October 13, 2023

VIA ELECTRONIC FILING

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: ISO New England Inc., Filing of 2024 Capital Budget and Revised Tariff Sheets for Recovery of 2024 Administrative Costs; Docket No. ER24-

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, Part 35 of the Rules and Regulations of the Federal Energy Regulatory Commission (the "Commission"), Section 12 of the Participants Agreement among ISO New England Inc., the New England Power Pool and any Individual Participants,[1] and Section IV.B.6.1 of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"),[2] ISO New England Inc. (the "ISO" or "ISO-NE") hereby submits its capital budget for calendar year 2024 (the "2024 Capital Budget") and a revised Section IV.A of the Tariff to reflect the collection of its administrative costs for calendar year 2024 (the "2024 Administrative Expenses Tariff"). The ISO requests that the Commission accept the 2024 Capital Budget and the 2024 Administrative Expenses Tariff, as filed, effective January 1, 2024.

Because the ISO is a non-profit entity without equity, it relies totally on collections under its Tariff to fund its operational expenses, including through depreciation. For this reason, the ISO is not in a position to make refunds should the Commission accept the 2024 Capital Budget or the 2024 Administrative Expenses Tariff for filing but set them for hearing subject to refund. That is, the only "refunds" that can be paid to ISO Customers during 2024 would have to be funded by additional charges to other Customers. For this reason, the ISO respectfully requests that the Commission accept the 2024 Capital Budget and the 2024 Administrative Expenses Tariff without suspension and not subject to refund.[3]

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[1] The Participants Agreement is available at https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf.

[2] Capitalized terms used but not otherwise defined in this filing have the meanings given them in the Tariff.

[3] This approach is consistent with NEPOOL's recommendation to the Commission that "contested budget increases should not be implemented subject to 'refunds'" because of the ISO's non-profit status, which means that any money spent "can only be reallocated among the stakeholders, negating any true refund." Comments of the New

The ISO respectfully requests that, should the Commission have any concerns regarding the 2024 Capital Budget or the 2024 Administrative Expenses Tariff, such concerns be resolved in an accelerated fashion and addressed in an Order issued prior to January 1, 2024. If the Commission decides to set any issues for hearing, the ISO requests that the Commission set the scope of any such hearing as specifically and narrowly as is feasible, and require a paper hearing process, to ensure conservation of ISO, stakeholder, and Commission staff resources.

I. ISO-NE's 2024 REVENUE REQUIREMENT AND REVISED SHEETS

A. Overview

This filing presents the 2024 Revenue Requirement[4] for operating the ISO. Before incorporating the true-up for 2022's actual expenses and collections, the 2024 Revenue Requirement is $276.9 million, which is $36.7 million more than in 2023. After the over-collection for 2022 is subtracted, the total 2024 Revenue Requirement decreases to $273.9 million. In comparison, the 2023 total – which was decreased by a larger over-collection – was $225.6 million.

In sum, the 2024 Revenue Requirement is 15.3% higher than in 2023 before the prior years' true-ups. When the two years' operating budgets are compared with inclusion of the true-ups, the 2024 Revenue Requirement is 21.4% higher than the 2023 Revenue Requirement.

For 2024, the most significant increases to the Revenue Requirement are (i) the continued preparation for the clean energy transition; (ii) costs of inflation and continued operations; and (iii) a net change in the Revenue Requirement true-up.[5] The specific elements of the first two drivers are discussed in more detail in Section I.C, below (explaining increases related to each strategic goal).

The 2024 Revenue Requirement represents the ISO's commitment to supporting the region as it transitions to clean energy and to ensuring that the organization's continued operations are efficient and reliable. As has been reported nationwide, the clean energy transition is creating increased grid complexity and competition for in-demand talent; the 2024 Revenue Requirement represents the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced

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England Power Pool Participants Committee at 3, Docket No. RM04-12-000 (Nov. 9, 2004) ("NEPOOL RTO Cost Comments").

[4] As used in this filing, "Revenue Requirement" refers to the combination of: the administrative costs of running the ISO (the "Core Operating Budget"); depreciation and amortization; and the true-up for past over-collection or under-collection in revenues versus expenses. Generally, numbers used herein are rounded for ease of reference and, accordingly, may not sum.

[5] *See* Budget Presentation at Slides 35, 42, 96 showing the net change in the Revenue Requirement true-up.

wholesale electricity, as well as developing new capabilities that will be necessary for supporting the grid of the future.[6]

On the supply side, substantial increases to the number of interconnected and behind-the-meter generating assets are changing how the transmission and distribution system operate and interact, and there is a shift from larger, dispatchable resources to smaller, non-dispatchable, weather-dependent, inverter-based resources. Additional resources connecting to the distribution system – outside of the ISO's current visibility – contribute to load variability and forecasting challenges.

On the demand side, changing load characteristics exacerbate operational complexity. With anticipated greater electrification of the heating and transportation sector, as well as installation of behind-the-meter photovoltaics and increased reliance on weather dependent resources, the ISO is observing and projecting new daily and seasonal demand patterns. Overall, it is projected that decarbonization goals will to lead to a grid with much higher loads, load-variability, and a much greater number of variable supply resources.

This changing resource mix will increase the ISO's workload in both the long- and short-term. By 2030, the ISO projects a doubling of installed capacity of solar resources, thousands of MW of planned offshore wind, substantial new transmission investment supporting inter- and intra-regional transfers, and a substantial increase in the number of energy resources integrated into the ISO markets per Commission Order 2222. Growing generation and fuel uncertainty will lead to an increased focus on energy adequacy efforts, and the changing resource mix will likely require different market designs. Additionally, as the New England region prioritizes the clean energy transition, there will be a greater focus on the ISO and its work and the need for more and different types of public and regulatory engagement.

Overall, the changes to the grid represent a step-up in system complexity that the ISO must be prepared to address in 2024 and throughout the remainder of the decade, specifically through handling greater administrative burdens, developing greater computational capacity, and designing more complex wholesale market products. The 2024 Revenue Requirement includes increases that explicitly support this clean energy transition through:[7]

- addressing the expanding interconnection queue and Commission Order 2023;
- investing in cloud capabilities to support data requirements for an increased number of resources;
- incorporating hybrid, storage, renewable, and smaller generating assets into the ISO markets;

[6] Additional detail regarding how the clean energy transition is increasing the complexity of the ISO's work and impacting the budget can be found in Mr. Ludlow's testimony at Exhibit 3 (pp. 13 – 16) and the Budget Presentation at Slides 14-31.

[7] The increases listed as supporting the clean energy transition correspond to the increases for each of the ISO's strategic goals described in Section I.C.1 of this filing letter.

- assessing a conceptual framework for a prompt/seasonal capacity market;
- assessing and implementing tools for improving ISO capabilities for modeling and maintaining situational awareness of distributed energy resources and changing load behavior;
- increasing granularity of weather forecasting for weather-dependent resources;
- supporting states' policy/project preferences and the NEPOOL prioritization process;
- addressing forthcoming Commission orders on long-term transmission planning for asset condition-based replacement and future-sizing of the transmission system; and
- developing and retaining in-demand skillsets for IT advancements needed for the clean energy transition.

Accordingly, the 2024 Core Operating Budget includes net funding for twenty-nine additional FTE employees.[8] As indicated in past filing letters, the ISO continually evaluates the most cost-effective way to address the evolving demands on the ISO and the rapidly evolving power system. In the past several years, the ISO supplemented staffing needs with contract additions, where practicable and to cover short term needs. Additionally, the ISO evaluates each position that becomes vacant to determine the continued need in that department and for possible repurposing for use in other areas of the organization. Since 2018, this practice has resulted in thirty-four reallocated positions and, in the five years prior to the proposed 2022 budget, the number of funded FTEs did not increase, on a net basis.

For the past few years, relying on contract additions and the reallocation of resources has not been sufficient to support the increasing demands on the ISO and the region's power system and as such, the 2024 Core Operating Budget includes funding of additional FTEs. As noted above, continued preparation for the clean energy transition requires the ISO to maintain current operations while incorporating new models, redesigning and implementing new systems, and planning the transmission system for the new mix of clean energy resources. This step-up in complexity represents a considerable increase to the ISO's workload and resultantly, thirty-five of the forty-one (gross) 2024 headcount additions are to address the clean energy transition.[9]

The remainder of this Section I describes:

[8] The 2024 Core Operating Budget includes the recruitment of forty-one additional positions with funding for twenty-nine FTEs with onboarding expected to occur throughout the year. In the 2023 Core Operating Budget, nine positions were deferred that are expected to be onboarded in 2024. Additionally, twenty of the forty-one additional positions for 2024 are reasonably expected to be onboarded in 2024. The funding for the full year of all forty-one FTEs will be included in the 2025 Core Operating Budget. *See* Budget Presentation at Slide 67 explaining the 2024 gross and net FTE funding needs.

[9] *See* Budget Presentation at Slides 64-66 with a breakdown of the FTE additions on a gross basis and which positions will support the clean energy transition.

- the 2024 budget development process (Section B);
- components of the 2024 Revenue Requirement (Section C);
- the three services provided by the ISO and funded by the 2024 Revenue Requirement (Section D); and
- the allocation of costs among the three primary schedules and the development of the rates reflected in the 2024 Administrative Expenses Tariff (Section E).

B. 2024 Budget Development Process

The ISO has always operated in a climate of cost accountability and transparency.[10] The ISO annually files with the Commission updated specific dollar-value, non-formula rates to collect the ISO's Revenue Requirement for each upcoming calendar year. Instead of using a formula rate allowing the automatic collection of every expense as incurred, the ISO revises its specific rates each year from a proposed annual Revenue Requirement that has been reviewed through a multi-stage stakeholder process, voted on by participants, approved by the ISO's independent Board of Directors, and ultimately filed with the Commission for approval in an open process in which any interested party may participate.

The ISO's budgeting process is driven by the ISO's strategic planning process. The strategic planning process includes a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can support, with the aim of creating value for ISO stakeholders. Included in the strategic planning process is the development of annual and five-year business plans that outline major priorities and activities in line with the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. The ISO ties its annual budget to resource requirements through goals, objectives, and initiatives, including five strategic goals:

- **Responsive Market Designs**: Improve the current market structure and continue to evolve and reposition the market design to accommodate the states' objectives and the transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to attract new entry;
- **Progress and Innovation**: Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services;

[10] The NEPOOL Participants Committee, the ISO's primary stakeholder body, has lauded the ISO's budget process, stating that it "works, not only because NEPOOL provides input, but also because ISO-NE is responsive to that input." NEPOOL RTO Cost Comments at 6.

- **Operational Excellence**: Continuously improve operations and processes, with a focus on efficiency and effectiveness, business results, and continuity of operations;
- **Stakeholder Engagement**: Collaboratively understand and anticipate needs, demonstrate thought leadership through high quality analysis and communication, and nurture productive relationships with the Commission, the states, and market participants; and
- **Attract, Develop, and Retain Talent**: Develop a sense of community around the ISO's core values, mission, vision, and goals; prepare the workforce; recognize and reward employees' success and innovation; and honor diversity and promote inclusion.

These goals formed the foundation for development of the ISO's 2024 Core Operating Budget. Additionally, the full seven-step process, throughout which stakeholder input was sought, requires the ISO to:

- define objectives, activities, and goals;
- identify efficiencies for each department;
- develop priorities;
- determine resource requirements;
- develop budget estimates for each department;
- adjust budgets to ensure that staff resources and activities are aligned with the business plan; and
- conduct senior staff review to ensure alignment of the budget with the business plan and overall fiscal constraint.

ISO-NE reviews the budgets with both NEPOOL and the states. To kick off this year's process, the ISO presented the preliminary budgets at a June 23, 2023 meeting with the New England states and the June 27, 2023 meeting of the NEPOOL Participants Committee. Following these discussions regarding the preliminary budget (which was substantially similar to the 2024 Revenue Requirement described herein),[11] the only follow-up comments the ISO received were from a participant requesting a meeting to clarify the drivers for the 2024 budget increases and from certain state agencies to include an additional headcount (described below).[12]

The ISO then developed its 2024 Revenue Requirement proposal and posted a detailed budget presentation, which includes approximately 200 slides regarding the 2024 Capital Budget

[11] Before incorporating the true-up, the 2024 Revenue Requirement presented in the preliminary budget was $277.2 million. The final 2024 Revenue Requirement (before true-up) was reduced to $276.9 million. *See* Budget Presentation at Slide 34.

[12] See Exhibit 3 at pp 9-10.

and the 2024 Revenue Requirement (the "Budget Presentation").[13] The ISO reviewed the Budget Presentation at the NEPOOL Budget and Finance Subcommittee's August 11, 2023 meeting and at a separate meeting of state agencies also on August 11, 2023.

Prior to the August 11 meeting, certain state agencies submitted a letter to the ISO requesting that the ISO consider adding to the 2024 Revenue Requirement funding for the creation of "a dedicated, executive level position focusing on energy and environmental justice to align ISO-NE's organizational objectives and operations with a just and equitable clean energy transition."[14] Following the August 11 meeting, certain state agencies submitted written questions regarding the budgets. The ISO provided answers, following which certain state agencies submitted written comments regarding the budgets.[15] In their comments, the state agencies stated that "[w]e accept this budget proposal given the challenges facing ISO-NE as the New England power system transitions to clean energy" but "[w]e are concerned with the size of the budget increase…[and] ask that the Board …ensure[s] that salary increases are narrowly implemented." In its response to this letter, the Board acknowledged and agreed that salary adjustment increases should be narrowly implemented;[16] noted the ISO's commitment to repurpose positions, if possible; and described the Board and its committees' careful review of the budget.

In addition to the state agencies joint letter, the ISO also received separate comments from the Connecticut Office of the Consumer Counsel, the New Hampshire Department of Energy, and the Maine Office of the Public Advocate. The supplemental comments of the Connecticut Office of the Consumer Counsel raised specific concerns regarding incentive compensation and depreciation expense. In its response to the Connecticut Office of the Consumer Counsel, the Board explained its role in oversight of employee compensation and explained the ISO's vacancy rate and depreciation expense variation. The comments of the New Hampshire Department of Energy focused on how the significant budget increase would impact New Hampshire's ratepayers. In its response to the New Hampshire Department of Energy, the

[13] The Budget Presentation (as updated) is available at https://www.iso-ne.com/static-assets/documents/100003/6_isone_2024_proposed_op_cap_budget_update_09_27_2023.pdf.

[14] The state agencies that joined such letter were the Massachusetts Executive Office of Energy and Environmental Affairs; the Massachusetts Department of Public Utilities; the Vermont Department of Public Service; the Vermont Public Utility Commission; the State of Rhode Island Office of Energy Resources; the Connecticut Department of Energy & Environmental Protection; the Connecticut Public Utilities Regulatory Authority; and the Maine Public Utilities Commission. In response to the states' request, the ISO received a letter from the New Hampshire Governor expressing concern over the "request made by five New England states to create an executive-level environmental justice position at ISO New England" noting that "such a position would represent a wasteful expense to accommodate policy goals that fall outside of ISO New England's mandate." The ISO has added a placeholder in the proposed 2024 budget for an environmental policy and community affairs FTE, to allow the ISO to evaluate the appropriate responsibilities and role of this position. *See* Budget Presentation at Slide 66.

[15] The state agencies that provided joint comments on the 2024 operating and capital budgets are: Connecticut (Office of Consumer Counsel and Public Utilities Regulatory Authority); Massachusetts (Department of Public Utilities); Rhode Island (Public Utilities Commission); and Vermont (Public Utility Commission).

[16] Additional detail regarding the impact of proposed salary increases on the 2024 Revenue Requirement can be found in Ms. deCastro's testimony at Exhibit 4.

Board explained its careful review and monitoring of the budget, stated that it considers consumer cost impacts when reviewing the budget, and noted that "both the clean energy transition and inflationary pressures are driving increases in compensation." Finally, the comments of the Maine Office of the Public Advocate expressed that the budget increase "raised concern regarding whether the overall budget has been carefully developed with the price impact on ratepayers in mind." In its response, the Board acknowledged the increase in the average monthly consumer cost, explained the ISO's budget process and the Board's role within that process, and explained that the "budget strikes the appropriate balance between [consumer] cost impact and the growing demands on the ISO." The states' comments and the ISO's responses are located at Exhibits 9 and 10 to this filing letter.[17]

The ISO reviewed the 2024 Capital Budget and the 2024 Revenue Requirement at the NEPOOL Participants Committee's meetings on September 7 and October 5, 2023. At the October 5 meeting, the two budgets were supported by the Participants Committee (with three oppositions and eight abstentions recorded).

Contemporaneously with the stakeholder processes, the Board of Directors undertakes its review of the budgets. The Board process includes review of particular elements of the budgets by Board committees with responsibility in a defined area. For example, compensation matters are reviewed by the Compensation and Human Resources Committee and projects with reliability implications are reviewed by the System Planning and Reliability Committee. The Audit and Finance Committee advises management throughout the development of the budgets and engages in a detailed review of the budgets in both May and August.

In addition to receiving updates throughout the process from management regarding the stakeholder process and from the Audit and Finance Committee, the Board discusses the budgets at its September meeting. At that meeting, the Board also reviewed the questions and comments of the participating state agencies. As a final step, after receiving any additional feedback from stakeholders, including the results of the Participants Committee's vote, the Board votes on the budgets.[18] In the instant case, after reviewing all input from stakeholders, including the vote of the Participants Committee, the ISO's Board of Directors approved the 2024 budgets effective October 12, 2023.

C. The 2024 Revenue Requirement

This section provides an overview of the 2024 Revenue Requirement and detail regarding its significant components. Additional detail can be found at Exhibit 3 in the testimony of Robert C. Ludlow, the ISO's Chief Financial Officer, and the exhibits thereto.

[17] Pursuant to a settlement agreement entered into among certain state agencies and the ISO regarding the 2013 budgets, ISO-NE is required to include these comments and its response in its budget filing.

[18] The ISO must report the results of all Participants Committee votes on the budgets to the Board of Directors and to the Commission. Participants Agreement at §§ 12.3, 12.5.

As noted above, the 2024 Revenue Requirement, after the true-up for 2022, is $273.9 million.[19] It includes the following components, each of which is discussed below.

- the 2024 core operating budget ($244.3 million);
- depreciation and amortization of regulatory assets ($32.6 million); and
- a true-up for 2022 that decreases the 2024 revenue requirement by $3.0 million as a result of an over-collection of ISO rates in 2022.[20]

While the ISO has amassed a consistent track record of spending integrity – since the inception of its self-funding tariff for calendar year 1998, the ISO's annual spending has never exceeded its budget – the risk exists that the ISO may have to incur additional expenditures during 2024 that exceed the allocated amounts and contingencies. Specific potential risks include: additional funding required to construct new models to study extreme weather and contingencies, and to conduct new studies related to the integration of variable resources and emerging technologies, including long-range transmission planning studies; additional resources required as operations evolve (*e.g.*, energy forecasting, load management) due to the evolving and changing resource mix; additional information technology funding for software licensing, maintenance costs, cloud migration, backup and storage, and desktop peripherals; higher than anticipated insurance policy renewals; unforeseeable litigation; interest rates that may impact the ISO's floating rates on tax exempt debt, pension and post-retirement benefit plan costs, and interest income on the ISO's settlement float balance; costs related to workforce sourcing challenges and related pay rates; costs related to supply chain disruption; costs related to inflationary pressures in the current economic environment; and funding required for additional or changing federal and/or state policy directives that could result in new requirements.

In general, the demands placed on the ISO by Market Participants and regulators will determine the extent of additional work and the resources the ISO will require. In any case, should the need ever arise for the ISO to spend more than a given year's Revenue Requirement, the ISO will first seek stakeholder support and then file a rate increase with the Commission, thus allowing stakeholder and Commission review before approving such increases.

1. Components of the Core Operating Budget Increase

As related to the strategic goals identified above, the ISO proposes to increase its Core Operating Budget from 2023 levels for: (i) Goal 5: Attract, Develop, and Retain Talent ($18.7 million); (ii) Goal 3: Operational Excellence ($10.1 million); (iii) Goal 1: Responsive Market Designs ($5.5 million); (iv) Goal 4: Stakeholder Engagement ($2.4 million); (v) Goal 2: Progress and Innovation ($1.1); and (vi) other miscellaneous increases ($1.4 million). Below, the ISO discusses the costs in each of these categories and then reviews the savings, efficiencies, and non-recurring work that offset these increases by $4.1 million.[21]

[19] *See* Appendices 1 and 5 to the Budget Presentation for a breakdown of the Revenue Requirement by category (Slides 91-105) and functional area (Slides 135-161).

[20] *See* the Budget Presentation (Slides 96-97) for a breakdown of the true-up amount.

[21] *See* the Budget Presentation for more information on all of these year-over-year budget changes.

a. Increases Related to Attract, Develop, and Retain Talent (Strategic Goal 5)

The funding increase of $18.7 million for this goal is attributable to funding in six categories: (1) to maintain competitive compensation ($16.7 million); (2) increases in employee benefits costs as a result of an increased number of employees in the Defined Contribution Benefit Plan[22] and increased payroll taxes ($800,000); (3) to fund higher costs related to recruiting, retention, and succession planning ($400,000); (4) funding for 3.25 FTEs for a talent program manager (0.75 FTE) and for early career technical talent FTEs to meet future talent needs (2.5 FTEs) ($400,000); (5) funding to support the intern program (including higher pay rates and an increase in the number of interns) ($300,000); and (6) to fund an increase in board member retainers based on compensation consultant recommendations ($100,000).

As noted above, the changing grid is increasing both the amount of work and the complexity of the work that the ISO is undertaking. As a result, it has become critically important for the ISO to remain competitive in the labor market and keep pace with compensation market changes (including inflationary effects) to attract and retain the necessary personnel to support the clean energy transition. The funding in this category to maintain competitive compensation ($16.7 million) includes a 4.0% increase in salaries based on merit; a 4.0% increase for equity adjustments and promotions; funding to reflect that targeted equity adjustments were made in late 2022/2023 using contingency funds that impact the salary rates for 2024; and an increase for employee incentive target amounts to better align ISO compensation with market rates. These increases reflect that, over the past few years, the challenges to the ISO's compensation program have intensified, resulting in higher turnover, rejection of the ISO's job offers in favor of higher paying positions, and the increasing need to use retention incentives to retain critical talent. The ISO's annualized turnover rate has increased over the past several years, heavily impacting critical departments (including information technology and engineering), and the ISO continues to face hiring challenges related to the shortage of critical talent in the utility industry and post-pandemic workplace labor market shifts.[23] With this turnover comes inefficiency; for example, it takes months to fill a transmission engineer vacancy, followed by an inevitable learning curve.

Resultantly, the ISO hired a compensation consultant to perform a job specific, one-for-one compensation benchmarking analysis.[24] The results of this analysis heavily impacted the increases included in the 2024 Core Operating Budget. First, the initial phase of the benchmarking analysis (completed in late 2022) required the ISO to make several late 2022 and 2023 equity adjustments for critical positions. These increased salaries had an impact in the total

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[22] *See* Budget Presentation, Slide 116 (explaining that in 2014 the pension plan became closed to new participants; as a result, all new hires in the organization are eligible under the Defined Contribution Benefit Plan).

[23] *See* Exhibit 4 at pp. 3-11. As noted in Ms. deCastro's testimony, the ISO's 2023 to-date turnover rate is showing significant improvement from recent years, likely as a result of compensation adjustments the ISO has made to address turnover and retention challenges. *See id.* at pp. 8-9.

[24] *See* Exhibit 4 at pp. 14-15; 21-22 for a more detailed explanation of the benchmarking survey and results.

amount budgeted for 2024. Furthermore, the results of the benchmarking analysis, which highlighted competitive pay discrepancies, heavily impacted the merit and promotional/equity increase budgets.[25] In developing the compensation budgets, the ISO also reviewed survey data from several national compensation consultants on expected merit and promotional pool increases[26] and expected salary increases of other ISOs/RTOs.[27]

For the 2024 Revenue Requirement, using the compensation benchmarking analysis initial results, the ISO's Compensation and Human Resources Committee of the Board of Directors approved a merit increase budget (4.0%) that is consistent with expected increases by the other RTOs/ISOs and the higher end of the survey data for the utility industry.[28] For the promotion/equity budget, the Compensation and Human Resources Committee approved a budget increase (4.0%) that was primarily based on the results of the compensation benchmarking study.[29] Because the data from national surveys and other ISOs/RTOs does not account for the fact that the ISO's compensation had fallen below competitive ranges for many critical positions, and the promotional/equity pool funds both promotions and targeted adjustments based on market competitiveness, the approved amount for the promotional/equity budget was significantly higher than the survey results.[30]

The ISO also complies with the standards of the Internal Revenue Service when determining executive compensation. These standards encompass all aspects of compensation, including base salary and all bonuses, and require that the ISO's executive and Board compensation fall within a range of competitive practices for total compensation paid by similarly-situated organizations, both taxable and tax-exempt, for functionally comparable positions.[31]

To ensure compliance with these standards, the ISO has engaged a nationally recognized, independent consulting firm, which evaluates the compensation offered by similarly-situated entities. This evaluation includes other system operators and select for-profit "peer" utility organizations (chosen for organizational size, complexity, and scope of responsibilities). It also incorporates a broader comparison across all industries for positions not unique to utilities (again, comparators are selected for organizational size, complexity, and scope of responsibilities). The resulting opinion each year has been that the ISO's executive and Board

[25] *See* Exhibit 4 at pp. 20-23.

[26] *See* Exhibit 4 at pp. 14, 19-20. The surveys that will used by the ISO were conducted by Mercer, WorldatWork, WillisTowersWatson, Aon, and The Conference Board. These surveys collectively poll thousands of employers and include both all-industry and utility-specific data.

[27] *See* Exhibit 4 at pp. 14, 19-20.

[28] *See* Exhibit 4 at pp. 22-23.

[29] *See id*.

[30] *See* Exhibit 4 at pp. 20-23.

[31] *See* Internal Revenue Code § 4958.

compensation is within a reasonable range of competitive practice for functionally comparable positions among similarly-situated entities. The Commission has found that this process results in just and reasonable compensation.[32]

The testimony of Kathleen deCastro, the ISO's Vice President, Human Resources and Chief People Diversity Officer (located at Exhibit 4), provides more detail on the ISO's compensation and benefits practices, as does the Budget Presentation (Appendix 2 at slides 106-123).

b. Increases Related to Operational Excellence (Strategic Goal 3)

The cost increase of $10.1 million related to Operational Excellence is related to headcount increases in various departments, support for various information technology initiatives and improvements, and study work. Specifically, the headcount increases will fund: 1.25 FTEs in Information Technology Cyber Security to bolster cyber threat response times, the addition of identity and access management functions, and for additional monitoring for cloud technologies; 1.0 FTE in Information Technology Enterprise Application Support for settlements support required as a result of the Day-Ahead Ancillary Services and Resource Capacity Accreditation projects and for continued integration and delivery of new software products; 0.75 FTE in Information Technology Infrastructure to provide additional support as new technologies are implemented; 1.0 FTE in Strategy, Risk, and Operations Compliance to support the ISO's resiliency program; 1.0 FTE in Internal Audit to support information technology, cyber security, and CIP related audits; 0.75 FTE in Participant Relations & Services to continue efforts to convert in-person training and webinar modules to self-paced micro-learning modules that provide time and costs savings to the ISO and participants; and 0.5 FTE in Advanced Technology Solutions for re-architecting and deployment of the integrated market simulator in a cloud environment.

The funding to support Goal 3 related to various information technology initiatives and improvements include infrastructure increases for operating system support, including extended coverage for unsupported versions while completing version upgrades; backup storage and recovery software; virtualization licenses; application maintenance on new products in various Information Technology and Cyber Security departments; cyber security costs for tools enhancements; information technology increases across the organization, including in the Enterprise Application Support and Architecture & Data Governance departments; increases in various software products as the workforce grows; and power system modeling license cost increases. Additionally, included in Goal 3 cost increases is funding for professional fees to support Information Technology reliability and cyber defenses.

Finally, Goal 3 funding study work includes support for a regional study with PJM and NYISO to assess a 1,200MW single source contingency limit and determine upgrades required to support a 2,000MW single source limit; and for professional fees to support distributed energy resources and minimum load studies to determine how to ensure system reliability when the

[32] ISO New England Inc., 117 FERC ¶ 61,310 at P 18 (2006); Order on paper hearing and finding rehearing to be moot, 119 FERC ¶ 61, 178 (2007).

system is powered solely by inverter-based resources. Goal 3 funding also includes minimal funding for facility updates and cyclical maintenance.

c. Increases Related to Responsive Market Designs (Strategic Goal 1)

The $5.5 million cost increase in this category is related to headcount increases in various departments and funding for specific market projects. Specifically, the headcount increases will fund: 3.0 FTEs in Market Development to support the ongoing market design and development efforts for Resource Capacity Accreditation, Day-Ahead Ancillary Services, Forward Capacity Market evolution and parameters, and the market integration of renewable resources; 2.0 FTEs in Market Development for the integration of distributed energy resources, and large scale storage resources including batteries; 1.0 FTE in Energy Management Systems for the integration and utilization of nGEM,[33] and to ensure a market structure that will support clean energy and reliability through the clean energy transition; 1.0 FTE in Market & Credit Risk for developing, designing, and testing the risk-based adequacy of market participant collateral obligations and supporting implementation of new Market Development projects; 0.5 FTE in Advanced Technology Solutions related to the development of market design; 0.5 FTE in Planning Services due to Resource Capacity Accreditation workload and increased use of probabilistic analysis in projects; 0.5 FTE in IT Application Software Development to add software development support for the Day-Ahead Ancillary Services and Resource Capacity Accreditation projects; and 0.25 FTE in Resource Adequacy to support work including: Commission Order 2222 and requirements related to a new resource category, additional qualification reviews regarding Sponsored Policy Resources as a result of the Minimum Offer Price Rule removal, and qualification changes related to Resource Capacity Accreditation.

Funding for Goal 1 related to market design projects include consulting support for the assessment of a prompt seasonal capacity market; the assessment of Resource Capacity Accreditation market mechanisms; and the build-out of a new margin model for Real-Time, Day-Ahead, and prompt seasonal capacity markets. Additionally, funding for this Goal will support the Forward Capacity Auction ("FCA") 21 Cost of New Entry parameter updates.

d. Increases Related to Stakeholder Engagement (Strategic Goal 4)

The cost increase of $2.4 million to support the Stakeholder Engagement strategic goal will support headcount additions and study work. Headcount additions will include: 1.25 FTEs in Transmission Planning to support expected increases in transmission request-for-proposals, to support project work (such as documenting Remedial Action Scheme limitations and load interruption thresholds), and to support stakeholder requests for long-term transmission studies; 1.0 FTE in Participant Relations & Services to assist in the gathering, managing, and supporting the assessment of participant proposals/requests for the ISO's Annual Work Plan; 1.0 FTE in Corporate Communications to support additional communications on ISO initiatives, projects, issue positions, emergency communications, and other related regional efforts; 0.5 FTE in Market Development for efforts on energy adequacy that may require significant assessment and

[33] Additional detail regarding the next Generation Market Management System ("nGEM") project can be found in Section II.C of this filing letter.

novel market initiatives; 0.5 FTE in Transmission Services to support volume increases in the interconnection queue; and 0.25 FTE in Planning Services to accommodate evolving economic study needs and environmental outlook efforts.

Other funding to support Goal 4 is related to study work, including funding for a medium-term energy adequacy assessment and for a Maine Interconnection Cluster Study. Funding for Goal 4 will also provide support for work related to New England states' requests.

e. Increases Related to Progress and Innovation (Strategic Goal 2)

The cost increase of $1.1 million to support the Progress and Innovation strategic goal will support headcount additions and an increase in computer services for higher utilization and related fees for cloud storage through Amazon Web Services. The headcount increases to support Goal 2 include: 1.5 FTEs in Power System Modeling to support modeling for reliability and planning as a result of the increase of renewables, storage, and distributed energy resources in the region; 1.0 FTE in Planning Services for evolving forecast needs and increased complexity/risk associated with the industry's clean energy transition; 0.75 FTE in Information Technology Architecture to leverage cloud technology benefits, including greater agility, reduced time to deploy infrastructure, infinitely scalable computing performance, and reduced hardware maintenance; 0.75 FTE in Advanced Technology Solutions for research and development needs in advanced modeling and simulation of inverter-based resources, to assess the impact of climate change and extreme weather on power system reliability, and the development of a more efficient market clearing algorithm; 0.5 FTE in Market Development for continuing work on integration of distributed energy resources and large scale storage integration; and 0.25 FTE in Transmission Services to support increased requirements to review, validate, and integrate inverter-based resource models.

f. Miscellaneous Increases

The cost increase of $1.4 million in this category is attributable to the assessment of Northeast Power Coordinating Council ("NPCC") and NERC dues; an increase in interest expense and fees due primarily to an increase in borrowings on the working capital line resulting from increases in the operating and capital budgets; and insurance policy premium increases.

g. Offsetting Savings; Direct Charge Activities

The ISO works to offset increased costs through cost-cutting, eliminating discontinued or non-repetitive work, and to the extent possible, reallocation of resources. For 2024, the ISO has realized $4.1 million of efficiencies, reductions, and other non-recurring costs.

The $4.1 million reflects reductions from non-recurring markets study work, including the Future Grid Phase II study, the Inventoried Energy Program, and Day-Ahead Ancillary and FCA19 parameters update reviews; reductions to reflect that significant work has been accomplished regarding the Resource Capacity Accreditation parameters and design project resulting in less funding for 2024; reductions for the Pathways Study Phase II work which will now be included in the Economic Planning for the Clean Energy Transition pilot study; a reduction for the Mystic Cost of Service Agreement fuel supply management work with the

agreement ending in mid-2024; the removal of funding for the 2050 Transmission Study work which will be completed in 2023; a forecasted increase in interest income due to rates and settlement account balances; a reduction for participant proposal support work that will largely be covered by internal staff; a reduction in board of director related expenses since no director searches will be required in 2024 and the completion of board evaluation work; a reduction for Information Technology patching staff augmentation to be covered by internal staff; a reduction for Transmission Planning and Analysis tool maintenance absorbed by internal staff; and a reduction to reflect the substantial completion of a communications campaign that will only require periodic updates.

The ISO will also offset its costs through certain direct charges. Section IV.A of the Tariff includes provisions for the ISO to assess direct charges to collect reasonable administrative costs for performing certain discrete functions, including transmission studies,[34] information requests,[35] non-standard contract provisions,[36] and non-standard billing.[37] Expected revenues to reimburse ISO staff efforts for studies (as opposed to revenues that are flowed through to contractors actually performing the studies) have been used to reduce the relevant schedule's 2024 Revenue Requirement.

2. Depreciation

As a non-profit entity without equity, the ISO must recover revenues consistent with its obligation to repay the loans funding its projects. In fact, the ability to obtain and maintain independent financing is dependent upon the ISO's being able to recover the principal portion of debt service through depreciation and amortization.

For 2024, the ISO's depreciation and amortization costs are $32.6 million, which is approximately $1.6 million more (5.1% increase) than in 2023. Increases in depreciation expense are primarily due to a full year of depreciation impacting the 2024 budget as a result of the 2023 mid-year go live date of the nGEM Market Clearing Engine Implementation project. Upon completion of that project, the following associated work-in progress projects began depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phases I and II.[38]

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[34] Tariff § IV.A.6.1 (Transmission Studies). This provision permits, for example, charging for the performance of System Impact Studies, Facilities Studies and FCM qualification studies.

[35] Tariff § IV.A.6.2 (Information Requests).

[36] Tariff § IV.A.6.3 (Non-Standard Provisions).

[37] Tariff § IV.A.6.4 (Non-Standard Billing Service).

[38] *See* Exhibit 3, RCL-5, Schedule 4, page 2 of 2.

The ISO's depreciation rates remain unchanged from those previously accepted by the Commission.[39] The ISO uses the straight-line depreciation methodology based on no net salvage value and the various average service lives described below. These service lives reflect the ISO's historical experience and forecasted expectations for capital projects placed into service, are necessary to comply with the ISO's funding mechanisms, are consistent with the ISO's historical experience, and have been repeatedly determined by independent auditors to be reasonable. The service lives are:

- Computer hardware, software and accessories: 3 to 5 years
- Software development costs: 3 to 5 years
- Furniture and fixtures: 7 years
- Machinery and equipment: 7 years
- Building: average of 25 years (based on the opinion of independent bond counsel and analysis of the service lives of the different aspects of the building (*e.g.*, the building's steel and concrete at 40 years, mechanical and electrical work at 25 years, and high wear-and-tear elements at 15 years).
- Leasehold/Building Improvements: lesser of 1 to 25 years or remaining life of the lease or building, as determined at the time of the purchase based on the nature of each such improvement (*e.g.*, rooftop railing at 25 years, air conditioning unit at 15 years, capacitor bank at 10 years).
- Vehicles: 3 to 7 years

3. True-Up Mechanism

As set forth in Section IV.A.2.2 of the Tariff, the 2024 Revenue Requirement includes an adjustment for deviations between actual collections and expenses for calendar year 2022. In general, the amount of the true-up is added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for the upcoming budget year. In the case of the 2022 true-up, the ISO collected $3,006,163 more than it needed to pay its expenses.

With respect to Schedule 1, the ISO had expenses of $43.6 million, and collected revenues of $43.2 million, resulting in an under-collection for Schedule 1 (*i.e.*, the increase to the 2024 Revenue Requirement for Schedule 1) of about $400,000.[40] With respect to Schedule 2, the ISO had expenses of $101.2 million and collected revenues of $106.5 million, resulting in an over-collection for Schedule 2 (*i.e.*, the decrease to the 2024 Revenue Requirement for Schedule

[39] In 2006, the Commission examined and accepted the ISO's depreciation rates after holding a paper hearing. *ISO New England Inc.*, 117 FERC ¶ 61,310 at P 18 (2006), *Order on paper hearing and finding rehearing to be moot*, 119 FERC § 61,178 (2007).

[40] *See* Exhibit 3, RCL-2, Schedule 2, page 2 of 2.

2) of approximately $5.3 million.[41] Finally, with respect to Schedule 3, the ISO had expenses of $64.8 million and collected revenues of $63.0 million, resulting in an under-collection for Schedule 3 (*i.e.*, the increase to the 2024 Revenue Requirement for Schedule 3) of approximately $1.9 million.[42]

D. Services Funded by the 2024 Revenue Requirement

This section discusses the three services the ISO provides, which correspond to the rate schedules through which the ISO recovers its Revenue Requirement: Schedule 1 – Scheduling, System Control and Dispatch Service ("Scheduling Service"); Schedule 2 – Energy Administration Service; and Schedule 3 – Reliability Administration Service.

1. Scheduling Service (Schedule 1)

Scheduling Service includes the transmission-related service required to schedule at the pool level the movement of power through, out of, within, or into the New England Control Area. It does not cover expenses of dispatching Energy, which are collected as part of the charges in Schedule 2. Scheduling Service can be provided only by the ISO, and all Transmission Customers must purchase Scheduling Service from the ISO. The 2024 Revenue Requirement for Schedule 1 (including true-ups) is $57.9 million.

Functions performed by the ISO in connection with Scheduling Service include:

- processing and implementation of requests for Regional Transmission Service, including support of the Open Access Same-Time Information System node;
- coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- billing associated with regional transmission services provided under the Tariff;
- transmission system planning that supports Scheduling Service; and
- administration costs associated with the aforementioned functions.

2. Energy Administration Service (Schedule 2)

Energy Administration Service is the service provided by the ISO to administer the Energy Market. The 2024 Revenue Requirement for Schedule 2 (including true-ups) is $129.3 million.

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[41] *See* Exhibit 3, RCL-2, Schedule 2, page 2 of 2. Pursuant to Section IV.A.2.2 of the Tariff, the true-up is calculated separately for Schedule 2. *See also* Section I.E.4.b of this transmittal letter.

[42] See Exhibit 3, RCL-2, Schedule 2 page 2 of 2.

The ISO's functions that comprise Energy Administration Service include:

- core operation of the Energy Market;
- generation and demand dispatch related to the Energy Market;
- energy accounting;
- loss determination and allocation;
- billing preparation;
- market power monitoring and mitigation for the Energy Market;
- sanctions activities;
- operation of Financial Transmission Rights auctions;
- market assessment and reports; and
- formulation of additional market rules and proposals to modify existing rules.

3. Reliability Administration Service (Schedule 3)

The ISO provides Reliability Administration Service to administer the Reliability Markets, including the Forward Capacity Market, in accordance with Market Rule 1 and to provide other reliability and informational services. These services are of a type not directly related to the services provided under Schedules 1 and 2, and are expenses of operating the New England Control Area generally, rather than expenses attributable to serving a particular Customer. The 2024 Revenue Requirement for Schedule 3 (including true-ups) is $86.7 million.

Examples of the functions performed (in addition to the core operation of the Reliability Markets) include:

- generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- billing preparation;
- generation emissions analysis;
- risk profile updates;
- triennial review of resource adequacy;
- studies and qualification of resources under FCM;
- preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission ("CELT") Reports; reports to the Energy Information Administration of the United States Department of Energy; reports to NERC; Regional System Plan);

- support of power supply, environmental, and market reliability planning activities;
- market power monitoring, mitigation, and assessment for the Reliability Markets; and
- formulation of additional market rules and proposals to modify existing rules.

E. Cost Allocation and Rate Development

This section describes the new rates proposed herein by: (i) detailing how the ISO generally allocates its costs among the three core rate schedules; (ii) explaining the billing determinants used by each schedule; (iii) explaining how the ISO adjusted the billing determinants for 2024; (iv) describing the rates ultimately derived for 2024 for each schedule; and (v) explaining how and why the Revenue Requirement for each schedule shifted.

1. Cost Allocation Among the ISO's Services

Most of the ISO's operating costs are fixed and do not vary based on the volume of a Customer's activity—a fact recognized by the Commission itself.[43] The ISO established the core rate design for its first three schedules through an uncontested settlement approved by the Commission in 2001,[44] with additional modifications reflecting necessary changes upon the commencement of Standard Market Design in New England. Although the 2001 settlement is no longer binding, the ISO followed the same cost allocation among the three primary schedules when establishing the rates proposed herein.

The Tariff structure relies upon the activity-based allocation of the ISO's costs to its three rate schedules, namely Scheduling Service, Energy Administration Service, and Reliability Administration Service. These rate schedules coincide with the main "service categories" of the ISO. Exhibit 3, RCL-3, Schedule 1 contains a Test Year 2024 cost of service for the three rate schedules. This exhibit lays out in detail how the ISO's costs were assigned to the schedules.

In assessing how costs should be assigned to the various categories of service that the ISO provides to its Customers, the objective is to reflect cost causation principles as much as possible. All costs that could be assigned to the three rate schedules using direct allocators were so allocated. Most activity costs consist of direct labor costs, employee benefits, and other non labor-related costs (*i.e.*, office supplies, software, hardware, depreciation, interest, etc.). For each activity code, both the labor-related and non labor-related costs are assigned to the rate schedule using the same allocator. Within a given department, known allocators (Alloc-Fixed) for specific cost categories or activities were used to allocate those labor costs that were specifically attributable to a schedule. All remaining labor costs within that department were

[43] *ISO New England Inc.*, 89 FERC ¶ 61,339 at p. 62, 019 (199), *reh'g denied*, 91 FERC ¶ 61,016 (2000) (finding that the ISO's expenses "are essentially fixed" and that the issue of rate design involves "not so much cost causation, as it does the equitable allocation of an essentially fixed amount of expenses among many users of the grid").

[44] *See* Settlement Agreement in Docket No. ER01-316-000 (filed June 1, 2001).

allocated in proportion to the distribution of the summed Alloc-Fixed labor costs among the three schedules. Labor costs within all departments were allocated in this manner and summed for the entire company.

2. Rate Design and Billing Determinants

As discussed below, each Schedule utilizes different billing determinants and attempts to reflect cost causation principles, to the extent possible. The ISO is not proposing any changes to the design of the billing determinants for 2024.

a. Schedule 1

The billing determinants for Schedule 1 are Monthly Regional Network Load and Reserved Capacity. Monthly Regional Network Load is measured in kilowatts. The determinant based on Reserved Capacity uses the highest amount of Reserved Capacity for an hour for each transaction scheduled to occur during the month as Through or Out Service, other than Coordinated External Transactions.[45] Schedule 1 revenues collected from Through or Out Service Customers are credited to each Network Customer that month in proportion to each Network Customer's Monthly Regional Network Load. Revenues from the Non-Participant Financial Transmission Rights ("FTR") fee described in Market Rule 1 and non-refundable Long Lead Facility deposits will be credited to the Schedule 1 Revenue Requirement through future true-ups.

b. Schedule 2

The Schedule 2 Revenue Requirement is allocated 15% to Transaction Units ("TUs") and 85% to Volumetric Measures ("VMs"), subject to the special true-up described below. TUs measure the frequency and duration of activity and are indifferent to the size (*e.g.*, capacity) of any particular transaction. Conversely, VMs seek to capture a Customer's "physical" reliance on the system administered by the ISO and thus the benefit received.

Schedule 2 utilizes three types of TUs: (i) those associated with Real-Time Energy Market transactions ("Energy TU Based Charges"), (ii) those associated with Increment Offers and Decrement Bids, and (iii) those associated with FTR auction bids.

Energy TU Based Charges: These charges equal the sum per month of a Customer's Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours, without reference to Coordinated External Transactions. Under the ISO's current rate design, a Customer's total monthly Energy TUs are priced under a three-

[45] Coordinated External Transactions are defined in Section I of the Tariff as transactions at external interfaces to which the enhanced scheduling procedures in the Coordinated Transaction Scheduling ("CTS") rules apply. These rules were adopted jointly with the NYISO to enhance the market efficiency of external transactions (*i.e.*, energy imports and exports) between the two regions through economic clearing of external transactions. *See* Tariff Section III.1.10.7.A.

tiered declining block rate structure. Under this regime, the highest unit rate applies to the first 12,500 Energy TUs incurred in a month. The Customer's next 27,000 Energy TUs are priced approximately 10% lower, with the balance of monthly Energy TUs (*i.e.*, those in excess of 39,500) priced at an additional savings of approximately 10%.

TU Charges Based on Increment Offers and Decrement Bids: These charges are based on both of the following: (i) a charge multiplied by the total number of Increment Offers and Decrement Bids submitted; plus (ii) a charge multiplied by the total number of Increment Offer and Decrement Bids that clear the Day-Ahead Energy Market. This category is sometimes referred to as "virtual activity."

TU Charges Based on FTR Auction Bids Submitted and Cleared: These charges are intended to recover all costs for operating the monthly, multi-month, and annual FTR auctions. The charges consist of: (i) a unitized charge multiplied by the total number of bids submitted to the FTR auctions; plus (ii) a unitized charge multiplied by the total number of bids that clear the FTR auctions.

Schedule 2 Volumetric Measures consist of the sum of a Customer's Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (each measured in megawatt hours (MW)) excluding any Monthly Real-Time Generation Obligation associated with certain energy imports and Coordinated External Transactions. Under the ISO's current rate regime, Schedule 2 VMs are priced under a three-tiered declining block wherein the highest unitized rate is assessed to the first 250,000 MWh each month. The Customer's next 1,250,000 MWh are priced at a discount of approximately 10% from the tier-1 unitized rate, and VMs in excess of 1,500,000 MWh incur the lowest unitized monthly rate.

c. Schedule 3

Schedule 3 allocates internal load activity based on Real-Time NCP [Non-Coincident Peak] Load Obligation. For Exports other than Coordinated External Transactions, Schedule 3 assesses a volumetric (per MWh) charge.[46] Specifically, the ISO divides the Schedule 3 Revenue Requirement by the real-time load obligation forecasted for the upcoming year in the most recent CELT Report to yield the unitized rate per kW-month.[47] The remaining revenue requirement for Schedule 3 (*i.e.*, net of that allocated to Exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

[46] The Commission accepted the current form of the Schedule 3 rate design that distinguishes Exports from internal activity in a June 2, 2006 Letter Order issued in Docket No. ER06-926-000.

[47] ISO New England Inc., *2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 1, 2023). *See* https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx. The 2024 Forecast is based on the May 2023 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced for behind-the-meter photovoltaic and energy efficiency).

3. Adjusting Billing Determinants for 2024

The data used in designing the proposed rates in the 2024 Administrative Expenses Tariff was taken from the ISO markets system for the 12-month period ending July 2023. Consistent with the practice reflected in the ISO's Tariff filings for 1999 through 2023, the ISO also relied on information contained in the annual CELT Report. The development of the escalation factors is shown in Exhibit 3, RCL-7, Schedules 1 and 2.

In sum, the ISO's analysis of CELT Report data, other load data, and transaction data through July 2023 suggests that the estimated data for August 2023 through December 2023 should be based on 2022 data.

The ISO's analysis of the data led to an increase of 1.1% in the projected data for 2024 (compared to 2023 levels) for the Schedule 1 (*i.e.*, Regional Network Load) billing determinant, the load-related (volumetric) measures in Schedule 2, and the Schedule 3 billing determinant related to Real-Time NCP Load Obligation.[48]

The Schedule 2 Energy TUs billing determinant was increased by 2.0%. As explained in Mr. Ludlow's testimony, the number of Energy TUs has increased consistently over the past several years, with an average increase over the past three years of 2.0%.[49] The Schedule 2 transaction unit determinants for virtual transactions and FTRs were left flat for 2024 due to historical inconsistent bidding patterns and fluctuating results of cleared bids; as explained in Mr. Ludlow's testimony, although there has been some fluctuation in virtual transactions over the past several years, the ISO has not identified any specific market change or participant behavior causing such fluctuation.[50] Similarly, there has been no clear pattern to FTR bidding activity with historical variation in activity, including over the past twelve months.[51] Data regarding these calculations appears in Exhibit 3, RCL-7.

Finally, the Schedule 3 volumetric charges for Exports were left flat for 2024, as shown in Exhibit 3, RCL-7, Schedule 2, column (k). The remainder of the Schedule 3 revenue requirement is assessed via a billing determinant related to NCP Load Obligation. This billing determinant, like the Schedule 2 volumetric measures and the Schedule 1 billing determinants, is increased by 1.1% based on CELT Report load data, as shown in column (j) of RCL-7, Schedule 2. NCP Load Obligation absorbs the remaining Schedule 3 revenue requirement.

4. Deriving the 2024 Rates

a. Rate Development for Scheduling Service (Schedule 1)

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[48] Exhibit 3, RCL-7, Schedule 2, columns (c), (i) & (j), Lines 16-27.

[49] *See* Exhibit 3 at pp. 44-45.

[50] *See id.* at pp. 44-48.

[51] *See id.*

The ISO's Revenue Requirement for Schedule 1 totals $57.9 million.[52] The total underlying annual billing determinants for Schedule 1 are 214,795,375 kilowatt-months,[53] reflecting the escalation factor discussed above, based on actual plus forecasted activity in 2023. The resulting rate is $0.26954 per kilowatt-month, which is billed as $0.00037 per kilowatt-hour.[54]

b. Rate Development for Energy Administration Service (Schedule 2)

In determining the ISO's Revenue Requirement for 2024, the ISO includes a true-up for 2022 based on both the TU and VM portions of Schedule 2.[55] In implementing the true-up adjustment for revenue differences in the VM portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for Schedule 2 for the coming year.

Revenue over-recoveries attributable to the TUs in Schedule 2 are treated in the same manner. However, if there is a revenue shortfall attributable to the TUs in Schedule 2, half of the shortfall will be subtracted from the 2024 Revenue Requirement for Schedule 2. An additional percentage of the shortfall will be added to the ISO's projected revenue requirement for the Schedule 2 VMs for each percentage decrease that was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year. The maximum percentage of the shortfall that will be added to the VMs is 100%, which would result if the percentage difference between the actual and forecasted TUs was 50% or greater. Any remaining revenue shortfalls will be added to the ISO's projected revenue requirement for the Schedule 2 TUs.

The TU recovery for 2022 was an over-collection of TU revenue in the amount of $166,219.[56] As a result of the TU over-collection, the allocation of Schedule 2 revenue will be 85% to VMs and 15% to TUs, with no adjustment necessary.[57]

The ISO's Revenue Requirement for Energy Administration Service consists of its expenses for the functions required to provide the Service, as described above. The year 2024 budget costs assigned to Schedule 2 total approximately $129.3 million after true-up.[58] Of this

[52] Exhibit 3, RCL-3, Schedule 1.

[53] Exhibit 3, RCL-7, Schedule 3, Line 2.

[54] Exhibit 3, RCL-7, Schedule 3, Line 2-3.

[55] Consistent with the 2001 Settlement, injections associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company (up to 300 MW) across the New Brunswick Tie are excluded for billing and rate calculation purposes from Energy Administration Service VMs.

[56] Exhibit 3, RCL-7, Schedule 5.

[57] Exhibit 3, RCL-7, Schedule 6. *See also* RCL-2, Schedule 2 and Section I.C.3. The overall Schedule 2 true-up is an over-collection of approximately $5,306,720. *Id.*

[58] Exhibit 3, RCL-3, Schedule 1.

total cost, $19.4 million (*i.e.*, 15% of the Energy Administration Service Revenue Requirement) is projected to be recovered pursuant to the rate design through user charges related to TUs.[59] Included in this amount is $18.2 million of costs assessed to Energy TUs under a declining block rate, billed as follows: $0.82494 per TU for Block 1; $0.74994 per TU for Block 2; and $0.67495 per TU for Block 3.[60] Total projected Energy TUs for 2024 are 23,176,532.[61] In addition, $1.1 million has been budgeted for operating the FTR auction, and will be recovered through the following rates: $2.77242 per FTR bid submitted; and $4.48021 per FTR bid that clears the auction.[62] Finally, the TU Revenue Requirement includes $123,576 for the submission and clearing of Increment Offers and Decrement Bids, which is billed as $0.00500 per submitted offer or bid, and $0.06000 per cleared offer or bid.[63]

The remainder of the total Schedule 2 cost for 2024, approximately $110 million[64] (*i.e.*, 85% of the Energy Administration Service Revenue Requirement), is projected to be recovered pursuant to the existing rate design through user charges related to VMs incurred under three different declining block rates. The rates are as follows: $0.48178 per VM for Block 1; $0.43798 per VM for Block 2; and $0.39418 per VM for Block 3.[65] Total projected Schedule 2 VMs for 2024 are 241,273,327.[66]

c. Rate Development for Reliability Administration Service (Schedule 3)

The ISO's 2024 Revenue Requirement for Reliability Administration Service consists of its expenses for the functions required to provide the Service, as described above. These expenses, totaling $86.7 million after true-up, are detailed in Exhibit 3, RCL-3, Schedule 1 to this filing. The ISO recovers its Schedule 3 Revenue Requirement from Market Participants through two separate rates: (i) a Real-Time NCP Load Obligation charge (assessed to internal load); and (ii) a per-MWh rate for Exports. The total underlying Real-Time NCP Load

[59] Exhibit 3, RCL-7, Schedule 3, Line 6.

[60] Exhibit 3, RCL-7, Schedule 3, Lines 16-19.

[61] Exhibit 3, RCL-7, Schedule 3, Line 20.

[62] Exhibit 3, RCL-7, Schedule 3, Lines 11-13.

[63] Exhibit 3, RCL-7, Schedule 3, Lines 7-9.

[64] Exhibit 3, RCL-7, Schedule 3, Line 22.

[65] Exhibit 3, RCL-7, Schedule 3, Line 23-25.

[66] Exhibit 3, RCL-7, Schedule 3, Line 26.

Obligation is 247,044,681 kilowatt-months.[67] The resulting rate is $0.34097 per kilowatt-month.[68] The Export rate is $0.70 per MWh.[69]

Schedule 3 also includes Reliability Administration Service fees applicable to Non-Market Participant Transmission Customers that take Through or Out Service under the OATT. The proposed Reliability Administration Service fees were developed by applying a ratio of the Schedule 3 forecasted 2024 Revenue Requirement to the Schedule 3 forecasted Revenue Requirement for 2002 to the 2002 Reliability Administration Service Fee, to obtain a monthly fee of $3,626.51, or an hourly rate of $4.97. *See* Mr. Ludlow's testimony at Exhibit 3 (pages 52-53) for more details on the calculation of this hourly rate.

5. Analysis of Cost Shifts Across Schedules

Before true-up, the breakdown by schedule shows an increase in Schedule 1 of $8,200,179 (from $49,273,547 to $57,473,726), an increase in Schedule 2 of $16,425,621 (from $118,209,011 to $134,634,632), and an increase in Schedule 3 of $12,065,720 (from $72,722,598 to $84,788,318). Several factors contributed to this result.[70]

Schedule 1. The increase in the Revenue Requirement for Schedule 1 results from 2024 cost increases and changes that impact all three schedules, including for: targeted compensation increases based on salary benchmarking data; employee benefit costs; computer service infrastructure and architecture (including transition to the cloud), cyber security, and application support; research and development including advanced modeling and the integration of new technologies; resources in Participant Relations & Services and External Affairs & Corporate Communications; interest expense; and corporate insurance policy premium increases. Also contributing to the increase in the Revenue Requirement for Schedule 1 is funding for Transmission Planning and Transmission Services support of long-term transmission planning related to the transition to a carbon free power system, including resources to support expected increases in transmission RFPs, to support stakeholder requests for long-term transmission studies (including New England states' requests), for a regional study with PJM and NYISO to evaluate the impact of increasing New England's single source contingency limit, and support for distributed energy resources and minimum load studies to determine requirements for ensuring reliability under conditions where the system is powered solely by inverter-based resources.

Schedule 2. The increase in the Schedule 2 Revenue Requirement is due to the increases that impact all three schedules, as discussed in the preceding paragraph. Also affecting the

[67] Exhibit 3, RCL-7, Schedule 3, Line 31.

[68] *Id.*

[69] Exhibit 3, RCL-7, Schedule 3, Line 32.

[70] For more information on the factors discussed below, *see* memo to NEPOOL Budget & Finance Subcommittee and Participants Committee from Bob Ludlow and Cheryl Arnold dated September 25, 2023. The memo is located at https://www.iso-ne.com/static-assets/documents/100004/npc-2023-10-05-composite-final.pdf (item 5a).

Schedule 2 Revenue Requirement, increase is depreciation expense increases related to the mid-2023 go-live of the nGEM platform projects, resulting in a full year of depreciation reflected in the 2024 Revenue Requirement.[71] The increase in the Schedule 2 Revenue Requirement is also attributable to funding for Market Development resources to continue progress towards integrating renewable resources and new resource types, including large scale storage resources and batteries into the market designs for the clean energy transition; and for work that affects Schedules 2 and 3, including future grid studies for a clean energy future, and a Participant Relations & Services resource to continue the integration of several new initiatives and projects into market training and the development of new training delivery methods.

Schedule 3. The increase in the Schedule 3 Revenue Requirement is attributable to increases that impact all three schedules and funding for items that impact Schedules 2 and 3, each as noted above. Additionally, the Schedule 3 Revenue Requirement increase is attributable to funding for the assessment of alternate capacity market commitment horizons including prompt and/or seasonal markets, for FCA21 Cost of New Entry (CONE) parameter updates, and increases in NPCC and NERC dues.

II. ISO-NE'S 2024 CAPITAL BUDGET

The 2024 Capital Budget is a list of the ISO's planned capital expenditures in 2024. The ISO does not make any collections through its capital budget; rather, the capital projects reflected in the budget are funded through private placement financing.[72] The ISO funds the capitalized portion of the interest on that financing through recovery of depreciation under its annual operating budget, as discussed in Section I.C.2 above. In sum, the costs of these projects are collected once only, through the depreciation recovery in the Revenue Requirement.

Before describing the projects that comprise the 2024 Capital Budget, the ISO provides context for the Capital Budget in the following Sections II.A and B.

A. The 2024 Capital Funding Arrangements

By way of review and introduction, Section IV.B of the Tariff (called the Capital Funding Arrangements) permits the ISO to collect from Market Participants:

(1) the costs of budgeted capital items, through a Capital Funding Charge, if the costs are not financed by the ISO;

[71] As explained in Section I.C.2 of the filing letter, the nGEM Market Clearing Engine Implementation project, completed in June 2023, included the following projects that began depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phase I and II.

[72] The debt was approved by the Commission in Docket No. ES04-39-000, 109 FERC ¶ 62,195 (2004) and Docket No. ES12-48-000, 140 FERC ¶ 62,173 (2012).

(2) through an Early Amortization Charge, the remaining unamortized costs of assets financed by the ISO in the event of termination, acceleration or required repayment of private financing or, in the case of non-amortizing private financing, payment at maturity if the ISO is unable to refinance such financing;

(3) the working capital amount required by the ISO, if financing arranged by the ISO to meet working capital requirements is terminated early or repayment is accelerated (and no replacement financing has been obtained by the ISO), through an Early Amortization Working Capital Charge; and

(4) The costs that would be required to be paid by the ISO in the event of termination, acceleration or required prepayment of private financing entered into by the ISO in support of weekly billing of a portion of the market settlement system (and no replacement financing has been obtained by the ISO), through an Early Payment Shortfall Funding Charge.

The "backstopping" reflected in the foregoing Capital Funding Arrangements is necessary to help the ISO obtain and/or maintain private financing. When approving the establishment of an independent system operator in New England, the Commission expressed its concern that financial arrangements directly relying on Market Participant support for capital projects could compromise the ISO's independence.[73] Although the Commission allowed the ISO to initially rely on contractual provisions with the NEPOOL to fund then-existing capital assets, the Commission made clear that, [t]o the extent the ISO required additional, similar facilities in the future, these facilities should be funded by the ISO, not NEPOOL…."[74]

After the ISO commenced operations in 1997, it spent several years trying to obtain third-party private financing consistent with the Commission's directive to maintain independence from NEPOOL participants. The ISO, however, faced a key problem: an inability to provide banks the assurances they needed that the ISO would have the funds to repay a loan in the event of its early termination or acceleration. As a non-profit, non-stock Delaware corporation that is tax-exempt under Section 501(c)(3) of the Internal Revenue Code, the ISO has no equity capital (or ability to raise capital) to fund capital expenditures or working capital. Substantially all of the ISO's revenues are derived from charges to Customers under Commission-approved arrangements.

Ultimately, a bank expressed willingness to lend to the ISO based on the "backstopping" provisions of the Tariff and the ability to recover debt service through depreciation and amortization charges. Thus, the ISO funds its capital projects with third-party financing to maintain independence from Market Participants, while banks rely on Sections IV.B and IV.A of the Tariff to provide sufficient assurances to finance the ISO.

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[73] *New England Power Pool*, 79 FERC ¶ 61,374 at p. 62,590 (1997).

[74] *Id*.

Given the structure and terms of the Capital Funding Arrangements (which remain unchanged for calendar year 2024 from those on file with and accepted by the Commission), if no termination or acceleration of that financing occurs, then none of the charges described above will be collected for these purposes. The ISO currently has planned financing for all elements of the 2024 Capital Budget given the structure of its existing Capital Funding Arrangements, and at this time, the ISO does not foresee the need to obtain capital funds from Market Participants pursuant to these arrangements in calendar year 2024. As a result, the ISO does not anticipate assessing charges to Market Participants under the Capital Funding Arrangements in calendar year 2024.

B. The Transparency of the 2024 Capital Budget

The ISO's process outlined below makes the ISO's capital budgeting process transparent to stakeholders and the Commission and keeps them well informed of changes in forecasts or actual expenditures. The process includes regular reviews with stakeholders, a vote on the annual capital budget by the ISO's independent Board of Directors, and quarterly and annual filings with the Commission pursuant to Section 205 of the Federal Power Act.

The annual capital budgeting process includes review with the NEPOOL Budget and Finance Subcommittee, the NEPOOL Participants Committee,[75] and representatives of the New England states' public utilities commissions.[76] Following this review, the ISO Board of Directors approves the annual capital budget.[77] These steps are precursors to a Section 205 filing of the annual capital budget.

In addition, on a quarterly basis, the ISO reviews updates to the capital budget at meetings of the NEPOOL Budget and Finance Subcommittee and then files these updates with the Commission under Section 205. These updates are described in Section IV.B.6.2 of the Tariff, which requires the ISO to file with the Commission under Section 205 on a quarterly basis: (i) a report specifying by project prior-year spending on multi-year projects, year to date spending, and a forecast of the spending to complete the project in each future calendar year; and (ii) a schedule of the unamortized costs of the ISO's funded capital expenditures at the end of the quarter and the allocation of those costs to the ISO's rates (*i.e.*, Schedules 1, 2, and 3 to Section IV.A of the Tariff).

Roughly contemporaneously with the instant filing, the ISO will make a separate quarterly filing for the third quarter of 2023. The accounting is consistent for those capital projects that are reported both in the quarterly update and in the 2024 Capital Budget, although the focus of the two filings is different (*i.e.*, 2023 versus 2024).

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[75] The process for Market Participant review of ISO budgets is specified in Section IV.B.6.1 of the Tariff.

[76] *See* Section I.B above for a description of the 2024 process.

[77] *See* Section IV.B.6.1 of the Tariff.

In sum, the ISO's capital budgeting practices create a high degree of transparency and accountability that is unparalleled among other independent system operators and regional transmission organizations—and even among other public utilities.

C. Elements of the 2024 Capital Budget

The 2024 Capital Budget is $35 million, an increase of $1.5 million from the 2023 Capital Budget. As explained in Mr. Ludlow's testimony, the capital budget has been incrementally increasing over the past several years from the previously consistent $28 million capital budget. Current projections are that the capital budget will level out at $40 million (currently projected in 2025).[78] The increase is necessitated by four primary drivers: (i) the replacement of the current market system platform (*i.e.*, the nGEM project, described in more detail below); (ii) major market and reliability related efforts that will have significant software requirements; (iii) cyber security needs; and (iv) required information technology asset and infrastructure upgrades. *See* Mr. Ludlow's testimony at Exhibit 3 (pages 54-60) for more details on these factors.

As described above, the ISO's capital project costs are largely funded by private placement debt, and as a result of the planned increase in the amount of capital budget spending, the ISO anticipates needing additional debt (to replace the existing private placement note and to increase the working capital line)[79] in late 2023 and 2024. The ISO will update the NEPOOL Budget and Finance Subcommittee regarding its borrowing needs and will make a Section 204 filing(s) with the Commission for the requisite approval(s).

The primary elements of the 2024 Capital Budget are anticipated to be the projects outlined below. The primary deliverables for a majority of the 2024 Capital Budget projects are application software and requisite hardware needed to maintain and improve bulk-power system reliability and/or wholesale electric markets.[80] Typically, the ISO's capital projects stem from market initiatives, identified in conjunction with stakeholders, to improve the energy, ancillary services and capacity markets. Other capital projects are driven by the need for increased reliability and information, increased cyber security, operational excellence activities that aim to improve the efficiency of the organization through measures such as automation of manual

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[78] *See* Exhibit 3 at pp. 54-55. As explained in the filing letter to support the 2023 capital budget, the ISO had previously expected the capital budget to level out at $35 million, but the ISO's current cash flow analysis now indicates that the ISO will need to increase the capital budget to $40 million. The primary reason for this change is a result of inflation of both labor and hardware costs and longer lead times on the more complex projects especially projects supporting cyber security and/or clean energy transition initiatives. Longer lead times on projects delay when they are placed into production which is the trigger allowing the ISO to begin collecting depreciation under the operating budget. *See id.*

[79] *See* Exhibit 3 at pp. 60-61; and the Budget Presentation (Slides 86-90) for a breakdown of the ISO's capital structure, expected debt needs, and cash flow.

[80] Capital projects also include project management and design work. If a project's design is approved and built, this work becomes part of the asset on which the ISO collects depreciation when the asset is placed in service and in future years via the operating budget. On the other hand, if the capital project is abandoned, the ISO writes off the entire project cost, including management and design work and recovers it in full in the year of abandonment.

business processes, or regulatory requirements imposed by the Commission. In each case, the ISO has determined that the capital project will benefit the region's stakeholders by improving the ISO's ability to maintain bulk-power system reliability, administer fair and efficient markets, and provide information to stakeholders to increase transparency and facilitate decision-making.

The following are the material projects that are anticipated to comprise the 2024 Capital Budget. The projects listed in Sections 1 through 9 are well-defined and have had charters approved by management;[81] the remainder are still in the planning stages or are subject to further Commission action.

1. Day-Ahead Ancillary Services Improvements ($3,800,000)

The Day-Ahead Ancillary Services Improvements project will implement market design enhancements for procuring and transparently pricing the ancillary service capabilities needed to develop a reliable next-day operating plan. These market enhancements will procure supply capability in the day-ahead market to meet the ISO's forecasted real-time load and operating reserve requirements.

The Day-Ahead Ancillary Services Improvements project will incorporate the market design elements into the ISO's day-ahead market bidding, clearing, and settlement systems. The first main element involves including the ISO's forecast of real-time load in the day-ahead market in order to ensure the load forecast is satisfied by procuring a combination of physical energy supply and a new day-ahead ancillary service (Energy Imbalance Reserve). The second main element involves procuring Flexible Response Services in the day-ahead market to ensure the system is prepared to recover from major contingencies during the operating day. The ISO will incorporate these elements into the day-ahead market in a way that allows for optimal scheduling of both day-ahead energy and ancillary services, requiring significant changes to the existing day-ahead market clearing engine. In addition, the project incorporates mitigation-related enhancements for the day-ahead market to evaluate the offers to provide these services and safeguard market competitiveness.

The targeted completion date for this project is March 2025.

2. nGem Software Development Part III ($2,500,000)

The ISO is co-funding the core product development for GE Grid Solutions' nGEM software development. The nGEM Software Development project will enhance data transfer technology, Day-Ahead and Real-Time market clearing engines, and bidding micro services. It will also include various software upgrades. Part I delivery, completed in October 2020, included enhanced data transfer technology and the elimination of the Habitat platform. Part II, completed

[81] All capital projects, prior to approval, must have a completed project charter. This charter documents the project's goals and objectives, schedule and milestones, and budget. The charters are reviewed to ensure that the cost estimates are reasonable and that no costs were double-counted. Before approving a new capital project, the ISO's senior management team reviews each project charter.

in June 2023, included Day-Ahead market clearing engine enhancements, bidding micro services, and Real-Time market clearing engine replacements.

Part III will implement advanced storage support in the nGEM Market Clearing Engine ("MCE") and Market CIMNet Simultaneous Feasibility Test software; enhance the nGEM MCE to further support real-time study modes and other components; and replace the Oracle based workflow controller with software designed as part of the Part II phase of the project.

The targeted completion date for this project is March 2025.

3. Operating System Server Upgrade Phase I ($1,200,000)

The ISO relies on a number of legacy servers for critical business functions that will be reaching end-of-life in the near future. The Operating System Server Upgrade project will be a multi-phase project to upgrade or retire these servers, and develop a server update lifecycle that will provide consistent, standard, and modern deployments of servers that support the ISO's business objectives. Phase I the project will establish a lifecycle process and include the upgrade or retirement of servers where support will end in 2024. This project will establish a timeline for a server refresh cycle consistent with published maintenance support dates, and replace or refresh servers prior to the end of a support period, thereby avoiding increased costs of extended server maintenance and support. This new life cycle will limit the number of supported operating systems, which will improve security analysis, patching efficiency, and threat vector risk.

Phase II of the project will upgrade or replace remaining servers, establish metrics and system improvements to allow the Information Technology management team to quickly assess the fleet of servers for decision-making purposes, and develop and implement process improvements to enable server life cycle management.

The targeted completion date for this project is July 2024.

4. Solar Do-Not-Exceed Dispatch Phase II ($900,000)

The quantity of in-front-of-the-meter solar generation in the New England region is increasing and expected to continue to increase. Integration of solar resources will require development of rules, processes, forecasts, and tools necessary to incorporate these resources into the Do-Not-Exceed ("DNE") dispatch processes. During Phase I, GE developed enhancements to the ISO's Renewable Plan ("RPlan") software to allow Market Participants to submit their medium- and long-term data for the availability of future power generation. Enhancements included upgrades to support provisions of solar power forecasts, and the ability to receive forecasts for both wind and solar from multiple vendors.

Phase II of the Solar DNE Dispatch project will perform the steps necessary to reliably and efficiently integrate solar resources into the DNE dispatch process. This will include introduction of in-front-of-the-meter solar resource power forecasts and incorporation into the Real-Time DNE dispatch process, the Energy Management System, and into System Operator Situational Awareness displays. In addition, Phase II will evaluate and develop additional solar-

specific reports and web-posting needs, including but not limited to: provisions of solar forecast data to Local Control Centers, development and distribution of solar forecast reports, and posting of solar undelivered energy reports (similar to what is currently being done for wind resources).

The targeted completion date for this project is October 2024.

5. Internal Market Monitoring Data Analysis Phase IV ($500,000)

The ISO's Internal Market Monitoring ("IMM") department analyzes market data to identify issues that may compromise the efficiency and integrity of market outcomes. Successful analysis requires access to a large variety of market data. The multi-phase IMM Data Analysis project has enabled IMM market analysts to explore data across multiple markets (*e.g.*, energy, capacity, and ancillary services) and multiple market products (*e.g.*, physical and financial). Previous phases of the IMM Data Analysis project developed a market data analysis system with access to data from Financial Transmission Rights, the Forward Reserve Market, the Day-Ahead and Real-Time market systems, the Forward Capacity Market, and Net Commitment Period Compensation. As a result, IMM analysts have access to energy and regulation market data and the ability to address outstanding requests for improvements/optimizations related to data tables. However, the process to collect and analyze data from the various sources is time consuming and requires validation and preparation before the data can be used.

The Internal Market Monitoring Data Analysis Phase IV project will develop a solution to enable IMM analysts to query data from all possible sources, with the objective of providing available data in a "readiness" state, reducing the amount of data preparation time, while also ensuring the data is accurate, consistent, reliable, and complete.

The targeted completion date for this project is May 2024.

6. Energy Management System Short-term Load Forecast Replacement ($400,000)

The Energy Management System's short term load forecast ("STLF") is a critical input to Real-Time unit commitment and unit dispatch software. The existing STLF software is unable to address the emergence of behind-the-meter solar to account for load patterns of weather and clouds, requiring significant manual intervention by control room operators in order to minimize market and reliability impacts. This issue has been growing in severity over the past several years and a variety of small-scale initiatives have been completed in order to allow system operators to manually adjust the STLF to account for behind-the-meter solar activity during the operating day. Because of the significant manual adjustments and rapid growth of behind-the-meter solar, replacement of the STLF engine is required for efficiency and accuracy.

The development of a new forecasting system to replace the current STLF will improve the price formation for Coordinated Transaction Scheduling, provide a more accurate input for Real-Time unit commitment and dispatch software; and reduce the time Control Room operators spend monitoring and manually intervening in the STLF results, allowing operators to focus

more on system conditions and reliability. This project will also develop and deliver a new forecasting system with a dynamic modeling process that will create a real-time load data feed and incorporate real-time behind-the-meter photovoltaic data for use in forecasting; develop new forecasting models; establish the necessary development, integration, and production environments for the load forecasting platform; train ISO personnel regarding the new system; and update the relevant internal procedures and process documentation.

The targeted completion date for this project is July 2024.

7. IT Asset Workflow Integration and Updates ($200,000)

The IT Asset Workflow ("ITAW") system is used for the business processes associated with procurement, installation, and deployment of information technology assets. The ITAW application provides all the necessary tracking, controls, and audit trails for these assets. The ITAW's workflows need to be updated to provide the ISO with search and data maintenance capabilities, specifically in the ISO's configuration management database. Additionally, the current ITAW was developed prior to the creation of certain cyber security and compliance standards.

ITAW updates in this project will include ensuring that current and accurate data is available in the configuration management database system; the ability to perform an impact analysis when changes are made to configured assets; reductions to audit and compliance risks by providing audit trails for actions associated with NERC Critical Infrastructure Protection ("CIP") and other cyber security standards; and a reduction to needed resources (*e.g.*, licensing fees and third party application support) that are currently required to keep multiple data sources in sync.

The targeted completion date for this project is of May 2024.

8. Energy Management System Host Monitoring Software Replacement ($100,000)

The ISO's current host monitoring software vendor will discontinue support for their antivirus protection as an on-premise endpoint detection and response ("EDR") solution in December 2023. ISO-NE uses this antivirus software to provide malware protection on certain Bulk Electric System ("BES") Cyber Assets, and it is a key part of the ISO's compliance with NERC CIP standards. The most cost efficient solution to ensure we maintain operational cyber security in the Energy Management System environment, as well as comply with CIP standards, is to select and deploy a new on-premise host based agent solution.

The Energy Management System Host Monitoring Software Replacement project will identify and implement a host monitoring solution to replace the existing software and applications for the EMS environment to comply with CIP standards. The scope of the project will include the procurement of the necessary applications and licenses for the new EDR solution; deployment and configuration of a user interface for management endpoints; deployment of the solution; integration of cyber security monitoring tools to enhance

identification and response abilities; and necessary updates to CIP compliance documentation, processes, and procedures.

The targeted completion date for this project is January 2024.

9. Settlement Technology Improvements Project ($100,000)

The Settlement Technology Improvements project will replace all settlement application servers and associated hardware that are outdated and do not contain the necessary components and features needed for ongoing support of the various settlement applications. The settlement applications include the Settlement Market System, Market Information System, and Financial Assurance Management system all serving critical functions related to settlement, billing, and reporting to Market Participants. The upgrade of settlement application servers and associated hardware will provide enhanced security features, flexible support controls for planned outages, enhanced features to monitor and control outage requests, and logging for detailed reporting on user access.

The targeted completion date for this project is March 2024.

10. nGem Real-Time Market Clearing Engine Implementation ($6,000,000)

The ISO's Market Management System ("MMS") is based on GE Grid Solution's suite of market applications known as the nGEM program. GE is redeveloping the Market Clearing Engine ("MCE"), a central component of the MMS.

Pursuant to a separate capital project, the Day-Ahead MCE has been developed and is in production. The nGEM Real-Time Market Clearing Engine ("RT MCE") project will build on the Day-Ahead MCE to develop and deploy the Real-Time MCE, including ISO-NE customizations.

During the first phase of the nGEM RT MCE project, two of the legacy RT MCE study modes (the Real-Time Unit Commitment ("RTUC") and Coordinated Transaction Scheduling Pricing Engine ("CTSPE") functions) will be replaced and the transition from Energy Management System to MMS interfaces will be started. The nGEM RT MCE project will provide performance improvements by enabling more intensive market clearing formulations; eliminate reliance on .CSV flat files for communication of data between the MCE and other parts of the MMS; and enhance installation, patching, and upgrades of MCE's in ISO infrastructure.

The targeted completion date for this project is June 2025.

11. FERC Order 881 Compliance ($3,300,000)

FERC Order 881 has several compliance requirements for the ISO regarding the accuracy and transparency of transmission line ratings. The compliance requirements will require the ISO

to comply with specific data reporting and record-keeping protocols. To ensure compliance, organizations need a robust software solution that automates data management, streamlines reporting processes, and maintains accurate records. The goal of this project is to implement the order requirements effectively and efficiently.

This project will include enhancements to existing Energy Management System ("EMS") products and the creation of a new product to handle compliance with transmission line limit exchanges among the ISO and transmission owners.

The targeted completion date for this project is June 2025.

12. CIP Electronic Security Perimeter Redesign Phase II ($2,000,000)

The CIP Electronic Security Perimeter Redesign project is a multi-phase project that will redesign the ISO's electronic security perimeter ("ESP") networks to enhance the ISO's overall network security posture to align with industry best practices regarding resiliency, recovery, and change management. This project will also facilitate compliance with NERC CIP standards. Phase I completed in July of 2021, involved the reconfiguration of both ISO facility data centers, the isolation and protection of management control functions, changes to network designs and firewalls to reduce complexity, and installation of conduit encryption for all inter-physical security perimeter connections.

The second phase will improve ESP network CIP compliance and will enhance the ISO's overall network security posture. Phase II efforts will consolidate the ISO's production and integration networks into one ESP, with fewer electronic access points; modernize the ISO's firewall platform; implement a modern access control mechanism for CIP networks, replacing a legacy terminal-server based system; and standardize the ISO's IP address scheme to enable easier network management. This project is also foundational for future CIP compliance projects.

The targeted completion date for this project is December 2024.

13. Enterprise Resource Planning System Replacement ($1,600,000)

The ISO's current financial Enterprise Resource Planning ("ERP") system reaches end-of-life in April 2026 and will need to be replaced. The ISO's ERP system provides the core framework for recording and reporting financial transactions and is a key component of settling the wholesale electricity markets, securing the necessary funding for ISO operations, and maintaining strict compliance with reporting and filing requirements (including FERC reporting requirements). This project will replace the current ERP system with an updated cloud-based product and will involve significant efforts to migrate ISO data and customizations within the current product.

The targeted completion date for this project is March 2025.

14. Resource Capacity Accreditation ($1,000,000)

In response to the evolving resource mix in the New England region and potential increasing risk of natural gas limitations in the winter, the ISO is considering changes to how resources are accredited in the Forward Capacity Market ("FCM"). As part of this project, three major areas will be considered for tariff changes: (1) improvements to resource performance and load assumptions used in the resource adequacy assessment ("RAA") process; (2) potential inclusion of energy limits on energy storage and natural gas-/oil-fired resources in the RAA; and (3) application of a marginal reliability impact ("MRI") approach to calculate the accredited capacity of resources. These changes will have a significant impact on the implementation of the FCM, requiring modification to the existing implementation and development of new functionality. Areas impacted will include, but are not limited to, RAA modeling assumptions, resource qualification, demand curve formulation, commercial and seasonal demonstrations, reconfiguration auction qualification, pay-for-performance, and compensation and cost allocation.

The targeted completion date for this project is December 2025.

15. Microsoft 365 Service Adoption ($1,000,000)

The capabilities and resiliency of the ISO's on-premise enterprise software (*e.g.*, directories, file shares, and mail servers) can be improved and consolidated using the cloud-based Microsoft 365 Services. Adoption of Microsoft 365 Services for certain enterprise software will significantly increase the ISO's business continuity posture and will allow employees to work more productively with natively built-in tools and features.

The migration to Microsoft 365 will improve employee collaboration, streamline IT operations with new management tools and automation, improve protection of end users and information with platform-wide security solutions, and reduce overhead associated with maintaining physical IT infrastructure.

The targeted completion date for this project is September 2024.

16. 2024 Issue Resolution Project ($1,000,000)

The ISO uses a corrective action/preventative action ("CAPA") approach to identify and track needed enhancements to existing systems and processes to more efficiently administer the market rules and procedures.

The 2024 Issue Resolution Project will focus on resolving CAPAs that enhance various software systems. Software changes can span a wide range of functionality including user interface improvements, internal and external reporting modifications, and other market related improvements.

The targeted completion date for this project is December 2024.

17. FERC Order 2222 ($500,000)

The Commission's Order 2222 requires that independent system operators and regional transmission organizations remove barriers to the participation of distributed energy resource aggregations ("DERAs") in wholesale electricity markets. In accordance with Order 2222, the ISO proposes to expand its current energy market models and add two new energy market participation models for DERAs: Settlement Only Distributed Energy Aggregation, and Demand Response Distributed Resource Aggregation. Additionally, the introduction of a new resource type, Distributed Energy Capacity Resource, will allow DERAs to participate in the Forward Capacity Market.

Compliance with Order 2222 will span two projects. The first project, Forward Capacity Market Order 2222, in development and scheduled to be completed in November 2023, will implement the necessary software changes to support the qualification and participation of Distributed Energy Capacity Resources in the Forward Capacity Market. The FERC Order 2222 project will include the software changes to allow for the integration of DERAs in the wholesale markets and operations systems and any remaining compliance obligations of the order.

The targeted completion date for this project is December 2026.

18. Privileged Account Management Security Enhancements Phase II ($500,000)

The ISO continually monitors the changing landscape with respect to phishing threats and email attacks. With advances in ransomware and persistent threats from nation states, privileged accounts are at higher risk and, if compromised, may have a significant impact on the organization's operations. Ransomware groups and nation-state advanced persistent threat ("APT") teams have targeted multiple electric sector companies with cyber attacks. Recent improvements to enterprise credential and access management have led to development of technology and practices available to companies called Privileged Access Management ("PAM") systems. PAM systems support use and management of credentials used in enterprise desktops and servers.

The PAM Security Enhancements Phase II project will continue 2022 efforts to develop technology and processes to protect and reduce the risk of these cyber attacks for high risk key accounts.

The targeted completion date for this project is December 2024.

19. Non-Project Capital Expenditures ($5,300,000), Other Emerging Work ($1,600,000), and Capitalized Interest ($1,500,000)

The 2024 Capital Budget includes a total of $5,300,000 for non-project capital expenditures. Non-project capital expenditures fund external and internal capitalized labor

necessary to program System Improvement Requests ($2,500,000); non-project related hardware purchases ($2,500,000); and building improvements, machinery & equipment, and furniture & fixtures ($300,000).[82]

The "Other Emerging Work" category ($1,600,000) is primarily intended to address emerging work requests during 2024 that result from operational needs, compliance obligations, or regulatory/stakeholder feedback.

Last, $1,500,000 is allocated to capitalized interest. Accounting conventions require that interest be capitalized for capital projects that cross years. In addition, loan fees associated with borrowings to fund capital assets are also capitalized.

D. Caveats

The 2024 Capital Budget cannot accurately predict the ISO's actual capital expenditures for 2024. For example, protracted stakeholder review of a proposal or extensive litigation contesting a proposal can delay implementation of market improvements, thereby affecting when the ISO might incur a capital expenditure and the amount of that expenditure, as well as the ISO's cost recovery and ability to fund future projects due to constraints on available lines of credit. It is also likely that the ISO's capital project priorities will change during the course of the year. Emerging needs that are difficult to anticipate in advance will likely require a shift in priorities. In such situations, it is likely that the distribution of the 2024 Capital Budget will change. The quarterly filings under Section IV.B.6.2 of the Tariff will keep stakeholders and the Commission apprised of necessary adjustments.

III. ADDITIONAL SUPPORTING INFORMATION

The ISO submits the following additional information pursuant to Sections 205 of the FPA and 35.13 of the Code of Federal Regulations:

35.13(b)(1) – In addition to this transmittal letter, the ISO provides the following materials:

- Clean Section IV.A of the Tariff (Exhibit 1);
- Blacklined version of Section IV.A of the Tariff (Exhibit 2);
- Prepared testimony and exhibits of Robert C. Ludlow regarding the 2024 Administrative Expenses Tariff (Exhibit 3);
- Prepared testimony of Kathleen deCastro regarding the 2024 Administrative Expenses Tariff (Exhibit 4);
- 2024 Capital Budget (Exhibit 5);

[82] *See* Appendix 7 to the Budget Presentation for additional detail regarding Non-Project Capital Expenditures (Slide 185).

- Table showing cross-references for Statement AA-BM data (Exhibit 6);
- Excerpts (income statement, balance sheet, cash flow, notes to the financial statements, and other schedules) from the ISO's Form 1 for 2022 (Exhibit 7);
- List of the governors and electric utility regulatory agencies for the six New England states to which the ISO has sent electronic copies of this filing (Exhibit 8);
- Comments of state agencies on proposed 2024 Budgets (Exhibit 9); and
- ISO-NE response to comments of state agencies on proposed 2024 Budgets (Exhibit 10).

As in the past, the ISO has included the cost of service data required by Statements AA-BM and relevant to the ISO through these exhibits, with Exhibit 6 showing the location in each exhibit by statement. Exhibit 6 also identifies those statements requiring data that are not relevant to the ISO's development of a Revenue Requirement, due to the ISO's nature as a not-for-profit RTO that does not own any generation or transmission assets. The Commission repeatedly has accepted the ISO's rates as supported in this manner, including an explicit acknowledgement that such data is sufficient.[83]

35.13(b)(2) – The ISO requests that the Commission accept the 2024 Capital Budget and the 2024 Administrative Expenses Tariff as filed, effective January 1, 2024.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants will be served electronically. The names and addresses of the Governance Participants are available through the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory. A copy of this transmittal letter and the accompanying materials have also been e-mailed to the governors and electric utility regulatory agencies for the six New England states and to the New England Conference of Public Utilities commissioners and the New England States Committee on Electricity. The names and e-mail addresses of these governors and regulatory agencies are shown in Exhibit 8. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Exhibit 8 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

35.13(b)(5) – This transmittal letter and supporting materials provide a statement of the reasons the Commission should accept the 2024 Capital Budget and the 2024 Administrative Expenses Tariff.

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[83] *ISO New England Inc.*, 86 FERC ¶ 61,453 at p. 62,680 (1998) (rejecting a protestor's request to require the ISO to file the cost of service statements set forth in Section 35.13(h) of the Commission's Rules and Regulations, "find[ing] that the ISO has provided sufficient information to meet the minimum filing requirements").

35.13(b)(6) – The ISO Board of Directors has approved the 2024 Capital Budget, the 2024 Revenue Requirement, and resulting rates herein. The ISO also notes that the NEPOOL Participants Committee voted to support the 2024 Capital Budget and the Revenue Requirement.

35.13(b)(7) – The ISO does not have any knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) – See Exhibit 3 for a comparison of the sales, services and revenues from the rate schedule to be superseded and under the rate schedule change.

35.13(c)(2) – The ISO has no other rates for similar services.

35.13(c)(3) – No specifically assignable facilities have been or will be installed or modified in order for the Commission to accept this filing.

IV. COMMUNICATIONS

Correspondence and communications regarding this filing should be addressed to the undersigned for the ISO as follows:

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V. CONCLUSION

For the reasons stated herein, the ISO requests that the Commission accept the 2024 Capital Budget and the 2024 Administrative Expenses Tariff, as filed, without suspension or hearing, with an effective date of January 1, 2024.

Respectfully submitted,

/s/ Jennifer M. Recht
Jennifer M. Recht
Assistant General Counsel – Corporate
ISO New England Inc.

Enclosures

EXHIBIT 1

SECTION IV.A
RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments. Notwithstanding the foregoing, for any instance of special purpose funding, in which funds are allocated and not to be used for any other purpose, the ISO may maintain any surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism described above until such time as the special purpose needs are completed, at which time the ISO will include any remaining funds in the Revenue Requirement adjustment being made pursuant to this Section (2).

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working

Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.
Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:

In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:

If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:

Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 [Reserved for Future Use]

IV.A.6.6 Re-billing Requests:

In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:

The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:

The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:

The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.26954 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $0.00037 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.82494 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.74994 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.67495 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions;

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded; and

(3) Monthly Real-Time Demand Reduction Obligation (MWh).

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.48178 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $0.43798 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $0.39418 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $2.77242 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $2.77242 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $4.48021 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $4.48021 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $4.97 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $0.34097 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $0.70000 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2023, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00701 per kilowatt times its Monthly Regional Network Load for that month.

EXHIBIT 2

SECTION IV.A

RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments. Notwithstanding the foregoing, for any instance of special purpose funding, in which funds are allocated and not to be used for any other purpose, the ISO may maintain any surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism described above until such time as the special purpose needs are completed, at which time the ISO will include any remaining funds in the Revenue Requirement adjustment being made pursuant to this Section (2).

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working

Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation. Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:

In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:

If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:

Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 [Reserved for Future Use]

IV.A.6.6 Re-billing Requests:

In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:

The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:

The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:

The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $~~$0.20475~~0.26954 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $~~0.00028~~0.00037 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $~~0.69888~~0.82494 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $~~0.63535~~0.74994 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $~~0.571810~~0.67495 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions;

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded; and

(3) Monthly Real-Time Demand Reduction Obligation (MWh).

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $~~0.402590~~0.48178 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $~~0.365990~~0.43798 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $~~0.329400~~0.39418 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $~~2.010082~~.77242 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $~~2.010082~~.77242 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $~~4.205394~~.48021 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $~~4.205394~~.48021 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $~~3.97~~4.97 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $~~0.262600~~.34097 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $~~0.550000~~0.70000 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2023, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00701 per kilowatt times its Monthly Regional Network Load for that month.

EXHIBIT 3

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER24-_____-000**

DIRECT TESTIMONY

OF

ROBERT C. LUDLOW

Filed on: October 13, 2023

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RCL-2: Revenue Requirement and True-Up

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RCL-5: 2024 Core Operating Budget

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RCL-8: NEPOOL Resolution

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO NEW ENGLAND INC.) Docket No. ER24-_____-000

Direct Testimony of Robert C. Ludlow

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert C. Ludlow. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Vice President and the Chief Financial and Compliance Officer of ISO New England Inc. (the "ISO"). I served in the role of Vice President and Chief Financial Officer from the time the ISO commenced its operations on July 1, 1997 until September 2000. At that time, I began working as an outside consultant for the ISO until August 2002, when I rejoined the ISO as Vice President and Chief Financial Officer. In July of 2008 my title changed to reflect my expanded responsibility for compliance. The compliance organization is responsible for developing and maintaining the Company's compliance management system. This system captures the Company's compliance obligations, including those of the North American Electric Reliability Corporation ("NERC"), North American Energy Standards Board, and the Northeast Power Coordinating Council ("NPCC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.B.A. in Accounting from St. Bonaventure University. Prior to joining the ISO, I was a Partner at the accounting firm of Marden, Harrison & Kreuter, CPAs. I also served as the Chief Financial Officer of Western Beef, Inc. I am a Certified Public Accountant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes. I previously have testified before the Commission to support prior administrative rate filings by the ISO in Docket Nos. ER23-94-000 (rates proposed for 2023); ER22-113-000 (rates proposed for 2022); ER21-106-000 (rates proposed for 2021); ER20-106-000 (rates proposed for 2020); ER19-107-000 (rates proposed for 2019); ER18-77-000 (rates proposed for 2018), ER17-116-000 (rates proposed for 2017), ER16-92-000 (rates proposed for 2016), ER15-112-000 (rates proposed for 2015), ER14-90-000 (rates proposed for 2014), ER13-185-000 (rates proposed for 2013), ER12-191-000 (rates proposed for 2012), ER11-1943-000 (rates proposed for 2011), ER10-154-000 (rates proposed for 2010), and others.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am providing this testimony primarily to support the ISO's proposed revenue requirement for 2024 ("2024 Revenue Requirement") and the updated rates to collect it. My Direct Testimony presents the ISO's 2024 Revenue Requirement as reflected in the proposed revised tariff sheets attached as **Exhibits 1 and 2** (clean and blacklined versions, respectively) to the filing letter.

Specifically, I will describe the ISO's budget process, summarize the elements of the ISO's 2024 Revenue Requirement (including the true-up mechanism), present the ISO's 2024 Core Operating Budget (*i.e.*, the administrative costs of running the ISO), and describe the ISO's activity accounting system. I will also present the development of the Test Year 2024 cost of service study associated with the ISO providing service under the three primary rate schedules included in Section IV.A of the ISO's Transmission, Markets and Services Tariff (the "Tariff").

Section IV.A of the Tariff provides for recovery of the ISO's administrative expenses. The three primary rate schedules are: (1) Schedule 1 – Scheduling, System Control and Dispatch Service ("Scheduling Service"); (2) Schedule 2 – Energy Administration Service; and (3) Schedule 3 – Reliability Administration Service.

Finally, I will present proposed escalation factors to adjust actual load data for the 12-month period ending July 2023 to the Test Year 2024 for the purpose of rate design, discuss the rate design utilized, and the proposed rates, including certain fixed fees.

In addition to the aforementioned testimony to support the proposed 2024 Revenue Requirement, I will also provide testimony to support the proposed capital budget for 2024 (the "2024 Capital Budget") which is increasing from $33.5 million in 2023 to $35 million in 2024, and related capital funding requirements.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. Before offering a conclusion, I will describe:

(i) the current operations and organizational structure of the ISO;

(ii) the budget development process;

(iii) the various elements of the 2024 Revenue Requirement;

(iv) the ISO's activity accounting system;

(v) how the ISO allocated its costs among the rates it proposes to charge in the Tariff's Schedules 1, 2, and 3;

(vi) the 2024 rate design and escalation factors;

(vii) the 2024 billing determinants;

(viii) a rate summary;

(x) fixed fees; and

(xi) the proposed increase to the 2024 Capital Budget.

CURRENT OPERATIONS AND ORGANIZATIONAL STRUCTURE OF THE ISO

Q. WHAT ARE THE CURRENT OPERATIONS AND ORGANIZATIONAL STRUCTURE OF THE ISO?

A. The ISO provides three basic services to its customers:

1. Scheduling Service (Schedule 1): Through this service, the ISO schedules at the pool level the movement of power through, out of, within, or into the New England Control Area.

2. Energy Administration Service (Schedule 2): Through this service, the ISO administers the energy markets and facilitates generation and demand dispatch, auctions for Financial Transmission Rights ("FTRs"), and other services (*i.e.*, under Section III of the Tariff).

3. Reliability Administration Service (Schedule 3): Through this service, the ISO administers the reliability markets (and facilitates reliability-related transactions and arrangements) in accordance with Market Rule 1 and provides other reliability and informational services.

The ISO is governed by an independent Board of Directors with a cross-section of skills and experience, including financial markets, law, electric power operations, and regulation. The ISO is overseen by a President and Chief Executive Officer ("CEO") who has seven direct reports. An Executive Vice President and Chief

Operating Officer is responsible for System Operations & Market Administration, System Planning, Market Development & Settlements, Program Management, Advanced Technology Solutions, Participant Relations & Services, and Information & Cyber Security Services. The other direct reports of the CEO are: Vice President and General Counsel; Vice President, Chief External Affairs & Communications Officer; Vice President, Chief Financial & Compliance Officer; Vice President, Human Resources & Chief People Diversity Officer; Executive Director, Market Monitoring; and Director, Internal Audit. The latter two positions report to the CEO for administrative purposes only. See RCL-1, attached to this testimony.

THE BUDGET DEVELOPMENT PROCESS

Q. HOW WERE THE ISO'S BUDGETS DEVELOPED FOR 2024?

A. The ISO's budgeting process is driven by the ISO's strategic planning process. The strategic planning process includes a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can support, with the aim of creating value for ISO stakeholders. Included in the strategic planning process is the development of annual and five-year business plans that outline major priorities and activities in line with the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean

energy. The ISO ties its annual budget to resource requirements by goals, objectives, and initiatives, including five strategic goals:

- **Responsive Market Designs**: Improve the current market structure and continue to evolve and reposition the market design to accommodate the states' objectives and the transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to attract new entry;

- **Progress and Innovation**: Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services;

- **Operational Excellence**: Continuously improve operations and processes, with a focus on efficiency and effectiveness, business results, and continuity of operations;

- **Stakeholder Engagement**: Collaboratively understand and anticipate needs, demonstrate thought leadership through high quality analysis and communication, and nurture productive relationships with the Commission, the states, and market participants; and

- **Attract, Develop, and Retain Talent**: Develop a sense of community around the ISO's core values, mission, vision, and goals; prepare the workforce; recognize and reward employees' success and innovation; and honor diversity and promote inclusion.

These goals formed the foundation for the development of the 2024 Core Operating Budget. Additionally, the ISO prepares budgets in advance of each upcoming year using a seven-step business planning process, throughout which stakeholder input is sought. Through this process, the ISO employs a rigorous budgeting methodology in arriving at the final budget. The process includes senior management presenting in May/June an estimated budget to discuss with stakeholders based on priorities and initiatives for the budget year. Incorporating the feedback from those discussions, the detailed budgets are developed using the following seven-step process:

1) define objectives, activities, and goals;
2) identify efficiencies for each department;
3) develop priorities;
4) determine resource requirements;
5) develop budget estimates for each department;
6) adjust budgets to ensure that staff resources and activities are aligned with the business plan; and

7) conduct senior staff review to ensure alignment of budget with the ISO's business plan and overall fiscal constraint.

Q. PLEASE SUMMARIZE THE STAKEHOLDER PROCESS USED TO REVIEW THE 2024 BUDGET.

A. After reviewing preliminary budgets with state agencies and the New England Power Pool ("NEPOOL") at meetings in June, the ISO presented the 2024 Revenue Requirement at the NEPOOL Budget and Finance Subcommittee's August 11, 2023 meeting and at a separate meeting for state agencies also on August 11, 2023. The ISO also presented the budgets to the NEPOOL Participants Committee at the Committee's meetings on September 7 and October 5, 2023. At the October 5 meeting, the ISO's 2024 Revenue Requirement was supported by the Participants Committee (with three oppositions and eight abstentions recorded). The terms of the NEPOOL Participants Committee's action are reflected in the resolution in RCL-8, attached to this testimony. In that same resolution, the NEPOOL Participants Committee also supported the capital budget for 2024. The ISO Board of Directors approved the budgets effective on October 12, 2023.

Q. DESCRIBE STAKEHOLDER FEEDBACK TO THE ISO'S PRELIMINARY BUDGET.

A. Following these discussions regarding the preliminary budget (which was substantially similar to the 2024 Revenue Requirement described herein), the only

follow-up comments the ISO received were from a participant requesting a meeting to clarify the drivers for the 2024 budget increases and from certain state agencies to include in the 2024 Revenue Requirement an additional headcount for the creation of "a dedicated, executive level position focusing on energy and environmental justice to align ISO-NE's organizational objectives and operations with a just and equitable clean energy transition." After review of the states' request, the ISO added a placeholder in the proposed 2024 budget for an environmental policy and community affairs FTE, to allow the ISO to evaluate the appropriate responsibilities and role of this position.

Q. DESCRIBE THE ISO'S HISTORY OF STAYING WITHIN ITS BUDGET.

A. The ISO has amassed a consistent track record of spending integrity; since the inception of its self-funding tariff for calendar year 1998, the ISO's annual spending has never exceeded the budget used to calculate the revenue requirement accepted by the Commission that forms the basis for the rates for the year in question. Should the need ever arise for the ISO to spend beyond a given year's budget (including contingencies), the ISO will first seek stakeholder support and then file a rate increase with the Commission, thus allowing stakeholder and Commission review before approving such increases.

DESCRIPTION OF THE 2024 REVENUE REQUIREMENT[1]

Q. WHAT IS THE 2024 REVENUE REQUIREMENT AND WHAT ARE ITS ELEMENTS?

A. As shown in RCL-2, Schedule 2, the 2024 Revenue Requirement is approximately $273.9 million (after true-up). The 2024 Revenue Requirement contains the following components, each of which is discussed below: (1) the 2024 operating budget ($240.9 million) (*i.e.*, the administrative costs of running the ISO); (2) depreciation and amortization of regulatory assets ($32.6 million); (3) interest expense of $3.5 million; and (iv) a final true-up adjustment for 2022 (the "2022 True-Up Amount") calculated pursuant to Section IV.A.2.2 of the Tariff (a decrease in the 2023 Revenue Requirement of approximately $3.0 million resulting from an over-collection in 2022).

Q. WHAT IS THE APPROXIMATE IMPACT OF THE REVENUE REQUIREMENT ON CONSUMER COSTS?

A. If the ISO's Revenue Requirement were fully passed through to end-use customers, their cost would average $1.46 per month.[2] (*See* slide 42 of the Budget Presentation (as defined in the filing letter).)

[1] Generally, numbers used herein are rounded for ease of reference and, accordingly, may not sum.

[2] The 2024 Forecast, used to calculate these passed through rates, is based on the May 2023 CELT Report Forecast Data Tab 1.5.2 (Gross Annual Energy (without reductions)). *See* https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx.

Q. WHAT ARE THE MOST SIGNIFICANT CHANGES IN THE 2024 OPERATING EXPENSE BUDGET COMPARED WITH THE 2023 OPERATING EXPENSE BUDGET?

A. As described in more detail below, for 2024, the most significant increases to the Core Operating Budget are (i) funding for the continued preparation for the clean energy transition; (ii) costs of inflation and continued operations; and (iii) a net change in the Revenue Requirement true-up. The ISO has also realized efficiencies and savings of $4.1 million, reducing the net increase to approximately $35.1 million.

To support the ISO's increasingly complex and demanding workload, the 2024 Core Operating Budget includes net funding for twenty-nine additional full-time equivalent ("FTEs") employees. The 2024 Core Operating Budget includes the recruitment of forty-one additional positions with funding for twenty-nine FTEs with onboarding expected to occur throughout the year. In the 2023 Core Operating Budget, nine positions were deferred that are expected to be onboarded in 2024. Additionally, twenty of the forty-one additional positions for 2024 are reasonably expected to be onboarded in 2024. The funding for the full year of all forty-one FTEs will be included in the 2025 Core Operating Budget.

The ISO continually evaluates the most cost-effective way to address the evolving demands on the ISO and the rapidly evolving power system. In the past several

years, the ISO supplemented staffing needs with contract additions, where practicable and to cover short term needs. Additionally, the ISO evaluates each position that becomes vacant to determine the continued need in that department and for possible repurposing for use in other areas of the organization. Since 2018, this has resulted in thirty-four reallocated positions. Although, the 2024 operating budget reflects funding for new FTEs, the ISO will continue to use contract additions and the reallocation of resources as appropriate based on a cost-benefit analysis.

Q. PLEASE DESCRIBE HOW THE CLEAN ENERGY TRANSITION IS IMPACTING THE 2024 BUDGET.

A. As noted above, the clean energy transition has significantly impacted the 2024 operating budget, including the addition of headcount. The 2024 Revenue Requirement represents the ISO's commitment to supporting the region as it transitions to clean energy and to ensuring that the organization's continued operations are efficient and reliable. The clean energy transition is creating increased grid complexity and competition for in-demand talent; the 2024 Revenue Requirement represents the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity, as well as

developing new capabilities that will be necessary for supporting the grid of the future.

Specifically, on the supply side, substantial increases to the number of interconnected and behind-the-meter generating assets are changing how the transmission and distribution system operate and interact, and there is a shift from larger, dispatchable resources to smaller, non-dispatchable, weather-dependent, inverter-based resources. Additional resources connecting to the distribution system – outside of the ISO's current visibility – contribute to load variability and forecasting challenges.

On the demand side, changing load characteristics exacerbate operational complexity. With anticipated greater electrification of the heating and transportation sector, as well as installation of behind-the-meter photovoltaics and increased reliance on weather dependent resources, the ISO is observing and projecting new daily and seasonal demand patterns. Overall, it is projected that decarbonization goals will to lead to a grid with much higher loads, load-variability, and a much greater number of variable supply resources.

This changing resource mix will increase the ISO's workload in both the long- and short-term. By 2030, the ISO projects a doubling of installed capacity of solar resources, thousands of MW of planned offshore wind, substantial new transmission investment supporting inter- and intra-regional transfers, and a

substantial increase in the number of energy resources integrated into the ISO markets per Commission Order 2222. Growing generation and fuel uncertainty will lead to an increased focus on energy adequacy efforts, and the changing resource mix will likely require different market designs. Additionally, as the New England region prioritizes the clean energy transition, there will be a greater focus on the ISO and its work and the need for more and different types of public and regulatory engagement.

Overall, the changes to the grid represent a step-up in system complexity that the ISO must be prepared to address in 2024 and throughout the remainder of the decade, specifically through handling greater administrative burdens, developing greater computational capacity, and designing more complex wholesale market products. The 2024 Revenue Requirement includes increases that explicitly support this clean energy transition through:[3]

- addressing the expanding interconnection queue and Commission Order 2023;
- investing in cloud capabilities to support data requirements for an increased number of resources;
- incorporating hybrid, storage, renewable, and smaller generating assets into the ISO markets;
- assessing a conceptual framework for a prompt/seasonal capacity market;

[3] The increases listed as supporting the clean energy transition correspond to the increases for each of the ISO's strategic goals described in Section I.C.1 of the filing letter and in my subsequent testimony.

- assessing and implementing tools for improving ISO capabilities for modeling and maintaining situational awareness of distributed energy resources and changing load behavior;
- increasing granularity of weather forecasting for weather-dependent resources;
- supporting states' policy/project preferences and the NEPOOL prioritization process;
- addressing forthcoming Commission orders on long-term transmission planning for asset condition-based replacement and future-sizing of the transmission system; and
- developing and retaining in-demand skillsets for IT advancements needed for the clean energy transition.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO ATTRACT, DEVELOP, AND RETAIN TALENT (STRATEGIC GOAL 5).

A. The funding increase of $18.7 million for this goal is attributable to funding in six categories: (1) to maintain competitive compensation ($16.7 million); (2) increases in employee benefits costs as a result of an increase number of employees in the Defined Contribution Benefit Plan[4] and increased payroll taxes ($800,000); (3) to fund higher costs related to recruiting, retention, and succession planning ($400,000); (4) funding for 3.25 FTEs for a talent program manager (0.75 FTE) and for early career technical talent FTEs to meet future talent needs

[4] *See* Budget Presentation, Slide 116 (explaining that in 2014 the pension plan became closed to new participants; as a result, all new hires in the organization are eligible under the Defined Contribution Benefit Plan).

(2.5 FTEs) ($400,000); (5) funding to support the intern program (including higher pay rates and an increase in the number of interns) ($300,000); and (6) to fund an increase in board member retainers based on compensation consultant recommendations ($100,000).

The funding in this category to maintain competitive compensation includes a 4.0% increase in salaries based on merit; a 4.0% increase for equity adjustments and promotions; funding to reflect that targeted equity adjustments were made in late 2022/2023 using contingency funds that impact the salary rates for 2024; and an increase for employee incentive target amounts to better align ISO compensation with market rates. The budgeted amounts for merit and promotion/equity budgets were developed based on the Mercer benchmarking compensation analysis (as described in Ms. deCastro's testimony), using data from several national compensation consultants, and review of other independent system operators and regional transmission organizations. Please see Ms. deCastro's testimony for details on the development of these allocations, compensation practices in general, health insurance costs, funding for the other components contributing to the increased funding to support Goal 5, and the ISO's compliance with the standards of the Internal Revenue Service regarding the reasonableness of executive compensation, and director compensation.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO OPERATIONAL EXCELLENCE (STRATEGIC GOAL 3).

A. The cost increase of $10.1 million related to Operational Excellence is related to headcount increases in various departments, support for various information technology initiatives and improvements, and study work. Specifically, the headcount increases will fund: 1.25 FTEs in Information Technology Cyber Security to bolster cyber threat response times, the addition of identity and access management functions, and for additional monitoring for cloud technologies; 1.0 FTE in Information Technology Enterprise Application Support for settlements support required as a result of the Day-Ahead Ancillary Services and Resource Capacity Accreditation projects and for continued integration and delivery of new software products; 0.75 FTE in Information Technology Infrastructure to provide additional support as new technologies are implemented; 1.0 FTE in Strategy, Risk, and Operations Compliance to support the ISO's resiliency program; 1.0 FTE in Internal Audit to support information technology, cyber security, and CIP related audits; 0.75 FTE in Participant Relations & Services to continue efforts to convert in-person training and webinar modules to self-paced micro-learning modules that provide time and costs savings to the ISO and participants; and 0.5 FTE in Advanced Technology Solutions for re-architecting and deployment of the integrated market simulator in a cloud environment.

The funding to support Goal 3 related to various information technology initiatives and improvements include infrastructure increases for operating system support, including extended coverage for unsupported versions while completing version upgrades; backup storage and recovery software; virtualization licenses; application maintenance on new products in various Information Technology and Cyber Security departments; cyber security costs for tools enhancements; information technology increases across the organization, including in the Enterprise Application Support and Architecture & Data Governance departments; increases in various software products as the workforce grows; and power system modeling license cost increases. Additionally, included in Goal 3 cost increases is funding for professional fees to support Information Technology reliability and cyber defenses.

Finally, Goal 3 funding study work includes support for a regional study with PJM and NYISO to assess a 1,200MW single source contingency limit and determine upgrades required to support a 2,000MW single source limit; and for professional fees to support distributed energy resources and minimum load studies to determine how to ensure system reliability when the system is powered solely by inverter-based resources. Goal 3 funding also includes minimal funding for facility updates and cyclical maintenance.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO RESPONSIVE MARKET DESIGNS (STRATEGIC GOAL 1).

A. The $5.5 million cost increase in this category is related to headcount increases in various departments and funding for specific market projects. Specifically, the headcount increases will fund: 3.0 FTEs in Market Development to support the ongoing market design and development efforts for Resource Capacity Accreditation, Day-Ahead Ancillary Services, Forward Capacity Market evolution and parameters, and the market integration of renewable resources; 2.0 FTEs in Market Development for the integration of distributed energy resources, and large scale storage resources including batteries; 1.0 FTE in Energy Management Systems for the integration and utilization of nGem, and to ensure a market structure that will support clean energy and reliability through the clean energy transition; 1.0 FTE in Market & Credit Risk for developing, designing, and testing the risk-based adequacy of market participant collateral obligations and supporting implementation of new Market Development projects; 0.5 FTE in Advanced Technology Solutions related to the development of market design; 0.5 FTE in Planning Services due to Resource Capacity Accreditation workload and increased use of probabilistic analysis in projects; 0.5 FTE in IT Application Software Development to add software development support for the Day-Ahead Ancillary Services and Resource Capacity Accreditation projects; and 0.25 FTE in Resource Adequacy to support work including: Commission Order 2222 and requirements related to a new resource category, additional qualification reviews

regarding Sponsored Policy Resources as a result of the Minimum Offer Price Rule removal, and qualification changes related to Resource Capacity Accreditation.

Funding for Goal 1 related to market design projects include consulting support for the assessment of a prompt seasonal capacity market; the assessment of Resource Capacity Accreditation market mechanisms; and the build-out of a new margin model for Real-Time, Day-Ahead, and prompt seasonal capacity markets. Additionally, funding for this Goal will support the Forward Capacity Auction ("FCA") 21 Cost of New Entry parameter updates.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO STAKEHOLDER ENGAGEMENT (STRATEGIC GOAL 4).

A. The cost increase of $2.4 million to support the Stakeholder Engagement strategic goal will support headcount additions, and study work. Headcount additions will include: 1.25 FTEs in Transmission Planning to support expected increases in transmission request-for-proposals, to support project work (such as documenting Remedial Action Scheme limitations and load interruption thresholds), and to support stakeholder requests for long-term transmission studies; 1.0 FTE in Participant Relations & Services to assist in the gathering, managing, and supporting the assessment of participant proposals/requests for the ISO's Annual Work Plan; 1.0 FTE in Corporate Communications to support additional communications on ISO initiatives, projects, issue positions, emergency

communications, and other related regional efforts; 0.5 FTE in Market Development for efforts on energy adequacy that may require significant assessment and novel market initiatives; 0.5 FTE in Transmission Services to support volume increases in the interconnection queue; and 0.25 FTE in Planning Services to accommodate evolving economic study needs and environmental outlook efforts.

Other funding to support Goal 4 is related to study work, including funding for a medium-term energy adequacy assessment and for a Maine Interconnection Cluster Study. Funding for Goal 4 will also provide support for work related to New England States' requests.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO PROGRESS AND INNOVATION (STRATEGIC GOAL 2).

A. The cost increase of $1.1 million to support the Progress and Innovation strategic goal will support headcount additions and an increase in computer services for higher utilization and related fees for cloud storage through Amazon Web Services. The headcount increases to support Goal 2 include: 1.5 FTEs in Power System Modeling to support modeling for reliability and planning as a result of the increase of renewables, storage, and distributed energy resources in the region; 1.0 FTE in Planning Services for evolving forecast needs and increased complexity/risk associated with the industry's clean energy transition; 0.75 FTE in Information Technology Architecture to leverage cloud technology benefits,

including greater agility, reduced time to deploy infrastructure, infinitely scalable computing performance, and reduced hardware maintenance; 0.75 FTE in Advanced Technology Solutions for research and development needs in advanced modeling and simulation of inverter-based resources, to assess the impact of climate change and extreme weather on power system reliability, and the development of a more efficient market clearing algorithm; 0.5 FTE in Market Development for continuing work on integration of distributed energy resources and large scale storage integration; and 0.25 FTE in Transmission Services to support increased requirements to review, validate, and integrate inverter-based resource models.

Q. PLEASE DESCRIBE THE MISCELLANEOUS INCREASES.

A. The cost increase of $1.4 million in this category is attributable to the assessment of NPCC and NERC dues; an increase in interest expense and fees due primarily to an increase in borrowings on the working capital line resulting from increases in the operating and capital budgets; and insurance policy premium increases.

Q. PLEASE DESCRIBE THE BUDGET CUTS AND DEFERRALS THAT OFFSET THESE INCREASED COSTS.

A. For 2024, the ISO has realized $4.1 million by reallocating resources, automating work, identifying efficiencies, and eliminating discontinued or non-repetitive work.

The $4.1 million reflects reductions from non-recurring markets study work, including the Future Grid Phase II study, the Inventoried Energy Program, and Day-Ahead Ancillary and FCA19 parameters update reviews; reductions to reflect that significant work has been accomplished regarding the Resource Capacity Accreditation parameters and design project resulting in less funding for 2024; reductions for the Pathways Study Phase II work which will now be included in the Economic Planning for the Clean Energy Transition pilot study; a reduction for the Mystic Cost of Service Agreement fuel supply management work with the agreement ending in mid-2024; the removal of funding for the 2050 Transmission Study work which will be completed in 2023; a forecasted increase in interest income due to rates and settlement account balances; a reduction for participant proposal support work that will largely be covered by internal staff; a reduction in board of director related expenses since no director searches will be required in 2024 and the completion of board evaluation work; a reduction for Information Technology patching staff augmentation to be covered by internal staff; a reduction for Transmission Planning and Analysis tool maintenance absorbed by internal staff; and a reduction to reflect the substantial completion of a communications campaign that will only require periodic updates.

Q. DOES THE REVENUE REQUIREMENT INCLUDE DEPRECIATION ON ITEMS IN THE CAPITAL BUDGET THAT ARE PLACED IN SERVICE IN 2024?

A. Yes. The ISO's depreciation rates remain unchanged from those accepted by the Commission in the ISO's 2023 Revenue Requirement. The ISO uses the straight-line depreciation methodology based on no net salvage value and the various average service lives described below. These service lives reflect the ISO's historical experience and forecasted expectations for capital projects placed into service, are necessary to comply with the ISO's funding mechanisms, are consistent with the ISO's historical experience, and have been repeatedly determined by independent auditors to be reasonable. The service lives are:

- Computer hardware, software and accessories: 3 to 5 years
- Software development costs: 3 to 5 years
- Furniture and fixtures: 7 years
- Machinery and equipment: 7 years
- Building: average of 25 years (based on the opinion of independent bond counsel and analysis of the service lives of the different aspects of the building (*e.g.*, the building's steel and concrete at 40 years, mechanical and electrical work at 25 years, and high wear-and-tear elements at 15 years))
- Leasehold/Building Improvements: lesser of 1 to 25 years or remaining life of the lease or building, as determined at the time of the purchase

based on the nature of each such improvement (*e.g.*, rooftop railing at 25 years, air conditioning unit at fifteen years, capacitor bank at ten years)

- Vehicles: 3 to 7 years

The ISO uses private placement debt, issued pursuant to Commission authorization under Section 204 of the Federal Power Act, to fund its capital program. The ISO funds future capital expenditures by using amounts collected for depreciation, with the private placement notes covering the delay between project expenditures and the collection of depreciation through rates. In addition, the ISO funds its working capital needs through a revolving line of credit.

The private placement notes are non-amortizing, with interest-only payments due semi-annually throughout the life of the notes, and the principal due at the end of the term. Revenue reserved for the depreciation of capital assets, as well as assets placed in service in prior years and still depreciable, will be available to repay the remaining principal amounts on outstanding debt.

Please note that capital projects include the cost of the necessary work performed by the project manager, test coordinator, and business analyst in the Program Management Office and design work. If the design is approved and built, this project management and design work is part of the asset on which depreciation is collected when the asset is placed in service in future years via the Revenue Requirement. On the other hand, if the capital project is abandoned, the ISO

writes off the entire project cost, including the project management and design work and recovers it in full in the year of abandonment. In addition, each capital project also includes the first year's maintenance cost for both hardware and software, and license fees for any newly capitalized software.

Q. HOW DOES THE ISO ADDRESS UNEXPECTED COSTS THAT MIGHT MATERIALIZE DURING 2024?

A. The 2024 Core Operating Budget includes two line items to address unexpected needs: (i) the CEO Emerging Work allowance of $2 million; and (ii) the Operating Contingency of $700,000. Inclusion of these contingency amounts recognizes that circumstances may arise that the ISO does not foresee in setting its 2024 Revenue Requirement for its various departments and programs.

The CEO Emerging Work Allowance covers new or deferred activities and initiatives that emerge or become priorities during the year. Approval from both the CEO and CFO is required before the ISO may draw upon these funds.

The Operating Contingency provides a funding source of last resort. ISO management cannot access this fund without first obtaining approval from the ISO's independent Board of Directors.

Q. DO YOU FORESEE ANY PARTICULAR CONTINGENCIES THAT WILL WARRANT THE ISO TAPPING INTO THESE FUNDS?

A. I cannot say for sure what type of contingencies might arise. There are, however, several ongoing issues that might require additional funds not included in the 2024 Core Operating Budget. Specific potential risks include: additional funding required to construct new models to study extreme weather and contingencies, and to conduct new studies related to the integration of variable resources and emerging technologies, including long-range transmission planning studies; additional resources required as operations evolve (*e.g.*, energy forecasting, load management) due to the evolving and changing resource mix; additional information technology funding for software licensing, maintenance costs, cloud migration, backup and storage, and desktop peripherals; higher than anticipated insurance policy renewals; unforeseeable litigation; interest rates that may impact the ISO's floating rates on tax exempt debt, pension and post-retirement benefit plan costs, and interest income on the ISO's settlement float balance; costs related to workforce sourcing challenges and related pay rates; costs related to supply chain disruption; costs related to inflationary pressures in the current economic environment; and funding required for additional or changing federal and/or state policy directives that could result in new requirements.

Q. HAS THE ISO TAKEN ANY ACTION TO MITIGATE THE RISK OF A CHANGING INTEREST RATE ENVIRONMENT?

A. The ISO has purchased an interest rate cap for a portion of its tax-exempt bond issuances. The tax-exempt bonds were issued in Massachusetts to fund the refurbishing of the Main Control Center and in Connecticut to fund the development of the Back-Up Control Center. Both sets of bonds are priced at a weekly variable rate. By opting for variable rates on both sets of bonds, the ISO has saved more than $20,000,000 since 2005 when the ISO first issued the Massachusetts tax-exempt bonds (the Connecticut bonds were issued in 2012).

The ISO has protected that savings through the interest rate cap. The cap effectively serves as an insurance policy or "stop loss" mechanism in a changing interest rate environment, and is intended to cover the ISO's interest rate exposure through February 1, 2024 if rates rise significantly.

The cap covers only the unhedged portion of the variable rate debt. The ISO has not purchased coverage for the portion of the debt that is hedged by the interest earned on the settlement float that the ISO has through the normal course of participant settlement, billing, and payment. In other words, for a portion of the ISO's debt, the interest earned on the balance carried in the settlement account (as amounts are due two days before they are paid out to customers) offsets the interest due on the bonds. Because the projected average balance in the settlement account does not provide complete cover for the floating rate tax-exempt debt, the

ISO purchased the 10-year interest rate cap to protect against a large uptick in the variable tax-exempt interest rates for the uncovered portion.

Since the tax-exempt bonds are amortizing, the hedge is only in place until the unamortized amount of the bonds drop below the projected average balance in the settlement account, which will occur in 2024. Therefore, the ISO will not renew the interest rate cap after it comes due on February 1, 2024. Because the interest rate cap will be fully amortized by the end of 2023 and as such there are no costs related to the cap in the 2024 budget.

Q. PLEASE DESCRIBE THE CALCULATION OF THE 2022 TRUE-UP.

A. As set forth in Section IV.A.2.2 of the Tariff, the ISO has reconciled calendar year 2022's actual expenses and collections under Schedules 1, 2, and 3 of the Tariff by means of a true-up. The actual difference between 2022 expenses and collections is an over-collection of approximately $3.0 million, which decreases the 2024 Revenue Requirement by that amount. *See* RCL–2, Schedule 2.

Q. HOW IS THE 2022 TRUE-UP AMOUNT ALLOCATED AMONG THE THREE SCHEDULES?

A. Schedule 1 increases by about $422,000; Schedule 2 decreases by about $5,307,000; and Schedule 3 increases by about $1,879,000. *See* RCL-2, Schedule 2.

ACTIVITY ACCOUNTING SYSTEM

Q. DESCRIBE THE ISO'S ACTIVITY ACCOUNTING SYSTEM AND THE EXTENT TO WHICH IT PROVIDES COST OF SERVICE INFORMATION FOR EACH OF THE THREE PRIMARY SCHEDULES.

A. The activity accounting system was implemented at the ISO's inception in 1997 and refined in 1998. All operating charges recorded in the general ledger system must be cross-referenced to an activity. Each department has identified its major activities. Most activities are department-specific, but some activities may be cross-charged if they are of a project nature. Activities within a department are known as either "direct" activities or "indirect" activities. Direct activities are of an operational nature and are allocated to one or more of the three schedules based on a fixed percentage. This fixed allocation is provided by the department manager annually in preparation for the next year's budget and tariff filing. Indirect activities are of an administrative nature and are allocated based on current direct labor charges. In addition, the majority of activities for administrative departments (Finance, Human Resources, etc.) are allocated based on the total labor charges within the Company.

The activity accounting system is largely manual, meaning that timesheets and invoices are coded manually. The ISO found that it would not be prudent to overly expand the system to require each employee to specify the schedule serviced through the week. Further, the ISO does not pre-code employees' time

because duties change often with seasonality or new projects. Therefore, the allocation of activities to the schedules is made at the manager level.

The activity system is not designed to track costs to individual markets or transaction units. An employee's time is not driven by the number of transaction units or markets, but by the number of tasks and projects.

If the activity accounting system were expanded to provide for accounting cost in more detail, it would be more costly and difficult to manage without substantially increasing its accuracy.

Q. HOW WAS THE TARIFF SCHEDULE ALLOCATION VERIFIED?

A. In developing the Revenue Requirement for each schedule, managers with cost center responsibilities are required to review the allocation of each and every activity under their control as to the appropriateness of the allocation. During this lengthy evaluation process, all of the activities used by the ISO are reviewed. It is this activity allocation structure that formed the basis of the revenue requirements for each of the three primary schedules.

2024 COST ALLOCATION AMONG SCHEDULES 1, 2, AND 3

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE DEVELOPMENT OF THE COST OF SERVICE ("COS") ANALYSIS?

A. Yes. The following schedules support the COS shown in RCL-3:

Schedule 1 Total Cost Allocation to Schedules by Department

Schedule 2	Total Direct Labor Allocation to Schedules by Department
Schedule 3	Total Cost Allocations to Schedules by Cost Category
Schedule 4	Direct Labor Cost Allocations to Schedules by Cost Category
Schedule 5	Allocation Factors by Cost Category
Schedule 6	Allocation on Depreciation and Amortization Expense

Q. WHAT IS THE ISO'S MAIN EXPENSE?

A. As a non-profit entity that operates, but does not own, generation or transmission assets, the ISO's main expense in the Core Operating Budget is personnel. As shown in RCL-5, Schedule 1, the ISO has budgeted $160 million of the ISO's 2024 Core Operating Budget for salaries and overhead. This category includes fees for the Board of Directors, as well.

Q. WOULD YOU PLEASE DESCRIBE YOUR RCL-3?

A. RCL-3, Schedule 1 contains the Test Year 2024 COS for each of the three primary rate schedules. The exhibit lays out in detail how the ISO's costs were assigned to the three schedules.

Most activity costs consist of direct labor costs, employee benefits, and other non-labor-related costs (*e.g.*, office supplies, software, hardware, depreciation, interest, consulting, etc.). For each Activity Code, both the labor-related and non-labor-related costs are assigned to the rate schedule using the same allocator.

Q. PLEASE EXPLAIN HOW LABOR RATIOS WERE DEVELOPED AND USED TO ALLOCATE COSTS IN RCL-3.

A. Schedule 4 of RCL-3 shows an allocation to the three schedules of all ISO direct labor costs as projected for Test Year 2024. Within a given department, known allocators ("Alloc-Fixed") for specific cost categories were used to allocate those labor costs that were specifically attributable to a schedule. The Alloc-Fixed labor costs were summed for that department and all remaining labor costs within that department were allocated in proportion to the summed Alloc-Fixed costs. Labor costs within all departments were allocated in this manner and summed for the entire company. Schedule 5 of RCL-3 summarizes the labor allocation factors or labor ratios for each Activity Code. These ratios were then used to allocate various cost items in Schedules 3, 4, and 6 of RCL-3.

Q. PLEASE SUMMARIZE YOUR PROPOSED 2024 COS RESULTS FROM RCL-3 FOR EACH OF THE THREE RATE SCHEDULES.

A. Table 1 below summarizes the results of all the allocations contained in Schedule 1 of RCL-3, at Lines 45, 47, and 49. The totals demonstrate an initial 2024 Operating Expense Revenue Requirement (also provided on line 10 to RCL-2, Schedule 2, page 1) decreased by the true-up amount (also provided on line 14 to RCL-2, Schedule 2, page 1) to result in the total 2024 Revenue Requirement (also provided on line 17 to RCL-2, Schedule 2, page 1).

Table 1
2024 Cost of Service Results (1)

Description	Test Year	True-Up	Total
(a)	(b)	(c)	(d)
Schedule 1, Scheduling, System Control and Dispatch Service	$ 57,473,726	$ 421,994	$ 57,895,721
Schedule 2, Energy Administration Service	134,634,632	(5,306,720)	129,327,912
Schedule 3, Reliability Administration Service	84,788,318	1,878,563	86,666,881
Total	$ 276,896,676	$ (3,006,163)	$ 273,890,514

(1) From Exhibit 3 (RCL-3), Schedule 1.0.

Q. EXCLUDING TRUE-UP AMOUNTS, HOW DO THE COS RESULTS IN SCHEDULE 1 OF RCL-3 COMPARE WITH THE TEST YEAR 2023 COS RESULTS, ON WHICH THE CURRENT ISO RATES ARE BASED?

A. Table 2 below compares, before taking into account any true-ups, the 2024 COS results from Schedule 1 of RCL-3 to the 2023 COS results. Table 2 demonstrates how, excluding the true-up amounts, the 2024 COS constitutes a $36.7 million increase from the 2023 COS accepted by the Commission last year.

Table 2
Comparison for Cost of Service Results

(Before True-Ups)

		ISO Tariff Schedules		
Description	Total	Schedule 1	Schedule 2	Schedule 3
(a)	(b)	(c)	(d)	(e)
2024 COS (1)	$276,896,676	$57,473,726	$134,634,632	$84,788,318
2023 COS (2)	$240,205,156	$49,273,547	$118,209,011	$72,722,598
Difference -$	$36,691,520	$8,200,179	$16,425,621	$12,065,720
-%	15.3%	16.6%	13.9%	16.6%

(1) From Table 1, Column (b).

(2) From Exhibit 3 (RCL-3), Sch. 1.0, Line 44, in FERC Docket No. ER23-94-000.

Q. HAVE YOU IDENTIFIED SPECIFIC ACTIVITY ITEMS THAT GIVE RISE TO THE INCREASES AND/OR DECREASES SHOWN ABOVE FOR THE THREE SCHEDULES?

A. Yes. Table 3 below highlights key activity items from Test Year 2024 allocated among the three primary schedules by cost category (RCL-3, Schedule 3), along with various depreciation/amortization items (RCL-3, Schedule 6), which changed from 2023. The identified activity items account for the majority of the cost shifts within each of the three schedules.

Table 3
Examples of Differences in 2024 Operating Expenses

Activity Code (a)	Description (b)	Total (c)	ISO Tariff Schedules Schedule 1 (d)	Schedule 2 (e)	Schedule 3 (f)
		Test Year 2024			
99995	NPCC/NERC Dues	$ 8,254,846	-	-	8,254,846
920XX	Depreciation	32,460,165	4,227,916	20,813,559	7,418,690
15085	Audit - Information Technology	564,903	121,737	292,337	150,829
21011	Capacity Market	4,722,431	-	-	4,722,431
22656	Energy, Reserve, and Regulation Markets	1,718,506	-	1,288,879	429,626
22657	Project: ORTP/CONE Updates	1,383,368	-	-	1,383,368
21201	Advanced Technology Solutions	4,292,759	925,090	2,221,503	1,146,167
17503	FCA - New Resource Qualification Support	1,419,234	-	-	1,419,234
Various	Salary Market Adjustments (based on survey data)	5,077,614	1,094,226	2,627,665	1,355,723
Various	Transmission Planning	10,491,754	10,239,352	-	252,401
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	57,019,864	8,336,304	32,017,630	16,665,929
Various	Information Technology Energy Management Systems	10,340,802	3,773,683	4,970,690	1,596,428
Various	Information Technology Cyber Security	7,520,518	1,620,672	3,891,868	2,007,978
	Totals	$ 145,266,763	$ 30,338,979	$ 68,124,132	$ 46,803,652
		Test Year 2023			
99995	NPCC/NERC Dues	$ 7,296,418	-	-	7,296,418
920XX	Depreciation	30,876,001	4,738,230	17,709,018	8,428,753
15085	Audit - Information Technology	-	-	-	-
21011	Capacity Market	513,028	-	-	513,028
22656	Energy, Reserve, and Regulation Markets	251,712	-	188,784	62,928
22657	Project: ORTP/CONE Updates	-	-	-	-
21201	Advanced Technology Solutions	4,004,363	862,940	2,072,258	1,069,165
17503	FCA - New Resource Qualification Support	982,836	-	-	982,836
Various	Salary Market Adjustments (based on survey data)	-	-	-	-
Various	Transmission Planning	6,590,619	6,514,297	-	76,322
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	49,371,705	7,617,602	27,485,106	14,268,997
Various	Information Technology Energy Management Systems	8,164,484	3,060,649	3,864,395	1,239,440
Various	Information Technology Cyber Security	5,916,009	1,274,900	3,061,535	1,579,574
	Totals	$ 113,967,175	$ 24,068,618	$ 54,381,096	$ 35,517,461
		Test Year 2024 Costs Minus Test Year 2023 Costs			
99995	NPCC/NERC Dues	$ 958,428	-	-	958,428
920XX	Depreciation	1,584,164	(510,314)	3,104,541	(1,010,063)
15085	Audit - Information Technology	564,903	121,737	292,337	150,829
21011	Capacity Market	4,209,403	-	-	4,209,403
22656	Energy, Reserve, and Regulation Markets	1,466,794	-	1,100,095	366,698
22657	Project: ORTP/CONE Updates	1,383,368	-	-	1,383,368
21201	Advanced Technology Solutions	288,397	62,149	149,245	77,002
17503	FCA - New Resource Qualification Support	436,398	-	-	436,398
Various	Salary Market Adjustments (based on survey data)	5,077,614	1,094,226	2,627,665	1,355,723
Various	Transmission Planning	3,901,135	3,725,055	-	176,079
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	7,648,159	718,702	4,532,524	2,396,932
Various	Information Technology Energy Management Systems	2,176,318	713,034	1,106,295	356,988
Various	Information Technology Cyber Security	1,604,509	345,772	830,333	428,404
	Totals	$ 31,299,589	$ 6,270,361	$ 13,743,036	$ 11,286,191
	All Other Unidentified Changes	$ 5,391,932	$ 1,929,818	$ 2,682,585	$ 779,529
	Total Change in Cost of Service	$ 36,691,520	$ 8,200,179	$ 16,425,621	$ 12,065,720
	% of Difference shown on Table 2	85.30%	76.47%	83.67%	93.54%

Q. PLEASE EXPLAIN IN FURTHER DETAIL HOW THE REVENUE REQUIREMENTS CHANGED FOR EACH SCHEDULE FROM THOSE UTILIZED IN THE FILING SUPPORTING THE 2023 RATE TO THOSE UTILIZED HERE FOR TEST YEAR 2024.

A. Schedule 1: The increase in the Revenue Requirement for Schedule 1 results from 2024 cost increases and changes that impact all three schedules, including for: targeted compensation increases based on salary benchmarking data; employee benefit costs; computer service infrastructure and architecture (including transition to the cloud), cyber security, and application support; research and development including advanced modeling and the integration of new technologies; resources in Participant Relations & Services and External Affairs & Corporate Communications; interest expense; and corporate insurance policy premium increases. Also contributing to the increase in the Revenue Requirement for Schedule 1 is funding for Transmission Planning and Transmission Services support of long-term transmission planning related to the transition to a carbon free power system, including resources to support expected increases in transmission RFPs, to support stakeholder requests for long-term transmission studies (including New England states' requests), for a regional study with PJM and NYISO to evaluate the impact of increasing New England's single source contingency limit, and support for distributed energy resources and minimum load studies to determine requirements for ensuring reliability under conditions where the system is powered solely by inverter-based resources.

Schedule 2: The increase in the Schedule 2 Revenue Requirement is due to the increases that impact all three schedules, as discussed in the preceding paragraph. Also affecting the Schedule 2 Revenue Requirement increase, is depreciation expense increases related to the mid-2023 go-live of the nGEM platform projects, resulting in a full year of depreciation reflected in the 2024 Revenue Requirement.[5] The increase in the Schedule 2 Revenue Requirement is also attributable to funding for Market Development resources to continue progress towards integrating renewable resources and new resource types, including large scale storage resources and batteries into the market designs for the clean energy transition; and for work that affects Schedules 2 and 3, including future grid studies for a clean energy future, and a Participant Relations & Services resource to continue the integration of several new initiatives and projects into market training and the development of new training delivery methods.

Schedule 3: The increase in the Schedule 3 Revenue Requirement is attributable to increases that impact all three schedules and funding for items that impact Schedules 2 and 3, each as noted above. Additionally, the Schedule 3 Revenue Requirement increase is attributable to funding for the assessment of alternate capacity market commitment horizons including prompt and/or seasonal markets,

[5] As explained in Section I.C.2 of the filing letter, the nGEM Market Clearing Engine Implementation project, completed in June 2023, included the following projects that began depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phase I and II.

for FCA21 Cost of New Entry (CONE) parameter updates, and increases in NPCC and NERC dues.

THE ISO RATE DESIGN AND ESCALATION FACTORS

Q. HOW DID YOU DEVELOP THE ESCALATION FACTORS?

A. Consistent with the practice reflected in the filings establishing the ISO's rates to collect its administrative costs for 1999-2023, escalation factors rely on information contained in the 2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission (the "CELT Report"), dated May 1, 2023. The CELT Report contains actual and estimated energy and peak loads for 2023-2032. The ISO also relied on information in the ISO markets system for the 12-month period ending July 2023. The development of the escalation factors is shown in RCL-7, Schedule 1.

Q. ARE YOU PROPOSING ANY CHANGES TO THE RATE DESIGN?

A. The ISO is not proposing any changes to the rate design from that in place in 2023.

Q. PLEASE OUTLINE THE CURRENT RATE DESIGN BEFORE DESCRIBING THE VARIOUS ESCALATION FACTORS.

A. As previously indicated, Section IV.A of the Tariff has three rate schedules to cover the ISO's expenses for providing its three services: Schedule 1 -

Scheduling Service; Schedule 2 – Energy Administration Service; and Schedule 3 – Reliability Administration Service.

- ***Schedule 1***

  The Schedule 1 revenue requirement is allocated 100% to Monthly Regional Network Load and the Reserved Capacity. The determinant based on Reserved Capacity uses the highest amount of Reserved Capacity for an hour for each transaction scheduled to occur during the month as Through or Out Service, other than Coordinated External Transactions.[6] Schedule 1 revenues collected from Through and Out Service Customers are credited to each Network Customer that month in proportion to each Network Customer's Monthly Regional Network Load. Revenues from the Non-Participant FTR fee described in Market Rule 1 and non-refundable Long Lead Facility deposits will be credited to the Schedule 1 Revenue Requirement through future true-ups.

- ***Schedule 2***

  The Schedule 2 revenue requirement is allocated 15% to Transaction Units ("TUs") and 85% to Volumetric Measures ("VMs"), subject to the special true-up described below. TUs measure the frequency and duration of activity and are indifferent to the size (*e.g.*, capacity) of any particular transaction. Conversely,

[6] Coordinated External Transactions are defined in Section I of the Tariff as transactions at external interfaces to which the enhanced scheduling procedures in the Coordinated Transaction Scheduling rules apply. These rules were adopted jointly with the NYISO to enhance the market efficiency of external transactions (*i.e.*, energy imports and

VMs seek to capture a customer's "physical" reliance on the system administered by the ISO and thus the benefit received.

A. Transaction Units

Schedule 2 currently utilizes three types of TUs: those associated with Real-Time Energy Market transactions (Energy TU Based Charges), those associated with Increment Offers and Decrement Bids, and those associated with FTR auction submitted and cleared bids.

Energy TUs equal the sum per month of a Customer's Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours, without reference to Coordinated External Transactions. Under the ISO's current rate design, a Customer's total monthly Energy TUs are priced under a three-tiered declining block rate structure. Under this regime, the highest unit rate applies to the first 12,500 Energy TUs incurred in a month; the Customer's next 27,000 Energy TUs are priced approximately 10% lower; and the balance of monthly Energy TUs, *i.e.*, those in excess of 39,500, are priced at an additional savings of approximately 10% on average.

exports) between the two regions through economic clearing of external transactions. *See* Tariff Section III.1.10.7.A.

TU Charges Based on Increment Offers and Decrement Bids are assessed based on both of the following: (i) a charge multiplied by the total number of Increment Offers and Decrement Bids submitted, plus (ii) a charge multiplied by the total number of Increment Offers and Decrement Bids that clear the Day-Ahead Energy Market. This category is sometimes referred to as "virtual activity," distinguishing it from physical activity.

TU Charges Based on FTR Auction Submitted and Cleared Bids are assessed through both of the following: (i) a charge multiplied by the total number of FTR auction bids submitted for that period, plus (ii) a charge multiplied by the total number of FTR auction bids cleared for that period. The FTR charges are designed to recoup the costs the ISO incurs for administering the FTR auctions. The FTR revenue offsets other Schedule 2 TU charge revenues.

B. Volumetric Measures

Schedule 2 Volumetric Measures consist of the sum of a Customer's Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (each measured in megawatt hours, MWh), excluding any Monthly Real-Time Generation Obligation associated with certain energy imports and Coordinated External Transactions. Under the ISO's current rate regime, Schedule 2 VMs are priced under a three-tiered declining block rate structure wherein the highest unitized rate is assessed to the first 250,000 MWh each month; the Customer's next 1,250,000 MWh are

priced at a discount of approximately 10% from the tier-1 unitized rate; and VMs in excess of 1,500,000 MWh incur the lowest unitized monthly rate.

- ***Schedule 3***

Schedule 3 allocates internal load activity based on Real-Time NCP [Non-Coincident Peak] Load Obligation. For Exports other than Coordinated External Transactions, Schedule 3 assesses a volumetric (per MWh) charge. Specifically, the ISO divides the Schedule 3 Revenue Requirement by the real-time load obligation forecasted for the upcoming year in the most recent CELT Report.[7] The remaining revenue requirement for Schedule 3 (*i.e.*, net of that allocated to Exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

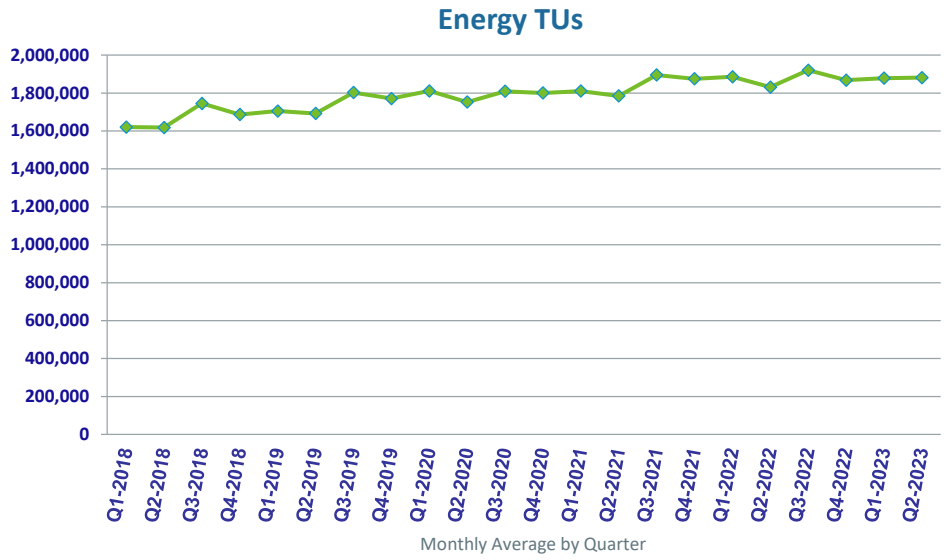
Q. PLEASE EXPLAIN THE ESCALATION FACTORS UTILIZED TO DEVELOP THE BILLING DETERMINANTS FOR 2024.

A. The Schedule 1 Network Load, the Schedule 2 Volumetric, and Schedule 3 Real-Time NCP Load Obligation billing determinants for 2024, were increased by an escalation factor of 1.011 based on CELT Report load data. See columns (c), (i), and (j), respectively, of RCL-7, Schedule 2.

[7] The 2024 Forecast is based on the May 2023 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced for behind-the-meter photovoltaic and energy efficiency). *See* https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx.

The Schedule 2 transaction unit determinants for Energy TUs, shown in column (d) of RCL-7, Schedule 2, were increased by an escalation factor of 1.020. As shown in Table 4A below (actual Energy TU data from 2018 through the second quarter of 2023), the number of Energy TUs has increased consistently over the past several years, with an average increase over the past 3 years of 2.0%.

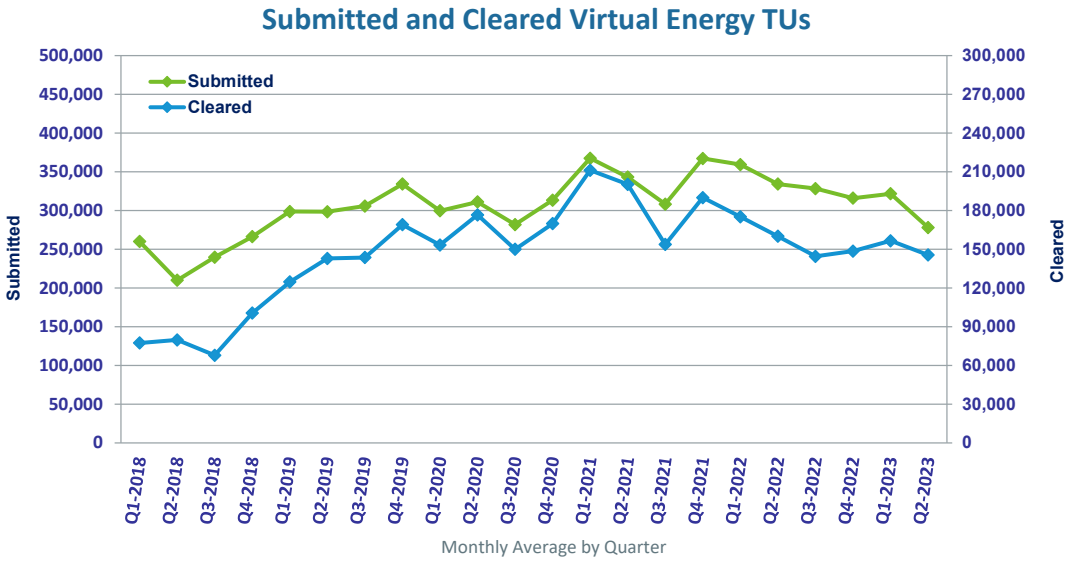
Table 4A



For 2024, the Schedule 2 virtual transactions have been left flat from 2023 levels (see columns (e) and (f) of RCL-7, Schedule 2). As shown in Table 4B below, the number of submitted virtual transactions has fluctuated over the past several years without an observable trend and, overall, has not changed significantly during this period. Therefore, the escalation factor for Submitted Virtual TU remains flat. Similarly, the number of Cleared Virtual Transactions has not shown an

observable trend and the ISO has not been able to identify any specific market change or participant behavior that can be attributed to the increase and, therefore, the ISO decided to leave the Cleared Virtual TU determinant flat. Table 4B below provides actual Virtual Energy TU data from 2018 through the second quarter of 2023.

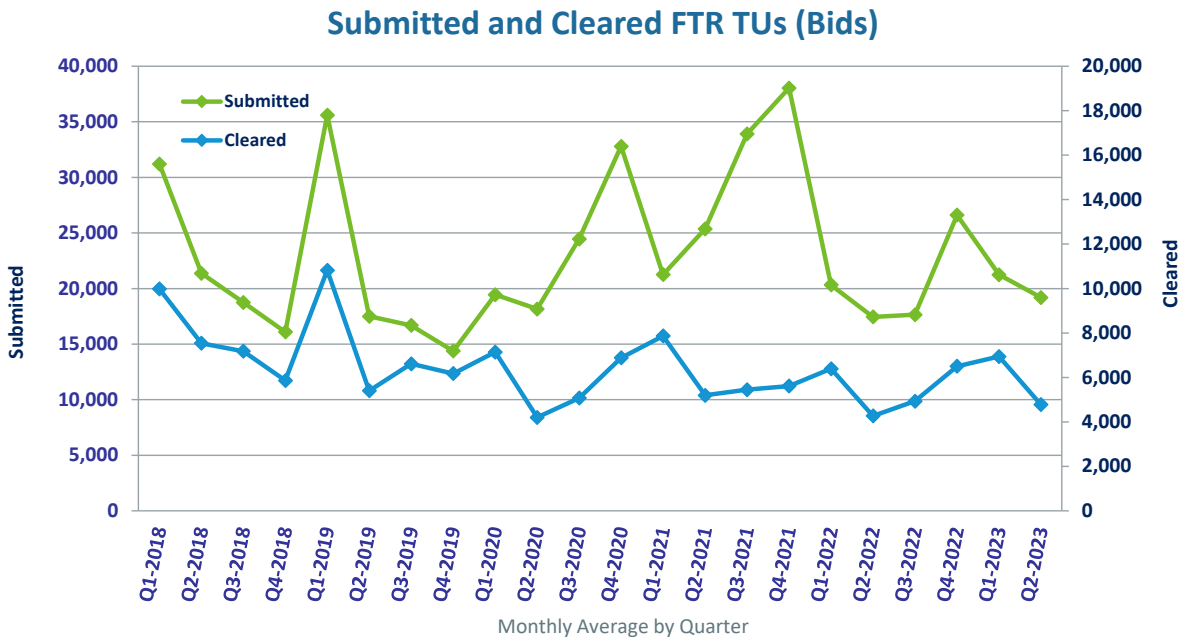
Table 4B



The Schedule 2 FTR determinants were left flat (see columns (g) and (h) of RCL-7, Schedule 2). The number of FTR transactions have fluctuated over the past several years and while the overall FTR cost has stayed relatively flat over the past twelve-month period, submitted and cleared FTRs have historically fluctuated in an inconsistent manner. Although monthly reconfiguration auctions were implemented in October 2019, it is unclear if such auctions have resulted in

different FTR bidding behavior. In sum the FTR billing determinants for 2024 were left flat due to the lack of a clear pattern in FTR bidding activity. Table 5 below provides actual FTR TU data from 2018 through the second quarter of 2023.

Table 5



Finally, the Schedule 3 billing determinant based on export volumes remains flat from 2023 levels as shown in RCL-7, Schedule 2, column (k). The remainder of the Schedule 3 revenue requirement is assessed via a billing determinant related to NCP Load Obligation which was escalated as noted above.

Leaving the billing determinants flat for the Schedule 2 virtual transactions and the Schedule 3 determinant based on export volumes does not pose a material risk

to 2024 tariff over or under collection because the combined amount of collections for these determinants is forecasted to be 1.3% of total collections.

THE 2024 BILLING DETERMINANTS

Q. PLEASE DESCRIBE THE SCHEDULE 1 RATE CALCULATION.

A. RCL-7, Schedule 3, lines 1 through 3 show the Schedule 1 Billing Determinants and the Revenue Requirement allocated thereto. Dividing the Revenue Requirement by the forecasted billing units yields the rate for 2024 of $0.00037/kW-hour.

Q. PLEASE DESCRIBE THE SCHEDULE 2 RATE CALCULATION.

A. Schedule 2 employs a declining blocked rate structure for Energy TUs and VMs. The three-tiered declining block structure is discussed earlier in my testimony. Increment Offers and Decrement Bid TUs and FTR TUs incur unitized charges. RCL-7 (Schedule 3) and Table 6 (below) provide the Schedule 2 rates proposed for 2024.

TABLE 6

Description		TY 2024	
(a)		(b)	
Transaction Units			
INC Offers/DEC Bids			
Submitted		$ 0.00500	/Offer or Bid
Cleared		$ 0.06000	/Offer or Bid
Financial Transmission Rights			
Submitted		$ 2.77242	/Bid
Cleared		$ 4.48021	/Bid
Energy Transaction Units			
Block 1 - 1st	12,500TUs	$ 0.82494	/TU-hour
Block 2 – Next	27,000TUs	$ 0.74994	/TU-hour
Block 3 – Over	39,500TUs	$ 0.67495	/TU-hour
Volumetric Measures			
Block 1 - 1st	250,000MWH	$ 0.48178	/MWh
Block 2 – Next	1,250,000MWH	$ 0.43798	/MWh
Block 3 – Over	1,500,000MWH	$ 0.39418	/MWh

Q. PLEASE EXPLAIN HOW THE RATES FOR EACH BLOCK ARE CALCULATED.

A. The rate components in all cases reflect an approximate 10% differential from the average rate.

Q. PLEASE DESCRIBE THE SCHEDULE 3 RATE CALCULATION.

A. RCL-7, Schedule 3 at lines 30 through 33 and Table 7 below list the billing rate calculation. Exports are assessed a unitized charge per MWh based on the Schedule 3 Revenue Requirement using the CELT Report's real-time load

obligation forecast for 2024.[8] The export rate is then applied to the total MWh of Exports forecasted for the test year to determine the portion of the Schedule 3 Revenue Requirement assessed to exports. The remaining Revenue Requirement for Schedule 3 (*i.e.*, net of that allocated to exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

TABLE 7

Description	TY 2024 Amount	%
Revenue Requirement ($)	$ 86,666,881	100.0%
Real-Time NCP Load Obligation	$ 84,234,299	97.2%
Export Rate	$ 2,432,582	2.8%
Billing Units		
Real-Time NCP Load Obligation	247,044,681 /kW-Mo.	
Export Rate	3,475,117 /MWh	
Rates		
Real-Time NCP Load Obligation	$ 0.34097 /kW-Mo.	
Rate on Exports	$ 0.70000 /MWh	

RATE SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE THE RATES FOR 2024 THAT YOU ARE SPONSORING?

A. Yes. These rates are summarized in Table 8.

[8] The 2024 Forecast is based on the May 2023 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced for behind-the-meter photovoltaic and energy efficiency). *See* https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx.

Table 8
2024 Rate Components (1)

Tariff Schedule	Jan. 1, 2024
Schedule 1	
Network Load (per kW-hour)	$0.00037
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$2.77242
Cleared	$4.48021
TU's	
Block 1 - 1st 12,500	$0.82494
Block 2 - Next 27,000	$0.74994
Block 3 - Over 39,500	$0.67495
Volumetric	
Block 1 - 1st 250,000	$0.48178
Block 2 - Next 1,250,000	$0.43798
Block 3 - Over 1,500,000	$0.39418
Schedule 3	
R-T NCP Load Obligation	$0.34097
Export Rate	$0.70000

(1) From Exh 3, RCL-7, Sch. 3

Q. PLEASE EXPLAIN THE SPECIAL CALCULATION FOR A REVENUE SHORTFALL ATTRIBUTABLE TO TUs USED IN SCHEDULE 2.

A. In the event of a revenue shortfall attributable to TUs in the true-up year (in this case, 2022), the shortfall allocation has two components. The first component allocates the first 50% of the shortfall to Schedule 2 VMs rather than the usual

15/85 allocation of Schedule 2 Revenue Requirements between TUs and VMs, respectively. The second component increases the percentage of the shortfall allocated to VMs by an additional percentage for each percentage decrease which occurred between the number of TUs used in the current true-up (based on year-to-date actual data through July of the current year) and the number of TUs that the ISO had used in the original projection of the rates for that year.

As shown in RCL-7, Schedule 6, the final 2022 amount is an over-collection of $166,219. Accordingly, there is no variation for 2024 to the 15/85 allocation of the Schedule 2 revenue requirement between TUs and VMs.

FIXED FEES

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE RATES INCLUDED IN THE PROPOSED 2024 TARIFF?

A. Yes. Schedule 3 includes certain RAS Fees that are applicable to Transmission Customers who are non-Market Participants. This fee is currently $3.97 (hourly). For 2024, I am proposing to increase this hourly fee to $4.97.

Q. PLEASE EXPLAIN HOW YOU DERIVED THE PROPOSED HOURLY RAS FEE.

A. The proposed RAS Fee was developed by applying a ratio of the Schedule 3 forecasted revenue requirement for 2024 to the Schedule 3 forecasted revenue requirement for 2002 to the 2002 RAS Monthly (($671 x

($86,666,881/$16,035,649) = $3,626.51), and breaking that down to an hourly rate ($3,626.51/730), which for 2024 is $4.97.

Q. DID YOU DEVELOP THE APPROPRIATE RAS FEES FOR THOSE CUSTOMERS WHO TAKE SERVICE FOR PERIODS OF LESS THAN ONE MONTH?

A. Yes. These charges are shown below in Table 9.

Table 9
RAS Fees

Line No.	Item	Current	Proposed Jan. 1, 2024
	(a)	(b)	(c)
1	Monthly Calculation	$ 2,894.99	$ 3,626.51
2	Hourly Fee	$ 3.97	$ 4.97

Q. UNDER THE RATES PROPOSED IN THIS FILING, WHAT HAPPENS TO THE REVENUE DERIVED FROM THESE RAS FEES?

A. Any revenue derived from the RAS Fees will be credited back on a monthly basis to all Market Participants who take service under Schedule 3 in proportion to the total charges incurred by the Market Participants for that month.

DESCRIPTION OF 2024 CAPITAL BUDGET INCREASE

Q. PLEASE GENERALLY DESCRIBE THE PURPOSE OF THE CAPITAL BUDGET AND THE PROPOSED 2024 CAPITAL BUDGET.

A. As described in the filing letter, the 2024 Capital Budget is a list of the ISO's planned capital expenditures in 2024. The ISO does not make any collections through its capital budget; rather, the capital projects reflected in the budget are funded through private placement financing. The ISO funds the capitalized portion of the interest on that financing through recovery of depreciation under its annual operating budget, as discussed in Section I.C.2 of the filing letter. In sum, the costs of these projects are collected once only, through the depreciation recovery in the Revenue Requirement. The proposed 2024 Capital Budget is $35 million, a $1.5 million increase from the 2023 Capital Budget of $33.5 million.

Q. PLEASE EXPLAIN THE REASON FOR THE INCREASE IN THE 2024 CAPITAL BUDGET.

A. The 2024 Capital Budget is $35 million, an increase of $1.5 million from the 2023 Capital Budget. As explained in my testimony in support of the 2022 and 2023 capital budgets, the ISO's capital budget had remained constant at $28 million per year for several years and I explained that the ISO expects its capital budget needs over the next five years to increase incrementally by up to $7 million (*i.e.*, from $28 million to $35 million). However, based on our current cash flow analysis (which includes a 10 year cash flow estimation with a focus on major capital

project spending), the ISO now expects the need to increase the capital budget to $40 million (expected in 2025) with the expectation that the capital budget will remain at that level at $40 million for several years. This revised expectation is primarily because of inflation, of both labor and hardware costs, and longer lead times on the more complex projects, especially projects supporting cyber security and/or clean energy transition initiatives. Longer lead times on projects delay when they are placed into production which is the trigger allowing the ISO to begin collecting depreciation under the operating budget.

The incremental increases to the capital budget, including the 2024 increase, are necessitated by four primary drivers: (i) the replacement of the current market system platform (*i.e.*, the nGem project, described in more detail below); (ii) major market and reliability related efforts that will have significant software requirements; (iii) cyber security needs; and (iv) required information technology asset and infrastructure replacements.

Q. PLEASE PROVIDE DETAILS REGARDING THE REPLACEMENT OF THE CURRENT MARKET SYSTEMS PLATFORM AS IT RELATES TO THE CAPITAL BUDGET INCREASE.

A. For several years, the ISO has been involved in various stages of the nGem project. General Electric (GE) proposed the nGem program (next Generation Markets) to upgrade core market software, replacing the ISO's current market

system. The cost of this upgrade is being shared among three independent system operators (ISO New England, PJM, and MISO) while the portion of the software upgrade unique to each entity will be shouldered by each independent system operator individually. The GE development is spread across several phases (beginning in 2019 and running through 2028). In addition to the development cost of the GE platform, the ISO will also have significant costs over the next several years to implement the new platform which will require adapting the base software to unique ISO functionality, testing, market trials with participants, new hardware and data models, and cutover. Specifically, the ISO had been working on the complex processes for customizing and implementing the day-ahead version of the new market clearing engine software and infrastructure. That phase of the project went into service in mid-2023. The next phases will include a real-time version of the market clearing engine software and will continue over the next several years, costing up to $54 million to complete.

Q. PLEASE PROVIDE DETAILS REGARDING THE MAJOR MARKET AND RELAIBILITY EFFORTS AS IT RELATES TO THE CAPITAL BUDGET INCREASE.

A. The capital budget supports the ISO's efforts to build or incorporate major market and reliability services and reforms and will continue to support the ISO's market design objectives for 2024 and beyond, including the four pillars to support a

successful clean energy transition.[9] Many of the market and reliability projects are complex efforts that will have long lead times to complete and have various external dependencies, such as stakeholder and Commission approval. The following projects have currently been identified for 2024 and beyond, but priorities may fluctuate based on the stakeholder and regulatory process: Day-Ahead Ancillary Services Improvements Design project (to procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving resource mix); Commission Order 2222 (software systems to integrate distributed energy resources into the wholesale markets); Energy Storage Modeling (enhancements to improve the modeling of energy storage in wholesale markets); Significant Capacity Market Reforms (work to mitigate energy adequacy risks as the power system evolves, including the assessment of a prompt and seasonal capacity auction construct); Resource Capacity Accreditation (accreditation of resources based on their marginal reliability contributions during reliability hours); Transmission Line Ratings Enhancements (in response to Commission orders and will require substantial information technology and database work to collect and appropriately use data in planning and operations); Market Simulator/21 Day Energy Simulator/Inverter-Based Resource Modeling (research and development efforts that will result in

[9] See the Budget Presentation, Slide 13, for an explanation of the four pillars of supporting a successful energy transition.

significant improvements to ISO modeling capabilities and situational awareness); and other projects as identified through the stakeholder prioritization progress, the rolling annual work plan process, and Commission orders. Based on the scope of the foregoing, these efforts are expected to cost approximately $45 million to $65 million, on a rolling basis, over the next five years. Major market and reliability efforts may extend beyond the five years and the ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

Q. PLEASE PROVIDE DETAILS REGARDING CYBER SECURITY AS IT RELATES TO THE CAPITAL BUDGET INCREASE.

A. As noted in prior filings, and in further support of the ISO's Operational Excellence (Goal 3) and Progress and Innovation (Goal 2) strategic goals, the ISO's cyber security efforts will need to continue to evolve and adapt to emerging threats and new attack vectors. The ISO expects that it will continue to invest in improved monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats. The combined costs for information technology asset and infrastructure upgrades (described below) and cyber security initiatives are expected to cost approximately $20 million to $40 million, on a rolling basis, over the next five years. Cyber security efforts will likely extend beyond the five years and the ISO will continue to inform the NEPOOL Budget and Finance

Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

Q. PLEASE PROVIDE DETAILS REGARDING INFORMATION TECHNOLOGY ASSET AND INFRASTRUCTURE UPGRADES AS IT RELATES TO THE CAPITAL BUDGET INCREASE.

A. In support of the ISO's Operational Excellence (Goal 3) and Progress and Innovation (Goal 2) strategic goals, the ISO has recently begun the process of a major hardware upgrade which includes moving a portion of the ISO's information technology services to web services. Specifically, the reliability of operating a modern system comprised of renewable and storage resources requires the processing, transfer, and storage of vast amounts of data. As a result, the ISO will be implementing cloud-computing infrastructure and virtualization technology to reduce reliance on energy-heavy data centers and enable a more dynamic expansion of computing capability, while maintaining reliability. As the ISO migrates to a cloud environment, the ISO also must comply with NERC CIP requirements that prohibit certain functions from being hosted in a cloud environment, resulting in the ISO needing to maintain on premise infrastructure for certain functions. The combined costs for information technology asset and infrastructure upgrades and cyber security initiatives (as described above) are expected to cost approximately $20 million to $40 million, on a rolling basis, over the next five years. Information technology asset and infrastructure upgrades may

extend beyond the five years and the ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

Q. PLEASE EXPLAIN HOW THE INCREASED CAPITAL BUDGET WILL IMPACT THE ISO'S CAPITAL STRUCTURE.

A. The ISO's capital project costs are largely funded by private placement debt, and as a result of the planned increase in the amount of capital budget spending over the next several years (*i.e.*, an increase from the $28 million capital budget in 2021 to $35 million in 2024, and likely $40 million in 2025 and beyond), the ISO anticipates needing additional debt in late 2023 and 2024 based on the cash flow needs of the various capital projects. As noted above, the increased capital budget needs are driven by four primary drivers and these drivers and individual project expenses are dependent on various external factors, including vendors (including professional services vendors), regulatory approvals, inflationary costs, and longer lead times to complete projects. Each of these impact the ISO's borrowing needs and timing of such needs. Longer lead times to complete capital projects results in a greater period of time from when the ISO spends capital funds to recovery through operating budget rate recovery (through capital project depreciation expense). Currently, capital project costs are largely funded by $50 million in Private Placement Notes that are set to expire in November 2024. In order to support the future capital program, we have determined that in addition to

renewing the notes, the ISO will also need another $25 million in available capital project funding to support the higher level of capital spending. As a result, the ISO anticipates using a working capital line to support this additional need until the Private Placement Notes are in place.

The ISO will update the NEPOOL Budget and Finance Subcommittee regarding its borrowing needs and will make a Section 204 filing(s) with the Commission for the requisite approval(s).

CONCLUSION

Q. DO YOU WISH TO OFFER ANY FURTHER TESTIMONY OR EXHIBITS?

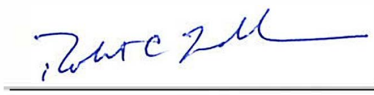
A. I would like to incorporate the Cross Reference Table regarding Statements AA-BM (Exhibit 6 to the filing letter) into my sworn testimony. This table identifies where the cost-of-service data identified in the Commission's Statements AA-BM can be found in my attached exhibits. The table also identifies what data identified in the Commission's Statements AA-BM is inapplicable to the ISO as a non-profit RTO that does not own any generation or transmission assets and is therefore not included in this filing.

Q. DOES THAT CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 13, 2023

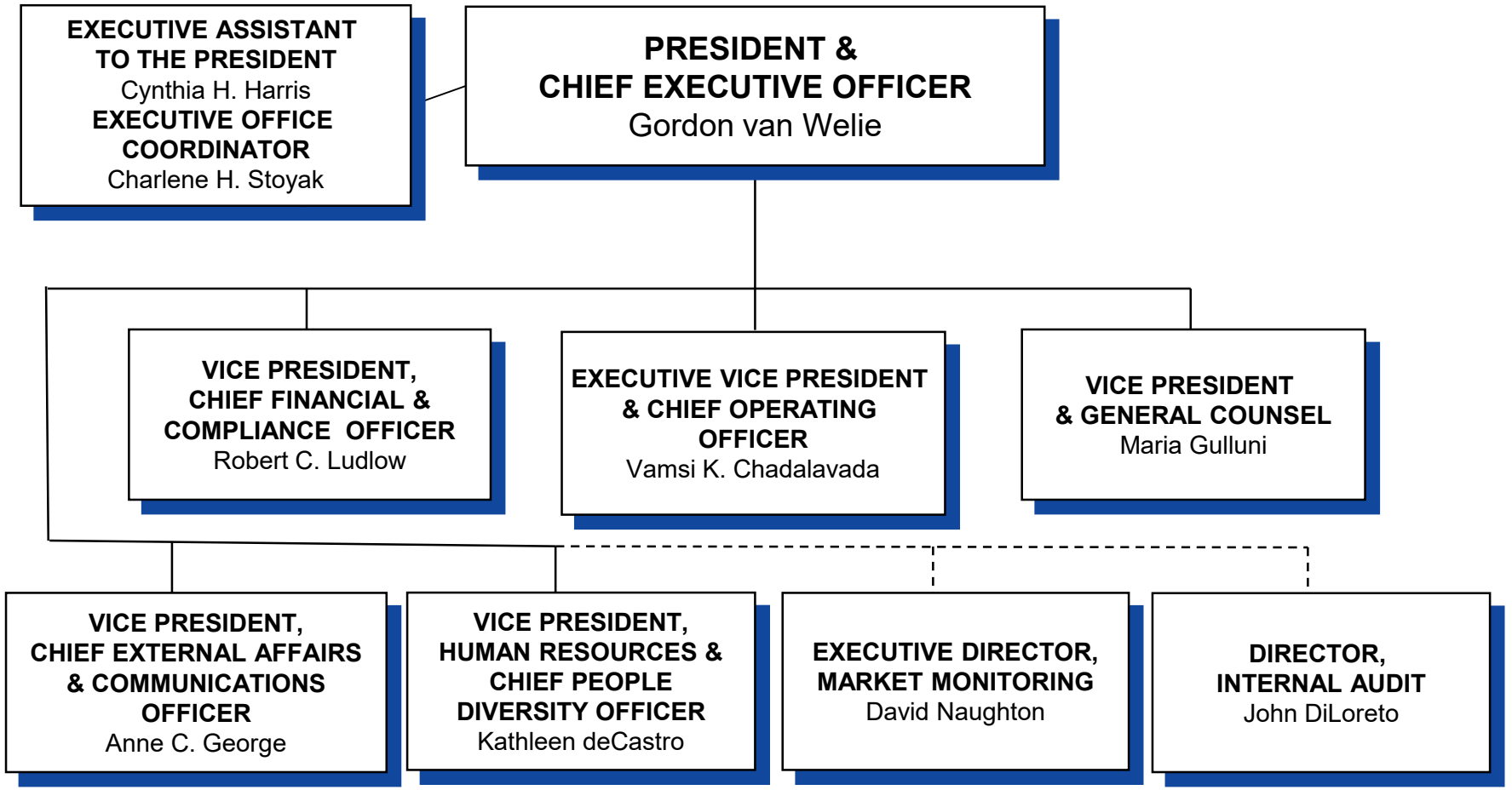


Robert C. Ludlow

Chief Executive Officer

Exhibit 3

RCL-1



ISO NEW ENGLAND INC.
2024 REVENUE REQUIREMENT

(in thousands of dollars)

Line No.				
	Operating Expense Budget:			
1	**Operating Budget**		$	240,878.1
2				
3	**Depreciation and interest expense**			
4	Depreciation	32,559.5		
5	Interest	3,459.1		
6				36,018.6
7				
8	**Total 2024 Operating Expense Budget**		**$**	**276,896.7**
9				
10	**2024 Operating Expense Revenue Requirement**		**$**	**276,896.7**
11				
12	**True-Up Amount**			
13				
14	2022 (Over)/ Under Collection		**$**	**(3,006.2)**
15				
16				
17	**Total 2024 ISO Revenue Requirement**		**$**	**273,890.5**

ISO New England Inc.
2022 True-Up Amount

Line No.		Total	Schedule 1	Schedule 2	Schedule 3
1	2022 Total Operating Expense	$ 209,652,207	$ 43,587,969	$ 101,227,770	$ 64,836,468
2	2022 Total Collections	$ 212,658,370	$ 43,165,975	$ 106,534,490	$ 62,957,905
3					
4	2022 Total (Over) / Under Collection	$ (3,006,163)	$ 421,994	$ (5,306,720)	$ 1,878,563

Exhibit 3 (RCL-3)

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER24-___-000

COST ALLOCATIONS

TEST YEAR 2024

Exhibits For Robert C. Ludlow

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATION TO SCHEDULES BY DEPARTMENT
TEST YEAR 2024

Line No.	Department Description	Self-Funding Tariff			
		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)
1	**Administration-CEO**	$ 12,100,148	$ 2,607,582	$ 6,261,827	$ 3,230,740
2					
3	**Finance**	74,428,849	11,530,859	38,369,050	24,528,940
4					
5	**Facilities & Security**	3,585,823	772,745	1,855,663	957,415
6					
7	**Strategy, Risk & Operations Compliance**	2,802,972	850,979	1,096,190	855,802
8					
9	**Market & Credit Risk**	322,918	69,589	167,110	86,219
10					
11	**Human Resources**	10,048,341	2,165,417	5,200,016	2,682,907
12					
13	**Legal Department**	12,758,062	1,980,509	6,955,090	3,822,462
14					
15	**Internal Audit**	3,186,353	530,642	1,997,451	658,259
16					
17	**ISO Operations**				
18	COO-Adm	2,032,531	503,726	901,257	627,548
19	System Operations & Market Administration	295,106	79,530	152,280	63,296
20	Operations	9,633,815	2,702,075	5,423,968	1,507,772
21	Operational Performance Trng and Integration	6,505,388	2,013,049	3,223,318	1,269,021
22	Operations Support Services	6,370,696	3,978,938	669,808	1,721,950
23	Market Monitoring	5,958,724	-	4,171,107	1,787,617
24	Market Administration & Auctions	1,958,161	155,763	1,786,929	15,469
25	Market Analysis & Settlements	3,209,858	436,606	1,481,005	1,292,247
26	Market Operations Support Services	1,410,529	200,876	761,986	447,666
27	Participant Support & Solutions	3,687,838	486,455	2,903,638	297,746
28	Participant Training Services	1,351,021	-	899,195	451,825
29	System Planning	1,396,818	310,099	557,554	529,166
30	Planning Services	5,176,111	230,366	308,564	4,637,181
31	Transmission Planning	10,491,754	10,239,352	-	252,401
32	Program Management	2,017,793	335,461	1,128,278	554,053
33	Advanced Technology Solutions	6,176,148	940,089	2,257,523	2,978,536
34	Market Development & Settlements Admin.	12,324,826	253,371	3,874,633	8,196,823
35	Participant Relations & Services	2,784,910	368,988	1,351,002	1,064,920
36	IT Management	6,909,109	1,625,223	3,441,558	1,842,328
37	IT Infrastructure Support	26,822,887	3,101,418	16,438,186	7,283,283
38	IT Database & Analytics	15,600,873	2,245,342	8,421,547	4,933,983
39	IT Enterprise Applications Development	2,910,447	7,184	2,318,939	584,323
40	IT Energy Management Systems	10,340,802	3,773,683	4,970,690	1,596,428
41	IT Cyber Security	7,520,518	1,620,672	3,891,868	2,007,978
42	IT Power System Modeling Management	4,776,548	1,357,136	1,397,399	2,022,012
43	Total ISO Operations	157,663,211	36,965,403	72,732,236	47,965,573
44					
45	Total ISO Revenue Requirement	$ 276,896,676	$ 57,473,726	$ 134,634,632	$ 84,788,318
46	True-up from 2022	(3,006,163)	421,994	(5,306,720)	1,878,563
47	Total True-up	$ (3,006,163)	$ 421,994	$ (5,306,720)	$ 1,878,563
48					
49	ISO Net Revenue Requirement	$ 273,890,514	$ 57,895,721	$ 129,327,912	$ 86,666,881

(1) From Exhibit 3 (RCL-3), Schedule 3.0.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL DIRECT LABOR ALLOCATION TO SCHEDULES BY DEPARTMENT
TEST YEAR 2024

Line No.	Department Description	Self-Funding Tariff			
		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)
1	**Administration-CEO**	$ 4,384,682	$ 944,899	$ 2,269,073	$ 1,170,710
2					
3	**Finance**	27,914,861	6,015,653	14,445,941	7,453,268
4					
5	**Facilities & Security**	675,724	145,619	349,687	180,418
6					
7	**Strategy, Risk & Operations Compliance**	2,669,827	809,500	1,047,728	812,598
8					
9	**Market & Credit Risk**	322,918	69,589	167,110	86,219
10					
11	**Human Resources**	5,636,968	1,214,767	2,917,131	1,505,070
12					
13	**Legal Department**	8,410,554	1,627,401	3,789,319	2,993,834
14					
15	**Internal Audit**	1,858,354	361,168	1,049,707	447,479
16					
17	**ISO Operations**				
18	COO-Adm	1,743,024	467,130	835,780	440,114
19	System Operations & Market Administration	212,791	51,099	114,070	47,623
20	Operations	9,576,992	2,688,556	5,390,195	1,498,241
21	Operational Performance Trng and Integration	6,433,375	1,987,375	3,190,574	1,255,425
22	Operations Support Services	6,254,647	3,929,851	628,388	1,696,408
23	Market Monitoring	4,630,968	-	3,241,677	1,389,290
24	Market Administration & Auctions	1,958,160	155,763	1,786,928	15,469
25	Market Analysis & Settlements	3,187,032	435,154	1,469,719	1,282,159
26	Market Operations Support Services	1,406,132	200,876	757,589	447,666
27	Participant Support & Solutions	1,447,374	376,317	955,267	115,790
28	Participant Training Services	3,448,662	95,905	2,767,396	585,360
29	System Planning	965,231	64,165	456,918	444,148
30	Planning Services	4,188,344	194,942	273,140	3,720,262
31	Transmission Planning	7,286,566	7,097,538	-	189,028
32	Program Management	2,007,026	333,066	1,122,856	551,105
33	Advanced Technology Solutions	5,182,386	829,889	1,992,889	2,359,607
34	Market Development & Settlements Admin.	8,616,988	249,219	3,524,736	4,843,034
35	Participant Relations & Services	1,839,219	332,929	943,538	562,752
36	IT Management	5,736,297	1,286,210	2,904,533	1,545,555
37	IT Infrastructure Support	8,179,650	1,475,753	4,209,666	2,494,231
38	IT Database & Analytics	7,797,684	1,318,229	4,393,038	2,086,417
39	IT Enterprise Applications Development	2,836,709	-	2,269,367	567,342
40	IT Energy Management Systems	5,399,569	1,876,281	2,675,087	848,201
41	IT Cyber Security	2,544,781	548,400	1,316,924	679,457
42	IT Power System Modeling Management	3,444,687	995,670	1,035,933	1,413,084
43	Total ISO Operations	106,324,293	26,990,317	48,256,208	31,077,769
44					
45	Total ISO Direct Labor	$ 158,198,182	$ 38,178,912	$ 74,291,904	$ 45,727,366

(1) From Exhibit 3 (RCL-3), Schedule 4.0.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 11,329,246	$ 2,441,453	$ 5,862,885	$ 3,024,909
3	12652	NEPOOL Committee Support	Total Dir Labor	3,113	671	1,611	831
4	12654	National Committee Support	Total Dir Labor	1,748	377	904	467
5	12657	Indirect Administrative Support for BCC	Total Dir Labor	766,042	165,082	396,427	204,533
6		Total		12,100,148	2,607,582	6,261,827	3,230,740
7							
8		**Finance**					
9	11601	Payroll Administration	Total Dir Labor	426,223	91,851	220,570	113,802
10	11701	Accounts Payable	Total Dir Labor	323,318	69,675	167,317	86,326
11	11702	Procurement	Total Dir Labor	444,107	95,705	229,825	118,576
12	11901	Settle for Power Transactions	Total Dir Labor	80,730	17,397	41,778	21,555
13	12001	Budgeting and Forecasting	Total Dir Labor	676,989	145,891	350,342	180,756
14	12005	Credit Administration	Total Dir Labor	1,865,708	402,060	965,504	498,144
15	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	524,742	113,082	271,554	140,106
16	12201	Treasury and Cash Management	Total Dir Labor	3,037,379	654,555	1,571,843	810,980
17	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
18	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,126	207,577
19	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
20	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,427	33,710	80,951	41,766
21	92008	Depreciation Expense 2008 Assets	Total Dir Labor	548	118	284	146
22	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,281	276	663	342
23	92010	Depreciation Expense 2010 Assets	Total Dir Labor	2,380	513	1,231	635
24	92012	Depreciation Expense 2012 Assets	Total Dir Labor	80,431	17,333	41,623	21,475
25	92013	Depreciation Expense 2013 Assets	Total Dir Labor	833,495	179,618	431,334	222,543
26	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	99,414	21,424	51,447	26,543
27	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	2,290	494	1,185	612
28	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	50,091	9,314	31,038	9,739
29	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	394,341	22,304	346,022	26,014
30	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	572,276	52,006	469,385	50,885
31	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	1,055,371	130,564	788,265	136,541
32	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	2,630,403	209,214	2,072,751	348,438
33	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	8,197,329	903,681	5,584,178	1,709,470
34	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	8,743,069	933,974	5,720,233	2,088,863
35	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	7,165,172	1,137,815	3,942,894	2,084,463
36	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	1,090,569	280,495	530,983	279,091
37	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
38	99995	NPCC/NERC Dues	Alloc-Fixed	8,052,434	-	-	8,052,434
39	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
40	99996	Operating Contingency	Total Dir Labor	2,000,000	431,000	1,035,000	534,000
41	99998	Payroll & Other Accruals	Total Dir Labor	23,797,756	5,128,416	12,315,339	6,354,001
42		Total		74,428,849	11,530,859	38,369,050	24,528,940
43							
44		**Facilities & Security**					
45	12664	Building Maintenance	Total Dir Labor	3,585,823	772,745	1,855,663	957,415
46		Total		3,585,823	772,745	1,855,663	957,415
47							
48		**Strategy, Risk & Operations Compliance**					
49	14803	Regional Committee Support	OS Labor	82,109	41,054	-	41,054
50	14804	National Committee Support	OS Labor	82,387	41,193	-	41,193
51	14806	Employee Development	Alloc-Fixed	171,811	95,441	33,211	43,159
52	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	154,363	77,181	-	77,181
53	14812	NPCC MP Referral	Alloc-Fixed	49,089	19,636	19,636	9,818
54	14815	Identifications and Description of Internal Controls	Total Dir Labor	466,345	100,497	241,333	124,514
55	14816	Support NE Compliance Groups	Total Dir Labor	49,089	10,579	25,404	13,107
56	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	98,178	21,157	50,807	26,213
57	22704	Record Retention Services	Alloc-Fixed	122,135	40,671	40,671	40,793
58	22705	Corporate Scorecard	Alloc-Fixed	73,633	24,520	24,520	24,594
59	22706	Document Management Services	Alloc-Fixed	159,114	63,645	47,734	47,734
60	22708	ERM Adminstration	Alloc-Fixed	7,384	1,591	3,821	1,971
61	22709	ERM Management	Alloc-Fixed	49,089	10,579	25,404	13,107
62	22719	Human Performance Improvement	Total Dir Labor	12,586	2,712	6,514	3,361
63	22721	Corp Strategic Risk	Total Dir Labor	610,355	131,532	315,859	162,965
64	22726	Project Risk Mngmt Meeting	Total Dir Labor	24,544	5,289	12,702	6,553
65	23006	Business Continuity Planning	Total Dir Labor	281,042	60,565	145,439	75,038
66	25011	Corrective Action/Preventive Action	Alloc-Fixed	309,719	103,136	103,136	103,446
67		Total		2,802,972	850,979	1,096,190	855,802
68							
69		**Market & Credit Risk**					
70	22714	FAP Analysis	Alloc-Fixed	322,918	69,589	167,110	86,219
71		Total		322,918	69,589	167,110	86,219
72							
73		**Human Resources**					
74	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	55,073	11,868	28,500	14,705
75	12701	Recruiting/Interviewing	Total Dir Labor	1,114,619	240,200	576,815	297,603
76	12702	Intern Expense	Total Dir Labor	239,228	51,554	123,801	63,874
77	12801	Employee Relations	Total Dir Labor	1,706	368	883	455
78	12901	Benefit Administration	Total Dir Labor	2,180,757	469,953	1,128,542	582,262
79	12951	Compensation	Total Dir Labor	1,262,293	272,024	653,237	337,032
80	12961	HR - General	Total Dir Labor	988,201	212,957	511,394	263,850
81	12962	HR - Training	Total Dir Labor	1,225,112	264,012	633,995	327,105
82	13410	Power Training & Development	Total Dir Labor	490,380	105,677	253,771	130,931
83	13411	Markets Training & Development	Total Dir Labor	142,745	30,761	73,870	38,113
84	13412	People Training & Development	Total Dir Labor	305,997	65,942	158,353	81,701
85	13413	Business Skills Training & Development	Total Dir Labor	683,322	147,256	353,619	182,447
86	13414	Technology Training & Development	Total Dir Labor	1,250,779	269,543	647,278	333,958
87	13901	Performance Eval/Salary Review	Total Dir Labor	108,131	23,302	55,958	28,871
88		Total		10,048,341	2,165,417	5,200,016	2,682,907

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	87,073	-	-	87,073
3	12502	Board of Directors	Total Dir Labor	239,436	51,598	123,908	63,929
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	1,756,700	-	1,756,700	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	120,000	25,860	62,100	32,040
6	12514	NEPOOL Participants Committee	Total Dir Labor	231,572	49,904	119,838	61,830
7	12517	Administrative and Clerical Support	Total Dir Labor	544,204	117,276	281,626	145,303
8	12543	Independent Market Advisor	Alloc-Fixed	1,300,000	-	910,000	390,000
9	12559	General Corporate	Total Dir Labor	1,796,860	387,223	929,875	479,762
10	12584	GC - SH - Installed Capacity Requirements	Alloc-Fixed	65,305	-	-	65,305
11	12587	Capacity Market Development	Alloc-Fixed	980,768	-	-	980,768
12	12606	GC - NERC	Alloc-Fixed	600	270	60	270
13	12611	GC - Ancillary Services Markets	Alloc-Fixed	87,073	-	-	87,073
14	12613	GC - CFTC/DOE/NRC/Other Federal Agency	Total Dir Labor	217,682	46,910	112,650	58,121
15	12619	Compliance	Alloc-Fixed	87,073	34,829	34,829	17,415
16	12621	GC - NOPRs and NOIs	Total Dir Labor	130,609	28,146	67,590	34,873
17	12622	Open Access Transmission Tariff	Alloc-Fixed	174,145	174,145	-	-
18	12663	Public Information	Total Dir Labor	2,009,961	433,147	1,040,155	536,660
19	12669	Government Affairs	Total Dir Labor	2,074,248	447,000	1,073,423	553,824
20	12675	Web Content Governance Steering Committee	Total Dir Labor	854,752	184,199	442,334	228,219
21		Total		12,758,062	1,980,509	6,955,090	3,822,462
22							
23		**Internal Audit**					
24	15001	Indirect Management Duties	Total Dir Labor	223,256	48,112	115,535	59,609
25	15002	Personnel Management	Total Dir Labor	59,672	12,859	30,880	15,932
26	15003	Budget & Forecasting	Total Dir Labor	14,918	3,215	7,720	3,983
27	15004	Audit Follow-up Activities	Total Dir Labor	59,672	12,859	30,880	15,932
28	15005	Audit & Finance Committee	Total Dir Labor	145,682	31,394	75,390	38,897
29	15006	Internal Audit Business Process Update	Total Dir Labor	14,918	3,215	7,720	3,983
30	15007	Annual Audit Work Plan	Total Dir Labor	130,764	28,180	67,670	34,914
31	15011	Internal Audit Meetings	Total Dir Labor	89,508	19,289	46,320	23,899
32	15013	Indirect Adminstrative Support	Total Dir Labor	56,174	12,106	29,070	14,999
33	15014	GRC Tool Admin and Development	Total Dir Labor	307,203	66,202	158,978	82,023
34	15021	Performance Measurements	Total Dir Labor	44,754	9,644	23,160	11,949
35	15022	Vendor Contracts	Total Dir Labor	14,918	3,215	7,720	3,983
36	15023	Wire Transfers	Total Dir Labor	14,918	3,215	7,720	3,983
37	15040	Audit-Operations	Total Dir Labor	223,769	48,222	115,800	59,746
38	15085	Audit - Information Technology	Total Dir Labor	564,903	121,737	292,337	150,829
39	15133	Satellite Operations Reviews	Total Dir Labor	16,202	3,492	8,384	4,326
40	15137	Satellite IT Reviews	Total Dir Labor	15,802	3,405	8,178	4,219
41	15150	Audit - Internal Audit Other	Total Dir Labor	453	98	234	121
42	15161	External Audit- Pension Audit	Total Dir Labor	81,426	17,547	42,138	21,741
43	15162	External Audit- Financial Audit	Total Dir Labor	158,455	34,147	82,000	42,307
44	15166	External Audit -Pricing Module Certification	Alloc-Fixed	143,716	-	143,716	-
45	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	14,740	3,176	7,628	3,936
46	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	44,754	9,644	23,160	11,949
47	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	591,402	-	591,402	-
48	28005	Fraud, Waste & Abuse Program	Total Dir Labor	47,398	10,214	24,528	12,655
49	28007	Contractor/Consultant Review	Total Dir Labor	27,098	5,840	14,023	7,235
50	28173	Audit - Identity and Access Management Audit	Total Dir Labor	28,420	8,526	8,526	11,368
51	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	36,541	7,875	18,910	9,757
52	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	14,918	3,215	7,720	3,983
53		Total		3,186,353	530,642	1,997,451	658,259
54							
55		**COO-Adm**					
56	19001	NEPOOL Committee Support	Total OPS Labor	273,844	73,390	131,308	69,146
57	19002	Regional Committee Support	Total OPS Labor	8,365	2,242	4,011	2,112
58	19003	National Committee Support	Total OPS Labor	12,081	3,238	5,793	3,050
59	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,585,287	424,857	760,145	400,285
60	19009	Renewable Resource Integration	Alloc-Fixed	152,955	-	-	152,955
61		Total		2,032,531	503,726	901,257	627,548
62							
63		**System Operations & Market Administration**					
64	14404	NEPOOL Committee Support	SOA Labor	1,250	432	580	238
65	14405	Indirect Supervision/Clerical Support	SOA Labor	169,040	58,387	78,469	32,185
66	14407	Regional Committee Support	SOA Labor	1,250	432	580	238
67	14408	National Committee Support	SOA Labor	58,715	20,280	27,255	11,179
68	19101	NEPOOL Committee Support	MOA Labor	64,851	-	45,396	19,455
69		Total		295,106	79,530	152,280	63,296

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	3,848,170	-	3,232,463	615,707
3	14002	Transmission Operations	Alloc-Fixed	2,748,693	2,198,954	137,435	412,304
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,205,662	110,283	1,742,473	352,906
5	14562	Ops - Regional Committee Support	OPS Labor	17,788	4,973	9,847	2,967
6	14563	National Committee Support	OPS Labor	233,594	65,313	129,317	38,963
7	14565	Employee Development	OPS Labor	23,436	6,553	12,974	3,909
8	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
9	14586	Ops - Other External Support Meetings	Alloc-Fixed	2,964	-	2,371	593
10	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	227,666	227,666	-	-
11	14702	Procedure Documentation	Alloc-Fixed	98,178	39,271	39,271	19,636
12		Total		9,633,815	2,702,075	5,423,968	1,507,772
13							
14		**Operational Performance Trng and Integration**					
15	14402	Operations Training	Alloc-Fixed	1,128,016	451,206	451,206	225,603
16	14462	OSS - General Systems Operations Support	TSO Labor	458,296	148,350	219,111	90,834
17	14564	Indirect Supervision/Clerical Support	OPS Labor	1,647,159	460,546	911,867	274,746
18	14574	OPTI Continuing Training	Alloc-Fixed	913,628	365,451	365,451	182,726
19	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	13,415	5,366	5,366	2,683
20	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	227,666	91,066	91,066	45,533
21	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	227,666	91,066	91,066	45,533
22	14579	Ops - OPTI TTSE Maintenance	OPS Labor	227,666	91,066	91,066	45,533
23	14581	Application Testing and Development	Total Dir Labor	455,332	98,124	235,634	121,574
24	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
25	14587	Ops - Other Internal Support Meetings	Total Dir Labor	227,666	49,062	117,817	60,787
26	15501	OA - Operations Analysis	Alloc-Fixed	751,212	112,682	525,849	112,682
27		Total		6,505,388	2,013,049	3,223,318	1,269,021
28							
29		**Operations Support Services**					
30	14453	National Committee Support	TSO Labor	28,354	9,178	13,556	5,620
31	14454	Indirect Supervision/Clerical Support	TSO Labor	621,590	201,209	297,182	123,199
32	14477	Participant project and outage coordination support	Alloc-Fixed	6,844	3,422	-	3,422
33	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	229,642	-	-	229,642
34	14760	Trans Outage LT (telecommute)	Alloc-Fixed	565,713	282,856	141,428	141,428
35	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	3,221,415	2,577,132	161,071	483,212
36	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,131,426	905,141	56,571	169,714
37	18382	Transmission Outage Application - Long Term	Alloc-Fixed	565,713	-	-	565,713
38		Total		6,370,696	3,978,938	669,808	1,721,950
39							
40		**Market Monitoring**					
41	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	5,956,229	-	4,169,360	1,786,869
42	16102	Regulatory Activities	Alloc-Fixed	2,495	-	1,747	749
43		Total		5,958,724	-	4,171,107	1,787,617
44							
45		**Market Administration & Auctions**					
46	21901	Day Ahead Price Monitoring	Alloc-Fixed	445,036	-	445,036	-
47	21902	Real Time Price Verification	Alloc-Fixed	489,540	-	489,540	-
48	21907	Indirect Supervision/Clerical Support	MA Labor	489,540	-	474,071	15,469
49	21915	FTR/Auction Administration	Alloc-Fixed	311,525	155,763	155,763	-
50	21917	Real Time Price Finalization	Alloc-Fixed	222,518	-	222,518	-
51		Total		1,958,161	155,763	1,786,929	15,469
52							
53		**Market Analysis & Settlements**					
54	1701	Billing Statements - Energy	Alloc-Fixed	97,695	-	97,695	-
55	1702	Billing Statements - Transmission	Alloc-Fixed	119,839	119,839	-	-
56	1713	Billing Statements - ISO Tariff	Total Dir Labor	14,329	3,088	7,415	3,826
57	1714	Billable Tariff Re-billings	Total Dir Labor	1,303	1,303	-	-
58	1717	Inventoried Energy Program	Alloc-Fixed	6,513	-	-	6,513
59	1718	Mystic COS	Alloc-Fixed	14,329	-	-	14,329
60	1719	FCM Daily	Alloc-Fixed	182,363	-	-	182,363
61	1722	NCC Trading FA	Alloc-Fixed	13,026	-	-	13,026
62	2047	Score Card	STLM Labor	3,908	578	1,903	1,426
63	2048	FCM	Alloc-Fixed	78,156	-	-	78,156
64	2049	Product Testing	Alloc-Fixed	18,236	-	14,589	3,647
65	2051	Legal Support	Alloc-Fixed	7,816	-	3,908	3,908
66	2005	Customer Service	STLM Labor	194,087	28,705	94,540	70,842
67	2007	Admin support - NEPOOL Committees	STLM Labor	9,161	1,355	4,462	3,344
68	2009	Indirect Supervision/Clerical Support	STLM Labor	899,001	132,962	437,903	328,135
69	2010	Employee Development	STLM Labor	206,520	30,544	100,596	75,380
70	2013	FTR Administration	Alloc-Fixed	37,775	-	37,775	-
71	2014	Billing Statements - NCPC	Alloc-Fixed	399,897	-	199,948	199,948
72	2020	Billing Disputes	Total Dir Labor	20,842	4,491	10,785	5,565
73	2021	Analysis & Reporting	Total Dir Labor	459,145	98,946	237,608	122,592
74	2024	ASM Regulation	Alloc-Fixed	29,960	-	-	29,960
75	2025	ASM Locational Forward Reserve	Alloc-Fixed	115,931	-	-	115,931
76	2026	Batch Processing	Total Dir Labor	36,473	7,860	18,875	9,738
77	2032	Billing	STLM Labor	46,893	6,936	22,842	17,116
78	2033	Market Analysis	Alloc-Fixed	183,658	-	183,658	-
79	2055	MAS - Market Monitoring Support	Alloc-Fixed	13,006	-	6,503	6,503
80		Total		3,209,858	436,606	1,481,005	1,292,247

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Operations Support Services**					
2	3000	Hourly Settlements Support	Alloc-Fixed	321,402	-	160,701	160,701
3	3002	Monthly Settlements Support	Alloc-Fixed	229,573	114,786	-	114,786
4	3006	Customer Service	Alloc-Fixed	114,786	-	114,786	-
5	3008	Admin Support	Alloc-Fixed	206,902	-	206,902	-
6	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	160,701	-	160,701	-
7	3010	Employee Development	Alloc-Fixed	27,068	-	27,068	-
8	3012	FERC Data Request	Alloc-Fixed	5,739	-	5,739	-
9	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	344,359	86,090	86,090	172,179
10		Total		1,410,529	200,876	761,986	447,666
11							
12		**Participant Support & Solutions**					
13	16001	Participant/membership support	Alloc-Fixed	112,241	-	56,120	56,120
14	16006	Call Support (Ask ISO)	Alloc-Fixed	1,502,114	390,550	991,395	120,169
15	16414	Direct Customer Contact	MS Labor	26,316	-	23,684	2,632
16	16419	Asset Registration Implemented	Alloc-Fixed	445,036	-	445,036	-
17	16422	Claimed Capability Audits	Alloc-Fixed	712,059	-	712,059	-
18	16432	New Generation Coordination and Registration	Alloc-Fixed	445,036	-	445,036	-
19	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	445,036	95,905	230,306	118,825
20		Total		3,687,838	486,455	2,903,638	297,746
21							
22		**Participant Training Services**					
23	16021	Training Development	Alloc-Fixed	903,651	-	451,825	451,825
24	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	447,370	-	447,370	-
25		Total		1,351,021	-	899,195	451,825
26							
27		**Planning Services**					
28	14313	National Committee Support	Alloc-Fixed	40,015	4,350	2,017	33,648
29	17101	Analysis	Alloc-Fixed	120,044	-	84,031	36,013
30	17131	Calculate Objective Capability	Alloc-Fixed	380,765	-	-	380,765
31	17331	NEPOOL Committee Support	Alloc-Fixed	20,012	2,175	1,009	16,828
32	17401	Indirect Supervisory Activities	Alloc-Fixed	40,019	4,350	2,017	33,652
33	17403	TCA Application Review	Alloc-Fixed	121,916	-	-	121,916
34	17405	Energy Efficiency Forecast	Alloc-Fixed	60,026	-	-	60,026
35	17409	Environmental/Emissions Supp	Total Dir Labor	200,073	-	-	200,073
36	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	211,810	-	-	211,810
37	17503	FCA - New Resource Qualification Support	Alloc-Fixed	1,419,234	-	-	1,419,234
38	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	128,379	-	-	128,379
39	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	85,586	-	-	85,586
40	17507	FCA - Auctions & Filings	Alloc-Fixed	1,042,367	-	-	1,042,367
41	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	128,379	-	-	128,379
42	18101	Develop Load Forecast	Alloc-Fixed	637,287	127,457	127,457	382,372
43	18121	Operations Forecast Support	Alloc-Fixed	280,102	56,020	56,020	168,061
44	18131	Other Load Forecasting Activities	Alloc-Fixed	20,007	4,001	4,001	12,004
45	18133	Solar Load Forecast Development	Alloc-Fixed	140,051	28,010	28,010	84,031
46	18134	Electrification Forecasts	Alloc-Fixed	20,007	4,001	4,001	12,004
47	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	80,029	-	-	80,029
48		Total		5,176,111	230,366	308,564	4,637,181
49							
50		**System Planning**					
51	18150	Regional Transmission Expansion Plan	Alloc-Fixed	113,552	85,164	28,388	-
52	18152	States Requests	Alloc-Fixed	51,710	25,855	12,928	12,928
53	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	1,032,476	-	516,238	516,238
54	18562	Project Management	Alloc-Fixed	199,080	199,080	-	-
55		Total		1,396,818	310,099	557,554	529,166
56							
57		**Transmission Planning**					
58	21660	Stability Case Building	Alloc-Fixed	128,379	-	-	128,379
59	14715	Non DOE Funded/Unallowable	Alloc-Fixed	124,022	-	-	124,022
60	18201	Transmission System Assessment	Alloc-Fixed	6,418,220	6,418,220	-	-
61	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	113,880	113,880	-	-
62	18333	General SIS/FS	Alloc-Fixed	1,783,631	1,783,631	-	-
63	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	1,115,348	1,115,348	-	-
64	18335	Regulatory Activities - NPCC	Alloc-Fixed	307,990	307,990	-	-
65	18336	National Activities	Alloc-Fixed	171,524	171,524	-	-
66	18337	TR - Regulatory Activities	Alloc-Fixed	31,077	31,077	-	-
67	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	42,793	42,793	-	-
68	18350	States Future Planning Studies	Alloc-Fixed	254,889	254,889	-	-
69		Total		10,491,754	10,239,352	-	252,401
70							
71		**Program Management**					
72	801	Program Management - Administration	Total Dir Labor	1,024,143	220,703	529,994	273,446
73	1661	ISO Program Management	Alloc-Fixed	461,478	-	323,035	138,443
74	1665	Product and Test Mgmt.	Total Dir Labor	531,282	114,491	274,939	141,852
75	25002	PMO Support	Alloc-Fixed	890	267	312	312
76		Total		2,017,793	335,461	1,128,278	554,053

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Advanced Technology Solutions**					
2	21201	Advanced Technology Solutions	Total Dir Labor	4,292,759	925,090	2,221,503	1,146,167
3	21203	Employee Development	Total Dir Labor	69,603	15,000	36,020	18,584
4	21207	Resource Capacity Accreditation	Total Dir Labor	1,813,786	-	-	1,813,786
5		Total		6,176,148	940,089	2,257,523	2,978,536
6							
7		**Market Development & Settlements Admin.**					
8	16607	National Committee Support	Total Dir Labor	29,949	6,454	15,499	7,996
9	19104	Indirect Supervision/Clerical Support	MOA Labor	369,851	-	258,896	110,955
10	21001	Market Development	Alloc-Fixed	1,195,027	-	597,514	597,514
11	21002	Administration	Total Dir Labor	610,531	131,569	315,950	163,012
12	21003	Employee Development	Total Dir Labor	222,510	47,951	115,149	59,410
13	21007	Budget/Forecast Support	Total Dir Labor	279,823	60,302	144,808	74,713
14	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	267,493	-	254,118	13,375
15	21011	Capacity Market	Alloc-Fixed	4,722,431	-	-	4,722,431
16	22401	Administration	Total Dir Labor	32,920	7,094	17,036	8,790
17	22402	Working Group Meetings and Support	Alloc-Fixed	16,460	-	8,230	8,230
18	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	1,718,506	-	1,288,879	429,626
19	22657	Project: ORTP/CONE Updates	Alloc-Fixed	1,383,368	-	-	1,383,368
20	22658	Storage	Alloc-Fixed	401,920	-	321,536	80,384
21	22660	Energy Security	Alloc-Fixed	475,968	-	237,984	237,984
22	22661	Project: DER Participation	Alloc-Fixed	598,067	-	299,034	299,034
23		Total		12,324,826	253,371	3,874,633	8,196,823
24							
25		**Participant Relations & Services**					
26	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	358,498	-	179,249	179,249
27	22607	NEPOOL Committee Administration	Total Dir Labor	1,712,239	368,988	886,084	457,168
28	22612	Future Grid Study and Modeling	Total Dir Labor	714,172	-	285,669	428,503
29		Total		2,784,910	368,988	1,351,002	1,064,920
30							
31		**IT Management**					
32	6517	Employee Development - Hardware/Software	Total Dir Labor	83,982	18,098	43,461	22,423
33	6519	Indirect Supervision and Clerical Support	Total Dir Labor	5,537,655	1,193,365	2,865,736	1,478,554
34	6552	Security	Total Dir Labor	190,004	40,946	98,327	50,731
35	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	208,726	44,981	108,016	55,730
36	6557	Information Technology Committee	Total Dir Labor	14,659	3,159	7,586	3,914
37	22501	Change Management Support	Alloc-Fixed	249,877	112,445	112,445	24,988
38	22505	Administrative	Alloc-Fixed	620,736	211,050	204,843	204,843
39	22511	IT CM/QA - Professional Training	Alloc-Fixed	3,470	1,180	1,145	1,145
40		Total		6,909,109	1,625,223	3,441,558	1,842,328
41							
42		**IT Infrastructure Support**					
43	6510	Desktop Support - Hardware	Total Dir Labor	671,394	144,685	347,446	179,262
44	6511	Desktop Support - Software	Total Dir Labor	1,519,017	327,348	786,091	405,578
45	6512	Host Computer - Hardware	Alloc-Fixed	3,171,221	-	2,378,416	792,805
46	6513	Host Computer - Software	Alloc-Fixed	7,928,327	-	5,946,245	1,982,082
47	6514	Networking - Hardware	Total Dir Labor	1,023,505	220,565	529,664	273,276
48	6515	Networking - Software	Total Dir Labor	3,459	745	1,790	923
49	6516	Communications	Total Dir Labor	3,599,120	775,610	1,862,545	960,965
50	6619	IT - Infrastructure Coordination	Total Dir Labor	554,791	119,558	287,104	148,129
51	6602	Help Desk Support	Total Dir Labor	219,249	47,248	113,461	58,540
52	6615	Host Computer Monitoring	Alloc-Fixed	1,331,608	-	665,804	665,804
53	6616	Desktop Support	Total Dir Labor	1,014,559	218,637	525,034	270,887
54	6618	System Administration - Windows	Total Dir Labor	153,279	33,032	79,322	40,925
55	6622	CIP & Systems Compliance	Total Dir Labor	2,356,264	507,775	1,219,367	629,123
56	6623	Asset Management	Total Dir Labor	732,450	157,843	379,043	195,564
57	6624	Infrastructure Review & Planning	Total Dir Labor	341,039	73,494	176,488	91,057
58	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	263,687	56,825	136,458	70,404
59	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	287,621	61,982	148,844	76,795
60	6627	IT - Infrastructure Support Request	Total Dir Labor	541,165	116,621	280,053	144,491
61	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	215,817	46,509	111,685	57,623
62	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	233,261	50,268	120,712	62,281
63	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	662,055	142,673	342,613	176,769
64		Total		26,822,887	3,101,418	16,438,186	7,283,283
65							
66		**IT Cyber Security**					
67	6540	Security Compliance and Reporting	Total Dir Labor	3,726,995	803,167	1,928,720	995,108
68	6540D	Intrusion Monitoring and Response	Total Dir Labor	2,349,092	506,229	1,215,655	627,208
69	6541	Security SW Tools Program	Total Dir Labor	1,108,392	238,858	573,593	295,941
70	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	39,578	8,529	20,482	10,567
71	6547	Cyber Security Training	Total Dir Labor	237,170	51,110	122,735	63,324
72	6548	CIP Compliance & Monitoring	Total Dir Labor	59,291	12,777	30,683	15,831
73		Total		7,520,518	1,620,672	3,891,868	2,007,978

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**IT Database & Analytics**					
2	6571	DBA Support - MOPS	Total Dir Labor	3,450,084	743,493	1,785,419	921,173
3	6591	Data Architect - MOPS	Total Dir Labor	430,031	92,672	222,541	114,818
4	6594	IT Data Analyst	Total Dir Labor	538,397	116,025	278,620	143,752
5	6595	IT WEB Application Support	Total Dir Labor	731,480	157,634	378,541	195,305
6	6596	IT Data Governance	Total Dir Labor	294,343	63,431	152,323	78,590
7	6597	IT - BI IT Commitments	Total Dir Labor	307,655	66,300	159,211	82,144
8	21706	Enterprise Software Support	Total Dir Labor	2,473,766	533,097	1,280,174	660,496
9	21801	Software Support - Settlements	Alloc-Fixed	953,355	-	762,684	190,671
10	21802	Software Support - Publishing	Alloc-Fixed	36,716	-	29,373	7,343
11	21803	Software Support - Finance	Alloc-Fixed	549,607	-	439,686	109,921
12	21804	Software Support - Mitigation	Alloc-Fixed	753,131	-	602,505	150,626
13	21805	Software Support - TSO	Total Dir Labor	676,168	145,714	349,917	180,537
14	21806	Software Support - Enterprise	Total Dir Labor	1,003,052	216,158	519,079	267,815
15	21807	Software Support - Planning	Alloc-Fixed	661,895	-	529,516	132,379
16	21808	Training Delivery to NON-IT	Alloc-Fixed	274,990	-	219,992	54,998
17	21811	Single Sign On Support	Alloc-Fixed	239,476	-	191,581	47,895
18	21812	GADS Support	Alloc-Fixed	146,865	-	117,492	29,373
19	21816	CMS Support	Total Dir Labor	183,583	39,562	95,004	49,017
20	21818	Discoverer Support	Total Dir Labor	84,820	18,279	43,894	22,647
21	21824	FCTS Support	Alloc-Fixed	1,394,651	-	-	1,394,651
22	21825	eTariff Support	Alloc-Fixed	73,433	-	58,746	14,687
23	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	245,844	52,979	127,224	65,640
24	21832	GDMA/Gateway Support	Alloc-Fixed	97,530	-	78,024	19,506
25		Total		15,600,873	2,245,342	8,421,547	4,933,983
26							
27		**IT Energy Management Systems**					
28	21600	Indirect Supervision and Administration	Total Dir Labor	54,800	11,809	28,359	14,632
29	21601	Power System Modeling	Total Dir Labor	83,976	18,097	43,458	22,422
30	21602	Applications Support	Total Dir Labor	348,370	75,074	180,281	93,015
31	21603	EMS Power System Applications Support	Total Dir Labor	853,851	184,005	441,868	227,978
32	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,807,896	2,246,317	561,579	-
33	21605	DAM FTR/ARR Support	Alloc-Fixed	2,105,078	421,016	1,263,047	421,016
34	21606	Real-time Market Support	Alloc-Fixed	3,649,446	729,889	2,189,667	729,889
35	21607	Forecast Support	Alloc-Fixed	437,385	87,477	262,431	87,477
36		Total		10,340,802	3,773,683	4,970,690	1,596,428
37							
38		**IT Enterprise Applications Development**					
39	6518	Employee Development - Software	Total Dir Labor	33,338	7,184	17,252	8,901
40	21707	Application Analysis and Conceptual Design	Alloc-Fixed	95,563	-	76,450	19,113
41	21708	Application Design Evaluation and Selection	Alloc-Fixed	414,105	-	331,284	82,821
42	21709	Technology Evaluation and Selection	Alloc-Fixed	1,093,505	-	874,804	218,701
43	21710	Indirect Supervision and Administration	Alloc-Fixed	1,118,943	-	895,154	223,789
44	21711	EWR and CAPA Analysis	Alloc-Fixed	154,993	-	123,995	30,999
45		Total		2,910,447	7,184	2,318,939	584,323
46							
47		**IT Power System Modeling Management**					
48	21650	Indirect Supervision and Administration	Total Dir Labor	198,110	42,693	102,522	52,895
49	21651	Power System Modeling	Alloc-Fixed	1,676,881	670,752	670,752	335,376
50	21652	System Application Support	Alloc-Fixed	152,726	61,091	61,091	30,545
51	21654	NX9 Administration	Alloc-Fixed	438,673	175,469	175,469	87,735
52	21655	ICCP Support	Alloc-Fixed	921,118	368,447	368,447	184,224
53	21656	Transmission Project Management	Alloc-Fixed	32,611	26,089	6,522	-
54	21657	Model On Demand Admin	Alloc-Fixed	1,049,430	-	-	1,049,430
55	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	223,026	-	-	223,026
56	21659	Synchrophasor Applications	Alloc-Fixed	83,973	12,596	12,596	58,781
57		Total		4,776,548	1,357,136	1,397,399	2,022,012
58							
59							
60		**Total ISO**		$ 276,896,676	$ 57,473,726	$ 134,634,632	$ 84,788,318

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 4,384,682	$ 944,899	$ 2,269,073	$ 1,170,710
3		Total		4,384,682	944,899	2,269,073	1,170,710
4							
5		**Finance**					
6	11601	Payroll Administration	Total Dir Labor	363,283	78,287	187,999	96,996
7	11701	Accounts Payable	Total Dir Labor	322,918	69,589	167,110	86,219
8	11702	Procurement	Total Dir Labor	444,012	95,685	229,776	118,551
9	11901	Settle for Power Transactions	Total Dir Labor	80,730	17,397	41,778	21,555
10	12001	Budgeting and Forecasting	Total Dir Labor	524,742	113,082	271,554	140,106
11	12005	Credit Administration	Total Dir Labor	1,364,490	294,048	706,124	364,319
12	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	524,742	113,082	271,554	140,106
13	12201	Treasury and Cash Management	Total Dir Labor	242,189	52,192	125,333	64,664
14	99998	Payroll & Other Accruals	Total Dir Labor	24,047,756	5,182,291	12,444,714	6,420,751
15		Total		27,914,861	6,015,653	14,445,941	7,453,268
16							
17		**Facilities & Security**					
18	12664	Building Maintenance	Total Dir Labor	675,724	145,619	349,687	180,418
19		Total		675,724	145,619	349,687	180,418
20							
21		**Strategy, Risk & Operations Compliance**					
22	14803	Regional Committee Support	OS Labor	73,633	36,817	-	36,817
23	14804	National Committee Support	OS Labor	73,633	36,817	-	36,817
24	14806	Employee Development	Alloc-Fixed	171,811	95,441	33,211	43,159
25	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	154,363	77,181	-	77,181
26	14812	NPCC MP Referral	Alloc-Fixed	49,089	19,636	19,636	9,818
27	14815	Identifications and Description of Internal Controls	Total Dir Labor	466,345	100,497	241,333	124,514
28	14816	Support NE Compliance Groups	Total Dir Labor	49,089	10,579	25,404	13,107
29	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	98,178	21,157	50,807	26,213
30	22704	Record Retention Services	Alloc-Fixed	73,633	24,520	24,520	24,594
31	22705	Corporate Scorecard	Alloc-Fixed	73,633	24,520	24,520	24,594
32	22706	Document Management Services	Alloc-Fixed	147,267	58,907	44,180	44,180
33	22709	ERM Management	Alloc-Fixed	49,089	10,579	25,404	13,107
34	22721	Corp Strategic Risk	Total Dir Labor	610,355	131,532	315,859	162,965
35	22726	Project Risk Mngmt Meeting	Total Dir Labor	24,544	5,289	12,702	6,553
36	23006	Business Continuity Planning	Total Dir Labor	245,445	52,893	127,018	65,534
37	25011	Corrective Action/Preventive Action	Alloc-Fixed	309,719	103,136	103,136	103,446
38		Total		2,669,827	809,500	1,047,728	812,598
39							
40		**Market & Credit Risk**					
41	22714	FAP Analysis	Alloc-Fixed	322,918	69,589	167,110	86,219
42		Total		322,918	69,589	167,110	86,219
43							
44		**Human Resources**					
45	12701	Recruiting/Interviewing	Total Dir Labor	678,356	146,186	351,049	181,121
46	12702	Intern Expense	Total Dir Labor	123,144	26,537	63,727	32,879
47	12901	Benefit Administration	Total Dir Labor	1,264,277	272,452	654,263	337,562
48	12951	Compensation	Total Dir Labor	738,863	159,225	382,362	197,276
49	12961	HR - General	Total Dir Labor	753,224	162,320	389,793	201,111
50	12962	HR - Training	Total Dir Labor	348,919	75,192	180,565	93,161
51	13410	Power Training & Development	Total Dir Labor	224,793	48,443	116,330	60,020
52	13411	Markets Training & Development	Total Dir Labor	112,751	24,298	58,349	30,105
53	13412	People Training & Development	Total Dir Labor	180,030	38,797	93,166	48,068
54	13413	Business Skills Training & Development	Total Dir Labor	400,010	86,202	207,005	106,803
55	13414	Technology Training & Development	Total Dir Labor	812,602	175,116	420,521	216,965
56		Total		5,636,968	1,214,767	2,917,131	1,505,070
57							
58		**Legal Department**					
59	12422	Interconnection Queue	Alloc-Fixed	87,073	-	-	87,073
60	12502	Board of Directors	Total Dir Labor	217,682	46,910	112,650	58,121
61	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	348,291	-	348,291	-
62	12514	NEPOOL Participants Committee	Total Dir Labor	217,682	46,910	112,650	58,121
63	12517	Administrative and Clerical Support	Total Dir Labor	544,204	117,276	281,626	145,303
64	12559	General Corporate	Total Dir Labor	1,323,628	285,242	684,977	353,409
65	12584	GC - SH - Installed Capacity Requirements	Alloc-Fixed	65,305	-	-	65,305
66	12587	Capacity Market Development	Alloc-Fixed	979,568	-	-	979,568
67	12611	GC - Ancillary Services Markets	Alloc-Fixed	87,073	-	-	87,073
68	12613	GC - CFTC/DOE/NRC/Other Federal Agency	Total Dir Labor	217,682	46,910	112,650	58,121
69	12619	Compliance	Alloc-Fixed	87,073	34,829	34,829	17,415
70	12621	GC - NOPRs and NOIs	Total Dir Labor	130,609	28,146	67,590	34,873
71	12622	Open Access Transmission Tariff	Alloc-Fixed	174,145	174,145	-	-
72	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	6,887	1,484	3,564	1,839
73	12663	Public Information	Total Dir Labor	1,619,292	348,957	837,984	432,351
74	12669	Government Affairs	Total Dir Labor	1,449,609	312,391	750,173	387,046
75	12675	Web Content Governance Steering Committee	Total Dir Labor	854,752	184,199	442,334	228,219
76		Total		8,410,554	1,627,401	3,789,319	2,993,834

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(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Internal Audit**					
2	15001	Indirect Management Duties	Total Dir Labor	216,774	46,715	112,180	57,879
3	15002	Personnel Management	Total Dir Labor	59,672	12,859	30,880	15,932
4	15003	Budget & Forecasting	Total Dir Labor	14,918	3,215	7,720	3,983
5	15004	Audit Follow-up Activities	Total Dir Labor	59,672	12,859	30,880	15,932
6	15005	Audit & Finance Committee	Total Dir Labor	145,682	31,394	75,390	38,897
7	15006	Internal Audit Business Process Update	Total Dir Labor	14,918	3,215	7,720	3,983
8	15007	Annual Audit Work Plan	Total Dir Labor	130,764	28,180	67,670	34,914
9	15011	Internal Audit Meetings	Total Dir Labor	89,508	19,289	46,320	23,899
10	15013	Indirect Adminstrative Support	Total Dir Labor	56,174	12,106	29,070	14,999
11	15014	GRC Tool Admin and Development	Total Dir Labor	171,811	37,025	88,912	45,874
12	15021	Performance Measurements	Total Dir Labor	44,754	9,644	23,160	11,949
13	15022	Vendor Contracts	Total Dir Labor	14,918	3,215	7,720	3,983
14	15023	Wire Transfers	Total Dir Labor	14,918	3,215	7,720	3,983
15	15040	Audit-Operations	Total Dir Labor	223,769	48,222	115,800	59,746
16	15085	Audit - Information Technology	Total Dir Labor	268,523	57,867	138,961	71,696
17	15133	Satellite Operations Reviews	Total Dir Labor	14,918	3,215	7,720	3,983
18	15137	Satellite IT Reviews	Total Dir Labor	14,918	3,215	7,720	3,983
19	15161	External Audit- Pension Audit	Total Dir Labor	29,836	6,430	15,440	7,966
20	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	44,754	9,644	23,160	11,949
21	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	182,402	-	182,402	-
22	28005	Fraud, Waste & Abuse Program	Total Dir Labor	14,918	3,215	7,720	3,983
23	28007	Contractor/Consultant Review	Total Dir Labor	14,918	3,215	7,720	3,983
24	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	14,918	3,215	7,720	3,983
25		Total		1,858,354	361,168	1,049,707	447,479
26							
27		**COO-Adm**					
28	19001	NEPOOL Committee Support	Total OPS Labor	178,844	47,930	85,756	45,158
29	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,564,180	419,200	750,024	394,955
30		Total		1,743,024	467,130	835,780	440,114
31							
32		**System Operations & Market Administration**					
33	14405	Indirect Supervision/Clerical Support	SOA Labor	147,940	51,099	68,674	28,168
34	19101	NEPOOL Committee Support	MOA Labor	64,851	-	45,396	19,455
35		Total		212,791	51,099	114,070	47,623
36							
37		**Operations**					
38	14001	Generation Dispatch	Alloc-Fixed	3,848,170	-	3,232,463	615,707
39	14002	Transmission Operations	Alloc-Fixed	2,748,693	2,198,954	137,435	412,304
40	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,198,954	109,948	1,737,174	351,833
41	14563	National Committee Support	OPS Labor	227,666	63,655	126,036	37,975
42	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
43	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	227,666	227,666	-	-
44	14702	Procedure Documentation	Alloc-Fixed	98,178	39,271	39,271	19,636
45		Total		9,576,992	2,688,556	5,390,195	1,498,241
46							
47		**Operational Performance Trng and Integration**					
48	14402	Operations Training	Alloc-Fixed	1,099,482	439,793	439,793	219,896
49	14462	OSS - General Systems Operations Support	TSO Labor	455,332	147,391	217,694	90,247
50	14564	Indirect Supervision/Clerical Support	OPS Labor	1,623,024	453,797	898,506	270,720
51	14574	OPTI Continuing Training	Alloc-Fixed	910,664	364,265	364,265	182,133
52	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	227,666	91,066	91,066	45,533
53	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	227,666	91,066	91,066	45,533
54	14579	Ops - OPTI TTSE Maintenance	OPS Labor	227,666	91,066	91,066	45,533
55	14581	Application Testing and Development	Total Dir Labor	455,332	98,124	235,634	121,574
56	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
57	14587	Ops - Other Internal Support Meetings	Total Dir Labor	227,666	49,062	117,817	60,787
58	15501	OA - Operations Analysis	Alloc-Fixed	751,212	112,682	525,849	112,682
59		Total		6,433,375	1,987,375	3,190,574	1,255,425
60							
61		**Operations Support Services**					
62	14454	Indirect Supervision/Clerical Support	TSO Labor	565,714	183,122	270,468	112,125
63	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	227,666	-	-	227,666
64	14760	Trans Outage LT (telecommute)	Alloc-Fixed	565,713	282,856	141,428	141,428
65	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	3,198,415	2,558,732	159,921	479,762
66	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,131,426	905,141	56,571	169,714
67	18382	Transmission Outage Application - Long Term	Alloc-Fixed	565,713	-	-	565,713
68		Total		6,254,647	3,929,851	628,388	1,696,408

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Market Monitoring**					
2	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	4,630,968	-	3,241,677	1,389,290
3		Total		4,630,968	-	3,241,677	1,389,290
4							
5		**Market Administration & Auctions**					
6	21901	Day Ahead Price Monitoring	Alloc-Fixed	445,036	-	445,036	-
7	21902	Real Time Price Verification	Alloc-Fixed	489,540	-	489,540	-
8	21907	Indirect Supervision/Clerical Support	MA Labor	489,539	-	474,070	15,469
9	21915	FTR/Auction Administration	Alloc-Fixed	311,525	155,763	155,763	-
10	21917	Real Time Price Finalization	Alloc-Fixed	222,518	-	222,518	-
11		Total		1,958,160	155,763	1,786,928	15,469
12							
13		**Market Analysis & Settlements**					
14	1701	Billing Statements - Energy	Alloc-Fixed	97,695	-	97,695	-
15	1702	Billing Statements - Transmission	Alloc-Fixed	119,839	119,839	-	-
16	1713	Billing Statements - ISO Tariff	Total Dir Labor	14,329	3,088	7,415	3,826
17	1714	Billable Tariff Re-billings	Total Dir Labor	1,303	1,303	-	-
18	1717	Inventoried Energy Program	Alloc-Fixed	6,513	-	-	6,513
19	1718	Mystic COS	Alloc-Fixed	14,329	-	-	14,329
20	1719	FCM Daily	Alloc-Fixed	182,363	-	-	182,363
21	1722	NCC Trading FA	Alloc-Fixed	13,026	-	-	13,026
22	2005	Customer Service	STLM Labor	194,087	28,705	94,540	70,842
23	2007	Admin support - NEPOOL Committees	STLM Labor	261	39	127	95
24	2009	Indirect Supervision/Clerical Support	STLM Labor	898,791	132,931	437,801	328,059
25	2010	Employee Development	STLM Labor	205,810	30,439	100,250	75,121
26	2013	FTR Administration	Alloc-Fixed	37,775	-	37,775	-
27	2014	Billing Statements - NCPC	Alloc-Fixed	399,897	-	199,948	199,948
28	2020	Billing Disputes	Total Dir Labor	20,842	4,491	10,785	5,565
29	2021	Analysis & Reporting	Total Dir Labor	459,145	98,946	237,608	122,592
30	2024	ASM Regulation	Alloc-Fixed	29,960	-	-	29,960
31	2025	ASM Locational Forward Reserve	Alloc-Fixed	115,931	-	-	115,931
32	2026	Batch Processing	Total Dir Labor	36,473	7,860	18,875	9,738
33	2032	Billing	STLM Labor	46,893	6,936	22,842	17,116
34	2033	Market Analysis	Alloc-Fixed	183,658	-	183,658	-
35	2047	Score Card	STLM Labor	3,908	578	1,903	1,426
36	2048	FCM	Alloc-Fixed	78,156	-	-	78,156
37	2049	Product Testing	Alloc-Fixed	18,236	-	14,589	3,647
38	2051	Legal Support	Alloc-Fixed	7,816	-	3,908	3,908
39		Total		3,187,032	435,154	1,469,719	1,282,159
40							
41		**Market Operations Support Services**					
42	3000	Hourly Settlements Support	Alloc-Fixed	321,402	-	160,701	160,701
43	3002	Monthly Settlements Support	Alloc-Fixed	229,573	114,786	-	114,786
44	3006	Customer Service	Alloc-Fixed	114,786	-	114,786	-
45	3008	Admin Support	Alloc-Fixed	206,615	-	206,615	-
46	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	160,701	-	160,701	-
47	3010	Employee Development	Alloc-Fixed	22,957	-	22,957	-
48	3012	FERC Data Request	Alloc-Fixed	5,739	-	5,739	-
49	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	344,359	86,090	86,090	172,179
50		Total		1,406,132	200,876	757,589	447,666
51							
52		**Participant Support & Solutions**					
53	16006	Call Support (Ask ISO)	Alloc-Fixed	1,447,374	376,317	955,267	115,790
54		Total		1,447,374	376,317	955,267	115,790
55							
56		**Participant Training Services**					
57	16001	Participant/membership support	Alloc-Fixed	26,316	-	13,158	13,158
58	16021	Training Development	Alloc-Fixed	901,492	-	450,746	450,746
59	16414	Direct Customer Contact	MS Labor	26,316	-	23,684	2,632
60	16419	Asset Registration Implemented	Alloc-Fixed	445,036	-	445,036	-
61	16422	Claimed Capability Audits	Alloc-Fixed	712,059	-	712,059	-
62	16432	New Generation Coordination and Registration	Alloc-Fixed	445,036	-	445,036	-
63	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	445,036	95,905	230,306	118,825
64	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	447,370	-	447,370	-
65		Total		3,448,662	95,905	2,767,396	585,360

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Planning Services**					
2	14313	National Committee Support	Alloc-Fixed	40,015	4,350	2,017	33,648
3	17101	Analysis	Alloc-Fixed	120,044	-	84,031	36,013
4	17131	Calculate Objective Capability	Alloc-Fixed	260,095	-	-	260,095
5	17331	NEPOOL Committee Support	Alloc-Fixed	20,012	2,175	1,009	16,828
6	17401	Indirect Supervisory Activities	Alloc-Fixed	40,019	4,350	2,017	33,652
7	17403	TCA Application Review	Alloc-Fixed	121,916	-	-	121,916
8	17405	Energy Efficiency Forecast	Alloc-Fixed	60,026	-	-	60,026
9	17409	Environmental/Emissions Supp	Total Dir Labor	200,073	-	-	200,073
10	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	211,810	-	-	211,810
11	17503	FCA - New Resource Qualification Support	Alloc-Fixed	1,241,001	-	-	1,241,001
12	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	128,379	-	-	128,379
13	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	85,586	-	-	85,586
14	17507	FCA - Auctions & Filings	Alloc-Fixed	530,623	-	-	530,623
15	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	128,379	-	-	128,379
16	18101	Develop Load Forecast	Alloc-Fixed	460,168	92,034	92,034	276,101
17	18121	Operations Forecast Support	Alloc-Fixed	280,102	56,020	56,020	168,061
18	18131	Other Load Forecasting Activities	Alloc-Fixed	20,007	4,001	4,001	12,004
19	18133	Solar Load Forecast Development	Alloc-Fixed	140,051	28,010	28,010	84,031
20	18134	Electrification Forecasts	Alloc-Fixed	20,007	4,001	4,001	12,004
21	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	80,029	-	-	80,029
22		Total		4,188,344	194,942	273,140	3,720,262
23							
24		**System Planning**					
25	18150	Regional Transmission Expansion Plan	Alloc-Fixed	51,080	38,310	12,770	-
26	18152	States Requests	Alloc-Fixed	51,710	25,855	12,928	12,928
27	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	862,441	-	431,221	431,221
28		Total		965,231	64,165	456,918	444,148
29							
30		**Transmission Planning**					
31	14715	Non DOE Funded/Unallowable	Alloc-Fixed	60,649	-	-	60,649
32	18201	Transmission System Assessment	Alloc-Fixed	3,498,042	3,498,042	-	-
33	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	113,880	113,880	-	-
34	18333	General SIS/FS	Alloc-Fixed	1,615,743	1,615,743	-	-
35	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	1,112,348	1,112,348	-	-
36	18335	Regulatory Activities - NPCC	Alloc-Fixed	297,030	297,030	-	-
37	18336	National Activities	Alloc-Fixed	131,736	131,736	-	-
38	18337	TR - Regulatory Activities	Alloc-Fixed	31,077	31,077	-	-
39	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	42,793	42,793	-	-
40	18350	States Future Planning Studies	Alloc-Fixed	254,889	254,889	-	-
41	21660	Stability Case Building	Alloc-Fixed	128,379	-	-	128,379
42		Total		7,286,566	7,097,538	-	189,028
43							
44		**Program Management**					
45	801	Program Management - Administration	Total Dir Labor	1,014,266	218,574	524,883	270,809
46	1661	ISO Program Management	Alloc-Fixed	461,478	-	323,035	138,443
47	1665	Product and Test Mgmt.	Total Dir Labor	531,282	114,491	274,939	141,852
48		Total		2,007,026	333,066	1,122,856	551,105
49							
50		**Advanced Technology Solutions**					
51	21201	Advanced Technology Solutions	Total Dir Labor	3,809,797	821,011	1,971,570	1,017,216
52	21203	Employee Development	Total Dir Labor	41,197	8,878	21,319	10,999
53	21207	Resource Capacity Accreditation	Total Dir Labor	1,331,392	-	-	1,331,392
54		Total		5,182,386	829,889	1,992,889	2,359,607
55							
56		**Market Development & Settlements Admin.**					
57	16607	National Committee Support	Total Dir Labor	16,460	3,547	8,518	4,395
58	19104	Indirect Supervision/Clerical Support	MOA Labor	369,851	-	258,896	110,955
59	21001	Market Development	Alloc-Fixed	994,992	-	497,496	497,496
60	21002	Administration	Total Dir Labor	610,531	131,569	315,950	163,012
61	21003	Employee Development	Total Dir Labor	216,733	46,706	112,159	57,868
62	21007	Budget/Forecast Support	Total Dir Labor	279,823	60,302	144,808	74,713
63	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	267,493	-	254,118	13,375
64	21011	Capacity Market	Alloc-Fixed	2,455,314	-	-	2,455,314
65	22401	Administration	Total Dir Labor	32,920	7,094	17,036	8,790
66	22402	Working Group Meetings and Support	Alloc-Fixed	16,460	-	8,230	8,230
67	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	1,715,939	-	1,286,954	428,985
68	22657	Project: ORTP/CONE Updates	Alloc-Fixed	640,485	-	-	640,485
69	22658	Storage	Alloc-Fixed	401,920	-	321,536	80,384
70	22661	Project: DER Participation	Alloc-Fixed	598,067	-	299,034	299,034
71		Total		8,616,988	249,219	3,524,736	4,843,034
72							
73		**Participant Relations & Services**					
74	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	263,232	-	131,616	131,616
75	22607	NEPOOL Committee Administration	Total Dir Labor	1,544,914	332,929	799,493	412,492
76	22612	Future Grid Study and Modeling	Total Dir Labor	31,072	-	12,429	18,643
77		Total		1,839,219	332,929	943,538	562,752

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**IT Management**					
2	6517	Employee Development - Hardware/Software	Total Dir Labor	47,151	10,161	24,400	12,589
3	6519	Indirect Supervision and Clerical Support	Total Dir Labor	5,113,637	1,101,989	2,646,307	1,365,341
4	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	208,726	44,981	108,016	55,730
5	22501	Change Management Support	Alloc-Fixed	39,756	17,890	17,890	3,976
6	22505	Administrative	Alloc-Fixed	327,026	111,189	107,919	107,919
7		Total		5,736,297	1,286,210	2,904,533	1,545,555
8							
9		**IT Infrastructure Support**					
10	6515	Networking - Software	Total Dir Labor	3,459	745	1,790	923
11	6516	Communications	Total Dir Labor	97,363	20,982	50,385	25,996
12	6602	Help Desk Support	Total Dir Labor	216,170	46,585	111,868	57,717
13	6615	Host Computer Monitoring	Alloc-Fixed	1,331,608	-	665,804	665,804
14	6616	Desktop Support	Total Dir Labor	1,014,559	218,637	525,034	270,887
15	6618	System Administration - Windows	Total Dir Labor	153,279	33,032	79,322	40,925
16	6619	IT - Infrastructure Coordination	Total Dir Labor	547,071	117,894	283,109	146,068
17	6622	CIP & Systems Compliance	Total Dir Labor	1,934,413	416,866	1,001,059	516,488
18	6623	Asset Management	Total Dir Labor	337,084	72,642	174,441	90,002
19	6624	Infrastructure Review & Planning	Total Dir Labor	341,039	73,494	176,488	91,057
20	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	263,687	56,825	136,458	70,404
21	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	287,621	61,982	148,844	76,795
22	6627	IT - Infrastructure Support Request	Total Dir Labor	541,165	116,621	280,053	144,491
23	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	215,817	46,509	111,685	57,623
24	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	233,261	50,268	120,712	62,281
25	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	662,055	142,673	342,613	176,769
26		Total		8,179,650	1,475,753	4,209,666	2,494,231
27							
28		**IT Cyber Security**					
29	6540D	Intrusion Monitoring and Response	Total Dir Labor	1,233,989	265,925	638,589	329,475
30	6540	Security Compliance and Reporting	Total Dir Labor	1,279,150	275,657	661,960	341,533
31	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	31,643	6,819	16,375	8,449
32				2,544,781	548,400	1,316,924	679,457
33		**IT Database & Analytics**					
34	6571	DBA Support - MOPS	Total Dir Labor	1,538,275	331,498	796,057	410,719
35	6591	Data Architect - MOPS	Total Dir Labor	430,031	92,672	222,541	114,818
36	6594	IT Data Analyst	Total Dir Labor	538,396	116,024	278,620	143,752
37	6595	IT WEB Application Support	Total Dir Labor	731,478	157,634	378,540	195,305
38	6596	IT Data Governance	Total Dir Labor	159,271	34,323	82,423	42,525
39	6597	IT - BI IT Commitments	Total Dir Labor	307,655	66,300	159,211	82,144
40	21706	Enterprise Software Support	Total Dir Labor	1,631,721	351,636	844,416	435,670
41	21801	Software Support - Settlements	Alloc-Fixed	536,417	-	429,134	107,283
42	21803	Software Support - Finance	Alloc-Fixed	292,591	-	234,073	58,518
43	21804	Software Support - Mitigation	Alloc-Fixed	461,483	-	369,186	92,297
44	21806	Software Support - Enterprise	Total Dir Labor	780,243	168,142	403,776	208,325
45	21811	Single Sign On Support	Alloc-Fixed	146,296	-	117,036	29,259
46	21824	FCTS Support	Alloc-Fixed	146,296	-	-	146,296
47	21832	GDMA/Gateway Support	Alloc-Fixed	97,530	-	78,024	19,506
48		Total		7,797,684	1,318,229	4,393,038	2,086,417
49							
50		**IT Enterprise Applications Development**					
51	21707	Application Analysis and Conceptual Design	Alloc-Fixed	95,563	-	76,450	19,113
52	21708	Application Design Evaluation and Selection	Alloc-Fixed	414,105	-	331,284	82,821
53	21709	Technology Evaluation and Selection	Alloc-Fixed	1,053,465	-	842,772	210,693
54	21710	Indirect Supervision and Administration	Alloc-Fixed	1,118,943	-	895,154	223,789
55	21711	EWR and CAPA Analysis	Alloc-Fixed	154,633	-	123,707	30,927
56		Total		2,836,709	-	2,269,367	567,342
57							
58		**IT Energy Management Systems**					
59	21600	Indirect Supervision and Administration	Total Dir Labor	54,800	11,809	28,359	14,632
60	21601	Power System Modeling	Total Dir Labor	83,972	18,096	43,456	22,421
61	21602	Applications Support	Total Dir Labor	328,800	70,856	170,154	87,790
62	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	1,315,199	1,052,159	263,040	-
63	21605	DAM FTR/ARR Support	Alloc-Fixed	1,698,799	339,760	1,019,279	339,760
64	21606	Real-time Market Support	Alloc-Fixed	1,917,999	383,600	1,150,799	383,600
65		Total		5,399,569	1,876,281	2,675,087	848,201
66							
67							
68		**IT Power System Modeling Management**					
69	21650	Indirect Supervision and Administration	Total Dir Labor	198,110	42,693	102,522	52,895
70	21654	NX9 Administration	Alloc-Fixed	167,944	67,178	67,178	33,589
71	21651	Power System Modeling	Alloc-Fixed	1,180,778	472,311	472,311	236,156
72	21652	System Application Support	Alloc-Fixed	152,726	61,091	61,091	30,545
73	21655	ICCP Support	Alloc-Fixed	784,283	313,713	313,713	156,857
74	21656	Transmission Project Management	Alloc-Fixed	32,611	26,089	6,522	-
75	21657	Model On Demand Admin	Alloc-Fixed	630,294	-	-	630,294
76	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	213,969	-	-	213,969
77	21659	Synchrophasor Applications	Alloc-Fixed	83,972	12,596	12,596	58,780
78		Total		3,444,687	995,670	1,035,933	1,413,084
79							
80		**Total ISO**		$ 158,198,182	$ 38,178,912	$ 74,291,904	$ 45,727,366
				100.0%	24.1%	47.0%	28.9%

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1	**Cost Ctr.**	**Summary Of Departmental Labor Allocation Using "Alloc-Fixed" Allocators**					
2	307	Administration-CEO		$ -	$ -	$ -	$ -
3			Adm Labor	0.00%	0.00%	0.00%	0.00%
4	302	Finance		$ -	$ -	$ -	$ -
5			Fin Labor	0.00%	0.00%	0.00%	0.00%
6	108	Facilities & Security		$ -	$ -	$ -	$ -
7			Bldg Labor	0.00%	0.00%	0.00%	0.00%
8	703	Strategy, Risk & Operations Compliance		$ 1,175,871	$ 487,553	$ 274,606	$ 413,711
9			SROC Labor	100.00%	41.46%	23.35%	35.18%
10	301	Human Resources		$ -	$ -	$ -	$ -
11			HR Labor	0.00%	0.00%	0.00%	0.00%
12	306	Legal Department		$ 1,828,527	$ 208,975	$ 383,120	$ 1,236,433
13			Legal Labor	100.00%	11.43%	20.95%	67.62%
14	305	Internal Audit		$ 182,402	$ -	$ 182,402	$ -
15			IA Labor	100.00%	0.00%	100.00%	0.00%
16	701	COO-Adm		$ 1,743,024	$ 467,130	$ 835,780	$ 440,114
17			COO Labor	100.00%	26.80%	47.95%	25.25%
18	310	Market & Credit Risk		$ 322,918	$ 69,589	$ 167,110	$ 86,219
19			MCR Labor	100.00%	21.55%	51.75%	26.70%
20	105	System Operations & Market Administration		$ 212,791	$ 51,099	$ 114,070	$ 47,623
21			SYSOPS Labor	100.00%	24.01%	53.61%	22.38%
22	101	Operations		$ 9,349,327	$ 2,639,494	$ 5,272,378	$ 1,437,454
23			OPS Labor	100.00%	28.23%	56.39%	15.37%
24	110	Operational Performance Trng and Integration		$ 5,522,711	$ 1,791,127	$ 2,719,306	$ 1,012,278
25			OPSPERF Labor	100.00%	32.43%	49.24%	18.33%
26	103	Operations Support Services		$ 6,254,647	$ 3,929,851	$ 628,388	$ 1,696,408
27			TSO Labor	100.00%	62.83%	10.05%	27.12%
28	404	Market Monitoring		$ 4,630,968	$ -	$ 3,241,677	$ 1,389,290
29			MMM Labor	100.00%	0.00%	70.00%	30.00%
30	416	Market Administration & Auctions		$ 1,958,160	$ 155,763	$ 1,786,928	$ 15,469
31			MA Labor	100.00%	7.95%	91.26%	0.79%
32	401	Market Analysis & Settlements		$ 2,654,941	$ 319,467	$ 1,195,036	$ 1,140,439
33			STLM Labor	100.00%	12.03%	45.01%	42.96%
34	411	Market Operations Support Services		$ 1,406,132	$ 200,876	$ 757,589	$ 447,666
35			MOSS Labor	100.00%	14.29%	53.88%	31.84%
36	406	Participant Support & Solutions		$ 1,447,374	$ 376,317	$ 955,267	$ 115,790
37			PSS Labor	100.00%	26.00%	66.00%	8.00%
38	410	Participant Training Services		$ 2,556,255	$ -	$ 2,089,720	$ 466,535
39			PTS Labor	100.00%	0.00%	81.75%	18.25%
40	204	System Planning		$ 965,231	$ 64,165	$ 456,918	$ 444,148
41			SP Labor	100.00%	6.65%	47.34%	46.01%
42	203	Planning Services		$ 3,988,271	$ 194,942	$ 273,140	$ 3,520,189
43			PSR Labor	100.00%	4.89%	6.85%	88.26%
44	205	Transmission Planning		$ 7,286,566	$ 7,097,538	$ -	$ 189,028
45			TP Labor	100.00%	97.41%	0.00%	2.59%
46	304	Program Management		$ 461,478	$ -	$ 323,035	$ 138,443
47			PMO Labor	100.00%	0.00%	70.00%	30.00%
48	315	Advanced Technology Solutions		$ -	$ -	$ -	$ -
49			ATS Labor	0.00%	0.00%	0.00%	0.00%
50	408	Market Development & Settlements Admin.		$ 7,460,522	$ -	$ 2,926,264	$ 4,534,258
51			MD Labor	100.00%	0.00%	39.22%	60.78%
52	407	Participant Relations & Services		$ 263,232	$ -	$ 131,616	$ 131,616
53			PRS Labor	100.00%	0.00%	50.00%	50.00%
54	210	IT Management		$ 366,782	$ 129,079	$ 125,809	$ 111,894
55			ITM Labor	100.00%	35.19%	34.30%	30.51%
56	201	IT Infrastructure Support		$ 1,331,608	$ -	$ 665,804	$ 665,804
57			ITS Labor	100.00%	0.00%	50.00%	50.00%
58	211	IT Database & Analytics		$ 1,680,613	$ -	$ 1,227,454	$ 453,159
59			ITDG Labor	100.00%	0.00%	73.04%	26.96%
60	212	IT Cyber Security		$ -	$ -	$ -	$ -
61			ITCS	0.00%	0.00%	0.00%	0.00%
62	102	IT Energy Management Systems		$ 4,931,997	$ 1,775,519	$ 2,433,118	$ 723,359
63			EMS Labor	100.00%	36.00%	49.33%	14.67%
64	213	IT Enterprise Applications Development		$ 2,836,709	$ -	$ 2,269,367	$ 567,342
65			ESD	100.00%	0.00%	80.00%	20.00%
66	216	IT Power System Modeling Management		$ 3,246,577	$ 952,977	$ 933,411	$ 1,360,189
67			ITPSM	100.00%	29.35%	28.75%	41.90%
68		Total Direct Labor		$ 76,065,632	$ 20,911,461	$ 32,369,312	$ 22,784,859
69				100.00%	27.49%	42.55%	29.95%
70							
71		**Summary Of Allocations Of Labor Based On Fixed Allocators and Allocated Departmental Labor**					
72		Total Direct Labor		$ 76,065,632	$ 20,911,461	$ 32,369,312	$ 22,784,859
73			Dir Labor	100.00%	27.49%	42.55%	29.95%
74		Total Indirect Labor		$ 82,132,549	$ 17,267,451	$ 41,922,592	$ 22,942,506
75			InDir Labor	100.00%	21.02%	51.04%	27.93%
76		Total Labor Expense		$ 158,198,182	$ 38,178,912	$ 74,291,904	$ 45,727,366
77			Total Dir Labor	100.00%	24.13%	46.96%	28.91%

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Administration-CEO						
2	12651	Indirect Administrative Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	12652	NEPOOL Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
4	12654	National Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
5	12657	Indirect Administrative Support for BCC	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6								
7		Finance						
8	11601	Payroll Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
9	11701	Accounts Payable	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
10	11702	Procurement	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	11901	Settle for Power Transactions	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
12	12001	Budgeting and Forecasting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
13	12005	Credit Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
14	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	12201	Treasury and Cash Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
16	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	100.00%	20.83%	52.21%	26.96%	Per ISO-NE Staff
17	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	100.00%	21.14%	52.01%	26.85%	Per ISO-NE Staff
18	92006	Depreciation Expense 2006 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
19	92007	Depreciation Expense 2007 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	92008	Depreciation Expense 2008 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	92009	Depreciation Expense 2009 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	92010	Depreciation Expense 2010 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23	92012	Depreciation Expense 2012 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	92013	Depreciation Expense 2013 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	100.00%	18.59%	61.96%	19.44%	Per ISO-NE Staff
28	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	100.00%	5.66%	87.75%	6.60%	Per ISO-NE Staff
29	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	100.00%	9.09%	82.02%	8.89%	Per ISO-NE Staff
30	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	100.00%	12.37%	74.69%	12.94%	Per ISO-NE Staff
31	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	100.00%	7.95%	78.80%	13.25%	Per ISO-NE Staff
32	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	100.00%	11.02%	68.12%	20.85%	Per ISO-NE Staff
33	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	100.00%	10.68%	65.43%	23.89%	Per ISO-NE Staff
34	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	100.00%	15.88%	55.03%	29.09%	Per ISO-NE Staff
35	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	100.00%	25.72%	48.69%	25.59%	Per ISO-NE Staff
36	99707	Amortization of Land Recovery	Alloc-Fixed	100.00%	6.26%	61.50%	32.24%	Per ISO-NE Staff
37	99995	NPCC/NERC Dues	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
38	99996	Operating Contingency	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
39	99998	Payroll & Other Accruals	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
40								
41		Facilities & Security						
42	12664	Building Maintenance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
43								
44		Strategy, Risk & Operations Compliance						
45	22704	Record Retention Services	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
46	22705	Corporate Scorecard	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
47	22706	Document Management Services	Alloc-Fixed	100.00%	40.00%	30.00%	30.00%	Per ISO-NE Staff
48	22708	ERM Adminstration	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
49	22709	ERM Management	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
50	22719	Human Performance Improvement	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
51	22721	Corp Strategic Risk	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
52	22726	Project Risk Mngmt Meeting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
53	23006	Business Continuity Planning	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
54	25011	Corrective Action/Preventive Action	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
55								
56		Market & Credit Risk						
57	22714	FAP Analysis	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
58								
59		Human Resources						
60	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
61	12701	Recruiting/Interviewing	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
62	12702	Intern Expense	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
63	12801	Employee Relations	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
64	12901	Benefit Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
65	12951	Compensation	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
66	12961	HR - General	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
67	12962	HR - Training	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
68	13410	Power Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
69	13411	Markets Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
70	13412	People Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
71	13413	Business Skills Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
72	13414	Technology Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
73	13901	Performance Eval/Salary Review	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

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Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Internal Audit						
2	15001	Indirect Management Duties	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	15002	Personnel Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
4	15003	Budget & Forecasting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
5	15004	Audit Follow-up Activities	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6	15005	Audit & Finance Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
7	15006	Internal Audit Business Process Update	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	15007	Annual Audit Work Plan	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
9	15011	Internal Audit Meetings	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
10	15013	Indirect Adminstrative Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	15014	GRC Tool Admin and Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
12	15021	Performance Measurements	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
13	15022	Vendor Contracts	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
14	15023	Wire Transfers	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	15040	Audit-Operations	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
16	15085	Audit - Information Technology	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
17	15133	Satellite Operations Reviews	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
18	15137	Satellite IT Reviews	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
19	15150	Audit - Internal Audit Other	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	15161	External Audit- Pension Audit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	15162	External Audit- Financial Audit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	15166	External Audit -Pricing Module Certification	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
23	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
26	28005	Fraud, Waste & Abuse Program	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	28007	Contractor/Consultant Review	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	28173	Audit - Identity and Access Management Audit	Total Dir Labor	100.00%	30.00%	30.00%	40.00%	Per ISO-NE Staff
29	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
30	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
31								
32		Legal Department						
33	12422	Interconnection Queue	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
34	12502	Board of Directors	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
35	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
36	12513	Miscellaneous Labor Matters	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
37	12514	NEPOOL Participants Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
38	12517	Administrative and Clerical Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
39	12543	Independent Market Advisor	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
40	12559	General Corporate	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
41	12584	GC - SH - Installed Capacity Requirements	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
42	12587	Capacity Market Development	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
43	12606	GC - NERC	Alloc-Fixed	100.00%	45.00%	10.00%	45.00%	Per ISO-NE Staff
44	12611	GC - Ancillary Services Markets	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
45	12613	GC - CFTC/DOE/NRC/Other Federal Agency	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
46	12619	Compliance	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
47	12621	GC - NOPRs and NOIs	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
48	12622	Open Access Transmission Tariff	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
49	12663	Public Information	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
50	12669	Government Affairs	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
51	12675	Web Content Governance Steering Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
52								
53		COO-Adm						
54	19001	NEPOOL Committee Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
55	19002	Regional Committee Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
56	19003	National Committee Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
57	19005	Indirect Supervision/Clerical Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
58	19009	Renewable Resource Integration	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
59								
60		System Operations & Market Administration						
61	14404	NEPOOL Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
62	14405	Indirect Supervision/Clerical Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
63	14407	Regional Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
64	14408	National Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
65	19101	NEPOOL Committee Support	MOA Labor	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Operations						
2	14001	Generation Dispatch	Alloc-Fixed	100.00%	0.00%	84.00%	16.00%	Per ISO-NE Staff
3	14002	Transmission Operations	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	100.00%	5.00%	79.00%	16.00%	Per ISO-NE Staff
5	14402	Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
6	14562	Ops - Regional Committee Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
7	14563	National Committee Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
8	14565	Employee Development	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
9	14579	Ops - OPTI TTSE Maintenance	OPS Labor	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
10	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	14586	Ops - Other External Support Meetings	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
12	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
13	14702	Procedure Documentation	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
14								
15		Operational Performance Trng and Integration						
16	14402	Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
17	14462	OSS - General Systems Operations Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
18	14564	Indirect Supervision/Clerical Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
19	14574	OPTI Continuing Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
20	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
21	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
22	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
23	14581	Application Testing and Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	14587	Ops - Other Internal Support Meetings	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	15501	OA - Operations Analysis	Alloc-Fixed	100.00%	15.00%	70.00%	15.00%	Per ISO-NE Staff
27								
28								
29		Operations Support Services						
30	14477	Participant project and outage coordination support	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
31	14453	National Committee Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
32	14454	Indirect Supervision/Clerical Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
33	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
34	14760	Trans Outage LT (telecommute)	Alloc-Fixed	100.00%	50.00%	25.00%	25.00%	Per ISO-NE Staff
35	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
36	18381	Transmission Outage Application - Short Term	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
37	18382	Transmission Outage Application - Long Term	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
38								
39		Market Monitoring						
40	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
41	16102	Regulatory Activities	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
42	16121	FCM Market Monitoring	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
43								
44		Market Administration & Auctions						
45	21901	Day Ahead Price Monitoring	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
46	21902	Real Time Price Verification	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
47	21907	Indirect Supervision/Clerical Support	MA Labor	100.00%	0.00%	96.84%	3.16%	Per ISO-NE Staff
48	21915	FTR/Auction Administration	Alloc-Fixed	100.00%	50.00%	50.00%	0.00%	Per ISO-NE Staff
49	21917	Real Time Price Finalization	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
50								
51		Market Analysis & Settlements						
52	1701	Billing Statements - Energy	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
53	1702	Billing Statements - Transmission	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
54	1713	Billing Statements - ISO Tariff	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
55	1714	Billable Tariff Re-billings	Total Dir Labor	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
56	1717	Inventoried Energy Program	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
57	1718	Mystic COS	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
58	1719	FCM Daily	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
59	1722	NCC Trading FA	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
60	2005	Customer Service	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
61	2007	Admin support - NEPOOL Committees	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
62	2009	Indirect Supervision/Clerical Support	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
63	2010	Employee Development	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
64	2013	FTR Administration	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
65	2014	Billing Statements - NCPC	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
66	2020	Billing Disputes	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
67	2021	Analysis & Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
68	2024	ASM Regulation	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
69	2025	ASM Locational Forward Reserve	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
70	2026	Batch Processing	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
71	2032	Billing	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
72	2033	Market Analysis	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
73	2047	Score Card	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
74	2048	FCM	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
75	2049	Product Testing	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
76	2051	Legal Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
77	2055	MAS - Market Monitoring Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff

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ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Market Operations Support Services						
2	3000	Hourly Settlements Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
3	3002	Monthly Settlements Support	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
4	3006	Customer Service	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
5	3008	Admin Support	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
6	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
7	3010	Employee Development	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
8	3012	FERC Data Request	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
9	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	100.00%	25.00%	25.00%	50.00%	Per ISO-NE Staff
10								
11		Participant Support & Solutions						
12	16001	Participant/membership support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
13	16006	Call Support (Ask ISO)	Alloc-Fixed	100.00%	26.00%	66.00%	8.00%	Per ISO-NE Staff
14	16414	Direct Customer Contact	MS Labor	100.00%	0.00%	90.00%	10.00%	Per ISO-NE Staff
15	16419	Asset Registration Implemented	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
16	16422	Claimed Capability Audits	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
17	16432	New Generation Coordination and Registration	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
18	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
19	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
20								
21		Participant Training Services						
22	16021	Training Development	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
23								
24		System Planning						
25	18150	Regional Transmission Expansion Plan	Alloc-Fixed	100.00%	75.00%	25.00%	0.00%	Per ISO-NE Staff
26	18152	States Requests	Alloc-Fixed	100.00%	50.00%	25.00%	25.00%	Per ISO-NE Staff
27	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
28	18562	Project Management	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
29								
30		Planning Services						
31	18101	Develop Load Forecast	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
32	18121	Operations Forecast Support	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
33	14313	National Committee Support	Alloc-Fixed	100.00%	10.87%	5.04%	84.09%	Per ISO-NE Staff
34	17101	Analysis	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
35	17131	Calculate Objective Capability	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
36	17331	NEPOOL Committee Support	Alloc-Fixed	100.00%	10.87%	5.04%	84.09%	Per ISO-NE Staff
37	17401	Indirect Supervisory Activities	Alloc-Fixed	100.00%	10.87%	5.04%	84.09%	Per ISO-NE Staff
38	17403	TCA Application Review	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
39	17405	Energy Efficiency Forecast	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
40	17409	Environmental/Emissions Supp	Total Dir Labor	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
41	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
42	17503	FCA - New Resource Qualification Support	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
43	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
44	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
45	17507	FCA - Auctions & Filings	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
46	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
47	18131	Other Load Forecasting Activities	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
48	18133	Solar Load Forecast Development	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
49	18134	Electrification Forecasts	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
50	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
51								
52		Transmission Planning						
53	21660	Stability Case Building	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
54	14715	Non DOE Funded/Unallowable	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
55	18201	Transmission System Assessment	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
56	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
57	18333	General SIS/FS	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
58	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
59	18335	Regulatory Activities - NPCC	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
60	18336	National Activities	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
61	18337	TR - Regulatory Activities	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
62	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
63	18350	States Future Planning Studies	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
64								
65		Program Management						
66	801	Program Management - Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
67	1661	ISO Program Management	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
68	1665	Product and Test Mgmt.	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
69	25002	PMO Support	Alloc-Fixed	100.00%	30.00%	35.00%	35.00%	Per ISO-NE Staff
70								
71		Advanced Technology Solutions						
72	21201	Advanced Technology Solutions	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
73	21203	Employee Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
74	21207	Resource Capacity Accreditation	Total Dir Labor	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Market Development & Settlements Admin.						
2	16607	National Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	19104	Indirect Supervision/Clerical Support	MOA Labor	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
4	21001	Market Development	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
5	21002	Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6	21003	Employee Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
7	21007	Budget/Forecast Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	100.00%	0.00%	95.00%	5.00%	Per ISO-NE Staff
9	21011	Capacity Market	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
10	22401	Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	22402	Working Group Meetings and Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
12	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
13	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
14	22657	Project: ORTP/CONE Updates	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
15	22658	Storage	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
16	22660	Energy Security	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
17	22661	Project: DER Participation	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
18								
19		Participant Relations & Services						
20	22607	NEPOOL Committee Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	22612	Future Grid Study and Modeling	Total Dir Labor	100.00%	0.00%	40.00%	60.00%	Per ISO-NE Staff
22								
23		IT Management						
24	6517	Employee Development - Hardware/Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	6519	Indirect Supervision and Clerical Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	6552	Security	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	6557	Information Technology Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
29	22501	Change Management Support	Alloc-Fixed	100.00%	45.00%	45.00%	10.00%	Per ISO-NE Staff
30	22505	Administrative	Alloc-Fixed	100.00%	34.00%	33.00%	33.00%	Per ISO-NE Staff
31	22511	IT CM/QA - Professional Training	Alloc-Fixed	100.00%	34.00%	33.00%	33.00%	Per ISO-NE Staff
32								
33		IT Infrastructure Support						
34	6510	Desktop Support - Hardware	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
35	6511	Desktop Support - Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
36	6512	Host Computer - Hardware	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
37	6513	Host Computer - Software	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
38	6514	Networking - Hardware	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
39	6515	Networking - Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
40	6516	Communications	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
41	6602	Help Desk Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
42	6615	Host Computer Monitoring	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
43	6616	Desktop Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
44	6618	System Administration - Windows	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
45	6619	IT - Infrastructure Coordination	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
46	6622	CIP & Systems Compliance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
47	6623	Asset Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
48	6624	Infrastructure Review & Planning	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
49	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
50	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
51	6627	IT - Infrastructure Support Request	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
52	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
53	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
54	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
55								
56		IT Cyber Security						
57	6540	Security Compliance and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
58	6540D	Intrusion Monitoring and Response	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
59	6541	Security SW Tools Program	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
60	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
61	6547	Cyber Security Training	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
62	6548	CIP Compliance & Monitoring	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2024

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		IT Database & Analytics						
2	21706	Enterprise Software Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	21801	Software Support - Settlements	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
4	21802	Software Support - Publishing	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
5	21803	Software Support - Finance	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
6	21804	Software Support - Mitigation	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
7	21805	Software Support - TSO	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	21806	Software Support - Enterprise	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
9	21807	Software Support - Planning	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
10	21808	Training Delivery to NON-IT	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
11	21811	Single Sign On Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
12	21812	GADS Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
13	21816	CMS Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
14	21818	Discoverer Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	21824	FCTS Support	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
16	21825	eTariff Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
17	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
18	21832	GDMA/Gateway Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
19	6571	DBA Support - MOPS	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	6591	Data Architect - MOPS	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	6594	IT Data Analyst	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	6595	IT WEB Application Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23	6596	IT Data Governance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	6597	IT - BI IT Commitments	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25								
26		IT Energy Management Systems						
27	21600	Indirect Supervision and Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	21601	Power System Modeling	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
29	21602	Applications Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
30	21603	EMS Power System Applications Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
31	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	100.00%	80.00%	20.00%	0.00%	Per ISO-NE Staff
32	21605	DAM FTR/ARR Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
33	21606	Real-time Market Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
34	21607	Forecast Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
35								
36		IT Enterprise Applications Development						
37	21707	Application Analysis and Conceptual Design	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
38	21708	Application Design Evaluation and Selection	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
39	21709	Technology Evaluation and Selection	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
40	21710	Indirect Supervision and Administration	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
41	21711	EWR and CAPA Analysis	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
42	6518	Employee Development - Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
43								
44		IT Power System Modeling Management						
45	21650	Indirect Supervision and Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
46	21651	Power System Modeling	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
47	21652	System Application Support	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
48	21654	NX9 Administration	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
49	21655	ICCP Support	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
50	21656	Transmission Project Management	Alloc-Fixed	100.00%	80.00%	20.00%	0.00%	Per ISO-NE Staff
51	21657	Model On Demand Admin	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
52	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
53	21659	Synchrophasor Applications	Alloc-Fixed	100.00%	15.00%	15.00%	70.00%	Per ISO-NE Staff
54								
55		Strategy, Risk & Operations Compliance						
56	14803	Regional Committee Support	OS Labor	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
57	14804	National Committee Support	OS Labor	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
58	14806	Employee Development	Alloc-Fixed	100.00%	55.55%	19.33%	25.12%	Per ISO-NE Staff
59	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
60	14812	NPCC MP Referral	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
61	14815	Identifications and Description of Internal Controls	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
62	14816	Support NE Compliance Groups	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
63	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER24-____-000

FERC COMPLIANCE FILING

ALLOCATION ON 2024 Budgeted Depreciation

Line No.	Description	Depreciation				Self-Funding Tariff			
		Total	Adjustments	Adj. Total		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**2024 Items:**								
2	Building Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -
3	Back-up Control Center	-	-	-		-	-	-	-
4	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
5	Non-Project Capital Spending (Hardware and Software)	473,236	-	473,236		473,236	101,982	244,900	126,354
6	Market Systems and Enhancement Projects	509,944	-	509,944		509,944	155,371	230,510	124,064
7	Non-Market Systems and Enhancement Projects	107,389	-	107,389		107,389	23,142	55,574	28,673
8	Total 2023 Items - $	$ 1,090,569	$ -	$ 1,090,569		$ 1,090,569	$ 280,495	$ 530,983	$ 279,091
9	Total 2023 Items - %					100.00%	25.72%	48.69%	25.59%
10									
1	**2023 Items:**								
2	Building Improvements	$ 22,055	$ -	$ 22,055		$ 22,055	$ 4,753	$ 11,414	$ 5,889
3	Back-up Control Center	-	-	-		-	-	-	-
4	Furniture, Fixtures, and Equipment	35,744	-	35,744		35,744	7,703	18,498	9,544
5	Non-Project Capital Spending (Hardware and Software)	1,211,671	-	1,211,671		1,211,671	261,115	627,040	323,516
6	Market Systems and Enhancement Projects	4,107,147	-	4,107,147		4,107,147	483,838	2,354,608	1,268,701
7	Non-Market Systems and Enhancement Projects	1,788,555	-	1,788,555		1,788,555	380,405	931,335	476,814
8	Total 2023 Items - $	$ 7,165,172	$ -	$ 7,165,172		$ 7,165,172	$ 1,137,815	$ 3,942,894	$ 2,084,463
9	Total 2023 Items - %					100.00%	15.88%	55.03%	29.09%
10									
11	**2022 Items:**								
12	Building Improvements	$ 5,053	$ -	$ 5,053		$ 5,053	$ 1,089	$ 2,615	$ 1,349
13	Back-up Control Center	-	-	-		-	-	-	-
14	Furniture, Fixtures, and Equipment	31,283	-	31,283		31,283	6,741	16,189	8,353
15	Non-Project Capital Spending (Hardware and Software)	1,086,808	-	1,086,808		1,086,808	234,207	562,423	290,178
16	Market Systems and Enhancement Projects	6,125,287	-	6,125,287		6,125,287	370,093	4,365,259	1,389,935
17	Non-Market Systems and Enhancement Projects	1,494,638	-	1,494,638		1,494,638	321,843	773,747	399,049
18	Total 2022 Items - $	$ 8,743,069	$ -	$ 8,743,069		$ 8,743,069	$ 933,974	$ 5,720,233	$ 2,088,863
19	Total 2022 Items - %					100.00%	10.68%	65.43%	23.89%
20									
21	**2021 Items:**								
22	Building Improvements	$ 57,744	$ -	$ 57,744		$ 57,744	$ 12,444	$ 29,882	$ 15,418
23	Back-up Control Center	-	-	-		-	-	-	-
24	Furniture, Fixtures, and Equipment	286	-	286		286	62	148	76
25	Non-Project Capital Spending (Hardware and Software)	571,758	-	571,758		571,758	123,214	295,885	152,659
26	Market Systems and Enhancement Projects	6,213,565	-	6,213,565		6,213,565	476,180	4,557,580	1,179,805
27	Non-Market Systems and Enhancement Projects	1,353,977	-	1,353,977		1,353,977	291,782	700,683	361,512
28	Total 2021 Items - $	$ 8,197,329	$ -	$ 8,197,329		$ 8,197,329	$ 903,681	$ 5,584,178	$ 1,709,470
29	Total 2021 Items - %					100.00%	11.02%	68.12%	20.85%
30									
31	**2020 Items:**								
32	Building Improvements	$ 53,812	$ -	$ 53,812		$ 53,812	$ 11,597	$ 27,848	$ 14,368
33	Back-up Control Center	-	-	-		-	-	-	-
34	Furniture, Fixtures, and Equipment	1,259	-	1,259		1,259	271	652	336
35	Non-Project Capital Spending (Hardware and Software)	108,816	-	108,816		108,816	23,450	56,312	29,054
36	Market Systems and Enhancement Projects	2,025,375	-	2,025,375		2,025,375	78,831	1,759,649	186,896
37	Non-Market Systems and Enhancement Projects	441,141	-	441,141		441,141	95,066	228,290	117,785
38	Total 2020 Items - $	$ 2,630,403	$ -	$ 2,630,403		$ 2,630,403	$ 209,214	$ 2,072,751	$ 348,438
39	Total 2020 Items - %					100.00%	7.95%	78.80%	13.25%
40									
41	**2019 Items:**								
42	Building Improvements	$ 19,981	$ -	$ 19,981		$ 19,981	$ 4,306	$ 10,340	$ 5,335
43	Back-up Control Center	-	-	-		-	-	-	-
44	Furniture, Fixtures, and Equipment	13,459.42	-	13,459		13,459	2,900.51	6,965.25	3,593.67
45	Non-Project Capital Spending (Hardware and Software)	637,552	-	637,552		637,552	40,525	572,044	24,984
46	Market Systems and Enhancement Projects	384,378	-	384,378		384,378	82,834	198,916	102,629
47	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
48	Total 2019 Items - $	$ 1,055,371	$ -	$ 1,055,371		$ 1,055,371	$ 130,564	$ 788,265	$ 136,541
49	Total 2019 Items - %					100.00%	12.37%	74.69%	12.94%
50									
51	**2018 Items:**								
52	Building Improvements	$ 2,106	$ -	$ 2,106		$ 2,106	$ 454	$ 1,090	$ 562
53	Back-up Control Center	-	-	-		-	-	-	-
54	Furniture, Fixtures, and Equipment	3,609	-	3,609		3,609	$ 778	$ 1,868	$ 964
55	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	$ -	$ -	$ -
56	Market Systems and Enhancement Projects	416,035	-	416,035		416,035	$ 18,336	$ 388,531	$ 9,168
57	Non-Market Systems and Enhancement Projects	150,527	-	150,527		150,527	$ 32,438	$ 77,897	$ 40,191
58	Total 2018 Items - $	$ 572,276	$ -	$ 572,276		$ 572,276	$ 52,006	$ 469,385	$ 50,885
59	Total 2018 Items - %					100.00%	9.09%	82.02%	8.89%
60									
61	**2017 Items:**								
62	Building Improvements	$ 62,283	$ -	$ 62,283		$ 62,283	$ 13,422	$ 32,232	$ 16,630
63	Back-up Control Center	-	-	-		-	-	-	-
64	Furniture, Fixtures, and Equipment	9,803	-	9,803		9,803	2,112	5,073	2,617
65	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
66	Market Systems and Enhancement Projects	301,018	-	301,018		301,018	2,193	297,727	1,097
67	Non-Market Systems and Enhancement Projects	21,237.24	-	21,237		21,237	4,576.62	10,990.27	5,670.34
68	Total 2017 Items - $	$ 394,341	$ -	$ 394,341		$ 394,341	$ 22,304	$ 346,022	$ 26,014
69	Total 2017 Items - %					100.00%	5.66%	87.75%	6.60%
70									
71	**2016 Items:**								
72	Building Improvements	$ 28,818	$ -	$ 28,818		$ 28,818	$ 6,210	$ 14,913	$ 7,694
73	Back-up Control Center	-	-	-		-	-	-	-
74	Furniture, Fixtures, and Equipment	398	-	398		398	86	206	106
75	Non-Project Capital Spending (Hardware and Software)	18,179	-	18,179		18,179	2,437	14,524	1,218
76	Market Systems and Enhancement Projects	2,695	-	2,695		2,695	581	1,395	720
77	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
78	Total 2016 Items - $	$ 50,091	$ -	$ 50,091		$ 50,091	$ 9,314	$ 31,038	$ 9,739
79	Total 2016 Items - %					100.00%	18.59%	61.96%	19.44%
80									
81	**2015 Items:**								
82	Building Improvements	$ 2,290	$ -	$ 2,290		$ 2,290	$ 494	$ 1,185	$ 612
83	Back-up Control Center	-	-	-		-	-	-	-
84	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
85	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
86	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
87	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
88	Total 2015 Items - $	$ 2,290	$ -	$ 2,290		$ 2,290	$ 494	$ 1,185	$ 612
89	Total 2015 Items - %					100.00%	21.55%	51.75%	26.70%
90									
91	**2014 Items:**								
92	Building Improvements	$ 4,505	$ -	$ 4,505		$ 4,505	$ 971	$ 2,331	$ 1,203
93	Back-up Control Center	73,004	-	73,004		73,004	15,732	37,780	19,492
94	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
95	Non-Project Capital Spending (Hardware and Software)	21,905	-	21,905		21,905	4,720	11,336	5,849
96	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
97	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
98	Total 2014 Items - $	$ 99,414	$ -	$ 99,414		$ 99,414	$ 21,424	$ 51,447	$ 26,543
99	Total 2014 Items - %					100.00%	21.55%	51.75%	26.70%
100									
101	**2013 Items:**								
102	Building Improvements	$ 2,528	$ -	$ 2,528		$ 2,528	$ 545	$ 1,308	$ 675

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER24-____-000

FERC COMPLIANCE FILING

ALLOCATION ON 2024 Budgeted Depreciation

Line No.	Description	Depreciation Total	Depreciation Adjustments	Depreciation Adj. Total		Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
103	Back-up Control Center	827,131	-	827,131		827,131	178,247	428,040	220,844
104	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
105	Non-Project Capital Spending (Hardware and Software)	3,836	-	3,836		3,836	827	1,985	1,024
106	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
107	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
108	Total 2013 Items - $	$ 833,495	$ -	$ 833,495		$ 833,495	$ 179,618	$ 431,334	$ 222,543
109	Total 2013 Items - %					100.00%	21.55%	51.75%	26.70%
110									
111	**2012 Items:**								
112	Building Improvements	$ 2,825	$ -	$ 2,825		$ 2,825	$ 609	$ 1,462	$ 754
113	Back-up Control Center	77,606	$ -	77,606		77,606	16,724	40,161	20,721
114	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
115	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
116	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
117	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
118	Total 2012 Items - $	$ 80,431	$ -	$ 80,431		$ 80,431	$ 17,333	$ 41,623	$ 21,475
119	Total 2012 Items - %					100.00%	21.55%	51.75%	26.70%
120									
121	**2011 Items:**								
122	Facilities Project	$ -	$ -	$ -		$ -	$ -	$ -	$ -
123	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
124	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
125	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
126	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
127	Total 2011 Items - $	$ -	$ -	$ -		$ -	$ -	$ -	$ -
128	Total 2011 Items - %					0.00%	0.00%	0.00%	0.00%
129									
130	**2010 Items:**								
131	Facilities Project	$ 2,380	$ -	$ 2,380		$ 2,380	$ 513	$ 1,232	$ 635
132	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
133	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
134	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
135	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
136	Total 2010 Items - $	$ 2,380	$ -	$ 2,380		$ 2,380	$ 513	$ 1,232	$ 635
137	Total 2010 Items - %					100.00%	21.55%	51.75%	26.70%
138									
139	**2009 Items:**								
140	Facilities Project	$ 1,281	$ -	$ 1,281		$ 1,281	$ 276	$ 663	$ 342
141	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
142	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
143	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
144	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
145	Total 2009 Items - $	$ 1,281	$ -	$ 1,281		$ 1,281	$ 276	$ 663	$ 342
146	Total 2009 Items - %					100.00%	21.55%	51.75%	26.70%
147									
148	**2008 Items:**								
149	Facilities Project	$ 548	$ -	$ 548		$ 548	$ 118	$ 284	$ 146
150	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
151	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
152	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
153	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
154	Total 2008 Items - $	$ 548	$ -	$ 548		$ 548	$ 118	$ 284	$ 146
155	Total 2008 Items - %					100.00%	21.55%	51.75%	26.70%
156									
157	**2007 Items:**								
158	Facilities Project	$ 156,427	$ -	$ 156,427		$ 156,427	$ 33,710	$ 80,951	$ 41,766
159	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
160	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
161	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
162	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
163	Total 2007 Items - $	$ 156,427	$ -	$ 156,427		$ 156,427	$ 33,710	$ 80,951	$ 41,766
164	Total 2007 Items - %					100.00%	21.55%	51.75%	26.70%
165									
166	**2006 Items:**								
167	Facilities Project	$ 568,947	$ -	$ 568,947		$ 568,947	$ 122,608	$ 294,430	$ 151,909
168	Furniture, Fixtures, and Equipment	-		-		-	-	-	-
169	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
170	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
171	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
172	Total 2006 Items - $	$ 568,947	$ -	$ 568,947		$ 568,947	$ 122,608	$ 294,430	$ 151,909
173	Total 2006 Items - %					100.00%	21.55%	51.75%	26.70%
174									
175									
176	**2005 Items:**								
177	Building/property improv. (Renov. workspace, network & voice rewiring)	$ 758,548	$ -	$ 758,548		$ 758,548	$ 163,467	$ 392,548	$ 202,532
178	Enhancements to Other Existing Market Systems	-	-	-		-	-	-	-
179	Hardware and Software Upgrades to existing Non Market Systems	-	-	-		-	-	-	-
180	Capital Interest/Fees	14,622	-	14,622		14,622	-	9,577	5,044
181	Internal Development Costs	-	-	-		-	-	-	-
182	Amortization of Reg Asset		-	-		-	-	-	-
183	Total 2005 Items - $	$ 773,169	$ -	$ 773,169		$ 773,169	$ 163,467	$ 402,126	$ 207,577
184	Total 2005 Items - %					100.00%	21.14%	52.01%	26.85%
185									
186	**2004 Items:**								
187	Building/property improv. (Renov. workspace, network & voice rewiring)	$ 41,709	$ -	$ 41,709		$ 41,709	$ 8,988	$ 21,585	$ 11,136
188	Enhancements to Other Existing Market Systems	-	-	-		-	-	-	-
189	Hardware and Software Upgrades to existing Non Market Systems	-		-		-	-	-	-
190	Internal Development Costs	-	-	-		-	-	-	-
191	Capital Interest/Fees	1,451	-	1,451		1,451	-	950	501
192	Total 2004 Items - $	$ 43,160	$ -	$ 43,160		$ 43,160	$ 8,988	$ 22,535	$ 11,637
193	Total 2004 Items - %					100.00%	20.83%	52.21%	26.96%
194									
195	**Total Unrecovered Plant in Service - $**	$ 32,460,164	$ -	$ 32,460,164		$ 32,460,164	$ 4,227,916	$ 20,813,559	$ 7,418,690
	- %					100.00%	13.02%	64.12%	22.85%

ISO NEW ENGLAND INC.
2024 Operating Expense Budget

Line No.	Cost Category		Amount
	(a)		(b)
1	**Revenues and Other Income**	$	(917,248)
2	**Salaries and Overhead**		159,815,001
3	**Professional Fees & Consultants**		29,257,137
4	**Building Services**		3,430,294
5	**Rents/Leases**		780,758
6	**Network Operations**		3,652,077
7	**Computer Services**		25,372,828
8	**Data Services and Office Expenses**		2,257,267
9	**NPCC/NERC Dues**		8,052,434
10	**Insurance Expense**		3,393,752
11	**Meetings & Related Expenses**		1,511,375
12	**Education & Training**		1,331,972
13	**Regulatory Fees, Taxes, and Licenses**		240,419
14	**CEO Emerging Work Allowance**		2,000,000
15	**Operating Contingency**		700,000
16	**Net Expense before Depreciation and Debt Service**		**240,878,066**
17			
18	**Depreciation and Debt Service**		36,018,610
19			
20	**Total Operating Expense Budget**	**$**	**276,896,676**

ISO New England Inc.
2024 Operating Expense Budget

Line No.			
	Revenues and Other Income		
1		Interest income	(675,780)
2		Fees for Participant training seminars and materials	(70,000)
3		Fees to transmission owners for scheduling services (OATI)	(61,464)
4		Purchase Discounts	(110,004)
5			**$ (917,248)**
6	**Salaries and Overhead**		
7		Salaries	122,139,660
8		Payroll Taxes and Employee Benefits	36,068,841
9		Board Fees and Expenses	1,606,500
10			**159,815,001**
11	**Professional Fees and Consultants**		
12	Consulting		
13		Information Technology support for market system and Energy Management System daily operations, Network and Desktop Support, Architecture planning, Cyber Security, NERC CIP Compliance, IT Asset Management and Network Model Tools.	9,509,525
14		Market Advisor, Market Development, Market Services, Various R&D projects including work for Development of Prompt Seasonal Capacity Markets, Resource Capacity Accreditation, FCA 21 Cost of New Entry (CONE) parameter updates, Economic Planning for Clean Energy Transition, Cloud Computing, Machine Learning and Quantum Computing Research and Inventoried Energy Program.	5,861,500
15		Resource Adequacy and Qualification (including Forward Capacity Market Analytical & Auction Work and Load Forecasting), Transmission Planning (including OATT/Generation Interconnection Work, 3rd Maine Cluster Study & Project Planning), support of a regional study with PJM and NYISO on Single Source Limit Studies, support for New England State's requests, and Operations Project Support (including Integration of Variable Resources), Operations, and Operations Planning.	4,475,189
16	Human Resource Consulting and Recruiting Services		2,493,304

ISO New England Inc.
2024 Operating Expense Budget

17	Legal fees		3,377,000
18		Includes legal fees for OATT, regulatory filings, energy markets, market rules and proceedings, Market Monitoring Support, Siting costs, billing disputes, new initiatives/emerging issues funding, tariff and corporate matters, and miscellaneous labor matters.	
19	External Affairs		471,919
20	Corporate Communications Support		200,000
21	Market Monitoring		794,496
22	Auditors fees - SSAE Type 18 Audit, Network and IT Systems, Operations, Financial, Pension		1,183,500
23	Market and Credit Risk		250,000
24	Strategy, Risk & Operational Compliance		169,240
25	Finance Support and Payroll Service, Misc Other		471,464
26			**29,257,137**
27	**Building Services**		
28		Repairs and maintenance	470,963
29		Utilities	1,580,800
30		Miscellaneous (grounds keeping, supplies, building security)	1,378,531
31			**3,430,294**
32	**Rents/Leases**		
33		Various office equipment leases	736,738
34		Auto leases and Auto Maintenance	44,020
35			**780,758**
36	**Network Operations**		
37		Shared microwave	188,568
38		Network circuits and Internet circuits	1,491,468
39		Telephone and long distance lines	1,652,465
40		Miscellaneous maintenance and service items	319,576
41			**3,652,077**
42	**Computer Services**		
43		Software and licensing costs	2,387,088
44		Maintenance contracts	22,594,196
45		Computer supplies	391,544

ISO New England Inc.
2024 Operating Expense Budget

46			**25,372,828**
47	**Data Services and Office expenses**		
48		Office supplies	94,288
49		Postage and courier	42,250
50		Printing Expense	62,900
51		Data Services, Dues, and subscriptions	2,006,729
52		Office equipment maintenance	28,000
53		Other Miscellaneous	23,100
54			**2,257,267**
55			
56	**NPCC/NERC Dues**		
57		Budget for NPCC and NERC Dues	8,034,495
58		Eastern Interconnect Data Sharing Network (EIDSN) Allocation/Dues	17,939
59			**8,052,434**
60			
61	**Insurance Expense**		
62		Property and liability (including Cyber Security)	2,979,584
63		Directors and officers	414,168
64			**3,393,752**
65			
66	**Meetings & Related Expenses**		**1,511,375**
67		Includes travel and related expenses for stakeholder meetings throughout the region, for regulatory meetings and support including FERC, NERC, NPCC, and state agencies, for Industry and Other Conference attendance, in addition to other miscellaneous travel reimbursement and employee service recognition	
68			
69	**Education & Training**		**1,331,972**
70		Includes funding for Enterprise wide training including Leadership and Management Development, Technical and NERC Certification Training, Communications and Presentation Training, Management and General Training, and Education Reimbursement	

ISO New England Inc.
2024 Operating Expense Budget

Regulatory Fees, Taxes and Licenses		
	Real estate tax	147,000
	Business license and Bank Fees	93,419
		240,419
CEO Emerging Work Allowance		
	New activities and initiatives that occur during the year.	**2,000,000**
Operating Contingency		
	Funding of last resort to cover unknown expenses (Board Approved).	**700,000**
Depreciation and Debt Service of Capitalized Costs		
	Depreciation and Amortization expense and Disposal	32,559,465
	Interest expense	3,459,145
		36,018,610
Total Operating Expense Budget		**$ 276,896,676**

Exhibit 3
RCL-5
Schedule 3

ISO New England Inc.
Operating Expense Budget
Variance Summary
Proposed Year 2024 Budget vs 2023 Budget
(amounts in thousands)

Line No.	DESCRIPTION	Proposed Annual Budget 2024	Original 2023 Budget	Variance 2024 Budget vs 2023 Budget Inc/(Decrease)
1	**Revenues and Other Income**	$ (917.2)	$ (694.4)	$ (222.9)
2	**Salaries and Overhead**	159,815.0	136,218.6	23,596.4
3	**Professional Fees & Consultants**	29,257.1	24,935.4	4,321.7
4	**Building Services**	3,430.3	3,122.5	307.8
5	**Rents/Leases**	780.8	897.6	(116.9)
6	**Network Operations**	3,652.1	3,269.9	382.2
7	**Computer Services**	25,372.8	20,397.8	4,975.0
8	**Data Services and Office Expenses**	2,257.3	2,015.1	242.1
9	**NPCC/NERC Dues**	8,052.4	7,296.4	756.0
10	**Insurance Expense**	3,393.8	3,140.2	253.6
11	**Meetings & Related Expenses**	1,511.4	1,272.4	239.0
12	**Education & Training**	1,332.0	1,326.9	5.1
13	**Regulatory Fees, Taxes, and Licenses**	240.4	193.9	46.5
14	**CEO Emerging Work Allowance**	2,000.0	2,000.0	-
15	**Operating Contingency**	700.0	700.0	-
16	**Net Expense before Depreciation and Debt Service**	**240,878.1**	**206,092.4**	**34,785.7**
17				
18	**Depreciation and Debt Service**	36,018.6	34,112.8	1,905.8
19				
20	**Total Operating Expense Budget**	**$ 276,896.7**	**$ 240,205.2**	**$ 36,691.5**

ISO NEW ENGLAND INC.
Change in Operating Expense Budgets
Proposed Year 2024 Budget vs. 2023 Budget
(Amounts in thousands)

Line No.				
1	**Revenues and Other Income**			
2		Interest Income increase due to higher rates on deposits compared to 2023 budget	(295.2)	
3		Participant Market Training Fees	84.3	
4		Purchase Discounts	(12.0)	
5	**Total change in Revenues and Other Income**			**$ (222.9)**
6				
7	**Salaries and Overhead**			
8		Merit and Promotion	14,153.7	
9		Increase for additional budgeted positions (Funding for 29 FTEs that includes 20 out of 41 new positions approved for 2024 and carry over of 9 positions from 2023 (that were deferred during that time)	5,432.0	
11		Higher Recruiting, Retention, and Succession Planning	2,561.1	
10		Employee Benefit Cost Changes	810.5	
12		Increase in intern program funding	299.0	
13		Conversion of two former consultants to FTEs	268.5	
14		Board of Directors	90.0	
14		Other minor changes	(18.4)	
15	**Total change in Salaries and Overhead**			**23,596.4**
16				
17	**Professional Fees and Consultants**			
18				
19		Internal Audit - Increases for NERC CIP readiness, market system Algorithm Recertifications, and SSAE 18 Type 2 Audit.	151.2	
20		Transmission Services & Resource Qualification - increases include Transmission Planning Regional Study with PJM and NYISO on single source transmission limits, DER and Minimum Load Studies, and develop and execute long range transmission planning studies in conjunction with the states.	2,042.1	
21		Funds added for the development of Prompt Seasonal Capacity Markets	1,500.0	
22		Market Development - Increases for consultant support for Forward Capacity Market Parameters recalculation for FCA 21, Medium Term Energy Adequacy, partially offset by reductions in future grid and pathways study phases, and Inventoried Energy Program gas contract criteria.	745.0	
23		Legal - Increase for higher support including employment tax law due to now having employees working from many states partially offset by a decrease for Board Evaluations.	42.5	
24		Advanced Technology Solutions - Decreased funding needed for Resource Capacity Accreditation gas modeling, Resource Capacity Accreditation related support and R&D projects partially offset by increases for Cloud Computing, Machine Learning and Quantum Computing Research and Collaboration, Salinity Gradient Power (SGP) Based Power Flow and Electricity Security through Market Based Solutions..	(830.0)	
25		NEPOOL Relations - Decrease in the support of the assessment of participant proposals/requests that the ISO will consider incorporating into Annual Work Plans.	(154.0)	
26		Finance - Decreases for non-recurring items including environmental, social and governance consultant, partially offset by increases in temporary support to augment staff, HR/Payroll services and contingency funds.	(62.9)	
27		Computer Service/Systems consulting to support Information Technology reliability and cyber defenses including the development of a cyber security framework, an engineer to support cyber security network monitoring and detection software, increases for cyber related social engineering assessment work, and a network reliability engineer.	565.4	
28		Corporate Communications - Reduction in funding for Communications Outreach Program	(75.0)	
29		Market Monitoring - Inflationary and other increases for existing consulting	64.5	
30		Human Resources - Increases for relocation, recruiting, benefits optimization, surveys and competitive analysis and board work.	381.6	
31		Operational Performance Training and Integration - Reduction for Training Support Consultant that was made a full time employee.	(135.0)	

ISO NEW ENGLAND INC.
Change in Operating Expense Budgets
Proposed Year 2024 Budget vs. 2023 Budget
(Amounts in thousands)

Line No.				
31		Market and Credit Risk - Consulting support for build out of new margin model for Real-Time, Day-Ahead, and Prompt Seasonal Capacity Markets	250.0	
32		Other minor changes	(163.7)	
33	**Total change in Professional Fees and Consultants**			**4,321.7**
34	**Building Services**	Increases in utility rates as a result of energy supply costs, miscellaneous facility upgrades, cyclical Capacitor and Fan Replacement at the Backup Control Center, and inflationary increases for other maintenance costs.		**307.8**
35				
36	**Rents/Leases**	Reduction due to current trend (due to lower quantity of leases in part to converting from 3 to 4 year leases on some PCs/laptops) as well as savings from no longer leasing monitors.		**(116.9)**
37				
38	**Network Operations**	Increased expense primarily related to inflationary costs on existing network lines, and the impact from the migration of Control Room communication technology to existing modern network infrastructure		**382.2**
39				
40	**Computer Services**	Increases include inflationary expense related to licensing and maintenance support driven by a steep increase in recent history across ISO's portfolio of products, infrastructure increases for operating system support including extended coverage for unsupported versions while completing version updates, additional backup storage needs, backup recovery software, and additional virtualization licensing; other increased expense resulting from application maintenance on new products, cyber security costs for cloud enterprise software, increased licensing needs due to larger workforce, and increased costs across multiple areas including Enterprise Application Support and Architecture and Data Governance		**4,975.0**
41				
42	**Data Services and Office Expenses**	Increases include Cyber Security subscription for readiness training to prepare cyber team for most recent threats, and FiscalNote subscription to monitor regional and national policy initiatives, and inflationary and vendor price increases for various subscriptions and lines.		**242.1**
43				
44	**NPCC/NERC Dues**	Increase for NPCC allocation of $597.7K, NERC allocation of $170.8K and EIDSN of $5.5K.		**756.0**
45				
46	**Insurance Expense**	Estimated insurance broker increases across insurance lines that average 8.1% above 2023 budget although variations exist across various lines.		**253.6**
47				
48	**Meetings & Related Expenses**	Meetings & related expense increases are a result of returning to pre-pandemic levels; higher costs for air, hotel and other travel related costs; and training related travel expense for new full-time employees.		**239.0**
49				
50	**Education & Training**	Minor adjustments in Education & Training funding.		**5.1**
51				
52	**Regulatory Fees, Taxes, and Licenses**	Increases due to higher bank fees as a result of lower earning credits and increase in vendor payments being done electronically with resulting fees.		**46.5**
53				
54				
55	**Total Change in Net Expense before Depreciation and Debt Service**			**$ 34,785.7**
56				
57	**Depreciation and Debt Service**	Depreciation expense increases due primarily to a full year of depreciation for nGEM projects that went live mid-2023, partially offset by decreases driven by changes in project completion dates and projects that came in under budget.	1,584.1	
58	**Interest Expense**	Increase in interest expense due primarily to an increase in borrowings on the working capital line resulting from increases in the operating and capital budgets.	321.7	
59	**Total Depreciation and Debt Service**			**1,905.8**
60				
61	**Total Change in Operating Expense Budget**			**$ 36,691.5**

ISO NEW ENGLAND INC.
Staffing Projections

Line No.	Department	2023 Budget Staff Level	2024 Budget Staff Level
1	**COO - Administration**	**9.0**	**8.0**
2			
3	System Operations & Market Administration	5.0	5.0
4	Operations	44.0	44.0
5	Operations Support Services	30.0	30.0
6	Operational Performance Trng and Integration	22.0	22.0
7	Market Administration & Auctions	25.0	25.0
8	**System Operations & Market Administration**	**126.0**	**126.0**
9			
10	Planning Services	19.0	21.0
11	Transmission Planning	20.0	22.0
12	Transmission Services & Resource Qualification	22.0	30.0
13	System Planning	4.0	4.0
14	**System Planning**	**65.0**	**77.0**
15			
16	Participant Relations & Services	8.0	10.0
17	Participant Support & Solutions	14.0	14.0
18	**Participant Relations & Services**	**22.0**	**24.0**
19			
20	Market Development & Settlements Admin	5.0	5.0
21	Market Analysis & Settlements	15.0	15.0
22	Market Operations Support Services	16.0	16.0
23	Market Development	11.0	12.0
24	Market Assessment	12.0	13.0
25	**Market Development & Settlements**	**59.0**	**61.0**
26			
27	Energy Management Systems	26.0	28.0
28	Enterprise Applications Development	17.0	18.0
29	Cyber Security	19.0	20.0
30	Enterprise Applications Support	21.0	23.0
31	IT Infrastructure Support	20.0	20.0
32	IT Management	6.0	6.0
33	Power System Modeling Management	19.0	14.0
34	Database & Analytics	17.0	19.0
35	Architecture & Data Governance	8.0	8.0
36	Software Development & Power System Supp Admin	2.0	2.0
37	Infrastructure & Enterprise Support Svs Admin	4.0	5.0
38	IT Change & Asset License Management	3.0	3.0
39	IT Service Delivery	19.0	19.0
40	**Information Technology**	**181.0**	**185.0**

ISO NEW ENGLAND INC.
Staffing Projections

Line No.	Department	2023 Budget Staff Level	2024 Budget Staff Level
41			
42	**Advanced Technology Solutions**	**14.0**	**17.0**
43	**Program Management**	**16.0**	**16.0**
44			
45	**Total COO**	**492.0**	**514.0**
46			
47	**Chief Executive Officer - Administration**	**9.0**	**9.0**
48			
49	Market & Credit Risk	5.0	5.0
50	Facilities & Security	4.0	4.0
51	Strategy, Risk & Operations Compliance	6.0	12.0
52	Finance	24.0	20.0
53	**Finance and Compliance**	**39.0**	**41.0**
54			
55	Legal Department	16.0	16.0
56	Corporate Communications & External Affairs	18.0	19.0
57	**Legal and Public Affairs**	**34.0**	**35.0**
58			
59	**Human Resources**	**16.0**	**20.0**
60			
61	**Market Monitoring and Mitigation**	**19.0**	**19.0**
62			
63	**Internal Audits**	**5.0**	**6.0**
64			
65	**Total Administration**	**122.0**	**130.0**
66			
67	**Total FTE's**	**614.0**	**644.0**
68			
69	**Total Part-timers (X @ 0.5)**	**0.5**	**0.5**
70			
71	**Total Number of Employees**	**614.5**	**644.5**

ISO New England Inc.
2024 Capital Budget

Line No.	Description	2024
1	***Capital Projects - Approved Charters***	
2	**. Day-Ahead Ancillary Service Improvements**	$ 3,811,500
3	**. nGEM Software Development Part III**	2,500,000
4	**. Operating System Server Upgrade Phase I**	1,215,500
5	**. Solar Do-Not-Exceed Dispatch Phase II**	920,500
6	**. Internal Market Monitoring Data Analysis Phase IV**	519,000
7	**. Energy Management System Short-term Load Forecast Replacement**	371,100
8	**. IT Asset Workflow Integration and Updates**	238,000
9	**. Energy Management System Host Monitoring Software Replacement**	31,900
10	**. Settlement Technology Improvements Project**	27,300
11	**Sub Total Projects with Approved Charters**	9,634,800
12	***Planning/Conceptual Design [2]***	
13	**. nGEM Real-Time Market Clearing Engine Implementation**	6,000,000
14	**. FERC Order 881 compliance**	3,300,000
15	**. CIP Electronic Security Perimeter Redesign Phase II**	2,000,000
16	**. Enterprise Resource Planning System Replacement**	1,600,000
17	**. Resource Capacity Accreditation**	1,000,000
18	**. Microsoft 365 Service Adoption**	1,000,000
19	**. 2024 Issue Resolution Project**	1,000,000
20	**. FERC Order 2222**	500,000
21	**. Privileged Account Management Security Enhancements Phase II**	500,000
22	**. Other Emerging Work**	1,631,200
23	**Subtotal Conceptual Design**	18,531,200
24	***. Non-Project Capital Expenditures***	5,334,000
25	***. Capitalized Interest and Loan Fees***	1,500,000
26	**TOTAL Capital Projects (including Capitalized Interest)**	$ 35,000,000

Exhibit 3
RCL-7
Schedule 1

ISO New England Inc.
FERC DOCKET NO. ER24 -000
Development of Escalation Factors

Line No.	Month	From CELT Report (As Published) Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	From Monthly Market Reports Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Jan-14	21,334	12,022	Actual	21,334	12,022	Actual
2	Feb-14	19,654	10,468	Actual	19,654	10,468	Actual
3	Mar-14	19,696	11,037	Actual	19,696	11,037	Actual
4	Apr-14	16,011	9,452	Actual	16,011	9,452	Actual
5	May-14	16,222	9,463	Actual	16,222	9,463	Actual
6	Jun-14	21,263	10,400	Actual	21,263	10,400	Actual
7	Jul-14	24,443	12,244	Actual	24,443	12,244	Actual
8	Aug-14	22,694	11,229	Actual	22,694	11,229	Actual
9	Sep-14	23,715	10,236	Actual	23,715	10,236	Actual
10	Oct-14	17,053	9,710	Actual	17,053	9,710	Actual
11	Nov-14	18,369	9,968	Actual	18,369	9,968	Actual
12	Dec-14	19,812	10,926	Actual	19,843	10,945	Actual
13	Jan-15	20,583	11,732	Actual	20,583	11,732	Actual
14	Feb-15	20,108	11,032	Actual	20,108	11,032	Actual
15	Mar-15	18,848	10,869	Actual	18,848	10,869	Actual
16	Apr-15	16,455	9,239	Actual	16,455	9,239	Actual
17	May-15	19,544	9,729	Actual	19,544	9,729	Actual
18	Jun-15	20,923	10,161	Actual	20,923	10,161	Actual
19	Jul-15	24,437	12,099	Actual	24,437	12,099	Actual
20	Aug-15	24,216	12,229	Actual	24,216	12,229	Actual
21	Sep-15	24,368	10,735	Actual	24,368	10,735	Actual
22	Oct-15	16,247	9,495	Actual	16,247	9,495	Actual
23	Nov-15	17,643	9,419	Actual	17,692	9,448	Actual
24	Dec-15	18,157	10,160	Actual	18,207	10,188	Actual
25	Jan-16	19,451	11,015	Actual	19,451	11,015	Actual
26	Feb-16	19,561	10,126	Actual	19,562	10,126	Actual
27	Mar-16	17,341	9,819	Actual	17,341	9,819	Actual
28	Apr-16	16,963	9,020	Actual	16,963	9,020	Actual
29	May-16	19,029	9,433	Actual	19,029	9,433	Actual
30	Jun-16	19,966	10,176	Actual	19,966	10,176	Actual
31	Jul-16	24,416	12,387	Actual	24,416	12,387	Actual
32	Aug-16	25,596	12,642	Actual	25,596	12,642	Actual
33	Sep-16	23,142	10,164	Actual	23,142	10,164	Actual
34	Oct-16	16,298	9,356	Actual	16,298	9,356	Actual
35	Nov-16	17,517	9,403	Actual	17,517	9,403	Actual
36	Dec-16	19,581	10,840	Actual	19,647	10,884	Actual
37	Jan-17	19,592	10,724	Actual	19,592	10,724	Actual
38	Feb-17	18,165	9,440	Actual	18,165	9,440	Actual
39	Mar-17	17,502	10,425	Actual	17,502	10,425	Actual
40	Apr-17	15,843	8,856	Actual	15,843	8,809	Actual
41	May-17	19,712	9,211	Actual	20,250	9,211	Actual
42	Jun-17	23,868	10,291	Actual	23,968	10,291	Actual

Line No.	Month	From CELT Report (As Published)			From Monthly Market Reports		
		Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
43	Jul-17	23,372	11,413	Actual	23,579	11,412	Actual
44	Aug-17	22,769	11,109	Actual	22,769	11,109	Actual
45	Sep-17	20,999	9,849	Actual	20,999	9,849	Actual
46	Oct-17	17,255	9,283	Actual	17,255	9,283	Actual
47	Nov-17	17,079	9,498	Actual	17,079	9,498	Actual
48	Dec-17	20,476	11,082	Actual	20,524	11,117	Actual
49	Jan-18	20,669	11,538	Actual	20,662	11,536	Actual
50	Feb-18	18,320	9,379	Actual	18,308	9,379	Actual
51	Mar-18	16,943	9,956	Actual	16,943	9,956	Actual
52	Apr-18	15,778	8,996	Actual	15,778	8,996	Actual
53	May-18	17,534	9,151	Actual	17,518	9,150	Actual
54	Jun-18	21,076	9,767	Actual	21,075	9,767	Actual
55	Jul-18	24,512	12,324	Actual	24,511	12,324	Actual
56	Aug-18	26,024	12,605	Actual	26,024	12,606	Actual
57	Sep-18	24,475	10,059	Actual	24,475	10,059	Actual
58	Oct-18	17,479	9,436	Actual	17,479	9,436	Actual
59	Nov-18	17,591	9,723	Actual	17,590	9,724	Actual
60	Dec-18	18,408	10,496	Actual	18,466	10,539	Actual
61	Jan-19	20,773	11,077	Actual	20,773	11,077	Actual
62	Feb-19	18,585	9,659	Actual	18,585	9,659	Actual
63	Mar-19	17,876	9,898	Actual	17,876	9,887	Actual
64	Apr-19	15,034	8,641	Actual	15,034	8,641	Actual
65	May-19	15,748	8,749	Actual	15,748	8,749	Actual
66	Jun-19	19,913	9,414	Actual	19,913	9,414	Actual
67	Jul-19	24,361	12,393	Actual	24,361	12,393	Actual
68	Aug-19	23,365	11,235	Actual	23,365	11,235	Actual
69	Sep-19	19,106	9,082	Actual	19,162	9,119	Actual
70	Oct-19	16,122	8,897	Actual	16,136	8,920	Actual
71	Nov-19	17,514	9,424	Actual	17,548	9,461	Actual
72	Dec-19	19,033	10,652	Actual	19,065	10,679	Actual
73	Jan-20	18,097	10,417	Actual	18,097	10,417	Actual
74	Feb-20	16,991	9,495	Actual	16,991	9,495	Actual
75	Mar-20	15,812	9,199	Actual	15,888	9,188	Actual
76	Apr-20	14,254	8,271	Actual	14,254	8,271	Actual
77	May-20	16,593	8,247	Actual	16,593	8,247	Actual
78	Jun-20	21,518	9,879	Actual	21,518	9,879	Actual
79	Jul-20	24,776	12,305	Actual	25,121	12,305	Actual
80	Aug-20	24,335	11,485	Actual	24,335	11,485	Actual
81	Sep-20	19,151	9,233	Actual	19,260	9,233	Actual
82	Oct-20	15,584	8,888	Actual	15,616	8,845	Actual
83	Nov-20	17,105	8,980	Actual	17,157	9,020	Actual
84	Dec-20	18,887	10,463	Actual	18,922	10,487	Actual
85	Jan-21	18,839	10,680	Actual	18,839	10,679	Actual
86	Feb-21	18,185	9,747	Actual	18,181	9,746	Actual
87	Mar-21	17,767	9,502	Actual	17,767	9,490	Actual
88	Apr-21	14,684	8,347	Actual	14,684	8,347	Actual
89	May-21	18,882	8,655	Actual	18,882	8,655	Actual
90	Jun-21	25,801	10,722	Actual	25,801	10,722	Actual
91	Jul-21	22,937	11,025	Actual	22,937	11,025	Actual
92	Aug-21	25,128	12,099	Actual	25,241	12,099	Actual
93	Sep-21	20,032	9,648	Actual	20,032	9,648	Actual

Line No.	Month	From CELT Report (As Published)			From Monthly Market Reports		
		Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
94	Oct-21	15,218	8,881	Actual	15,218	8,881	Actual
95	Nov-21	17,003	9,104	Actual	17,039	9,151	Actual
96	Dec-21	17,943	10,296	Actual	17,970	10,315	Actual
97	Jan-22	19,756	11,313	Actual	19,756	11,313	Actual
98	Feb-22	18,500	9,654	Actual	18,500	9,654	Actual
99	Mar-22	16,932	9,615	Actual	16,932	9,603	Actual
100	Apr-22	14,438	8,307	Actual	14,438	8,307	Actual
101	May-22	18,939	8,962	Actual	18,939	8,962	Actual
102	Jun-22	19,972	9,505	Actual	19,972	9,505	Actual
103	Jul-22	24,644	12,140	Actual	24,644	12,140	Actual
104	Aug-22	24,780	12,245	Actual	24,780	12,245	Actual
105	Sep-22	17,749	9,140	Actual	17,749	9,140	Actual
106	Oct-22	14,688	8,659	Actual	14,688	8,659	Actual
107	Nov-22	16,904	8,935	Actual	16,827	8,994	Actual
108	Dec-22	17,949	10,403	Actual	17,956	10,405	Actual
109	Jan-23	17,294	10,232	Actual	17,304	10,233	Actual
110	Feb-23	19,645	9,323	Actual	19,662	9,327	Actual
111	Mar-23	17,812	10,047	Forecast	16,202	9,434	Actual
112	Apr-23	15,580	8,863	Forecast	14,606	8,131	Actual
113	May-23	17,866	8,980	Forecast	14,788	8,213	Actual
114	Jun-23	21,541	10,097	Forecast	18,670	9,222	Actual
115	Jul-23	24,605	11,776	Forecast	22,975	12,029	Actual
116	Aug-23	23,354	11,681	Forecast	23,354	11,681	Forecast
117	Sep-23	19,565	9,608	Forecast	19,565	9,608	Forecast
118	Oct-23	16,005	9,329	Forecast	16,005	9,329	Forecast
119	Nov-23	17,616	9,643	Forecast	17,616	9,643	Forecast
120	Dec-23	19,385	10,943	Forecast	19,385	10,943	Forecast
121	Jan-24	20,269	11,372	Forecast	20,269	11,372	Forecast
122	Feb-24	19,279	10,304	Forecast	19,279	10,304	Forecast
123	Mar-24	18,016	10,152	Forecast	18,016	10,152	Forecast
124	Apr-24	15,768	8,921	Forecast	15,768	8,921	Forecast
125	May-24	17,984	8,999	Forecast	17,984	8,999	Forecast
126	Jun-24	21,530	10,147	Forecast	21,530	10,147	Forecast
127	Jul-24	24,633	11,838	Forecast	24,633	11,838	Forecast
128	Aug-24	23,372	11,768	Forecast	23,372	11,768	Forecast
129	Sep-24	19,583	9,665	Forecast	19,583	9,665	Forecast
130	Oct-24	16,233	9,409	Forecast	16,233	9,409	Forecast
131	Nov-24	17,826	9,770	Forecast	17,826	9,770	Forecast
132	Dec-24	19,612	11,116	Forecast	19,612	11,116	Forecast

Line No.	Month	From CELT Report (As Published) Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	From Monthly Market Reports Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1			**Annualized Figures**				
2		Average	Total		Average	Total	Month
3	**2014**	20,022	127,155		20,025	127,174	
4	**2015**	20,127	126,899		20,136	126,956	
5	**2016**	19,905	124,382		19,911	124,425	
6	**2017**	19,719	121,181		19,794	121,168	
7	**2018**	19,901	123,431		19,902	123,472	
8	**2019**	18,952	119,122		18,964	119,234	
9	**2020**	18,592	116,862		18,646	116,872	
10	**2021**	19,368	118,706		19,383	118,758	
11	**2022**	18,771	118,878		18,765	118,927	
12	**2023**	19,189	120,522		18,344	117,793	
13	**2024**	19,509	123,461		19,509	123,461	
14			**Annual Escalation**				
15	**2015**	1.0053	0.9980		1.0055	0.9983	
16	**2016**	0.9890	0.9802		0.9888	0.9801	
17	**2017**	0.9907	0.9743		0.9941	0.9738	
18	**2018**	1.0092	1.0186		1.0055	1.0190	
19	**2019**	0.9524	0.9651		0.9528	0.9657	
20	**2020**	0.9810	0.9810		0.9832	0.9802	
21	**2021**	1.0418	1.0158		1.0395	1.0161	
22	**2022**	0.9692	1.0014		0.9681	1.0014	
23	**2023**	1.0223	1.0138		0.9776	0.9905	
24	**2024**	1.0167	1.0244		1.0635	1.0481	
25					**0.998**	**0.997**	**NOT USED**
26			**Last Five Months of Calendar Year**				
27		Average	Total		Average	Total	
28	Dec-14	20,329	52,069		20,335	52,088	Actual
29	Dec-15	20,126	52,038		20,146	52,095	Actual
30	Dec-16	20,427	52,406		20,440	52,449	Actual
31	Dec-17	19,716	50,821		19,725	50,856	Actual
32	Dec-18	20,795	52,320		20,807	52,364	Actual
33	Dec-19	19,028	49,290		19,055	49,414	Actual
34	Dec-20	19,012	49,049		19,058	49,070	Actual
35	Dec-21	19,065	50,028		19,100	50,094	Actual
36	Dec-22	18,414	49,382		18,400	49,443	Actual
37	Dec-23	19,185	51,204		19,185	51,204	Forecast
38			**Escalation Used for Last Five Months of Calendar Year**				
39	Dec-15				0.9907	1.0001	Actual
40	Dec-16				1.0146	1.0068	Actual
41	Dec-17				0.9650	0.9696	Actual
42	Dec-18				1.0548	1.0297	Actual
43	Dec-19				0.9158	0.9437	Actual
44	Dec-20				1.0001	0.9930	Actual
45	Dec-21				1.0022	1.0209	Actual
46	Dec-22				0.9634	0.9870	Actual
47	Dec-23				1.0427	1.0356	Forecast
48					**0.994**	**0.998**	**NOT USED**

ISO New England Inc.
FERC DOCKET NO. ER24 -000
Billing Determinants for Calendar Year 2023 and Test Year 2024
TEST YEAR 2024

Line No.	Month	Data Source	Schedule 1 Network Load (kW)	Schedule 2 Transaction Units (TUs) Energy TUs	Schedule 2 Transaction Units (TUs) Submitted Virtual Energy	Schedule 2 Transaction Units (TUs) Cleared Virtual Energy	Schedule 2 Financial Transmission Rights (FTRs) Submitted FTR Bids	Schedule 2 Financial Transmission Rights (FTRs) Cleared FTR Bids	Schedule 2 Volumes (GWH)	Schedule 3 Peak Volumes Electrical Load (kW)	Schedule 3 Export Volumes (MWh)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
						CALENDAR YEAR 2023					
1	Jan-23	Actual	16,845,066	1,938,018	320,796	165,365	33,834	10,773	20,540,420	19,649,835	360,809
2	Feb-23	Actual	19,399,200	1,759,969	287,261	133,111	13,565	4,934	18,775,810	21,561,717	260,004
3	Mar-23	Actual	15,740,268	1,937,385	357,262	171,432	16,346	5,109	19,832,723	18,109,934	323,510
4	Apr-23	Actual	14,611,677	1,800,781	296,711	156,098	17,932	4,740	17,174,014	17,325,725	309,507
5	May-23	Actual	14,550,293	1,912,323	325,591	171,536	18,620	4,790	16,989,870	18,288,160	240,616
6	Jun-23	Actual	18,250,765	1,930,472	211,618	109,234	21,026	4,804	18,370,167	21,295,868	159,013
7	Jul-23	Actual	22,623,030	2,030,998	216,668	111,963	24,640	4,613	24,447,432	25,863,441	273,840
8	Aug-23	Est.	24,609,211 a	1,953,490 a	363,182 a	155,314 a	15,087 a	4,197 a	25,327,754 a	27,294,240 a	363,441 a
9	Sep-23	Est.	17,566,309 a	1,854,574 a	283,976 a	138,793 a	25,229 a	7,099 a	19,197,867 a	19,687,989 a	328,822 a
10	Oct-23	Est.	14,426,200 a	1,833,964 a	270,202 a	132,832 a	27,736 a	6,717 a	17,952,634 a	16,570,340 a	253,937 a
11	Nov-23	Est.	16,433,785 a	1,838,857 a	324,536 a	160,065 a	27,832 a	6,889 a	18,953,071 a	18,519,795 a	310,434 a
12	Dec-23	Est.	17,402,529 a	1,931,259 a	353,372 a	152,927 a	24,244 a	5,904 a	21,086,434 a	20,189,713 a	291,185 a
13	Totals		212,458,333	22,722,090	3,611,175	1,758,670	266,091	70,569	238,648,197	244,356,757	3,475,117
14											
15						**TEST YEAR 2024**					
16	Jan-24	Est.	17,030,362 b	1,976,778 c	320,796 a	165,365 a	33,834 a	10,773 a	20,766,365 b	19,865,983 b	360,809 a
17	Feb-24	Est.	19,612,591 b	1,795,168 c	287,261 a	133,111 a	13,565 a	4,934 a	18,982,344 b	21,798,896 b	260,004 a
18	Mar-24	Est.	15,913,411 b	1,976,133 c	357,262 a	171,432 a	16,346 a	5,109 a	20,050,883 b	18,309,143 b	323,510 a
19	Apr-24	Est.	14,772,405 b	1,836,797 c	296,711 a	156,098 a	17,932 a	4,740 a	17,362,929 b	17,516,308 b	309,507 a
20	May-24	Est.	14,710,346 b	1,950,569 c	325,591 a	171,536 a	18,620 a	4,790 a	17,176,759 b	18,489,330 b	240,616 a
21	Jun-24	Est.	18,451,523 b	1,969,081 c	211,618 a	109,234 a	21,026 a	4,804 a	18,572,238 b	21,530,123 b	159,013 a
22	Jul-24	Est.	22,871,883 b	2,071,618 c	216,668 a	111,963 a	24,640 a	4,613 a	24,716,354 b	26,147,939 b	273,840 a
23	Aug-24	Est.	24,879,912 b	1,992,560 c	363,182 a	155,314 a	15,087 a	4,197 a	25,606,359 b	27,594,477 b	363,441 a
24	Sep-24	Est.	17,759,538 b	1,891,665 c	283,976 a	138,793 a	25,229 a	7,099 a	19,409,044 b	19,904,557 b	328,822 a
25	Oct-24	Est.	14,584,888 b	1,870,643 c	270,202 a	132,832 a	27,736 a	6,717 a	18,150,113 b	16,752,614 b	253,937 a
26	Nov-24	Est.	16,614,557 b	1,875,634 c	324,536 a	160,065 a	27,832 a	6,889 a	19,161,555 b	18,723,513 b	310,434 a
27	Dec-24	Est.	17,593,957 b	1,969,884 c	353,372 a	152,927 a	24,244 a	5,904 a	21,318,385 b	20,411,800 b	291,185 a
28	Total		214,795,375	23,176,532	3,611,175	1,758,670	266,091	70,569	241,273,327	247,044,681	3,475,117

Escalation factors:	
a	1.000
b	1.011
c	1.020

Exhibit 3
RCL-7
Schedule 3

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24 -000
Rate Design Summary
TEST YEAR 2024

Line No.	Tariff Schedule	Revenue Requirement for Test Year 2024	Billing Units			Proposed Rates		Calculated Revenue
			Blocks		Total			
	(a)	(b)	(c)		(d)	(e)	(f)	(g) (d) x (e)
1	**Schedule 1**	**$ 57,895,721**						
2	Network		Total		214,795,375	$ 0.26954	/kW-mo.	**$ 57,895,721**
3	Through or Out Service					**$ 0.00037**	/kW-hour	
4								
5	**Schedule 2**	**$ 129,327,912**						
6	Transaction Units	$ 19,399,187	15.00%					
7	INC Offers/DEC Bids	$ 123,576						
8	Submitted				3,611,175	$ 0.00500	/Offer or Bid	$ 18,056
9	Cleared				1,758,670	$ 0.06000	/Offer or Bid	$ 105,520
10			Total		5,369,845			$ 123,576
11	Financial Transmission Rights	$ 1,053,880						
12	Submitted FTR Bids	$ 737,716	70%		266,091	$ 2.77242	/Bid	$ 737,716
13	Cleared FTR Bids	$ 316,164	30%		70,569	$ 4.48021	/Bid	$ 316,164
14			Total		336,660			$ 1,053,880
15								
16	Energy TUs	$ 18,221,731						
17	Block 1		First	12,500	14,855,723	$ 0.82494	/TU-hour	$ 12,255,024
18	Block 2		Next	27,000	4,674,962	$ 0.74994	/TU-hour	$ 3,505,951
19	Block 3		Over	39,500	3,645,847	$ 0.67495	/TU-hour	$ 2,460,756
20			Total		23,176,532			$ 18,221,731
21								
22	Volumetric Measures	$ 109,928,725	85.00%					
23	Block 1		First	250,000	118,867,490	$ 0.48178	/mWh	$ 57,267,886
24	Block 2		Next	1,250,000	100,701,604	$ 0.43798	/mWh	$ 44,105,400
25	Block 3		Over	1,500,000	21,704,233	$ 0.39418	/mWh	$ 8,555,440
26			Total		241,273,327			$ 109,928,725
27								
28			Total					**$ 129,327,912**
29								
30	**Schedule 3**	**$ 86,666,881**						
31	RT NCP Load Obligation	$ 84,234,299	Total		247,044,681	$ 0.34097	/kW-mo.	$ 84,234,299
32	Exports	$ 2,432,582	Total		3,475,117	$ 0.70000	/mWh	$ 2,432,582
33								**$ 86,666,881**
34								
35	Totals	**$ 273,890,514**						**$ 273,890,514**

Exhibit 3
RCL-7
Schedule 4

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24 -000
Annual Revenue Comparison at Present and Proposed Rates
TEST YEAR 2024

Line No.	Tariff Schedule	2024 Billing Units			Annual Revenue Analysis						Change	
					2023 Approved Rates			2024 Proposed Rates				
			Blocks	Total	Effective Rates		Calculated Revenue	Proposed Rates		Total Revenue (1)	$	%
	(a)		(b)	(c)	(d)	(e)	(f) (c) x (d)	(g)	(h)	(i)	(j) (i) - (f)	(k) (j) / (f)
1	**Schedule 1**											
2	Network	Total		214,795,375	$0.20475	/kW-mo.	**$ 43,979,353**	$ 0.26954	/kW-mo.	**$ 57,895,721**	**$ 13,916,368**	**31.64%**
3												
4	**Schedule 2**											
5	Transaction Units											
6	INC Offers/DEC Bids											
7	Submitted			3,611,175	$0.00500	/Offer or Bid	$ 18,056	$ 0.00500	/Offer or Bid	$ 18,056		
8	Cleared			1,758,670	$0.06000	/Offer or Bid	$ 105,520	$ 0.06000	/Offer or Bid	$ 105,520		
9			Total	5,369,845			$ 123,576			$ 123,576		
10	Financial Transmission Rights											
11	Submitted FTR Bids			266,091	$2.01008	/Bid	$ 534,864	$ 2.77242	/Bid	$ 737,716		
12	Cleared FTR Bids			70,569	$4.20539	/Bid	$ 296,770	$ 4.48021	/Bid	$ 316,164		
13			Total	336,660			$ 831,634			$ 1,053,880		
14												
15	Energy Transaction Units											
16	Block 1	First	12,500	14,855,723	$0.69888	/TU-hour	$ 10,382,367	$ 0.82494	/TU-hour	$ 12,255,024		
17	Block 2	Next	27,000	4,674,962	$0.63535	/TU-hour	$ 2,970,237	$ 0.74994	/TU-hour	$ 3,505,951		
18	Block 3	Over	39,500	3,645,847	$0.57181	/TU-hour	$ 2,084,732	$ 0.67495	/TU-hour	$ 2,460,756		
19		Total		23,176,532			$ 15,437,336			$ 18,221,731		
20	Volumetric Measures											
21	Block 1	First	250,000	118,867,490	$0.40259	/mWh	$ 47,854,863	$ 0.48178	/mWh	$ 57,267,886		
22	Block 2	Next	1,250,000	100,701,604	$0.36599	/mWh	$ 36,855,780	$ 0.43798	/mWh	$ 44,105,400		
23	Block 3	Over	1,500,000	21,704,233	$0.32940	/mWh	$ 7,149,374	$ 0.39418	/mWh	$ 8,555,440		
24		Total		241,273,327			$ 91,860,017			$ 109,928,725		
25												
26		Total					**$ 108,252,564**			**$ 129,327,912**	**$ 21,075,348**	**19.47%**
27	**Schedule 3**											
28	RT NCP Load Obligation	Total		247,044,681	$0.26260	/kW-mo.	$ 64,873,933	$ 0.34097	/kW-mo.	$ 84,234,299		
29	Exports	Total		3,475,117	$0.55000	/mWh	$ 1,911,314	$ 0.70000	/mWh	$ 2,432,582		
30							**$ 66,785,248**			**$ 86,666,881**	**$ 19,881,633**	**29.77%**
31												
32	Totals						**$ 219,017,164**			**$ 273,890,514**	**$ 54,873,350**	**25.05%**

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24 -000
Comparison of Schedule 2 Revenues from Transaction Units (TUs) for 2022
TEST YEAR 2024

Line No.	Month	Source For TY 2021	TUs Per ISO Tariff Filing for TY 2022 Total TUs	First 12,500	Next 27,000	Over 39,500	Source For TY 2023	TUs Per ISO Tariff Filing for CY 2022 Total TUs	First 12,500	Next 27,000	Over 39,500
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
						Comparison Of Monthly TU Data For CY 2022					
						Billing Determinants - Energy TUs					
1	Jan-22	Jan-21	1,902,837	1,211,654	414,072	277,111	Actual	1,956,649	1,280,258	352,445	323,946
2	Feb-22	Feb-21	1,721,046	1,095,897	374,513	250,637	Actual	1,763,431	1,171,497	315,498	276,436
3	Mar-22	Mar-21	1,883,899	1,199,595	409,951	274,353	Actual	1,937,132	1,250,572	352,150	334,410
4	Apr-22	Apr-21	1,759,197	1,120,189	382,815	256,193	Actual	1,771,062	1,184,251	323,765	263,046
5	May-22	May-21	1,839,199	1,171,132	400,224	267,843	Actual	1,853,059	1,223,068	339,414	290,577
6	Jun-22	Jun-21	1,826,673	1,163,156	397,498	266,019	Actual	1,868,414	1,227,571	350,672	290,171
7	Jul-22	Jul-21	1,925,813	1,226,284	419,072	280,457	Actual	1,952,767	1,271,906	369,417	311,444
8	Aug-22	Aug-20	1,870,737	1,191,214	407,087	272,436	Actual	1,953,490	1,265,329	374,093	314,068
9	Sep-22	Sep-20	1,761,999	1,121,974	383,424	256,601	Actual	1,854,574	1,218,684	351,971	283,919
10	Oct-22	Oct-20	1,798,211	1,145,033	391,304	261,874	Actual	1,833,964	1,220,133	357,205	256,626
11	Nov-22	Nov-20	1,780,886	1,134,000	387,534	259,351	Actual	1,838,857	1,209,739	356,979	272,139
12	Dec-22	Dec-20	1,897,165	1,208,042	412,837	276,285	Actual	1,931,259	1,233,745	367,294	330,220
13	Totals		21,967,663	13,988,171	4,780,330	3,199,161		22,514,658	14,756,753	4,210,903	3,547,002
14											
15	**Totals**		**21,967,663**					**22,514,658**			
16											
17	2022 Approved Rates for Schedule 2			$0.70614	$0.64195	$0.57775			$0.70614	$0.64195	$0.57775
18											
19						Initial Estimate of Revenue From Energy TUs					
20	Jan-22	Jan-21	$ 1,281,512	$ 855,597	$ 265,813	$ 160,101	Actual	$ 1,317,453	$ 904,041	$ 226,252	$ 187,160
21	Feb-22	Feb-21	$ 1,159,080	$ 773,856	$ 240,418	$ 144,805	Actual	$ 1,189,486	$ 827,241	$ 202,534	$ 159,711
22	Mar-22	Mar-21	$ 1,268,758	$ 847,082	$ 263,168	$ 158,508	Actual	$ 1,302,347	$ 883,079	$ 226,063	$ 193,205
23	Apr-22	Apr-21	$ 1,184,774	$ 791,011	$ 245,748	$ 148,015	Actual	$ 1,196,063	$ 836,247	$ 207,841	$ 151,975
24	May-22	May-21	$ 1,238,653	$ 826,983	$ 256,924	$ 154,747	Actual	$ 1,249,425	$ 863,657	$ 217,887	$ 167,881
25	Jun-22	Jun-21	$ 1,230,217	$ 821,351	$ 255,174	$ 153,693	Actual	$ 1,259,597	$ 866,837	$ 225,114	$ 167,646
26	Jul-22	Jul-21	$ 1,296,986	$ 865,929	$ 269,023	$ 162,034	Actual	$ 1,315,228	$ 898,144	$ 237,147	$ 179,937
27	Aug-22	Aug-20	$ 1,259,893	$ 841,164	$ 261,329	$ 157,400	Actual	$ 1,315,101	$ 893,499	$ 240,149	$ 181,453
28	Sep-22	Sep-20	$ 1,186,661	$ 792,271	$ 246,139	$ 148,251	Actual	$ 1,250,544	$ 860,562	$ 225,948	$ 164,034
29	Oct-22	Oct-20	$ 1,211,049	$ 808,553	$ 251,198	$ 151,298	Actual	$ 1,239,158	$ 861,585	$ 229,308	$ 148,266
30	Nov-22	Nov-20	$ 1,199,381	$ 800,763	$ 248,778	$ 149,840	Actual	$ 1,240,636	$ 854,245	$ 229,163	$ 157,228
31	Dec-22	Dec-20	$ 1,277,692	$ 853,047	$ 265,021	$ 159,624	Actual	$ 1,297,766	$ 871,197	$ 235,784	$ 190,785
32	Totals		14,794,656	9,877,607	3,068,733	1,848,316		15,172,803	10,420,334	2,703,189	2,049,280
33											
34	**Total Energy TU- Revenue**		**$ 14,794,656**					**$ 15,172,803**			
35				**Total**	**Rate**	**($)**			**Total**	**Rate**	**($)**
36	Submitted Virtual Energy Bids/Offers TUs			3,970,590	$0.00500	19,853			4,014,096	$0.00500	20,070
37	Cleared Virtual Energy Bids/Offers TUs			2,216,800	$0.06000	133,008			1,885,442	$0.06000	113,127
38						**$ 152,861**					**$ 133,197**
39				**Total**	**Rate**	**($)**			**Total**	**Rate**	**($)**
40	Submitted FTR Bid TUs			319,407	$2.13776	682,816			246,078	$2.13776	526,056
41	Cleared FTR Bid TUs			75,423	$3.87993	292,636			66,272	$3.87993	257,131
42						**$ 975,451**					**$ 783,186**
43											
44	**Total Schedule 2 TU- Revenue**		**$ 15,922,968**					**$ 16,089,187**			
45	**Initial True-Up Estimate - Over (Under) Recovery For Jan - Dec**							**$ 166,219**			

Exhibit 3
RCL-7
Schedule 6

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER24- -000
Schedule 2 TU True-Up Summary
TEST YEAR 2024

Line No.		Total Schedule 2 TU Revenues	% TU Difference	
1				
2	**Final 2022 True-Up**			
3	2022 Final TU Collections	$ 16,089,187		
4	Projected TU Collections in TY 2022 Filing	$ 15,922,968		
5	Final Schedule 2 TU Over/(Under) Collection	$ 166,219	1.04%	
6				
7				
8	**Initial Allocation to Volumetric 50%**	**N/A - Over Collected**		
9	**2022 Final True-Up (as calculated above)**			
10	**Total Projected Undercollection to Vol. Meas.**			
11				
12			**Allocated to**	
13		**Total**	**TUs**	**VMs**
14	Schedule 2 Allocation before True-up	$ 129,327,912	$ 19,399,187	$ 109,928,725
15	Allocated TU Under-recovery	$ -	$ -	$ -
16	Total Revenue Requirement After True-Up	**$ 129,327,912**	**$ 19,399,187**	**$ 109,928,725**
17	% Allocation	100.00%	15.00%	85.00%

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

October 5, 2023

RESOLUTION REGARDING THE ISO 2024 BUDGET

RESOLVED, that the Participants Committee supports the Year 2024 operating budget and capital budget proposed by the ISO, as presented at this meeting.

EXHIBIT 4

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER24-___-000**

TESTIMONY

OF

KATHLEEN DECASTRO

Filed on: October 13, 2023

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO NEW ENGLAND INC.) Docket No. ER24-___-000

Testimony of Kathleen deCastro

Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Kathleen deCastro. I am the Vice President, Human Resources and Chief People Diversity Officer at ISO New England Inc. (the "ISO" or "ISO-NE"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE, BRIEFLY, YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND AND THE SCOPE OF YOUR CURRENT POSITION AT ISO NEW ENGLAND.

A. I joined the ISO in June 2022 as the Vice President, Human Resources and Chief People Diversity Officer. In this role, my department and I provide leadership, expertise, programs, and processes to attract, hire, lead, develop, engage, and retain diverse talent for the ISO. I also support the Compensation and Human Resources Committee of the Board of Directors as well as the Joint Nominating Committee, which is responsible for nominating directors to the Board.

I hold an M.A. in Industrial and Organizational Psychology from the University of New Haven and a B.A. in Psychology from the University of Saint Joseph. I have held a variety of senior human resources leadership roles, including Chief Talent Officer at The Hartford Financial Services Company, US Head of Human Resources at Sun Life Financial, Chief Human Resources Officer at Hanover Insurance Group, and Vice President of Human Resources at Travelers Insurance Company. In all of those positions, I was accountable for building and executing human resources strategies and plans to enable business outcomes and delivering functional excellence in talent acquisition, talent management and development, HR information systems, compensation, and employee wellbeing through large, diverse, geographically dispersed teams.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the components of the proposed 2024 administrative expenses related to compensation and funding to support the ISO's strategic goal to attract, develop, and retain talent.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- objective of compensation program
- components of compensation

- budget for merit and promotional/equity salary increases and other compensation adjustments
- health insurance program
- framework for determining executive compensation
- conclusion

OBJECTIVE OF COMPENSATION PROGRAM

Q. WHAT IS THE OBJECTIVE OF THE ISO'S COMPENSATION PROGRAM?

A. The objective of the compensation program is to offer competitive compensation that enables the ISO to attract and retain the highly-skilled employees needed to lead the ISO and meet its business goals for the New England region. We believe that meeting this objective is ultimately less expensive than high levels of turnover, considering the costs of recruiting, relocation, development time, and the disruption of workflow. We also believe that meeting this objective minimizes disruptions to the ISO's critical operations that may be caused by extended time-to-fill rates for open, critical roles.

Q. WHAT ARE THE CHALLENGES TO MEETING THE OBJECTIVE OF THE ISO'S COMPENSATION PROGRAM?

A. There are multiple challenges. First, there is a shortage of critical talent in the utility industry. Second, the most critical functions within our organization, information technology and engineering, are also the most difficult to recruit for

and retain. Near full employment of these professionals and the highly competitive labor market, along with a COVID-19 pandemic-influenced increase in 100% remote work arrangements offered by many organizations have combined to make sourcing of replacements for open positions more challenging, particularly in engineering, software development, and cyber security, resulting in longer times-to-fill. Third, larger workforce trends with respect to the U.S. labor force and with respect to the clean energy transition occurring throughout the industry have exacerbated an already competitive labor market.

Lastly, the ISO's historical compensation practices have also impacted our current ability to meet the objectives of our compensation program. Historically, we benchmarked our compensation to generalized salary budget survey data (explained in more detail below), which does not account for the fact that compensation increases for certain positions may outpace the general market. Over time, as we budgeted based on the generalized national survey data, the market competitiveness compensation gap for certain positions compounded.

In 2022, as these challenges continued to manifest, and retention and turnover challenges increased, we engaged Mercer, a compensation consulting firm, to conduct one-for-one matches on our specific roles across the organization. I explain this Mercer benchmarking study in more detail below.

Q. PLEASE DESCRIBE THE SHORTAGE OF CRITICAL TALENT IN THE UTILITY INDUSTRY.

A. Over the past two decades, numerous studies have documented the aging of electric industry workforce members. While the rate of eligible retirements has not changed significantly during this period, it has caused unprecedented disruption as the energy industry, as a whole, has undergone significant transformation resulting in the need to replace many retiring workers with talent skilled predominately in data analytics and cyber security, and who are facile with leading edge technologies.

Job growth in these fields and other STEM-related fields has continually outpaced that of other occupations. The U.S. Bureau of Labor Statistics projects the growth in STEM occupations to be significantly higher than the growth seen in all other occupations over the next ten years (10.8% versus 2.3%); specific areas of projected growth include Computer and Information Research Scientists (23%) and Software Developers (25%).

Q. PLEASE DESCRIBE THE CHALLENGE IN RECRUITING FOR THE MOST CRITICAL FUNCTIONS WITHIN THE ORGANIZATION (INFORMATION TECHNOLOGY AND ENGINEERING).

A. As noted earlier, workers with the skill sets to perform the ISO's most critical functions are in high demand. One-third of the ISO is comprised of information technology professionals. According to the Bureau of Labor Statistics, U.S.

Department of Labor's Occupational Outlook Handbook, employment of computer and information technology occupations is projected to grow much faster than the average for all occupations from 2022 to 2032, "due to employment growth and the need to replace workers who leave their occupations permanently." Finally, with the heightened awareness of cyber security threats (which is of particular importance for electric grid infrastructure), companies are struggling to fill cyber security positions. Employment of information security analysts is projected to grow 32% from 2022 to 2032.

An additional hiring challenge is the pressure of strong salaries for information technology and engineering professionals that the ISO seeks to employ. The Bureau of Labor Statistics cites that, as of May 2022, the median annual wages for electrical engineers in the U.S. was $103,320, and median annual wages for the types of Information Technology professionals that the ISO employs are between $93,000 and $131,490.

Q. PLEASE DESCRIBE THE WORKFORCE CHALLENGES RELATED TO LARGER MARKET TRENDS.

A. As noted earlier, another challenge to meeting the objectives of the ISO compensation program is responding to market changes as the workforce evolves. America's talent shortage has a clear impact on worker availability generally, with the U.S. Chamber of Commerce estimating that there are 9.8 million job openings in the U.S., but only 5.9 million unemployed workers. Current labor

force participation rates are down to 62.8%, from 63.4% in February 2020. This shrinks the pool of available talent considerably on an overall basis. In New England, according to the U.S. Chamber of Commerce Workforce Shortage Index, five of the six New England states have "severe" to "most severe" labor shortages. Massachusetts, where the ISO's Main Control Center is located, has a "most severe" labor shortage. This complicates the search for and retention of talent, even more so in the specialized fields from which we tend to recruit. Additionally, because many of the ISO's critical roles cannot be performed fully remote, we are required to search for candidates that are either located, or willing to relocate, within commutable distance of our two offices. With tight overall competition for all talent, the ISO is compelled to ensure our salaries are attractive and competitive with compensation offered by other companies who would seek to employ our talent (current employees and potential hires).

Q. PLEASE DESCRIBE THE WORKFORCE CHALLENGES RELATED TO THE CLEAN ENERGY TRANSITION.

A. As more fully explained in Mr. Ludlow's testimony, the ISO is at a critical juncture as it works to support the region's transition to clean energy while ensuring power grid operations remain efficient and reliable. The clean energy transition is driving substantial changes to the New England power system and, as a result, the ISO's workload is increasing and operations are becoming increasingly complex. Similar transitions in the energy industry are underway

nationwide, affecting all aspects of the industry beyond the New England region. Traditionally high demand for transmission planning and operations engineers is additionally heightened as a result of the national infrastructure bill. This transition, alongside the effects of inflation, is compounding the already competitive labor market, particularly in fields related to energy efficiency, renewable energy, and smart grid design.

Q. HOW ARE THESE CHALLENGES MANIFESTING THEMSELVES?

A. These challenges are manifested predominantly in the time it takes to fill open positions (with an increasing number of offer declines due to compensation) and in our ability to retain talent with in-demand skills (reflected in turnover trends and the increasing need to use retention incentives to retain critical talent). We are seeing a decline in activity in the candidate pool for most of our general business openings, as well as roles requiring specialized skills in Information Technology, Electrical Engineering-Power Systems, and Market/Data Analytics. The high demand for these skills, coupled with the lower job loss rate, continues to affect our ability to attract candidates. We average 10 openings per month that remain unfilled after being open for over 90 days. These positions include our market analysts, system operators, engineers, developers, and other back office positions in human resources and finance.

While the ISO's turnover has historically been relatively low, with the exception of the COVID-19 pandemic related decrease in voluntary turnover in 2020, it has

increased over the past several years (2017 - 5.1%; 2018 - 7.1%; 2019 - 7.3%; 2020 - 5.5%; 2021 - 10.5%; 2022 – 9.1%). The year-to-date turnover rate of 3.7% (through September 2023, expected to be approximately 5.0% annualized) is significantly lower than recent trend. The 2023 year-to-date results indicate that our compensation adjustment work completed to date, targeting the subset of employees with the greatest turnover risk (as explained in more detail below), is producing meaningful results.

Nonetheless, despite the lower than average year-to-date turnover rate, a large portion of individuals departing were, and continue to be, information technology and engineering professionals from departments that are most critical to operating the grid and running the New England Markets; they also represent those positions that are amongst the hardest to fill. In addition, approximately 19% of the ISO's workforce is currently retirement-eligible. To enable the ISO to transition to and operate under a future grid that takes into account state energy and environmental policies, the Company expects these positions to be replaced predominately with individuals possessing these same in-demand skills.

Traditionally, the ISO's salaries for these positions have been equal to, or in many cases, lower than the going market rate, making it even more challenging to fill these roles and this discrepancy has a greater impact in competitive labor markets. The skills we seek are largely not present in the local marketplace, requiring candidates to relocate which adds to the difficulty of hiring. Our offer acceptance

rate was 95% in the year 2020, but has since then steadily declined to, as of August 2023, a 75% acceptance rate. Though not all of our offer declines have been on the basis of compensation, it is a prevailing factor in approximately half of our offer declines (*i.e.*, where the candidate took a higher paying position). This trend was also a key indicator that the more in depth, job-specific salary benchmarking work was needed.

An additional dynamic that has impacted the ISO over the past several years, is the increased use of retention incentives for employees in critical roles and departments to prevent the loss of talent that would have a disproportionately negative impact on the ISO's ability to meet its critical responsibilities. Generally, the ISO believes that one-off retention agreements are a short-term limited solution that don't provide the longer term results that a competitive compensation program would provide.

Finally, the COVID-19 pandemic added to our hiring challenges and may continue to do so as workplaces adapt to a post-COVID-19 labor market. Employers have shifted employment practices, including the increased use of remote work. While the ISO currently offers the opportunity for much of the workforce to use hybrid work arrangements, certain positions cannot be performed on a hybrid schedule and require full-time office work (*e.g.*, control room operators and certain cyber security positions). For other positions, particularly in the information technology department, the hybrid options do not

offer as much flexibility as other information technology organizations that offer fully remote work. This has impacted both employee departures and job offer declines and ultimately has affected our ability to attract information technology talent. While some companies have announced plans to return their workforce to the office full-time, those that continue to offer some level of hybrid remote work options fare better in the talent market. According to the Wall Street Journal's account of analysis from Scoop Technologies, a software firm that tracks workplace policies, and People Data Labs, a data technology company, companies that allow at least one day of remote work each week increased staffing at nearly twice the rate in the year ended in May than those with full-time office requirements, according to an analysis of more than 3,600 companies.

Q. GIVEN THESE CHALLENGES PLEASE DESCRIBE THE FUNDING INCLUDED IN THE 2024 BUDGET RELATED TO SUPPORT STRATEGIC GOAL 5 TO ATTRACT, DEVELOP, AND RETAIN TALENT.

A. As explained in Mr. Ludlow's testimony, the 2024 Core Operating Budget includes an $18.7 million funding increase in support of the Attract, Develop, and Retain Talent Strategic Goal (Strategic Goal 5). As explained below, included in this amount is funding to maintain competitive compensation ($16.7 million).[1] To

[1] The $16.7 million figure is the total of the merit and promotional/equity increases and the 2024 budgetary impact of the late 2022/2023 salary equity adjustments (combined $14.1 million), and an increase for

address the hiring and retention challenges described above, it also includes funding to support higher costs related to recruiting (including relocation expenses, recruiter fees, and an increase in the cost of background checks) ($400,000), and for a Talent Program Manager (0.75 FTE) to lead and support the design and improvement of Human Resources programs ($100,000).

In further support of Strategic Goal 5, the 2024 proposed budget also includes increased funding for our intern program to reflect an increase in the number of interns and higher pay rates ($300,000). The intern program is an integral part of our efforts to attract and retain talent. Specifically, of the 35 budgeted interns for the 2024 summer, approximately 14 will be assigned to a department that has headcount addition needs in 2024. Since the program's inception in 2007, 70 interns have converted to full-time employees making this a key pool of talent for the organization. Relatedly, the 2024 budget also includes funding for 2.5 early career technical talent FTEs to meet future talent needs with continued investment in attracting, developing, and retaining talent ($300,000). The addition of these headcount will provide us the flexibility to hire additional interns where a headcount was not previously budgeted for, but the talent is needed, specifically in support of key corporate initiatives.

employee incentive target amounts ($2.6 million), each as explained in more detail below. These amounts correspond to Slide 52 of the Budget Presentation (as defined in the filing letter).

Finally, the 2024 Core Operating Budget funding to attract, develop, and retain talent (Strategic Goal 5) also includes $800,000 of funding for increases in employee benefit costs, primarily related to the increased number of employees in the Defined Contribution Benefit Plan and payroll taxes. Additional detail regarding the ISO's retirement plan offerings, participation numbers, and impact on the budget can be found at Slides 93 and 116-118 of the Budget Presentation (as defined in the filing letter).

Q. HOW DOES THE ISO SEEK TO MAINTAIN THE COMPETITIVENESS OF ITS COMPENSATION?

A. The ISO first identifies the industries with which it competes for talent – in other words, the industries from which the ISO recruits, and to which the ISO loses employees. These are other ISOs and RTOs, for-profit utility companies, energy-related consulting firms, and the broader industry (for positions not specific to utilities).

Next, the ISO defines target ranges of compensation within these markets. For non-exempt, non-union employees, the target market range of compensation is the 50th percentile of the local market. For executives, middle management, and professionals (such as information technology, analyst, and engineering positions), this target is the 50th to 75th percentile of the national market. For middle management and professionals, the following factors led to the determination of this target: nation-wide recruitment; national shortages of

qualified candidates; and difficulty in attracting candidates to the location. For executives, we also considered: complexity of responsibilities; alignment with higher salaries paid in the Northeast; and the limited promotional opportunities in a smaller organization.

Additionally, as discussed in more detail below in the portion of my testimony regarding how we set compensation budgets, the ISO monitors national salary budget survey data, reviews expected compensation budget increases of other ISOs and RTOs, and has retained a compensation consulting firm to assist with an ISO- and job-specific competitive pay analysis. Over the past few years, we added these last two sources (*i.e.*, data from other ISOs/RTOs and the compensation consultant) as additional data points for us to evaluate competiveness.

Specifically, in 2022, because of the challenges I have described we engaged Mercer, a consulting firm that provides strategic compensation and salary planning solutions, to provide a job specific, one-for-one benchmarking analysis. The first phase of the study, completed in late 2022, assessed compensation levels for our most technical engineering and IT roles, approximately 1/3 of our organization. During 2023, we have been assessing another 1/3 of the organization, with a continued focus on IT and other roles requiring significant technical expertise (Phase 2). And, at the completion of Phase 2, we will assess the remainder of the roles in the organization (Phase 3). As challenges to meeting our compensation objectives continue to impact our organizational goals, we have

found that using the Mercer data is a more accurate source to measure competitiveness and appropriate budget increases than relying on generalized national survey data as we have in the past.

Although national surveys provide us important information about average merit increase percentages across all roles within participant companies, job specific benchmarking provides the detail required to understand the competitiveness of our salaries for roles impacted by talent shortages and critical to our ability to achieve our stated goals.

Although we have made progress, our work to realize our compensation philosophy to attract and retain the highest caliber talent is not complete. We are continuing to track the compensation competitiveness of the positions assessed in Phase 1, which continue to move with the market at a faster rate than some other roles. We also need to complete the remaining phases of the benchmarking study. This ongoing work is vital to achieve our compensation goals in furtherance of the ISO's strategic objectives.

COMPONENTS OF COMPENSATION

Q. WHAT ARE THE COMPONENTS OF THE ISO'S COMPENSATION?

A. The ISO has a "pay for performance" compensation program composed of two components for all employees, and an additional long-term component for officers.

The first component is annual base salary, which reflects external competitiveness, the employee's productivity and performance, the qualifications for the position, and internal equity. An employee's annual base salary evolves based on his or her job performance, following the annual performance review process. (These are the merit and promotional increases that will be discussed below.) These changes are necessary for the ISO to meet its compensation philosophy of providing competitive pay, to ensure the ISO is able to meet its critical responsibilities.

The second component of compensation is annual incentive compensation. This program is intended to motivate employees to achieve superior performance on annual business and customer service objectives and goals that are critical to carrying out the organization's mission and achieving its strategic goals. Subject to eligibility criteria, employees may receive an annual award based on a formula that includes company performance, individual performance, annual base salary, and a grade-related salary percentage. Company performance is determined using goals that are set in advance by the Board. These goals are objective and measurable using various operational and performance metrics. And, in addition to incenting timely and on-budget delivery of critical projects, these goals include measures important to supporting organizational goals, including operational excellence; stakeholder engagement; responsive market designs; attracting, developing, and retaining talent; and progress and innovation. Performance

against these goals is measured using a corporate scorecard that is regularly published to all employees, and the calculation of which is verified by the ISO's internal auditors. The Board of Directors then assigns a final score to the achievement of annual goals.

Periodically, each of these components may need adjustments to maintain competitive compensation. In other words, as illustrated by the ISO's salary benchmarking study, if salaries for specific positions within the ISO are no longer competitive, then adjustments outside of the annual compensation cycle may be required. As was the case during the 2023 budget year, if such adjustments are required, the ISO works within its approved budget and utilizes funds available from the CEO Emerging Work Allowance (as explained in Mr. Ludlow's testimony) to fund any required salary adjustments.

For officers, the third and final component of compensation is a long-term incentive plan that is designed to encourage retention by deferring payments for two and one-half years after they are declared. This program is intended to provide compensation in lieu of the stock programs provided by for-profit competitors. These awards are determined using a formula of company performance against specific corporate goals, individual performance, executive-level related salary percentage, and annual base salary. Again, the goals and their performance are determined by the Board. Additionally, before the payout, the

Board conducts a retrospective review of the quality and impact of the goal achievement supporting the award.

Employees are not eligible for either type of award in a year in which they receive a performance rating of "Clearly Below Expectations" or in the event of a major collapse of the bulk electric power system. Similarly, if the ISO underperforms in the management of the bulk electric power system or in its other functions in a manner that is not captured in the goal performance score, the Board of Directors can reduce or eliminate the payment of the awards. The Board has taken this step in the past.

BUDGET FOR MERIT AND PROMOTIONAL/EQUITY SALARY INCREASES AND OTHER COMPENSATION ADJUSTMENTS

Q: PLEASE EXPLAIN THE MERIT AND PROMOTIONAL/EQUITY INCREASE BUDGET.

A. This is a budget that establishes annually the amount that management and the Board can distribute to the entire employee base for salary increases following the annual performance review process that occurs in the first quarter of each year, changes as a result of promotion, and other targeted equity increases (including, as a result of the Mercer study) that are required to maintain salary competiveness. This salary increase process is a critical component of our ability to maintain competitive salaries, which supports our ability to retain our employees in a very competitive marketplace for their talent.

Q. HOW IS THIS BUDGET DETERMINED?

A. The Compensation and Human Resources Committee of the Board of Directors determines this budget annually with the input of several data points. Historically, the Compensation and Human Resources Committee would determine the budget after reviewing national survey data that project what other employers plan for salary increases in the coming year. We gather data from several consulting firm's salary budget surveys. This year, the surveys we reviewed are from Mercer, WorldatWork, WillisTowersWatson, Aon, and The Conference Board. The surveys report the planned salary budget increases of several thousand employers, including nearly 200 energy and utility companies. These surveys provide information on all industries nationwide, as well as the utility industry separately. The ISO utilizes nationwide benchmark data for both all-industry and utility-specific employers, because it recruits many of its employees on a nationwide basis given the unique skill sets required for many of its positions.

Additionally, because many ISOs and RTOs face similar hiring challenges, management reviewed, and the Compensation and Human Resources Committee of the Board of Directors considered expected salary increases of other ISOs and RTOs.

Finally, as explained above, the ISO has engaged a compensation consultant, Mercer, to benchmark critical roles across the organization (and eventually all

positions). Given the more detailed nature of the benchmarking work, management relied most heavily on those results in establishing the compensation budgets and provided such information to the Compensation and Human Resources Committee of the Board of Directors for consideration in approving salary increase budget.

Q. WHAT WERE THE SURVEY RESULTS REGARDING PROJECTED INCREASES FOR 2024?

A. Data received from the surveys show an average merit increase of 3.5% - 3.7% for all industries nationwide, and a range of 3.7% - 4.0% for the utility industry. For promotional increase budgets, data from the surveys show an average of 0.5% - 1.0% for industries nationwide and 0.0% - 0.5% for the energy and utility industry. The data collected from other ISOs and RTOs reflected a higher range for merit increases of 4.0% - 5.0% and for promotion/equity increases 0.75% - 1.5%. Notably, the data from national surveys and other ISOs/RTOs does not account for the fact that ISO-NE's compensation had fallen below competitive ranges for many critical positions. As a result, the promotional/equity survey results likely reflect a narrower adjustment pool (*e.g.*, for company promotions) than the ISO's 2024 promotional/equity increase budget that will cover not only promotional increases, but a much larger set of increases based on the Mercer benchmarking study.

Q. WHAT DID THE COMPENSATION CONSULTANT BENCHMARKING RESULTS INDICATE REGARDING THE ISO'S SALARIES?

A. As noted above, we engaged Mercer to perform a multi-year competitive compensation benchmarking study to examine salary competitiveness across the organization.

The first roles studied in 2022 included many of our most technical engineering, analyst, and information technology roles. We discovered that our base salaries were below market, and requested a higher salary adjustment budget for 2023 than in prior years so that we could begin to address deficits. The 2024 budget funding (as part of the 4.0% promotional/equity budget explained below) includes funding for further adjustments needed to align the salaries of these critical roles with market. Phase 1 of our efforts with Mercer included our most technical and sought after positions, including those where the most turnover was being observed. As we expected, the assessment of those positions showed that our aim to be within the median range for those jobs required that we provide compensation increases. Using contingency funding in the 2023 budget, we made certain critical adjustments but have not fully been able to address the identified deficiencies.

We are currently in the process of conducting Phase 2 of the analysis, covering an additional 200+ employees. While at the time of this filing, the final Phase 2 assessment is not yet complete, early insights from Mercer are trending towards

results we were anticipating: that Phase 2 will show less of a competitive gap than the Phase 1 roles, while still requiring some significant adjustments (as reflected in the 2024 budget). This correlation is to be expected as the phases of the Mercer analysis were designed to start with those positions most in demand and include in later phases those jobs more easily filled and that we expect will already be closer to the current market median. In 2024, we will conduct Phase 3 of the analysis, covering all remaining employees.

Q. WHAT ARE THE ISO'S MERIT AND PROMOTIONAL/EQUITY INCREASE BUDGETS FOR 2024?

A. After reviewing the results of the Mercer benchmarking survey, national salary budget survey data, and other ISO/RTO data, the Compensation and Human Resources Committee approved a merit increase budget of 4.0% (which is consistent with the higher end of the survey data and ISO/RTO data) and a promotional/equity increase budget of 4.0% (which is higher than survey results as a result of adjustments based on the Mercer benchmarking results). The overall increase (8.0%) is necessary to fund typical market-driven salary increases, and to make the appropriate adjustments to base salaries, as informed by the Mercer benchmarking study, to address the competitive shortfalls explained above.

As noted above, although we have made progress addressing the discrepancies identified in Phase 1 of the Mercer study, we still have targeted adjustments to make to close the identified competitive gap. Furthermore, we are still awaiting

final results of Phase 2 and have not started Phase 3. Although we expect the Phase 2 and 3 results to require less significant adjustments, we do expect that certain positions will require equity adjustments. The 8.0% budgeted salary increase is based on the actual dollars needed to close the rest of the gap for Phase 1, and estimates for salary adjustments in 2024 based on Phase 2 and Phase 3 results. Importantly, however, because the benchmarking study is job specific, the ISO will only make equity adjustments where the results indicate a market lag. Additionally, when developing the 4.0% promotional/equity increase (for phases of the job benchmarking study that have not been completed yet), we did not use a blanket assumption regarding positions that would require a salary equity adjustment. In other words, we recognized that certain positions in the remaining phases likely will not require the same types of adjustments that Phase 1 positions required.

Finally, if the results of the final two study phases indicate that lower salary adjustments than budgeted are required, then any additional funds will be returned to the CEO Emerging Work Allowance.

Q. ARE THERE OTHER COMPENSATION IMPACTS REFLECTED IN THE 2024 BUDGET?

A. Yes. In addition to the typical merit and promotional/equity increase budget, the 2024 budget includes a 2.0% increase in employee salaries which reflects the impact of late 2022 and 2023 salary equity adjustments. (This amount is included

in the $14.1 million figure explained above). As explained above, the first phase of the Mercer study, which was completed in late 2022, required adjustments for the salaries of several critical roles at the ISO. In late 2022 and 2023, we began addressing these discrepancies using the approved salary budgets and funds from the CEO Emerging Work Allowance. The 2.0% increase is the 2024 impact of the late 2022/2023 adjustments. In other words, the adjusted base salaries require 2024 budget adjustments.

Additionally, beginning in 2023, based on competitive analysis, we have adjusted how we budget for employee incentive amounts to allow a greater percentage of the employee population to fully qualify for the target award they are eligible for under the terms of the incentive plan. Historically, as a budgetary practice, we have restricted the number of employees that received a "maximum" award, but this conservative approach further exacerbated the compensation competiveness issues that were highlighted by the Mercer benchmarking study. Additionally, in 2023, the Board approved increases to the plan targets in both the Executive Annual Incentive Plan, and in the Executive Deferred Incentive Plan, based on competitive analysis. (The $2.6 million figure noted earlier in my testimony covers both changes discussed in this paragraph).

HEALTH INSURANCE PROGRAM

Q. DOES THE BUDGET INCLUDE ANY INCREASES IN HEALTH INSURANCE COSTS?

A. No, for the 2024 plan year, the medical and dental plans were renewed with no plan premium increases.

Q. DO ISO-NE EMPLOYEES PAY THEIR FAIR SHARE OF HEALTH INSURANCE COSTS?

A. Yes. As part of maintaining a competitive compensation program the ISO has established and administers competitive benefit programs, including the selection, design, and administration of all health and welfare benefits (*e.g.*, medical, life insurance, etc.). The Human Resources Department benchmarks all benefits on an ongoing basis. In engaging such analysis, the Human Resources Department has found that the amount of employee contributions are in line with similarly situated companies.

FRAMEWORK FOR DETERMINING EXECUTIVE COMPENSATION

Q. WHAT IS THE FRAMEWORK FOR THE ISO'S DETERMINATION OF EXECUTIVE COMPENSATION?

A. The ISO is a not-for-profit company under Section 501(c)(3) of the Internal Revenue Code. The Internal Revenue Code and related Treasury regulations require that the compensation paid to executive officers meet a standard of "reasonableness." Specifically, compensation must fall within a range of

competitive practices for total compensation paid by similarly-situated organizations, both taxable and tax-exempt, for functionally comparable positions.

The Internal Revenue Code allows a tax-exempt organization to establish a "rebuttable presumption" of reasonableness. This places the onus on the Internal Revenue Service to show that compensation is unreasonable. The rebuttable presumption requires that the compensation arrangement be approved in advance by independent individuals (*e.g.*, the Board of Directors), that the Board has obtained and relied upon appropriate data as to comparability (*i.e.*, compensation paid by similarly-situated entities – taxable and tax-exempt – for positions with a similar scope of responsibility), and that the Board adequately documents the basis for its determination.

Q. HOW HAS THE ISO ATTEMPTED TO SECURE THE BENEFIT OF THE PRESUMPTION OF REASONABLENESS?

A. The ISO's Board of Directors approves all executive compensation, and documents the basis for its determination. In order to ensure that the Board has obtained and relied upon appropriate data as to comparability, the ISO retains an outside compensation advisor, Mercer. Mercer prepares an opinion annually on the reasonableness of the ISO's executive compensation, using as comparators other ISOs and RTOs, as well as for-profit utilities and other companies, based on their organizational character/complexity, geographic location, role of the

incumbent, and labor market for the executive team. The data for these groups is then blended to create a composite market reference as an overall benchmark. This composite reflects the fact that the ISO competes for executive talent in the energy industry, as well as in the broader general industry for positions in areas like Legal, Finance, and Human Resources.

Q. WHAT IS THE BOARD'S PROCESS FOR DETERMINING EXECUTIVE COMPENSATION?

A. This process occurs in the first quarter of each year. In determining executive compensation, the Board first asks the Compensation and Human Resources Committee to consider appropriate compensation. Both the Compensation and Human Resources Committee, and then the Board, consider the CEO's appraisal of each executive's experience, responsibilities, performance, specific skill set, and contribution to strategic goal achievement (and, for the CEO, the Chair's appraisal of the same factors as related to the CEO), and the ISO's financial and operational achievement. The Board then provides its compensation recommendations to Mercer for an opinion on reasonableness, prior to implementation.

Q. WHAT WAS THE CONCLUSION OF MERCER'S MOST RECENT REASONABLENESS OPINION?

A. Mercer's most recent reasonableness opinion concluded that the proposed 2023 total compensation for executives was reasonable.

Q. HOW WILL 2024 EXECUTIVE COMPENSATION BE DETERMINED?

A. The Board will use the same process described above, involving the Compensation and Human Resources Committee's review and approval followed by full Board approval of executive compensation. Likewise, the Board will employ Mercer to ensure the reasonableness of 2024 compensation. While 2024 compensation has not yet been determined, 2023 executive compensation will be the base for 2024 compensation.

In 2023 the Board, based on Mercer's recommendations around competitiveness, approved changes to the executive incentive programs (effective on January 1, 2024). These changes did not change the overall structure of the incentive programs, but over a two-year period (2024 and 2025), increased the award opportunities by increasing the salary and performance percentages applied in the formula. The Board has not authorized any wholesale changes to the compensation programs described above. After accounting for the executive incentive program plan changes that I have just described, preliminary information provided by Mercer, suggests that it is reasonable to presume that the 2024 executive compensation will be similar to the 2023 compensation, with minimal changes necessary to maintain competitiveness.

Q. IS THE ISO'S EXECUTIVE COMPENSATION PUBLICLY DISCLOSED?

A. Yes. The ISO discloses the total compensation for each executive in its Internal Revenue Service Form 990, a copy of which the ISO is required to provide to

anyone who requests it. The ISO also includes information regarding base salary for each officer on page 104 of its annual FERC Form 1.

Q. IS DIRECTOR COMPENSATION REVIEWED FOR REASONABLENESS?

A. Yes, similar to the reasonableness analysis for executive compensation, the ISO engages Mercer to provide a reasonableness opinion for director compensation. Mercer's most recent reasonableness opinion concluded that the ISO's director compensation, including the increases included in the proposed 2024 operating budget, was reasonable. Mercer's recent analysis also suggested that an adjustment for Board of Director retainer fees was advisable to maintain competitiveness. As a result, the proposed 2024 operating budget includes $100,000 of funding for Board retainer adjustments.

CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed as of October 13, 2023.

Kathleen deCastro

EXHIBIT 5

Exhibit 5

ISO New England Inc.
2024 Capital Projects Schedule

($000's)	Project-To-Date	Current Year (2023) Cost to Complete [1]	2024 Cost to Complete	Future Cost to Complete	Total Project Costs		Estimated Complete Date
Capital Projects - Approved Charters							
. Day-Ahead Ancillary Service Improvements	1,898.0	2,463.6	3,811.6	951.9	9,125.1		03/25
. nGEM Software Development Part III	9.8	1,372.4	2,500.0	585.6	4,467.8		03/25
. Operating System Server Upgrade Phase I	-	1,167.5	1,215.5	-	2,383.0		07/24
. Solar Do-Not-Exceed Dispatch Phase II	252.8	657.2	920.5	-	1,830.5		10/24
. Internal Market Monitoring Data Analysis Phase IV	103.9	564.1	519.0	-	1,187.0		05/24
. Energy Management System Short-term Load Forecast Replacement	48.9	733.1	371.1	-	1,153.1		07/24
. IT Asset Workflow Integration and Updates	446.8	372.2	238.0	-	1,057.0		05/24
. Energy Management System Host Monitoring Software Replacement	50.2	198.5	31.9	-	280.6		01/24
. Settlement Technology Improvements Project	132.0	383.2	27.3	-	542.5		03/24
Sub Total Projects with Approved Charters	2,942.4	7,911.8	9,634.8	1,537.5	22,026.6		
Planning/Conceptual Design [2]							
. nGEM Real-Time Market Clearing Engine Implementation	1,891.8	1,971.9	6,000.0	7,000.0	16,863.7		06/25
. FERC Order 881 Compliance		1,270.0	3,300.0	3,200.0	7,770.0		06/25
. CIP Electronic Security Perimeter Redesign Phase II	25.6	500.0	2,000.0	-	2,525.6		12/24
. Enterprise Resource Planning System Replacement	-	194.6	1,600.0	700.0	2,494.6		03/25
. Resource Capacity Accreditation	0.9	199.1	1,000.0	2,000.0	3,200.0		12/25
. Microsoft 365 Service Adoption	-	100.0	1,000.0	1,000.0	2,100.0		09/25
. 2024 Issue Resolution Project	-	-	1,000.0	-	1,000.0		12/24
. Long-term FTRs	907.5	-	-	-	907.5	[3]	TBD
. FERC Order 2222	-	-	500.0	6,700.0	7,200.0		12/26
. Privileged Account Management Security Enhancements Phase II	-	-	500.0	-	500.0		12/24
. Other Emerging Work	-	-	1,631.2	-	1,631.2		
. Sub-Total Conceptual Design	2,825.8	4,235.6	18,531.2	20,600.0	46,192.6		
. Non-Project Capital Expenditures	-	-	5,334.0	-	5,334.0		
. Capitalized Interest and Loan Fees	-	-	1,500.0	-	1,500.0		
Total Capital Projects (Including Capitalized Interest)	**$ 5,768.2**	**$ 12,147.4**	**$ 35,000.0**	**$ 22,137.5**	**$ 75,053.1**		

[1] The amounts under the "Current Year (2023) Cost to Complete" list only includes those projects with budgeted costs in 2024 and beyond.

[2] The 2024 Budget for Projects in Planning and Conceptual Design is not final. Once the project scope and timeline have been determined the budget will be finalized.

[3] The Long-term FTRs project has been indefinitely deferred pending the development of appropriate credit requirements.

EXHIBIT 6

CROSS-REFERENCE TABLE
(showing location in the ISO's filing of applicable items from
Statements AA - BM in Section 35.13(h))

Statement AA	Balance sheets: See balance sheets from ISO's 2022 Form 1 (Exhibit 7).
Statement AB	Income statements: See income statements from ISO's 2022 Form 1 (Exhibit 7 hereto). A comparison of budgeted net operating expenses for 2024 with budgeted 2023 operating expenses is contained in Exhibit 3, RCL-5, Schedules 3 and 4.
Statement AC	Retained earnings statement: Not applicable.
Statement AD	Cost of plant: The ISO's "plant" consists of office furniture and equipment (Account 391). The ISO does not own generation, transmission or distribution equipment. See 2022 ISO Form 1 balance sheet (Exhibit 7) at page 110, lines 2 and 4. The three "functions" of the ISO (and reflected in Section IV.A. of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff")) are the three Services[1] provided by the ISO.
Statement AE	Accumulated depreciation and amortization: See 2022 ISO Form 1 balance sheet (Exhibit 7) at page 110, line 5.
Statement AF	Specified deferred credits: Not applicable.
Statement AG	Specified plant accounts (other than plant in service): Not applicable, because the ISO is not seeking a return on rate base.
Statement AH	Operation and maintenance expenses: These are functionalized among the Services in Exhibit 3. See ISO's 2022 Form 1 pages 320-323 Electric Operation & Maintenance Expenses (Exhibit 7).
Statement AI	Wages and salaries: These are functionalized among the Services in Exhibit 3, RCL-3, Schedules 2.0 and 4.0. A comparison of staffing levels for 2023 and 2024 is contained in Exhibit 3, RCL-5, Schedule 5.
Statement AJ	Depreciation and amortization (lease and sublease) expenses: These are functionalized among the Services in Exhibit 3, RCL-3, Schedule 3.0. Depreciation and amortization rates are discussed in

[1] Capitalized terms not otherwise defined in this Exhibit have the meanings ascribed thereto in the Tariff.

	Section I.C.2 of the transmittal letter and in Mr. Ludlow's testimony (Exhibit 3).
Statement AK	Taxes other than income taxes: See Exhibit 3, RCL-5, Schedules 1 and 2.
Statement AL	Working capital: The Commission has authorized a revolving line of credit of $20 million for the ISO's working capital needs. *See* 183 FERC ¶ 62,113 (2023). Due to the nature of the limited plant owned by the ISO, the concepts of supplies, fuel supplies, plant materials and operating supplies are not applicable to the ISO. Prepaid expenses for the ISO consist mainly of insurance costs.
Statement AM	Construction work in process. See ISO's 2022 Form 1 page 216 Construction Work in Progress – Electric (Exhibit 7).
Statement AN	Notes payable: see description of notes authorized in 109 FERC ¶ 62,194 (2004); 140 FERC ¶ 62,172 (2012); 140 FERC ¶ 62,173 (2012); 144 FERC ¶ 62,087 (2013). See ISO's 2022 Form 1 pages 256-257 Long-Term Debt (Exhibit 7).
Statement AO	Rate for allowance for funds used during construction: not applicable
Statement AP	Federal income tax deductions - interest: The ISO is exempt from federal income taxation.
Statement AQ	Federal income tax deductions - other than interest: The ISO is exempt from federal income taxation.
Statement AR	Federal tax adjustments: The ISO is exempt from federal income taxation.
Statement AS	Additional state income tax deductions: The ISO pays no state income taxes.
Statement AT	State tax adjustments: The ISO pays no state income taxes.
Statement AU	Revenue credits: Not applicable with respect to generation or transmission. The 2024 Revenue Requirement reflects a decrease from the 2022 true-up, as described in Section I.C.3 of the filing letter, and Exhibit 3, RCL-2.
Statement AV	Rate of return: Not applicable because the ISO seeks no rate of return.

Statement AW	Cost of short-term debt: No short-term debt.
Statement AX	Other recent and pending rate changes: The ISO has no operating revenues that are currently subject to refund.
Statement AY	Income and revenue tax rate data: Not applicable because the ISO pays no federal or state income tax, and no revenue taxes.
Statement BA	Wholesale customer rate groups: For each Service (i.e., each Rate Schedule), the cost of service equals the revenues from the customer group, as ensured by the true-up mechanism contained in Section IV.A.2.2 of the Tariff. For Rate Schedule 1, all transmission customers under the Open Access Transmission Tariff (Section II of the Tariff); for Rate Schedule 2, all Market Participants that participate in the New England Markets for energy; for Rate Schedule 3, all Market Participants that have load, and non-Participant Point-to-Point Transmission Service customers.
Statement BB	Allocation demand and capability data: Not applicable because the ISO's revenue requirement is not based on generation or transmission expenses. The denominators used in the rate design for each Service are explained in Section I.E of the transmittal letter.
Statement BC	Reliability data: Not applicable because the ISO's revenue requirement is not based on generation or transmission expenses. The denominators used in the rate design for each Service are explained in Section I.E of the filing letter.
Statement BD	Allocation energy and supporting data: Not applicable because the ISO's revenue requirement is not based on generation expenses. The denominators used in the rate design for each Service are explained in Section I.E of the transmittal letter.
Statement BE	Specific assignment data: See Exhibit 3 for direct allocations to the three rate schedules in Section IV.A of the Tariff.
Statement BF	Exclusive-use commitments of major power supply facilities: Not applicable.
Statement BG	Revenue data to reflect changed rates: See Sections I.C and I.E of the transmittal letter. The entire projected revenue requirement for a Service (discussed in Exhibit 3) is paid for by the corresponding

customer group described in the Statement BA discussion, above. The billing determinants for each Service are discussed in Section I.E of the filing letter. The ISO has no fuel clause.

Statement BH	Revenue data to reflect present rate: See Sections I.C. and I.E of the filing letter.
Statement BI	Fuel cost adjustment factors: not applicable.
Statement BJ	Summary cost tables: See Exhibit 3.
Statement BK	Electric utility department cost of service: See Exhibit 3.
Statement BL	Rate design information: See Section I.E of the filing letter.
Statement BM	Construction program statement: Not applicable.

EXHIBIT 7

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	445,600,781	438,988,853
3	Construction Work in Progress (107)	200	42,940,388	30,858,057
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		488,541,169	469,846,910
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	381,261,601	368,746,014
6	Net Utility Plant (Enter Total of line 4 less 5)		107,279,568	101,100,896
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		107,279,568	101,100,896
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		2,124,397	2,337,576
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)		20,701	739
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,145,098	2,338,315
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		178,315,911	160,676,228
36	Special Deposits (132-134)		38,188,771	30,852,873
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		39,313,634	66,114,378
41	Other Accounts Receivable (143)			
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)			
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)			
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227		
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
57	Prepayments (165)		7,359,452	5,977,593
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)		333,409,056	244,959,963
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)		20,701	739
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		20,701	739
67	Total Current and Accrued Assets (Lines 34 through 66)		596,587,324	508,581,535
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		509,740	575,871
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	24,666,908	76,241,114
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	638,678	677,981
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234		
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		25,815,326	77,494,966

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		731,827,316	689,515,712

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250		
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(49,899)	(140,461)
16	Total Proprietary Capital (lines 2 through 15)		(49,899)	(140,461)
17	LONG-TERM DEBT			
18	Bonds (221)	256	39,925,000	43,105,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	50,000,000	50,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		89,925,000	93,105,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		363,676	627,739
27	Accumulated Provision for Property Insurance (228.1)			

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)		24,666,908	74,260,773
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)			
35	Total Other Noncurrent Liabilities (lines 26 through 34)		25,030,584	74,888,512
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		158,587,433	169,086,799
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)			
41	Customer Deposits (235)		414,171,375	311,694,947
42	Taxes Accrued (236)	262		
43	Interest Accrued (237)		491,948	334,464
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)			
48	Miscellaneous Current and Accrued Liabilities (242)		[a]25,580,042	24,440,378
49	Obligations Under Capital Leases-Current (243)		495,925	608,277
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		599,326,723	506,164,865

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	17,594,908	15,497,796
60	Other Regulatory Liabilities (254)	278		
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)			
64	Accum. Deferred Income Taxes-Other (283)			
65	Total Deferred Credits (lines 56 through 64)		17,594,908	15,497,796
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		731,827,316	689,515,712

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousCurrentAndAccruedLiabilities

On September 30, 2022, ISO New England Inc. entered into a settlement agreement with the Federal Energy Regulatory Commission's Office of Enforcement to resolve a dispute stemming from the delay in the commercialization of the Salem Harbor Power Development generating facility in Massachusetts (formerly known as Footprint Power) and its receipt of capacity payments. As outlined in the settlement agreement, a $500,000 penalty that was paid in October 2022, was funded through a reduction in executive compensation. In the Form 1 filing, the penalty payment resulted in a reduction in accrued compensation made via account 242 Miscellaneous Current and Accrued Liabilities.

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF INCOME

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
1	UTILITY OPERATING INCOME							
2	Operating Revenues (400)	300	209,827,909	201,521,263			209,827,909	201,521,263
3	Operating Expenses							
4	Operation Expenses (401)	320	133,046,341	126,558,628			133,046,341	126,558,628
5	Maintenance Expenses (402)	320	50,452,828	46,761,756			50,452,828	46,761,756
6	Depreciation Expense (403)	336	25,007,982	26,182,047			25,007,982	26,182,047
7	Depreciation Expense for Asset Retirement Costs (403.1)	336						
8	Amort. & Depl. of Utility Plant (404-405)	336	39,303	39,303			39,303	39,303
9	Amort. of Utility Plant Acq. Adj. (406)	336						
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)							
11	Amort. of Conversion Expenses (407.2)							
12	Regulatory Debits (407.3)							
13	(Less) Regulatory Credits (407.4)							
14	Taxes Other Than Income Taxes (408.1)	262						
15	Income Taxes - Federal (409.1)	262						
16	Income Taxes - Other (409.1)	262						
17	Provision for Deferred Income Taxes (410.1)	234, 272						

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272						
19	Investment Tax Credit Adj. - Net (411.4)	266						
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,475	325			1,475	325
21	Losses from Disp. of Utility Plant (411.7)							
22	(Less) Gains from Disposition of Allowances (411.8)			0				
23	Losses from Disposition of Allowances (411.9)							
24	Accretion Expense (411.10)							
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		208,544,979	199,541,409			208,544,979	199,541,409
27	Net Util Oper Inc (Enter Tot line 2 less 25)		1,282,930	1,979,854			1,282,930	1,979,854
28	Other Income and Deductions							
29	Other Income							
30	Nonutilty Operating Income							
31	Revenues From Merchandising, Jobbing and Contract Work (415)							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)							
33	Revenues From Nonutility Operations (417)							
34	(Less) Expenses of Nonutility Operations (417.1)							
35	Nonoperating Rental Income (418)							

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
36	Equity in Earnings of Subsidiary Companies (418.1)	119						
37	Interest and Dividend Income (419)		984,014	163,971				
38	Allowance for Other Funds Used During Construction (419.1)							
39	Miscellaneous Nonoperating Income (421)							
40	Gain on Disposition of Property (421.1)							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		984,014	163,971				
42	Other Income Deductions							
43	Loss on Disposition of Property (421.2)							
44	Miscellaneous Amortization (425)							
45	Donations (426.1)		18,250	23,383				
46	Life Insurance (426.2)							
47	Penalties (426.3)							
48	Exp. for Certain Civic, Political & Related Activities (426.4)							
49	Other Deductions (426.5)							
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		18,250	23,383				
51	Taxes Applic. to Other Income and Deductions							
52	Taxes Other Than Income Taxes (408.2)	262						
53	Income Taxes-Federal (409.2)	262						

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
54	Income Taxes-Other (409.2)	262						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272						
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272						
57	Investment Tax Credit Adj.-Net (411.5)							
58	(Less) Investment Tax Credits (420)							
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)							
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		965,764	140,588				
61	Interest Charges							
62	Interest on Long-Term Debt (427)		2,167,356	2,027,112				
63	Amort. of Debt Disc. and Expense (428)		66,130	70,420				
64	Amortization of Loss on Reaquired Debt (428.1)							
65	(Less) Amort. of Premium on Debt-Credit (429)							
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)							
67	Interest on Debt to Assoc. Companies (430)							
68	Other Interest Expense (431)		15,208	22,910				
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)							
70	Net Interest Charges (Total of lines 62 thru 69)		2,248,694	2,120,442				

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		0	0				
72	Extraordinary Items							
73	Extraordinary Income (434)							
74	(Less) Extraordinary Deductions (435)							
75	Net Extraordinary Items (Total of line 73 less line 74)							
76	Income Taxes-Federal and Other (409.3)	262						
77	Extraordinary Items After Taxes (line 75 less line 76)							
78	Net Income (Total of line 71 and 77)		0	0				

STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
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STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
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STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
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Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF CASH FLOWS

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	0	0
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	25,007,982	26,182,047
5	Amortization of (Specify) (footnote details)		
8	Deferred Income Taxes (Net)		
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(70,047,493)	(51,745,863)
11	Net (Increase) Decrease in Inventory		
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	45,401,042	117,888,372
14	Net (Increase) Decrease in Other Regulatory Assets	51,574,206	32,485,297
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Net (increase) / Decrease in Derivative Asset Instruments	(19,962)	(412)
18.2	Net Increase / (Decrease) in Accumulated Other Comprehensive Income	90,562	71,012
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	52,006,337	124,880,453
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(31,186,654)	(27,218,253)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		

STATEMENT OF CASH FLOWS			
Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(31,186,654)	(27,218,253)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(31,186,654)	(27,218,253)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)		
72	Payments for Retirement of:		
73	Long-term Debt (b)	(3,180,000)	(3,180,000)
74	Preferred Stock		

STATEMENT OF CASH FLOWS			
Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
75	Common Stock		
76	Other (provide details in footnote):		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(3,180,000)	(3,180,000)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	17,639,683	94,482,200
88	Cash and Cash Equivalents at Beginning of Period	160,676,228	66,194,028
90	Cash and Cash Equivalents at End of Period	178,315,911	160,676,228

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

The accompanying financial statements on pages 110 through 121 (excluding pages 116, 118, and 119) of this Form 1 Report of ISO New England Inc. were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles ("GAAP").

The primary differences between the Company's FERC financial statements and GAAP financial statements are:

(1)The gross presentation of accounts receivable and accounts payable;

(2)The presentation of regulatory assets and regulatory liabilities in the balance sheet under GAAP requirements differs from FERC requirements, although no differences exist for the reporting periods;

(3)The segregation of unamortized debt expenses from property and equipment;

(4)The inclusion of debt issuance costs directly attributable to issuing a debt instrument as part of unamortized debt expenses and bonds on the FERC balance sheet;

(5)The presentation of an interest rate cap agreement as a Derivative Asset-Hedge on the Form 1 balance sheet instead of Deferred charges and Other Assets for the unamortized balance and fair market value, respectively.

(6)Restricted cash on deposit, reported as Special Deposits, includes no distinction in classification between current and long-term;

(7)Accrued compensation, reported as Miscellaneous Current and Accrued Liabilities, includes no distinction in classification between current and long-term;

(8)There is no current liability classification of the current portion of long-term debt in the FERC balance sheet;

(9)The presentation of the difference between book value and fair market value of an interest rate cap agreement as Accumulated Other Comprehensive Income on the Form 1 Balance Sheet instead of Deferred Income;

(10)Combined Deposit payable and Restricted cash on deposit payable into Customer Deposits on the Form 1, with no distinction in classification between current and long-term;

(11)The presentation of term loan fees as Other Interest Expense on the Form 1 Statement of Income instead of Administrative and other expense; and

(12)The presentation of the change in Special Deposits, Customer Deposits, and Other Assets on the statements of cash flows as an operating activity instead of a financing activity as required by US GAAP;

(13) The inclusion of Right-of-use asset, both current and non-current, as Property and Equipment on the Form 1 balance sheet.

The notes below are excerpts from the Company's GAAP basis financial statements as of and for the years ended December 31, 2022 and 2021. The following disclosures contain information in accordance with GAAP reporting requirements. As such, due to the differences between FERC and GAAP reporting requirements, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

1. Summary of Significant Accounting Policies Description of Business

ISO New England Inc. (the "Company" or "ISO") is the Regional Transmission Organization ("RTO") for New England in compliance with the requirements of the Federal Energy Regulatory Commission ("FERC"). On January 1, 2013, the ISO became the central counterparty to market transactions that flow through the ISO. The change to central counterparty was the result of a FERC rulemaking designed to afford the ISO and market participants more protection in bankruptcy. The ISO's assumption of the central counterparty role did not have a material effect on the ISO's settlement of the markets or on business operations.

The ISO's mission, in collaboration with its stakeholders, is to ensure that New England has reliable, competitively priced wholesale electricity through three interconnected responsibilities: managing the operation of the region's high-voltage power grid; administering the region's billion-dollar competitive markets for buying and selling wholesale electricity; and engaging in planning, studies, and analysis to make sure New England's electricity needs will be met over the next ten years.

The ISO is governed by an independent board of directors and is regulated by FERC. FERC's mandated or approved rules are detailed in the ISO New England Inc. Transmission, Markets, and Services Tariff (the "Tariff" or "ISO Tariff").

On January 13, 2014, the ISO, along with several Reliability Coordinators (as that term is defined by the North American Electric Reliability Corporation ("NERC")), became a member of EIDSN, Inc. ("EIDSN"). EIDSN is a 501(c)(6), nonstock, nonprofit corporation that was established to, among other things, facilitate the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among its members and/or other applicable parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk power system.

Basis of Accounting and Presentation

The accompanying financial statements have been prepared on an accrual basis of accounting in accordance with U.S. generally accepted accounting principles and Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 980, *Regulated Operations,* and FASB ASC 958, *Not-for-Profit Entities*.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include the useful lives of fixed assets; and assumptions utilized in the accounting for employee benefit obligations such as discount rates, return on assets, fair value of investments and other contingencies.

Regulatory Accounting

The Company's financial statements are prepared in accordance with generally accepted accounting principles for rate-regulated entities. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the ISO concludes that it is probable future revenues will be provided to permit recovery of the previously incurred cost. A regulatory liability is recorded when amounts that have been recorded by the ISO are likely to be refunded to customers through the rate-setting process.

Cash and Cash Equivalents

The Company considers cash on hand and short-term marketable securities with original maturities of three months or less to be cash equivalents. The cash equivalents at December 31, 2022 and 2021 were held in overnight repurchase agreements, money market accounts as well as in direct and indirect obligations of the United States, with original maturities of three months or less.

Restricted Cash on Deposit

The balance of approximately $39,331,000 and $30,853,000 at December 31, 2022 and 2021, respectively, recorded as restricted cash on deposit, represents the Forward Capacity Market Forfeited Funds, the Congestion Revenue Fund, and Cluster Study Funds. The balance has a corresponding liability on the accompanying Statements of Financial Position. The restricted cash on deposit at December 31, 2022 and 2021 was held in overnight repurchase agreements and in direct and indirect obligations of the United States of America, with original maturities of three months or less.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Statements of Financial Position that sum to the total of the same such amounts shown in the Statements of Cash Flows.

	December 31,	
	2022	2021
Cash and cash equivalents	$ 178,316,000	$ 160,677,000
Restricted cash on deposit	21,268,000	16,633,000
Restricted cash on deposit, net of current portion	18,063,000	14,220,000
Total	$ 217,647,000	$ 191,530,000

The cash and cash equivalents and restricted cash on deposit are recorded at fair market value and are classified as Level 1.

Accounts Receivable and Accounts Payable

In the course of bulk power transactions administered by the Company on behalf of market participants ("Participants"), amounts for energy purchased and sold among Participants become payable to and receivable from such Participants. The Company summarizes and prices the energy transactions and provides an invoice or remittance advice to each Participant that summarizes the amount either receivable from or payable to each Participant twice per

week.

Accounts payable on the accompanying Statements of Financial Position are segregated between (i) the amounts owed for energy transactions and transmission, for which the ISO functions as paying agent, and are included in Accounts payable as "Settlement, net," and (ii) the administrative expenses incurred by the Company in the course of operations. The reference to "Settlement, net" is used due to the nature of billing and payment for the amounts owed for energy transactions and transmission markets, and represents the Participants' net amount due, less any amounts that may have been owed to them.

The net unbilled receivables, the majority of which have been determined from the settlement process, include those amounts that will be billed and included in the invoice or remittance advice to Participants on subsequent invoices issued twice per week. The balance at the end of the year primarily represents ISO Tariff revenues. The net payables and receivables for these energy transactions are settled with the Participants in the same week.

Property and Equipment in Service and Work in Process

Property and equipment in service is stated at cost, net of accumulated depreciation and amortization. The Company capitalizes the interest and fees associated with borrowings that the Company has entered into for the acquisition of assets related to a project that has a material effect on the Company's financial position as required by FASB ASC Topic 980, *Regulated Operations*.

The Company capitalizes the cost of payroll, payroll-related costs and third-party consulting fees incurred in the direct development or enhancement of solutions as internal-use software. Development costs incurred during the preliminary project stage or costs incurred for requirements gathering, data conversion activities, training, maintenance and minor enhancements are expensed as incurred. Development costs incurred for the coding, configuration, interfacing, automation and testing of new functionality after the preliminary project stage is complete are capitalized. Capitalized software costs are amortized on a straight-line basis over three to five years based on the nature and estimated useful life of the applicable solution. Amortization of capitalized software costs is included in depreciation and amortization expense within the Statements of Activities.

Depreciation and Amortization

Depreciation is generally computed using the straight-line method over an estimated useful life ranging from three years to twenty-five years (e.g., computer hardware, software and accessories - three to five years; software development costs - three to five years; vehicles - three to seven years; furniture and fixtures and machinery and equipment - seven years; building and building improvements - one to twenty-five years or remaining life of the building improvement; and building - twenty-five years). Capitalized interest and fees are amortized over the same useful life of the asset to which it pertains, principally software development costs and building. No depreciation is recorded for assets classified as work in process until the assets are placed into service (Note 3).

Leases

The Company determines whether an arrangement is a lease at the inception of the arrangement based on the terms and conditions in the contract. A contract contains a lease if there is an identified asset and the Company has the right to control the asset.

Right-of-use ("ROU") assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at the commencement date based on the present value of lease payments over the lease term. Most of the Company's leases do not provide the lessor's implicit rate; the Company uses its incremental borrowing rate at the commencement date in determining the present value of lease payments. Lease terms include options to extend the lease when it is reasonably certain those options will be exercised. The Company has not entered into any leases that contain a residual value guarantee or a variable lease payment. Leases with an initial term of 12 months or less are not recorded on the Statements of Financial Position, and lease expense is recognized on a straight-line basis over the lease term.

The Company has lease agreements with lease and non-lease components, which are accounted for as a single lease component for all asset classes. Additionally, for equipment leases, the portfolio approach is applied to account for the operating lease ROU assets and lease liabilities. In the Statements of Activities, lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

Deferred Charges and Regulatory Assets and Liabilities

As a regulated entity, the Company, in appropriate circumstances, establishes regulatory assets or liabilities, and thereby defers the Statements of Activities impact of certain charges or revenues because it is probable to be collected or refunded through future customer billings.

The Company incurred costs with the purchase of land located at Sullivan Road and Helmsford Way. The costs of the land at both locations, which were deferred, are being amortized, and the current year amortization is included in the current year's filing pursuant to Section IV.A, Recovery of ISO Administrative Expenses, of the ISO Tariff. The land located at Sullivan Road is fully amortized. The remaining cost for the land located at Helmsford Way will be collected in future filings.

In 2020, the Company filed for a change to the general true-up provision in the ISO Tariff to allow for special purpose funding which became effective January 1, 2021. The Company may maintain any special purpose funding surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism until such time as the special purpose needs are completed and any remaining funds will be included in the Revenue Requirement adjustment. As such, the amount from 2021 has been included in the Revenue Requirement adjustment and there is no special purpose funding as of December 31, 2022.

The following table is a detail of the deferred charges, regulatory assets and liabilities balances as presented in the accompanying Statements of Financial Position at December 31:

Deferred charges	2022	2021
Land located on Helmsford Way	$ 639,000	$ 678,000
Interest Rate Cap	70,000	141,000
	$ 709,000	$ 819,000

Regulatory assets - current	2022	2021
Actual 2020 under collection	$ -	$ 1,980,000
	$ -	$ 1,980,000

Regulatory assets, net of current portion	2022	2021
Asset related to pension and postretirement benefit liabilities (Note 5)	$ 24,667,000	$ 74,261,000
	$ 24,667,000	$ 74,261,000

Regulatory liability - current	2022	2021
Actual 2020 over collection-special purpose funding	$ -	$ 909,000
Actual 2021 over collection	14,589,000	-
Mark to Market Interest Rate Cap	21,000	-
	$ 14,610,000	$ 909,000

Regulatory liability, net of current portion	2022	2021
Actual 2021 over collection	$ -	$ 14,589,000
Actual 2022 over collection	3,006,000	-
	$ 3,006,000	$ 14,589,000

Income Taxes

The Company is an entity organized as a non-stock corporation under the General Corporation Law, as amended, of the State of Delaware. The Company has been recognized by the Internal Revenue Service as an organization described in Internal Revenue Code (IRC) 501(c)(3) and is generally exempt from income taxes under IRC Section 501(a). The Company has determined prior to recording any benefit in the financial statements that it is more likely than not that the tax position will be sustained upon examination by the appropriate taxing authorities, as required by the Accounting for Uncertainty within Income Taxes in FASB ASC Topic 740, *Income Taxes*. A tax position is measured at the largest amount of benefit that is greater than fifty percent likely of being realized upon settlement.

Pension and Other Postretirement Plans

The Company has two noncontributory defined benefit pension plans. The benefits are based on age, years of service, and average compensation. The Company also sponsors a defined postretirement benefit health, dental, and life insurance plan.

The Company records annual amounts relating to its pension and other postretirement plans based on calculations that incorporate various actuarial and other assumptions, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates, and healthcare cost trend rates. The Company reviews its assumptions on an annual basis and makes modifications to the assumptions based on current rates and trends when it is appropriate to do so. The Company believes that the assumptions utilized in recording its obligations under its plans are reasonable based on its experience and market conditions.

Security Deposits and Deposit Payable

The Participants are required to comply with the Financial Assurance Policy under the ISO's Tariff. Under the Financial Assurance Policy, most Participants are required to provide financial assurance due to their market activity or if they do not qualify for a credit limit. Participants must provide such financial assurance in an acceptable form which may be cash collateral. Any Participant utilizing the cash collateral option must sign a security and control agreement with the ISO granting the ISO a continued security interest in the collateral. The balance at December 31, 2022 and 2021 were $333,409,000 and $244,960,000, respectively, and recorded as an asset on the accompanying Statements of Financial Position.

The following table provides a reconciliation of Deposit Payable as reported within the Statements of Financial Position.

	December 31, 2022	2021
Security deposit payable	$ 333,409,000	$ 244,960,000
System Impact Studies deposit	30,439,000	29,915,000
Forward Capacity Market deposit	2,288,000	2,315,000
Other deposit payable	8,010,000	298,000
Total	$ 374,146,000	$ 277,488,000

Revenue Recognition

The Company recovers its operating and debt service costs pursuant to Section IV of the ISO's Tariff, which provides for recovery of expenses through three schedules to Section IV.A. Scheduling, System Control and Dispatch Service (Schedule 1), Energy Administration Service (Schedule 2), and Reliability Administration Service (Schedule 3) recover related costs through a pre-approved rate applied to each month's activity. Schedules 1, 2, and 3 are subject to true-up through subsequent years' rates, and any over or under collection are recorded as regulatory assets or regulatory liabilities and will be recovered under future filings to recover the ISO's expenses.

In addition to the recovery of these operating and debt service costs, the Company acts as a billing agent for a number of different pass-through expenditures on behalf of Participants and other regulatory bodies, including system impact study expenses, the FERC's Annual Electric Charges, and amounts related to the annual budget of the New England States' Committee on Electricity, each as required by the Tariff.

Concentrations

The Company's top 10 Participants represented approximately 54% or $114,705,000 and 53% or $115,135,000 in Tariff revenues for the years ended December 31, 2022 and 2021, respectively. The Company's top 10 Participants with unbilled receivable balances represented approximately 52% or $18,713,000 and 51% or $18,313,000 as of December 31, 2022 and 2021, respectively.

Liquidity Information

In order to provide additional information about liquidity, assets have been sequenced according to their nearness to conversion to cash, and liabilities have been sequenced according to the nearness of their resulting use of cash. Financial assets available for general expenditures without donor or other restrictions limiting their use, within one year of the respective Statement of Financial Position date, comprise the following:

	December 31,	
	2022	2021
Cash and cash equivalents	$ 178,316,000	$ 160,677,000
Unbilled receivables, net	39,036,000	37,333,000
Regulatory assets	-	1,980,000
Total	$ 217,352,000	$ 199,990,000

The Company's recovery of operating and debt service cost, as described in the Revenue Recognition and Accounts Receivable and Accounts Payable disclosure within this footnote, are collected in arrears, and as a result, the Company's working capital and cash flows may vary throughout the year. To manage unanticipated liquidity needs, the Company has in place a revolving credit agreement, as described within Credit Facilities (note 4), to be used as needed to cover expenses as a result of the timing of cash flows.

Fair Value of Financial Instruments

In determining fair value of financial assets and liabilities, the Company uses various valuation techniques. The availability of inputs observable in the market varies from instrument to instrument and depends on a variety of factors including the type of instrument, whether the instrument is actively traded, and other characteristics particular to the transaction. For many financial instruments, pricing inputs are readily observable in the market, the valuation methodology used is widely accepted by investors, and the valuation does not require significant management discretion. For other financial instruments, pricing inputs are less observable in the market and may require management's judgment. The level in the fair value hierarchy within which a fair value measurement in its entirety falls is based on the lowest-level input that is available for that particular financial instrument.

We assess the inputs used to measure fair value using the following three-tier hierarchy, which indicates the extent to which inputs used are observable in the market.

Level 1 Valuation is based upon unadjusted quoted prices for identical instruments traded in active markets.

Level 2 Valuation is pricing inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the same term of the assets. Inputs are obtained from various sources including investors and dealers.

Level 3 Valuation is generated from model-based techniques that use at least one significant assumption not observable in the market. These unobservable assumptions may include management's own judgments about the assumptions investors would use in pricing the asset or liability. Valuation techniques include use of option pricing models, discounted cash flow models and similar techniques.

2. Commitments and Contingencies

Capital and Administrative Funding Tariff

FERC accepted the ISO's capital and administrative funding filings to recover administrative expenses for 2022 and 2021. These filings, made pursuant to Section IV of the Tariff, support the ISO's loan arrangements with various banks and note holders to fund the capital and working capital requirements of the Company.

Legal Proceedings

The Company is involved in various claims and legal proceedings of a nature considered normal to its business. The claims are in various stages and some may ultimately be brought to trial. While it is not feasible to predict or determine the outcome of these claims, it is the opinion of management that the final outcome of these claims will not materially impact the operating results of the Company.

3. **Property and Equipment In-Service, Net and Work in Process**

	December 31, 2022	2021
Computer hardware, software and accessories	$ 255,667,000	$ 248,853,000
Software development costs	108,632,000	108,778,000
Furniture and fixtures	4,270,000	4,250,000
Machinery and equipment	351,000	152,000
Building and building improvements	67,408,000	67,354,000
Capitalized interest and fees	9,148,000	9,101,000
Vehicles	19,000	19,000
	445,495,000	438,507,000
Less: accumulated depreciation and amortization	(381,711,000)	(369,154,000)
Property and equipment in-service, net	**$ 63,784,000**	**$ 69,353,000**
Work in process ("WIP")	**$ 42,940,000**	**$ 30,858,000**

Costs within WIP primarily include the following projects: Next Generation Markets ("nGEM") Market Clearing Engine ("MCE") Implementation which includes nGEM Development Parts I and II and hardware, Forward Capacity Tracking System Infrastructure Conversion Part III and Solar Do Not Exceed Dispatch Phase I which all began between 2017 and 2021 and continued into 2022. Additionally, a number of new projects began in 2022 such as the 2022 Issue Resolution Project, Forward Capacity Market Order 2222, nGEM Real Time MCE Implementation, Integrated Market Simulator Phase II, Day-ahead Ancillary Services Improvements, and various other market enhancement projects that have not been placed in service as of December 31, 2022.

Depreciation and amortization expense was $25,047,000 and $26,221,000 for the years ended December 31, 2022 and 2021, respectively.

4. **Credit Facilities**

Revolving Credit Arrangement

In July 2021, the Company entered into a $20,000,000 revolving credit arrangement that expires on July 1, 2024, and any outstanding balance must be paid by this date. In March 2021, the Company filed under Federal Power Act Section 204 with FERC to issue this new debt; the filing was approved in May 2021. Interest accrues on the revolving credit at either Base Rate or LIBOR of which the Company has the option of selecting the Overnight, Weekly, 30, 60, 90, or 180-day rate. Interest is paid at the earlier of the selected LIBOR term or 30 days. The Company is charged an annual fee of 0.075% on the unused amount on the line of credit. The Company has amended the revolving credit agreement to replace LIBOR with a benchmark replacement, such as SOFR, upon notification from the bank.

The outstanding balance for each of the years ended December 31, 2022 and 2021 was $0 and the weighted average interest for each of the years was 0% and 0.76%, respectively.

In July 2021, the Company entered into a $4,000,000 revolving credit arrangement that expires on July 1, 2024, and any outstanding balance must be paid by this date. In March 2021, the Company filed under Federal Power Act Section 204 with FERC to issue this new debt; the filing was approved in May 2021. Interest accrues on the revolving credit at either Base Rate or LIBOR of which the Company has the option of selecting the Overnight, Weekly, 30, 60, 90, or 180-day rate. Interest is paid at the earlier of the selected LIBOR term or 30 days. The Company is charged an annual fee of 0.075% on the unused amount on the line of credit. The Company has amended the revolving credit agreement to replace LIBOR with a benchmark replacement, such as SOFR, upon notification from the bank.

The outstanding balance and weighted average interest for each of the years ended December 31, 2022 and 2021 was $0 and 0%, respectively.

Long Term Debt

At December 31, 2022, the following amounts were outstanding on long-term debt:

	Private Placement (i)	Private Placement (ii)	Tax-exempt Bonds (iii)	Tax-exempt CT Bonds (iv)	Total
Total outstanding:					
Maturities	$ 11,000,000	39,000,000	16,835,000	23,090,000	89,925,000
Less unamortized debt issuance costs	-	(6,000)	(42,000)	(157,000)	(205,000)
Total debt, net	$ 11,000,000	38,994,000	16,793,000	22,933,000	89,720,000
Current portion:					
Maturities	$ -	-	1,820,000	1,360,000	3,180,000
Less unamortized debt issuance costs	-	-	-	-	-
Total current portion	$ -	-	1,820,000	1,360,000	3,180,000
Long term portion:					
Maturities	$ 11,000,000	39,000,000	15,015,000	21,730,000	86,745,000
Less unamortized debt issuance costs	0	(6,000)	(42,000)	(157,000)	(205,000)
Total long term portion	$ 11,000,000	38,994,000	14,973,000	21,573,000	86,540,000
Fair market value at year-end	$ 10,651,000	$ 38,675,000			
Incremental borrowing rate (for FMV)	4.96%	4.96%			
Weighted average SIFMA interest			1.22%	1.23%	
Weighted average floating interest rate			1.13%	1.15%	

At December 31, 2021, the following amounts were outstanding on long-term debt:

	Private Placement (i)	Private Placement (ii)	Tax-exempt Bonds (iii)	Tax-exempt CT Bonds (iv)	Total
Total outstanding:					
Maturities	$ 11,000,000	39,000,000	18,655,000	24,450,000	93,105,000
Less unamortized debt issuance costs	(5,000)	(11,000)	(48,000)	(166,000)	(230,000)
Total debt, net	$ 10,995,000	38,989,000	18,607,000	24,284,000	92,875,000
Current portion:					
Maturities	$ -	-	1,820,000	1,360,000	3,180,000
Less unamortized debt issuance costs	-	-	-	-	-
Total current portion	$ -	-	1,820,000	1,360,000	3,180,000
Long term portion:					
Maturities	$ 11,000,000	39,000,000	16,835,000	23,090,000	89,925,000
Less unamortized debt issuance costs	(5,000)	(11,000)	(48,000)	(166,000)	(230,000)
Total long term portion	$ 10,995,000	38,989,000	16,787,000	22,924,000	89,695,000
Fair market value at year-end	$ 11,419,000	$ 41,935,000			
Incremental borrowing rate (for FMV)	1.77%	1.77%			
Weighted average SIFMA interest			0.04%	0.04%	
Weighted average floating interest rate			0.04%	0.04%	

(i & ii) Private Placement Debt

In November 2012, the Company entered into an $11,000,000 private placement loan, which is made up of a twelve year 3.15% senior note. Payment is due in full on November 8, 2024 with mandatory prepayments upon certain contingent events occurring, and interest is accrued and paid semi-annually.

In September 2013, the Company entered into an agreement for funding of a $39,000,000 private placement loan, which is made up of a ten year 4.49% senior note. Payment is due in full on November 8, 2024 with mandatory prepayments upon certain contingent events occurring, and interest is accrued and paid semi-annually.

The loans are included in long-term debt on the accompanying Statements of Financial Position. The fair value is estimated using discount cash flow analysis based on the Company's incremental borrowing rates for similar types of borrowing arrangements and the debt is classified as Level 2.

(iii) Tax-Exempt Bonds

In February 2005, the Company entered into tax-exempt financing of $45,500,000 in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds ("Bonds"), which were issued by the Massachusetts Development Finance Agency. The proceeds of the Bonds were loaned to the Company to assist in financing and refinancing a construction project located at the Main Control Center. Principal payments of $455,000, paid quarterly, began in May 2007 with the final repayment due on February 1, 2032. The tax-exempt financing is backed by a letter of credit that the Company originally entered into in February 2005. The letter of credit will expire in August 2024 and contains an evergreen clause that will automatically renew annually with the beneficiaries. The par value of the Bonds approximates the fair value and the Bonds are classified as Level 2.

Interest accrues quarterly on the Bonds at a weekly variable rate based upon the Securities Industry and Financial Markets Association "SIFMA" Swap Index. The Company is charged an annual fee of 0.38% paid quarterly based on the maximum amount available to be drawn under the letter of credit including principal and interest commitments.

(iv) Tax-Exempt CT Bonds

In December 2012, the Company entered into tax-exempt financing of $36,000,000 in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds ("CT Bonds"), which were issued by Connecticut Innovations Incorporated. The proceeds of the CT Bonds were loaned to the Company to assist in financing a project located in Windsor, Connecticut to acquire real property and construct an office building with data center and control center, including miscellaneous property and equipment to serve as a Back-up Control Center. Principal payments of $340,000 are paid quarterly, with the first payment being made in November 2014 for $680,000 and the final repayment due in November 2039. The tax-exempt financing is backed by a letter of credit that the Company originally entered into in December 2012. The letter of credit will expire in December 2024 and contains an evergreen clause that will automatically renew annually with the beneficiaries. The par value of the Bonds approximates the fair value and the Bonds are classified as Level 2.

Interest accrues quarterly on the $36,000,000 tax-exempt bonds, at a weekly variable rate based upon the SIFMA. The Company is charged an annual fee of 0.38% paid quarterly based on the maximum amount available to be drawn under the letter of credit including principal and interest commitments.

Principal payments on the private placement debt and tax-exempt bonds, excluding debt issuance costs, are due annually as follows:

2023	$ 3,180,000
2024	53,180,000
2025	3,180,000
2026	3,180,000
2027	3,180,000
Thereafter	24,025,000
	$ 89,925,000

Interest incurred on the revolving credit arrangement, private placement debt, and tax-exempt bonds for the years ended December 31, 2022 and 2021 was approximately $2,578,000 and $2,128,000, respectively.

Interest Rate Cap

The Company has entered into an interest rate cap to mitigate the interest rate risks associated with the tax-exempt debt. On October 31, 2013, the Company purchased an interest rate cap for $706,000 for a predetermined notional amount to lock into a derivative arrangement whereby the Company will receive a payment whenever 74% of the one-month SOFR exceeds 2.48%. The interest rate cap is recorded as deferred charges under noncurrent assets on the accompanying Statements of Financial Position. The derivative arrangement was amended and restated effective May 1, 2022 to February 1, 2024 with the notional amount of $5,225,000, which is amortized to zero as the floating rate debt is repaid. The fair market value of the interest rate cap as of December 31, 2022 and 2021 was $20,700 and $700, respectively. The fair market values were recorded as an other asset and regulatory liability in 2022 and 2021 on the accompanying Statements of Financial Position. The fair market values are derived from third-party financial institutions and the interest rate cap is classified as Level 2.

5. Pension and Other Postretirement Benefits

The Company sponsors two defined benefit pension plans (one for union and the other for non- union employees), also referred to herein as the non-contract and contract plans, each of which is funded solely by Company contributions. Benefits are determined based on years of service and average compensation. Effective January 1, 2014, the defined benefit pension plans were closed to all employees hired or rehired on or after January 1, 2014.

The Company sponsors a postretirement benefit plan that provides medical, dental, and life insurance benefits for eligible employees and their beneficiaries. The medical benefits are contributory with participants' contributions adjusted annually, and participants are responsible for deductible and coinsurance amounts. Dental benefits are non-contributory but participants are responsible for deductible and coinsurance amounts. The life insurance benefits are non- contributory. Effective January 1, 2016, the postretirement benefit plan was closed to employees hired or rehired on or after January 1, 2016.

The Company accounts for the plans as required in FASB ASC Topic 715, *Compensation - Retirement Benefits*. The measurement date used to determine pension and other postretirement benefit obligations is December 31. Additionally, the Company discloses net periodic benefit cost for the defined benefit pension and other postretirement benefit plan for each annual period for which a Statements of Activities is presented as required by the employers' disclosures. As required in Topic 980, *Regulated Operations*, the Company has disclosed the difference in the timing of recognition of net periodic benefit cost as an expense and as such records the difference as an asset or a liability created by the actions of the regulator under rate making regulations and rules.

Under the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act (collectively, the "Health Care Acts") there are several provisions that may affect a company's postretirement benefit plans, including eliminating lifetime and annual coverage limits, reducing subsidies to Medicare Advantage plans, and extending coverage for adult children until age 26. The Company has evaluated the effects of the provisions of the Health Care Acts and concluded that as of December 31, 2022, none of the provisions have a material impact on its postretirement benefit plan. The Company does not provide benefits that are actuarially equivalent to the Medicare prescription drug benefit in its postretirement benefit plan.

The following table sets forth the plans' benefit obligations, fair value of the plans' assets, and the plans' funded status:

	Pension Benefits Years Ended December 31,		Other Postretirement Benefits Years Ended December 31,	
	2022	2021	2022	2021
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 315,967,000	$ 332,588,000	$ 30,327,000	$ 30,327,000
Service cost	10,931,000	12,138,000	1,611,000	1,671,000
Interest cost	8,449,000	8,008,000	858,000	667,000
Benefits paid	(18,664,000)	(24,488,000)	(1,537,000)	(1,267,000)
Plan participants' contributions	-	-	495,000	389,000
Actuarial (gain)/loss	(97,522,000)	(12,279,000)	(4,814,000)	(1,460,000)
Benefit obligation at end of year	219,161,000	315,967,000	26,940,000	30,327,000
Change in plan assets:				
Fair value of plan assets at beginning of year	243,650,000	230,504,000	28,383,000	25,876,000
Actual return on plan assets	(37,710,000)	27,232,000	(4,019,000)	3,057,000
Employer contributions	10,472,000	10,402,000	364,000	328,000
Plan participants' contributions	-	-	495,000	389,000
Benefits paid	(18,664,000)	(24,488,000)	(1,537,000)	(1,267,000)
Fair value of plan assets at end of year	197,748,000	243,650,000	23,686,000	28,383,000
Funded status at end of the year	(21,413,000)	(72,317,000)	(3,254,000)	(1,944,000)
Net amount recognized as non-current liabilities	$ (21,413,000)	$ (72,317,000)	$ (3,254,000)	$ (1,944,000)

The Company has determined that the pension liability is probable of recovery through Section IV.A. of the Tariff and has recorded a regulatory asset as of December 31, 2022 and 2021 in the accompanying Statements of Financial Position.

	Pension Benefits Years ended December 31,		Other Postretirement Benefits Years ended December 31,	
	2022	2021	2022	2021
Components of net periodic benefit cost:				
Service cost	$ 10,931,000	$ 12,138,000	$ 1,611,000	$ 1,671,000
Interest cost (1)	8,449,000	8,008,000	858,000	667,000
Expected return on plan assets (1)	(14,142,000)	(14,705,000)	(1,664,000)	(1,651,000)
Amortization of net actuarial loss (1)	3,501,000	6,736,000	86,000	114,000
Amortization of unrecognized prior service credit (1)	-	-	(77,000)	(104,000)
Net periodic benefit cost	8,739,000	12,177,000	814,000	697,000
Amount deferred due to actions of the regulator	1,130,000	(2,498,000)	(505,000)	(423,000)
Net periodic benefit cost recognized	$ 9,869,000	$ 9,679,000	$ 309,000	$ 274,000

(1) The components of net periodic pension cost other than service cost component are included in the line item "Other expense (income)" in the Statement of Activities.

The Company's accumulated benefit obligation for the pension benefit plans (non-contract and contract) was $180,873,000 and $251,295,000 at December 31, 2022 and 2021, respectively.

The following is a gain/loss transaction reflected in the measurement of the benefit obligation for the pension benefit plans (non-contract and contract) as of December 31, 2022:

The discount rate changed from 2.79% to 5.01% on the non-contract plan. This change had the impact of decreasing the projected benefit obligation by approximately $94,563,000. The discount rate changed from 2.87% to 5.03% on the contract plan. This change had the impact of decreasing the projected benefit obligation by approximately $2,580,000.

The following are gains/loss transactions reflected in the measurement of the benefit obligation for the other postretirement plan, as of December 31, 2022:

The discount rate changed from 2.62% to 4.92%. This change had the impact of decreasing benefit obligations by approximately $8,063,000.

The following table sets forth the amount expected to be amortized into net periodic benefit cost over the next fiscal year ending December 31, 2023:

	Pension Benefits	Other Postretirement Benefits
Expected amortization of net actuarial (gain)/loss	$ (53,000)	$ -
Expected amortization of prior service (credit)/cost	-	(41,000)

The primary economic assumptions, based on prevailing economic conditions, used to value these liabilities are summarized in the following table.

Weighted-average assumptions used to determine net periodic benefit cost for the following years ended:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2022	2021	2022	2021
Discount rate	See Below	See Below	2.62%	2.23%
Expected long-term rate of return on plan assets	6.00%	6.50%	6.00%	6.50%
Rate of compensation increase prior to age 40	6.25%	6.00%	6.25%	6.00%
Rate of compensation increase for ages 40-59	4.25%	4.00%	4.25%	4.00%
Rate of compensation increase for ages 60 and after	3.25%	3.00%	3.25%	3.00%
Health Care cost trend rates - initial	-	-	6.75%	7.00%
Dental Care cost trend rates - initial	-	-	3.50%	3.50%
Health Care cost trend rates - ultimate	-	-	4.50%	4.50%
Ultimate year	-	-	2033	2033

Separate discount rates are used in the pension calculations for the non-contract and the contract plans. The December 31, 2022 discount rate for the non-contract and the contract plan was 2.79% and 2.87%, respectively. The December 31, 2021 discount rate for the non-contract and the contract plan was 2.45% and 2.60%, respectively.

Weighted-average assumptions used to determine benefit obligation for the following years ended:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2022	2021	2022	2021
Discount rate	See Below	See Below	4.92%	2.62%
Rate of compensation increase prior to age 40	6.25%	6.25%	6.25%	6.25%
Rate of compensation increase for ages 40-59	4.25%	4.25%	4.25%	4.25%
Rate of compensation increase for ages 60 and after	3.25%	3.25%	3.25%	3.25%

Separate discount rates are used in the pension calculations for the non-contract and the contract plans. The December 31, 2022 discount rate for the non-contract and the contract plan were 5.01% and 5.03%, respectively. The December 31, 2021 discount rate for the non-contract and the contract plan were 2.79% and 2.87%, respectively.

The ISO's pension plan and postretirement benefit plan weighted-average asset allocations and expected returns by asset category are as follows:

Pension and Postretirement Plan Assets

	Target Allocation 2023	Percentage of Plan Assets at December 31 2022	2021	Weighted Average Expected Long-Term Rate of Return - 2023
Equity Securities	46%	46%	54%	3.76%
Debt Securities	42%	42%	41%	1.72%
Real Estate	0%	4%	5%	0.00%
Other	12%	8%	0%	0.77%
Total	100%	100%	100%	6.25%

The forward-looking estimates of total return were developed based on assumptions for each underlying component, reflecting observable inflation and interest rate information available in the fixed income markets as well as consensus economics forecasts. Long-term assumptions for other asset classes (i.e., equities) are based on historical results, current market characteristics, and professional judgment. In setting this assumption, the ISO relied upon capital market assumptions developed by a market-leading provider of investment services to corporate pension plans.

The respective plan's investment portfolio is to be invested to provide benefits for qualified employees of the ISO. Investments are to be compatible with the liquidity requirements determined by the plan's actuary. An optimal target allocation of 60/40 between equities and fixed income investments is to be kept with an allowance of fifteen percent (15%) over/under deviation from the optimal allocation target.

The fair values of the pension plan assets at December 31, 2022 and 2021 by asset category are as follows:

	Market Value at 12/31/22	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
Long Duration Corporate Bonds	$ 57,854,000	$ -	$ 57,854,000	$ -
Long Duration Government Bonds	13,012,000	-	13,012,000	-
Reinsurance Bond	17,000	-	17,000	-
Total	70,883,000	-	70,883,000	-
Collective Investment Trust				
DB Growth Portfolio	123,000,000	-	123,000,000	-
Total	123,000,000	-	123,000,000	-
Cash and cash equivalents	3,865,000	3,865,000	-	-
Total long-term investments	$ 197,748,000	$ 3,865,000	$ 193,883,000	$ -

	Market Value at 12/31/21	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
Long Duration Corporate Bonds	$ 69,601,000	$ -	$ 69,601,000	$ -
Long Duration Government Bonds	17,863,000	-	17,863,000	-
Reinsurance Bond	149,000	-	149,000	-
Total	87,613,000	-	87,613,000	-
Collective Investment Trust				
DB Growth Portfolio	151,898,000	-	151,898,000	-
Total	151,898,000	-	151,898,000	-
Cash and cash equivalents	4,139,000	4,139,000	-	-
Total long-term investments	$ 243,650,000	$ 4,139,000	$ 239,511,000	$ -

The fair values of the other postretirement benefit plan assets at December are as follows:

	Market Value at 12/31/22	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
U.S. and global core fixed income funds	$ 10,355,000	$ 10,355,000	$ -	$ -
Reinsurance Bond	4,000		4,000	-
Total	10,359,000	10,355,000	4,000	-
US Large Cap	6,638,000	6,638,000	-	-
US Small Cap	1,156,000	1,156,000	-	-
Total	7,794,000	7,794,000	-	-
Global (ex-U.S.) equities:				
Developed markets	3,771,000	3,771,000	-	-
Total	3,771,000	3,771,000	-	-
Hedged equity funds of funds:				
Absolute return/multiple strategies	215,000	215,000	-	-
Multiple strategies	617,000	617,000	-	-
Total	832,000	832,000	-	-
Real assets:				
Private real estate	576,000	576,000	-	-
Total	576,000	576,000	-	-
Cash and cash equivalents	354,000	354,000	-	-
Total long-term investments	$ 23,686,000	$ 23,682,000	$ 4,000	$ -

	Market Value at 12/31/21	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
U.S. and global core fixed income funds	$ 11,038,000	$ 11,038,000	$ -	$ -
Reinsurance Bond	36,000	36,000	-	-
Total	11,074,000	11,074,000	-	-
US Large Cap	8,982,000	8,982,000	-	-
US Small Cap	2,039,000	2,039,000	-	-
Total	11,021,000	11,021,000	-	-
Global (ex-U.S.) equities:				
Developed markets	3,565,000	3,565,000	-	-
Emerging markets	835,000	835,000	-	-
Total	4,400,000	4,400,000	-	-
Hedged equity funds of funds:				
Absolute return/multiple strategies	218,000	218,000	-	-
Multiple strategies	717,000	717,000	-	-
Total	935,000	935,000	-	-
Real assets:				
Private real estate	531,000	531,000	-	-
Total	531,000	531,000	-	-
Cash and cash equivalents	422,000	422,000	-	-
Total long-term investments	$ 28,383,000	$ 28,383,000	$ -	$ -

The Company expects to contribute approximately $10,000,000 to its pension plans and $965,000 to its postretirement benefit plan in 2023.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Postretirement Benefits
2023	$ 10,853,000	$ 1,859,000
2024	10,951,000	1,870,000
2025	11,480,000	1,896,000
2026	12,161,000	1,864,000
2027	12,579,000	1,878,000
Years 2028-2032	77,858,000	10,582,000
Total	$ 135,882,000	$ 19,949,000

6. Other Benefit Plans

The Company has a 401(k) Retirement and Savings Plan (the "401(k) Plan") open to substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee contributions up to 3% of eligible compensation and provides a 50% match on the next 2% of eligible compensation. The matching contributions for the Company were $3,348,000 and $3,290,000, for the years ended December 31, 2022 and 2021, respectively.

In 2014, the Company amended the 401(k) Plan to provide for a special contribution for new employees hired after January 1, 2014. The Company funds the contribution into the 401(k) Plan based on a formula of employee's age, service, and compensation. The contributions paid by the Company were $1,672,000 and $1,406,000 for the years ended December 31, 2022 and 2021, respectively.

The Company maintains a 457(b) Plan that provides for certain members of senior management to defer a portion of their current compensation and have it credited under a supplemental unfunded savings program. The 457(b) Plan is intended to satisfy the requirements of an eligible deferred compensation plan maintained by the ISO as a nongovernment tax-exempt entity under Code section 457(e)(1)(B). The plan participants may direct that these funds be invested in the same investments offered by the ISO 401(k) plan at their discretion. The investment balance was $2,125,000 and $2,337,000 as of December 31, 2022 and 2021, respectively and recorded within other assets and the corresponding deferred compensation liability is recorded in long-term portion of Accrued compensation in the accompanying Statements of Financial Position. The investments are recorded at fair value and are classified as Level 1.

7. Leases

The Company has operating leases for office equipment, computer hardware, and motor vehicles. The Company's leases have remaining lease terms of 1

year to 5 years. For purposes of calculating operating lease liabilities, lease terms may be deemed to include options to extend the lease when it is reasonably certain that the Company will exercise those options. The Company's lease arrangements do not contain any material restrictive covenants. The Company's incremental borrowing rate is 2.30%, which is reviewed each time the Company enters into a new lease.

The components of lease cost for operating leases for the years ended December 31, 2022 and 2021 were as follows:

The components of lease cost for operating leases:

	Years ended December 31,	
	2022	2021
Operating lease cost	$ 675,000	$ 762,000
Short-term lease cost	-	-
Total Lease Cost	$ 675,000	$ 762,000

The operating lease cost is equal to the cash paid from operating cash flows.

Maturity of Lease Liabilities at December 31, 2022

	Operating Leases
2023	$ 509,000
2024	263,000
2025	96,000
2026	10,000
2027	-
Total future undiscounted lease payments	878,000
Less: Interest	(18,000)
Present value of lease liabilites	$ 860,000

The Company calculates the weighted-average remaining lease term based on the remaining lease term and the lease liability balance for each lease at the reporting date. For the years ended December 31, 2022 and 2021, the Company discloses a weighted-average remaining lease term of 1.97 and 2.32 years respectively, for its operating leases.

The Company calculates the weighted-average discount rate based on the remaining lease payments and discount rate for each lease at the reporting date. For the years ended December 31, 2022 and 2021, the Company discloses a weighted-average discount rate 2.21% and 2.20%, respectively for its operating leases.

8. Functional Classification of Expenses

Operating expenses presented by natural and function classification are as follows:

	December 31, 2022		
	Program Service Expenses	Management & General Expenses	Total
Salaries and benefits	$ 109,693,000	$ 17,227,000	$ 126,920,000
Depreciation and amortization expense	24,843,000	204,000	25,047,000
Professional fees and consultants	17,445,000	2,388,000	19,833,000
Computer Services	16,205,000	1,277,000	17,482,000
All other expenses	19,634,000	1,896,000	21,530,000
Total expenses	$ 187,820,000	$ 22,992,000	$ 210,812,000

	December 31, 2021		
	Program Service Expenses	Management & General Expenses	Total
Salaries and benefits	$ 105,541,000	$ 16,712,000	$ 122,253,000
Depreciation and amortization expense	26,021,000	200,000	26,221,000
Professional fees and consultants	17,816,000	1,879,000	19,695,000
Computer Services	14,808,000	1,144,000	15,952,000
All other expenses	15,813,000	1,751,000	17,564,000
Total expenses	$ 179,999,000	$ 21,686,000	$ 201,685,000

One of the Company's primary responsibilities is to ensure the reliability of the power system for the New England area and as such, our departments are specifically designed to support that function. Those departmental costs are deemed directly identifiable to program services as summarized in the above tables. Other departments that are solely for supporting the Company, such as human resources, are categorized as management and general expenses as summarized in the above tables. For any department that is providing both program and management and general services, an analysis was performed to allocate the costs based on the time spent supporting program services or management and general, and categorized accordingly.

All expenses summarized above, except for depreciation and amortization expense are allocated in the method described above. Depreciation is allocated based on estimated useful life of an asset. Assets with 3-5 year life are primarily computer hardware and software designed for power system and are classified as program service expenses. Any asset with a life of 7 years or greater is related to equipment and building and therefore is allocated under the method described above.

9. **Subsequent Events**

The Company has evaluated subsequent events from the Statements of Financial Position date through March 16, 2023, the date at which the financial statements were available to be issued, and determined that there are no items to disclose that occurred in the subsequent period.

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	nGEM Market Clearing Engine Implementation	12,514,898
2	nGEM Development Part II	3,745,605
3	Security Information and Event Mgt (SIEM) Log Monitoring Replacement	3,482,257
4	nGEM Hardware Phase II	3,265,858
5	Forward Capacity Tracking System Infrastructure Conversion Part III	1,905,620
6	2022 System Enhancements	1,484,139
7	Solar Do Not Exceed Dispatch Phase I	1,431,651
8	Long-Term Transmission Rights	1,296,978
9	Internal Market Monitoring Data Analysis Phase III	1,177,365
10	Integrated Market Simulator Phase I	1,019,703
11	Other minor projects (less than 5% and $1,000,000)	11,616,314
43	Total	42,940,388

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)
1	Bonds (Account 221)						
2	Tax Exempt Bond Financing		45,500,000		375,242		
3	Tax Exempt Bond Financing		36,000,000		555,436		
4	Subtotal		81,500,000		930,678		
5	Reacquired Bonds (Account 222)						
6							
7							
8							
9	Subtotal						
10	Advances from Associated Companies (Account 223)						
11							
12							
13							
14	Subtotal						
15	Other Long Term Debt (Account 224)						
16	Private Placement Debt		39,000,000		180,254		
17	Private Placement Debt		11,000,000		94,067		
18	Subtotal		50,000,000		274,321		
33	TOTAL		131,500,000				

LONG-TERM DEBT (Account 221, 222, 223 and 224)						
Line No.	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1						
2	02/01/2005	02/01/2032	06/01/2006	06/01/2031	16,835,000	423,468
3	12/13/2012	11/13/2039	12/13/2012	12/13/2027	23,090,000	393,848
4					39,925,000	817,316
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16	05/22/2014	11/08/2024	06/01/2014	06/01/2024	39,000,000	1,127,028
17	11/08/2012	11/08/2024	11/30/2012	11/30/2022	11,000,000	223,011
18					50,000,000	1,350,039
33					89,925,000	2,167,355

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/13/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)		
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,992,615	5,291,545
85	(561.1) Load Dispatch-Reliability	3,465,049	3,541,505
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,984,433	7,897,562
87	(561.3) Load Dispatch-Transmission Service and Scheduling	7,529,404	7,478,244

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	13,180,387	13,192,460
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	1,350,099	1,121,316
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses		
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	39,501,987	38,522,632
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	2,756,406	2,868,400
104	(569.2) Maintenance of Computer Software	16,922,267	14,457,306
105	(569.3) Maintenance of Communication Equipment	164,012	135,230
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment		
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines		
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	19,842,685	17,460,936
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	59,344,672	55,983,568
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	4,133,180	3,919,368

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
116	(575.2) Day-Ahead and Real-Time Market Facilitation	10,125,953	10,321,972
117	(575.3) Transmission Rights Market Facilitation	320,105	305,958
118	(575.4) Capacity Market Facilitation	6,490,472	4,401,436
119	(575.5) Ancillary Services Market Facilitation	688,994	509,109
120	(575.6) Market Monitoring and Compliance	5,515,078	6,084,026
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents	372,250	408,585
123	Total Operation (Lines 115 thru 122)	27,646,032	25,950,454
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	604,635	481,457
126	(576.2) Maintenance of Computer Hardware	1,939,693	2,151,300
127	(576.3) Maintenance of Computer Software	25,314,404	24,319,840
128	(576.4) Maintenance of Communication Equipment	115,416	101,423
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	27,974,148	27,054,020
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	55,620,180	53,004,474
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)		
145	Maintenance		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	584,221	654,904
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses	3,814,332	3,599,218
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	4,398,553	4,254,122
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	2,918,532	2,917,233
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	2,918,532	2,917,233
172	7. SALES EXPENSES		
173	Operation		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	22,921,010	22,052,686
182	(921) Office Supplies and Expenses	717,926	658,216
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	4,164,265	3,533,658
185	(924) Property Insurance	2,278,243	1,838,087
186	(925) Injuries and Damages	354,707	314,454
187	(926) Employee Pensions and Benefits	19,031,596	17,762,118
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	8,790,221	8,386,441
193	(931) Rents	323,270	368,528
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	58,581,238	54,914,188
195	Maintenance		
196	(935) Maintenance of General Plant	2,635,994	2,246,799
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	61,217,232	57,160,987
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	183,499,169	173,320,384

EXHIBIT 8

New England Governors, State Utility Regulators and Related Agencies*

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New England Governors, State Utility Regulators and Related Agencies*

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EXHIBIT 9

September 5, 2023

Cheryl LaFleur
Chair
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2024 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

On behalf of the undersigned New England state agencies, we submit our comments regarding the ISO New England (ISO-NE) proposed 2024 Operating and Capital Budgets.

We accept this budget proposal given the challenges facing ISO-NE as the New England power system transitions to clean energy. However, we are concerned with the size of the budget increase. We note that the proposal as of August 2023 is 800 thousand dollars more than what was proposed back in June 2023 when presented to NECPUC, for an overall $35.3 million or 16.9% increase from the 2023 operating budget (before depreciation). ISO-NE is also proposing an increase to its capital budget of 4.5%. These are significant increases and follow material increases in each of the last couple of years. ISO-NE also projects relatively large increases in the foreseeable future. For the proposed 2024 operating budget, the increase is overwhelmingly driven by changes in payroll costs, higher salaries and benefits, and for consultants. The other significant driver of the increase is expected higher costs for computer services. While we appreciate that budget increases are necessary in light of changes to the New England power system that are increasing its complexity, and due to the tight and competitive labor market that ISO-NE faces, these increases should be fully vetted to ensure that they reflect prudent management and efficient operations.

Of particular concern for the States are the salary increases included in the proposed budget. These costs are significant and become more so as the salary increases are expanded over a larger segment of ISO-NE's employees. While it is important that ISO-NE be able to attract employees with the necessary talent and skill sets to fulfill its

responsibilities and it is appropriate to periodically assess that ability, salary increases should be narrowly implemented on those specific positions where the current ISO-NE salary is below the competitive range for the position. It should not be the case that the job benchmark study ends up raising all ISO-NE salaries. Also, with more FTEs and higher salaries, it is even more incumbent on ISO-NE to effectively use its personnel through multitasking and repurposing as appropriate.

CONCLUSION

We accept the proposed 2024 budget in light of the New England power system transition to clean energy, but ask that the Board carefully review how ISO-NE uses the job benchmark study and ensure that salary increases are narrowly implemented while maintaining a competitive range of salaries.

Respectfully submitted,

Connecticut Office of Consumer Counsel
Claire E. Coleman, Consumer Counsel
10 Franklin Square
New Britain, CT 06051

Connecticut Public Utilities Regulatory Authority
Marissa Paslick Gillett, Chairman
John W. Betkoski, Vice-Chairman
Michael A. Caron, Commissioner
10 Franklin Square
New Britain, CT 06051

Massachusetts Department of Public Utilities
James M. Van Nostrand, Chair
Cecile M. Fraser, Commissioner
Staci Rubin, Commissioner
1 South Station, 3rd Floor
Boston, MA 02110

Rhode Island Public Utilities Commission
Ronald T. Gerwatowski, Chairman
Abigail Anthony, Commissioner
John C. Revens, Jr., Commissioner
89 Jefferson Blvd.
Warwick, RI 02888

Vermont Public Utility Commission
Anthony Z. Roisman, Chair
Margaret Cheney, Commissioner
Riley Allen, Commissioner
112 State Street, 4th Floor
Montpelier, VT 05620-2701

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September 5, 2023

Kathleen Abernathy, Chair,
ISO-New England
One Sullivan Road
Holyoke, MA 01040

Re: Comments on ISO-NE 2024 Budget

Dear Ms. Abernathy:

The Connecticut Office of Consumer Counsel ("OCC") hereby submits these supplemental Comments regarding the ISO-New England proposed 2034 Operating and Capital Budgets (2024 Budget).[1]

OCC supports ISO-New England's efforts to ensure it has the staff and resources needed to fulfil its mission and support the clean energy transition, and we also recognize the inflationary pressures that the entire energy industry has experienced. At the same time, given that New England consumers have experienced continued high energy prices, it is imperative that ISO-New England budget with as much constraint as is possible. Separately from the joint New England state comments also submitted today, OCC would also like to raise specific concerns in the areas of incentive compensation and depreciation expenses, and to encourage generally more overall transparency in the budgeting process.

Incentive Compensation. The 2024 Budget includes an increase to the incentive compensation plan in 2024 of a projected $2.561 million. In ISO-NE's responses to OCC's questions, it indicated that this represented an increase of 0.9 percent to the starting incentive levels (from levels that begin at 5.6% of an employee's salary to 6.5% of an employee's base salary.) ISO did not provide the rationale upon which those bonuses will be paid, as requested, stating that the bonuses are awarded based on meeting "corporate and personal performance" and that the "policy is not a public document." Response to CTOCC-3. Given the increases to the proposed incentive compensation payouts, ISO-NE should be more transparent about its incentive compensation plan, providing general information on the range of payouts (range of dollar figures and percent of salary) within the organization, as well as the standards upon which the bonuses will be awarded. ISO-NE should also provide a general listing of the performance

[1] OCC has also signed comments submitted by New England state agencies which identified concerns with the size of the budget increase and significant salary increases.

goals that are measured to determine incentive plan payouts so that stakeholders can ensure that employees are being encouraged to act in ways that align with the goals of the member organizations.

OCC is sympathetic to ISO-NE's professed desire to hire the most capable and skilled workforce and thus understands the need to increase salaries and positions at ISO-NE in order to perform expanding duties that are being assigned to the agency. OCC, however, is also aware that in general the payroll budget should be based on a historic vacancy factor and should be based on FTE positions that will be filled in 2024, instead of simply setting the funding levels at half of the positions that the agency seeks to fill during the course of 2024. Relying on those historic figures will give ISO-NE and stakeholders a better understanding of the level of funding that will be required to pay for staff at the regional agency should it meet the expected hiring goals over the course of the year.

Depreciation. When budgeted depreciation expense increases as significantly as anticipated in the 2024 Budget – by more $7.5 million, representing a 30% increase over 2022 levels – ISO-NE should present clear evidence as to why the increased expense is warranted. In future budget presentations, OCC would appreciate more transparency regarding explanations of the alterations to the depreciation expense. Future budget presentations should include detailed workpapers showing the calculation of the last historic year's depreciation expense, as well as the current budgeted year and the budget being proposed for the upcoming year.

Respectfully submitted,

STATE OF CONNECTICUT
OFFICE OF CONSUMER COUNSEL

CLAIRE E. COLEMAN
CONSUMER COUNSEL

By: ***/s/ James Talbert-Slagle***
James Talbert-Slagle
Staff Attorney
Richard Sobolewski
Supervisor of Utility Financial Analysis

cc: Service List

COMMISSIONER
Jared S. Chicoine

DEPUTY COMMISSIONER
Christopher J. Ellms, Jr.

STATE OF NEW HAMPSHIRE

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DEPARTMENT OF ENERGY
21 S. Fruit St., Suite 10
Concord, N.H. 03301-2429

September 6, 2023

Robert Ludlow
Chief Financial Officer
ISO New England
1 Sullivan Road
Holyoke, Massachusetts 01040

Mr. Ludlow,

We appreciate and welcome the opportunity to offer feedback on ISO-NE's proposed budget. The New England states have an important job in reviewing the budget, as our ratepayers are ultimately responsible for every cost that goes into their bills. Unfortunately, we write expressing our discomfort with the 2024 and 2025 preliminary budget.

ISO-NE's proposed budget raises significant concerns and calls for strict scrutiny, given the 21.5 percent increase in the ISO's revenue requirement. The ISO board has adopted a resolution to consider customer affordability, and this proposed increase works against that goal. More than half of the increase is driven by salary increases, including increases to bonuses. The ISO is a non-profit entity – there shouldn't be a drive for more and more revenue – and this budget lacks that vision.

Significant cost increases are attributed to the clean energy transition and environmental justice policies legislated by other states. These are clear examples of costs shifting to New Hampshire citizens that fall outside of the ISO's mandate. Furthermore, thirty-five full-time, highly compensated jobs are being devoted to the so-called grid of the future, when what we really need is a reliable, affordable system today.

We're disappointed that our grid operator has proposed a budget misaligned with the needs of New Hampshire's ratepayers during a time of already high energy costs and economic uncertainty for so many. ISO-NE should reconsider its priorities, devote resources to its core functions, and put forth a responsible budget that focuses on safe, reliable, and affordable energy.

Sincerely,

Jared Chicoine
Commissioner
Department of Energy

Donald M. Kreis
Consumer Advocate
Office of the Consumer Advocate

Daniel C. Goldner
Chairman
Public Utilities Commission

Pradip K. Chattopadhyay
Commissioner
Public Utilities Commission

Carleton B. Simpson
Commissioner
Public Utilities Commission

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Janet T. Mills
GOVERNOR

William S. Harwood
PUBLIC ADVOCATE

September 18, 2023

Cheryl LaFleur
Chair, Board of Directors
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2024 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

On behalf of the Maine Office of the Public Advocate, we offer the following comments regarding the ISO New England proposed 2024 Operating and Capital Budgets.

We appreciate the ongoing efforts of ISO New England in maintaining the reliability of the regional electric grid and operating regional markets, as well as in working with its constituent states to facilitate their efforts to achieve climate policy goals. We are concerned, however, that in developing its 2024 budget, ISO New England has not adequately considered the price impact of its decisions on Maine or New England utility ratepayers.

Even given recent inflationary pressures, the proposed 21.5 percent increase in the budget is an extremely aggressive increase. We understand that a portion of this is due to a reconciliation of a prior period under recovery. However, even ignoring this factor, the budget reflects a 16.4% increase in revenue requirement.

In our view this increase is unnecessarily high given the significant upward rate pressure that consumers have faced due to commodity price increases and other factors. While some increase in spending is reasonably expected, the level of increase raises concern regarding whether the overall budget has been carefully developed with the price impact on ratepayers in mind.

To address these concerns, we urge the Board of Directors of ISO New England to carefully examine the proposed budget, to challenge ISO New England management to justify its aggressive spending proposals, to be cautious in spending related to the implementation of new initiatives, to reduce this spending as appropriate, and to direct ISO New England management to balance more carefully the fulfillment of its responsibilities with the cost impact on utility ratepayers.

Thank you for your consideration of our concerns.

Sincerely,

William S. Harwood

William S. Harwood
Public Advocate

Andrew Landry
Deputy Public Advocate

Cc: Maria Gulluni, Corporate Secretary, ISO NE

EXHIBIT 10

September 19, 2023

Via Electronic Mail

Claire E. Coleman, Consumer Counsel, Connecticut Office of Consumer Counsel
Marissa Paslick Gillett, Chairman, Connecticut Public Utilities Regulatory Authority
John W. Betkoski, Vice-Chairman, Connecticut Public Utilities Regulatory Authority
Michael A. Caron, Commissioner, Connecticut Public Utilities Regulatory Authority
James M. Van Nostrand, Chair, Massachusetts Department of Public Utilities
Cecile M. Fraser, Commissioner, Massachusetts Department of Public Utilities
Staci Rubin, Commissioner, Massachusetts Department of Public Utilities
Ronald T. Gerwatowski, Chairman, Rhode Island Public Utilities Commission
Abigail Anthony, Commissioner, Rhode Island Public Utilities Commission
John C. Revens, Jr., Commissioner, Rhode Island Public Utilities Commission
Anthony Z. Roisman, Chair, Vermont Public Utility Commission
Margaret Cheney, Commissioner, Vermont Public Utility Commission
Riley Allen, Commissioner, Vermont Public Utility Commission

Dear State Officials:

Thank you for your letter dated September 5, 2023 outlining your comments on ISO New England's proposed 2024 operating and capital budgets. We are pleased that you accept the proposed 2024 budgets and recognize the challenges facing the ISO as the region's power system transitions to clean energy.

The Board of Directors agrees with your comment that the budget increases should be fully vetted to ensure that they reflect prudent management and efficient operations, particularly with respect to the key drivers impacting the proposed increases to the 2024 operating and capital budgets. As noted in your comments, salary increases have a significant impact on the proposed 2024 budget increase. The Board of Directors, and specifically, the Compensation and Human Resources Committee of the Board of Directors, in consultation with relevant experts, have carefully reviewed the currently available results of the of the job benchmark study and will continue to review the results of the future phases of the study. The Board has also focused on how the shortage of talent to effect the clean energy transition is impacting the energy labor market and further exacerbating an already competitive market.

Furthermore, we acknowledge and agree that salary adjustment increases should be narrowly implemented. As noted in the 2024 budget presentation, the salary benchmarking study is job specific and, as such, the results allow the ISO to adjust only salaries for positions where results indicated that salaries were below market. Additionally, when budgeting for the impact of salary adjustments in the 2024 budget (for phases of the job benchmarking study that have not been

completed yet), the ISO did not use a blanket assumption regarding positions that would require a salary equity adjustment. Finally, if the results of the final two study phases indicate that lower salary adjustments than budgeted are required, then any additional funds will be returned to the CEO emerging work allowance. Unused portions of the work allowance are included in the annual true-up to reduce the subsequent year's budget. In sum, the ISO is committed to ensuring that salary adjustments are narrowly tailored to aid the ISO in attracting and retaining critical talent required to achieve the ISO's strategic objectives.

The ISO also remains committed to its prior commitment to evaluate each position that becomes vacant to determine if there is a continued need in the area and for possible repurposing of that headcount for use in other areas of the organization. We agree that this commitment remains important and takes on additional significance as the organization adds headcount.

Finally, regarding the variance between the preliminary budget presented in June and the detailed, bottom-up budget presented in August, as your letter notes, the $800,000 increase is the variance of the proposed operating budgets before depreciation. The rates that the ISO collects through the *ISO New England Inc. Transmission, Markets, and Services Tariff* are based on the Revenue Requirement which includes depreciation and the true-up. When comparing the change in the Revenue Requirement from the preliminary June budget to the August budget, there was a $100,000 reduction.

The Board of Directors appreciates your input and your acknowledgment that budget increases are necessary in light of the changes to the New England power system. We look forward to our continued collaboration with the New England states as we work towards the transition to the future grid.

Sincerely,

Cheryl LaFleur
Chair, ISO New England Board of Directors

September 19, 2023

Via Electronic Mail

Claire E. Coleman, Consumer Counsel, Connecticut Office of Consumer Counsel
James Talbert-Slagle, Staff Attorney, Connecticut Office of Consumer Counsel
Richard Sobolewski, Supervisor of Utility Financial Analysis, Connecticut Office of Consumer Counsel

Dear Ms. Coleman:

Thank you for your letter dated September 5, 2023 providing your supplemental comments on ISO New England's proposed 2024 operating and capital budgets. We appreciate your recognition of the importance of ensuring the ISO has the appropriate staff and resources to fulfill its mission and support the region's clean energy transition. We also acknowledge the two specific concerns that you raised regarding incentive compensation and depreciation expense.

As the ISO is a non-profit corporation governed by an independent Board of Directors, its Board of Directors is responsible for ensuring that the organization's salary levels remain both fiscally prudent and sufficiently competitive to allow the ISO to achieve its mission and strategic objectives. The Board of Directors and the Compensation and Human Resources Committee of the Board of Directors, in consultation with appropriate experts, carefully monitor the structure of employee compensation programs, including incentive compensation. The ISO's incentive compensation program is designed to motivate employees to achieve superior performance on critical annual business and customer service objectives and goals, and awards are based on a formula that includes both company performance and individual performance. Company performance is determined using objective and measurable goals that are set in advance by the Board as informed by the Company's publicly disclosed objectives and initiatives, calculation of the awards and achievement of the goals are verified by the ISO's internal auditors, and payouts are only made after the Board reviews corporate performance and the achievement of the organizational goals. The Company's strategic plan summarizing the Company's 2023 goals and objectives is available here and a summary of the Company's accomplishments, as measured against the 2022 initiatives, is included as Appendix 3 to the budget presentation.

Regarding the vacancy factor, as reflected on Slide 121 of the 2024 budget presentation, the ISO does in fact use a historical based vacancy rate to develop each year's salary budget. For 2024, the ISO used a 5.0% budgeted vacancy rate. The historical vacancy rate, however, is not applied to new positions because a more accurate way to budget for new positions is to only budget for the portion of the authorized headcount that the ISO reasonably expects to be able to fill during the year based

ISO New England Inc.
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on the length of time to recruit and onboard new hires. As explained on Slide 67 of the budget presentation, this resulted in the ISO budgeting for 20 of the 41 authorized positions in 2024.

Finally, with respect to budgeted depreciation expense and depreciation variances, we agree to provide additional information driving such variances in future years' budget presentations. The ISO's depreciation rates remain unchanged from those previously accepted by the Federal Energy Regulatory Commission. What drives the variance in depreciation expense each year are the capital projects that go-live in any given year. As explained in prior budget filings, capital projects costs include software, hardware, project management, and design work. When a capital project is placed into service, the ISO begins collecting depreciation on such project in accordance with the approved service lives.

The significant increase in the 2024 depreciation expense is as a result of completion of certain phases of the multi-phase next Generation Electricity Management (nGEM) platform project. Since 2020, in collaboration with its vendor, General Electric, and the Midcontinent Independent System Operator, Inc. and PJM Interconnection LLC, the ISO has been working to replace its 20+ year old Market Management System with the nGEM platform. This enhanced market platform is foundational to supporting a system with a growing number and type of grid assets, new and more complex market features, multiplying security threats, and advancing IT technologies. In 2023, the ISO completed the customization and implementation of the day-ahead version of the new market clearing engine software and infrastructure service. Upon completion, this phase of the project began depreciating and impacted depreciation expense for the 2023 and 2024 budgets.

The Board of Directors appreciates your input and will consider the issues you have raised carefully as it considers the 2024 and future budgets.

Sincerely,

Cheryl LaFleur
Chair, ISO New England Board of Directors

September 19, 2023

Via Electronic Mail

Jared Chicoine, Commissioner, New Hampshire Department of Energy
Donald M. Kreis, Consumer Advocate, New Hampshire Office of the Consumer Advocate
Daniel C. Goldner, Chairman, New Hampshire Public Utilities Commission
Pradip K. Chattopadhyay, Commissioner, New Hampshire Public Utilities Commission
Carleton B. Simpson, Commissioner, New Hampshire Public Utilities Commission

Dear New Hampshire Officials:

Thank you for your letter dated September 6, 2023 providing your comments on ISO New England's proposed 2024 operating and capital budgets. On behalf of the ISO New England Board of Directors, I'd like to respond to the concerns you raised in your letter.

As the ISO is a non-profit corporation governed by an independent Board of Directors, the Board agrees with your comment that the budget should receive strict scrutiny. We believe that the process we follow with the New England states, stakeholders, and our regulator allows for a full examination of the proposed budget to ensure that it reflects prudent management and efficient operation. The Board of Directors carefully monitors and reviews the budget, including the drivers that impact the revenue needs of the company. As you note, this year's budget is driven primarily by the increasing complexities associated with the clean energy transition. This transition is due in large part to public policies at both the federal and state level, but also in part to industry changes and technological advancements.

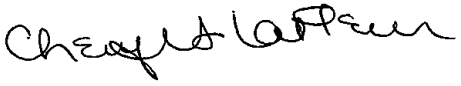
ISO New England has the critical responsibility to ensure the reliability of the regional power system during this transition. The budget provides the necessary resources for the ISO to fulfill its mission and vision and to comply with the increasingly strict reliability standards required by the North American Electric Reliability Corporation in this evolving energy landscape.

With regard to our workforce needs, both the clean energy transition and inflationary pressures are driving increases in compensation. Competition for skilled employees has increased dramatically and the Board has been carefully monitoring the structure of employee compensation programs to ensure the ISO can continue to meet our critical responsibilities as the regional power system becomes more complex. While we are a non-profit corporation, we compete with for-profit companies for the engineers, economists, IT professionals, and other skilled employees that are in high demand in this tight labor market. This proposed budget includes increases to salaries and

performance-based compensation to ensure we can continue to attract and retain the talent necessary to operate this rapidly evolving electric grid.

Finally, I want to assure you that the Board takes consumer cost impacts into account when we review our overall budget and revenue requirement. In fact, this was a key factor in constraining our employee additions over the many years since the 2013 budget settlement with the states. However, we are now experiencing an unavoidable step-change in the workload required to manage the needs of the system given the changing resource mix. We believe this is a responsible budget that strikes the appropriate balance between cost impact and the growing demands on the ISO and will allow the company to continue to meet our critical responsibilities and serve the needs of all New Englanders.

Sincerely,



Cheryl LaFleur
Chair, ISO New England Board of Directors

September 25, 2023

Via Electronic Mail

William S. Harwood, Public Advocate, Maine Office of the Public Advocate
Andrew Landry, Deputy Public Advocate, Maine Office of the Public Advocate

Dear Maine Officials:

Thank you for your letter dated September 18, 2023 providing your comments on ISO New England's proposed 2024 operating and capital budgets. On behalf of the ISO New England Board of Directors, I'd like to respond to the concerns you raised in your letter and assure you that the Board carefully examines the ISO's proposed budgets and, in doing so, considers how proposed budget increases impact consumer costs.

As reflected on Slide 42 of the ISO's budget presentation, the 2024 proposed revenue requirement will result in an average monthly consumer cost (based on an average consumption of 750kWh per month) of $1.46. We acknowledge that this is a significant increase from the 2023 average monthly consumer cost impact of $1.18, and we understand your concern. We believe, however, that the budget strikes the appropriate balance between cost impact and the growing demands on the ISO.

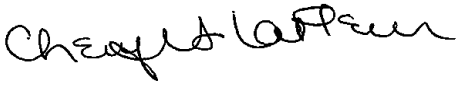
The ISO and the New England region are at a critical juncture in the clean energy transition. This transition, which involves increasingly complex operations and significant shifts within the power system, is due in large part to public policies at both the federal and state level, but also to industry changes and technological advancements. Throughout the transition, the ISO has the critical responsibility to ensure the reliability of the current regional power system. The budget provides the necessary resources for the ISO to fulfill its mission and vision under the current system, and reflects its commitment to supporting the region through the transition.

Furthermore, the ISO has a robust budget development process, which is part of the company's integrated strategic planning approach. This allows the ISO to align its budget with key priorities and initiatives while identifying efficiencies, reductions, and non-recurring costs, and provides multiple opportunities for the Board of Directors and stakeholders to provide input regarding prioritization and cost impacts. The Board process includes review of particular elements of the budgets by Board committees with responsibility in a defined area. For example, compensation matters are reviewed by the Compensation and Human Resources Committee and projects with reliability implications are reviewed by the System Planning and Reliability Committee. The Audit and Finance Committee advises management throughout the development of the budgets and engages in a detailed review of the budgets in both May and August. During its holistic review of proposed budgets, the Board of Directors considers, among other factors, whether the proposed budget adequately supports the

Company's strategic goals and whether management has identified efficiencies and savings. Finally, after reviewing the New England states' questions and comments, and considering the vote of the NEPOOL Participants Committee, the Board votes on the budgets.

We appreciate your input and look forward to continued conversations as the region undergoes a major grid transformation.

Sincerely,



Cheryl LaFleur
Chair, ISO New England Board of Directors