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| **DOCKET NO. 490** – The United Illuminating Company application for a Certificate of Environmental Compatibility and Public Need for the Old Town Substation Rebuild Project that entails construction, maintenance and operation of a 115/13.8-kilovolt (kV) air-insulated replacement substation facility located on the existing Old Town Substation parcel at 282 Kaechele Place and two parcels immediately north totaling approximately 3 acres that are owned by the United Illuminating Company at 312 and 330 Kaechele Place, Bridgeport, Connecticut, and related transmission structure and interconnection improvements. | } | Connecticut<br>Siting<br>Council<br>January 28, 2021 |

## Findings of Fact

### Introduction

1. The United Illuminating Company (UI or Applicant), in accordance with provisions of Connecticut General Statutes (C.G.S.) § 16-50g, et seq., and 16-50j-1 et seq. of the Regulations of Connecticut State Agencies (R.C.S.A.), applied to the Connecticut Siting Council (Council) on June 30, 2020 for a Certificate of Environmental Compatibility and Public Need (Certificate) for the construction, maintenance, and operation of a replacement 115/13.8 kilovolt (kV) air insulated substation at 282, 312 and 330 Kaechele Place, Bridgeport, Connecticut. (UI 1, p. FR-1 and ES-1)

2. UI provides electrical distribution service to approximately 320,000 customers in 17 municipalities located in southwestern Connecticut. (Transcript 1, October 15, 2020, 2:00 p.m. [Tr. 1], p. 14)

3. The parties in this proceeding are the Applicant and The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource). (Tr. 1, p. 6)

4. The proposed replacement substation would replace UI's existing 115-kV/13.8-kV air insulated Old Town Substation, which is located at 282 Kaechele Place, Bridgeport. (UI 1, p. FR-1)

5. The purpose of the proposed replacement substation facility is to improve the reliability of service to customers in the Bridgeport area and to the New England power grid by addressing issues associated with the physical condition of the existing substation equipment and infrastructure. (UI 1, pp. FR-1 and 1-1)

6. Pursuant to C.G.S. § 16-50*l* (b), public notice of the filing of the application to the Council was published in the Connecticut Post on June 19, 2020. (UI 1, Tab H – Formal Requirements)

7. Pursuant to C.G.S. § 16-50*l* (b), notice of the application was provided to all abutting property owners. Certified mail receipts or confirmation of UPS delivery from all abutting property owners were received except for Eversource and Worldwide Properties LLC. UI has had extensive consultations with Eversource. A notice was resent to Worldwide Properties via Priority Mail on September 15, 2020. (UI 1, Tab H – Formal Requirements; UI 2, response 1 – Attachment A)

8. In accordance with the Council's Application Guide for an Electric Substation Facility, UI provided notice to a number of area community groups including, but not limited to, land trusts, environmental groups, historic preservation groups, and a local water company. (UI 1, Tab H – Formal Requirements)

9. On June 26, 2020, UI provided notice to all federal, state and local officials and agencies listed in C.G.S. § 16-50*l* (b). (UI 1, Tab H – Formal Requirements)

**Procedural Matters**

10. On March 10, 2020, Governor Lamont issued a Declaration of Public Health and Civil Preparedness Emergencies, proclaiming a state of emergency throughout the state as a result of the COVID-19 pandemic. (Council Administrative Notice Item No. 68)

11. On March 12, 2020, Governor Lamont issued Executive Order No. (EO) 7 ordering a prohibition of large gatherings, among other orders and directives. (Council Administrative Notice Item No. 68)

12. On March 14, 2020 and as subsequently extended, Governor Lamont issued EO 7B ordering suspension of in-person open meeting requirements of all public agencies under CGS §1-225. The Freedom of Information Act defines "meeting" in relevant part as "any hearing or other proceeding of a public agency." (Council Administrative Notice Item No. 68, CGS §1-200, *et seq*. (2019))

13. EO 7B allows public agencies to hold remote meetings provided that:
    a) The public has the ability to view or listen to each meeting or proceeding in real-time, by telephone, video, or other technology;
    b) Any such meeting or proceeding is recorded or transcribed and such recording or transcript shall be posted on the agency's website within seven (7) days of the meeting or proceeding;
    c) The required notice and agenda for each meeting or proceeding is posted on the agency's website and shall include information on how the meeting will be conducted and how the public can access it;
    d) Any materials relevant to matters on the agenda shall be submitted to the agency and posted on the agency's website for public inspection prior to, during and after the meeting; and
    e) All speakers taking part in any such meeting shall clearly state their name and title before speaking on each occasion they speak.

    (Council Administrative Notice Item No. 68)

14. On March 25, 2020 and as subsequently extended, Governor Lamont issued EO 7M allowing for an extension of all statutory and regulatory deadlines of administrative agencies for a period of no longer than 90 days. (Record; Council Administrative Notice Item No. 68)

15. On July 10, 2020, the Council sent a letter to the State Treasurer, with a copy to the Chief Elected Official of the City of Bridgeport (City) stating that $25,000 was received from UI and deposited in the Office of State Treasurer's Municipal Participation Account for use by the City to apply for a portion of the funds if they become a participant in the proceeding, pursuant to CGS §16-50bb. (Record)

16. During a regular Council meeting on August 27, 2020, the application was deemed complete pursuant to R.C.S.A. § 16-50*l*-1a and EO 7M, and the public hearing schedule was approved by the Council pursuant to EO 7B. (Record)

17. Pursuant to Governor Lamont's EO 7B and C.G.S. § 16-50m, the Council published legal notice of the date and time of the remote public hearing via Zoom conferencing in the Connecticut Post on September 1, 2020. (Record)

18. Pursuant to Governor Lamont's EO 7B and C.G.S. § 16-50m, on August 28, 2020, the Council sent a letter to the City of Bridgeport and the Town of Trumbull* to provide notification of the scheduled remote public hearing via Zoom conferencing and to invite the municipality to participate.

    *The Town of Trumbull is located within 2,500 feet of the proposed replacement facility.

    (Record; UI 1, p. 1-2, Figure 1 – Project Area)

19. In compliance with Governor Lamont's EO 7 prohibition of large gatherings, the Council's Hearing Notice did not refer to a public field review of the proposed site. (Council's Hearing Notice dated August 28, 2020)

20. Field reviews are not an integral part of the public hearing process. The purpose of a site visit is an investigative tool to acquaint members of a reviewing commission with the subject property. (Council Administrative Notice Item Nos. 69 and 70)

21. On September 8, 2020, in lieu of an in-person field review of the proposed site, the Council requested that UI submit photographic documentation of site-specific features into the record intended to serve as a "virtual" field review of the site. On September 25, 2020, UI submitted such information in response to the Council's interrogatories. (Record; UI 2, response 22)

22. On September 23, 2020, the Council held a pre-hearing teleconference on procedural matters for parties and intervenors to discuss the requirements for pre-filed testimony, exhibit lists, administrative notice lists, expected witness lists, and filing of pre-hearing interrogatories. Procedures for the remote public hearing via Zoom conferencing were also discussed. (Council Pre-Hearing Conference Memoranda, dated September 16, 2020 and September 24, 2020)

23. In compliance with R.C.S.A. § 16-50j-21, UI installed a four-foot by six-foot sign at the entrance to the subject property on September 24, 2020. The sign presented information regarding the project and the Council's public hearing. (UI 3)

24. Pursuant to C.G.S. § 16-50m, the Council, after giving due notice thereof, held a remote public hearing on October 15, 2020, beginning with the evidentiary session at 2:00 p.m. and continuing with the public comment session at 6:30 p.m. via Zoom conferencing. The Council provided access information for video/computer access or audio only telephone access. (Council's Hearing Notice dated August 28, 2020; Tr. 1, p. 1; Transcript 2 – 6:30 p.m. [Tr. 2], p. 90)

25. In compliance with Governor Lamont's EO 7B:

    a) The public had the ability to view and listen to the remote public hearing in real-time, by computer, smartphone, tablet or telephone;
    b) The remote public hearing was recorded and transcribed, and such recording and transcript were posted on the Council's website on October 16, 2020 and October 20, 2020, respectively;

c) The Hearing Notice, Hearing Program, Citizens Guide for Siting Council Procedures and Instructions for Public Access to the Remote Hearing were posted on the agency's website;
d) The record of the proceeding is available on the Council's website for public inspection prior to, during and after the remote public hearing; and
e) The Council, parties and intervenors provided their information for identification purposes during the remote public hearing.

(Hearing Notice dated August 28, 2020; Tr. 1; Tr. 2; Record)

**Municipal Consultation and Community Outreach**

26. UI initially met with City of Bridgeport officials on August 27, 2019 to provide general information about the proposed project. (UI 1, p. 8-2 and Tab H – Formal Requirements, Outreach Log)

27. UI formally commenced the 60-day pre-application municipal consultation process by providing a copy of the technical report to the Chief Elected Officials of the City of Bridgeport and the Town of Trumbull on January 17, 2020. (UI 1, pp. ES-6 and 8-1; UI 1f)

28. UI did not receive any feedback on the project from the City of Bridgeport or the Town of Trumbull subsequent to the submittal of the technical report. (Tr. 1, p. 14)

29. On March 9, 2020, UI held a public meeting on the proposed project at the Lake Forest Clubhouse. (UI 1, p. 8-2 and Tab H – Formal Requirements, Outreach Log)

30. In June and July 2020, Eversource, in coordination with UI, consulted with municipal officials in the City of Bridgeport to brief them on the proposed project. In September 2020, Eversource consulted with the City of Bridgeport to obtain off right-of-way (ROW) access across the City of Bridgeport property on Kaechele Place. Eversource provided the City of Bridgeport with a draft permanent access agreement. (Eversource 2, pp. 8-9; Tr. 1, p. 78)

31. UI has also held discussions with the City of Bridgeport regarding acquiring an approximately 0.15 acre easement located within Elton Rodgers Woodland Park (ERWP) to accommodate clearance requirements for the transmission connections to the proposed replacement substation. Easement documentation is being drafted. (UI 1, pp. ES-4 and 2-1; Tr. 1, pp. 14-15)

**State Agency Comment**

32. Pursuant to C.G.S. § 16-50j (g), on August 28, 2020, the following state agencies were solicited by the Council to submit written comments regarding the proposed facility: Department of Energy and Environmental Protection (DEEP); Department of Public Health (DPH); Council on Environmental Quality (CEQ); Public Utilities Regulatory Authority (PURA); Office of Policy and Management (OPM); Department of Economic and Community Development (DECD); Department of Agriculture (DOAg); Department of Transportation (DOT); Connecticut Airport Authority (CAA); Department of Emergency Services and Public Protection (DESPP); and State Historic Preservation Office (SHPO). (Record)

33. The Council did not receive any comments from the state agencies solicited. (Record)

34. While the Council is obligated to consult with and solicit comments from state agencies by statute, the Council is not required to abide by the comments from state agencies. (*Corcoran v. Connecticut Siting Council*, 284 Conn. 455 (2007)).

**System Planning and Mandatory Reliability Standards**

35. ISO New England Inc. (ISO-NE) is the non-for-profit corporation responsible for the reliable and economical operation of New England's electric power system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system. The planning process includes the periodic preparation of a Regional System Plan (RSP) in accordance with the ISO's *Open Access Transmission Tariff* (OATT) and other parts of the *Transmission, Markets, and Services Tariff* (the ISO tariff), approved by the Federal Energy Regulatory Commission (FERC). RSPs meet the tariff requirements by summarizing planning activities that include the following:

    a) Forecasts of annual energy use and peak loads (i.e. the demand for electricity) for a 10-year planning horizon and the need for resources (i.e., capacity)
    b) Information about the amounts, locations, and characteristics of market responses (e.g., generation or demand resources or elective transmission upgrades) that can meet the defined system needs both systemwide and in specific areas
    c) Descriptions of transmission projects for the region that meet the identified needs, as summarized in an RSP Project List, which includes information on project status and cost estimates and is updated several times each year.

    (Council Administrative Notice Item No. 21 – 2019 RSP, p. iii)

36. New England's electric power grid is planned and operated as a unified system of transmission owners and market participants. The New England system integrates resources with the transmission system to serve all regional load regardless of state boundaries. Most of the transmission lines are relatively short and networked as a grid. Therefore, the electrical performance in one part of the system affects all areas of the system. (Council Administrative Notice Item No. 21 – 2019 RSP, p. 27)

37. In DEEP's 2018 Comprehensive Energy Strategy, Strategy No. 5 is "Continue to improve grid reliability and resiliency through state and regional efforts." (Council Administrative Notice Item No. 52 – 2018 Comprehensive Energy Strategy, p. 45)

38. In 2016, ISO-NE created a New England Asset-Condition Update List (ACUL) to capture all asset condition Planning Advisory Committee presentations that occur after May 18, 2015. ISO-NE updates the ACUL three times per year along with its RSP Project List. (Council Administrative Notice Item No. 21 – 2019 RSP, p. 92)

39. A rebuild/replacement of the Old Town Substation is neither identified on the October 2019 ACUL nor the October 2019 RSP Project List. (Council Administrative Notice Item No. 22 – October 2019 RSP Project List; Council Administrative Notice Item No. 23 – October 2019 ACUL)

40. The Old Town Substation Rebuild Project was identified in UI's 2020 Ten-Year Forecast of Electric Loads and Resources Report. (Tr. 1, pp. 15-16, 19)

## Public Need

### Bridgeport Area Electric System

41. Three overhead 115-kV transmission lines owned by Eversource are the #1222 Line, #1710 Line and the #1714 Line and occupy the ROW that extends through the existing Old Town Substation site. (UI 1, p. ES-1)

42. The overhead transmission lines in the vicinity of the existing substation are supported by two double-circuit 105-foot tall lattice structures. Structure No. 857 is located east of the substation and within the Eversource ROW, and Structure No. 857A is located immediately north of the substation and within the Eversource ROW. (UI 1, p. 2-4 and Appendix A – Drawing SK-25233-003-001 SH2)

43. Structure No. 857 supports the #1714 Line on the north side of the structure and the #1710 on the south side of the structure. Structure No. 857A supports the #1714 Line on the north side of the structure and the #1222 Line on the south side of the structure. (UI 1, p. 2-4 and Appendix A – Drawing SK-25233-003-001 SH2)

### Existing Old Town Substation

44. The existing Old Town Substation was constructed and placed into service in the 1960s. The substation connects to the #1710 Line and the #1222 Line which terminate within the substation fence line, and the substation steps down the voltage delivered from these transmission lines to feed UI's local distribution system. (UI 1, p. 1-3; Tr. 2, p. 98)

45. The #1714 Line bypasses the existing Old Town Substation and links UI's Trumbull Substation and Eversource's Weston Substation. (UI 1, p. 1-3)

46. The existing Old Town Substation is geographically located to feed the distribution capacity needs of the City of Bridgeport, as well as the neighboring municipalities of Easton, Fairfield and Trumbull. Approximately 90 percent of the substation's load is centered around the Bridgeport and Trumbull area. The substation serves approximately 17,000 customers. (UI 1, p. 1-3; Tr. 2, p. 98)

47. The existing Old Town Substation consists of the following components including, but not limited to:

    a) Substation yard;
    b) Control enclosure with two electrical distribution buses and distribution switchgear;
    c) 115-kV oil circuit breaker (OCB);
    d) Two 60 megavolt ampere (MVA) 115-kV/13.8-kV power transformers;
    e) 115-kV bus structure;
    f) Number 3 13.8-kV bus enclosure;
    g) One 13.8-kV 7.2 megavolt ampere reactive (MVAR) capacitor bank enclosure; and
    h) Support structures for overhead transmission line switches and electrical components such as current transformers, capacitive coupled voltage transformers and lightning arrestors.

    (UI 1, p. 1-3)

UI Reliability Planning

48. As part of efforts to assess the condition of its transmission line and substation infrastructure, UI conducted studies to evaluate the present and future viability of the existing Old Town Substation. These studies included the following:

a) A comprehensive physical evaluation of the substation that involved analyses of the substation foundations, perimeter fencing, grounding components, control wiring, conduit, and control enclosure;
b) A condition assessment of the existing short-circuit adequacy of equipment and bus structures, lightning protection, and conformance to National Electrical Safety Code (NESC) clearance requirements and UI design standards; and
c) A 3D Light Detection and Ranging (LiDAR) survey of the 115-kV yard to evaluate conformance to American National Standards Institute (ANSI), NESC, and UI clearance requirements with a focus on the areas surrounding the 115-kV OCB and associated disconnect switches.

(UI 1, p. 1-6)

49. As a result of its studies, UI determined that Old Town Substation contains the following deficiencies in terms of reliability and physical condition:

a) **Inadequate Lightning Protection** – The substation bus infrastructure does not adequately protect the exposed equipment (such as disconnect switches) from direct stroke lightning strikes. UI's analysis determined that there is a 99.8 percent probability that the exposed equipment would be damaged from lightning strikes;
b) **Insufficient Control Enclosure Space** – The existing control enclosure does not meet NESC criteria for sufficient work room and cannot be expanded due to the small size of the existing substation site. As result, the control enclosure cannot be upgraded to support any needed improvements at the substation;
c) **Single Point of Failure** – Both mains to and feeders from the No. 3 bus enclosure extend though the same manhole in the substation yard. This design is unique to Old Town Substation and is not found elsewhere in UI's system. A catastrophic event in this manhole, such as a cable fault, has the potential to de-energize the entire substation as these sections of cable are covered by the transformer differential protection scheme. Thus, there is a significant risk of interrupting all customer load supplied by the substation for an extended period of time due to the design of this manhole;
d) **Bus No. 3 Enclosure Issues** – Bus No. 3 is essentially a metal enclosed switchgear. It is located on piers rather than a flat slab foundation. The steer bus is buckling from the weight of the circuit breakers, so it is becoming more difficult to "rack in" and "rack out" the circuit breakers. UI has had several incidents of where the breakers do not operate properly because of the shifting of the floor. Thus, remediation is required. While UI has performed maintenance to address the breaker issues, the underlying problem leading to these failures persists, and it requires frequent and more difficult maintenance due to the age of the equipment and the lack of available replacement parts;
e) **OCB Replacement** – The substation's 115-kV OCB is obsolete and poses increased risk of failure. It is the only OCB that UI still has in its system. Other OCBs have already been replaced with gas insulated circuit breakers. This existing OCB is difficult to maintain due to its age and availability of spare parts;

f) **Lack of Mobile Substation Access** – UI owns two 50 MVA 115-kV/13.8-kV mobile substation transformers that can be deployed to substations in the event of a transformer failure in order to maintain service to customers. However, the existing Old Town Substation was designed for a single point of access for mobile substation deployment and has insufficient space to deploy even UI's smallest mobile transformer without violating clearances to the overhead strain bus. In addition, the only available location for a mobile transformer is over the substation's septic system. No other space is available due to the location of the substation equipment and the small overall size of the existing substation site;

g) **Disconnect Switch Maintenance Issues** – The OCB disconnect switches are outdated and increasingly difficult to maintain due to absence of replacement parts and long lead times for specialty fabricated components. In addition, the disconnect switches do not conform to current ANSI standards; and

h) **Corroded Capacitor Coupled Voltage Transformers (CCVTs)** – Two CCVTs for the #1710 Line require replacement. These CCVTs are corroded with a high risk of moisture penetration into the internal components.

(UI 1, pp. 1-6 and 1-7; Tr. 1, pp. 17-19)

Contingency Modeling – Old Town Substation

50. A 90/10 load forecast contains load projections based on a plausible worst-case hot weather scenario. It means that there is only a 10 percent chance that the projected peak load would be exceeded in a given year. 90/10 load forecasts are used for utility infrastructure planning. (Council Administrative Notice Item No. 43 – Council 2017/2018 Forecast of Electric Loads and Resources, pp. 9 and 20)

51. The weather-normalized 90/10 loading of the existing Old Town Substation was 64.82 MVA during 2019. Based on UI's 2019 90/10 Ten Year Load Forecast, this loading is projected to grow to 66 MVA by 2030; this results in a compound annual growth rate (CAGR) of approximately 0.164 percent. (UI 2, responses 4, 8 and 9; Council Administrative Notice Item No. 43 – Council 2017/2018 Forecast of Electric Loads and Resources, CAGR Formula, p. 20)

52. The existing Old Town Substation transformers have a total capacity of approximately 85 MVA. Thus, UI's proposed replacement of the Old Town Substation is not due to an existing MVA capacity issue. (UI 2, response 4; Tr. 1, p. 16)

53. The proposed replacement substation would be constructed with two transformers with a top nameplate rating of 75 MVA. The MVA capacity of the proposed replacement substation depends on the emergency load ability of the transformers and would be determined based on a thermal analysis of the as-built transformers. Notwithstanding, the MVA capacity of the proposed replacement substation is expected to be significantly greater than the nameplate rating of 75 MVA. (UI 2, response 8; Tr. 1, p. 16)

54. The proposed replacement substation would also be designed to accommodate a mobile transformer for emergency conditions. (UI 1, p. 2-3; UI 2, response 15)

**System Alternatives**

55. UI considered three potential system alternatives as noted below:

    a) No action;
    b) Rebuild the entire substation in place, over the existing footprint; or
    c) Full replacement on a different site.

    (UI 1, pp. 9-1 to 9-5)

56. With the "No Action" alternative, the existing Old Town Substation would continue in-service at the present site, and there would be no improvements made to upgrade the substation's transmission and distribution system infrastructure. Thus, the current infrastructure issues would remain including, but not limited to: reliability and operating issues relating to the substation's transmission and distribution infrastructure; obsolete 115-kV OCB and associated disconnect switches; inadequate control enclosure; insufficient access/clearance for emergency mobile transformers; and inadequate lightning protection. Thus, the "No Action" alternative was rejected because it would not resolve the asset condition issues at the Old Town Substation, and it would not improve the reliability of the electric system. The substation would remain outdated and at risk for equipment failures that would lead to extended duration outages affecting customers and the bulk power system. (UI 1, p. 9-2)

57. With the "Rebuild in Place" alternative, the existing Old Town Substation would be upgraded including, but not limited to, replacement of the transformers to conform to UI's current standard; provision of access for a mobile substation transformer; and addition of a new pre-fabricated control enclosure. Such upgrades would cost approximately $47M. (UI 1, p. 9-3; Tr. 1, p. 20)

58. The "Rebuild in Place" alternative was rejected because it would result in various constraints and construction challenges. For example, the existing substation would have to be taken out of service for an extensive length of time, and construction activities would have to be closely coordinated with available outage periods. A mobile substation would be required at the site to maintain reliable service to UI customers; the mobile substation would be unavailable for other uses; and it would further increase the complexity of the substation construction. There would be increased safety risk during construction because substation upgrades would have to be performed in proximity to energized equipment. The "Rebuild in Place" alternative does not include any provisions for the expansion of the substation to serve future customer needs or for the replacement of equipment that may become obsolete in the future. Lastly, the "Rebuild in Place" alterative would be more costly at $47M than the proposed replacement substation which is estimated to cost about $39.1M. (UI 1, p. 9-3; UI 2, response 6)

59. After determining that the asset condition issues at Old Town Substation could not feasibly be addressed by the "Rebuild in Place" alternative, UI conducted a review to identify and assess potential sites for a replacement Old Town Substation. (UI 1, p. 9-4)

**Location Alternatives**

60. In its search for a substation site, UI considered the following standard criteria below:

a) Minimize the need to acquire residences and viable commercial/industrial uses to accommodate substation development;
b) Maintain consistency/compatibility with existing land uses and land use plans to the extent possible;
c) Minimize adverse effects on sensitive environmental resources;
d) Protect public health and safety; and
e) Demonstrate cost-effectiveness while adhering to good engineering and sound environmental planning practices.

(UI 1, p. 9-4)

61. UI also considered the following site-specific criteria relative to a replacement substation site.

a) Distance to the existing Old Town Substation and the Eversource 115-kV transmission lines that must connect to the substation;
b) Availability of property, e.g. sites that are UI-owned, vacant/undeveloped, for sale, or would not require the removal or relocation of existing commercial or residential uses;
c) Site size of at least 2.75 acres, including undeveloped buffers and setbacks needed for a 115/13.8-kV AIS facility of the type required for the replacement substation;
d) Site topography and subsurface conditions;
e) Environmental and land use characteristics, including present and past property uses, e.g. presence of jurisdictional water resources, cultural resources, threatened/endangered species, and need for environmental remediation;
f) Substation constructability;
g) Availability of property (e.g. via fee ownership or easement) for transmission and distribution line connections to the substation and the required lengths of new transmission and distribution line segments needed to connect the replacement substation;
h) Accessibility;
i) Permit-ability, i.e. the anticipated ability to obtain all required regulatory approvals for construction at the site; and
j) Cost.

(UI 1, pp. 9-4 and 9-5)

62. UI identified seven potential sites to construct a replacement substation. These sites are listed below:

a) 4750 Park Avenue, Bridgeport;
b) 561 Frenchtown Road, Bridgeport;
c) 280, 312, 330 Kaechele Place, Bridgeport (i.e. the proposed site);
d) 2300 Reservoir Avenue, Trumbull;
e) Quarry Road, Trumbull;
f) Rocky Ridge Drive/Quail Trail, Trumbull; and
g) Huntington Turnpike, Trumbull.

(UI 1, p. 9-8)

63. After examining the potential sites, UI selected the proposed site for a replacement substation. None of the remaining six sites are presently owned by UI or dedicated to utility use. As a result, property acquisition would pose challenges and would increase costs. Additionally, none of the six remaining sites are located in the immediate vicinity of the existing Old Town Substation; thus, no efficiencies would be realized via minimizing new transmission and distribution connections. Several of the six remaining sites have land use constraints (e.g. presence of wetlands and recreational uses), and others would require costly distribution system connections. (UI 1, p. 9-7)

64. After the proposed site was identified as the preferred location for a replacement substation, UI also reviewed substation configuration options such as an air insulated substation (AIS) design versus a gas insulation substation (GIS) design. UI selected the AIS design because the proposed site has sufficient space to accommodate this design, and a GIS design would be more costly. (UI 1, p. 9-2)

**Proposed Site Location**

65. The proposed replacement substation site includes a 0.9-acre UI-owned parcel located at 282 Kaechele Place that contains UI's existing Old Town Substation and a total of 3 acres of undeveloped UI-owned parcels at 312 and 330 Kaechele Place (collectively, the subject property). (UI 1, p. ES-1)

66. The existing substation parcel is entirely developed for utility use and contains no vegetation other than lawn and ornamental vegetation along Kaechele Place. The undeveloped UI parcels contain upland forest, shrub vegetation, and a wetland. (UI 1, p. ES-1)

67. The subject property is located within the City's Residential (R-A) Zone. (UI 1, p. 4-7)

68. Commercial development exists west of the subject property along Kaechele Place and Main Street. A single commercially-developed property, which fronts on Main Street, and multiple residentially-developed properties located along Sequoia Road abut the subject property to the north. ERWP, a City of Bridgeport park and a large wooded property, abuts the subject property to the east and south. ERWP is undeveloped but does have some blazed hiking trails. The Eversource electrical transmission ROW extends from the east through ERWP and through a portion of the existing substation site before continuing to the west. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 1 and Existing Conditions Photo-simulation)

69. There are approximately 89 residences located within a 1,000-foot radius of the center of the proposed replacement substation. (UI 2, response 2)

70. The nearest residence is located approximately 90 feet southwest of the proposed replacement substation fence line. (UI 1, Appendix G – Electric and Magnetic Field Report, pp. 13-14)

**Proposed Replacement Substation Description**

71. The proposed replacement substation would have an irregular shape with an interior fenced area totaling 2.25 acres (or approximately 98,000 square feet) which consists of 0.9 acre of the existing substation parcel and 1.35 acre of the 3 acres of additional parcels. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p.1 and Proposed Conditions Photo-simulation)

72. The proposed replacement substation would be enclosed by a 14-foot high chain link fence with privacy slats and one foot of barbed wire on top. (UI 1, p. ES-2 and 2-4)

73. To accommodate existing topography and minimize grading, a concrete retaining wall approximately 700 feet in length and ranging from two to ten feet in height would be constructed around portions of the substation perimeter, and the chain link fence would be installed on top of the retaining wall. (UI 1, pp. ES-4 and 2-4)

74. Access to the substation would be via a new paved access drive inside the fenced substation from two gates* located off of Kaechele Place.

*A third gate not associated with the access drive will be located within the transmission line ROW. (UI 1, p. 2-1 and Appendix A – Drawing SK-25233-003-001 SH2; Tr. 1, pp. 21-22)

75. The interior surface of the proposed replacement substation would consist of traprock, with the exception of areas occupied by equipment/enclosures and the access drive. (UI 1, pp. 3-2 and 3-5; Tr. 1, pp. 21-22)

76. The primary substation components would include, but not be limited to:

a) A new approximately 3,840 square foot control enclosure and 13.8-kV switchgear enclosure with dimensions of 120 feet long by 32 feet wide by 16 feet high;
b) Two 115-kV/13.8-kV 45/60/75 MVA power transformers;
c) Three 115-kV sulfur hexafluoride ($SF_6$) dead tank circuit breakers;
d) 115-kV disconnect switches;
e) Capacitor coupled voltage transformers;
f) Associated 115-kV insulators, tubular aluminum bus, surge arrestors, and connectors;
g) Provisions to accommodate a temporary mobile transformer for emergency conditions;
h) Lightning masts; and
i) Associated structural steel to support electrical equipment.

(UI 1, p. 2-3)

77. The proposed control enclosure and switchgear enclosure would contain the following including, but not limited to:

a) Protection and control panels with associated relay and metering equipment;
b) Battery banks and associated chargers;
c) AC/DC distribution panels;
d) Lavatory facility;
e) Communications equipment;
f) Heating, ventilation and air conditioning (HVAC) equipment;
g) The switchgear room would accommodate construction of four new lineups of indoor 13.8-kV gas insulated substation switchgear separated with space for future additions.

(UI 1, p. 2-3)

78. The existing Eversource transmission connections would be relocated to the proposed replacement substation. Specifically, the #1710 Line and the #1222 Line would connect to the line terminals at the proposed replacement substation. The #1714 Line would be re-routed through the proposed substation yard in anticipation of a future connection, but it would not be connected to the substation at this time. (UI 1, p. 2-4)

79. Eversource would replace the two existing steel lattice towers with four new monopoles to accommodate the transmission interconnection. The four new monopoles would be approximately 105 feet above ground level (agl) which is the same height as the two existing self-supporting lattice structures to be replaced. UI would install five monopoles inside the proposed replacement substation, each reaching a height of less than 100 feet agl. All nine proposed monopoles would have a galvanized steel finish. (UI 1, pp. 2-4, 2-5 and Appendix D – Visual Assessment and Photo-Simulations, p. 1; Tr. 1, p. 21; UI 2, response 12)

80. Eversource would own the four monopoles located outside of the proposed replacement substation along with the insulators and hardware attached to the monopoles. UI would own the five monopoles located inside the proposed replacement substation, conductors entering and exiting the substation to reach the Eversource monopoles, and substation equipment. (UI 1, p. 1-10; Tr. 1, p. 42)

81. UI's proposed replacement substation project would require approximately 18 to 24* months to construct. This includes, but is not limited to, the construction of the replacement substation and installation of new line connections, as well as removal of the 115-kV line connections to the existing Old Town Substation. Construction would commence in early 2023, and the replacement substation is projected to be in service by the end of second quarter 2024. The decommissioning work for the existing Old Town Substation could extend beyond this projected schedule window.

*Once the replacement substation is substantially complete by UI, Eversource's line construction work would commence and would require approximately four months to complete. (UI 1, pp. 3-7 and 7-1; Eversource 2, p. 8)

82. Construction hours for UI and Eversource would generally occur from 7:00 a.m. to 7:00 p.m. Monday through Saturday. Some extended hours and Sunday work may be necessary due to circumstances such as inclement weather, outage constraints, and construction work that must occur on a continuous basis such as concrete pours and foundation installations. (UI 1, p. 3-7; Eversource 2, p. 8)

83. After the proposed replacement substation is constructed, the 115-kV transmission lines and 13.8-kV distribution lines are connected, and the facility is commissioned and placed into service, UI will decommission the existing Old Town Substation and associated 115-kV/13.8-kV line connections. This decommission work would include, but not be limited to:

    a) Decommission and remove electrical components within the substation e.g. 115-kV 60 MVA transformers, OCB, bus and structures, CCVTs, switchgear and control enclosure;
    b) Remove aboveground structural components within the substation; and
    c) Eversource would dismantle and remove the existing overhead transmission line connections to the substation e.g. remove conductors, arms and structures.

    (UI 1, p. 2-6)

## Environmental Considerations

### Coastal Area Resources

84. The proposed site is not located within a Coastal Boundary. (UI 2, response 19)

Agricultural Resources

85. There are no Prime Farmland Soils located on the proposed site. (UI 2, response 20)

Historic and Archaeological Resources

86. No previously identified archaeological sites or properties listed or eligible for listing on the National Register of Historic Places are located within 0.5 mile of the proposed project area. (UI 1, Appendix B – SHPO Letter dated January 16, 2020)

87. No historic properties would be affected by the proposed project. (UI 1, Appendix B - SHPO Letter dated January 16, 2020)

Forest

88. On the subject property, UI would clear shrub vegetation and remove approximately 60 trees of six inches diameter or greater to construct the project. In addition, within the easement in the ERWP, approximately 10 additional trees of six inches diameter or greater would be removed to accommodate the relocated overhead 115-kV transmission line connections to the proposed replacement substation. (UI 1, p. 3-3)

89. No tree clearing or widening of the ROW would be necessary for the installation of Eversource's monopole structures. (Eversource 2, p. 5)

90. No tree clearing within core forest is proposed for this project. (UI 2, response 21)

Wildlife

91. By letter dated October 18, 2019, DEEP reviewed the Natural Diversity Database (NDDB) and found that the eastern box turtle (EBT), a state-listed Species of Species Concern, occurs in the area of the proposed site. DEEP included protective measures for the EBT including, but not limited to, performing work during the active season of April through October; hiring a qualified herpetologist; use of exclusion fencing; contractor training; protection of wetland habitat; and reporting requirements. UI would implement the protective measures for the EBT. (UI 1, Appendix B.2.2 – DEEP NDDB Letter dated October 18, 2019; UI 1, pp. 5-5 and 5-6; Tr. 1, p. 53)

92. UI consulted with the U.S. Fish and Wildlife Service (USFWS) regarding the northern long-eared bat (NLEB), a federally-listed Threatened Species and state-listed Endangered Species. USFWS indicated that no NLEB habitat occurs at the site. However, based on UI's ecological assessment of the site, three to five viable NLEB roosting trees were identified at the proposed site. In the unlikely event that NLEB utilizes such trees as roosting or nursery habitat, UI would limit clearing to outside of the June through July pup season. (UI 1, p. 4-5; UI 1, Appendix C – Ecological Assessment Report, p. 1; Council Administrative Notice Item No. 54 – 2015 DEEP Endangered, Threatened and Special Concern Species)

93. Depending upon the type of species identified, Eversource would employ appropriate wildlife protection measures including time of year construction. (Tr. 1, p. 81)

Wetlands and Watercourses

94. The Inland Wetlands and Watercourses Act (IWWA), CGS §22a-36, *et seq.*, contains a specific legislative finding that the inland wetlands and watercourses of the state are an indispensable and irreplaceable but fragile natural resource with which the citizens of the state have been endowed, and the preservation and protection of the wetlands and watercourses from random, unnecessary, undesirable and unregulated uses, disturbance or destruction is in the public interest and is essential to the health, welfare and safety of the citizens of the state. (CGS §22a-36, et seq.)

95. The IWWA grants regulatory agencies with the authority to regulate upland review areas in its discretion if it finds such regulations necessary to protect wetlands or watercourses from activity that will likely affect those areas. (CGS §22a-42a)

96. The IWWA forbids regulatory agencies from issuing a permit for a regulated activity unless it finds on the basis of the record that a feasible and prudent alternative does not exist. (CGS §22a-41)

97. UI performed an on-site wetland and watercourse investigation of the proposed site on April 23, 2018. (UI 1, Appendix C – Ecological Assessment Report, p. 1)

98. Wetland A is an on-site 0.49 acre wetland and unnamed intermittent stream identified in the northern portion of the site. (UI 1, Appendix C – Ecological Assessment Report, pp. 2, 4 and Wetland Delineation, Figure 3)

99. Wetland B is an off-site wetland and unnamed intermittent stream identified southeast of the proposed site within the ERWP as well as within the Eversource ROW. (UI 1, Appendix C – Ecological Assessment Report, pp. 3, 4 and Wetland Delineation, Figure 3)

100. As a result of construction, UI does not anticipate any permanent impacts to Wetland A, e.g. fill being placed within Wetland A. However, as the design of the substation is finalized, it is possible that some vegetation may need to be cut in this wetland, and some construction activities (including the installation of the retaining wall) may necessitate the use of temporary construction matting in the western portion of the wetland. (UI 1, p. 5-3; Tr. 1, pp. 60, 72)

101. If any temporary wetland impacts are required, UI would consult with and provide necessary submittals to DEEP and the U.S. Army Corps of Engineers (ACOE). If any portion of Wetland A must be filled to develop the substation, UI would also consult with and secure appropriate permitting from DEEP and ACOE. (UI 1, p. 5-3)

102. During the April 2018 wetland and watercourse delineation, Wetland B was initially identified as potential habitat for breeding amphibians. Wetland A was not identified as potential habitat for breeding amphibians due to inadequate hydrology. On April 5, 2019, a follow-up survey was performed, and no obligate vernal pool species were identified in Wetland B. Thus, Wetland B is not considered viable vernal pool habitat. (UI 1, Appendix C – Ecological Assessment Report, p. 10)

103. During construction of the project, UI would implement measures to minimize the potential for runoff into municipal sewers and to protect water resources (e.g. wetland and streams) and would utilize erosion and sedimentation control measures in accordance with its Stormwater Pollution Control Plan (SWPCP) and DEEP Stormwater Permit. (UI 1, p. 5-3)

Groundwater

104. The proposed substation site is not located within a DEEP-designated Aquifer Protection Area (APA). (Council Administrative Notice Item No. 85 – DEEP statewide APA Map; UI 1, p. 4-3)

105. Groundwater in the project area is classified by DEEP as GB. Water with a GB classification includes industrial process and cooling waters and base flows for hydraulically connected water bodies. Such water is presumed not suitable for human consumption without treatment. (UI 1, p. 4-3)

106. The depth to groundwater in project area is estimated at approximately 10 feet below grade. (UI 1, p. 4-3)

107. UI would prepare a SWPCP in accordance with the DEEP Stormwater Permit. (UI 1, pp. 3-6 and 3-7)

108. The proposed project would comply with the 2004 Connecticut Stormwater Quality Manual. (Tr. 1, pp. 23-24)

109. Dewatering protocols would be implemented as necessary consistent with the SWPCP and the DEEP Stormwater Permit. (UI 1, p. 5-2)

110. If any contaminated groundwater is encountered, it would be managed in accordance with DEEP requirements. (UI 1, pp. 5-2 and 5-3)

111. Each of the proposed transformers would have a secondary containment system designed to hold 110 percent of a transformer's insulating (mineral) oil capacity and would include accidental spill prevention measures. UI would also have a Spill Prevention Control and Countermeasures Plan. (UI 1, pp. 3-5 and 5-4; Tr. 1, pp. 64, 73)

Soil and Earthwork

112. UI's and Eversource's erosion and sedimentation controls would be consistent with the 2002 Connecticut Guidelines for Erosion and Sediment Control. Eversource would also comply Eversource Best Management Practices (BMPs). (UI 1, p. 3-6; Tr. 1, pp. 80-81)

113. Approximately 9,300 cubic yards of cut and 8,800 cubic yards of fill would be required to grade the site for construction. Any spoils generated during the project construction would be managed in accordance with UI procedures and applicable regulatory requirements. (UI 2, response 13; UI 1, p. 3-7; Tr. 1, p. 23)

Flood Hazard Areas

114. The proposed site is not located within any mapped 100-year or 500-year Federal Emergency Management Agency flood zones. (UI 1, p. 4-3; Tr. 1, p. 52)

Visibility

115. The tallest features of the proposed project would be Eversource's four new monopoles that would reach a height of 105 feet agl which is the same height as the two existing self-supporting lattice structures to be replaced. UI's five monopoles to be constructed inside the proposed replacement substation would each reach a height of less than 100 feet agl.

*Lightning masts on top of the structures are not expected to be necessary.

(UI 1, pp. 2-4, 2-5 and Appendix D – Visual Assessment and Photo-Simulations, p. 1; Tr. 1, p. 21)

116. The most prominent views of the proposed replacement substation would from nearby locations along Kaechele Place and Main Street immediately west of the subject property. During leaf-off conditions, portions of the substation's infrastructure would also be visible from locations on Sequoia Road north of the subject property. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 2)

117. In general, views of the proposed replacement substation from Main Street would be screened by existing intervening commercial buildings. Many nearby views of the substation would be mitigated seasonally by foliage (which includes new plantings) and screening elements incorporated into the facility design. (UI 1, Appendix D – Visual Assessment and Photo-Simulations, p. 2)

118. The Merritt Parkway (Route 15), a National Scenic Byway, is located approximately 0.4 mile north of the proposed project. No views of the proposed project would be expected from the Merritt Parkway. No other state or locally designated scenic roads are located within the vicinity of the proposed project. (UI 2, response 3)

119. The nearest publicly accessible recreational resource is ERWP which is located directly east of the proposed site and contains a portion of the existing Eversource transmission ROW. ERWP contains hiking trails, but not other recreational facilities. No views of the proposed project would be expected from the blazed hiking trails within ERWP. (UI 1, pp. 4-9 to 4-11 and Appendix D – Visual Assessment and Photo-Simulations, p. 2)

120. The nearest school to the proposed replacement substation site is Valley Medical Institute located approximately 0.11 mile to the southwest. The nearest daycare facility to the proposed replacement substation site is Cheyenne's Early Learning Center located approximately 0.15 mile to the southwest. (UI 1, pp. 4-10 and 4-11)

121. The proposed project would be located immediately east of a developed urban area that is well lit due to existing commercial facilities and a nearby transportation network. As a result, the construction and operation of the proposed project would result in only localized and minor modifications to the lighting environment. (UI 1, p. 5-11)

122. The proposed replacement substation would include general task lighting that would only be turned on during maintenance or switching operations. UI would also install an entry lighting which may be controlled by a photocell so it would operate at night. Security lighting is also required. UI would work closely with its security department as well as neighbors in the direct vicinity with respect to security lighting. (UI 1, p. 3-5; Tr. 1, pp. 71-72)

**Public Safety**

123. UI's proposed replacement substation would comply with the standards of the NESC, ANSI, the Institute of Electrical and Electronic Engineers (IEEE), good utility practices, and UI specifications. (UI 1, p. 3-1)

124. For fire protection, the proposed replacement substation would meet the requirements of IEEE/ANSI as well as the National Fire Protection Association. (UI 1, p. 3-8)

125. UI trains its employees and the local fire department on safe methods to address a substation fire. (UI 1, p. 3-8)

126. UI would secure the control house and equip it with fire extinguishers and remotely monitored smoke detectors. Smoke detection would automatically activate an alarm at the UI System Operations Center, and the system operators would then take appropriate action. (UI 1, p. 3-9)

127. The proposed replacement substation yard would be gated and locked. Security devices would constantly monitor the substation to alert UI of any abnormal or emergency situations. (UI 1, p. 3-9)

128. Appropriate signs would be posted at the proposed replacement substation fence and gates in order to alert the general public of the presence of high-voltage facilities. (UI 1, p. 3-9)

129. The three proposed 115-kV circuit breakers would contain $SF_6$, a greenhouse gas, and each would be pressurized to approximately 80 pounds per square inch. No leakage of $SF_6$ is anticipated; however, as a precaution, the breakers would be alarmed and monitored by UI on a 24/7 basis. (Tr. 1, pp. 25-26, 69)

130. Notice to the Federal Aviation Administration (FAA) is not required for UI's proposed replacement substation or Eversource's four proposed permanent transmission structures. UI and Eversource would check on the need for submitting notice to FAA for temporary structures such as cranes to be used during construction. (UI 2, response 16)

131. By letter dated September 9, 2014, the ISO-NE Reliability Committee (ISO-NE RC) determined that the proposed project would not have a significant adverse effect on the reliability or operating characteristics of the transmission system. (UI 2, response 18)

132. UI would equip the proposed replacement substation with measures designed to ensure continued service in the event of outages of faults in transmission or substation equipment. If an energized line or piece of equipment fails, protective relaying equipment would immediately remove the failed line or equipment from service, thereby protecting the public and the remaining equipment within the substation. (UI 1, p. 3-8)

133. The project design would include protective relaying equipment to automatically detect abnormal system conditions (e.g. a faulted overhead transmission line) and to send a protective trip signal to circuit breakers to isolate the faulted section of the transmission system. The protective relaying schemes would have redundant primary and backup equipment so that a failure of one scheme would not require the portion of the system monitored by that equipment to be removed from service. (UI 1, p. 3-8)

134. The protective relaying and associated equipment, along with a SCADA system for 24/7 remote control and equipment monitoring, would be housed at UI's System Operations Center. (UI 1, p. 3-8)

135. Corona noise generated by the 115-kV system is too weak and too low a frequency to interfere with communications in the very high frequency (VHF) and ultra-high frequency (UHF) bands in radio, wireless, telecommunications, or cable or satellite television. (UI 2, response 17)

136. In December 2009, President Obama proclaimed power grids as critical infrastructure vital to the United States. The Department of Homeland Security, in collaboration with other federal stakeholders, state, local, and tribal governments, and private sector partners, has developed the National Infrastructure Protection Plan (NIPP) to establish a framework for securing our resources and maintaining their resilience from all hazards during an event or emergency. (Council Administrative Notice Item No. 4)

137. On February 12, 2013, President Obama signed Executive Order 13636 on Improving Cyber Security for Critical Infrastructure, along with an accompanying Presidential Policy Directive on Critical Infrastructure Security and Resilience. The order established the U.S. policy to "enhance the security and resilience of the nation's critical infrastructure." The Secretary of Homeland Security has been given the overall responsibility for critical infrastructure protection and identifies the Department of Energy as the sector-specific agency responsible for the energy sector. The Department of Energy may draw upon the North American Electric Reliability Corporation's (NERC) expertise. (Council Administrative Notice Item No. 5; Council Administrative Notice Item No. 65)

138. NERC developed Physical Security Reliability Standard CIP-014-1 to address threats and vulnerability to the physical security of critical infrastructure on the bulk power system. CIP-014-1 consists of standards and requirements related to security of electronic perimeters, protection of critical cyber assets including personnel, training, security management and disaster recovery planning. CIP-014-1 requires transmission owners to deploy systems for monitoring security events and to have comprehensive contingency plans for cyberattacks, natural disasters and other unplanned events. (Council Administrative Notice Item No. 10; Council Administrative Notice Item No. 65)

Noise

139. The sources of noise for the proposed replacement substation facility would include the two proposed transformers. (UI 1, Appendix F – Environmental Noise Assessment, p. 1)

140. The proposed project is considered a Class C (industrial) noise emitter, and abutting properties are either Class A (residential) or Class B (commercial) receptors. The DEEP noise limit for a Class C emitter to a Class A receptor is 61 dBA during the day and 51 dBA at night. (UI 1, Appendix F – Environmental Noise Assessment, p. 3)

141. UI's noise consultant performed ambient level noise measurements in the vicinity of the proposed site. Short-term and long-term noise monitoring locations are listed below.

| Receptor/ Meas. Site ID | Description | Predicted Facility Noise Level (dBA) | Land Use | Applicable Sound Level Limit (dBA) |
|---|---|---|---|---|
| LT-1 | Property line; backyard of 60/76 Sequoia Rd. | 43 | Residential | 61 day / 51 night |
| ST-1 AM | 60 Sequoia Rd. | 37 | Residential | 61 day / 51 night |
| ST-1 PM | 25/61 Sequoia Rd. | 37 | Residential | 61 day / 51 night |
| ST-2 | Greentree townhomes on Frenchtown Rd. | 29 | Residential | 61 day / 51 night |
| ST-3 | Behind 2 Hillview St. on Kaechele Pl. | 44 | Residential | 61 day / 51 night |
| ST-4 | Corner of Main St./Minturn Rd. | 33 | Residential | 61 day / 51 night |

(UI 1, Appendix F – Environmental Noise Assessment, p. 8)

142. UI's projected overall noise levels from the proposed replacement substation during the daytime and nighttime are listed below.

| Receptor / Measurement Site ID | Allowable Daytime Limit (dBA) | Predicted Facility Noise Level (dBA) | Daytime Ambient $L_{eq}$ (dBA)* | Daytime Total Sound Level (dBA)** | Increase in Daytime Sound Level (dB)*** |
|---|---|---|---|---|---|
| LT-1 | 61 | 43 | 49 | 50 | 1 |
| ST-1 AM | 61 | 37 | 49‡ | 49 | 0 |
| ST-1 PM | 61 | 37 | 49‡ | 49 | 0 |
| ST-2 | 61 | 29 | 46 | 46 | 0 |
| ST-3 | 61 | 44 | 53 | 54 | 1 |
| ST-4 | 61 | 33 | 64 | 64 | 0 |

| Receptor / Measurement Site ID | Allowable Nighttime Limit (dBA) | Predicted Facility Noise Level (dBA) | Nighttime Ambient $L_{eq}$ (dBA)* | Nighttime Total Sound Level (dBA)** | Increase in Nighttime Sound Level (dBA)*** |
|---|---|---|---|---|---|
| LT-1 | 51 | 43 | 42 | 46 | 4 |
| ST-1 AM | 51 | 37 | 42‡ | 43 | 1 |
| ST-1 PM | 51 | 37 | 42‡ | 43 | 1 |
| ST-2 | 51 | 29 | 44 | 44 | 0 |
| ST-3 | 51 | 44 | 44 | 47 | 3 |
| ST-4 | 51 | 33 | 58 | 58 | 0 |

*Ambient $L_{eq}$ is Filtered $L_{eq}$.

**The "Total" sound level is the decibel addition of the Predicted Facility Noise Level and the Ambient $L_{eq}$.

***Apparent discrepancies due to rounding.

ǂSites ST-1 AM and ST-1 PM are assumed to have the same daytime ambient noise level for the first table and the same nighttime ambient noise level for the second table.

(UI 1, Appendix F – Environmental Noise Assessment, p. 9)

143. While location ST-4 has a projected total sound level (i.e. proposed facility noise level plus ambient noise level) of 64 dBA during the daytime and 58 dBA during the nighttime and this exceeds the 61 dBA/51 dBA daytime/nighttime DEEP noise control limits, this does not represent a violation of the noise limits because the sound levels due to the proposed project (i.e. 33 dBA for daytime and nighttime) are less than the background/ambient noise levels. Thus, the proposed project is expected to comply with DEEP noise control standards. (UI 1, Appendix F – Environmental Noise Assessment, pp. 1 to 10; Tr. 1, p. 38)

**Electric and Magnetic Field Levels**

144. Electric fields (EF) and magnetic fields (MF) are two forms of energy that surround an electrical device. Transmission lines are a source of both EF and MF. (Council Administrative Notice Item No. 41)

145. EF is produced whenever voltage is applied to electrical conductors and equipment. Electric fields are typically measured in units of kilovolts/meter. As the weight of scientific evidence indicates that exposure to electric fields, beyond levels traditionally established for safety, does not cause adverse health effects, and as safety concerns for electric fields are sufficiently addressed by adherence to the NESC, as amended, health concerns regarding Electric and Magnetic Fields (EMF) focus on MF rather than EF. (Council Administrative Notice Item No. 41)

146. MF is produced by the flow of electric currents. The magnetic field at any point depends on the characteristics of the source, including the arrangement of conductors, the amount of current flow through the source, and the distance between the source and the point of measurement. Magnetic fields are typically measured in units of milligauss (mG). (Council Administrative Notice Item No. 41)

147. International health and safety agencies, including the World Health Organization, the International Agency for Research on Cancer (IARC), and the International Commission on Non-Ionizing Radiation Protection (ICNIRP), have studied the scientific evidence regarding possible health effects from MF produced by non-ionizing, low-frequency 60-Hertz alternating currents in transmission lines. Two of these agencies attempted to advise on quantitative guidelines for mG limits protective of health, but were able to do so only by extrapolation from research not directly related to health: by this method, the maximum exposure advised by the International Committee on Electromagnetic Safety (ICES, part of IARC) is 9,040 mG, and the maximum exposure advise by the ICNIRP is 2,000 mG. Otherwise, no quantitative exposure standards based on demonstrated health effects have been set world-wide for 60-Hertz MF, nor are there any such state or federal standards in the U.S. The existing and calculated MF levels for this project are well below these recommended exposure levels. (Council Administrative Notice Item No. 41)

148. ICNIRP limits for general public exposure to 60 Hz electric fields is 4.2 kV/m. ICES limits for general public exposure to 60 Hz electric fields is 5 kV/m.*

*Within power line ROWs, the guideline is 10 kV/m.

(UI 1, Tab G – Electric and Magnetic Field Report, p. 8)

149. Although substations are not the subject of the Council's EMF Best Management Practices (BMPs) for the Construction of Electric Transmission Lines in Connecticut, UI applied certain design/analysis elements that comport with the Council's BMPs as follows:

a) The project is not sited adjacent to any statutory facilities with the exception of ERWP;
b) The proposed replacement substation would be located adjacent to and would encompass the existing substation property, and the proposed relocations of the optimally phased overhead transmission lines within the subject property would have essentially no effect on the calculated magnetic field at the closest residences;
c) The replacement substation would avoid the construction of a new substation in a new location with transmission line connections that would be a new source of EMF;
d) The project includes new structures only on UI property within the substation and within Eversource ROW adjacent to the substation on the east side; and
e) The two transmission lines supported by double-circuit lattice structures are optimally phased and are not proposed to be altered as a result of the project.

(UI 1, Tab G – Electric and Magnetic Field Report, pp. 9-10; UI 1, p. 6-6)

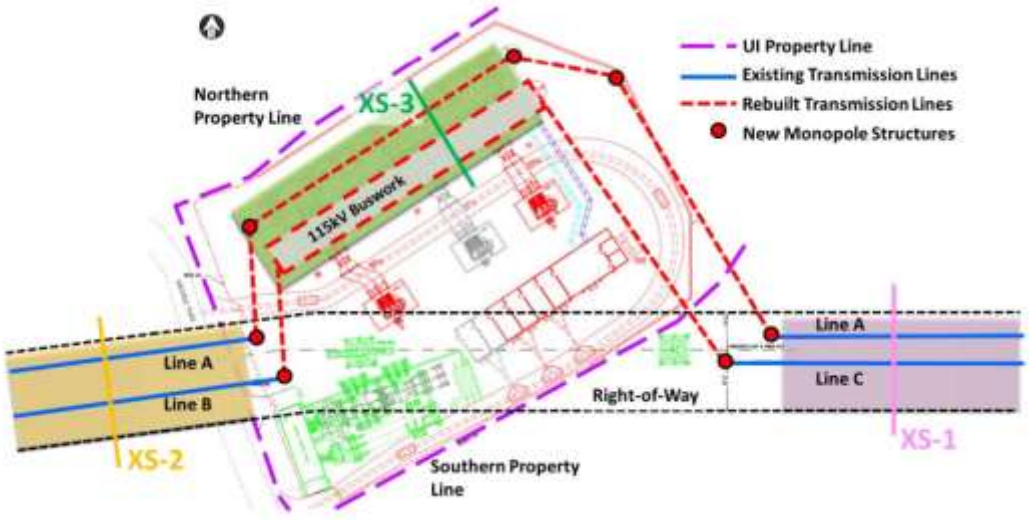
150. In UI's EMF analysis, "existing" or "Pre-Project" conditions assume that the transmission lines are in their existing alignment, and the existing Old Town Substation is in service. "Post-Project" conditions assume that the proposed replacement substation is in service, the existing substation is de-energized, and the existing transmission lines are connected to the proposed replacement substation.*

*The #1714 Line would "pass through" the proposed replacement substation, but it would not be connected to the substation at this time.

(UI 1, p. 1-3 and Tab G – Electric and Magnetic Field Report, p. iii; UI 2, response 14)

151. Average daily peak load conditions are referred to as "average load conditions" in UI's EMF analysis. (UI 1, Tab G – Electric and Magnetic Field Report, p. 1)

152. The existing and post-construction magnetic field levels based on average load conditions are indicated below.



| Section | Configuration | 100 feet from South ROW edge | South edge of ROW | Max on profile | North edge of ROW | 100 feet from North ROW edge |
|---|---|---|---|---|---|---|
| XS-1 | Pre-Project | 1.3 | 10 | 22 | 15 | 1.5 |
| | Post-Project | 1.3 | 10 | 22 | 15 | 1.5 |
| XS-2 | Pre-Project | 4.0 | 22 | 47 | 37 | 5.5 |
| | Post-Project | 3.9 | 21 | 47 | 37 | 5.4 |

| Section | Configuration | 100 feet from Southern Property Line | Southern Property Line | Max on profile | Northern Property Line | 100 feet from Northern Property Line |
|---|---|---|---|---|---|---|
| XS-3 | Post-Project | 0.7 | 1.4 | 216 | 18 | 3.0 |

(UI 1, Tab G – Electric and Magnetic Field Report, pp. 6 and B-1)

**Project Cost and Cost Allocation**

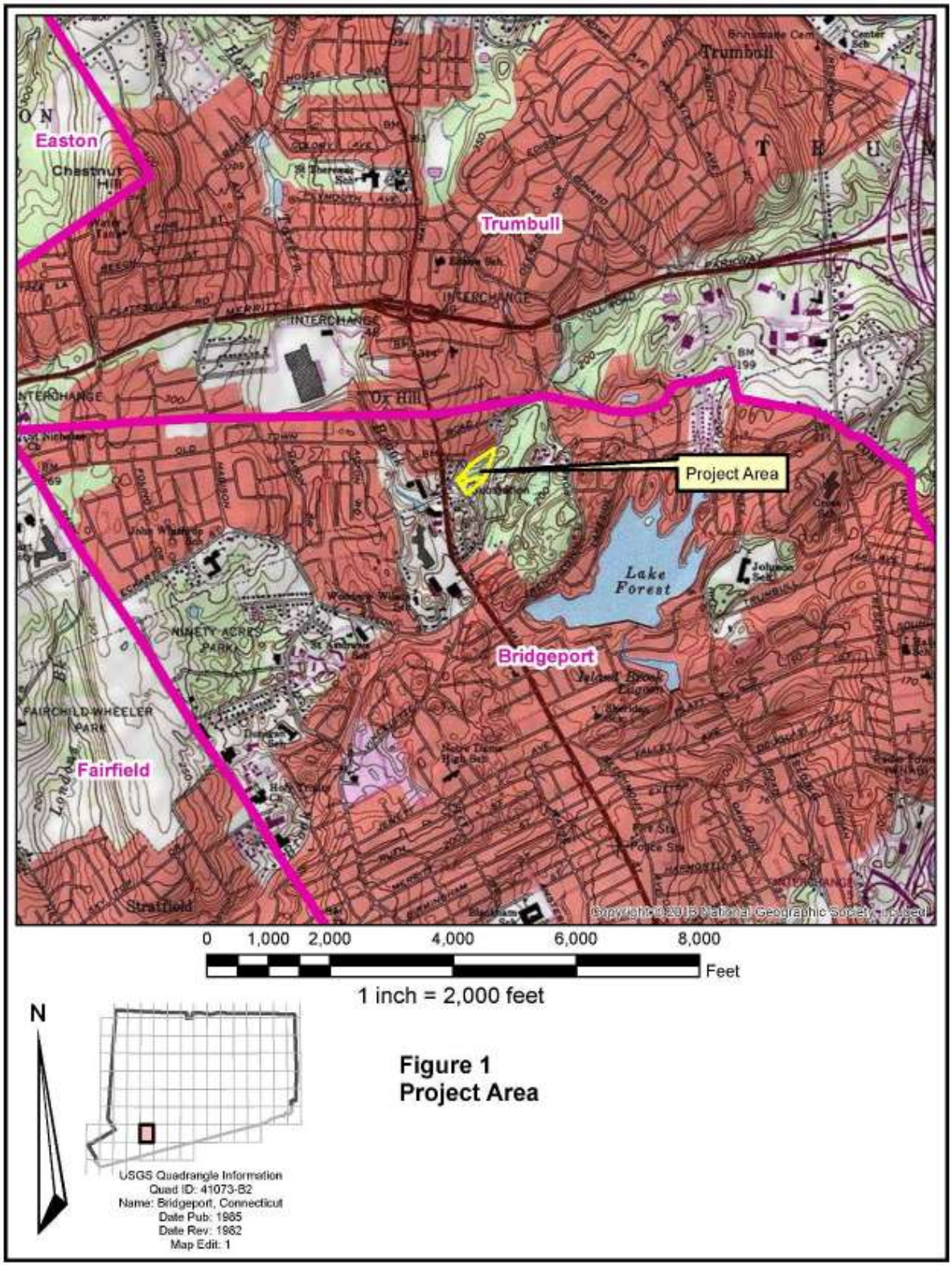
153. Costs of the Project would be recovered through regionalized and localized cost allocation. In general, distribution costs are localized, and most transmission costs are regionalized provided that ISO-NE determines the transmission project provides a regional reliability benefit and it is in accordance with good utility practices. (UI 2, response 6)

154. UI's estimated project cost is approximately $39.1M*. Approximately $23.4M of the project's costs would be regionalized across all New England ratepayers based on load share which is approximately 75 percent New England (or $17.5M) and 25 percent Connecticut (or $5.9M). The remaining $15.6M of project costs are related to distribution and non-Pool Transmission Facilities costs which are typically borne by UI customers.

*The approximately $3M cost for Eversource's portion of the project is not included in this total, and Eversource expects that the entire $3M cost would be regionalized. (UI 2, response 6; Tr. 1, p. 30; Tr. 1, pp. 30, 81-82, 85)

155. Pool transmission facilities (PTF) are the facilities rated 69-kV or higher owned by the participating transmission owners, over which ISO-NE has operating authority in accordance with the terms of the Transmission Operating Agreements. (Council Administrative Notice Item No. 21 – 2019 Regional System Plan)

**Figure 1 – Site Location**

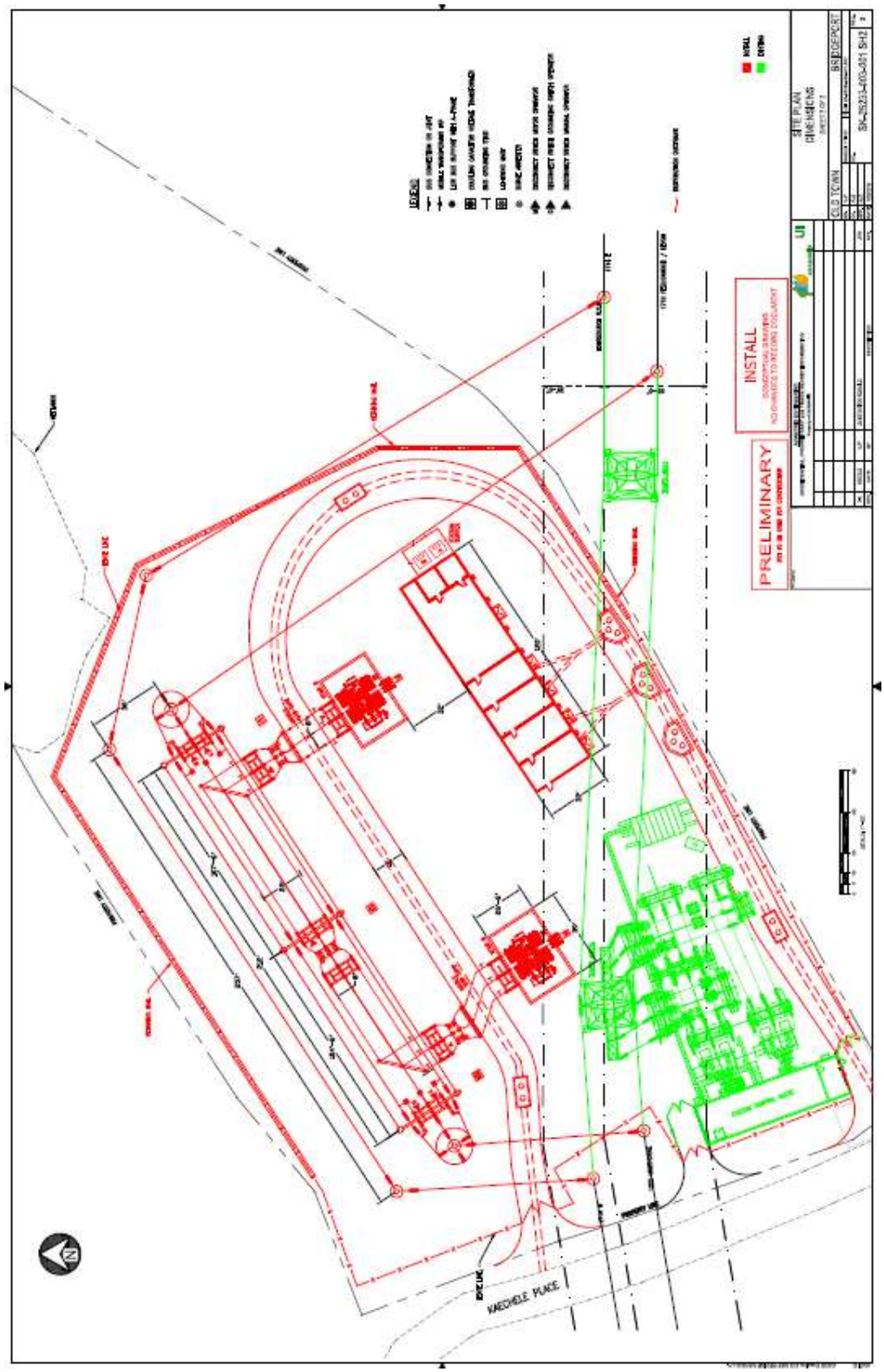



(UI 1, p. 1-2)

**Figure 2 – General Site Plan**


(UI 1, Appendix A)

**Figure 3 – Proposed Replacement Substation Site Plan**




(UI 1, Appendix A)

**Figure 4 – Aerial View and Simulation of Proposed Project**

(UI 1, Appendix D – Visual Assessment and Photo-Simulations, Proposed Conditions)