Connecticut Department of Energy & Environmental Protection
Connecticut Public Utilities Regulatory Authority

RESOURCE ASSESSMENT OF MILLSTONE PURSUANT TO EXECUTIVE ORDER NO. 59 AND PUBLIC ACT 17-3; DETERMINATION PURSUANT TO PUBLIC ACT 17-3

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EXECUTIVE SUMMARY

DEEP and PURA have prepared a Resource Assessment and Appraisal to satisfy the multiple, related requirements of Executive Order No. 59 (July 25, 2017) and Public Act 17-3. The results of the Resource Assessment and Appraisal are summarized in this Report and in a companion Assessment prepared by Levitan & Associates (LAI), a consultant retained by DEEP and PURA to assist with this proceeding. With respect to the specific items to be addressed pursuant to the Executive Order and the Act, DEEP and PURA's summary findings are as follows:

- The current and projected economic condition of Millstone hinges on energy market revenues and plant operating costs. The LAI Assessment concludes that the Millstone Nuclear Units are economically viable under expected market conditions through 2035 and thus unlikely to retire prior to that date. In the absence of verified historic operational costs for the units that DEEP/PURA requested from Dominion in August 2017, LAI used the best available public information to develop cost assumptions for the two Millstone units. After the LAI analysis was complete, Dominion submitted a two-page summary of high-level, short term forward financial projections on November 30, 2017, and a longer, redacted document on January 10, 2018.

- In consideration of these confidential documents, comments received on the Draft Report and LAI Assessment, and a significant change in federal tax policy that occurred in late December 2017, DEEP and PURA conducted a series of high-level sensitivity scenarios to assess the impact of different assumptions on Millstone's profitability. The sensitivity scenarios indicated that Millstone Station's profitability is highly correlated with the cost assumptions highlighted in Dominion's and others' comments, and that, when some adjustments are made, the financial viability of Millstone's continued operation could be at risk. Note that a sensitivity scenario can confirm how much impact a key input or assumption will have on the outcome of a financial model, but it cannot confirm which assumption is correct or most accurate to use. Additional detailed, auditable financial data, such as that requested from Dominion in August, would be necessary to verify the accuracy of asserted cost figures to warrant changing inputs to the LAI model. Constraints imposed by the timing of the Dominion submissions, the need for verification, and complexity of the detailed LAI analysis made it impossible for DEEP and PURA to verify the cost assumptions asserted in this proceeding.

- The hypothetical retirement of the Millstone Nuclear Units would have significant negative impacts on the region's electric grid with respect to fuel diversity, energy security, and grid reliability. The retirement of Millstone's 2,200 MW facility would not trigger the need for new capacity in Connecticut specifically, but it would cause the New England region as a whole to need new generation capacity. Replacement capacity procured through the ISO New England market would likely be natural gas-fired, exacerbating security and system reliability issues due to the region's over dependence on natural gas.

- Retirement of the Millstone Nuclear units would increase CO_2 emissions for the entire New England electric sector by 80 million short tons, or 25 percent over the modeling horizon. Replacing at least 25 percent of Millstone's 2,200 MW of zero emission generation facilities with large-scale hydropower, demand reduction, energy storage, and zero emission renewable energy would be necessary for Connecticut to not backslide on its statutory greenhouse gas emissions reductions targets, and would cost the state's ratepayers an estimated $1.8 billion (2017 dollars); even with that investment, regional emissions would increase by 20 percent Replacing 100 percent of Millstone's output with zero carbon resources would cost Connecticut ratepayers approximately $5.5 billion.

- A variety of mechanisms can be utilized, in theory, to provide revenue stability for new and existing zero carbon resources, including long-term power purchase contracts (such as authorized by Public Act 17-3) and zero emissions credits (ZECs). At present, there are no mechanisms to retain Millstone and allocate the costs regionally. The ISO New England has indicated in this proceeding that Millstone would not be eligible for a reliability-must-run contract on a transmission security basis. In January 2018, FERC rejected a DOE Notice of Proposed Rulemaking (NOPR) that would have required the region to compensate nuclear facilities, among other things, on a cost-of-service basis. Promising concepts such as the Brookfield-CLF Dynamic Clean Energy Forward Market are still under discussion. Meanwhile, the ISO New England has recently released a fuel security study that predicts the region would experience rolling blackouts if Millstone were unavailable in future winters, underscoring the regional dependence on the unit.

This Resource Assessment and Appraisal concludes, based on best available public information used in the initial LAI analysis, that the Millstone units are profitable through 2035 under multiple scenarios. Considering stakeholder comments and submissions from Dominion, DEEP and PURA further conclude that certain changed cost inputs, if verified by review of audited financial documents, could result in the Millstone units being at risk. Moreover, the Millstone units are critical to both Connecticut and the New England region, in terms of fuel security and meeting greenhouse gas reduction goals.

In the absence of actionable regional mechanisms, DEEP and PURA conclude that a procurement under Public Act 17-3 (the Act) should go forward, with certain conditions to ensure that the state's ratepayers are protected from paying above-market costs for resources that are not verified to be at risk of retirement. These conditions are detailed in the Determination at the end of this document. Going forward, DEEP and PURA will continue to seek other more regionally-integrated mechanisms such as a Dynamic Clean Energy Forward Market or ZECs that are harmonized with the existing competitive market and will ensure that any investments, if needed, to retain key nuclear generating facilities are shared appropriately with the region that benefits from them. DEEP and PURA are inviting stakeholder comment on this Draft Resource Assessment and Determination by Thursday, January 25, 2018.

RESOURCE ASSESSMENT AND APPRAISAL

I. PROCEDURAL BACKGROUND

This Report responds to two recent actions: an Executive Order and a Public Act.

First, on July 25, 2017, Governor Dannel P. Malloy signed Executive Order No. 59, which directs the Department of Energy and Environmental Protection (DEEP) and the Public Utilities Regulatory Authority (PURA) to conduct a resource assessment of: (1) the current and projected economic viability of the Millstone nuclear generating facilities; (2) the role of zero emission generation facilities like nuclear, large-scale hydropower, demand reduction, energy storage, and zero emission renewable energy in helping the state meet its statutory greenhouse gas emissions reductions targets and maintaining the reliability of the electric grid; (3) the best mechanisms to ensure continued progress towards those targets; (4) the compatibility of such mechanisms with competitive wholesale and retail electricity markets, and the resulting financial impact on electric ratepayers of such mechanisms. DEEP and PURA are required to submit the findings of its resources assessment to the Governor, the chairpersons and ranking members of the Energy and Technology Committee of the General Assembly, and to the Governor's Council on Climate Change no later than February 1, 2018. DEEP and PURA initiated the instant proceeding (Proceeding) to implement Executive Order No. 59.

Second, June Special Session Public Act 17-3, *An Act Concerning Zero Carbon Solicitation and Procurement* (the Act), requires DEEP and PURA to conduct an appraisal of nuclear power generating facilities assessing: the current and projected economic condition of those facilities; the impact on the electric markets, fuel diversity, energy security, grid reliability, and greenhouse gas emissions; and impact on the state, regional and local economy if those facilities retire. DEEP and PURA must submit their appraisal, along with a determination of whether to conduct a procurement for nuclear power generating facilities pursuant to the Act, to the Connecticut General Assembly by February 1, 2018. If the results of the appraisal demonstrate that action is necessary, DEEP may issue one or more solicitations for zero carbon generation facilities, such as nuclear power, hydropower, Class I renewable energy sources, and energy storage. If DEEP finds any proposals submitted in response to a solicitation are in the best interest of ratepayers, DEEP may direct the EDCs to enter into long-term agreements with those resources and submit any agreements to PURA for review and approval.

DEEP and PURA initiated a joint proceeding on August 2, 2017 to implement Executive Order No. 59, and invited stakeholder comment on a draft scope of the proceeding, which was issued on August 9, 2017. After DEEP and PURA initiated this proceeding in response to Executive Order No. 59, the Connecticut General Assembly passed June Special Session Public Act 17-3 on October 26, 2017. In the interest of carrying out our responsibilities in a timely and cost-efficient manner (including minimizing the cost of technical consultants necessary for such assessment), DEEP and PURA have acted in a manner such that the findings and conclusions of this Proceeding will satisfy the requirements of both the Executive Order 59 and the Act. For the purpose of this analysis, the Millstone units (the study subject of Executive Order No. 59) serve as a reasonable proxy for all nuclear generating facilities located in the ISO New England control area (the study subject pursuant to the Act).

In August 2017, DEEP and PURA issued a draft study scope, received and considered oral and written comments on that scope, and issued a revised scope. DEEP and PURA retained the consultant services of Levitan & Associates (LAI) to model and analyze Millstone's economic viability and the role of zero-carbon resources in helping the state achieve its mandatory carbon reduction targets (satisfying Numbers 1 and 2 in Executive Order 59 and the appraisal requirements identified in the Act).

On December 14, 2017, DEEP and PURA issued a Draft Report that introduced and provided contextual information relevant to the two topic areas covered in the accompanying Assessment prepared by LAI (LAI Assessment), as well as other pertinent findings of DEEP and PURA. Specifically, the Draft Report provided: (1) background on nuclear generation, the New England electricity sector, and Connecticut's relevant environmental and energy public policies; (2) market trends in the ISO New England region; (3) a summary of the results from the LAI assessment of economic and emission implications; and (4) a discussion of policy options going forward.

DEEP and PURA held two public meetings and received 553 public comments on the findings in the Draft Report and LAI Assessment, and on specific questions included in a Notice of Request for Written Comments.[1]

DEEP and PURA are now inviting stakeholder comment on an expedited schedule on this Draft Resource Assessment and Determination. This updated document reflects (a) additional discussion of the financial viability of the Millstone facilities, informed by stakeholder comments, the Dominion submission and the passage of federal tax reforms in late December 2017; and (b) a determination, required by Public Act 17-3, as to "whether a solicitation process for nuclear power generating facilities shall be conducted" pursuant to that Act, including conditions under which such a solicitation should go forward. With the benefit of stakeholder input, DEEP and PURA will finalize the Resource Assessment and Determination for release on February 1, 2018. DEEP and PURA are required to submit the findings of its resources assessment to the Governor, the chairpersons and ranking members of the Energy and Technology Committee of the

[1] The Notice of Request for Written Comments (issued on December 14, 2017) invited stakeholder comment on (1) the appropriateness of the assumptions used in the Draft Report and Resource Assessment; and (2) the policy options discussed in the Draft Report.

General Assembly, and to the Governor's Council on Climate Change no later than February 1, 2018.

II. BACKGROUND: NUCLEAR GENERATION, THE NEW ENGLAND ELECTRICITY SECTOR, AND CONNECTICUT PUBLIC POLICY

A. Development of the New England Nuclear Fleet

New England's nuclear generating fleet reflects investments made in the latter half of the twentieth century. At one time, New England had eight operating reactors; the expected closure of Pilgrim Nuclear Power Station in 2019 now leaves three operating reactors remaining in the region: two reactors at Millstone, and one at Seabrook.[2]

The Millstone Nuclear Power Station consists of two pressurized water reactors (PWR) and is located in Waterford, Connecticut. Millstone Unit 2 is an 882 megawatt (MW) Combustion Engineering reactor that came online in 1975 at a cost of $424 million. Millstone Unit 3 is a Westinghouse PWR rated at 1230 MW that came on line in 1986 at a cost of $3.8 billion. Collectively, the two Millstone reactors constitute the largest single generation facility and the only multi-reactor plant in New England. The principal owner and operator of Millstone Station is Dominion Energy Nuclear Connecticut, Inc., a subsidiary of Virginia-based Dominion Energy (Dominion). Millstone Unit No. 2 is wholly owned by Dominion. Dominion owns 93.47 percent of Millstone Unit No. 3. The other owners are the Massachusetts Municipal Wholesale Electric Company (MMWEC) (4.8 percent) and Central Vermont Public Service Corporation (1.73 percent). The Nuclear Regulatory Commission on Nov. 28, 2005 approved Dominion's request for 20-year operating license extensions for Millstone Units No. 2 and 3. The license for Millstone Unit No. 2 now expires July 2035 and the license for Millstone Unit No. 3 now expires in Nov. 2045.[3]

The Seabrook power station in New Hampshire was originally designed with two reactors but, due to cost overruns and delays, only one reactor was completed. The single operating reactor at Seabrook is a 1244 MW Westinghouse pressurized water reactor which is the largest individual generation unit in ISO New England. Construction began in 1976 and full power operation began in 1990 at a total cost of $6.2 billion. The overruns and vast expenses associated with Seabrook led to the bankruptcy of its major utility owner, the Public Service Company of New Hampshire. The current principal owner and operator of Seabrook Station is NextEra Energy Resources LLC, a subsidiary of Florida-based FPL Group, Inc. NextEra owns 88.2 percent of Seabrook Station. The other

[2] Yankee Rowe, Vermont Yankee, Connecticut Yankee, Maine Yankee, and Millstone 1 have all closed down for a variety of reasons related to the economics of operating smaller (less than 1000 MW) reactors and, in some cases, local opposition.
[3] http://www.mmwec.org/millstone-nuclear.html

owners are MMWEC (11.59 percent) and two Massachusetts municipal utilities, the Taunton Municipal Lighting Plant (0.1 percent) and the Hudson Light & Power Department (0.08 percent). NextEra has announced plans to seek an extension of its Seabrook operating license, from the current license expiration date of 2026, to 2050.[4]

All of the nuclear reactors built in New England were constructed prior to deregulation. During this time regulated utilities were permitted to develop, own, and operate electric generating facilities with financing backed by electric ratepayers. This investment structure is referred to as a "cost-of-service" regime, in which utilities, with the oversight of state utility commissions, would recover from electric ratepayers their projected fixed capital and operating and maintenance (O&M) costs plus a return on capital expenditures. Under the "vertically integrated" or "fully regulated" structure of power supply, electric utilities maintained monopoly ownership of generation (power plants), transmission (high voltage transportation of electricity) and distribution (lower voltage lines into homes and businesses).

Starting in the mid-1990s, many states chose to restructure or "unbundle" the three components of the power supply. Following decisions of the Federal Energy Regulatory Commission (FERC), which initiated reforms to allow unregulated, or "merchant" generators access the transmission system, many states enacted legislation and regulatory changes to expose the power generation sector to greater competition. Through deregulation, those states ended cost-of-service regulation of utility-owned generation, choosing to rely on a regional competitive, wholesale electricity market to determine electric generation pricing.

Connecticut restructured its electric market in 1998 through Public Act 98-28. The act required the state's two electric companies, The Connecticut Light and Power Company (CL&P) d/b/a Eversource Energy (Eversource) and The United Illuminating (UI), and PURA's predecessor, the Department of Public Utility Control, to take steps to divest the generation assets from the electric companies' portfolios, among other things. The auction for non-nuclear assets was required to take place by January 1, 2000 and for nuclear generation by January 1, 2004. CL&P and UI had ownership interests in nuclear units Millstone in Connecticut and Seabrook in New Hampshire that they were required to divest under Public Act 98-28. In August 2000, Dominion Resources purchased Millstone for approximately $1.3 billion from CL&P. CL&P and UI subsequently auctioned their ownership interests in the Seabrook plant.

Since the amount received from the sale of the ownership interests in the Millstone Station and Seabrook fell short of the regulated depreciated cost of the assets, CL&P and UI had unrecovered (or "stranded") costs related to the sale of the assets. These stranded costs were prudently incurred under regulation, but were above market in the deregulated environment in which the assets were sold. To be fair regarding the investments made by CL&P and UI, the stranded costs were allowed to be recovered from ratepayers over time

[4] http://www.mmwec.org/seabrook-nuclear.html

through the Competitive Transition Assessment (CTA) charge. At this juncture, stranded costs—in excess of $2.1 billion—have been fully recovered from ratepayers for UI and nearly so for CL&P.[5]

As another step of deregulation, Public Act 98-28 also authorized third parties to sell electricity to retail customers, creating a market for competitive retail supply. To ensure stability in the retail electricity market, CL&P and UI were required to continue to provide a retail electricity rate offering (called the "standard offer" for residential customers, and "last resort service" for commercial and industrial customers), but customers could elect to choose between the utility and competitive supply offers.

Anticipated advantages associated with restructuring included: providing greater customer choice; increased efficiencies from producing electricity from the most efficient generators; and shifting the risk of long-lived, capital-intensive investments from ratepayers to merchant generators. It should be noted, however, that while merchant generators in a restructured model accept the risk of long-lived, capital-intensive investments, they are not tied to a fixed or guaranteed rate of return. It is up to each merchant generator to determine what return on investment is necessary to justify the continued operation of their generation assets.

Since purchasing the Millstone facility, Dominion has invested more than $1.1 billion into the Millstone Station. According to Dominion, these investments resulted in significant gains in productivity leading to annual electricity generation from two units equal to that of the previous owner's when operating all three units.[6]

B. Connecticut Public Policy Requirements

The same Public Act 98-28 that deregulated Connecticut's utility-owned generation in 1998 established a Renewable Portfolio Standard (RPS) and a Conservation & Load Management (C&LM) program. The RPS requires an increasing percentage of retail electric sales in Connecticut to be sourced from certain classes of renewable generation, as a means to spur investment in new renewable facilities. Through subsequent legislative revisions, the state's RPS currently requires 20 percent of electricity sales to be sourced from Class I renewables by 2020.[7] With funding of approximately $180 million per year, the C&LM program funds investment in utility-administered energy efficiency measures to reduce electricity demand in the state.

In 2005, seven northeast states, including Connecticut, announced an agreement to implement the Regional Greenhouse Gas Initiative (RGGI), a market-based carbon reduction program. Through RGGI, participating states establish a cap on the amount of

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[5] See, Decision dated 7/7/99 in Docket No. 99-02-05, p. 1; Decision dated 8/4/99 in Docket No. 99-03-04. P.1.

[6] Dominion response to Question 8, September 9, 2017 in Docket No. 17-07-32.

[7] Class I resources include solar, wind, small hydro, biomass, anaerobic digestion, and fuel cells. Nuclear generation is an existing resource and is not considered a renewable energy resource therefore it does not qualify as RPS Class I-eligible.

greenhouse gases that can be emitted from fossil fueled power plants 25 MW or greater. CO_2 emission credits are distributed to the compliance entities through quarterly auctions. Less efficient fossil power plants are required to account for their emissions in their generation costs, conferring a competitive advantage on low and emissions-free generators like Millstone. In this way, the RGGI program provides an important policy support for Millstone in the ISO New England market.

In 2008, the Connecticut General Assembly enacted the Global Warming Solutions Act (GWSA), which set mandatory economy-wide greenhouse gas (GHG) emissions reduction targets of 10 percent below 1990 levels by 2020 and 80 percent below 2001 levels by 2050.[8] Connecticut's 2014 GHG inventory, the year for which the most recent data is available, shows that the state has reduced emissions 4 percent below 1990 levels and 14 percent below 2001 levels.[9]

As a zero carbon resource, nuclear power is critical to meeting Connecticut's and the region's emission reduction targets. For instance, nuclear power typically provides 25-30 percent of the electric generation and as much as 75 percent of the carbon free power for all of New England (though this number will decrease with the retirement of Pilgrim Nuclear Power Station in June 2019). In Connecticut's GHG inventory—the basis for tracking progress towards the 2020 and 2050 GHG emission targets—emissions from electricity consumption in the state are calculated by utilizing an emission factor that accounts for the carbon intensity of all electric generation within the ISO New England grid as well as electricity imported into the region from Canada, New York, and other jurisdictions. Connecticut has no contracts with either Millstone or Seabrook; therefore, these zero carbon resources are factored into the average New England grid emissions. Proportionally, because Connecticut represents 25 percent of the overall electricity consumption in New England, this means Connecticut's inventory currently "counts" only 25 percent of Millstone's zero carbon output, as it is produced in the market. The rest of Millstone's output is theoretically proportionally accounted for by other New England states.

A federal standard for economy-wide GHG accounting does not currently exist. In this absence, states often differ in their accounting methodologies. For example, Massachusetts utilizes a different accounting methodology that recognizes the state is a net electricity importer. The accounting approach includes emissions from all in-state power plants plus a portion of emissions from power plants in the other New England states that generate more electricity than they use in a given year. In addition to this, the Massachusetts methodology explicitly and fully accounts for the purchase of Renewable Energy Credits (zero-carbon resources) by Massachusetts retail electricity sellers.[10]

[8] Conn. Gen. Stat. § 22a-200a.
[9] DEEP, 2013 Connecticut Greenhouse Gas Emissions Inventory.
[10] MassDEP *Statewide Greenhouse Gas Emissions Level: 1990 Baseline and 2020 Business As Usual Projection Update*. Accessed on December 5, 2017 http://www.mass.gov/eea/docs/dep/air/climate/gwsa-update-16.pdf

Historically, Connecticut has not been a net electricity exporter, meaning that Millstone's zero carbon generation has not been included in the Massachusetts GHG inventory. Accounting methodologies for electric emissions in other New England states are unclear at this time. Therefore, the loss of Millstone may not significantly impact other states' emissions accounting to the same high degree that it would impact Connecticut's.

On April 22, 2015, Governor Malloy signed Executive Order No. 46 establishing the Governor's Council on Climate Change (GC3). The GC3 is comprised of 15 individuals from state agencies, businesses, and non-profits, whose purpose is to monitor the state's progress in achieving its GHG reduction targets, establish an interim target that ensures the state is on a path to achieve its 2050 target, and recommend policies or legislative action to assist in achieving said targets. The GC3 spent the past year deliberating interim GHG reduction goals for the year 2030, ranging from 35-55 percent below 2001 levels. On January 19, 2018, at the GC3's public meeting, the GC3 recommended a 2030 goal of 45 percent below 2001 levels, representing a straight-line trajectory from current emissions to 80 percent below 2001 levels by 2050.[11] All reduction scenarios considered by the GC3 in this range were modeled assuming the continued operation of both Millstone units through the conclusion of their respective NRC licenses in 2035 and 2045.

In addition, all of the 2030 reduction scenarios evaluated by the GC3 would require transformative technological and business model changes within the home heating and transportation sectors, and increasing energy efficiency and renewable energy deployment. More specifically, this transformation includes the widespread electrification of building thermal loads, and a 9 to 22 percent replacement of light-duty fossil fuel combustion vehicles with electric by 2030. Consequently, electricity becomes an increasingly dominant component of our energy supply, and achieving the interim GHG goals contemplated by the GC3 would require electricity generation to be 60 to 80 percent zero-carbon by 2030 in order to meet the mid-term targets contemplated by the GC3. All of the 2030 reduction scenarios the GC3 has considered assume the continued operation of both Millstone units and the Seabrook facility through at least 2035. Without the carbon-free electricity provided by nuclear facilities, most notably, the Millstone units, any interim emissions reduction target set by the GC3 become increasingly difficult to achieve. For example, without the Millstone Station, Connecticut would need to secure the equivalent of 25 percent of the facility's output, which represents Connecticut's share of the units, from other zero-carbon generating resources in order to prevent backsliding on current progress towards the GWSA targets. This 25 percent of the facility's output represents approximately 12.5 percent of Connecticut's energy demand, meaning that Connecticut would have to procure 12.5 percent of load from zero-carbon resources *in addition* to the growing portion of those resources required to actually meet the GWSA target and the state RPS.

[11] The GC3 is developing a formal set of principles to accompany and provide needed context to the 45 percent goal. These principles will highlight, among other things, that the goal should be achieved in the most cost-effective manner, the inherent uncertainty around such fixed goals, the role of the private sector in achieving the goal, and the magnitude of the challenge that goal (or frankly any other) represents.

C. ISO New England Wholesale Market Framework

The ISO New England wholesale electricity markets are designed to select the "lowest cost" resources needed to serve demand and achieve certain other reliability-related outcomes. The products traded in New England's wholesale electricity markets comprise three major categories:

- Energy markets for buying and selling day-to-day wholesale electric power
- A capacity market for ensuring long-term system reliability
- Ancillary services for ensuring short-term system reliability

The wholesale electricity markets are designed to procure resources that are least cost without giving undue preference to any particular technology. That is, the market ostensibly is indifferent to characteristics such as fuel source. As such, left to itself, the market will procure only what is the least-cost resource at the time. The wholesale markets are not designed to promote fuel diversity, lower emissions, or produce resiliency attributes such as fuel security. To date, in order to procure these other characteristics, the states have implemented policies such as the RPS or run competitive solicitations for certain resource types. The ISO has also taken modest steps to encourage fuel diversity by instituting a winter reliability program and adding performance requirement in the Forward Capacity Market. The FCM market rules also include an allowance for state policy resources known as the Renewable Technology Resource ("RTR") exemption in the forward capacity market.

This Draft Report and the associated LAI Assessment used the best available information to assess the current and projected economic viability of Millstone through 2035. Millstone's economic viability largely consists of its going-forward costs through 2035, expected revenues from the ISO New England wholesale markets over the same time period, and the risk that costs or revenues will differ from expectations. Regardless of what the analysis contained in the LAI Assessment may suggest, the resource owners' view of what constitutes sufficient net profit to continue participating in the wholesale markets ultimately determines asset decisions, including the decision to retire.

1. Day Ahead and Real-Time Energy Market

Electricity production must continuously and instantaneously match demand on the system, and real-time energy prices adjust as often as every five minutes as the levels of supply and demand change on the system. In both day-ahead and the real-time energy markets, resources offer prices and quantities of electricity they are willing to schedule and produce around their expected marginal fuel costs, the largest factor in most units' marginal costs. Load serving entities place bids for the maximum amount they are willing to pay for the anticipated amount to be used.

In the ISO New England energy markets, electricity is traded in three ways: through the Day-Ahead Energy Market; through a balancing market called the Real-Time Energy Market, and through longer-term bilateral transactions directly between buyers and sellers. Market participants can choose to partake in any combination of trading opportunities to manage their daily production and delivery of wholesale electricity throughout New England and to manage their portfolios as efficiently as possible.[12] In both the day-ahead and real-time markets, the offered price by the last resource, or marginal unit, needed to supply the level of demand at a given time, sets the market clearing price.

Natural gas fired resources fuel nearly half the region's electricity annually—49 percent in 2016. Further, it is the primary fuel source for over 40 percent of regional capacity and an alternate fuel source for over 10 percent more. Natural-gas-fired generators set the clearing price for wholesale electricity 75 percent of the time.[13] Consequently, the price of wholesale electricity in New England is highly correlated to the price of delivered natural gas.

Nuclear power plants have high capacity factors which means that they operate for most hours of most days, and are typically price takers in the energy markets. Nuclear plants are also particularly dependent upon energy revenues. This is because nuclear generation units have very high fixed capital costs and very low marginal costs and therefore are deemed "infra-marginal" units, which means that their marginal costs are lower than the hourly clearing price of the energy market. A typical large single unit nuclear power plant requires about 600 workers to operate and a comparably sized gas plant only needs about 30. This is due in part to the significantly greater regulatory oversight of commercial nuclear reactors by the Nuclear Regulatory Commission (NRC). In addition, the hazards of working with highly radioactive fuel and waste products as well as the unique security required by the NRC for a nuclear power station will always mean that such a facility will have greater labor needs. While the on-site presence of skilled workers with sophisticated monitoring equipment and continuous and thorough inspection by plant workers and NRC staff has resulted in remarkably few safety incidents, the costs associated with keeping a large, well-paid staff operating 24 hours a day means that nuclear power will continue to have high overhead costs.

Because of their reliance on infra-marginal energy profits, energy prices must, on average, be sufficiently above the marginal energy cost of the nuclear unit to allow the resource owner to recover the high fixed costs. Consequently, high or low wholesale energy prices make cost recovery easier or more difficult, respectively, for Millstone. To compound the sensitivity that nuclear resources have around energy pricing, expected revenue is also subject to additional risks of variance due to unplanned shutdowns and extended outages. During such occurrences, the facilities are not generating power or receiving revenue, yet the high fixed costs remain. In addition, nuclear fuel is loaded only once approximately every 18 months so that the fuel costs are also essentially fixed.

[12] https://www.iso-ne.com/static-assets/documents/2016/10/iso101_studentbook_20161004.pdf
[13] ISO New England, 2017 Regional Electricity Outlook, p. 24 and 25.

Therefore, unlike fossil electric generating units where the large marginal avoided cost associated with fuel partially offsets lost revenue during unplanned outages, nuclear power generating units continue to incur large fixed costs for similar events. If such unanticipated outages occur during a scarcity event on the system as defined in the ISO New England tariff,[14] pay for performance penalties in the Forward Capacity Market can further reduce expected capacity revenue.[15] Lost revenue from such unanticipated shutdowns can significantly deteriorate the expected margins from the Millstone Power Station and is source of operational risk for the units. Older fossil units, such oil and coal units, are not as susceptible to this phenomenon as they generally have low fixed costs and high marginal costs.

2. Forward Capacity Market

Another important, but smaller, source of revenue for Millstone is the ISO New England forward capacity market (FCM). The FCM is a long-term wholesale electricity market that assures resource adequacy, locally and system wide. Capacity resources eligible for participation in the FCM may be new or existing qualified resources, and include supply from power plants, import capacity, or demand resources. To purchase enough qualified capacity and allow enough time to construct new capacity resources, a Forward Capacity Auction (FCA) is held annually approximately three years in advance of when the capacity resources must provide service, or the capacity commitment period (CCP). Capacity resources compete in the annual FCA to obtain a capacity supply obligation (CSO). Suppliers with the lowest-priced offers clear the auction and receive capacity payments based on the auction clearing price—these payments are in addition to what resources receive in the energy and reserve markets. In exchange for capacity payments, the resources have an obligation to be operational and bid into the energy markets.[16]

Millstone has a CSO for the 2020-21 delivery year, committing them to operate through that time. As an existing resource that did not submit a retirement bid in March of 2017, Millstone will bid into the upcoming FCA-12 in February and will almost certainly obtain a CSO for the 2021-22 CCP. Dominion could submit a retirement bid in March 2018, complete the retirement delist process in FCA-13 and not obtain any additional CSO with the CCP beginning in July 2022. Understanding the rules governing the exit of generation resources from the ISO New England markets is critical to understanding Dominion’s options for retiring Millstone. Those rules are discussed in the next section.

3. Resource Retirement Process

[14] Section III.13.7.1.1.1 of the tariff.
[15] It should be noted, however, that if a shortage event occurs while a unit is running, it can earn extra profits.
[16] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions

DEEP and PURA issued data requests to ISO New England relating to the rules and process for generator delisting and retirement, and the subsequent ISO process for assessing whether potential retirements would impact transmission reliability. ISO New England provided a response to that data request, which is discussed in this Draft Report. The ISO New England provided a detailed description of the process for a generation facility owner to request to permanently delist (retire) a generating facility ("resource retirement rules").[17] A summary of that process is included below.

Existing Capacity Resources may retire coincident with the start of the next CCP provided a priced retirement de-list bid is submitted to the ISO approximately four years in advance. Each year, during a two-week period in March, Existing Capacity Resources seeking to retire in the upcoming auction must submit a priced retirement de-list bid to the ISO for review and approval. The priced retirement de-list bid window for FCA-13 will open on March 9, 2018 and close on March 23, 2018 for Existing Capacity Resources seeking to retire at the start of the 2022–2023 CCP. A retirement de-list bid cannot be modified or withdrawn after the Existing Capacity Retirement Deadline. If the resource owner selects unconditional retirement, the resource will retire no matter the price in the upcoming auction. If the resource owner selects conditional retirement, the resource will proceed to the auction but only take on an obligation if the clearing price in the auction is above its originally submitted retirement de-list bid price. To the extent the resource clears the FCA with a retirement delist bid, the following year, the resource owner may submit updated information and documentation to support a new retirement de-list bid price for the Existing Capacity Resource.

When an Existing Capacity Resource submits a retirement de-list bid, ISO New England conducts a study to assess the impact of the retirement on the overall reliability of the region's bulk power system. To the extent a reliability need exists, a generator can choose to remain in operation until the identified reliability need is addressed under a cost-of-service agreement with the ISO. The capacity associated with a retirement de-list bid would be deemed needed for reliability only if it is needed to address a local reliability (i.e., transmission security) issue. Regardless of the outcome of the reliability study, the ISO does not have the authority to prevent a resource from choosing to move forward with retirement.[18]

Important to note for the purposes of discussion below, Dominion Energy indicated that it currently has no intention of retiring one Millstone unit and leaving the other unit operational, and cannot presently foresee a scenario where this circumstance would occur.[19]

a. Risk of Retirement during CSO Period (2018-2022)

[17] *See* ISO New England, Response to Data Request #2 (September 8, 2017), *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/f54b51ba2d03640385258198003eddc2/$FILE/iso_new_england_response_data_request_2_deep_pura_joint_proceeding_docket_17-07-32_signed_combined.pdf
[18] Id.
[19] See, Dominion response to Question #28, filed September 19, 2017 in Docket No. 17-07-32.

A CSO is a financial agreement, awarding payment for the future availability of a generator resource. The CSO is binding for the seller. If a generator wishes to shut down, or otherwise exit the market prior to the end it its CCP, it must shed its CSO to a qualified resource or buy its way out of the obligation by "walking up the demand curve" in the annual reconfiguration auction. ISO New England discussed this process as follows.

A resource may shed (in full or in part) its CSO via bilateral transaction(s) or by submitting a demand bid(s) in an ARA. In general, Participant-submitted demand bids in the ARA are traded against the system demand curve, but if a resource is part of a modeled Capacity Zone, the Capacity Zone demand curve is also considered. Connecticut was modeled as a separate Capacity Zone in FCA-9 (CCP 2018-2019), but not for FCA-10 (CCP 2019-2020) or FCA-11 (CCP 2020-2021).[20]

As noted previously, Millstone has CSOs for almost 2,100 MW of qualified capacity through the 2020-21 CCP. To shed a CSO of this magnitude, Dominion would have to find a large number of substitute megawatts from resources willing to assume the CSO or pay a very high price to buy its way out of its obligations. Because most qualified capacity resources are already committed in the FCM, there is limited liquidity in the annual reconfiguration auctions on which to trade out a large CSO, making it prohibitively expensive for Dominion to shed the Millstone Station's CSO in an annual reconfiguration auction. The high anticipated cost of shedding Millstone Station's CSO makes it highly unlikely that Millstone would effectively retire before the end of its final CCP. Further, Dominion did not submit a retirement election for the upcoming FCA-12, in accordance with the notice requirements discussed previously and will almost certainly be awarded another CSO for the 2021-22 CCP.

b. **Risk of Retirement in 2022 and beyond**

Due to the existing and expected CSO commitments, should Dominion seek to retire Millstone without shedding its existing CSOs, the earliest this could occur would likely be in mid-2022. To accomplish that, Dominion would need to submit a retirement delist bid to the ISO New England during the period March 9-23, 2018, in accordance with the notice requirements previously discussed. That sets the retirement process in motion, with ISO New England then performing a reliability and economic review of the retirement de-list bid. Again, it is important to note that regardless of the outcome of the reliability and economic review by the ISO New England, the retirement election by any resource participating in the FCM is irrevocable, even if it enters into a Reliability Must Run (RMR) agreements with the ISO New England.

[20] *See* ISO New England, Response to Data Request #2 (September 8, 2017). With the use of demand curves, it is not necessary that sufficient supply is available for a resource to trade out of a CSO. Trading out of an existing CSO with the demand curve is a function of pricing on the curve, i.e. with less supply, the price will be higher. Though there are different demand curve shapes for a resource to shed a CSO for FCA-9, FCA-10 and FCA-11, the outcome is the same.

The ISO New England offered some insight on the Connecticut Local Sourcing Requirements (CT LSR) assuming the retirement of one or both of the Millstone units. ISO presented the CT LSR without Millstone as follows:

CT LSR without the Millstone Station

Data and Assumptions consistent with CCP 2021-2022 (FCA#12)	New England (MW)	CT without Millstone Station (MW)
Peak Load (50/50) net of BTM PV	29,436	7,367
Existing Capacity Resources	32,471	8,060
Installed Capacity Requirement	34,748	N/A
NET ICR (ICR minus 958 MW HQICCs)	33,790	N/A
Local Sourcing Requirement		6,574
Transmission Security Analysis		6,574
Local Resource Adequacy Requirement		6,470

Based on the data above, even if Dominion were to retire the Millstone Station, Connecticut would still have 1,486 MW in existing generation capacity in excess of its LSR. This suggests that the ISO New England would not likely find that the Millstone Station is needed for LSR, and therefore ineligible for an RMR agreement. Even if the Millstone Station were eligible for an RMR agreement, Dominion cannot be forced to continue operating the Millstone Station under such an agreement.

In their submission to DEEP and PURA, the ISO New England indicated that “[t]he capacity associated with a retirement delist bid would be deemed needed for reliability only if it is needed to address a local reliability (i.e., transmission security) issue.”[21] Significantly, in its response to the DEEP and PURA data request, the ISO New England declined to identify fuel security as a basis for finding a reliability need. This suggests that even if a resource retirement of a non-gas powered generator will make the system reliant upon natural gas generation without adequate supply of natural gas, the implication from the ISO is that it cannot take actions to help avoid the resource’s retirement.

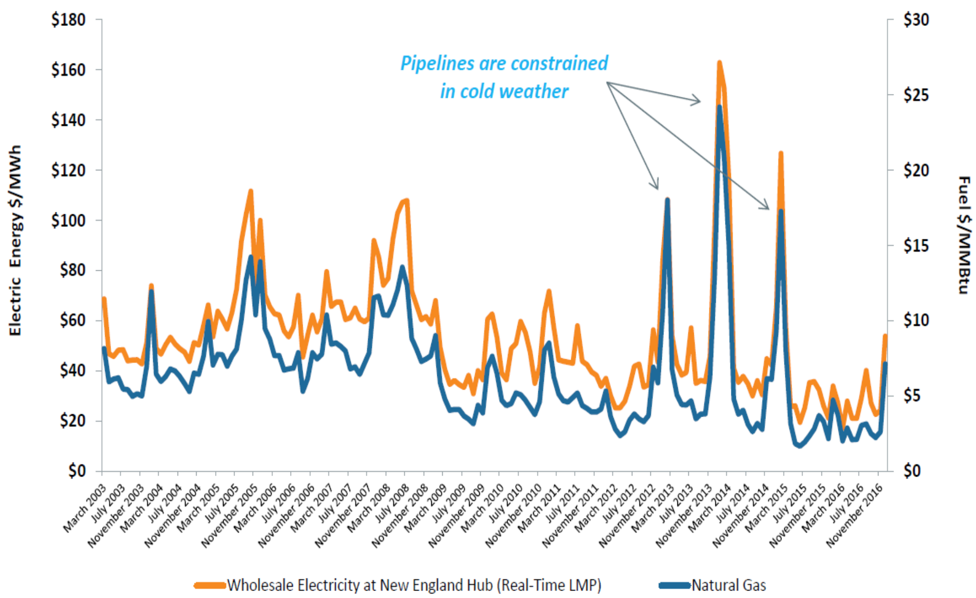
III. MARKET TRENDS

Eighty percent of new capacity built in New England since 1997 runs on natural gas, and nearly 40 percent of all proposed new generation will use natural gas. In the energy market, natural gas generation also dominates as the marginal unit setting the market clearing price cost of electricity 75 percent of the time.[22] As such, the price of electricity in New England is highly correlated to the price of natural gas. This phenomenon is

[21] ISO New England’s Response to Data Request #2
[22] ISO New England Key Grid and Market Statistics https://www.iso-ne.com/about/key-stats

expected to continue into the foreseeable future in New England, even with expected additions of state-sponsored clean energy resources entering the market.[23]

Monthly Average Natural Gas and Wholesale Electricity Prices in New England



Source: ISO New England Regional Electricity Outlook, 2017

Investment in natural gas-fired generation has enabled the New England region to take advantage of very low-cost gas prices, and therefore low electricity prices. Beginning in the mid-2000s, changes in natural gas extraction technologies (primarily hydraulic fracturing of shale formations or "fracking") permitted domestic oil and gas producers to significantly reduce production costs and materially expand the area of profitable commercial oil and gas development in the continental U.S.[24] This quickly resulted in an oversupply of natural gas driving down wholesale gas commodity prices from $9.3 to $3.2/MMBtu between 2008 and 2015.

As the cost of natural gas dropped below both oil and coal on a per-thermal-unit basis, it rapidly became the fuel of choice for new generation. Between 2005 and 2016, natural gas's contribution to total U.S. electric generation increased from around 19 to 33

[23] New England States Committee on Electricity, *Renewable and Clean Energy Scenario Analysis and Mechanisms, Phase I: Scenario Analysis* (Winter 2017), at 34, 35, and App. B slide 10, available at http://nescoe.com/wp-content/uploads/2017/03/Mechanisms_PhaseI-ScenarioAnalysis_Winter2017.pdf
[24] One of the major production areas (technically known as a "shale play") underlies portions of Pennsylvania and New York and is known as the Marcellus Shale. This region, located less than 100 miles from Connecticut, continues to produce significant amounts of low-cost natural gas.

percent.[25] This growth is even more pronounced in New England, where gas-fired generation grew from 15 percent of the fuel mix in 2000 to 49 percent in 2016.[26] This has translated into historically low electricity prices in New England. In 2016, the average annual price of wholesale electricity in New England reached its lowest level since the current markets were launched in 2003.[27]

These trends have significantly affected the profitability of nuclear generation units, which rely heavily on energy markets for their revenue to counterbalance their relatively high capital costs. "Power prices have fallen significantly since 2008, putting commercial nuclear reactors in the United States under substantial financial pressure. . . . the analysis shows that about two thirds of the 100 GW nuclear capacity are uncompetitive over the next few years. . . [in] deregulated markets, 21 GW are retiring or at high risk of retiring prematurely."[28] In New England, poor market conditions and reduced revenues resulting from low gas and electricity wholesale prices as well as increased operational costs[29] were a major contributing factor in owners' decisions to close the Vermont Yankee (closed in December 2014)[30] and Pilgrim nuclear power stations (slated to close in 2019).[31] Both of these facilities were distinguishable from Millstone and Seabrook in that they were smaller-sized commercial reactors, specifically 640 MW and 690 MW respectively. Smaller reactors are even more vulnerable to low energy prices because it requires essentially the same number of people to operate a 600 MW reactor as a 1,000 MW reactor and the economies of scale make smaller ones wholly uneconomical in the current environment.[32] Vermont Yankee and Pilgrim were also negatively impacted by safety and operational performance issues prior to their owner's decision to cease operations.[33]

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[25] https://www.eia.gov/todayinenergy/detail.php?id=25392

[26] ISO New England, 2017 Regional Electricity Outlook, p. 12.

[27] ISO New England's Internal Market Monitor 2016 Annual Markets Report, May 30, 2017, p. 31.

[28] See Geoffrey Haratyk, Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options, MIT Center for Energy and Environmental Policy Research Working Paper 2017-009, March 2017. http://ceepr.mit.edu/publications/working-papers/662

[29] Entergy Press releases http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2769 and http://www.entergynewsroom.com/latest-news/entergy-close-pilgrim-nuclear-power-station-massachusetts-no-later-than-june2019/

[30] Please note that in its Post Shutdown Decommissioning Report, it is estimated that decommissioning of Vermont Yankee will cost $1.24 billion. The Vermont Yankee decommissioning fund only has $665 million in it.

[31] Other factors included local opposition to nuclear power, and significant expenses to address safety in the post-Fukushima regulatory environment.

[32] This is particularly relevant because the three remaining nuclear installations in New England are Millstone Unit 2 at 882 MW, Unit 3 at 1230 and Seabrook at 1244 MW. Of the three remaining reactors, Unit 2 is the most vulnerable and it should be noted that Dominion has written ISO New England seeking information regarding obtaining alternative sources to replace its capacity supply obligations (CSO) for Unit 2. Furthermore, Dominion has not announced any plans to pursue a second re-licensing for Units 2 or 3 and thus these reactors may well shut down no later than 2035 and 2045, respectively.

[33] In 2015, the NRC determined that the performance at Pilgrim degraded to Repetitive Degraded Cornerstone Column of the NRC's Reactor Oversight Process (ROP) Action Matrix - the second lowest level of performance. US NRC's Annual Assessment Letter For Pilgrim Nuclear Power Station (Report 05000293/2015006) dated March 2, 2016. The organizational, operational, and capital costs required to resolve these issues would have contributed to significantly increased costs at the stations.

Although natural gas commodity prices may be projected to be relatively low, as discussed in more detail in the LAI Assessment, the increased proliferation of natural gas use for the electric system has also rendered New England vulnerable to spikes in delivered natural gas prices and could pose a grave threat to system reliability.

Due in part to a mismatch between the ISO New England market construct and the financial commitments required to construct additional capacity facilities, gas-fired generators — who now produce more than half of the region's electricity — typically do not directly contract for firm rights to the gas capacity they need to run. To compound matters, New England sits at the end of three major natural gas interstate pipelines serving the region. There is limited "excess" pipeline capacity, particularly in the winter months when existing gas capacity is needed for thermal heating. Consequently, the wholesale spot market price of natural gas delivered to New England in winter is significantly higher; trading as high as almost $14 per MMBtu in the 2013-2014 winter season, during which a Polar Vortex occurred. These increased delivered gas prices cost the New England region an additional $3 billion in wholesale electricity costs, driving up retail generation rates for families and businesses across the region.[34] Additionally, more expensive, higher-emitting, non-gas units were called to generate power, leaving little excess non-gas capacity available (a reliability challenge), increasing harmful air emissions, and sending wholesale electricity prices to unprecedented levels.

Those high, Polar Vortex prices created significant, short-term disruptions in the retail electricity market, causing electric ratepayers who subscribed to variable generation rates with retail suppliers to see their generation rates nearly double, and creating the potential for nuclear generators—with high capacity factors and low marginal costs—to earn significantly higher revenues. Such conditions could easily occur again with prolonged cold weather, but are difficult to predict or plan for from a revenue standpoint.

Going forward, the price volatility and reliability challenges of natural gas dependence are expected to worsen. In the *2017 Regional Electricity Outlook*, the ISO New England projected that 4,200 MW of non-gas resources, an amount equal to almost 15 percent of the region's current generating capacity, will retire between 2012 and 2020, citing profitability and other factors. These megawatts are being replaced primarily by new natural-gas-fired plants. Over 5,500 MW of additional oil and coal capacity are at risk for retirement in coming years, not including the additional uncertainty surrounding the future of 3,300 MW from the region's remaining nuclear plants. Major generator retirements limit the ISO New England's options for meeting winter peak demand.[35] Further, ISO New England has also foreshadowed that without timely investment to expand natural gas or LNG infrastructure, the region should expect more frequent instances when the gas

[34]See, 2014 Integrated Resources Plan for Connecticut, dated March 17, 2015, ES-ii.
[35] ISO New England, 2017 Regional Electricity Outlook, p. 27 and 28. https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf

pipelines are constrained. ISO New England acknowledged that increased natural gas pipeline constraints can lead to price volatility.[36]

ISO New England indicated that it is already "skating by on the coldest days."[37] With over 35,000 MW of regional generating capability, demand resources, and imports, meeting New England's winter peak demand of roughly 21,000 MW, plus a reserve margin of about 2,600 MW, should be routine for ISO New England system operations. However, despite sufficient capacity and some relatively mild winters, ISO system operators have actually had to manage very tight operating conditions over recent years. To keep the power flowing, the ISO New England has relied heavily on non-gas-fired generators and had to implement special operating procedures to increase power supply and reduce demand several times when energy from available resources was insufficient. The ISO New England indicated this risk will increase after the upcoming scheduled generator retirements. Among the possible events the ISO has to prepare for during extreme temperatures are: fuel constraints that can sideline thousands of megawatts of natural-gas-fired generation; mechanical problems for some of the region's aging non-gas-fired generators; reduced imports from neighboring grids dealing with the same weather; and delays of oil and LNG deliveries. If a perfect storm of these problems were to occur, ISO New England system operators could be forced to use more extreme measures including ordering controlled power outages.[38]

The ISO New England has concluded that timely solutions to the problem of natural gas pipeline constraints are imperative for this major challenge to the regional power system.[39] On January 17, 2018, ISO New England published an Operational Fuel-Security Analysis (Fuel Security Study) which evaluated the level of operational risk posed to the power system by a variety of potential fuel-mix scenarios. In the Fuel Security Study, ISO New England has confirmed and quantified its concerns raised in the *2017 Regional Electricity Outlook* and has declared that fuel-security risk (i.e., the possibility that power plants do not have secure access to the fuel they need to run, particularly in winter) is the foremost challenge to a reliable power grid in New England. ISO New England studied a wide range of possible future power system conditions during the winter of 2024/2025 to determine whether enough fuel would be available to meet demand and to evaluate the operational risks. The ISO New England concluded that energy shortfalls due to inadequate fuel would occur with almost every fuel-mix scenario

[36] ISO New England, 2017 Regional Electricity Outlook, p. 25 and 31.
[37] ISO New England, 2017 Regional Electricity Outlook, p. 29.
[38] ISO New England, 2017 Regional Electricity Outlook, p. 29.
[39] ISO New England, 2017 Regional Electricity Outlook, p. 23 -26. Some pipeline capacity was added in 2016 and more is expected in 2017 to serve increased demand from retail gas customers. Over the next few winters, some of this capacity will likely be available for generators on the coldest days, helping to lessen fuel supply concerns and associated volatility in wholesale electricity prices. However, eventually this extra capacity will likely be used for heating as gas utilities sign up more customers. To compound matters, electricity-related demand is expected to increase as well, as new natural-gas-fired generators fill the void of retiring non-gas-fired power plants. In other words, though the pipeline "pie" may be getting bigger, there will be more mouths to feed. When it comes to the power system's ability to meet electricity demand on the coldest days, the results may be a wash. Id.

in winter 2024/2025, requiring frequent use of emergency actions to keep power flowing and protect the grid.[40]

Among the various hypothetical outcomes analyzed in the Fuel Security Study, ISO New England modeled a season-long loss of the Millstone Station under different resource mix scenarios, including a scenario of low retirements/moderate levels of other variables (Reference Case) and, at the other extreme, a combination scenario with maximum retirement levels and maximum levels of renewable penetration on the system (Max Case). To assess the risks, the ISO New England quantified the amount of hours it would need to implement several key emergency actions, including public requests for energy conservation, load shedding (i.e., rolling blackouts), as well as the number of hours when the ISO New England would have to deplete 10-minute reserves to keep the lights on.[41]

Specifically with regard to the Millstone Station, ISO New England concluded that without this baseload resource, more resources that use other fuels, including natural gas, oil, and LNG, would be needed more often, depleting their fuel sources. As a result, the loss of Millstone would require 47 hours of load shedding over 10 days in the Reference Case. If Millstone were unavailable for a whole season in the Max Case, more renewables would help when available, but the absence of the retired coal- and oil-fired generators coupled with the nuclear outage would mean virtually all the power plants with stored fuel in New England would be unavailable, resulting in 70 hours of load shedding over 12 days. Simply put, even the highest assumed potential levels of LNG, oil, imports, and renewables would not avoid load shedding in New England if a major energy facility such as the Millstone Station, is not operational for a prolonged period of time.[42]

In summary, the decline of natural gas commodity prices, coupled with increased investment in gas-fired power generation in New England, has caused wholesale electricity prices to drop to historic lows in the region. Ratepayers are enjoying the benefits of lower generation rates as a result. Meanwhile, non-gas power plants, such as nuclear units, that are particularly dependent on energy market revenues (and were very profitable during periods of higher natural gas prices) have seen their profitability decline. These trends have contributed to retirements of coal, oil, and smaller (single unit) nuclear power plants in New England, which are being replaced with new natural gas power plants.[43] Given New England's unique circumstances of limited natural gas pipeline infrastructure in the region, increased dependence on natural gas generation has exposed the region to price volatility and threats to reliability. As a result of inadequate infrastructure, the ISO New England has identified significant fuel security risks expected

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[40] See, Fuel Security Study, pp. 1-5. https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[41] See, Fuel Security Study, pp. 28-31, 42.

[42] See, Fuel Security Study, pp. 42, 43-45

[43] Nationwide, since 2013, five nuclear power stations have closed and nine have announced shutdowns in the near term. These trends do not signify, however, that all merchant nuclear generators are unprofitable, as each nuclear generator is subject to a unique mix of financial, regulatory, and engineering requirements and influences.

in the region, as early as 2024. Further, the ISO New England has concluded that significant amounts of load shedding in the region are unavoidable in the event of a retirement of the Millstone Station.

IV. SUMMARY OF RESULTS FROM LAI ASSESSMENT

Pursuant to the combined requirements of the Executive Order 59 and the June Special Session Public Act 17-3, DEEP and PURA retained LAI to help assess:

- The current and projected economic condition of nuclear generating facilities located in the ISO New England region;
- The role of zero emission generation facilities like nuclear, large-scale hydropower, demand reduction, energy storage, and zero emission renewable energy in helping the state meet its greenhouse gas emissions reductions goals and maintaining the reliability of the electric grid; and
- The impact on the electric markets, fuel diversity, energy security, grid reliability, the state's greenhouse gas emissions, and the state, regional and local economy if those nuclear generating facilities retire.

This section summarizes these findings.

A. Current and Projected Economic Condition of Millstone

There are significant inherent difficulties in confirming the actual economic financial viability of particular nuclear generators in a restructured environment. Unlike in a cost-of-service regime, where state commissions would have the ability to review the financial information of a regulated generator to assess its revenues, operating costs, and profitability, merchant generators are not required to provide financial information to regulators. Owners of merchant generation bear all of the risks and rewards of operating in a competitive market, and they and their shareholders—not state regulators—make the determination of what is a sufficient return on their capital investment. Merchant generators' financial goals may exceed the regulated rate of return earned by cost-of-service generators, given merchant generators' exposure to the risks of low energy prices, unplanned outages, and other costs that a regulated generator can recover from electric ratepayers. Ultimately, these financial goals are unknown to state regulators in a deregulated market.

Such is the challenge in assessing the financial viability of Millstone, and the advisability of mechanisms that would shift some of the risk of energy price volatility to the ratepayers of Connecticut.

On August 15, 2017, DEEP and PURA issued data requests to Dominion seeking information relating to expected performance, revenues, and expenses of Millstone, along with other financial and decommissioning information about Millstone. On September 1, 2017 and September 19, 2017, Dominion responded to a limited number of the data requests and shared publicly available information relevant to certain questions. In response to many of these data requests, Dominion declined to provide "competitively sensitive or proprietary information."[44] Consequently, DEEP and PURA directed LAI to proceed by utilizing the best available information in order to complete the assessment by February 1. Thus, LAI was limited to modeling Millstone's financial viability using the best publicly available information. The information, analyses, and recommendations contained in this assessment must be viewed through that lens.

While Dominion did not respond fully to the DEEP and PURA's data requests, as noted above, it did provide some financial projections of costs and revenues for Millstone, in submissions on November 30, 2017 and on January 10, 2018. Dominion provided a two-page, high level document with forward looking financial projections on November 30, 2017 that lacked the standard documentation supporting the projections concerning its actual financial condition. On January 10, 2018 Dominion submitted a more detailed document with forward looking financial projections. Dominion did not provide the specific data or documentation (e.g., audited financial data) sought in the data requests in this proceeding regarding verifiable projected costs and expected revenues of Millstone. Dominion's confidential information was limited to a short- to intermediate-term assessment, while the LAI analysis covers a longer-term assessment of Millstone through 2035.

DEEP, PURA, and LAI have reviewed the information submitted by Dominion on November 30, 2017, and have considered that information in comparison to LAI's technical analysis of Millstone's economic viability. DEEP and PURA have also reviewed comments received from Dominion Energy (including the January 10, 2018 Dominion submission) and other stakeholders on the cost assumptions used by LAI in their analysis.

The current and projected economic condition of Millstone hinges on two things: revenues and costs. Specifically, a profitable and viable nuclear power plant will have revenues that exceed costs over time, generating a return on investment to the plant owner that meets their business portfolio and investor needs.[45] As with any assessment based on market projections, determining viability cannot be conclusively determined. Even the most careful analysis is fraught with uncertainty, since revenues and/or costs in the future will not precisely follow modeled projections. This element of uncertainty and

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[44] Dominion Energy, Response to Data Requests, Second Set, DEEP's "Governor's Executive Order Number 59: DEEP and PURA Joint Proceeding," PURA Docket No. 17-07-32, "DEEP and PURA Joint Proceeding to Implement the Governor's Executive Order Number 59" (Sep. 19, 2017).

[45] In regulated markets the expected costs and revenues for a facility are reviewed by a public utilities commission, which sets the return on the investments in the facility. But in deregulated markets, such as the one in which Millstone operates, the public does not have direct access to a facility's expected costs and revenues, nor is there a regulated rate of return on investments. Due to higher risk of merchant generators in deregulated systems, it is reasonable to assume that facility owners, i.e., Dominion in the case of the Millstone units, would expect higher rates of return than what are set/allowed in regulated markets.

how it is viewed causes one person to look at the potential viability and to proceed, and another to look at it and decline to proceed.

A consequential assumption in the analysis is that LAI estimated the going forward economic condition or viability of the Millstone units, and in doing so treated all historical investments in the units as sunk costs for which recovery and a return are not included/required.[46] Based on this analysis, the LAI Assessment concludes that the Millstone units will be profitable over the period 2021 through 2035. Under the base case assumptions, the profitability is expected to amount to a net present value of $2,373 million in 2017. Even under the most unfavorable assumptions, Millstone's profitability falls to a net present value of $1,282 million in 2017.[47]

2. Estimate of Millstone's Going Forward Operating Costs

The LAI Assessment estimates the operating costs that the Millstone units can expect to face over the period from 2018 through 2035. Since the LAI Assessment concludes that Dominion is highly unlikely to retire its Millstone units prior to May 31, 2021, the focus period of the cost analysis is 2021 – 2035.[48] Since Dominion did not provide unit-specific verifiable projected costs and expected revenues of Millstone to DEEP and PURA in response to our data requests, LAI used public sources of information in order to develop reasonable indicators of Millstone's operating costs. Such a process of determining operating costs is necessarily second best and creates more uncertainty as to the likelihood of the resulting projections. In drawing its conclusions as to these expected revenues, the LAI Assessment explains the assumptions that were used, including assumptions regarding going forward fuel costs, O&M expenses, capital expenditures, depreciation, taxes, general and administrative expenses, and insurance expense.[49]

Based on the assumptions made, the LAI Assessment concludes that the going forward costs of the Millstone units are likely to range from approximately $625 million to $750 million per year most years during the focus period.[50] Alternative assumptions/scenarios included high capital expenditure scenarios (10 percent higher and 25 percent higher) and a high total cost scenario, where all costs were increased 10 percent.[51] Based on these alternative assumptions, the LAI Assessment concludes that the costs facing the Millstone units in the high total cost scenario would increase expenses in the low gas revenue scenario (i.e., the "worst case scenario" for Dominion profits) by around $30 million annually.[52]

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[46] Sunk costs refer to costs/investments that were historically incurred and cannot be undone, and, thus, have no bearing on the going forward considerations of merchant facilities in an unregulated market. These sunk costs are distinct from going forward capital expenditures that have yet to be spent and are a key component of the going forward consideration.
[47] LAI Assessment, pp. 83 – 90.
[48] LAI Assessment, p. 29.
[49] LAI Assessment, pp. 61 – 77.
[50] LAI Assessment, pp. 84 – 85.
[51] LAI Assessment, pp. 77 and 78.
[52] LAI Assessment, pp. 88 - 90

None of these alternative cost scenarios/assumptions considered the possibility that the Millstone units will have to invest in additional operational and/or technological controls to minimize adverse environmental impacts associated with the operation its cooling water intake structures as part of its National Pollutant Discharge Elimination System (NPDES) permit renewal. Since the imposition of new controls would mean incurring costs ranging from a hundred million to over a billion dollars, it is difficult to incorporate these potential NPDES requirements into a meaningful probabilistic scenario. As such, these potential requirements sit outside the analysis and, if required, would likely materially change the expected cost requirements presented above.

As noted above, DEEP and PURA received submissions from Dominion and several comments on the LAI assumptions and analysis of Millstone's going forward operating costs. Some commenters asserted that LAI's choice of Dominion's Virginia nuclear stations as proxies for operating and maintenance (O&M) costs underestimated actual costs at Millstone due to regional differences in the cost of labor, differences in design between the two Millstone operating units, and physical differences in site characteristics. Dominion also commented that the estimates used for general and administrative (G&A) costs were not reflective of the actual cost of corporate support provided to its nuclear stations, including Millstone. Other commenters also noted that the enactment of federal tax law changes in late December 2017 (after the Draft Report was issued) could significantly enhance Millstone's profitability. As stated in the LAI study, the actual financial information for these costs at Millstone is not publicly available, and Dominion declined to provide the specific auditable financials when requested by DEEP and PURA. As such, it is not possible to verify the commenters' assertions.

Although received very late in this proceeding, in recognition of the variability in nuclear station costs and in considering comments on the draft report, DEEP and PURA evaluated the Dominion submission by conducting a series of high-level sensitivity scenarios, in which the LAI cost assumptions were adjusted using the alternative cost proxies, and in which rough assumptions on the impact of the recent federal tax law changes were applied. These sensitivity scenarios suggested that, if accurate, the cost assumptions asserted in Dominion and others' comments could have a significant impact on Millstone Station's profitability, such that the financial viability of Millstone's continued operation could be at risk. Again, however, more detailed and auditable financial data is necessary to verify the accuracy of actual costs to warrant changing inputs to the LAI model. If such costs were verified, the LAI model would need to be rerun with the changes incorporated in order to determine whether the conclusion of the LAI Assessment—that the Millstone units are profitable—should be changed. The LAI model is more comprehensive than the necessarily simplified sensitivity scenarios conducted by DEEP and PURA. Constraints imposed by the timing of the Dominion submissions, the need for verification, and complexity of the detailed LAI analysis made it impossible for DEEP and PURA to verify the asserted cost assumptions in this proceeding.

1. Projected Market Revenues

The LAI Assessment lays out in detail the energy, ancillary services, and capacity revenues that the Millstone units can expect to receive from 2018 through 2035. Total combined revenues per year, includes both energy market and capacity market revenues, range from $200 million to over $350 million over the 2022 to 2034 time frame.[53] Based on the assumptions made regarding going forward natural gas and other fuel prices, new renewable projects to be built and other new entry, electricity load, and generator retirements, the LAI Assessment concludes that the **energy market revenues** available to the Millstone units average around $40 per MWh in 2017 real dollars over the period from 2018 through 2035.[54],[55]

Given the uncertainty surrounding the base case assumptions and resulting revenues, the LAI Assessment tested the base case assumptions using through comparison to alternative scenarios. These alternative assumptions/scenarios included a high-cost gas price scenario, a low-cost gas price scenario, a scenario assuming greater new renewable projects, and a high penetration of electric vehicles scenario.[56] Based on these alternative assumptions, the LAI Assessment concludes that the energy market revenues available to the Millstone units range from a low of around $30/MWh (roughly $500 million annually) (low gas scenario) to a high of around $60/MWh (roughly $1 billion annually) (high gas scenario).[57]

In addition to energy market revenues, the Millstone units also get **capacity market revenues** in the form of a base capacity payment and a capacity performance payment (CPP). Based on its assumptions regarding the capacity market, the LAI Assessment projects capacity market revenues in the range of $6-$8/kW-Month (approximately $150 million to $200 million annually) over the period 2018-2035. The LAI Assessment recalculated this result based on its alternative assumptions/scenarios and noted somewhat higher capacity revenues under a low gas scenario and somewhat lower capacity revenues under a high gas scenario. Given the role of the capacity market to recover “missing money” from the energy market, these results are to be expected. The LAI Assessment also assessed the Millstone units’ exposure to penalties for unit nonperformance during shortage events stemming from the CPP and concluded that while such penalties could be significant the more likely outcome is a net positive for nuclear resources.[58]

As noted above, several commenters correctly indicated the enactment of federal tax law changes in late December 2017, subsequent to the release of the LAI Assessment, could significantly enhance Millstone’s profitability. It should be observed that while the tax changes will favorably impact the profitability of the Millstone units, the impact is somewhat complicated by the dynamic nature of the economic impact. For example, expected capacity revenues would likely decrease as the cost of entry of new units into

[53] LAI Assessment, p. ES-3.
[54] LAI Assessment, pp. 1 – 19.
[55] LAI Assessment, p. 34.
[56] LAI Assessment, pp. 19 – 29.
[57] Amounts in 2017 real dollars over the period from 2018 through 2035. LAI Assessment, pp. 35 - 38
[58] LAI Assessment, pp. 49 – 60.

the market decreases. There was not sufficient time remaining in this proceeding to model the impact of those potential second order effects.

B. Retirement/Replacement Scenarios

Executive Order No. 59 required DEEP and PURA to assess "the role of zero emission generation facilities like nuclear, large-scale hydropower, demand reduction, energy storage, and zero emission renewable energy in helping the state meet its greenhouse gas emissions reductions goals and maintaining the reliability of the electric grid." Public Act 17-3 called on DEEP and PURA to assess "the impact on the electric markets, fuel diversity, energy security, grid reliability, the state's greenhouse gas emissions, and the state, regional and local economy if [nuclear power generating] facilities retire." In this Proceeding, DEEP and PURA are assessing these combined requirements by modeling three so-called "replacement scenarios." Separate and independent from the assessment of the financial viability of the Millstone units, per Dominion's response to information requests, these replacement scenarios *assume* that both Millstone units retire,[59] and evaluate the impacts on greenhouse gas emissions and GWSA compliance, electric reliability, fuel security and fuel diversity, and the state, regional, and local economy under three different scenarios.

In the first scenario, a "**0% Replacement**" scenario, both Millstone units retire, Connecticut takes no independent action and the Millstone capacity is replaced, as needed, through the regular function of the ISO New England competitive markets. The Millstone retirement is not expected to trigger the need for new capacity in Connecticut; however, the reserve margin in New England falls below the requisite ISO New England Net ICR level. Based on energy market forces, natural gas-fired combined cycle plants will be added to meet the Net ICR requirement and no incremental clean energy resources will be added in Connecticut.[60]

In a second scenario, called the "**25% Replacement Scenario,"** both Millstone unites retire, and Connecticut takes action to replace 25 percent of output of the Millstone units with zero-emission resources. Recall that Connecticut currently "counts" only 25 percent of the zero-emission aspect of Millstone's production towards its GWSA compliance. The 25 percent level preserves Connecticut's current status quo relative to the thresholds set in the GWSA since Connecticut counts 25 percent of the Millstone output towards those thresholds. For purposes of this analysis, the LAI Assessment assumes the Millstone units retire effective June 1, 2021 and that utility-scale solar and energy efficiency/passive demand response (EE/PDR) resources are procured by the Connecticut EDCs to replace 25 percent of Millstone's energy production with non-emitting energy resources. The remainder of Millstone's energy production will be replaced by merchant gas-fired additions as needed. Of the additional non-emitting energy resources, one half of the output (a capacity of 1,206 MW) is assumed to be utility-scale solar procured at a

[59] Dominion responses September 1, 2017 and September 11, 2017.
[60] LAI Assessment, p. 95

weighted levelized price of $96.40 per MWh (2017 dollars)[61] for energy and RECs combined and one half of the output (a capacity of 339 MW) is assumed to be EE/PDR projects procured at a weighted levelized price of $59.27 per MWh[62] for energy and RECs combined. These non-emitting resources are assumed phased in during the years 2020 through 2023.[63]

In a third scenario, a "**100% Replacement Scenario**," both Millstone units retire, and Connecticut takes action to replace 100 percent of the output of the Millstone units with zero-emission resources. In this case, it is assumed that hydropower resources in Canada are paired with incremental high-voltage direct current (HVDC) transmission capacity, and off-shore wind (OSW) resources are added, along with solar and EE/PDR resources above the levels from the 25 percent Replacement Scenario. As with the 25 percent Replacement Scenario, these resources are phased in over several years around the time of the Millstone units' retirement.[64]

All three of these scenarios are compared to a "**Reference Case**," which assumes that the Millstone units remain operational, without any intervention, through 2035. The reference case assumptions are detailed in the LAI Assessment.[65] Note that the Reference Case, and all of the Replacement Scenarios, assume that the New England states deploy planned clean energy investments to meet currently established policies, separate and apart from any nuclear replacement effort. Specifically, it is assumed that certain OSW projects will be built, including 1600 MW in Massachusetts, and that New England states' RPS requirements are met. As discussed in more detail in the LAI Assessment, the utility scale solar, the energy efficiency resources and some of the natural gas generation resources in the various replacement scenarios are assumed to be built in Connecticut.

The detailed assumptions and findings of each Replacement Scenario, and comparisons to the reference case, are presented in the LAI Assessment. A few of the key findings are excerpted below.

1. GHG Emissions and GWSA Compliance

Currently, Millstone provides far and away the largest single source of zero carbon energy in Connecticut and New England. The Nuclear Energy Institute (NEI) estimates that the power generated by Millstone prevents the release of 8.3 million metric tons of carbon dioxide annually. NEI further estimates that, by 2030, the continued operation of Millstone will have provided more than $6 billion in avoided emissions based on the EPA's

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[61] PPA costs for solar projects are based on the average of all selected projects from both the Clean Energy RFP and the small-scale (2-20 MW) renewable procurement under P.A. 15-107 Section b. LAI Assessment, p. 92.
[62] EE/PDR costs are based on one such project selected in the 2-20 MW renewable procurement. Id.
[63] LAI Assessment, pp. 91, 92, 96 and 97.
[64] LAI Assessment, p. 107.
[65] LAI Assessment, pp. 3 – 19.

Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, published in July 2, 2016.[66]

Analysis in the LAI Assessment shows that in the Reference Case, with the Millstone units retained in the generation mix, annual CO_2 emissions for New England decline over the modeling horizon[67] reflecting the assumption that Connecticut and the region will continue to make progress in deploying the additional energy efficiency, renewable energy, and other zero-emission resources needed and independently planned to achieve long-term emission reduction goals.

However, the LAI Assessment shows that in the 0% Replacement Scenario, if Millstone retires in 2022, annual CO_2 emissions in the region increase by more than 80 million short tons, or approximately 25 percent, over the modeling time horizon.[68] Most generic modeling of carbon emissions avoidance assumes that, in the event of the shutdown of a nuclear power station, replacement power would be provided by new, highly efficient gas-fired generation. However, New England's natural gas pipeline infrastructure capacity deficiencies suggest that even though the LAI modeling assumes that natural gas generation will replace nuclear power stations, there may simply not be enough pipeline capacity to support that generation reliably, such that Millstone's nuclear power would be replaced by oil or coal units that are too expensive to run otherwise.[69] This suggests that carbon emissions after a shutdown will be significantly higher than the models assume.

2. Ratepayer Costs of Replacement Scenarios

Under the reference case, the LAI Assessment assumes/concludes that the Millstone units are profitable under market revenues, that the units do not retire and that, therefor, there is a relatively limited need for incremental new capacity. As such, the LAI Assessment shows the reference case as a "zero cost case" and compares the various Replacement scenarios to this case.[70]

Compared to the reference case, the 0% Replacement Scenario increases the energy cost-to-load for Connecticut by $292 million (2017 dollars) and the capacity cost-to-load for Connecticut by $427 million (2017 dollars) for a total increase in ratepayer cost of roughly $719 million present value (2017 dollars).[71]

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66 *Millstone Generates Billions in Annual Benefits for New England*, Nuclear Energy Institute, January 12, 2017, available at https://www.nei.org/News-Media/News/News-Archives/2017/Millstone-Generates-Billions-in-Annual-Benefits-fo.
67 LAI Assessment p. 41.
68 LAI Assessment, p. 109.
69 This assumes that there is coal fired generation at all. After the retirement of Brayton Point (1527 MW) in May 2017 and planned conversion of Bridgeport Harbor (468 MW) in June 2019 there will only be approximately 268 MW of coal generation in New England.
70 LAI Assessment, pp. 110 – 115.
71 LAI Assessment, p. 95.

Compared to the reference case, the 25% Replacement Scenario increases the energy and capacity cost-to-load for Connecticut by a total ratepayer cost of roughly $600 million present value (2017 dollars).[72] Since this scenario assumes resources are procured by the Connecticut EDCs to replace 25 percent of Millstone's energy production with non-emitting energy resources, there are additional above market costs involved. The LAI Assessment calculates these costs to be approximately $1.2 billion present value (2017 dollars) for a total ratepayer cost of approximately $1.8 billion present value (2017 dollars).[73]

Compared to the reference case, the 100% Replacement Scenario increases the energy and capacity cost-to-load for Connecticut by a total ratepayer cost of roughly $250 million present value (2017 dollars).[74] Since this scenario assumes resources are procured by the Connecticut EDCs to replace 100 percent of Millstone's energy production with non-emitting energy resources, there are additional above market costs involved. The LAI Report calculates these costs to be approximately $5.2 billion present value (2017 dollars) for a total ratepayer cost of approximately $5.5 billion present value (2017 dollars).[75]

None of the reference cases considered the feasibility of siting or constructing the replacement technologies. DEEP and PURA recognize that siting 1,206 MW of solar in Connecticut for the 25% Replacement Scenario and the 2,421 MW of solar in the 100% Replacement Scenario would present a challenge. DEEP and PURA also recognize that siting the necessary gas infrastructure into Connecticut to supply the fuel for the added combine cycle plants would be challenging.

DEEP and PURA received several comments from stakeholders contending that the LAI Assessment overstates the price of renewables in its Replacement Scenarios, and that the prices are higher because the resources would be phased in quickly from 2020 through 2023, rather than at a slower pace. The assumptions used for the price of renewables (and all other assumptions in the Assessment) were based on the best publicly available information. Moreover, if Millstone were to retire, zero carbon resources would need to be built quickly to replace Millstone to remain in compliance with GWSA targets and support regional reliability.

3. Fuel Diversity and Fuel Security

The ISO New England's submission indicates that if Millstone were to retire, Connecticut would still be well long of its local resource requirement. Therefore, the potential exists that, after a reliability review, the ISO New England may not find the capacity of the Millstone station needs to be retained for reliability reasons. However, the loss of Millstone's 2,200 MW would cause the reserve margin in New England to fall below

[72] LAI Assessment, p. ES-9.
[73] Id.
[74] Id.
[75] Id.

the requisite ISO New England Net Installed Capacity Requirement (ICR) level. Based on energy market forces, natural gas-fired combined cycle plants may be added to meet the Net ICR requirement and no incremental clean energy resources will be added in Connecticut.[76]

As discussed in more detail in Section III-Market Trends, the ISO has identified that the loss of the Millstone Station – even for a single season – would result in persistent energy shortages that would require frequent and long periods of rolling blackouts. Since the ISO New England currently interprets its tariff as not providing for a reliability need based on fuel security, the ISO does not appear to have a mechanism in place to retain the Millstone Station in the event a retirement election is made.

3. Socioeconomic Impacts

Based on its analysis and assumptions, the LAI Assessment found that in the Reference Case, continued operation of Millstone creates in-state annual outputs of $350.7 million (2017 dollars) through 2032 before tapering down for a total present value of $4.2 billion from 2018 to 2040. Contrasted with a scenario that has the Millstone units retiring in mid-2021, where the net present value is $1.5 billion, continued operation is net beneficial in terms of in-state output by $2.7 billion. This net beneficial amount is primarily attributable to increased employment at the Millstone units and the accompanying income multiplier effect of such employment. The $2.7 billion net benefit amount is reduced to the extent laid-off Millstone workers under a retirement scenario might be absorbed by defense contractors in search of skilled local labor,[77] although a number of commenters suggested that this was an overly optimistic assumption by LAI.

The LAI Assessment did not directly analyze the benefit of in-state spending on zero emissions resources in the 25% and 100% Replacement Scenarios. However, the LAI Assessment did observe that the level of employment in solar, wind, and incremental EE/PDR would create new jobs during the construction phase. Employment would be limited, for those investments, during the operational phase of these resources.[78]

Millstone employs approximately 1100 workers (average salary about $167,000) and perhaps 400 more contractors in one capacity or another. An analysis by the NEI states that Millstone provides economic benefits of about $1.3 billion in Connecticut and another $1.3 billion to the rest of New England. This figure is derived from totals of the direct economic benefits such as salaries to workers, local and state tax revenues, and other goods and services purchased by Millstone for its operations as well as the indirect benefits to the state and region from lower electricity costs and the ripple effect on the greater economy from its direct benefits.[79] A separate analysis of the annual economic

[76] LAI Assessment, p. 95.
[77] LAI Assessment, pp. 116 -121
[78] LAI Assessment, p. 116
[79] Nuclear Energy Institute study, “Economic Impacts of the Millstone Power Station” released January 2017.

benefit to the State of Connecticut from Millstone put the figure at $1.5 billion and that direct and secondary employment amounted to 3,900 jobs.[80] The Town of Waterford receives roughly $30 million per year in property tax payments from the Millstone units.[81]

V. POLICY OPTIONS

Executive Order No. 59 requires DEEP and PURA to assess the best mechanisms to ensure continued progress towards the state's GHG emission reduction targets, in the context of competitive wholesale and retail electricity markets, and considering ratepayer impacts. Furthermore, Public Act 17-3 requires DEEP and PURA to determine whether a competitive solicitation process for long-term contracts for energy, capacity, and/or environmental attributes should be conducted pursuant to that Act. In the Draft Report, issued on December 14, 2017, DEEP and PURA summarized several potential mechanisms (relevant to Executive Order No. 59), and the competitive solicitation process under Public Act 17-3. DEEP and PURA invited comment on these mechanisms, other mechanisms that should be considered under the executive order, the circumstances under which any mechanism should be employed, and the objectives or principles any mechanism should pursue.

Importantly, as the analysis above points out, Millstone provides benefits in terms of GHG emissions avoidance, fuel diversity, and fuel security, that are accrue to the entire New England region. Several potential mechanisms would share the costs of any policy supports across the region as well, through market rule changes that are within FERC's or the states' jurisdiction to enact. DEEP and PURA received comments from several stakeholders who urged that the state should not take action, but rather wait for a regional or federal mechanism to emerge.

As part of the Integrating Markets and Public Policy (IMAPP) stakeholder process initiated in 2016 by the New England power pool (NEPOOL), a variety of proposals have been advanced that would compensate for zero-carbon resources, including existing nuclear units, through the ISO New England markets.[82] These include, and are not limited to, proposals for a carbon adder (carbon price) in the ISO New England energy market, several variations of a Forward Clean Energy Market, including a proposal for a Dynamic Forward Clean Energy Market which the Conservation Law Foundation (CLF) has recommended DEEP and PURA to consider in this proceeding.[83]

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[80] CHMURA Economics & Analytics Report "The Economic Impact of the Millstone Power Station in Connecticut" dated October 4, 2016.
[81] LAI Assessment, p. 121.
[82] To view IMAPP proposals and related documents, please go to http://www.nepool.com/IMAPP.php
[83] Conservation Law Foundation, Comment (December 7, 2017), *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/34c5c3ac5a8ab66d852581ef00741ef2/$FILE/75596275.pdf

The states, through the New England States Committee on Electricity (NESCOE), have provided detailed, collective feedback on these proposals, including design objectives and priorities ("goal posts"). The states have raised concerns about the cost and efficacy of some of these approaches, such as the carbon adder, and the importance of not having one state pay for another state's public policy. It is beyond the scope of this report to repeat the states' concerns and feedback here, but it can be reviewed on the IMAPP website.[84] NEPOOL IMAPP meetings have been on hold pending the consideration of near-term ISO New England proposal that attempts to accommodate public policy resource entry into the forward capacity market.

Meanwhile, the U.S. Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) in September 2017, requiring FERC to consider a rulemaking that would provide cost recovery to coal and nuclear plants in states with deregulated markets purportedly to ensure that "reliability and resilience attributes" of those generation technologies are fully valued.[85] FERC received extensive comments on the NOPR. DEEP and PURA, through NESCOE and in separate comments, urged FERC to reject the DOE NOPR approach, which would upend competitive markets and override legitimate state jurisdictional interests in resource adequacy and environmental policies. Such comments also encouraged FERC, to the extent that it pursues a rulemaking, to allow the New England region to develop any needed market changes using appropriate processes within the region to tailor solutions and account for unique market designs and state public policy goals.

On January 8, 2018, FERC issued an order terminating the DOE NOPR and initiating a new proceeding to assess the resilience of the bulk power system in regions (like New England) that are operated by independent system operators (ISO). FERC concluded that the NOPR did not demonstrate that ISO tariffs were unjust and unreasonable, nor that its solution—cost-of-service rates for certain coal and nuclear generators, regardless of need or cost to the system—would be just and reasonable.[86] FERC initiated a new proceeding to, among other things, establish a common understanding of "resilience," investigate how RTOs and ISOs assess resilience, and consider whether any Commission action is appropriate regarding resilience. The new proceeding will focus on RTO/ISO submissions, due in the months ahead. Setting the merits (or demerits) of the DOE NOPR aside, it is clear that the NOPR will not be a viable mechanism for nuclear retention going forward.

Connecticut could undertake several actions that fall within its authorities and jurisdiction, or in coordination with other states acting within their respective authorities. The section that follows explores two potential mechanisms for supporting Millstone or

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[84] *See, e.g.* http://www.nepool.com/uploads/IMAPP_20170517_NESCOE_Memo_20170407.pdf. *See also* http://www.nepool.com/IMAPP.php.
[85] Notice of Proposed Rulemaking, Grid Reliability and Resiliency Pricing Rule, p. 1, FERC Docket No. RM18-1-000, (September 28, 2017).
[86] Order terminating rulemaking proceeding, initiating new proceedings, & establishing additional procedures re Grid Reliability & Resilience Pricing under RM18-1 et al. at 8-9, FERC Docket Nos. RM18-1-000, AD18-7-000 (Jan. 8, 2018).

other zero-emission resources to fulfill state policy objectives, including Power Purchase Agreements, Zero-emission Energy Credits, and multi-state coordination using either these tools or other state policy actions. Each of these methods has been successfully used in similar circumstances in Connecticut and other states.

1. Power Purchase Agreement (PPA)

One approach to stabilize revenues for an existing nuclear facility is the power purchase agreement (PPA). A PPA is a contract between a generator and a credit worthy counterparty, often a state regulated utility, usually an electric distribution company (EDC), that pays an agreed upon price for an agreed upon contract term for power, capacity and/or environmental attributes. The PPA can be for any portion of the generator's output. Importantly, the EDCs take ownership of the purchased power, and re-sell the power into the market. If energy prices are higher than the PPA price, the net profit is returned as a bill credit to ratepayers, saving them money. If the energy price is less than the PPA price, the net loss is charged to ratepayers, causing them to pay "above market" prices for energy. The gains or costs of the contract are recovered through utility rates. PPAs are common and used for a variety of purposes by utilities and other parties. DEEP and PURA have demonstrated that they can conduct an RFP and award a PPA in a short period of time.

PPAs are flexible tools. PPAs could be crafted to cover any time period between now and 2035, either through a specific term of the contract, or through successive contracts. A PPA can be tailored to the specific needs of a particular facility and the purchasing entity at that time. A PPA can be developed to recover the actual cost of service, or could offer a fixed price based on bids into a competitive procurement, or amounts agreed upon in negotiations.

Connecticut currently has legal authority under the Act to conduct a procurement (after the required assessment and making the required determination of need) for a variety of zero carbon resources like Class I renewable energy sources, nuclear, and hydropower, and to require the EDCs to enter into PPAs for those resources.[87] Some stakeholders submitted comments encouraging DEEP and PURA to consider other existing resources, such as hydropower and energy storage, as a potential solution to a Millstone retirement. Those resources are eligible to compete in any solicitation issued under the Act.

Connecticut has used similar statutory procurement and PPA authority in the past in the advancement of state energy and environmental policy goals, and has demonstrated that these types of PPAs fit within the state, federal, and ISO New England regulatory framework and market rules.[88] Finally, PPAs can be designed to promote efficiency and economic effectiveness. For example, a fixed price PPA only pays the generator when it actually produces power; a cost of service PPA would only pay the generator what is needed to operate, plus a reasonable rate of return.

[87] June Special Session Public Act 17-3, Section 1(d) and Section 1(e)(1) and (2).
[88] See *Allco v. Klee*, 861 F.3d 82 (2d Cir. 2017).

2. Zero-emission Energy Credits (ZECs)

In a broad sense, energy credits are payments made to electricity resources for particular attributes of the energy they provide. These payments are above and beyond the payments received for energy in the energy market and are only paid to resources that provide those attributes.

Connecticut currently uses Renewable Energy Credits (RECs) as part of its RPS.[89] New York recently developed a Zero-emission Energy Credit (ZEC) system for existing nuclear facilities that incorporates features similar to a REC but for which the price is set by looking at the extent to which the expected price of energy differs from $39 per /MWh, which may serve as a relevant model policy option for Connecticut.

In order to promote the development of clean energy as part of New York's effort to staunch global warning, the New York Public Service Commission (PSC) issued the Clean Energy Standard (CES) Order on August 1, 2016. The CES Order created two programs – RECs and ZECs – in furtherance of New York's goal to generate fifty percent of its electricity using renewable sources by 2030, and New York's broader goal to reduce greenhouse gas emissions economy-wide by forty percent by 2030.

Under New York's ZEC program, a ZEC is a "credit for the zero-emissions attributes of one megawatt-hour of electricity production by" an eligible nuclear facility.[90] Through the ZEC program, New York aims to "encourage the preservation of the environmental values or attributes of zero-emissions nuclear-powered electric generating facilities for the benefit of the electric system, its customers and environment."[91] In particular, the ZEC program ensures that New York's nuclear generators — which comprise thirty-one percent of New York's electric generation mix and collectively avoid the emission of over fifteen million tons of carbon dioxide per year — continue to contribute to New York's

[89] The foundation for Connecticut's renewable deployment efforts is the state's RPS, which was enacted as part of the Connecticut's electric restructuring legislation in 1998. A RPS creates a financial incentive for renewable energy projects by requiring electricity suppliers to purchase set quantities of renewable energy over time. The RPS thereby guarantees a market and potential stream of revenue for renewable generators. This incentive is called a REC, and provides additional revenue above the amount a developer would receive in the wholesale energy and capacity markets. When first conceived, RECs were meant to be the primary means to finance renewable generation. In theory, REC revenue plus energy revenues would provide the total revenues necessary to finance renewable projects. More recently, long term PPAs have taken over as the primary method to fund the development of grid-size renewable energy projects. New or existing nuclear generation is not eligible for RECs under any RPS class in Connecticut or any of the other New England states. DEEP believes that a separate class for these resources is preferable to including them in the current Class 1 RPS. Existing nuclear facilities need less of an incentive than that needed for new renewable generation facilities.
[90] CES Order, App'x E, p. 1, available at https://www.nyserda.ny.gov/ces
[91] Id.

electric generation mix pending the development of new renewable energy resources between now and 2030.[92]

Under New York's CES Order, a nuclear generator is eligible for ZECs if it makes a showing of "public necessity," i.e., the facility's revenues "are at a level that is insufficient to provide adequate compensation to preserve the zero-emission environmental values or attributes historically provided by the facility."[93] Any nuclear generator, regardless of its location, is eligible for ZECs, so long as the generator has historically contributed to the resource mix of clean energy consumed by New York retail consumers. The nuclear generators sell their ZECs to NYSERDA at a price administratively determined by the PSC. Load serving entities (LSEs) are required to purchase ZECs from NYSERDA in an amount proportional to their customers' share of the total energy consumed in New York. The LSEs pass the costs of their ZEC purchases to their ratepayers. [94]

ZEC prices are calculated by the PSC using the federal estimate of the social cost of carbon and a forecast of wholesale electricity prices. Specifically, for a two-year period, the price of each ZEC is the social cost of carbon, less the generator's putative value of avoided greenhouse gas emissions, less the amount of the forecast energy price. If the forecast wholesale price of electricity increases above the $39/MWh baseline, the price of a ZEC decreases. For the first two years of the ZEC program, from April 1, 2017, through March 31, 2019, the PSC has set the ZEC price at $17.48 per MWh. The New York ZEC program is a 12 year program broken into 2 year tranches.

A New York-style ZEC program, or a variation thereof, could be flexibly designed to only provide revenues when needed and to withhold them when not, because it requires participating generators to demonstrate need, i.e., open their books, in order to qualify for the subsidy. Furthermore, a ZEC program need not be limited to Millstone only, or nuclear plant retention only; it is versatile enough to include other nuclear facilities, such as Seabrook, and other zero carbon resources, such as large scale hydropower.

The New York-style ZEC program recently withstood legal challenge in New York federal court,[95] and would undoubtedly fit within the state, federal, and ISO New England

[92] According to the CES Order, losing the nuclear energy contributed by the generators before new renewable resources are developed "would undoubtedly result in significantly increased air emissions" and a "dangerously higher reliance on natural gas"; without the carbon-free attributes of the nuclear generators, New York would have to rely more heavily on existing fossil-fueled energy plants or the construction of new natural gas plants for its electricity, all of which would significantly increase carbon emissions. CES Order, pp. 123 The CES Order cited Germany as a case in point: when Germany abruptly closed its nuclear plants following the Fukushima nuclear disaster, the electricity that had formerly been produced by nuclear generation was replaced by electricity generated by coal, causing carbon emissions to rise despite a simultaneous and "aggressive" increase in solar generation. CES Order, pp. 19.

[93] CES Order, pp. 124.

[94] CES Order, pp. 127-128

[95] *Coalition for Competitive Electricity v. Zibleman, et al*, 16-CV-8164 (S.D.N.Y.) (July 25, 2017). https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/201_07_25_CCE_v_Zibelman_SDNY_ruling.pdf

regulatory framework and market rules.[96] Finally, ZECs are designed to promote efficiency and economic effectiveness – they only provide a subsidy after a demonstration of need. Moreover, a ZEC program could be implemented on a regional basis, and could be linked to the ZEC program currently under development in Massachusetts. A multi-state trading system for ZECs would regionalize the costs of nuclear retention, and would be more efficient and effective than Connecticut acting alone.

Both PPAs and ZECs have the *potential* to operate with multiple states through a coordinated effort. Massachusetts, Rhode Island and Connecticut have undertaken joint clean energy procurements in the past for new renewable and hydropower resources. For informational purposes only, we note that Massachusetts has finalized its Clean Energy Standard regulations and does not allow for existing generation with a vintage of 2010 or older (i.e., Seabrook or Millstone), to be eligible for a REC-like requirement on energy suppliers in Massachusetts.[97] It is important to underscore that there are no discussions under way among the New England states to engage in a coordinated procurement or ZEC program for existing nuclear resources.

3. Utilize Contracted Power for Retail Supply ("Cut out the Middle Man")

In response to the request for comments in this proceeding, DEEP and PURA received a letter, signed by 58 members of the General Assembly, urging the agencies to utilize the authority available in Public Act 17-3 to initiate a solicitation for bids from nuclear power generating facilities.[98] The letter from legislators focuses on the reliability and price benefits of nuclear generation during prolonged cold weather such as the region experienced in early January 2018. The letter asserts that Public Act 17-3 allows the state to seek bids from nuclear power generating facilities to "supply power to Connecticut electric consumers directly."

In fact, the Act did not confer on DEEP or PURA the authority to directly supply Connecticut retail customers with electricity from Millstone or any other resource eligible to bid under the Act, for that matter. The Act contemplates the utilities entering into medium- to long-term fixed-price contracts to purchase electricity and other resources from eligible generators. The utilities would take ownership of the electricity and re-sell it into the wholesale market. If the purchase price is below the market price, all Connecticut ratepayers receive a credit on the distribution portion of their electric bill. If the purchase price is above the market price, all Connecticut ratepayers pay the difference through a charge on the distribution rates. Given the large potential quantity of electricity that can

[96] Since RECs have been and presumably ZECs would be considered in-market revenues in the region, changes to these revenues could be considered a changed circumstance that the internal market monitor would use as a basis for allowing an alteration in a retirement delist bid.
[97] http://www.massdep.org/BAW/air/cesf-amend.pdf
[98] CT General Assembly comment letter, Jan. 9, 2018, available at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/039bf2acf6774b5785258210004c1254/$FILE/CT%20General%20Assembly%20Legislative%20public%20comment%20Executive%20Order%2059%20and%20PA%2017-3.pdf

be purchased under the Act—up to twelve million megawatt hours, equivalent to approximately 75 percent of Millstone's output and approximately 44 percent of Connecticut's total electric consumption of 27.5 million MWh—even a $0.01/kWh average annual difference between the market and contract price for the full twelve million megawatt hours would result in roughly a $120 million net annual charge or credit to ratepayers.[99]

As noted in the Resource Assessment, Connecticut's electricity deregulation statute gave all Connecticut customers the freedom to choose their electric supplier. Today, 49 percent of Eversource residential customers and 36 percent of United Illuminating residential customers as well as roughly 92 percent of commercial and industrial load for both utilities purchase their electricity from third-party suppliers in a competitive market. The remainder purchase from the utilities through the Standard Offer rate (for residential customers) or Last Resort Service (for commercial and industrial customers). In the mid-2000s, these utility offerings were procured through portfolios of three-year fixed price contracts: at any given time, the utility rate comprised a blend of costs for power purchased over the previous three years. As prices rose, this proved a viable strategy. When prices fell after 2007, however, Connecticut was burdened with long-term, and now very high-priced contracts. For this reason, in 2011 the General Assembly mandated a new utility procurement process, which ensures that the utilities purchase power for Standard Service and Last Resort Service on shorter terms that more closely follow market dynamics (e.g., no power is purchased more than one year in advance).

The Act did not alter or amend retail choice. There is no requirement for retail customers to buy electricity obtained by the utilities from a generator under the Act. If the utilities were to enter into a contract with Millstone under the Act, and the contract price turned out to be lower than market prices, the utilities could, in theory, use some of the purchased electricity for Standard Service or Last Resort Service. At the present time, however, UI does not have the capability to self-supply, and Eversource has suspended the practice. Moreover, customers on SS and LRS cannot be compelled to stay on those rates. If the Millstone price ended up being above market, SS and LRS customers would flee to competitive supply offers, such that the utilities would have to resort to the distribution charge to recover the costs of the Millstone contract from all ratepayers. If the Millstone price ended up being below market, only SS and LRS customers would reap those benefits of a lower retail rate. This creates an inequity where all ratepayers—including those on competitive supply contracts—would bear the risk of an above-market contract, and only some would benefit from a contract that turns out to beat the market price. If the legislature wanted a different arrangement, to avoid the retail "markup," they would have had to enact restrictions on customer retail choice.

DETERMINATION

[99] For the sake of comparison, the total cost of energy in 2017 was approximately $2.2 billion.

As required by the Section 1(b) of Public Act 17-3, DEEP and PURA must determine "whether a solicitation process for nuclear power generating facilities shall be conducted pursuant to the Act." This determination is predicated on the following findings:

- **Under the initial LAI analysis, the Millstone Nuclear Units are profitable under expected market revenues through 2035.** LAI utilized the best available public sources of information in order to develop reasonable assumptions with respect to Millstone's forward operating costs. Under the LAI base case assumptions, the profitability of the Millstone units is expected to be $2,373 million in net present value. Under the most unfavorable assumptions regarding the units analyzed in the LAI Report, the profitability is still $1,282 million in net present value. Recent federal tax law changes have improved the likely profitability, although the extent of that improvement is difficult to confirm without further modeling.

- **The finding that the Millstone Nuclear Units are viable and/or unlikely to retire is uncertain.** Sensitivities around the base case in the LAI Report – including low gas prices, higher costs, and unexpected capital expenditures – showed the potential for reduced profitability of the Millstone Nuclear Units. The choice of assumptions – including the operating similarities between the two Millstone units, regional costs of labor, and corporate, general, and administrative costs – greatly impact profitability. Additional first-order cost sensitivities conducted by DEEP and PURA confirm that, if true, Dominion's assertions with respect to these cost assumptions show a significant reduction to profitability, suggesting that potential returns on invested capital could be insufficient to justify continued operation of the Millstone units.

  Dominion's late-filed, unsubstantiated, summary data (submitted under protective order) suggests that the generating facility's profitability is low. Lack of access to audited operational data and costs caused by Dominion's incomplete response to the data requests in this proceeding creates uncertainty in the state's assessment of the financial viability of Millstone Nuclear Units. Dominion's unknown return requirements and expectations on return on investment could lead to an unanticipated retirement decision.

- **The Millstone nuclear units provide significant value, not just to Connecticut, but to the entire New England region.** DEEP and PURA evaluated impacts on fuel diversity, fuel security, and compliance with environmental goals, among other things, if the two Millstone units were to retire. Millstone's zero-carbon electricity generation is critical to meeting Connecticut's ambitious GHG emission reduction targets, as recently proposed by the GC3. The loss of Millstone would result in an increase in New England's annual carbon emissions by roughly 7 short tons, or over 80 million short tons over the period from 2021 to 2035.

  A loss of Millstone would likely cause an increase in regional electric price volatility and a materially decreased ability to reliably/safely operate the electric system during extreme winter conditions. The loss of Millstone would materially affect fuel diversity, which could make the wholesale energy market more dependent on natural gas. This would likely result in vulnerabilities in the electricity system during periods of increased natural gas demand (cold snaps) or reduced supply (supply disruptions). Present value wholesale market electricity costs, capacity and energy, are expected to be $719 million higher over the period of 2021 to 2035 if the two Millstone units were to retire.

- **Additional or new zero emission generating resources provide value to Connecticut and the New England region.** New zero emission generating resources, or incremental additions to existing zero emission resources like large scale hydropower, displace carbon emissions in Connecticut and New England, and are necessary to meet the GHG reduction targets of Connecticut's GWSA. New non-gas resources improve system fuel diversity and decrease the gas commodity and gas pipeline capacity needed to meet electricity demand. The Millstone replacement scenarios with new zero emission generation resources show reduced wholesale market electricity costs, capacity and energy, relative to a scenario where these resources are not procured. New in-state zero emission resources increase employment and state revenue as a result of construction and, to a lesser degree, the operating phase of those new resources.

- **Existing zero emission electricity generating resources provide benefits to Connecticut.** As a zero carbon resource, retaining nuclear power electric generation is critical to meeting Connecticut's GWSA emission reduction targets. Because Connecticut's electricity consumption is equal to 25 percent of the ISO New England system, Connecticut's electric sector GHG inventory currently accounts for only 25 percent of Millstone's zero carbon electricity output. However, because Millstone's environmental attributes are not currently under contract, Connecticut could contract directly with Millstone to purchase the environmental attributes beyond the 25 percent the state already accounts for, helping to meet the emission reduction targets in the GWSA. Other existing zero emission resources may be similarly situated.

- **The competitive solicitation process under June Special Session Public Act 17-3 is a reasonable mechanism through which to determine if it is in the interest of ratepayers to secure the value offered by new and existing zero emission resources.** The competitive solicitation process for power purchase agreement(s) (PPA) is already authorized by the General Assembly. PPAs are flexible tools and can be crafted for any particular term, pricing structure, facility and/or attribute or product. PPAs can be designed to promote efficiency and economic effectiveness. Furthermore, a competitive solicitation process does not mandate DEEP to select any particular resource or bid, if the results of the process do not demonstrate benefits to ratepayers.

Based on our comprehensive assessment of the Millstone nuclear generating facilities, the need to maintain zero-carbon resources in the state's electric generation mix in order to achieve the greenhouse gas emissions reduction targets set in the GWSA, and our appraisal of nuclear power generating facilities in New England, **DEEP and PURA conclude that pursuant to June Special Session Public Act 17-3, DEEP should conduct a procurement or procurements for new and existing zero carbon generation facilities, according to the conditions and structure outlined below**.[100]

Public Act 17-3 requires DEEP to evaluate bids based on price ("whether the delivered prices of sources included in such contract or proposal are less than the forecasted price of energy and capacity") and a variety of non-price criteria, including impacts on electric system reliability; contribution to local capacity requirements; contribution to meeting the Connecticut GWSA and other clean air requirements; fuel diversity; and contribution to other state policy goals (e.g., the Integrated Resource Plan and the Comprehensive Energy Strategy).

In the case of Millstone, and perhaps other existing resources, the findings of this proceeding show that there is some uncertainty as to the viability of certain existing resources and their continued operation as part of the current or reference case. For this reason, it is fair and prudent to allow existing resources to demonstrate through the submission of credible financial data that they are at risk to retire. The resource would then not be assumed part of the existing or reference set of resources. In the event of such demonstration, the existing resource would bid and be scored on the same set of non-price benefits as new resources.

DEEP will conduct a conduct a procurement or procurements for new and existing zero carbon generation facilities, according to the following conditions:

- <u>New Resources</u> will be scored based on both price and non-price criteria, as is typical with other DEEP resource procurements.

- <u>Existing Resources</u>, such as Millstone and Seabrook, which are not newly delivered to ISO New England, are eligible to bid into a procurement under Public Act 17-3. To the extent that these existing resources are assumed to be part of the current or "reference" set of generation resources in New England, their bids will only be scored based on price—in other words, whether the bid price is less than the forecasted energy and capacity price in the reference case. The non-price benefits of existing resources will not be evaluated and scored to the extent that they are not incremental.

- <u>Existing Resources Confirmed at Risk</u>. An existing resource, of greater than 100 MW, may elect to provide to DEEP and PURA credible evidence, such as audited financials, in a filing subject to an appropriate protective order. If DEEP and PURA conclude, based on review of this evidence, that the evidence is sufficient to support a finding that the resource is not profitable and will likely retire without ratepayer support, then the resource may be deemed an "existing resource

[100] This could include multiple procurements over many years to ensure Connecticut has sufficient zero carbon generation facilities to meet its GWSA targets.

confirmed at risk." In that event, the forecast of energy and capacity prices will reflect the assumed retirement of the at-risk resource by the relevant date, and a bid from the at-risk resource will be scored based on both price and non-price criteria.

Pursuant to Public Act 17-3, renewable and storage resources may receive contracts for up to 20 years in length, while hydropower and nuclear resources may receive contracts between 3-10 years in length. The aggregate total of all contracted resources may not exceed 12 million MWh annually. The criteria used for judging the bids may reflect that shorter contracts for smaller quantities represent significantly less risk for ratepayers. The bids could be structured so that contract terms may be extended for additional years at the election of the Commissioner (with the approval of PURA and subject to the evaluation requirements in the Act) at the original price term.

These and other details regarding contract terms, the bidding process (including the process for confirming that an existing resource is at risk of retirement), schedule, and the like will be presented for stakeholder comment in the normal course of DEEP's solicitation. If this recommendation is not rejected by the General Assembly, DEEP will initiate its solicitation sometime after the General Assembly's statutorily-mandated review of this determination under Section 1(b) of Public Act 17-3 (which must occur on or before March 1, 2018), and no later than May 1, 2018, as required by Section 1(d). As it has done in its previous procurements, the DEEP solicitation would include, among other things, a draft RFP and public comment period.

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Pursuant to a Notice of Request for Written Comments issued contemporaneously with this Draft Resource Assessment and Determination, DEEP and PURA now seek stakeholder comment on an expedited basis. DEEP and PURA will prepare a final Resource Assessment and Determination no later than February 1, 2018, for public issuance and submission to the Governor and the General Assembly. Section 1(b) of the Act provides that DEEP and PURA submit the appraisal results and determination to the Connecticut General Assembly on or before February 1, 2018. If the General Assembly does not reject the results by March 1, 2018, then the Resource Assessment and Determination is deemed approved.

ERRATA

The following graph is an erratum amending Figure 13 on page 17 of LAI's Resource Assessment.