are not responsive to very large price swings (i.e., inelastic).

Theoretically, rate stability may also be preferable because constant fluctuations in rates can erode consumer faith in competitive markets as a whole, including both retail supply markets and wholesale energy markets. Additionally, the absence of stable rates creates a challenging environment both for CEPs (i.e., boom-and-bust cycles) and for wholesale suppliers of default service (i.e., volumetric risk). If default supply rates exhibit large variation from one pricing period to the next, this variability may prompt customers to opportunistically switch into and out of default service frequently and in large numbers. This additional layer of potential volumetric risk is, by design, absorbed by the wholesale suppliers in the FRCs. Absorbing this risk, however, may prompt suppliers to incorporate a larger risk premium into their offers, which in turn would increase both the level and variability of default service rates. Thus, contract laddering with procurement timing, procurement frequency, and/or contract length diversity can also self-reinforce rate stability. Lastly, default service rates serve as a price heuristic for other competitive retail

> The overwhelming majority of customers wanted the Maine PUC to structure standard offer service as a stable price that did not change frequently even if it meant that the price was slightly higher than a volatile price. When asked, ''If you had to choose between having your standard offer price as low as possible, or increasing the number of competitive suppliers from which you could choose, which would you choose?,'' 74 percent favored the lower standard offer price. When asked if the standard offer price should be increased in order to encourage more suppliers to compete and possibly offer a lower price, two-thirds of the respondents did not favor this approach.

See: Alexander, B. R. (2010). "Dynamic pricing? Not so fast! A residential consumer perspective." *The Electricity Journal*, *23*, 39-49.

[153] Because laddered costs, like other default service costs, are subject to reconciliation, they do not create deferred stranded costs.

supply offers on the open market.[154] Thus, more stable rates preclude CEPs from offering very high-priced rates.

Exeter's recommendations regarding laddering are sensitive to the assumptions outlined above, as well as the policy preferences of New Hampshire as they apply to potential trade-offs between rate stability and market reflectiveness. **If key stakeholders value market reflectiveness higher than rate stability, Exeter recommends that New Hampshire maintain the current procurement approach (subject to the other recommendations discussed in the report). If key stakeholders value rate stability higher than market reflectiveness, potentially for the reasons outlined above, Exeter recommends implementing laddering for residential and small customers both in terms of delivery period (i.e., overhanging contracts) and products (i.e., multiple, stacked procurements for each period).** The justifications for similar laddering arrangements to serve large customers are weaker. Instead, as discussed in Subsection 2. "Product Types" above, additional pass-through of wholesale costs is more appropriate for large customers.

To implement laddered contracts, Exeter recommends the use of two sets of contracts. During the initial procurement, each utility should procure one set of contracts totaling 50% of the Small Customer Group load for six months, and a second set of contracts totaling 50% of load for one year. Then, in the subsequent procurement, when the six-month contracts expire, a new set of contracts should be solicited for an additional 50% of the load during the next year. That same arrangement would be in place for all subsequent years such that half of the total Small Customer Group load for each utility would be repriced every six months. This approach is consistent with the below recommendation to maintain biannual procurements (see Subsection 4. "Timing" below).

For these processes, **Exeter recommends the use of one-year overlapping contracts in place of shorter- or longer-term contracts in order to balance rate stability with administrative cost and potential risk premium.** Although longer contracts promote additional rate stability, they potentially introduce additional supplier risk premium. These premiums relate to uncertainties characteristic of the ISO-NE market, community power aggregation activity, and more limited contract liquidity for hedging purposes. Shorter-term contracts, meanwhile, require more frequent price adjustments. They also reduce the attractiveness of the product to wholesale suppliers, especially when subdivided into multiple tranches. Twelve-month products, therefore, represent a middle ground appropriate to the size of market context of the New Hampshire EDUs.

[154] See: Tsai, C. H., & Tsai, Y. L. (2018). "Competitive retail electricity market under continuous price regulation." *Energy Policy*, *114*, 274-287; Brown, D. P., Eckert, A., & Olmstead, D. E. (2022). "Procurement auctions for regulated retail service contracts in restructured electricity markets." *Energy Economics*, *116*, 106387; Esplin, R., Davis, B., Rai, A., & Nelson, T. (2020). "The impacts of price regulation on price dispersion in Australia's retail electricity markets." *Energy Policy*, *147*, 111829.

Although Exeter also recommends stacking contracts through temporally diversified procurements, this strategy deviates from current procurement practice of minimizing the time between solicitation and contract maturity. For example, under a biannual schedule with overhanging contracts, procuring stacked contracts would require Unitil and Liberty to solicit 12-month duration FRCs for 25% of load approximately nine months in advance of contract start. The total length of time from solicitation to contract end in this example falls within the 24-month duration discussed above (see Subsection 4. “Timing” below). Nevertheless, **Exeter recommends delaying implementation of stacked contracts until after implementing overhanging contracts.** This delay will simplify the initial implementation of laddering by minimizing the number of concurrent contract periods being procured at one time. It will also ensure sufficient time for the market to adapt to the above recommended changes before introducing additional timing risk due to stacking. Finally, it is unclear whether community choice aggregation will shrink available Small Customer Group loads to levels below the target levels needed to procure two or more stacked procurements for each overhanging contract phase.

Lastly, to address concerns raised by some stakeholders, Exeter does not anticipate that laddering will distort the competitiveness of procurements. That is, wholesale suppliers are indifferent to whether contracts are laddered as long as the products are standardized, of a reasonable size, and procured within a reasonable window in terms of contract timing. Additionally, laddering may also reduce, not increase, the “boom and bust” cycles experienced by retail suppliers. That is, laddering can result in a smaller price differential between default and wholesale prices over a longer period, versus a larger price differential for a shorter period under existing procurement strategies. Finally, there is no clear evidence that laddering has impeded switching in other jurisdictions; switching levels and trends are consistent in all jurisdictions, with growth primarily driven by community power aggregation activity.[155]

Several additional considerations influence the above laddering strategies but are applicable irrespective of the laddering approach that New Hampshire adopts. For all customer classes relying on FRCs for default service supply, the number of FRC tranches to be procured, the size of the tranches, and restrictions on the number of tranches that any one supplier may be awarded should balance the competing goals of minimizing administrative costs, maximizing market participation, and controlling the risk of supplier default. Within these constraints, maximizing the number of tranches increases the amount of flexibility to implement various procurement strategies, including laddering. Appropriately sized tranches can also attract additional bidders and help enforce market discipline on default supply prices. This discipline, in turn, promotes both lower and more stable pricing.

[155] See: https://www.eia.gov/todayinenergy/detail.php?id=55820.

The utilities currently use procurement groups that include customers that vary dramatically in size. For example, Liberty's Large Customer Group includes customers with demand as small as 20 kVA, while the minimum Large Customer Group customer size for Until is 200 kVA on average. **Exeter recommends reclassifying Unitil's current Medium Customer Group, inclusive of Rate G2 and Rate OL customers, as part of Unitil's Small Customer Group, and moving Liberty's Rate G-2 customer class from Liberty's Large Customer Group into the Small Customer Group.** These changes will more consistently define large customers as customers with demand in excess of 100 kW or 200 kVA.

The amount of default service load served by Liberty and Unitil appears large enough to support 25% tranches for the revised Small Customer Groups, consistent with Vitol's comment that the target tranche size should range from 5-50 MW. There is also evidence from Eversource that increasing the number of tranches attracts additional participation and results in more price offers to choose from. **Exeter recommends maintaining eight tranches (each equal to 12.5% of the load) for Eversource and implementing two tranches (each equal to 50% of the load) for Liberty and Unitil for each utility's Small Customer Group.** Smaller tranches, in this case, do not preclude suppliers from serving higher shares of the load by submitting multiple bids. They do, however, allow smaller suppliers and suppliers with more limited risk tolerance to participate by taking on smaller positions. More specifically, very large tranche sizes can be difficult to execute in the ISO-NE market, precluding participation by suppliers that do not have "natural" hedge capabilities, meaning generation resources they can use to support default supply service. Smaller tranche sizes, therefore, increase bidder flexibility. Although Eversource could support additional, smaller tranches, Exeter recommends eight tranches in order to avoid the administrative complexity of a potentially higher number of providers. Additionally, Exeter only recommends two tranches each for Liberty's and Unitil's Small Customer Groups on account of community choice aggregation risk. **Exeter does not recommend any changes to tranche sizes for the Large Customer Groups.** The above recommendations regarding customer groupings and tranche size apply even in the absence of laddering.

4. Timing

Default service timing decisions, including the duration of product delivery, frequency and consistency of procurement, timing of product periods, and timing of solicitation and approval, have immense practical importance to default service outcomes despite being largely administrative choices. Important outcomes include, for example, the impact of these decisions on the participation, risk premium, and bid strategies adopted by wholesale suppliers; the administrative complexity and cost for EDUs and the PUC; the resultant comparability of default and CEP products; and the cost, certainty, and stability of resultant consumer prices.

Contract duration has the most explicit connection to default service policy objectives. Longer-duration contracts explicitly support rate stability by providing energy for a specified time period at a known price. Such contracts effectively "lock in" a price, therefore insulating customers from wholesale market volatility. At the conclusion of a longer-period contract, however, customers are exposed to the full extent of wholesale market price changes, which can be substantial depending on the contract time frame. By contrast, contracts for shorter periods of time are more reflective of prevailing market conditions but, as a result, are potentially volatile. That is, contracts for shorter periods of time provide less price certainty by the nature of being regularly adjusted. Further, short-term contracts can add administrative costs by adding additional procurement events and, depending on the product size, may not attract the requisite number of bidders to ensure a competitive solicitation.[156]

As the contract term increases beyond a certain threshold (e.g., longer than 36 months), wholesale supplier participation in default supply procurements may be lower, or suppliers may increase the risk premiums to their bids to account for the higher risk and uncertainty associated with the longer contractual obligation. In an ISO-NE context, this threshold is lower due to market fundamentals. Notably, constrained access to fuel and heightened winter demand due to severe weather cause price and load uncertainty in the region. Over longer time horizons, these conditions magnify risk uncertainty. Additionally, certain full-requirements obligations are unknown beyond several years. For example, ISO-NE capacity costs are only known on a three-year forward basis. Additionally, ISO-NE is exploring wholesale market reforms, such as the Day-Ahead Ancillary Services Initiative,[157] and considering new out-of-market interventions, such as proposed revisions to the Inventoried Energy Program,[158] that create uncertainty regarding market prices over longer time horizons. Given these considerations, all ISO-NE retail restructured states currently employ FRCs of 12 months' duration or less, as compared to periods extending as far out as 36 months in PJM jurisdictions. **Should New Hampshire adopt longer-duration (i.e., greater than six months) contracts, Exeter recommends approving contract durations of no longer than 24 months on account of uncertainties characteristic of the ISO-NE market. Additionally, contract durations equal to or less than 12 months are appropriate in the near term due to uncertainty related to community power aggregation.**

All New Hampshire utilities currently conduct biannual procurements as a result of past efforts to balance the administrative cost of more frequent procurements with minimization of the length of time between procurement and contract start or end (i.e., maturity). This

[156] That is, a shorter-term contract makes less load available to suppliers and, therefore, reduces the opportunity to earn a return on the unitized profit margin embedded in each winning bidder's default service rates.

[157] See, for example: https://www.iso-ne.com/static-assets/documents/2023/07/a03_2023_07_11_dasi_iso_presentation.pdf.

[158] See, for example: https://isonewswire.com/2023/05/15/iso-ne-issues-early-analysis-of-winter-2024-2025-operations-with-without-everett-lng-facility/.

cadence is less frequent than the quarterly schedule used for at least some customer groups in Connecticut, Massachusetts, and Rhode Island, but more frequent than Maine's annual procurement process. Outside of ISO-NE, jurisdictions that use FRCs tend to conduct biannual or annual auctions. **Exeter recommends maintaining the current biannual procurement schedule.**

The frequency of procurements also addresses considerations related to procurement timing. Whereas procurement schedules for PJM jurisdictions typically align with the PJM delivery year (i.e., June 1-May 31), schedules in ISO-NE states attempt to minimize price volatility stemming from high-cost winter months. Notably, Massachusetts recently adopted the same product periods as New Hampshire (i.e., February to July and August to January) in order to split January and February, two high-cost months. This approach was accepted by the Massachusetts Department of Public utilities as a best practice approach to reduce price differences between product periods (and therefore improve rate stability). **Exeter recommends continuing to mitigate seasonal price volatility by either splitting up January and February or, for small customers, procuring longer-duration contracts that smooth out fixed costs over at least 12 months.** A 12-month contract, for example, would average higher winter and summer costs with lower shoulder season costs, thereby leveling out overall prices. A 12-month contract would also avoid the potential risk premium associated with procuring non-standard, less liquid wholesale contracts that split up ISO-NE winter months. Exeter did not, however, observe any evidence that New Hampshire's current procurement schedule affects wholesale supplier participation or bids.[159]

A variety of parties in both DOE INV 2023-001 and PUC Docket IR 22-053 endorsed shortening the time frames from RFP solicitation to approval as a way to reduce wholesale supplier risk premium.[160] The current approach, which takes up to eight business days from final submission until the wholesale supplier receives PUC approval, theoretically requires wholesale suppliers to maintain an open, unhedged position. In practice, wholesale suppliers appear to execute their hedges after the initial bid acceptance by the utilities. Under this arrangement, the PUC must accept the bids put forth by the utility or risk introducing substantial, irreversible risk into the bid process. In practice, some suppliers would exit the New Hampshire market versus take on this risk if there is a potential that the PUC rejects a bid accepted by the utility. This circumstance has never occurred in New Hampshire. Nevertheless, instances like Massachusetts' recent decision to reject an approved rate highlight the potential disruptions from a long bid-to-acceptance window. Exeter therefore recommends introducing an independent advisor to review and facilitate approval of default

[159] Evaluated based on Exeter's assessment of actual bids for each utility during the last five years, provided in response to DOE INV 2023-001, DR 2-009, and wholesale supplier feedback cited in response to several DOE INV 2023-001, DR 2 questions.

[160] Many of the same parties also supported these changes in response to PUC Docket IR 14-338, *Investigation Into Alternatives to Default Service Procurement*, nearly a decade earlier.

service bids in a timelier fashion, as discussed above (see Subsection 1. "Default Service Provider and Procurement Entity" above).

Additionally, as noted above, New Hampshire has the shortest time frame between price acceptance and end of the contract (eight months total) of the 11 jurisdictions that utilize FRCs. This, coupled with the relatively short period between the final bid submission and contract maturity (less than two months), reduces contract price and load risk. It also, however, creates time pressure that precludes thorough participation or adequate review of alternatives in contingency circumstances. Extending the time between bidding and the start of the contract delivery period by as little as two to four weeks could provide parties with more flexibility to investigate the reasons for a failed auction and review contingency plans as necessary.

Procuring further in advance of contract maturity also reduces wholesale supplier sensitivity to near-term price volatility. That is, bids reflect less risk premium associated with intraday shifts in forward contract costs. Thus, a trade-off exists between uncertainty regarding delivery period costs, which increases as the time between contract solicitation and maturity increases, and sensitivity to price volatility, which decreases as the time between contract solicitation and maturity increases. Six retail restructured jurisdictions secure final bid prices at least three months prior to contract maturity. **Exeter recommends extending the period of time between final bid approval and contract maturity to at least 2.5 months (from less than two months, typically) in order to support contingency planning, but not more than seven months to minimize uncertainty-related risk premium.** Seven months represents an approximate average amount of time between default service procurement and contract maturity (for at least a portion of default service load) based on the five restructured New England states.

5. Oversight

Different retail restructured jurisdictions vary in terms of the degree of discretion they give default service providers to establish requirements and conduct solicitations for default service. Jurisdictions also vary in the degree of oversight that regulators have over these processes. Most retail restructured jurisdictions, however, are like New Hampshire—the default service provider follows a basic approach previously approved by a commission on an indefinite-term basis. **Exeter does not recommend changing the level of Commission oversight of default service procurement, such as by adopting a managed portfolio approach.** A managed portfolio approach, akin to how coops and munis currently procure default service, might give EDUs additional discretion to enter into hedging arrangements that could reduce price volatility. These arrangements, however, would likely necessitate additional commission oversight to ensure the costs associated with EDU decisions are prudent, just, and reasonable, with accompanying administrative costs. They would also introduce similar downside risks as those of block-and-spot or long-term contract procurements, as discussed above (see Subsection 2. "Product Types" above).

Regular changes to a default service provider's procurement plan can introduce uncertainty regarding bidding conditions, potentially affecting supplier participation. A time-limited schedule also makes certain laddering approaches more challenging. **Exeter recommends continuation of indefinite-term procurement strategies, subject to revision at the Commission's discretion.** Although Exeter does not recommend regular revisions to default service strategy, the Commission should retain the flexibility needed to accommodate changes to default service procurement processes in response to unforeseen market conditions or other exigencies. Additionally, regulators should continue to periodically revisit default service procurement approaches as market and policy conditions evolve.

6. Procurement Method

Both DOE and OCA encouraged additional exploration of different procurement methods as part of PUC Docket IR 22-053. Subsequently, in response to DOE INV 2023-001, several stakeholders commented about the potential benefits of adopting reverse auctions. One such approach is a single, statewide, descending-clock-auction. This auction would simultaneously offer multiple products from each utility and provide bidders with the flexibility to switch their bids between these products. Although the EDUs would remain the default service provider and procurement entity, the bidding process would be managed by an auction manager, as funded and overseen by the utilities, similar to the model employed by New Jersey utilities.

One potential benefit of this approach is an increase in supplier participation. Most directly, wholesale suppliers who currently bid on FRCs for only one utility (e.g., Eversource, who historically attracts the most bidders) would have greater ability to bid on the FRCs for other utilities (e.g., Liberty and Unitil) as well. This method also diminishes the utility's role in evaluating bids against the proxy price. Instead, the auction manager would set the proxy price range in advance, potentially addressing inconsistencies in its use and application. Finally, reverse auctions can accommodate various product types and durations as long as there is some degree of product conformity.

Despite the above benefits, the initial setup of an auction can be costly, including the administrative effort required to align all three IOUs in terms of product. It might also not yield substantial or measurable benefits. Additionally, reverse auctions are hampered by the transparency they provide in situations with very limited provider participation; the absence of competitive bidding could be exacerbated in a reverse auction setting. While a built-in reserve price might mitigate this issue, it remains arbitrary and could increase auction risk in a constrained, volatile market. Moreover, transitioning to an auction-based system may make it challenging to revert to the RFP process, potentially leading to increased reliance on self-supply as the best alternative in contingency circumstances. Given these considerations, **Exeter does not recommend adopting reverse auctions or other alternative procurement methods at this time**. Additionally, it is notable that sealed-bid procurements are widely used by smaller retail restructured jurisdictions. RFPs, therefore, offer a more stable and familiar framework for procurement. Going forward, however, reverse auction approaches may become more appropriate after adopting other recommended changes, such as larger Small Customer Groups and an increased number of tranches.

7. Supplier Eligibility

Default service providers typically require prospective wholesale suppliers to meet a variety of eligibility requirements in advance of bidding to provide service. No stakeholders identified existing financial security, commitment, or capacity requirements as a barrier to procurement participation. Additionally, the absence of wholesale supplier defaults in recent history, even in the face of severe market turbulence, suggests existing requirements sufficiently mitigate counterparty risk. Thus, **Exeter does not recommend adjusting existing wholesale supplier eligibility requirements.**

Relatedly, several jurisdictions target a minimum number of winning bidders or cap the maximum amount of load a particular supplier can serve. These requirements are most common for jurisdictions with larger default service loads and higher levels of wholesale supplier participation. **Exeter does not recommend deviating from the existing bid evaluation approach that prioritizes the selection of least-cost providers, regardless of the amount of load they serve.** This current approach is consistent with PUC precedent and RSA 374-F.

8. Anti-Gaming and Migration Control

Some states attempt to reduce load risk by putting rules in place to prevent customers from strategically switching between standard offer and retail supply. These types of restrictions, although moderately common in other retail restructured jurisdictions, are not necessary if large customers are switched to rates that pass-through wholesale energy costs, as discussed above (see Subsection 2. “Product Types” above). Cost pass-through, regardless of whether it is on a lagged monthly basis or hourly basis, precludes gaming behavior due to the limited amount of time available for customers to take advantage of price discrepancies—by the time customers observe higher or lower default service prices, they will have already missed the window to avoid or capture those prices. Notably, anti-gaming benefits were among the reasons cited by Unitil when developing its current default service procurement approach for large customers; variable pricing, according to Unitil, discourages customers from moving between competitive supply and fixed-rate default service on a regular basis.

Exeter recommends restricting the frequency of switching for large customers to the extent that the Commission does not require pass-through pricing for large customers. Common practice is that large customers can switch to default service anytime, but must remain a customer for one year. Another reasonable approach would be to require that large customers, once returned to default supply, remain in the service through the current product period and the next. Imposing such limits on small customers, meanwhile, diminishes the ability of default service rates to serve as a safety net, as required by RSA 374-F. These limits can also unduly encourage small consumers to adopt or retain unfavorable CEP arrangements. Thus, **Exeter does not recommend introducing additional anti-gaming limitations for small customers at this time.**

Another load risk mitigation strategy is volume bandwidths, as used for default service in Delaware and under consideration in Ohio. This strategy involves benchmarking tranche sizes with volumetric caps. This approach is most appropriate in jurisdictions with high levels of actual or potential migration *into* default service. Given the emergence of community power aggregation, this strategy may be useful in the future if an aggregator has the potential to return a large amount of load to default service with minimal notice. It is less useful, however, to address large migrations away from default service, as anticipated going forward. Thus, to address aggregation-related load risk, **Exeter recommends implementing regulation providing additional community power aggregation process and timing clarity rather than adjusting existing FRCs on account of migration risk**. Aggregation is further discussed below as part of Subsection C. “Other Topics” below.

9. Default Service Cost Components

New Hampshire can reduce price risk by allowing default service suppliers to pass-through certain wholesale market costs. It is generally appropriate to absorb and pass-through large, variable, and un-hedgeable charges because, in the absence of such pass-through, suppliers may include significant and potentially variable price premiums in their bids on account of the associated risk. This view is consistently articulated by wholesale suppliers in their correspondence with utilities. Additionally, in some cases, the presence of un-hedgeable costs has led wholesale suppliers to not participate in default supply procurements.[161] Maine recently accepted the above arguments when establishing provisions to pass-through Mystic Generating Station costs during CY 2023.[162] Other allowances for cost pass-through going forward should be made sparingly, and should not insulate suppliers from hedgeable risks that are typical to the course of normal business, such as those stemming from geopolitical events, weather, and fuel availability. One reason for such an exercise of caution is that passing through costs can create cost recovery imbalances that require reconciliation, undermining rate stability.

[161] See utility responses to DOE INV 2023-001 DRs 2-001, 2-002, 2-003, and 2-004.

[162] See Maine PUC. Docket 2022-00091. Order Designating Standard Offer Providers and Order Modifying Standard Offer Pass Through Charge.

Exeter recommends that the PUC evaluate potential costs for pass-through based on a three-pronged assessment of whether the cost is large, variable, and un-hedgeable, and consider treatment on an *ad hoc* basis. If the Commission approves pass-through of certain costs, reasonable accommodation should also be made to allow CEPs an opportunity to also avail themselves of similar pass-through mechanisms. For example, CEPs might be relieved of their obligation to provide their retail customers with specified pass-through services in favor of having the EDU manage all associated costs for all customers.

10. Reconciliation

Reconciliation balances, when large, can undermine the rate stability afforded by fixed-price FRCs and create cost uncertainty. The timing of reconciliation settlement can also create intergenerational equity issues, especially if the customers that cause additional default service costs no longer receive default service when those costs are passed through to remaining customers. In general, **Exeter recommends minimizing reconciliation costs to the maximum extent possible and, when such costs apply, pass them on to customers as close to their occurrence as feasible.** For very small reconciliation costs, such as those they apply to ongoing default service administration expenses, pass-through should occur periodically, such as the current annual window used by New Hampshire utilities, to consolidate associated review and implementation effort. For large reconciliation expenses, such as those incurred during self-supply when using spot purchases to meet load, costs should be passed through no later than the subsequent month. Rapid adjustment, in this case, ensures that the prices paid by default service customers are reflective of the prevailing market conditions. It also minimizes opportunities for gaming.

Default service customers should absorb responsibility for all reconciliation costs directly attributable to default service, as is consistent with the principle of cost causation and RSA 374-F. If, however, high costs are caused by customer migration, it may be appropriate to allocate costs across all customers regardless of their current service provider. The Massachusetts Department of Public Utilities recently approved a request from Fitchburg Gas & Electric Light Company, a Unitil affiliate, to allocate certain default service costs to all customers for reasons related to community power aggregation. **Exeter recommends addressing unique reconciliation circumstances, such as those related to mass migration, on an *ad hoc* basis.**

11. Contingency Provisions (Failed Solicitation)

Recent market volatility highlighted the importance of establishing robust contingency provisions. Ideally, contingency plans should be available in advance of the circumstance causing disruption, allowing rapid evaluation and implementation. Plans should also be adaptable to prevailing market circumstances. For example, reliance on re-issuance of a solicitation may be impractical in volatile wholesale market conditions. Additionally, these plans should not only address failed solicitations, but also instances of default service supplier default. **Exeter recommends that the PUC work with the EDUs to develop preemptive contingency plans that include multiple, ranked contingency strategies as well as thresholds to determine when contingency strategies are required.**

New Hampshire’s contingency plans should incorporate multiple potential contingency approaches, such as issuance of a "lightning" RFP round, self-supply, allowances for additional cost pass-through, and accepted alterations to standard RFPs based on circumstance. Contingency strategies should vary by customer group in relation to the default service product used to serve each group. **Exeter recommends that the Commission prioritize issuance of a replacement RFP as part of contingency plans for Small Customer Groups.** This approach is consistent with past practice in New Hampshire. The appropriate strategy for the Large Customer Group should vary based on procurement timing and product type. Even with contingency plans in place, the PUC should also retain the authority to allow deviations from existing plans in unique circumstances. Thus, as discussed above (see “Timing” section), the procurement schedule should afford parties adequate time to evaluate the necessity of contingency approaches and, if necessary, propose alternative approaches to meet default service requirements.

Proxy price thresholds play a crucial role in determining the appropriateness of default service bids. They can also be used to mitigate the exercise of market power and identify potential collusion among bidders. Best practice involves setting thresholds that consider various factors such as the number of bidders, the prices offered, the clustering of prices, expected wholesale market costs, and historical bid patterns. While all New Hampshire utilities appear to account for these factors, how these thresholds influence decision-making remains inconsistent. **Exeter recommends confidentially standardizing both the proxy prices developed by EDUs and the application of these prices to the extent that DOE does not implement an independent advisor to oversee bid evaluation.** Specifically, Unitil's approach should be aligned more closely with the practices of Liberty and Eversource. However, proxy prices and threshold criteria should remain confidential in order to prevent strategic bidding and protect the integrity of bid evaluation. **These standardization efforts should not eliminate flexibility to account for market circumstance as part of bid evaluation.**

12. Self-Supply

Evidence from Exeter’s evaluation of historical costs under a hypothetical self-supply arrangement shows that a direct pass-through of wholesale prices results in generally lower costs, with some of the difference owing to forward pricing and risk premium. Nevertheless, **Exeter does not recommend adopting self-supply procurement methods except in contingency circumstances.** First, the evidence presented in the above analysis of self-supply suggests caution when assessing recent price differentials between estimated self-supply price and actual default service rates. Although some degree of potential savings is observed from adopting self-supply, these estimates are subject to a high degree of uncertainty as statistically assessed through confidence intervals. Further, the wholesale cost buildup-based rates presented above could differ from the actual default service rates under self-supply in several ways that encourage additional caution. For example, default service rates are set before the costs are incurred (by as many as six months) based on forecasted costs, potentially changing the applicable comparison. Self-supply also results in additional costs that are not represented, such as the working capital requirements necessary for the utility to interface with ISO-NE.

Second, direct participation by electric utilities in the ISO-NE wholesale power markets would expose default service customers to substantial price risks which may not be fully mitigated even through active hedging strategies. Price spikes may create unacceptably high short-term costs for some small customers despite lower overall costs. Price spikes may also induce gaming behavior by large customers. They also introduce the potential for intergeneration cost transfers due to migration; customers that exit default service after high-cost months can potentially avoid paying their share of incurred costs.

Third, spot purchases and block-and-spot procurement strategies introduce volatility in the form of ongoing reconciliation. In the case of significant positive or negative balances in the retainage accounts, it will be necessary to increase or decrease rates, respectively, to reconcile. As discussed above in Subsection 2. "Product Types" and Subsection 3. "Laddering," these attributes are undesirable, especially for small customers.

Fourth, self-supply approaches decrease the comparability of default service and CEP offers. Under self-supply, the EDUs can eventually pass through all costs incurred as a result of their wholesale service requirements even when providing fixed-rate service. CEPs cannot conduct similar reconciliation except when offering customers variable rate service.

Fifth, blending FRCs with some element of self-supply may create negative feedback cycles that increase FRC costs. For example, substantially decreasing the amount of load available to FRCs may magnify load and price risks for the residual portion. This risk can be observed through Large Customer Group default service prices.

Finally, New Hampshire's EDUs are not well positioned today to provide self-supply on a permanent basis. More specifically, the utilities all raised concerns about the lack of existing in-house expertise to implement hedging and position management programs that minimize cost and risk. Additionally, Unitil has never utilized self-supply in any form within New Hampshire. Thus, implementing a managed self-supply strategy would require additional administrative resources with associated costs.

The potential downsides of self-supply, including price risk and potential rate volatility, are less acute for larger customers than smaller customers. As discussed above, however, Exeter recommends energy cost pass-through for large customers coupled with FRCs. Specifically, **to the extent that real-time pricing is a preferred part of the default**

service portfolio, Exeter recommends incorporating these pricing components into default service FRCs (rather than adopting self-supply). FRCs, in this case, alleviate the utility of staffing and credit obligations that can be more easily fulfilled by wholesale suppliers. Further, this hybrid product does not require EDUs to take on new risks or obligations in wholesale markets. Consequently, it is more straightforward to implement. The Commission also retains self-supply as an option for contingency plans.

If the Commission and other stakeholders determine that greater exposure to real-time pricing is a priority for all customer classes, then a similar strategy may also be appropriate for smaller customers. For smaller or larger customers, **Exeter recommends fixing all costs (e.g., capacity, ancillary services, etc.) with the exception of energy when incorporating real-time pricing components into default service**. This avoids the necessity of creating subaccounts to manage periodically determined costs like some ancillaries.

C. Other Topics

Default service intertwines with various parts of New Hampshire's utility, electricity, regulatory, and policy ecosystems. Thus, a variety of New Hampshire characteristics are of key importance to default service outcomes even if they are outside the scope of potential reforms considered as part of this Investigation. Although Exeter did not develop full recommendations for each of the following topics, several suggestions are relevant to future policy and regulatory action in the state.

- ISOs/RTOs: As discussed above, ongoing reform of the ISO-NE wholesale market significantly influences market conditions, often with downstream impacts on various default service outcomes. In almost all cases, existing default service paradigms can adapt to these changes. If New Hampshire adopts new regulatory structures, however, such as a return to vertically integrated utilities, the above default service recommendations would no longer apply.

- Types of Restructured Utilities: Munis and coops in New Hampshire are not regulated by the PUC and use fundamentally different, managed portfolio strategies to provide "default service." These strategies support distinct goals and business models that differ from the regulated IOUs. Despite these distinctions, many of the above recommendations could, in a vacuum, also apply to munis and coops.

- Low-Income Customer Rules: Several jurisdictions have implemented policies or regulations that establish separate retail market requirements for low-income customers, often with the intent of protecting low-income customers from predatory CEP behavior and/or ensuring appropriate use of electricity assistance program funding. New Hampshire does not currently have rules that directly affect low-income customers' ability to take CEP service in place of default service. If this changes in the future, however, **Exeter does not recommend conducting separate default service procurements for low-income customers**. This approach, as applied in Ohio, can support the administration of certain low-income programs. There is no evidence, however, that it promotes preferable pricing or other desirable outcomes for either low-income or non-low-income customers.

- Rate Design: All three EDUs currently offer time-varying distribution rates, including TOU pricing. Equivalent time-varying rate elements, however, do not apply to default supply prices.[163] In order to send a consistent rate signal, some retail restructured jurisdictions also apply TOU pricing to default service rates. **To the extent New Hampshire incorporates TOU elements into default supply service, Exeter recommends that the EDUs align applicable TOU rates with those that apply to distribution rates. Exeter does not recommend conducting separate default service procurements for TOU-rate customers but, instead, deriving a TOU default supply rate administratively.** This process may introduce additional reconciliation requirements. However, it also minimizes procurement risk associated with splitting FRCs into non-standard, time-specific products.

- RPS Fulfillment: Volatile RPS costs were among the energy commodity procurement subjects raised by the PUC in Docket IR 22-053. Although RPS costs are distinct from wholesale market costs, they form part of the full-requirements obligation in most retail restructured jurisdictions. Practices vary by jurisdiction regarding the assignment of REC obligations between the utilities, CEPs, and wholesale suppliers of default service. At this time, **Exeter does not currently recommend reassigning default service customers' RPS requirements to wholesale suppliers (in place of EDUs) due to recent REC price uncertainty**. Rather, continued utility management of these costs, including pass-through on a 1:1 basis, minimizes costs. This responsibility may be reevaluated in the future as REC market conditions change and New Hampshire RPS policy conditions stabilize.

- Net Metering: New Hampshire has recently revisited its net metering rules and regulations as part of a separate PUC proceeding.[164] How the state approaches net metering impacts the amount of load served by default service providers. Other key considerations include the netting obligation of default service, potential differences between competitive suppliers and default service with regards to compensation, and reasonable expectations for future behind-the-meter resource deployment. These factors need careful examination to ensure that net metering policies align with the objectives of default service provision.

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[163] For example, Liberty distinguishes on- and off-peak rates for the Domestic Service Rate D-10 Optional Peak Load Pricing Rate schedule, but currently applies the same default service rate to both time periods.

[164] New Hampshire PUC (2023). Docket DE 22-060. Order 26,769. *Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators*.

- Community Aggregation: Community aggregation affects the amount of load served by default providers. Thus, additional transparency and certainty regarding the timing of aggregation activity (including both start and end) could reduce load risk. Current requirements, such as the 90-day notice when a community power aggregation precedes the start of a default service supply period, could be extended. The PUC could also require aggregators to implement default service on more strict timelines after achieving all necessary approvals. **Exeter recommends addressing default-service-specific aggregation implementation issues as part of a separate aggregation proceeding. Future aggregation regulations should increase certainty regarding the timeline from aggregation approval to implementation.**

VI. APPENDICES

Appendix A – Utility Rate Classes with Current Default Service Customer Group

Table 3. Utility Rate Classes with Current Default Service Customer Group		
Utility and Rate Class	**Tariff Size limit**	**Current Default Group**
Liberty		
Rate D Domestic Service	Available for all domestic purposes in an individual private dwelling or apartment	Small Customer
Rate D-10 Domestic Service Optional Peak Load Pricing	Available for all domestic purposes in an individual private dwelling or apartment	Small Customer
Rate T Limited Total Electrical Living	Available to those who use electricity as the sole source of energy for space heating and water heating, and customers were either previously served under Total Electric Living or requested service under this rate prior to May 1, 1982	Small Customer
Rate G-1 General Service Time-of-Use	Average demand greater than or equal to 200 kW	Large Customer
Rate G-2 General Long-Hour Service	Average demand greater than or equal to 20 kW but less than 200 kW	Large Customer
Rate G-3 General Service	Average demand less than 20 kW	Small Customer
Rate V Limited Commercial Space Heating	Available for space heating and air conditioning that use electricity as the sole source of energy and customers were either previously served under commercial space Heating Rate or requested service under this rate prior to May 1, 1982	Small Customer
Rate M Outdoor Lighting	Available for lighting for streets, highways, and areas within the public domain for customers	Small Customer
Eversource		
Rate R Residential	Available to all customers living in individual residences and apartments	Small Customer
Rate G General Service	Demand does not exceed 100 kW	Small Customer
Rate GV Commercial and Industrial	Demand does not exceed 1,000 kW	Large Customer
Rate LG Commercial and Industrial	Demands in excess of 1,000 kW	Large Customer

Utility and Rate Class	Tariff Size limit	Current Default Group
Rate OL Streetlight	Available for street and area lighting	Same as associated accounts
Unitil		
Rate D Domestic Rate	All residential customers	Small Customer
Rate G2 General Service Rate	Average usage of less than 100,000 kWh/month and 200 kVA of demand	Medium Customer
Rate OL Outdoor Lighting	Outdoor Lighting	Medium Customer
Rate G1 Large General Service	Average usage of at least 100,000 kWh/month and 200 kVA of demand	Large Customer

Appendix B – Energy Sales and Peak Demand Data – New Hampshire Utilities (2022-2023)

Table 4. Energy Sales and Peak Demand Data – New Hampshire Utilities (2022-2023)

Company/ Customer Group	Tranche Size (%)	Total Megawatt-Hours (Jul 2022- Jun 2023)	Aug-Oct	Nov-Jan	Feb-Apr	May-Jul	Peak MW[1]
Eversource							
Small Default	12.5	3,269,637	1,738,802		1,530,834		989
Small Total		*4,865,861*	*2,520,034*		*2,345,828*		
Large Default	50	181,472	104,540		76,932		52
Large Total		*2,747,037*	*1,410,768*		*1,336,269*		
Liberty							
Small Default	100	323,802	169,717		154,086		106
Small Total		*377,488*	*191,860*		*185,627*		
Large Default	100	92,579	24,662	22,992	23,406	21,518	22
Large Total		*494,361*	*137,062*	*114,240*	*116,123*	*126,937*	
Unitil							
Small Default[1]	100	437,900	233,577		204,323		154
Small Total[1]		*491,210*	*256,932*		*234,278*		
Medium Default	100	161,674	84,895		76,779		43
Medium Total		*308,856*	*156,819*		*152,037*		
Large Default	100	49,983	26,170		23,814		14
Large Total		*321,060*	*163,365*		*157,695*		

[1] The most recent 12 months of available data were used to determine peak MW. For Eversource, the 12-month period July 2022 – June 2023 was used. For Liberty and Unitil, the 12-month period of May 2022 – April 2023 was used.

Source: Migration data provided by utilities in response to DR No. DOE 2-12, INV 2023-001. Peak demand derived from data provided by the utilities for their most recent procurement.

Appendix C – Retail Choice Jurisdiction Matrix

	CONNECTICUT	DELAWARE	DIST. OF COLUMBIA	ILLINOIS	MAINE	MARYLAND	MASSACHUSETTS
General Details							
RTO/ISO[1]	ISO-NE	PJM	PJM	PJM/MISO	ISO-NE	PJM	ISO-NE
Year of Restructuring[2]	1998	1999	1999	1997	1997	1999	1997
Year of Retail Choice[3]	2000	1999	1999	1999	2000	2002	1998
Enabling Legislation/Law	Public Act No. 98-28, “An Act Concerning Electric Restructuring”	Electric Utility Restructuring Act of 1999	Retail Electric Competition and Consumer Protection Act of 1999	The Illinois Public Utilities Act (PUA) of 1997	PL 1997, c. 316 (LD 1804)	Electric Customer Choice and Competition Act of 1999	Massachusetts Electric Industry Restructuring Act; 20 CMR 11
Retail Choice Details							
Utility Type Mandated to Provide Retail Choice	IOUs	IOUs	IOUs	IOUs	IOUs	IOUs and coops	IOUs
Other Voluntary Provider	N/A	Coops	N/A[5]	Munis and coops	Munis and coops	Munis	Munis
Res. Low Income Customer Rules	Suppliers must guarantee savings	None	None	Customers on housing assistance excluded from choice	None	Suppliers must guarantee savings	None
Anti-Gaming Rules[7]	Utility has a 6-mo. switching moratorium for DS and a 12-mo. moratorium for LC	None	Non-res. returning to DS subject to 12-mo. stay requirement[8]	12-mo. stay provision when returning to DS	Opt-out fee applies to certain C&I customers that received DS service for less than 12 mos.	None	Indust. customers not allowed to switch to a competitive supplier within 6 mos. of returning to DS for certain utilities
Standard Offer Service Procurement Details							
Default Service Provider[9]	EDU[10]	EDU	EDU	Illinois Power Authority (IPA) & EDU	Retail supplier	EDU	EDU
Procurement Entity[12]	EDU	EDU	EDU	IPA	Commission	EDU	EDU
Independent Monitor	Yes	Yes	No	Yes	No	Yes	No
Procurement Frequency[13]	Quarterly	Bi-annually[14]	Annually	Bi-annually and spot as needed	Annually	Quarterly for LC	Bi-Annually for Res. & SC; Quarterly for MC, LC & Indust.
Month Procurement Held	January, April, July & October	January & November	January	Spring & fall	September	January, April, July & October	Either Mar, Jun, Sep, Dec; or Feb, May, Aug, Nov
Duration of Product Phases	6 mos.	24 mos. for Res. & SC; 12 mos. for MC and LC	36 mos. for Res. & SC; 12 mos. for LC	3 years, some long-term contracts and spot	12 mos.	3-24 mos.	Two adjacent 6 mos. for Res. & SC; 3 mos. for MC, LC & Ind.
Length of Time Between Price Approval and Contract Maturity	Varies, but ranges from 3-14 mos.	Varies, but ranges from 5-7 mos.	Approx. 3 mos.	Varies, but typically a couple mos. prior	3 mos.	Varies, but ranges from 3-17 mos.	Varies, but ranges from 2-10 mos.

	CONNECTICUT	DELAWARE	DIST. OF COLUMBIA	ILLINOIS	MAINE	MARYLAND	MASSACHUSETTS
Res. Laddered Procurement[16]	Yes	Yes	Yes	Yes	No	Yes	Yes
Products Procured	Tranche auctions with FRCs	Tranche auctions with FRCs[17]	Tranche auctions with FRCs	Block contracts & spot purchases	Tranche auctions with FRCs	Tranche auctions with FRCs	Tranche auctions with FRCs[18]
Procurement Method	Sealed bid	Reverse auction[21]	Sealed bid	Sealed bid	Sealed bid	Sealed bid	Sealed bid
Standard Offer Service Offer Details							
Small Customer Rate Design[22]	6-mo. FPR; TOU 6-mo. FPR	Seasonal block FPR; TOU[23]	Seasonal block FPR	Seasonal FPR; seasonal block FPR; variable, hourly pricing	12-mo. FPR	Seasonal FPR; TOU	6-mo. FPR; monthly FPR[24]
Other Non-Res. Rate Design[22]	6-mo. FPR; TOU	Seasonal FPR; TOU; variable, hourly pricing	Seasonal FPR; seasonal block FPR; TOU	Seasonal FPR; seasonal block FPR; variable, hourly pricing[27]	Monthly FPR	Seasonal FPR; 3-mo. block FPR; TOU; variable, hourly pricing	3-mo. FPR; 6-mo. FPR; monthly FPR[28]
RPS Responsibility	Retail/wholesale suppliers[30]	EDU	Retail/wholesale suppliers	IPA/EDU[31]	Retail suppliers	Retail/wholesale suppliers	EDU or retail/ wholesale suppliers[32]
Other							
Opt-Out Government Aggregation	None	None	Opt-in only	Opt-out (affirmative vote); opt-in	None	Yes (Res. & SC only)[35]	Opt-out (affirmative vote)
Responsible for Net Metering Reconciliation	EDU	EDU	EDU and retail suppliers[36]	EDU and/or retail suppliers[37]	EDU	EDU	EDU

	NEW HAMPSHIRE	NEW JERSEY	NEW YORK	OHIO	PENNSYLVANIA	RHODE ISLAND	TEXAS
General Details							
RTO/ISO[1]	**ISO-NE**	PJM	NYISO	PJM	PJM	ISO-NE	ERCOT
Year of Restructuring[2]	**1996**	1999	1996	1999	1996	1996	1996
Year of Retail Choice[3]	**1998**	1999	2001	2001	2001	1998	2002
Enabling Legislation/Law	**RSA 374-F**	Electric Discount and Energy Competition Act (EDECA) of 1999	N/A[4]	Am. Sub. SB 3, the Ohio Electric Restructuring Act	Electricity Generation Customer Choice and Competition Act	Rhode Island Utility Restructuring Act of 1996; R.I. Gen. Laws 39-1-27.3	SB 7 of 1999
Retail Choice Details							
Utility Type Mandated to Provide Retail Choice	**IOUs and Coops**	IOUs	IOUs	IOUs	IOUs	IOUs	IOUs
Other Voluntary Provider	**N/A**	N/A	Public utility	N/A	N/A	Munis and coops	Munis and coops
Res. Low Income Customer Rules	**None**	None	Suppliers must receive a waiver and guarantee savings[6]	Excluded from choice and has separate DS procurement	Excluded from choice by certain utilities	None	None
Anti-Gaming Rules[7]	**None**	C&I customers who return to DS may be prohibited under certain conditions from switching again for one year	None	None	None	None	None
Standard Offer Service Procurement Details							
Default Service Provider[9]	**EDU**	EDU	EDU	EDU	EDU[11]	EDU	Retail supplier
Procurement Entity[12]	**EDU**	EDU	EDU	EDU	EDU	EDU	Retail supplier
Independent Monitor	**No**	Yes	No	Yes	Yes	No	No
Procurement Frequency[13]	**Bi-annually**	Annually	Utility-dependent[15]	Varies, but typically biannually	Quarterly or biannually	Quarterly	N/A
Month Procurement Held	**June & December**	February	Utility-dependent[15]	Varies, but typically Jan, Mar, Oct or Apr & Oct; or Feb, Jul, Sep or Mar & Nov	Varies, but typically Apr & Oct or Mar & Sep; or Mar, Jun, Sep, Dec or Apr & Nov	Mar, Jun, Sep & Dec	N/A
Duration of Product Phases	**6 mos.**	3 years	Utility-dependent[15]	Typically 12, 24 or 36 mos.	3-12 mos. for Res. & SC; 3 or 12 mos. for C&I depending on the EDU	6 mos. for Res.; 3 mos. for C&I	N/A
Length of Time Between Price Approval and Contract Maturity	**2 mos.**	4 mos.	Utility-dependent[15]	Varies, but ranges from 2-11 mos.	Varies, but ranges from 2-8 mos.	Varies, but ranges from 2-6 mos.	N/A
Res. Laddered Procurement[16]	**No**	Yes	Yes[15]	Yes	Yes	Yes	N/A
Products Procured	**Tranche auction with FRCs[19]**	Tranche auctions with FRCs	Hedging, spot market purchases, block products, long-term	Tranche auctions with FRCs	Varies by utility, but typically tranche auctions with load-	Tranche auctions with FRCs[20]	N/A

	NEW HAMPSHIRE	NEW JERSEY	NEW YORK	OHIO	PENNSYLVANIA	RHODE ISLAND	TEXAS
			contracts[15]		following products, multi-year fixed-price contracts, and/or spot market purchases		
Procurement Method	**Sealed bid**	Simultaneous, multi-round, descending-clock auction	Utility-dependent[15]	Descending-price clock auction	Sealed bid, descending-clock auction, or reverse auction	Sealed bid	N/A
Standard Offer Service Offer Details							
Small Customer Rate Design[22]	**6-mo. FPR[25]**	Seasonal FPR; TOU	Monthly or bi-monthly FPRs are blended rates from all purchases	1-year FPR; seasonal FPR; block rates; TOU; variable FPR[26]	Either 3- or 6-mo. FPR	6-mo. FPR	VPR
Other Non-Res. Rate Design[22]	**Monthly FPR; 1-mo. lag of average real-time LMP**	Seasonal FPR; TOU; variable, hourly pricing	Monthly or bi-monthly FPR; variable, hourly rates	1-year FPR; seasonal FPR; block rates; TOU; variable FPR[26]	3- or 6-mo. FPR; variable, hourly pricing; spot market	6-mo. or monthly FPR[29]	VPR
RPS Responsibility	**EDU or retail/ wholesale suppliers[32]**	Retail/wholesale suppliers	EDU/state agency[33]	EDU and retail/ wholesale suppliers[34]	EDU or retail/wholesale suppliers[32]	EDU	Retail suppliers
Other							
Opt-Out Government Aggregation	**Opt-out (affirmative vote); opt-in**	Opt-out (Res. only); opt-in (C&I)	Opt-out (Res. & SC); opt-in	Opt-out (affirmative vote); opt-in	None	Opt-out	Opt-in only
Responsible for Net Metering Reconciliation	**EDU or retail suppliers**	EDU	EDU	EDU	EDU or retail suppliers	EDU	Retail suppliers

Key: C&I=commercial & industrial; Coops=cooperatives; DS=default service; EDU=electric distribution company; FPR=fixed-price rate; FRC=full-requirements, load-following contract; Indust.=industrial; IOU=investor-owned utility; LC=large commercial; LMP=locational marginal price; LRS=last resort service; MC=medium commercial; Munis=municipal utilities; N/A=not applicable; Res.=residential; RPS=renewable portfolio standard; SC=small commercial; TOU=time-of-use; VPR=variable-price rate.

[1] This row lists the predominant ISO/RTO in which the state operates. Several states operate in more than one ISO/RTO. For example, in Maine, Central Maine Power Co. and Versant Power – Bangor Hydro District operate within ISO-NE, while Versant Power – Maine Public District does not. In Pennsylvania, all of the state's IOUs operate within PJM with the exception of Pike County Light and Power, which operates within NYISO.

[2] The dates are approximations of when restructuring began based on the year of legislative mandate.

[3] Dates are the first year that any customer was able to switch to a competitive retail supplier. In many jurisdictions, this process was gradual, with different customer classes able to switch at different times. For example, in Illinois, large & multi-locational customers were offered retail choice in 1999, followed by all non-residential in 2000 and residential in 2002.

[4] Retail competition was introduced by the regulatory commission, not legislation.

[5] D.C. does not have other providers.

[6] To get a waiver from the regulatory commission, the retail supplier must guarantee savings.

[7] Most utilities have limits on the number of switches per month (i.e., no more than 2 switches and 2 drops per month) and have exceptions for supplier default.

[8] Stay provisions do not apply to Market Price Service customers.

[9] The party(ies) responsible for providing the actual supply, which might involve buying it from other wholesale market participants.

[10] Utilities historically offered DS and LRS (business customers only) as separate services.

[11] The EDUs are obligated to provide DS unless they can successfully petition a waiver to provide service and an alternative supplier successfully wins a bid to provide DS as per Pennsylvania Code § 54.183.
[12] The party responsible for setting requirements and conducting the procurement.
[13] The months are indicative of what is typically done.
[14] Two auctions are held per year. The November auction is held in tandem with the January auction held in the following year.
[15] Utility procurement is subject to regulatory commission review but is largely confidential to the public due to concerns that public strategies may allow other parties to drive up hedging prices.
[16] Most large C&I DS supply is not laddered, with the exception of Ohio. Ohio's DS is procured for all customer classes in one procurement. If SC is grouped with Res., then SC load is also laddered.
[17] Bidders are required to bid in blocks of 50 MW which represents a certain and specific percentage of the associated DS load of the utility.
[18] Load is procured by customer group and by load zone (i.e., Northeast Massachusetts and Boston [NEMA], Southeast Massachusetts [SEMA], West-Central) at fixed monthly prices.
[19] Load is procured by size of customer group (small, medium, large). Two utilities, Liberty and Eversource, only have two groups, small and large customers.
[20] Hedging is allowed with regulatory commission approval. Hedging or other variable costs, and the related contract costs incurred for energy procurement, may be recovered in standard offer rates.
[21] Delaware previously used the sealed-bid procurement method and then switched to reverse auction format in 2008.
[22] The rate design for customer classes vary by utility in most jurisdictions. All possible rates are listed.
[23] Block rates are fixed rates that change (decline or incline) per unit of consumption.
[24] Customers are put on the 6-month rate design; however, customers can elect to switch to the other type of rate. Unitil has a pilot residential TOU program under DS.
[25] Unitil allows small and medium customer classes to choose between one FPR for 6 months or monthly FPR. Unitil also has a pilot residential TOU program.
[26] Ohio has several pass-through rates included in the calculation of the default service price that change at different times throughout the year, resulting in the DS price changing at inconsistent intervals.
[27] There are some exceptions for customers not classified as competitive.
[28] Customers are put on monthly rates; however, customers can elect to switch to the other type of rate.
[29] General and large C&I customers can only switch between monthly and 6-month rates once per year.
[30] Connecticut, through its Department of Energy and Environmental Protection, held a one-time, long-term procurement of RPS projects in 2015 through the authority under Connecticut Public Act 15-107.
[31] IPA is responsible for procurement, but the EDU has financial obligations.
[32] RPS responsibility varies by utility.
[33] Utilities procure certain RPS credits by auction, but also procure other RPS credits from a state agency.
[34] Utilities may satisfy a portion of Ohio's RPS through their own procurement and a portion through wholesale suppliers.
[35] Government aggregation is on a pilot basis for one county.
[36] If the supplier offers net metering, then it is both the supplier's and EDU's responsibility. If a supplier does not offer net metering, then it is only the EDU's responsibility.
[37] Both suppliers and EDUs are required to provide net metering service and compensation for customers up to a certain usage, but how the suppliers' and EDUs' responsibility is shared is not clear.

GLOSSARY

Ancillary services: Services necessary to support the transmission of capacity from generation resources to customer loads while maintaining the reliable operation of the transmission system. Such services include frequency and voltage regulation, load following and ramping, black start, and spinning and non-spinning reserve capacity.

Anglo-Dutch Hybrid Approach: A procurement method where the auction starts as a descending-price-clock auction. When close to a final price, bidders are requested to submit their best and final price, as well as load quantities, via sealed bid. It is a combination of the descending-price-clock auction and sealed-bid auctions.

Bid evaluation criteria: The factors considered by utilities when assessing bids, including price, credit requirements, delivery firmness, and supplier's experience.

Block purchase: An energy product for a fixed quantity of power at a fixed price. Blocks are purchased for a specific number of days and number of hours. For example, a 7x24 block includes supply provided seven days a week, 24 hours a day.

Community power aggregation: The process by which a town, city, county, or other municipality procures energy on behalf of its residents and businesses, instead of the default service provider or retail service provider. It can be opt-in, where residents choose to be served by the municipality selected supplier, or opt-out, where residents are automatically served by this supplier unless they decide not to participate.

Competitive electricity provider (CEP): Entity that competes in the electricity market to provide supply services to customers. It operates in a market environment where retail electric customers have the right to choose their electricity supplier from among competing providers.

Contingency plan: A strategy for addressing failed solicitations, such as re-issuing an RFP or resorting to spot market purchases.

Contract maturity: The period of time when the delivery outlined in a contract begins.

Customer group: Classification of utility customers into groups based on their energy demand or consumption patterns.

Default service: The basic electricity service provided to customers who cannot, or choose not to, receive power from a CEP or other wholesale market participant. Also known as standard offer service or basic service.

Default service provider: The entity that sets the requirements for the competitive procurement of default service, maintains responsibility for fulfilling default customers' requirements, and assembles the product provided to default service customers. Acts as the load-serving entity and can be a regulated utility, a state agency, or an unregulated third-party supplier. It often serves as a backstop supplier when other wholesale suppliers are unavailable.

Demand: The maximum amount of electric energy at a given instant that is being delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts. It can also indicate the amount of power that must be supplied to a customer or an aggregate of customers (i.e., a load), typically expressed in megawatts.

Descending-price-clock auction (clock auction): A procurement method where the auctioneer proposes a price for multiple products simultaneously, and participants bid in load quantities. The price decreases each auction round until the necessary load is reached. It is a variant of reverse auctions.

Electric cooperative (Coop): A type of utility owned by the customers it serves, where the customers are the members of the cooperative. It usually operates in a specific area and is involved in distributing electricity to its members, often in rural areas.

Electric Distribution Utility (EDU): An entity primarily responsible for the distribution of electricity to end-users. It operates the infrastructure needed to deliver electricity from the transmission system to residential, commercial, and industrial customers.

Electric restructuring: The process by which electric utilities separate their generation services from their transmission and distribution services, then sell their generation assets. This separates electricity into competitive (generation) and non-competitive (transmission, distribution) segments. Also known as electric deregulation.

Federal Energy Regulatory Commission (FERC): A U.S. federal agency responsible for regulating the interstate transmission of electricity, natural gas, and oil. FERC oversees wholesale electric transactions, natural gas pricing, and mergers and acquisitions in the energy sector, as well as licenses hydropower projects. The agency plays a key role in promoting competitive energy markets and non-discriminatory transmission access.

Fixed price: A pricing scheme in which rates remain the same, or "fixed," for a certain period.

Full requirements, load-following contract (FRC): A contract where the supplier is responsible for a portion, or all, of the default service provider's load, including all related responsibilities such as capacity, at an agreed-upon unit price.

Gaming: A method in which customers may switch between default service and competitive supply service to take advantage of temporary differences in prices in a manner that may disadvantage other customers.

Hedging: A contractual strategy used to reduce exposure to the volatility of wholesale market costs through advanced purchases of supply.

Independent System Operator (ISO): An organization formed at the direction or recommendation of the FERC to coordinate, control, and monitor operation of the electrical power system. An ISO's jurisdiction may be in one state or multiple states. Note that ISOs typically perform the same or similar functions as RTOs, but RTOs tend to have jurisdiction over larger geographic areas than ISOs. Some ISOs and RTOs also administer the marketplace for wholesale electricity.

Investor-owned utility (IOU): A utility whose assets are owned by investors (distinct from public power agencies, coop, and munis). An IOU is a for-profit, tax-paying utility company.

Laddering: A procurement strategy where different contracts for wholesale power expire and are replaced at varying times, with unaffected contracts remaining in the portfolio. This approach ensures only the portion being repriced affects the weighted average price of the portfolio, offering a balance between price stability, risk mitigation, and reflection of current market conditions.

Load: Kilowatt or megawatt demand placed on the electric system by consumers of power.

Load-serving entity: The retail provider responsible for fulfilling customer requirements and paying associated wholesale market costs.

Managed portfolio: Approach to energy procurement where the default service provider actively directs energy procurements in response to changing market conditions, often with the goal of hedging risk.

Master Power Supply Agreement: A contract between parties for the baseline terms between a wholesale supplier and load-serving entity. It is typically a requirement for suppliers bidding to provide default service, indicating their financial capacity and commitment to fulfill contractual obligations.

Municipal-owned utility (Muni): An electric company owned and operated by a municipality serving residential, commercial, and/or industrial customers, usually within the boundaries of the municipality.

Net metering: A billing system that measures the flow of energy into and out of the energy grid by customers who generate their own electricity. The system allows these customers to sell the excess electricity generated by their distributed generation back to their electric utility.

New Hampshire Public Utilities Commission (PUC): A regulatory body in New Hampshire responsible for overseeing the electricity service sectors, among other utility industries. It plays a critical role in implementing restructuring of the electric utility industry, setting rates and regulations, and ensuring reliable and equitable service for consumers.

Off-peak period: Those hours or other periods defined by North American Energy Standards Board (NAESB) business practices, contracts, agreements, or guides as periods of lower electrical demand.

On-peak period: Times when demand for electricity is highest. Typically occurs on weekdays during the summer months, when normal demand is high and when air conditioning is operating. Similarly, in some areas, on-peak times may be in the winter when high demand is combined with high heating-related power use.

Overhanging contract: A type of contract laddering where contracts are purchased at different solicitations for varied durations and portions of the load.

Peak demand: The maximum instantaneous power draws from end-user loads over a designated period of time (e.g., a year, a month, or a season).

Power Purchase Agreement (PPA): A contractual agreement between an electricity generator and a purchaser, typically involving the sale of generated power. The agreement specifies the terms of the sale, including the price per megawatt-hour, which can escalate over time. It often directly connects to a generating resource.

Procurement entity: The entity responsible for overseeing the development of supply specifications, preparation of bid documents, solicitation of offers to meet those specifications, post-selection contracting, and ongoing monitoring of contracted obligations.

Proxy price: A representative price, also referred to as a comparison or benchmark price, used to assess the reasonableness of provided bids.

Reconciliation: The process of balancing default service supply and procurement costs with revenue generated, affecting customer credits or costs.

Regional Transmission Organization (RTO): An independent entity that coordinates, controls, and monitors a multi-state electric grid. It also administers electricity markets, ensuring reliability and efficiency of the electric power system across large geographic areas.

Renewable Energy Credit (REC): Represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source, and typically represents 1 MWh of renewable energy generation. Also known as a renewable energy certificate.

Renewable Portfolio Standard (RPS): Jurisdiction-specific policies that require a specific portion of retail electricity supply to come from specified renewable resources. Compliance is typically evaluated based on the retirement of RECs.

Request for proposal (RFP): The process by which an entity (such as a utility or a regulatory authority) solicits bids from potential suppliers for the provision of goods or services. In the context of electric service, RFPs are used to procure default electric service, and suppliers are required to meet certain criteria and follow specified procedures to participate in these bids.

Retail rate: The final price paid by end-use customers.

Reverse auction: A procurement method where participants bid successively lower prices during the auction period until no further bids are made or the time expires.

Round-the-clock (RTC): Refers to a consistent and uninterrupted supply of energy, typically applied in the context of energy contracts or supply agreements, where the provider ensures a continuous supply of electricity throughout the day.

Sealed-bid auction: A procurement method where suppliers submit confidential bids in response to an RFP). This method is commonly used for default service procurement.

Self-supply: When the default service provider procures energy and related services directly in the wholesale market to fulfill all or part of the necessary load, instead of contracting with a wholesale supplier for full-requirements service.

Sequential auction: A procurement method where products are auctioned one after the other, with pricing revealed after each round.

Spot market purchase: An energy product purchased on the real-time market for a quantity needed.

Stacked contract: A type of contract laddering where contracts are purchased at different solicitations for the same duration and covering the same portion of the load.

Time-of-Use (TOU): A pricing scheme in which electricity rates vary depending on the time of day. Rates are typically higher during peak demand hours and lower during off-peak times. This system is designed to encourage consumers to reduce or shift their electricity usage to off-peak times.

Transmission and distribution (T&D): The different stages of carrying electricity through lines and poles from generators to an end-user. Transmission lines move electricity from a generator or power plant to various substations and operate at higher voltage ranges than distribution lines. Distribution lines carry electricity from the substation to the customer.

Wholesale energy market: A financial market that allows for the purchase and sale of large quantities of the electricity produced by different energy resources between utility companies and energy suppliers.