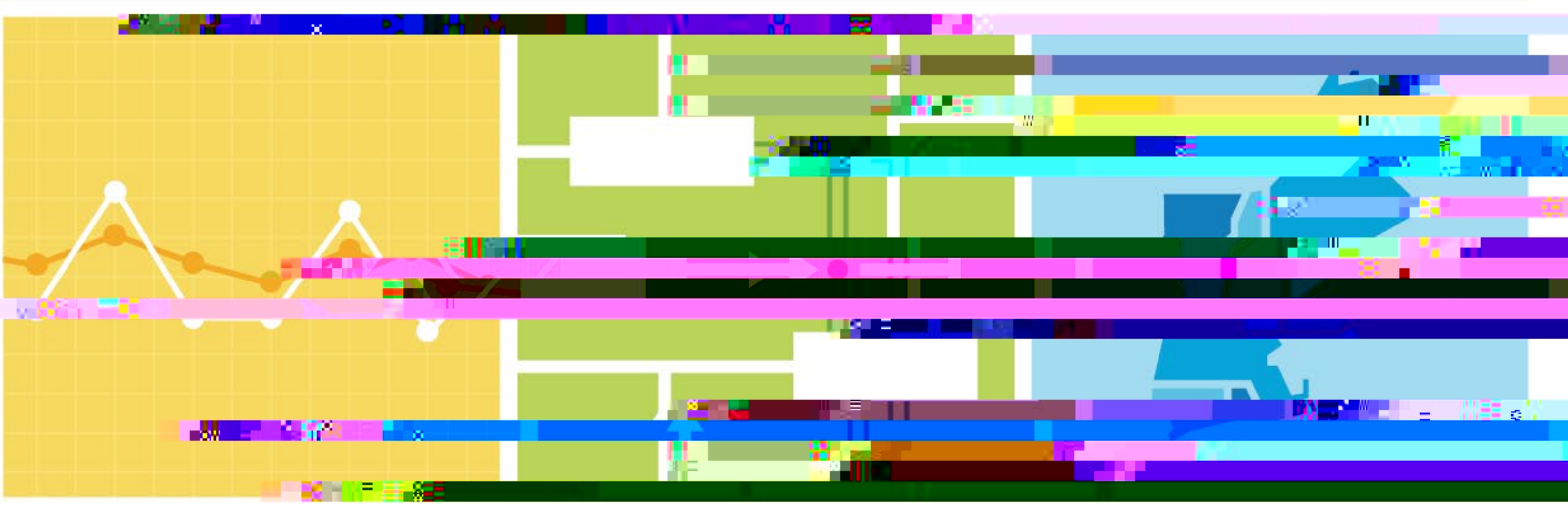
2050 Transmission Study

Transmission Planning

FEBRUARY 12, 2024



Project Team

Peter Bernard

Reid Collins

Liam Durkin

Annie Kleeman

Andrew Kniska

Brent Oberlin

Dan Schwarting

Kannan Sreenivasachar

Marvin Valencia Perez

Pradip Vijayan

Supporting Departments:

Corporate Communications

External Affairs

Economic Studies & Environmental Outlook

Contents

Figures

Section 1: Study Overview

The New England power system is in the midst of an unprecedented shift in the ways in which electricity is produced and consumed. Five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% by 2050, prompting ongoing changes in the grid's resource mix and the increased electrification of the heating and transportation sectors.[1] Driven largely by these statewide commitments, the grid continues its shift toward renewable resources like wind and solar photovoltaic (PV) generation. Over the next several decades, these renewable resources are expected to substantially displace natural gas-fired generation as the region's primary resource type. At the same time, increased electrification is expected to significantly increase overall consumer demand for electricity and drive changes in usage patterns that include seasonal and daily shifts in peak demand.

Among ISO New England's responsibilities as a Federal Energy Regulatory Commission (FERC)-authorized Regional Transmission Organization is ensuring the regional power system continues to operate reliably as system conditions change. Transmission planning helps to maintain system reliability and enhance the region's ability to support a robust, competitive wholesale power market by moving power from various internal and external sources to the region's load centers. This 2050 Transmission Study is a pioneering look at the ways in which the transmission system in New England may be affected by changes to the power grid, and includes roadmaps designed to assist stakeholders in their efforts to facilitate a smooth, reliable clean energy transition.

1.1 Study Background and Objectives

In October 2020, the New England States Committee on Electricity (NESCOE) released the New England States' Vision for a Clean, Affordable, and

The longer-term transmission study process is currently informational. The process does not include a formal mechanism for triggering the construction of a new transmission project. However, the ISO is currently discussing the second phase of the longer-term transmission study Tariff changes that will establish a process to enable the states, through NESCOE, to move policy-related transmission projects forward, with an associated cost allocation. This effort began at stakeholder meetings in October 2023, and will continue through early 2024.

1.1.1 Development of Study Objectives and Study-Specific Terms

In 2021, the ISO began coordination with NESCOE to develop objectives and assumptions for this study.

The 2050 Transmission Study has two main objectives:

- Determine the region's transmission needs in order to serve load while satisfying North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and ISO reliability criteria.[2]
- Develop [illegible] for transmission upgrades [illegible] considering both the feasibility of construction and cost.

In this study, the term is intended as a high-level plan designed to show generally how transmission-related objectives can be accomplished. The roadmaps provided in this study are not intended as comprehensive or detailed plans for construction. They include:

- Conceptual projects specific to the input assumptions of the study.
-

substation equipment. This contingency analysis was designed to test peak load boundary conditions, which represent the most extreme or severe cases of combined load and renewable resource output that could realistically be expected to occur. An example of a boundary condition would be a particularly cold winter peak hour, corresponding with high loads, in which weather conditions resulted in low renewable resource production. Essentially, boundary conditions in this study were designed to represent the realistic “worst case scenario” for future transmission planning needs related to serving peak loads.

It is important to note that all conceptual projects in this 2050 Transmission Study are formulated from one particular pathway among the eight mentioned in the MA Deep Decarbonization Roadmap. Changing inputs to the No Thermal Pathway, or the 100% Renewable Pathway, for example, would impact the conceptual projects list.[4] It is likely that the future power system will differ from the assumptions found in the All Options Pathway. As an example, the expected nameplate capacity of battery energy storage for 2030 has already exceeded the All Options Pathway’s assumptions for 2035. As the system evolves, the qstmmioisqsp.i.9 (ns)0.76 (20-5.9 (t)5.4 (hc)-72.3 (o)4.
P h e o

comparison, the highest load observed to date on the New England system was the 2006 summer peak of just over 28 GW, and the highest winter load observed to date was the January 2004 peak of just below 23 GW. The loads analyzed in each year studied are shown in Figure 1-1.

Figure 1-1: Load Levels Analyzed by Study Year

These loads were assumed to be served by a generation fleet that differs significantly from today's resource mix. All coal, oil, diesel, and municipal solid waste-fueled generation, as well as a portion of today's natural-gas-fueled generation, was assumed retired by 2035, the earliest year studied. The remainder of today's natural-gas-fueled generation, as well as biomass, nuclear, hydroelectric, and renewable generators, were assumed to remain operational through 2050. The retired generation, as well as the increases in load, were assumed to be offset by a significant increase in wind and solar generation, as well as battery energy storage and increased imports from neighboring power systems in New York and Québec. Much of this increased wind capacity is located offshore, either off the coast of southeastern Massachusetts and Rhode Island, or in the Gulf of Maine. Figure 1-2

Figure 1-2: Renewable Generation and Energy Storage Input Assumptions

While the All Options Pathway specified a total amount of each generation type by state, transmission planning studies like the 2050 Transmission Study require location data on a more granular level. Exact generator location is needed to develop useful results. In this study, new offshore wind generation was initially assumed to interconnect at major 345 kilovolt (kV) substations near the coast of New England, in order to minimize the length of cables between the interconnection points and offshore wind locations. As the study progressed, some of these interconnection points were relocated in order to eliminate transmission system concerns to the extent possible without changing the total amount of generation in each state (see section 2.4 for further details on generator relocation decisions). Similarly, energy storage facilities were initially assumed to interconnect at major 345 kV stations, but were later relocated within the same state to reduce transmission concerns where possible. Many of these relocations were from 345 kV stations

Section 2: Key Takeaways

The 2050 Transmission Study resulted in several high-level observations related to Pti]TJ-0.0.4 jE0.3 (o0.4 (el00.0.4 j (n(m)9t)7 (89 (i)-16.3 94 6.7 (89 6 ( )32.461l0.7 (2. (4.2o .6 ( )3(e o)10.9 (ut)11.4 (o)10.9 (f)8.7 (heat)16.16 (a(r)

New England retains some stored fuels like natural gas, oil, propane, hydrogen, etc. for heating and transportation. Since loads above 51 GW would only occur during extremely cold winter days, peak load could be limited to 51 GW in a scenario in which the grid is 100% electrified for most of the year, with only the coldest days using some stored fuels for heating. If the full 6 GW of load reduction came out of heating, this could still represent approximately 80% heating electrification while still mainta26.4 (i)-2 (TD[w)-10.2 (C0.8 (i (h).6 (0 194 Tg52.3 (nt)5(G)-5.91194 T5.6 ( )32.5 3l)3 (e) Tg52.(r

In an effort to identify high-likelihood concerns and other transmission overloads, the locations of new generator interconnections were optimized, within reason. By locating these interconnections so as to minimize transmission overloads observed under peak load conditions, any remaining overloads would likely only be solved through transmission expansion. Concerns that could be alleviated by new generation interconnections (within the bounds of the total amounts of generation in each New England state assumed for this study) are therefore not included in the results because they were resolved by the change of generation interconnection location.

2.3 Incremental Upgrades Can Be Made as Opportunities Arise

Many of the transmission system concerns identified in the 2050 Transmission Study could be addressed by rebuilding existing transmission lines with larger conductors, rather than expanding the transmission system into new locations. In many cases, replacing transmission lines with larger conductors and increasing their power transfer capability would allow the system to serve significantly higher peak loads. This type of conductor replacement, or reconductoring, may also require replacing some or all of a transmission line's structures in order to accommodate heavier, larger conductors. Advanced conductor technologies that may be able to make use of existing structures while still delivering higher ratings and lower losses could also be considered. Additionally, other incremental upgrades could be beneficial; examples include bundling multiple conductors per phase on 115 kV lines (already a common practice on 345 kV lines in New England) or rebuilding transmission lines to allow for a higher operating voltage.

Limiting brand new line construction by taking advantage of line rebuilds could minimize costs, especially in densely populated areas in southern New England. In many areas, expanding existing rights-of-way or constructing new rights-of-way could be difficult, expensive, and environmentally disruptive, and thus maximizing the use of existing rights-of-way is critical to the success of the region's transmission system reliability through the clean energy transition.

While these incremental upgrades should be considered crucial to the improvement of New England's transmission system, it is not necessarily prudent for the region to pursue large numbers of line rebuilds immediately. Many of these line rebuilds are highly dependent on the locations of generator interconnections, the geographic distribution of end-user load, and the locations of new load-serving substations. Since these incremental upgrades can generally be built in a shorter timeframe than new transmission on new rights-of-way, it may be more practical to address these incremental needs via the traditional ten-year reliability planning process rather than the longer-term planning process that prompted this study. This strategy would allow the region to hold off on committing to further transmission system investment until new information is available, and also provide opportunities for more cost-effective "right-sizing" transmission projects.

"Right-sizing" is a term used to describe combining line rebuilds necessitated by increased loads with replacements designed to meet asset condition needs. In New England, asset condition projects are identified by transmission owners when equipment exceeds its useful life. Since a significant portion of New England's transmission system was developed in the mid-20th century, many transmission lines are beginning to reach the end of their life and must be replaced. During such an asset condition replacement project, the incremental cost of upgrading a transmission line to a larger conductor size and stronger structures is relatively low. Many expenses inherent in transmission line rebuilds are unrelated to the line's capacity; costs related to building access roads along a right-of-way, labor for building structures, and financing an ongoing project are not significantly affected by the size of the conductor chosen. Therefore, upgrading the capacity of lines as the opportunity arises, or "right-sizing" asset condition projects when they occur, could be a

more power across long distances while minimizing losses of power along the way. However, this additional power transferred along higher voltage lines must eventually “step down” to 115 kV via transformers on its way to distribution substations fed by 115 kV lines, and these transformers must be able to support the increase in load and power injection. Results from the studied snapshots show that the existing transformer fleet will not be able to adequately support future power flows from the 345 kV to the 115 kV system. This is not an issue with the transformers themselves, but rather is a predictable consequence of increases in load and the fact that this increased load is originating predominantly from locations far away from the generation.

One of the simplifying assumptions of this study was to model load on the 115 kV system, rather than on the distribution system. As a result, this takeaway applies to transformers with windings at or above 115 kV. Presumably, a large number of additional distribution transformers will be required to step down from 115 kV to individual customers. This distribution infrastructure is beyond the scope of this study, and the related planning responsibility lies with the distribution utilities and their state regulators

Section 3: High-Likelihood Concerns

In response to stakeholder interest and feedback, the 2050 Transmission Study identified what the ISO has termed high-likelihood concerns, as discussed in Section 2.2. It is helpful to identify the transmission concerns that have a high likelihood of occurring even if the assumptions used in the study do not unfold exactly as predicted. This allows the New England region to prioritize concerns station is added to that area, roughly the same amount of power will still flow over the major transmission line between areas.

Roadmaps that could address each of these high-likelihood concerns are included in Section 4, along with graphic representations of each roadmap.

3.1 High-Likelihood Concerns: North-South

The Maine-New Hampshire and North-South transmission interfaces connect Maine and New Hampshire to northeastern Massachusetts.[12] The 2050 Transmission Study found that these interfaces are high-likelihood concerns due to a variety of thermal overloads that met the criteria described in the previous section. These concerns were observed primarily during winter peak snapshots and were precipitated by the large volume of offshore wind production flowing from relatively generation-heavy and light-load areas in Maine and New Hampshire into the dense, high-load areas in southern New England. Although less severe than the winter observations, concerns were also observed during the summer daytime peak snapshots, precipitated by large excesses in solar production in northern New Ehr-w-euse6 0(M)4.4 (v)en r H6.3 -.(u15.48 4.7 (-)TjAw)u.8 (uw)u.8 (u(i(r)16.

interface. The precise interconnection locations for offshore wind in the Gulf of Maine will depend on many factors, including the exact location of wind lease areas that have not yet been finalized.

3.2 High-Likelihood Concerns: Boston Import

Table 3-1: Miles of Transmission Lines Overloaded in the Boston Subregion by Snapshot Year/Load

Year Studied	

Figure 3-1: Line Mileage Overloaded in Boston with Generator Interconnection Locations Optimized

Alternative approaches that might address these issues yield trade-offs between cost and effectiveness. Moving generator interconnection locations will address some of the identified concerns during peak load conditions, but may be less optimal under off-peak or high-wind-output conditions. Optimizing generator interconnection locations may be more cost-effective than building new t20.6 (o)46.1oireo(m)-16.7 (a)26.e5u are d(.(m)1.161 TD)-16.7 (a)26.e m c[32.8 (l)3 80.004 Tw 11.16

Section 4: Roadmaps and Representative Transmission Solutions

The term is intended in this study as a high-level plan designed to show generally how transmission-related objectives can be accomplished. The roadmaps provided in this study are not intended as comprehensive or detailed plans for construction. They include conceptual projects specific to the study's input assumptions—projects that could be useful in addressing high-likelihood concerns, including line rebuilds, and lessons learned that could be applied to future long-term transmission studies. Roadmaps were developed for groupings of high-likelihood concerns for North-South, Boston Import, and Northwestern Vermont Import. Roadmaps were not developed for Southwest Connecticut or other high-likelihood concerns, since these concerns had a relatively clear single solution, and any alternatives were much costlier. The North-South and Boston Import roadmaps were combined, since these areas were heavily dependent on each other. The cost assumptions for the representative transmission solutions are described in Section 5.

To develop each roadmap, the ISO first focused on designing solutions to meet the 2050 Summer Peak snapshots along with the 2050 51 GW Winter Peak snapshot. Once those solutions were would require approximately 666 miles of overhead line rebuilds to reliably serve a 51 GW load and 1,058 miles of overhead line rebuilds to reliably serve a 57 GW load.

This option is somewhat limited in its flexibility due to constrained rights-of-way along much of the path, since lines connecting Maine to Massachusetts should be overhead in order to have enough capacity. While it may be possible to add new 345 kV transmission to existing rights-of-way, there will be expenses associated with reconfiguring existing lines. Additionally, the risk that all lines in a right-of-way may be lost (e.g., due to brush fires) would need to be evaluated further outside of this study. Figure 4-1 represents the general direction of power flow and location of major new transmission lines in this roadmap.

Figure 4-1: North-South/Boston Import AC Roadmap

4.1.2 North-South/Boston Import Roadmap #2: Minimization of New Lines Roadmap

the same solutions as other roadmaps as more lines were added. If this roadmap is followed, the region could potentially use demand response, energy efficiency, and other measures to achieve 6 GW of load reduction and avoid a 57 GW winter peak. However, these solutions also have associated costs. This roadmap would be easier to site than roadmaps #1 and #3, although building fewer new lines would likely come with disadvantages related to stability and voltage performance that cannot be accurately quantified in this study. The concerns regarding loss of right-of-way described at the end of section 4.1.1 with regard to roadmap #1 would apply to this roadmap as well. Figure 4-2 represents the approximate locations of rebuilds described in this roadmap.

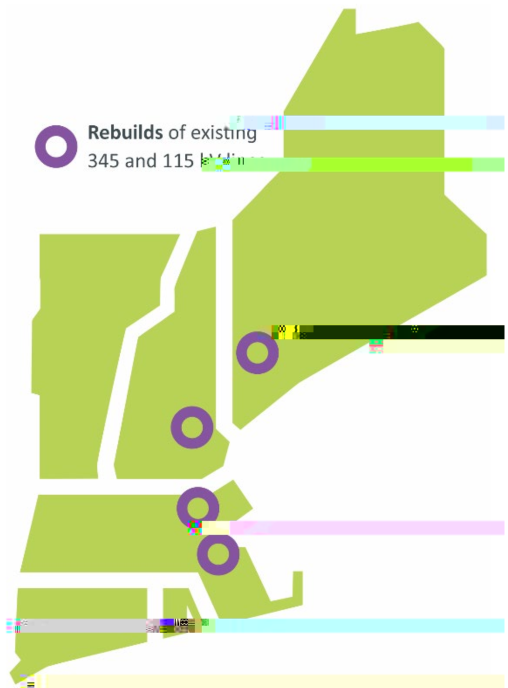


Figure 4-2: North-South/Boston Import Minimization of New Lines Roadmap

4.1.3 North-South/Boston Import Roadmap #3: Point-to-point HVDC Roadmap

The third roadmap centers around a potential point-to-point HVDC framework. It consists of a single 1,200 MW HVDC line from the Surowiec substation in Pownal, Maine to the Mystic substation in Everett, Massachusetts. Additionally, the new AC cable from Stoughton to K Street described in Roadmap #1 would be required to help resolve import issues in the southern and western portions of the Boston sub-region. This roadmap is useful for addressing high-likelihood concerns for all snapshots through 51 GW of load. In order to reliably serve the 57 GW load level in the 2050 winter peak snapshot, an additional 1,200 MW HVDC line would need to be constructed between 2040 and 2050 from the South Gorham substation in Gorham, Maine to the Tewksbury substation in Tewksbury, Massachusetts. The HVDC lines in this roadmap could be constructed overhead, underground, or underwater, offering flexibility for siting. The DC/AC converters at each terminal of the HVDC lines may also have short-circuit and stability benefits that were not quantified by this study. The main disadvantage to this roadmap will likely be related to land availability in Boston for siting the large DC/AC converter stations needed to terminate these new HVDC lines; although the Tewksbury area likely has enough land availability for this converter station, and Mystic may have enough availability once the existing generation at that location has been retired. In addition to the major upgrades described above, this roadmap would require approximately 624 miles of overhead line rebuilds to reliably serve a 51 GW load and 1,027 miles of overhead line rebuilds to reliably serve a 57 GW load. Figure 4-3 represents the general direction of power flow and location of major new transmission lines in this roadmap.

Figure 4-3: North-South/Boston Import Point-to-Point HVDC Roadmap

4.1.4 North-South/Boston Import Roadmap #4: Offshore Grid Roadmap

The final roadmap would make use of an offshore grid framework by connecting up to three offshore wind plants. These would be connected with offshore HVDC cables to form new paths between wind farms. In combination with the cables already built to connect these wind farms to on-shore substations, these offshore connections will enable the transfer of power between various sub-regions in New England. Several different configurations were examined. Initially, the study investigated a grid connecting offshore wind that interconnected in Maine, New Hampshire, and Boston. This solution was not efficient, since offshore grids are most effective when there is excess capacity on the offshore cables, i.e., when wind output is relatively low and more spare capacity is available to transfer power through the cables. The North-South interface was most highly overloaded during the winter peak snapshots, when wind output was at its highest, meaning that each 1,200 MW offshore connection had just ~200 MW of excess capacity available. This made only a minor difference in resolving overloads. Overloads on lines crossing the North-South interface were so high that roughly 10 connections between northern New England and Boston would be required (under the offshore grid framework) to solve the concerns, and there were not enough offshore wind i offshore connections would lead to significantly higher costs than other roadmaps for North-South transfers.

The offshore grid was much more effective in the summer peak snapshots, when the wind production was low and there was more spare capacity available on the cables. Many of the Boston Import overloads were worse in the summer, when wind injections into Boston dropped. When overloads were observed in winter, they were relatively small. The offshore grid is therefore a good candidate for solving these particular concerns.

Various configurations were examined b
canIate r (o)10.9 (n)5.6 (6231.4 (i)-1(.)7.5 ( )]TJ0 Tc 0 Tw 20.1.9 (v)-227g)6.14.6 (t5.6 (ed)34.9 (b (.)7.4 5.6 (ed)3z

Figure 4-4: Boston Import Offshore Grid Roadmap

4.1.5 Other Projects to Resolve Concerns in Boston

The roadmaps described in previous sections resolve many concerns related to bringing power into the Boston sub-region from elsewhere in New England. However, these roadmaps do not resolve a number of concerns related to moving power around the Boston sub-region. These concerns were caused primarily by the need to bring power from the major 345 kV hubs in Boston to each individual 115 kV substation where power is delivered to the local distribution network. As described previously, relocation of offshore wind interconnections addresses some of these concerns. The remaining concerns, shown in Figure 3-1, are addressed with a combination of the Boston-related portions of the other roadmaps and the following projects.[15]

[15] Replacement of existing pipe-type underground cables in the Boston area for asset condition reasons, as mentioned on slide 13 of a July 2023 presentation

Figure 4-5: Northwestern Vermont Import PV-20 Upgrade and Doubling of K-43 Roadmap

4.2.2 Northwestern Vermont Import Roadmap #2: Coolidge-Essex Roadmap

The second roadmap would require the construction of a new 345 kV line from the Coolidge substation north of Ludlow, Vermont, to the Essex substation just outside of the city of Burlington, Vermont. This line would be approximately 90 miles long and would likely require the expansion of existing transmission rights-of-way for the majority of its length. New 345 kV substation equipment, including a 345/115 kV transformer, would be required at the Essex substation, as this station is currently only capable of 115 kV operation. This option would require approximately 105 [illegible]

Figure 4-6: Northwestern Vermont Import Coolidge-Essex Roadmap

4.2.3 Northwestern Vermont Import Roadmap #3: New Haven-Essex and Granite-Essex Roadmap

The third roadmap would require construction of a new 345 kV line from the New Haven substation in New Haven, VermontV e r m o n

Figure 4-7: Northwestern Vermont Import New Haven-Essex and Granite-Essex Roadmap

Northwestern Vermont Import Roadmap #4: Minimization of New Lines Roadmap

A variation on the first roadmap was also examined to determine if the Vermont high-likelihood concerns could be resolved without constructing entirely new overhead lines. Results showed that the new line in parallel to the K-43 line could be eliminated if the 0.4 mile underground section of the K-65 line between the North Ferrisburg substation and Charlotte substation, along with the 1.7 mile underground section of the K-65 line between the Shelburne substation and the Queen City substation in southern Burlington, had an additional parallel cable added to each section. The PV-20 upgrade from 115 kV to 230 kV (in both New York and in Vermont), along with the new 230/115 kV transformer, would still be required. This option would require approximately 142 miles of 115 kV overhead line rebuilds to reliably serve a 51 GW load and approximately 192 miles of overhead line rebuilds to reliably serve a 57 GW load. Three new 345/115 kV transformers would need to be installed to reach 51 GW of load, and an additional two 345/115 kV transformers would be needed to reach 57 GW. The choice between the first roadmap and this variation is therefore a choice between building a 20.8 mile overhead line versus doubling up 2.1 miles of underground cables plus rebuilding approximately 41 miles of overhead lines to reliably serve a 57 GW load. However,

115 kV lines and 6 miles of underground 345 kV lines must be rebuilt, and two 345/115 kV transformers must be added in order to reliably serve a 51 GW winter peak load.

Additional 345 kV capacity into Southwest Connecticut would be required to serve a 57 GW winter peak load. Today, the region is fed by only two 345 kV paths: one from Long Mountain (in New Milford, CT), and the other from Beseck (in Wallingford, CT). Portions of the path from Long Mountain to Norwalk are underground, leading to lower ratings than a typical 345 kV overhead line. While additional 345 kV overhead lines would provide the capacity needed, these lines would be lengthy and would be difficult to route and site through the densely populated areas of Southwest Connecticut. Instead, this study suggests re-using an unused underground segment of the Long Mountain-Norwalk path, which would allow for more power flow. This cable was originally de-energized due to temporary over-voltage concerns.[17] Additional study would be required to ensure that the cable could be re-energized safely without risking equipment damage; additional substation equipment may be necessary to manage voltage if this cable is placed into service. The costs of this study work and substation equipment would likely be far less than developing a third 345 kV path into Southwest Connecticut. Along with re-energizing this cable, an additional two 345/115 kV transformers, 125 miles of rebuilt overhead 115 kV lines, and 21 miles of rebuilt overhead 345 kV lines would be necessary to reliably serve Southwest Connecticut at the 57 GW winter peak load level. Figure 4-9 represents the general direction of power flows and location of major new transmission lines in this roadmap.

Figure 4-9: Southwest Connecticut Import Transmission Additions

4.4 Transformer Additions

As described in section 2.5, transformer capacity has the potential to create bottlenecks in the marked "post-optimization" show the effects of optimization on reducing transmission overloads. All results in this table are exclusive of any representative transmission upgrades.

Table 4-1: Transformer Overloads by Snapshot Year, Pre- and Post-Optimization

Year Studied	Number of PTF Transformers Overloaded[18]	
	Pre-Optimization Results	Post-Optimization Results
2035 (35 GW Winter Peak)	14	16
2040 (43 GW Winter Peak)	56	43
2050 (51 GW Winter Peak)	86	57
2050 (57 GW Winter Peak)	99	81

- Build two new overhead 345 kV lines between Brayton Point and Grand Army (both in Somerset, MA), for a total of 3 miles of new construction.
- Increase the rating of the series capacitor on line 3023 in Orrington, ME.

These upgrades are scattered around New England, rather than concentrated in a particular area. Full details on these additional upgrades can be found in the Technical Appendix to this report.

4.6 Non-High-Likelihood Concerns

Finally, many concerns found in this study were not considered high-likelihood concerns, and are mainly related to serving load for the 57 GW winter peak load level. Since they only appear at this load level, they are particularly sensitive to the distribution of load among individual substations. If the evolution of the region's distribution system differs significantly from the assumptions studied, it is possible that new distribution substations will be located in a way that changes the severity

4.7 Maps of All Transmission Upgrades and Additions

The maps in this section show the full set of transmission upgrades identified as conceptual roadmaps in this study. Rebuilds of existing transmission lines are shown in purple and new transmission lines are shown in red.

The maps below should not be considered authoritative lists of all line rebuilds; due to the scale of the maps and approximations of substation locations, some lines are difficult or impossible to distinguish from each other. All transmission lines are represented as straight lines between endpoints, and thus do not reflect actual line routes or locations of rights-of-way. This study examined four different northwestern Vermont roadmaps and four different North – South/Boston Import roadmaps. The northwestern Vermont roadmaps were far enough away from the North – South/Boston Import roadmaps that they can be considered to be independent from each other. The maps below show one northwestern Vermont roadmap paired with one North – South/Boston Import roadmap each, but these could be paired in any combination, rather than being limited to the ones shown below. A full list of rebuilt transmission lines for each roadmap may be found in the Technical Appendix to this report.

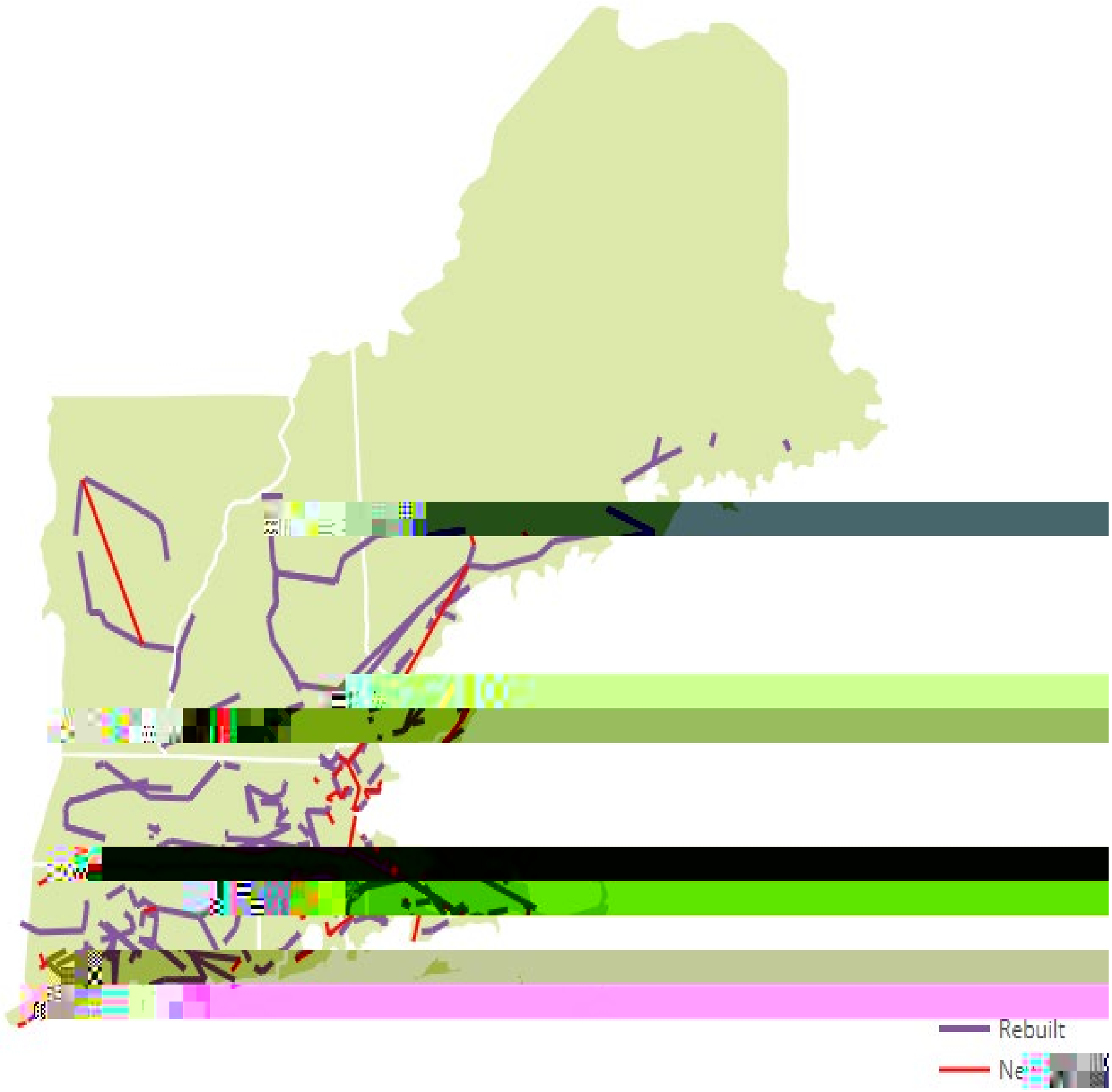


Figure 4-10: Transmission Upgrades and Additions for the Coolidge -Essex Roadmap and the AC Roadmap

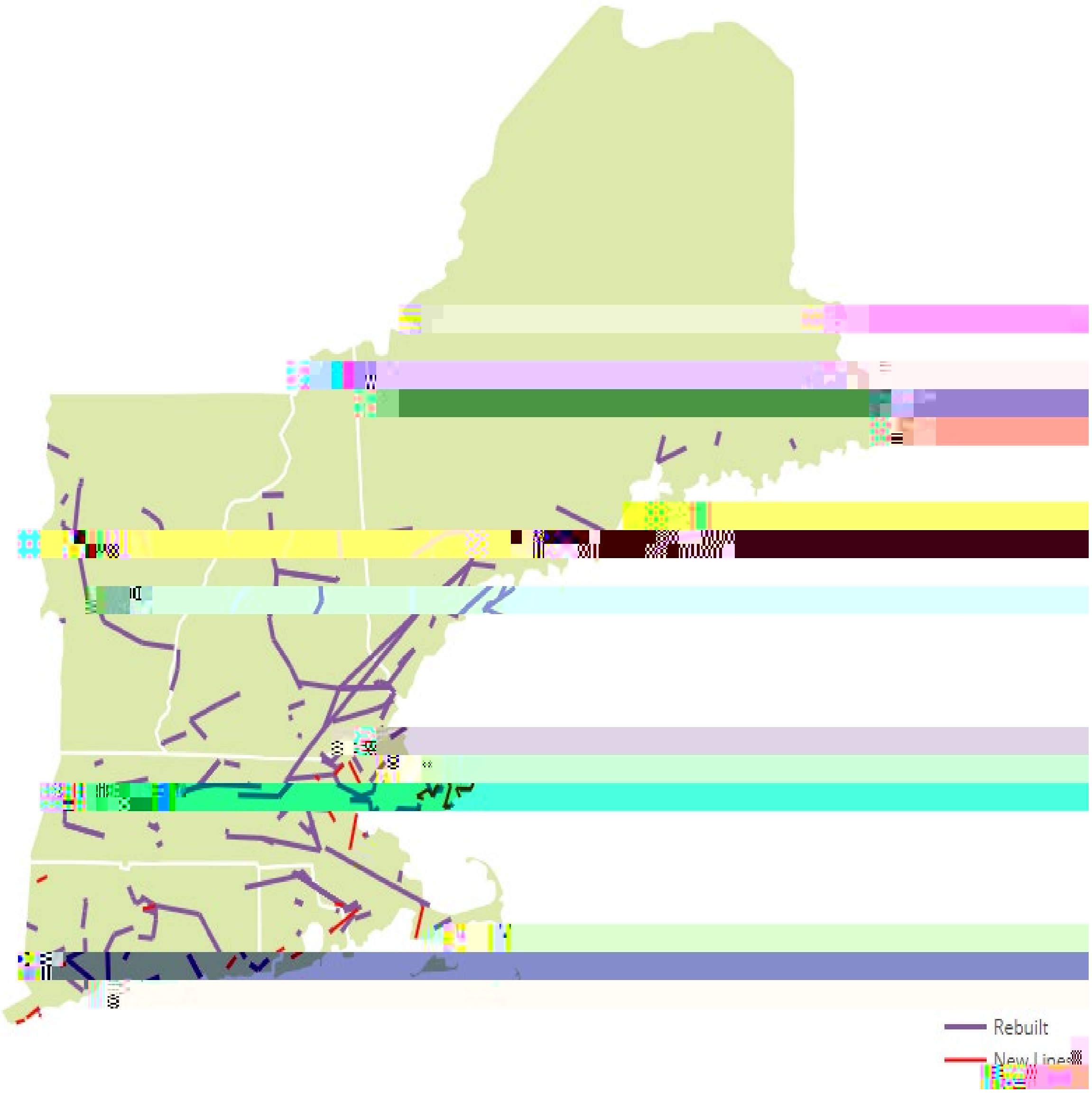


Figure 4-11: Transmission Upgrades and Additions for the Minimization of New Lines Roadmaps

These cost assumptions were used for rebuilds of existing lines and other less complex projects. Because of the sheer number of transmission projects included in this study, this approach provided a more cost-effective method for estimating costs. Conducting detailed cost analysis for these transmission line rebuilds and other simpler projects would be expensive, time-consuming, and unlikely to add significant precision. Some projects will likely exceed the costs calculated using these assumptions, and other projects will be less expensive than the assumptions, but the ISO's expectation is that the aggregated cost of the full list of these projects will be within an order-of-magnitude range of accuracy.

Costs illustrated in Table 5-3 and Figure 5-1 are associated with the North-South/Boston Import roadmaps. These costs will be affected by the choice of four roadmaps detailed in Section 4.1. Figure 5-2 and Figure 5-3 categorize the costs by rebuild type for both the 51 GW and 57 GW winter peak load snapshots.

Table 5-3: Estimated Cumulative Costs for North-South/Boston Import Roadmaps

Year/Load Level	AC Roadmap	Minimization of New Lines Roadmap	Point-to-Point HVDC Roadmap	Offshore Grid Roadmap 2035
2035				

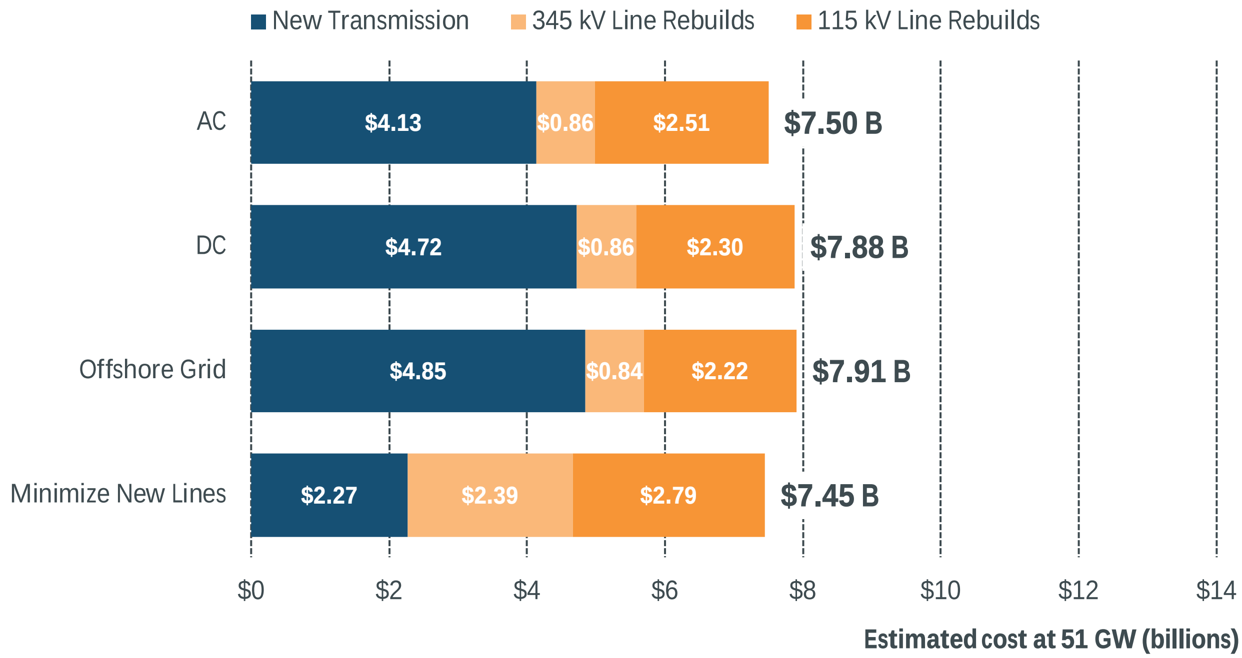


Figure 5-2: Cost Categories for North-South/Boston Import Roadmaps: 51 GW Winter Peak

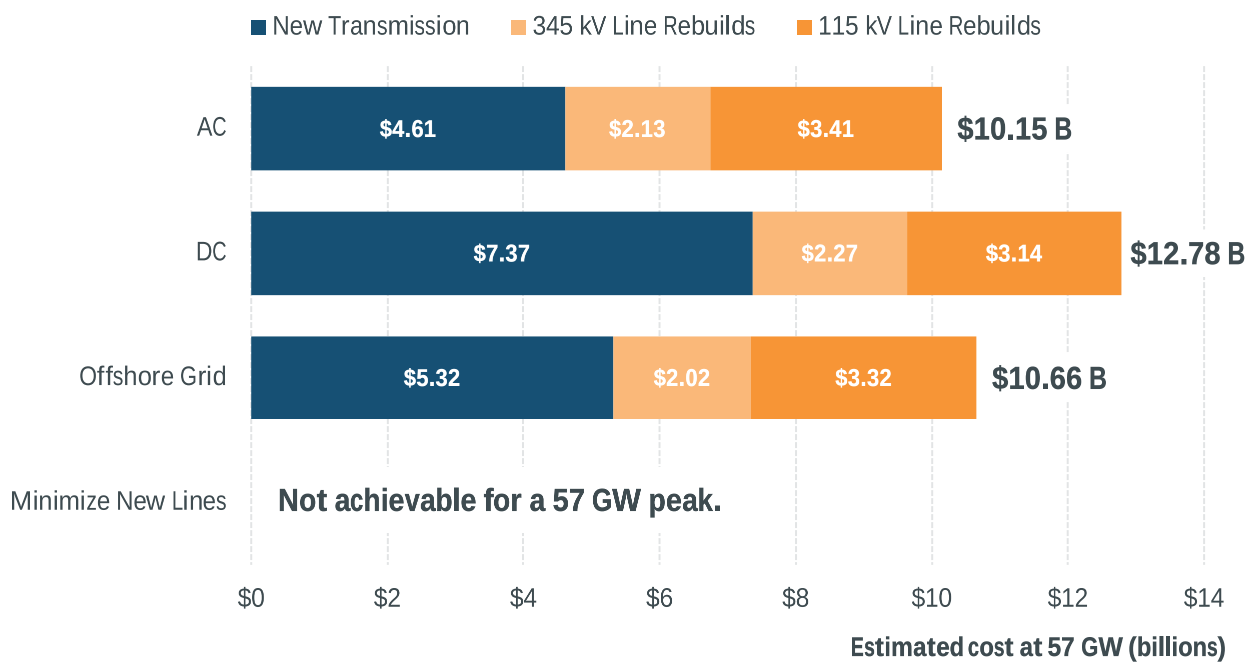


Figure 5-3: Cost Categories for North-South/Boston Import Roadmaps: 57 GW Winter Peak

Costs illustrated in Table 5-4 and Figure 5-4 are associated with the Northwest Vermont roadmaps. As with North-South/Boston Import costs above, multiple roadmaps were developed for this high-likelihood concern and detailed in Section 4.2. Figure 5-5 and Figure 5-6 categorize the costs by rebuild type for both the 51 GW and 57 GW winter peak load snapshots.

Table 5-4: Estimated Cumulative Costs for Northwestern Vermont Import Roadmaps

Year/Load Level	PV-20 Upgrade and Doubling of K-43 Roadmap	Coolidge – Essex Roadmap	New Haven –

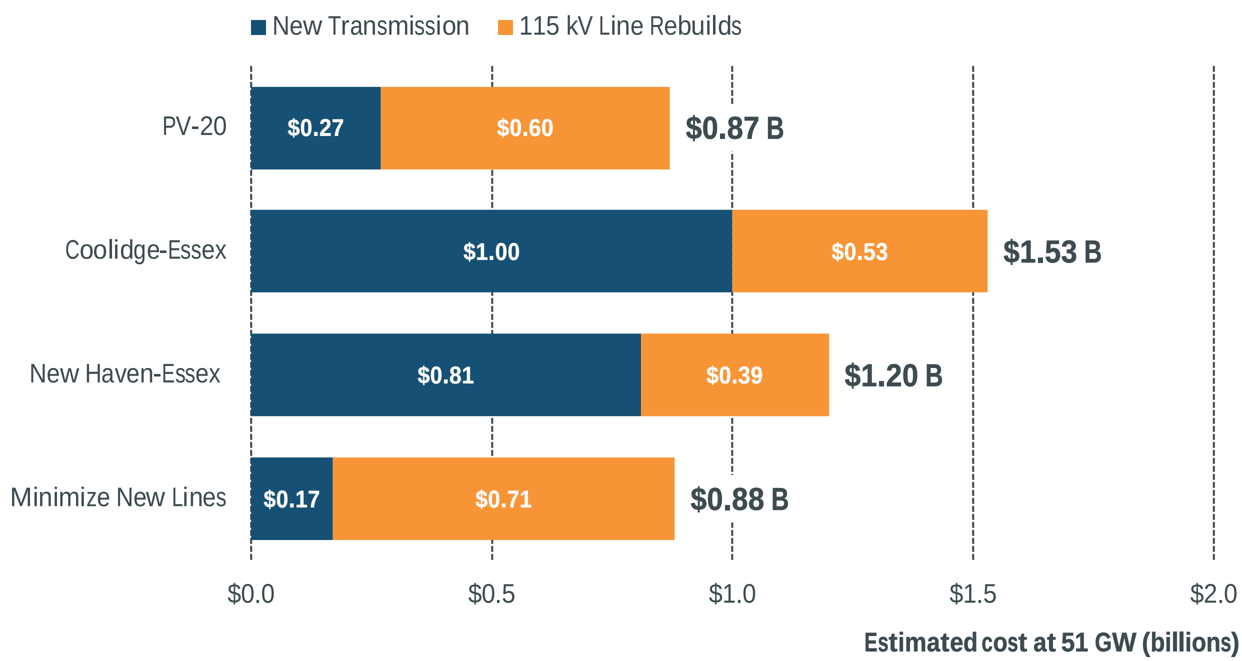


Figure 5-5: Cost Categories for NWVT Import Roadmaps: 51 GW Winter Peak

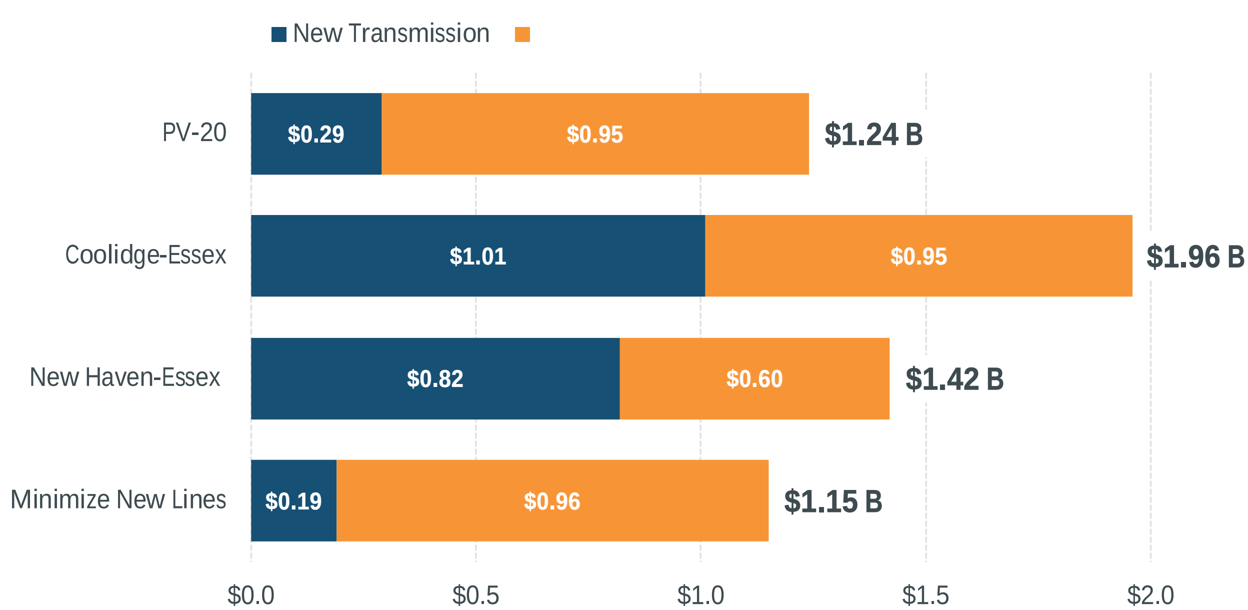


Figure 5-6: Cost Categories for NWVT Import Roadmaps: 57 GW Winter Peak

Table 5-7: Estimated Cumulative Costs for Non-High-Likelihood Concerns

Table 5-8: Estimated Cumulative Costs by Year Studied

Year/Load Level	Maximum Load Served (MW)	Total Cost Range	Cost Breakdown
2035			

Figure 5-7: Total Costs by Year Studied

Note that these costs are only part of the required total investment in the transmission system. Other costs include asset condition projects

Section 6: Future Work

The 2050 Transmission Study is the first longer-term transmission study conducted for New England. Results revealed many important lessons about the future development of New England's transmission system, and many opportunities for similar studies in the future. As time passes, the assumptions regarding generator types, sizes, and locations used in this study will be replaced with real-life data, providing more precision around the transmission system upgrades that will be required in the future.

One potential area of focus for future longer-term transmission studies is the addition of analysis beyond steady-0.004

Section 7: Conclusion

As the clean energy transition accelerates, power flows across New England's transmission system will eclipse all previous highs. The "best case" 51 GW winter peak load snapshot analyzed in this study is more than double the highest winter peak ever recorded in New England, January 2004's 23GW level, and the "worst case" 57 GW winter peak load snapshot is almost 150% higher. Assuming increased build-outs of renewables continue, and electrification of heating and transportation proceeds as expected, the region's aging transmission system has the potential to become a significant bottleneck to progress if it does not keep pace with changes to other elements of the power system.

In 2021, NESCOE and the ISO recognized that the traditional 10-year planning horizon was no longer sufficient to adequately analyze a transmission system undergoing such immense change. The 2050 Transmission Study is an unprecedented look at the future of New England's transmission system, and the results produced by this study will assist stakeholders and the ISO in making important decisions about improvements and pathways forward. Processes developed and lessons learned in this study also pave the way for future studies, as the ISO continues to meet its commitment to overseeing a reliable and cost-effective regional transmission system. With the addition of the Longer-Term Transmission Planning process to the ISO New England Open Access Transmission Tariff, studies like this one will be conductederiodcally to re -assess the long-term evolution of the transmission system and associated costs.

Although the roadmaps provided in this study are not intended as comprehensive plans, and overloads and issues associated with the high-li