

**BUSINESS PROCESS AUDIT
OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a
EVERSOURCE ENERGY'S NEW HAMPSHIRE
DISTRIBUTION CAPITAL PROJECTS
JULY 2023**

APPENDICES

**REQUESTED BY
THE NEW HAMPSHIRE
DEPARTMENT OF ENERGY'S
DDIVISION OF REGULATORY SUPPORT
ELECTRIC DIVISION**

**PREPARED BY
RIVER CONSULTING GROUP, INC.**

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Appendix A

2020 Design Violations Summary Report

Bulk Substations

Non-Bulk Substations

Appendix A: 2020 Design Violations Summary Report - Bulk Substations

| Substation | Region | Existing | | | | | | Solution | | | | |
|------------------------|----------|--------------|------------------------------|--------------|--------------|--------|--|--------------|------------------------------|--------------|--------|---|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | Violation | Voltage (kV) | MVA | MW Load 2020 | # Fdrs | Other |
| Bedford | Central | 115-34.5kV | TB164 - 44.8 TB191 - 44.8 | 2004 2004 | 61.00 | 7 | N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 65.00 | 7 | Replace with larger transformers |
| Eddy | Central | 115-34.5kV | TB26 - 44.8 TB81 - 44.8 | 1978 1968 | 61.00 | 6 | Unhealthy transformers TB26 and TB81; N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBD | 72.00 | 6 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Garvins | Central | 115-34.5kV | TB39 - 67.2 TB51 - 67.2 | 1974 1974 | 69.00 | 7 | Unhealthy transformer TB39; N-1 bus fault violation | 115-34.5kV | TB39 - 67.2 TB51 - 67.2 | 75.00 | 7 | Add series bus tie breakers |
| Huse Road | Central | 115-34.5kV | TB46 - 44.8 TB58 - 48.0 | 1987 1969 | 72.00 | 5 | Unhealthy TB58; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 80.00 | 5 | Replace with larger transformers; add series tie breakers |
| Pine Hill | Central | 115-34.5kV | TB118 - 44.8 TB161 - 44.8 | 2003 1968 | 59.00 | 4 | N-1 STE violation; N-1 bus tie violation | 115-34.5kV | TBD | 60.00 | 4 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Rimmon | Central | 115-34.5kV | TB26 - 44.8 TB81 - 44.8 | 2015 2015 | 65.00 | 7 | N-1 STE violation | 115-34.5kV | TBD | 69.00 | 7 | Solution TBD - depends on Bedford and Huse Road substations final configuration |
| Cocheco Street (Dover) | Eastern | 115-34.5kV | TB22 - 44.8 TB55 - 44.8 | 1972 2001 | 80.00 | 4 | Unhealthy transformer TB22; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 82.00 | 4 | Replace with larger transformers; add series bus tie breakers |
| Great Bay | Eastern | 115-34.5kV | TB171 - 44.8 | 2002 | 45.00 | 2 | N-0 base case load violation | 115-34.5kV | TB171 - 44.8 | 45.00 | 2 | Transfer load to Timmer Swamp Substation |
| Madbury | Eastern | 115-34.5kV | TB65 - 44.8 TB74 - 44.8 | 1971 1976 | 70.00 | 4 | Unhealthy transformer TB65; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 80.00 | 5 | Replace with larger transformers; add series bus tie breakers; add new feeder |
| Mill Pond | Eastern | 115-12.47kV | TB171 - 44.8 | 2014 | 10.00 | 4 | N-0 base case load violation | 115-12.47kV | TB171 - 44.8 | 13.00 | 4 | Replace transformer at Cutts Street Substation; upgrade distribution lines |
| Rochester | Eastern | 115-34.5kV | TB53 - 44.8 TB57 - 44.8 | 1968 2002 | 60.00 | 4 | N-1 STE violation | 115-34.5kV | TB53 - 44.8 TB57 - 44.8 | 65.00 | 4 | Transfer load to Tasker Farm Substation |
| Ashland | Northern | 115-34.5kV | TB5 - 44.8 | 2005 | 36.00 | 2 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB5 - 44.8 TBXX - TBD | 38.00 | 2 | Add second transformer; add third and fourth feeder to Meredith and Ashland Municipal to utilize increased capacity; solves violations at other substations |
| Beebe River | Northern | 115-34.5kV | TB62 - 44.8 | 1974 | 21.00 | 2 | Unhealthy transformer TB62; N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB62 - 44.8 | 21.00 | 2 | Add second transformer at Ashland Substation |
| Berlin (Eastside) | Northern | 115-34.5kV | TB83 - 15.0 TB115 - 20.0 | 1954 1947 | 17.00 | 3 | Unhealthy transformers TB83 and TB115; N-1 bus fault violation | 115-34.5kV | TBD | 21.00 | 3 | Solution TBD - voltage support along 34.5kV line |
| Laconia | Northern | 115-34.5kV | TB24 - 44.8 TB125 - 44.8 | 1977 2002 | 61.00 | 5 | Unhealthy transformer TB24; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TB24 - 44.8 TB125 - 44.8 | 69.00 | 5 | Transfer load to Webster/Daniel Substation; add series bus tie breakers |
| Lost Nation | Northern | 115-34.5kV | TB033 - 28.0 TX129 - 44.8 | 1961 2017 | 10.00 | 4 | Unhealthy TB033; N-1 bus fault violation | 115-34.5kV | TB033 - 28.0 TX129 - 44.8 | 11.00 | 4 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| North Woodstock | Northern | 115-34.5kV | TB67 - 44.8 | 1986 | 9.00 | 2 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB67 - 44.8 | 12.00 | 2 | NH Electric Coop to add D-SCADA to 34.5kV |
| Oak Hill | Northern | 115-34.5kV | TB15 - 44.8 TB84 - 45.0 | 2003 1991 | 68.00 | 4 | N-1 STE violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TB15 - 44.8 TB84 - 45.0 | 69.00 | 4 | Transfer load to Garvins Substation |
| Pemigewasset | Northern | 115-34.5kV | TX88 - 62.5 | 2018 | 25.00 | 3 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TX88 - 62.5 | 25.00 | 3 | Add second transformer at Ashland Substation. [Note: 20 MVA TB88 was replaced with a new 62.5 MVA TX88, Q4 2020.] |
| Saco Valley | Northern | 115-34.5kV | TB60 - 44.8 | 1976 | 20.00 | 3 | N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB60 - 44.8 | 23.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| Webster and Daniel | Northern | 115-34.5kV | TB43 - 44.8 TB59 - 44.8 | 2016 2016 | 39.00 | 3 | N-1 bus fault violation; N-1 bus tie violation; N-1 transmission violation | 115-34.5kV | TB43 - 44.8 TB59 - 44.8 | 41.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| White Lake | Northern | 115-34.5kV | TB76 - 28.0 TB82 - 28.0 | 1964 1963 | 49.00 | 4 | Unhealthy transformers TB76 and TB82; base load violation; N-1 transformer violation; N-1 STE violation; N-1 bus fault violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 50.00 | 4 | Replace both transformers; add series bus tie breakers |
| Whitefield | Northern | 115-34.5kV | TB89 - 44.8 | 1966 | 20.00 | 3 | Unhealthy TB89; N-1 bus fault violation | 115-34.5kV | TB89 - 44.8 | 25.00 | 3 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| Amherst | Southern | 345-34.5kV | TB68 - 140.0 TB85 - 140.0 | 1987 2003 | 105.00 | 5 | N-1 bus fault violation; N-1 bus tie violation | 345-34.5kV | TB68 - 140.0 TB85 - 140.0 | 110.00 | 5 | Replace and add a 2nd transformer at South Milford Substation; replace both transformers at Bridge Street Substation |

Appendix A: 2020 Design Violations Summary Report - Bulk Substations

| Substation | Region | Existing | | | | | | Solution | | | | |
|------------------------|----------|--------------|---|--------------------------------------|--------------|--------|--|--------------|--|--------------|--------|--|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | Violation | Voltage (kV) | MVA | MW Load 2020 | # Fdrs | Other |
| Bridge Street | Southern | 115-34.5kV | TB45 - 44.8 TB52 - 44.8 | 1973 1973 | 55.00 | 5 | Unhealthy transformers TB45 and TB52; N-1 STE violation; N-1 bus fault violation; N-1 transmission violation | 115-34.5kV | TBxx - 62.5 TBxx - 62.5 | 59.00 | 5 | Replace both transformers; solution TBD for N-1 transmission violation |
| Bridge Street 4kV | Southern | 115-4.16kV | TB15C - 10.5 | 2007 | 7.20 | 6 | N-1 transformer violation; N-1 bus fault violation; N-1 bus tie violation | 115-4.16kV | TB15C - 10.5 | 8.00 | 6 | Deploy mobile 34.5-4.16kV substation in an emergency (typical procedure for non-bulk substations) |
| Hudson | Southern | 115-34.5kV | TB33 - 44.8 TB44 - 44.8 | 2005 1974 | 43.00 | 6 | N-1 bus fault violation | 115-34.5kV | TB33 - 44.8 TB44 - 44.8 | 47.00 | 6 | Transfer load or add series bus tie breakers (study needed to determine best alternative) |
| Lawrence Road | Southern | 345-34.5kV | TB48 - 140.0 | 1995 | 49.00 | 5 | N-1 transformer violation; N-1 bus fault violation | 345-34.5kV | TB48 - 140.0 | 49.00 | 5 | Add transformer breaker to Lawrence Road Substation; study needed to determine if bus tie breaker or additional capacity at neighboring substations will resolve N-1 bus fault violation |
| Long Hill | Southern | 115-34.5kV | TB10 - 44.8 TB20 - 44.8 | 2005 1969 | 65.00 | 4 | Unhealthy transformer TB20; N-1 STE violation; N-1 bus fault violation; N-1 transmission violation | 115-34.5kV | TB10 - 62.5 TB20 - 62.5 | 71.00 | 4 | New transmission line from South Milford Substation; replace both transformers; add series bus tie breakers |
| Scobie Pond | Southern | 115-12.47kV | TB131 - 30.0 TB132 - 30.0 | 2011 2011 | 33.00 | 6 | N-1 bus fault violation; N-1 bus tie violation; N-1 transmission violation | 115-12.47kV | TB131 - 30.0 TB132 - 30.0 | 32.00 | 6 | Enhance 12.47kV distribution to increase line capacity; add series bus tie breakers |
| South Milford | Southern | 115-34.5kV | TB86 - 44.8 | 2014 | 45.00 | 2 | N-0 base load violation; N-1 transformer violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TB86 - 62.5 TBxx - 62.5 | 50.00 | 2 | Replace transformer; add 2nd transformer; add new feeder; construct new transmission line into South Milford |
| Chestnut Hill | Western | 115-34.5kV | TB87 - 12.5 TB98 - 12.5 | 1947 1947 | 17.00 | 2 | Unhealthy transformers TB87 and TB98; N-1 transformer violation; N-1 bus fault violation | 115-34.5kV | TB87 - 44.8 TB98 - 44.8 | 18.00 | 2 | Replace both transformers with 44.8 MVA or 62.5 MVA; add series bus tie breakers; add 2 feeder breakers |
| Emerald Street (Keene) | Western | 115-12.47kV | TB18 - 12.5 TB23 - 12.5 TB3 - 22.4 TB7 - 22.4 TB12 - 22.4 | 1953 1954 2000 1964 1969 | 31.00 | 10 | Unhealthy: TB18, TB23, TB7, TB12; N-1 bus tie violation | 115-12.47kV | TB3 - 22.4 TBxx - 30.0 TBxx - 30.0 | 40.00 | 10 | Replace 12.47kV switchgear; replace 4 unhealthy transformers with 2-30 MVA transformers; solution TBD for N-1 bus tie violation |
| Jackman | Western | 115-34.5kV | TB61 - 28.0 TB33 - 44.8 | 1964 2008 | 36.00 | 5 | Unhealthy transformer TB61; N-1 bus fault violation | 115-34.5kV | TB61 - 28.0 TB33 - 44.8 | 38.00 | 5 | Add series bus tie breakers |
| Monadnock | Western | 115-34.5kV | TB80 - 28.0 TB40 - 20.0 | 1965 1951 | 35.00 | 3 | Unhealthy TB40; N-1 transformer violation; N-1 STE violation; N-1 bus fault violation; N-1 bus tie violation | 115-34.5kV | TBxx - 44.8 TBxx - 44.8 | 40.00 | 3 | Replace both transformers with 44.8 MVA or 62.5 MVA; add series bus-tie breakers; add cap bank to supplement existing |
| North Keene | Western | 345-34.5kV | TB145 - 140.0 | 2015 | 19.00 | 5 | N-1 bus fault violation; N-1 bus tie violation | 345-34.5kV | TB145 - 140.0 | 22.00 | 5 | Replace manual load-break switch with SCADA-controlled device to restore load on radial feeder |
| North Road | Western | 115-34.5kV | TB38 - 44.8 TB49 - 44.8 | 1971 1971 | 40.00 | 4 | Unhealthy transformers TB38 and TB49; N-1 bus fault violation | 115-34.5kV | TB38 - 44.8 TB49 - 44.8 | 42.00 | 4 | Add series bus tie breakers |

Source: Attachment BPA 1-006, October 1 2021 --> 2020 Design Violations Summary Report - New Hampshire Distribution System Planning, revised March 18 2021

Central 6
 Eastern 5
 Northern 12
 Southern 8
 Western 6

 Substations 37

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Appendix A: 2020 Design Violations Summary Report - Non-Bulk Substations

| Substation | Location | Existing | | | | | Violation | Solution | | | | |
|-----------------------|-----------|--------------|-------------|------------|--------------|--------|---|--------------|--------------------------|--------------|--------|---|
| | | Voltage (kV) | MVA | Install Yr | MW Load 2020 | # Fdrs | | Voltage (kV) | MVA | MW Load 2029 | # Fdrs | Other |
| Cutts Street 15W4 | SE Corner | 34.5-12.47 | 15W4 - 4.5 | 1956 | 3.80 | 1 | Unhealthy transformer 15W4 | 34.5-12.47 | 15W4 - 12.5 | 4.20 | 1 | Replace transformer with 12.5 MVA unit (solves Mill Pond capacity problem); enhance distribution system with D-SCADA and possible reconductoring and/or reconfiguration |
| Goffstown 27W2 | SE Corner | 34.5-12.47 | 27W2 - 3.0 | 1956 | 1.80 | 1 | Unhealthy transformer 27W2; N-0 base load violation | n/a | n/a | 3.20 | 1 | Remove 27W2 and 45H1 subs (1 feeder each); upgrade distribution line to 34.5kV |
| Goffstown 45H1 | SE Corner | 34.5-4.16 | 45H1 - 1.8 | 1955 | 1.90 | 1 | Unhealthy transformer 45H1; N-0 base load violation | n/a | n/a | 3.10 | 1 | |
| Loudon 31W1 | SE Corner | 34.5-12.47 | 31W1 - 5.25 | 2006 | 4.00 | 1 | N-0 base load violation | 34.5-12.47 | 31Wx - 12.5 | 5.60 | 1 | Replace 31W1 and 31W2 with <u>single</u> transformer; NWA candidate |
| Loudon 31W2 | SE Corner | 34.5-12.47 | 31W2 - 3.36 | 1964 | 3.60 | 1 | Unhealthy transformer 31W2; N-0 base load violation | | | 3.80 | 1 | |
| Rye 48H1 | SE Corner | 34.5-4.16 | 15W4 - 3.75 | 1956 | 3.50 | 2 | Unhealthy transformer 15W4; N-0 base load violation | ??? | ??? | 4.10 | 2 | ??? (error in report) |
| Salmon Falls 51H1 | SE Corner | 13.8-4.16 | 51H1 - 1.5 | 1996 | 1.50 | 1 | N-0 base load violation | 13.8-4.16 | 51H1 - 1.5 51Hx - 1.5 | 1.70 | 1 | Add second 1.5 MVA transformer |
| Hanover Street 16W3 | SE Center | 34.5-12.47 | 16W3 - 3.36 | 1962 | 3.60 | 1 | Unhealthy transformer 16W3; N-0 base load violation | 34.5-12.47 | 16W3 - 3.36 | 4.00 | 1 | Transfer 12.47kV load to 34.5kV distribution system; NWA candidate |
| Meetinghouse Road 3W2 | SE Center | 34.5-12.47 | 3W2 - 5.04 | 1969 | 5.35 | 1 | N-0 base load violation | 34.5-12.47 | 3W2 - 5.04 | 5.85 | 1 | Transfer 12.47kV load to 34.5kV distribution system |
| Suncook 44W2 | SE Center | 34.5-12.47 | 44W2 - 5.04 | 1965 | 4.90 | 1 | Unhealthy transformer 44W2; N-0 base load violation | 34.5-12.47 | 44W2 - 5.04 | 5.10 | 1 | Transfer 12.47kV load to 34.5kV distribution system |
| Opechee Bay TB10 | Center | 34.5-12.47 | TB10 - 2.5 | 1956 | 3.00 | 1 | Unhealthy transformer TB10; N-0 base load violation | 34.5-12.47 | TB10 - 2.5 | 3.20 | 1 | Transfer load to Messer Street |
| Weirs | Center | n/a | n/a | n/a | n/a | n/a | Site of future 34.5-12.4 kV substation | n/a | n/a | n/a | n/a | Site of future 34.5-12.4 kV substation |

Source: Attachment BPA 1-006, October 1 2021 --> 2020 Design Violations Summary Report - New Hampshire Distribution System Planning, revised March 18 2021

SE Corner 7
SE Center 3
Center 2

Substations 12

Appendix B

Software Tools

Commercial

Aspen OneLiner – Short circuit and relay coordination software package for electric power system protection engineers from Aspen.

Cascade – Asset inventory, maintenance, and condition-tracking software from DNV.

Clik Field Services Management – Crew tablet scheduling software from Clik Software. This software is planned to be replaced.

DistriView™ – An integrated suite of voltage-drop, short circuit, relay coordination, harmonics, and reliability calculation software for utility distribution systems from Aspen.

e-Builder – Construction management software from Trimble.

GIS – Geographic Information System for capturing, storing, checking, and displaying geographic position data.

IBM Planning Analytics – Enterprise financial planning software tool from IBM designed to implement collaborative planning, budgeting, and forecasting solutions.

Inventor 3D Design Software – Professional-grade 3D CAD software for product design and engineering for both solid and surface modeling from Autodesk.

Jira Software – Software tool from Atlassian that helps facilitate the agile process, which is an iterative and collaborative approach to managing the work associated with a project.

Maximo – Asset management, monitoring, and predictive maintenance software package from IBM. Work orders are created in this software and capture material, contract, and time charges. The project number from PowerPlan links these charges to the plant accounting system.

Planning Analytics – Business performance management software suite from IBM. It is designed to implement collaborative planning, budgeting, and forecasting solutions, interactive "what-if" analyses, as well as analytical and reporting.

PowerPlan – Integration hub specialty project accounting software that automates key accounting functions, and manages interfaces between sources of transactions, including general ledger, project accounting, plant accounting, and book depreciation from PowerPlan, Inc. Project numbers are initiated within this software and become the link to charges made to specific work orders created in Maximo.

Power BI Tool – Dashboard generating tool from Microsoft.

Primavera P6 – Project management and scheduling software from Oracle.

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PSCAD™ – Power systems EMT (Electro-Magnetic Transient) simulations from PSCAD, a subsidiary of Manitoba Hydro International Ltd.

PSS/E – Electric power system analysis software package from Siemens [came with PTI purchase] used for transmission studies.

PTLOAD – Power transformer load simulation software package from EPRI.

PTX Software – Power transformer condition assessment software (Power Transformer Expert System) from EPRI.

Synergi Electric – Power distribution simulation software package from DNV.

Synergis Adept – Engineering document (drawings) management software from Synergis Technologies, LLC.

Teams – Proprietary business communication platform developed by Microsoft for video conferencing and meetings management.

WorkDay – Human Resource Information System (HRIS) software from Workday for data analytics, HR, finance, management, and enterprise planning.

Custom In-House

NWA Screening Tool¹ – An Excel-based Eversource internal document that allows System Planning to screen capacity project needs at specific locations for potential application of NWA solutions. The Tool is designed to enable rapid initial screening of NWA options against traditional system upgrade projects. And will provide appropriate sizing of such locations.

Custom modifications to EPRI PTX Software tool – To better focus on transformer health management.

¹ LCIRP, March 31, 2021 Supplement, Appendix A-1, “Non-Wires Alternative Framework, Version 2.0.

Appendix C

Abbreviations

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| | |
|----------------|--|
| ABR | Automatic Bus Restoral scheme |
| ADA | Advanced Data Analytics |
| ADMS | Advanced Distribution Management System |
| ADR | Active Demand Response |
| AEIC | Association of Edison Illuminating Companies |
| AFUDC | Allowance for Funds Used During Construction |
| AI | Artificial Intelligence |
| AMF | Advanced Metering Functionality |
| AMI | Advanced Metering Infrastructure |
| AMR | Automated Meter Reading |
| ANSI | American National Standards Institute |
| APPR | Approved (in MAXIMO) |
| APS | Accounting Policy Statement |
| APS-01 | Accounting Policy Statement 01 (corporate accounting policy) |
| ARO | Asset Retirement Obligation |
| AS&E | Administrative Salaries and Expenses |
| ASCE | American Society of Civil Engineers |
| Aspen OneLiner | (Aspen) Software for studying power system protection |
| AVG | Average |
| BCA | Benefit Cost Analysis |
| BES | Bulk Electric System |
| BESS | Battery Energy Storage System |
| BMS | Business Management System |
| BOD | Board of Directors |
| BOM | Bill of Materials |
| BOT | Board of Trustees |
| BP | Best Practices |
| BPA | Business Process Audit |
| BPS | Bulk Power System |
| BTM | Behind-the-Meter |

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Bulk Distribution Substation – A collection of equipment and transformers used to step the Transmission source voltage (115 kV and higher) down to a Distribution voltage (usually 34.5 kV and below)

Non-Bulk Distribution Substation – A collection of equipment and transformers used to step the Distribution source voltage (46 kV and 34.5 kV) down to a lower Distribution voltage (usually 12.47 kV and 4.16 kV)

| | |
|------------|--|
| BUG | Back-Up Generation |
| CAIDI | Customer Average Interruption Duration Index |
| CAGR | Compound Annual Growth Rate |
| CAM | Cost Allocation Manual |
| CapEx | Capital Expense |
| CBRC | Capital Budget Review Committee |
| CBC | Capital By Category |
| OCA | Office of Consumer Advocate |
| CCA | Chromated Copper Arsenate |
| CCNC | Completed Construction Not Classified |
| CCVT | Coupling Capacitor Voltage Transformer |
| CDG | Community Distributed Generation |
| CEG | Cost Estimating Group |
| CENH | Clean Energy New Hampshire |
| CEO | Chief Executive Officer |
| CESIR | Coordinated Electric System Interconnection Review |
| CFO | Chief Financial Officer |
| CGS | Certificate of Good Standing |
| CHP | Combined Heat and Power |
| CI | Customers Interrupted |
| CII | Customers Interrupted per Interruption Index |
| C/I or C&I | Commercial/Industrial or Commercial & Industrial customers |
| CIP | Capital Improvement Plan (or Critical Infrastructure Protection) |
| CIO | Chief Information Officer |
| CIS | Customer Information System |

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| | |
|----------|---|
| CLF | Conservation Law Foundation |
| CMI | Customer Minutes Interrupted |
| CMS | Customer Meter Services |
| CoA | Certificate of Assurance |
| COC | Contractors of Choice |
| CoE | Center of Excellence |
| Company | Public Service Company of NH d/b/a Eversource Energy |
| COO | Chief Operating Officer |
| CO2 | Carbon Dioxide |
| COSAIDI | Company System Average Interruption Duration Index |
| COVID-19 | Pandemic |
| CPP | Critical Peak Pricing |
| CPPM | Capital Project Process Model |
| CRIS | Customer Related Information System |
| CS | Customer Solutions (or Customers Served) |
| CSDBR | Company Sanctioned Data Backup Required |
| CSOC | Cyber Security Operations Center |
| CSS | Customer Service System |
| CU | Compatible Unit |
| CVA | Certificate of Vote/Authority |
| CVR | Conservation Voltage Reduction |
| CY | Calendar Year |
| CYME | International power systems solutions and software provider |
| CYMDIST | CYME distribution system analysis software |
| CYMTCC | CYME over-current protection analysis software |
| DA | Distribution Automation |
| DAL | Drastic Action Limit |
| DAS | Distribution Automation Switching |
| DC | Direct Current |
| DEC | Department of Environmental Conservation |

Business Process Audit of PSCNH (Eversource) DE 19-057

| | |
|-------------|--|
| DER | Distributed Energy Resource |
| DERs | Distributed Energy Resources |
| DERMS | Distributed Energy Resource Management System |
| DES | Department of Environmental Services |
| DG | Distributed Generation |
| DIP | Distribution Integrated Planning |
| DistriView | ASPEN DistriView Integrated Software Package |
| Division | Department of Energy Regulatory Support Division (Staff) |
| DLC Program | Direct Load Control Program |
| DLM | Dynamic Load Management |
| DMS | Distribution Management System |
| DoA | Delegation of Authority |
| DOE | NH Department of Energy |
| DoNHDE | New Hampshire Distribution Engineering |
| DP | Distribution Provider |
| DPC | Distribution Planning Criteria |
| DR | Demand Response (Distributed Resource or Data Request) |
| DRWG | IEEE's Distribution Reliability Working Group |
| D-SCADA | Distribution Supervisory Control and Data Acquisition |
| DSINPRG | Design in Progress (in MAXIMO) |
| DSM | Demand Side Management |
| DSOC | Distribution System Operations Center |
| DSP | Distributed System Platform |
| DSPG | Distribution System Planning Guide |
| DSS | Distribution System Supply |
| DTS | Distribution Transfer Switching |
| EAM | Earnings Adjustment Mechanism |
| EBIT | Earnings Before Income Tax |
| EBU | Electric Business Unit |
| EDI | Electronic Data Interchange |

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| | |
|-------|---|
| E2E | End-to-End |
| E&S | Engineering and Supervision |
| EE | Energy Efficiency (can also mean Eversource Energy) |
| EERS | Energy Efficiency Resource Standard |
| EG | Emergency Generation |
| ELF | Electric Load Forecast |
| EMS | Energy Management System |
| EMT | Electromagnetic Transients |
| ENST | Eversource NWS Screening Toolset |
| EOC | Engineers of Choice |
| EPA | Environmental Protection Agency |
| EPAC | Eversource Project Approval/Authorization Committee |
| EPC | Engineer-Procure-Construct |
| EPRI | Electric Power Research Institute |
| EPS | Electric Power System |
| ERISA | Employee Retirement Income Security Act |
| ERM | Enterprise Risk Management |
| ERP | Enterprise Resource Planning |
| ESP | Electric System Planning |
| ES | Energy Storage |
| E&S | Engineering and Supervision |
| ESCC | Electric System Control Center |
| ESP | Electronic Security Perimeter |
| Esri | Global leader in GIS software |
| ESS | Energy Storage System |
| ETT | Enhanced Tree Trimming |
| EV | Electric Vehicle |
| Event | Single contingency (N-1) lasting one cycle (24 hrs) |
| EWR | Engineering Work Request |
| FC | Fuel Cell |

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| | |
|-----------|---|
| FERC | Federal Energy Regulatory Commission |
| FLISR | Fault Location, Isolation, and Service Restoration |
| FSSP | Financial Simplification and Standardization Project |
| FTE | Full-Time Equivalent |
| FTM | Front of the Meter |
| FWO | Field Work Order (created in MAXIMO) |
| FY | Fiscal Year |
| GAGAS | (Federal) General Accountings Government Auditing Standards |
| GHG | Greenhouse Gas |
| GIS | Geographic Information System |
| GMSG | Grid Modernization Stakeholder Group |
| GOP | Generator Operator |
| GPS | Global Positioning System |
| GridLab-D | Power distribution simulation software from PNNL |
| Grid Mod | Grid Modernization |
| GST | Granite State Test |
| GSU | Generator Step-Up transformer |
| GTEP | Grid Transformation and Enablement Program |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| HC | Hosting Capacity |
| HCA | Hosting Capacity Analysis |
| HR | Human Resources Organization |
| HRIS | Human Resource Information System |
| IA | Internal Auditing (can also mean Interconnection Agreement) |
| IBM | International Business Machines |
| IDP | Integrated Distribution Plan |
| IEEE | Institute of Electrical & Electronics Engineers |
| IFC | Issued For Construction |
| IFR | Initial Funding Request |

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| | |
|------------|---|
| IFRF | Internal Funding Request Form |
| IMP | Integrity Management Plan |
| IMS | Incident Management System |
| INIT | Initiate (in MAXIMO) |
| IoT | Internet of Things |
| IOU | Investor-Owned Utility |
| IPE | Independent Professional Engineer |
| IT | Information Technology |
| IS | Information Systems |
| ISO | Independent System Operator |
| ISO-NE | Independent System Operator – New England |
| ISOC | Integrated System Operations Center |
| IT | Information Technology |
| JM-AM-2001 | Corporate project approval process |
| KPI | Key Performance Indicator |
| kV | Kilovolt |
| kvar | Kilovar |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LBMP | Locational-Based Marginal Price |
| LCC | Load Carrying Capacity |
| LCE | Lead Commissioning Engineer |
| LCIRP | Least-Cost Integrated Resource Plan |
| LCTA | Least Cost Technically Acceptable |
| LED | Light-Emitting Diode |
| LRP | Long Range Plan |
| LSP | Local System Plan/Planning |
| LSR | Large-Scale Renewables |
| LTC | Load Tap Changer |
| LTE | Long Term Emergency rating |

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| | |
|--------|--|
| LVA | Locational Value Analysis |
| LVMs | Line Voltage Monitors |
| MADC | Marginal Avoided Distribution Capacity |
| MAIFI | Momentary Average Interruption Frequency Index |
| M&C | Maintenance and Construction |
| MAX | Maximum |
| Maximo | Work and Asset Management System software |
| MBI | Months Between Interruptions (months in period divided by SAIFI) |
| MCOS | Marginal Cost of Service |
| MDEC | Miscellaneous Distribution Expense Capitalization |
| MDM | Meter and Data Management |
| MDMS | Meter Data Management Services |
| MED | Major Event Days/Definition |
| METT | Maintenance of the Enhanced Tree Trimming specification |
| MIN | Minimum |
| MTM | Market to Market |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NARUC | National Association of Regulatory Utility Commissioners |
| NEC | National Electric Code |
| NE-ISO | New England Independent System Operator |
| NEPOOL | New England Power Pool |
| NERC | North American Electric Reliability Corporation |
| NESC | National Electrical Safety Code |
| NH | New Hampshire |
| NHDOT | New Hampshire Department of Transportation |
| NHEC | New Hampshire Electric Cooperative |
| NHPAC | New Hampshire Project Approval/Authorization Committee |
| NHPUC | New Hampshire Public Utilities Commission |
| NPCC | Northeast Power Coordinating Council |

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| | |
|-------------|---|
| NPV | Net Present Value |
| NREL | National Renewable Energy Laboratory |
| NTF | National Transmission Forum |
| NWA | Non-Wires Alternatives |
| NWS | Non-Wires Solutions |
| OCA | NH Office of the Consumer Advocate |
| OCB | Oil Circuit Breaker |
| O&M | Operations and Maintenance |
| OMS | Outage Management System |
| OPAF | Operations Project Authorization Form |
| OpEx or O&M | Operations Expense or Operations & Maintenance Expenses |
| OPGW | Asset Management Programs for Replacements |
| OPM | Operational Performance Management |
| OQ | Operator Qualifications |
| OQ'd | Operator Qualified |
| OT | Operational Technology |
| OTAF | Operations Technical Approval Form |
| PAC | Planning Advisory Committee (or Project Approval Committee) |
| PACT | Protection And Control Test committee |
| PAF | Project Authorization Form |
| P&L | Profit and Loss |
| PCM | Portfolio Calibration Meeting |
| PE | Professional Engineer |
| PEX | Performance Excellence |
| PFR | Partial Funding Request |
| PHEV | Plug-in Hybrid Electric Vehicle |
| PI | Planned Interruption |
| PLC | Power Line Carrier (or Project Life Cycle) |
| PM | Project Manager |
| PMI | Project Management Institute |

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| | |
|----------------|---|
| PMO | Project Management Office |
| PNNL | Pacific Northwest National Laboratory |
| PQ | Power Quality |
| POC | Point of Control |
| POI | Point of Interconnection |
| PowerPlan | Integration hub software from PowerPlan, Inc. |
| PP4 | Planning Procedure 4 |
| PSNH/EE | Public Service Company of NH d/b/a Eversource Energy |
| PSPM | Protection System Maintenance Program |
| PSS/E | Power system software package from Siemens |
| PTF | Pool Transmission Facility |
| PTLoad | EPRI transformer loading software package |
| PTO | Participating Transmission Owners |
| PTX | Power Transformer Expert System |
| PUC/NHPUC | State of New Hampshire Public Utilities Commission |
| PV | Photovoltaic (Solar) |
| QA/QC | Quality Assurance/Quality Control |
| RCG | River Consulting Group |
| Regulated Load | Load that has voltage regulation at a 34.5kV primary voltage beyond the bulk distribution facility/substation |
| RDISP | Ready to Dispatch (in MAXIMO) |
| REP | Reliability Enhancement Program |
| RIDS | Risk Informed Decision Support |
| RFI | Request for Information |
| RFP | Request for Proposal |
| RM | Risk Management |
| ROE | Return on Equity |
| ROW | Right of Way |
| RSA | Revised Statutes Annotated |
| RSP | Regional System Plan |

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| | |
|------------------|---|
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SAMP | Strategic Asset Management Plan |
| SCADA | System Control and Data Acquisition |
| SCLL | Single Contingency Load Loss |
| SCT | Societal Cost Test |
| SD | System Design |
| SDC | Solution Design Committee (or Substation Design Change) |
| SDM | Substations Design Manual |
| SEC | Securities and Exchange Commission |
| SFR | Supplemental Funding Request |
| SGIP | Small Generator Interconnection Process |
| SHE | Safety, Health, and Environmental |
| SIR | Standardized Interconnection Requirements |
| SLA | Service Level Agreement |
| Smallworld | Software GIS mapping tool |
| SME | Subject Matter Expert |
| SMT | Scheduled Maintenance Trimming |
| SOC | System Operations Center |
| SPCA | Spacer Cable |
| SRF | Supplemental Request Form |
| SSF | Solution Selection Form |
| Staff | New Hampshire DOE Staff (Regulatory Support) |
| STE | Short Term Emergency rating |
| Sub-T | Sub-transmission |
| SVC | Static VAR Compensator |
| Synergi Electric | Power Distribution System and Electrical Simulation software package from DNV |

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| | |
|------------------|---|
| Synergis Adept | Engineering document (drawings) management software from Synergis Technologies, LLC |
| TAF | Technical Approval Form |
| T&D | Transmission and Distribution |
| T&M | Time and Material |
| TFRAT | Transformer Rating, bulk transformer “loss of life” used historically by legacy PSNH (superseded by SYSPLAN-008) |
| THI | Temperature Humidity Index |
| TO | Transmission Owner |
| TOP | Transmission Operator |
| TOU | Time-of-Use |
| TRC | Total Resource Cost |
| TRS | Trouble Reporting System |
| TVP | Time-Varying Pricing |
| UCT | Utility Cost Test |
| UG | Underground |
| UER | Utility Energy Registry |
| UES | Unitil Energy Systems |
| Unregulated Load | Load that has no voltage regulation at a 34.5kV primary voltage beyond the bulk distribution facility/substation |
| URD | Underground Residential Distribution |
| USDOE | US Department of Energy |
| USSC | US Sanction Committee |
| VAD | Value Added Data |
| VCB | Vacuum Circuit Breaker |
| VDER | Value of Distributed Energy Resources |
| VP | Vice President |
| VT | Voltage Transformer |
| VTOU | Voluntary Time-of-Use |
| VVO | Volt-VAR Optimization |
| VVO/CVR | Volt-VAR Optimization /Conservation Voltage Reduction |

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| | |
|-------------|---|
| WO | Work Order |
| WTBS | Waiting To Be Scheduled (In MAXIMO) |
| WTHI | Weighted Temperature Humidity Index |
| Yellow Book | Federal General Accountings Government Auditing Standards |
| ZEV | Zero-Emission Vehicle |

Appendix D

Projects Review

A sampling of capital projects was reviewed² to evaluate adherence to Company processes/guidelines and standard industry practices. Information reviewed included the following: History, planning violations, solution alternatives, preferred solution rationale, and project-specific lessons learned.

A review of projects indicated an established engineering process was being followed. However, RCG believes more comprehensive and consistent communications and project oversight could have identified/resolved issues earlier in the project development process, including how best to use outside contracted resources.

The following projects were reviewed *[a representative sample taken from hearings, rate case, data requests, LCIRP, Company website, system planning studies (criteria violations), Staff concerns/questions, and budget variances]*:

- I. East Northwood Phase Extension
- II. Loudon Station
- III. Nashua Millyard Substation
- IV. Monadnock Distribution Substation Rebuild
- V. Pack Monadnock Distribution Line Rebuild
- VI. Pemigewasset Transformer Project
- VII. Reconductor New Boston Road, Bedford
- VIII. West Rye Substation Rebuild
- IX. Viper Replacement Project
- X. Rimmon Substation Animal Protection
- XI. Goffstown Substation Elimination – Phase 1
- XII. Replace Notre Dame Substation with MITS and Dunbarton Road Substation with Pad-mounted Step Transformer

For each project, *summaries and observations* are provided followed by project-specific *lessons learned*.

I. East Northwood Phase Extension (2020-2021)³

1 - Planning violations: Low voltages; phase overloads/imbalances; and protection issues.

² Process reviews were conducted not technical reviews.

³ Data Requests BPA 8-001; BPA 9-010; BPA 9-011; BPA 1-013

2 - Three (3) alternatives were considered.

- Alternatives #1 and #2 were significantly more expensive, did not resolve all technical issues, and were not fully investigated.
- Alternative #3 (preferred alternative): 63W1 Reconductor Drake Hill Road was the lowest cost and resolved all technical issues.

3 - Funding approval process:

- Challenge Session Form: \$900,000 - August 24, 2020
- PAF: \$1,062,000 - January 21, 2021
- Actual indirect costs were greater than PAF estimated costs because they were based on historical average costs per foot rather than actual project work scope estimates.
- Tree-trimming cost estimates were not obtained for the PAF.
- Competitive bids for line construction contractor labor costs (the largest component of most distribution line projects) were also not obtained for the PAF.

Lessons learned per the Company:

- Project-specific unit construction estimates should be used instead of typical estimates when competing PAFs.
- The results of competitive contractor bids should be used when completing PAFs, such as tree trimming, construction oversight, and ledge pole sets.
- Cost estimates developed by engineering personnel need to be based on specific work scopes rather than historical average labor rates when completing PAFs.
- **RCG conclusion:** Overall project documentation was delivered to RCG in pieces, requiring multiple DRs, and complicating the review process.

II. Loudon Station⁴ (project still under review; no approved PAF as of this writing⁵)

1 - Planning violations: N-0 base load violation; and unhealthy transformers.

2 - Five (5) potential traditional solutions were evaluated, and ten (10) potential NWA solutions (using the NWA Screening Tool).

- Preferred traditional solution: Replace 31W1 and 31W2 transformers with a single transformer.
- Preferred NWA solution: Mobile generators (3) operating 3-to-6 days per year as part of a 5-year deferral strategy.

⁴ LCIRP Mar 31 2021, Supplement, Appendix A-2; Data Request BPA 1-006, 10/01/21 Attachment

⁵ Interview #18

3 - Funding options:

- Traditional Solution -> \$6,500,000 (if deferred 5 years, net present value savings would be \$1,657,186)
- NWA Solution -> \$194,928/year (if implemented)

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** The Loudon study was a good example of how the NWA Screening Tool can be used to quantify potential NWA solutions which can serve as an example for future projects.

III. Nashua Millyard Substation (2016-2022)⁶

1 - Planning violations: Obsolete equipment (>65 years old); and congested physical site.

2 - Seven (7) alternatives were considered.

- Alternative #4 was selected as the preferred solution based on receiving the highest total-ranking score, using a decision matrix of 9 weighting factors, 2 of which were operating costs and system-loss savings.
- Alternative # 4 was not the least-cost solution.

3 - The project was initiated (2016) before the inception of EPAC or SDC and was initially reviewed at CPAC, the predecessor to EPAC. When SDC and EPAC processes were established, the Millyard project was brought before both committees. Full funding was approved by EPAC in 2021.

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** The systematic ranking process used to arrive at the preferred alternative (Alternative # 4) was a good, objective way to arrive at and subsequently support the decision even though it was not the lowest cost solution.
- **RCG conclusion:** Project checklists for the new capital approval process are more comprehensive than the forms completed and approved for this project.

⁶ Data Request BPA 7-001; BPA 7-002; IR-48a; IR 48b

IV. Monadnock Distribution Substation Rebuild (2020-2023)⁷

1 - Planning violations: Unhealthy transformer⁸; (N-1) transformer violation; (N-1) STE violation; (N-1) bus fault violation; and (N-1) bus-tie violation.

2 - Two (2) alternatives were scoped in detail by an outside engineering firm.

- Alternative #1 breaker-and-a-half design.
- Alternative #2 was a ring-bus design. Included: Replacement of both transformers; the addition of series bus-tie breakers; and the addition of an additional capacitor bank as a supplement to the existing capacitor bank.
- Alternative #2 was selected because it addressed reliability issues.

3 - Funding approval process:

- An initial Solution Selection Form (SSF) was submitted on March 16, 2021, with no budget estimates since the project was in the early initiation stages. An NWA was not considered since the Company does not evaluate NWA solutions for asset condition issues. A greenfield site was selected to facilitate construction and scheduled outages.
- SDC approved an updated SSF on September 29, 2021, along with conceptual budget estimates (30%-40% engineering completed).
- On November 29, 2021, an outside engineering firm provided detailed project estimates for Alternative #2 totaling \$23,399,900 with a range of -25% (\$17,550,000) and +50% (\$35,100,000).

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** More detailed and accurate project estimates are needed for funding approval. The tolerance ranges of -25% to +50% are too large. A more industry-accepted range is +/-10%.

⁷ LCIRP Mar 31 2021 Supplement, Appendix E-3; BPA 1-006, 10-01/21 Attachment; BPA 6-008, 11/29/21 Attachment

⁸ Data Request BPA 8-004: The following factors are used by the PTX tool to create a health index → Normal degradation, abnormal thermal condition, abnormal electrical condition, abnormal core condition, oil quality, and age.

V. Pack Monadnock Distribution Line Rebuild (2017-2021)⁹

1 - Planning violations: This off-road, 1-phase distribution line, was not up to code and could present a safety hazard to the public following a request by a third-party telecom company to attach equipment to the line.

2 - Multiple alternatives were considered and reviewed with external stakeholders (due to the sensitivity of the site), including overhead and underground options.

- Project plans were revised to incorporate feedback. The Company continued communications with stakeholders throughout the pre-and post-construction phases.
- The best overall solution was to reconductor with tree wire and upgrade with stronger poles to accommodate additional equipment and better withstand adverse weather conditions.
- Potential NWA solutions were not applicable in this case.

3 - In 2020, the Company submitted permit applications. All approvals were secured in time to complete line construction in 2021.

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** Maintaining regular communications with stakeholders throughout all project phases (planning, construction, commissioning) was effective on this project and should be a standard process for all projects.

VI. Pemigewasset Transformer Project (2017-2020)¹⁰

1 - Planning violations: (N-1) transformer violation; and (N-1) bus fault violation.

2 - Five (5) alternatives were considered.

- Alternative #2 was selected as the preferred alternative using a decision matrix with weighting factors.
- Alternative #2 was neither the highest nor the lowest cost but was considered the best overall technical solution since it resolved (N-1) violations at adjacent substations (Ashland and Laconia).
- NWA status is unknown since it was not included in the PAF.

4 - Funding approval process: (details below)

⁹ LCIRP Mar 31 2021 Supplement, Appendix F-1; Data Requests BPA 9-009; BPA 9-007; BPA 9-006

¹⁰ Data Request BPA 8-002; DE 19-057 dated 07-19-21; Data Request BPA 5-010

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- PAF: \$4,063,000 - February 14, 2018 (EPAC approved)
- SFR: \$2,754,000 - June 10, 2020 (EPAC approved)
- SFR (revised): \$3,700,000 - April 14 2021
- The \$4.063M PAF included a "Project Checklist" where the initiator indicated a "field constructability review (had) been completed." However, this was only a cursory review since a detailed site walk-through (constructability review) was not conducted until 2019.
- The \$2.754M SFR was to cover a larger control house (the existing control house is too small), bringing the total funding request to \$6.817M.
- The \$2.754M SFR was replaced with a larger \$3.7M SFR to cover engineering costs (internal + outside engineering firm) to correct a transformer issue (synch scope wiring error discovered during initial energization testing), animal protection, smart grid enhancements, and improperly (by the outside engineering firm) accounted for Company overhead costs. The PAF + revised SFR totaled \$7.7M (which EPAC approved on 4/14/21). However, a PUC \$900,000 disallowance occurred due to PSNH's failure to hold the primary contractor liable for the wiring error.

Lessons learned per the Company:

- The legacy authorization process was in place for this project (i.e., prior to 2018 capital approval process changes),¹¹ meaning PAF completion did not follow the new capital SDC/EPAC approval process which requires engineering to validate major assumptions prior to submitting the PAFs.
- Indirect cost estimates in the original PAF were prepared by an outside engineering firm that did not properly account for Company overheads.
- The Company believes animal protection should have been submitted for separate funding approval since it was not included in the original PAF.
- Better checks and balances and communications were needed throughout this project. Improvements made by the Company due in part to this project include the following:¹²
 - Formation of an Engineering Project Controls Group in late 2019.
 - Creation of an *Administrative Procedure M7-EN-2000 Engineering Deliverables* effective 7/1/20.

¹¹ DE 19-057, 07-19-21, page 22

¹² Data Request BPA 5-010

- **RCG conclusion:** Better attention to engineering design details and project oversight might have prevented issues with control house size requirements after initial funding approval had been received; e.g., the increased number of switchgear bays should have been an early red flag.
- **RCG conclusion:** The new capital approval process might have reduced or eliminated the need for supplemental funding requests.

VII. Reconductor New Boston Road, Bedford (2020-2021)¹³

NOTE: The New Boston Road Project was submitted by the Company as a typical distribution capital project. A comprehensive project timeline was overlaid on the process flow chart provided with Data Request BPA 8-005.

1 - Planning violations: Major load imbalance; and potential low-voltage issues.

2 - Three alternatives were considered. Only the preferred alternative met all technical requirements.

- Preferred alternative: Replace 1-phase conductor with 3-phase 477 spacer cable. Redistribute load from phase C (1-phase) to two new phases (A & B). Replace the single-phase recloser with the three-phase recloser. Collateral benefits: Contributes to establishing a long-needed circuit tie between circuits 3194X1 and 322X10, improving reliability. Spacer cable improves resiliency.
- NWA status is unknown since it was not included in the PAF.

3 - Funding approval process:

- Challenge Session: September 2, 2020 (delayed from Aug)
- PAF: \$825,000 - February 11, 2021 (approved by NH-PAC)
 - Funding estimates were based on historical cost-per-foot values and considered limited risk since the project involved standard overhead construction. The Company's preference moving forward is to have the design completed and actual construction bids in hand (if using contract resources) before presenting full funding requests for approval.
- A preliminary engineering design was completed in January 2021.
- An initial, high-level constructability review with Electric Field Operations was conducted in January 2021.

¹³ Data Request BPA 8-005

- A PAF was created in January 2021 (and approved in February as indicated above).
- Detailed engineering constructability reviews were conducted in April 2021 (after PAF approval). While constructability reviews are required for all distribution line projects, *formal constructability documentation was not required at the time. Going forward, the Company intends to make this a requirement.*

Lessons learned per the Company:

No specific lessons learned were recorded by the Company for this project. However, lessons learned (documented on pages 3-4 of BPA 8-005) accumulated from similar projects (per Data Request BPA 8-005) follow:

- If outside resources are to be used, estimates should be based on results from a competitive bidding process.
- Full funding requests should include contingency amounts for items such as ledge pole sets, Company pole sets in non-Company maintenance areas, and other potential unknown costs.
- Overall project cost estimates should include:
 - Tree-trimming costs from the Vegetation Management Department.
 - Internal labor costs for items such as recloser settings development, equipment testing, commissioning, and project management which are not in the compatible units of the Work Management System (Maximo).
 - Labor costs for construction representatives.

VIII. West Rye Substation Rebuild (2016-2018)¹⁴

1 - Planning violations: Unhealthy transformers (age, gassing); obsolete equipment¹⁵; loading issues; and low voltage issues.

2 - Two (2) alternatives were considered. Only the preferred alternative met all technical and environmental requirements.

- Preferred alternative: Replace two 1.5 MVA 34.5-4.16 kV substation transformers with one 10/12 MVA 34.5 - 12.47 kV substation (Eversource standard transformer size). Install 3 reclosers along with RTUs (for distribution automation).

¹⁴ Data Requests BPA 7-005; BPA 11-001; DE 19-057 dated 12-23-19

¹⁵ Replacement parts are no longer available to maintain the equipment.

- NWA status is unknown as it was not included in the PAF.

3 - Funding approval process:

- PAF: \$1,303,000 - April 12, 2016
- SFR #1: \$286,189 - July 20, 2017
- SFR #2: \$712,118 - February 28, 2018
- SFR #3: \$364,000 - September 28, 2018
- SFR #4: \$524,597 - October 4, 2019
- Total Funding after SFRs = \$3,190,715 (245% increase)

4 - SFR #1: To include design/materials/construction for mobile transformer tap on 3105X line. More than expected contractor resources were used for design work (an outside consultant was used for all engineering/design). More than expected material costs. Station service, PTs, site expansion, fencing, grounding, and stoning were not included in the original estimate.

5 - SFR #2: To cover increased costs for construction, testing, and commissioning based on actual bid pricing. The work scope for line taps was not appropriately defined. Responsible parties were not clearly identified. ROW clearing and environmental monitoring were not considered. Oversights occurred due to SFR #1 not being written by the project manager, but by the engineering lead. The Company indicated this was due to the construction window only being 3 months long, and issues arose after construction had started. Issues also occurred with the closeout and material reconciliation processes.

6 - SFR #3: To cover increased costs by the construction company to remedy civil and electrical design issues in the field. The materials ordered differed from the drawing specifications. Other issues included poor materials handling, discrepancies between internal/external designs, discrepancies in stock-coded materials, and wiring discrepancies in pre-wired junction boxes.

7 - SFR #4: To cover a scope increase (line work) after the start of new substation construction due to a lack of clarity on the demarcation between line costs tied to the substation and line costs associated with a voltage conversion project. Antenna/radio materials were also not included in the original work scope because the protection and control bill of materials was not available until after the construction contractor had been awarded the job. Animal protection materials were also not included in SFR #3 (only the labor to install the materials was included in SFR #3). Other contributing factors for SFR #4: Materials previously missed by the contractor and Eversource during the bidding process; siting and construction services were higher than expected; testing and commissioning services were needed longer than expected; property taxes were not included in any of the previous SFRs or the original PAF, and indirect costs increased more than expected between 2017 and 2018.

Lessons learned per the Company:

- Lessons learned taken from SFR #3 (as submitted):
 - Project managers (PMs) and Engineering groups should work together in the estimating process to ensure checklists and documentation are complete.
 - Cost analysts need to use updated overhead and loader costs.
 - PMs should not submit SFRs before approving any field changes not already in the budget.
- **RCG conclusion:** More detailed documentation, more complete explanations and better communications are needed from project inception through project completion to facilitate “a more administratively efficient review process for Staff and Commission.”¹⁶

IX. Viper Replacement Project (2018-2018)¹⁷

1 - Violations: Reliability/safety concerns due to an installed recloser vacuum bottle defect that could result in violent failures. Recloser refurbishment and/or replacement needed ASAP (262 units). The recloser defect was discovered after 15 field failures. “It was kind of scary because we had so many failures in a short amount of time. We were worried about having some major reliability impacts while waiting for vendor repairs.”¹⁸

2 - This project was not a typical reliability improvement or load-driven project due to reliability/safety concerns with defective reclosers and negotiations with suppliers.

3 - Solution alternatives:

- **Alternative #1** - Replace defective reclosers with rebuilt units at zero material costs and minimal protection-and-control engineering costs, temporarily bypassing the defective units until rebuilt units could be delivered and installed (5-week estimate).
- **Alternative #2** (preferred alternative) - The Company’s senior management decided to expedite the project due to safety/reliability concerns by acquiring replacement equipment from alternative recloser vendors, substantially increasing material and labor costs. Since it was not possible to determine which defective reclosers would fail, expedited replacement of all affected units was approved by Company management
 - Refurbish and reinstall 165 defective reclosers.

¹⁶ DE 19-057, 12-01-20, page 52, lines 21-23

¹⁷ Data Requests BPA 9-012; BPA 9-013; BPA 9-014; DE-057, DR TS2-056 dated 10/28/19; DE 19-057, DR Staff 12-045 dated 09/20/19, Attachment Staff 12-045 AE

¹⁸ Interview #34

- Replace 97 defective reclosers with alternative vendor equipment.
- Refurbished reclosers (165 units) are to be redeployed when needed on the distribution system at \$0.00 material cost. Since the defect was known and corrected by the manufacturer, the Company was confident refurbished units would perform reliably.¹⁹
- **NWA** alternatives were not considered applicable and as a result, were not investigated.

4 - Funding approval process:

- PAF: \$950,000 - January 22 2018
- SFR: \$8,929,000 - February 27 2018
- Total Funding Request after SFRs: \$9,879,000
- Total Project Costs: \$5,796,925 [approximately \$4M lower than SFR due to lower-than-expected defective recloser replacement costs (\$7,065 each instead of \$13,000); lower-than-expected alternative vendor costs (\$61,288 each instead of \$75,000); and lower-than-expected indirect costs of \$1,100,000].
- The February 17 2018 SFR was submitted immediately after the original PAF to switch the project from Alternative #1 to the highly expedited Alternative #2.

Lessons learned per the Company:

- The Viper project occurred prior to the new capital project approval process. Today, this kind of project would be managed by the Director of NH Distribution Engineering and his team working with the Protection & Control (P&C) group and approved by the NH-PAC (since it was a distribution line project). SDC/EPAC approvals would not be required since the project was not a substation project.
- If expedited project scenarios are foreseen as a possibility, the fiscal impacts of these scenarios should be included in the PAFs.²⁰
- **RCG conclusion:** The value of reliability and safety should have been quantified on PAF and SFR forms to justify expediting defective recloser replacements at substantially higher costs.

¹⁹ Data Request BPA 9-013

²⁰ Data Request BPA 9-014

- **RCG conclusion:** The Company should have presented a more rigorous financial analysis to demonstrate due diligence in obtaining the least-cost supplier pricing.
- **RCG conclusion:** The Company should have presented a more rigorous engineering analysis to quantify why only 97 defective reclosers (out of a total number of 262) had to be replaced with alternative vendor equipment.
- **RCG conclusion:** The Company should have provided more detailed and easier-to-understand documentation with the filing²¹ to make it easier for Staff to evaluate what had been done and why additional funding was needed/justified.

X. Rimmon Substation Animal Protection (2019-2022)²²

NOTE: The Rimmon SS Animal Protection Project was submitted by the Company as a typical substation capital project. A comprehensive project timeline was overlaid on the process flow chart provided with Data Request BPA 8-005.

1 - Violations: Outages caused by ravens. Ravens damaged traditional animal coverings on insulators by pecking away at them. Eventually, the coverings failed, and outages ensued.²³ The problem began in 2018 with 10 outages caused by ravens.

2 - Eight (8) alternatives were considered. Alternative #1 was initially selected but rejected following an SDC review/challenge. Alternative #6 was ultimately selected (to install lasers as a deterrent) as the preferred alternative.

- NWA is unknown since it was not addressed in the PAF.

3 - Funding approval process:

- SSF #1: no funding request - January 7, 2019 SDC
- IFRF: \$100,000 - June 10 2019
- SSF #2: Eight Alternatives - January 21, 2020 SDC
- Alternative #1 was first proposed to the SDC at a cost of \$4,500,000. SDC challenges led to a much cheaper alternative (Alternative # 6) at a cost of only \$339,000.

4 - Detailed documentation was maintained throughout the funding approval process including detailed budget estimates for all eight alternatives, site drawings, site pictures, completed constructability review forms, control panel layouts, and a project scope document.

Lessons learned per the Company:

²¹ DE 19-057, 10/28/2019

²² Data Request BPA 8-003; BPA 9-018

²³ Interview #73

- Documentation must be *clear*; justification must be in terms of asset health or maintenance record if asset-based; or must be tied to specific planning criteria if reliability based.
- SDC/EPAC challenges resulted in a more cost-effective solution than would not have otherwise been discovered.
- More detailed cost estimates provided a more accurate basis for comparing alternative solutions which is consistent with the new process.
- Conducting field constructability reviews **after** detailed designs are completed validates assumptions and identifies outstanding issues/risks.
- Metal-clad switchgear offers better animal protection than open-air switchgear and is more secure.²⁴
- **RCG conclusion:** This project is a good example of how SDC/EPAC challenges can lead to lower-cost solutions while meeting technical and environmental objectives.

XI. Goffstown Substation Elimination – Phase 1²⁵

A full-funding PAF was submitted on 4/27/21 along with two of five alternatives. In a Goffstown System Planning Study published November 2019, five (5) alternatives were evaluated, including an NWA option.

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** All five alternatives should have been included in the PAF for completeness.

XII. Replace Notre Dame Substation with MITS and Dunbarton Road Substation with Pad-mounted Step Transformer²⁶

This project was not included in the 2021 capital budget, but the Company plans to submit it for future consideration. Estimated cost: \$3,512,000.

The proposed use of MITS (Modular Integrated Transportable Substation) technology in this project is a good example of how engineering and construction costs can be saved by using

²⁴ Interview #73

²⁵ Data Request BPA 10-001 and Attachments

²⁶ Data Request BPA 1-014 and Attachment B

modular substation designs. MITS was also considered for the Milford Substation and there did seem to be potential cost savings, but the MITS option was not selected as a preferred alternative.²⁷

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** Where feasible and ratings permit, modular substation designs should be more widely considered. Modular substations are rapidly deployable and highly standardized compared to traditional substation designs, reducing engineering and construction costs.

2020 Design Violations Summary Report - Projects (Appendix A) (Data Request BPA 1-006)

Thirty-seven (37) bulk substation projects and twelve (12) non-bulk substation projects were identified in the *2020 Design Violations Summary Report*²⁸. None have moved through the capital approval process as more study is needed.

Lessons learned per the Company:

- None was given.
- **RCG conclusion:** Of the 49 projects (37 + 12) in the *2020 Design Violations Summary Report*, only two were flagged as potential NWA candidates: Loudon 31W1 and 31W2; and Hanover Street 16W3. Per DSPG 2020 requirements, the NWA Framework screening tool is to be used to evaluate potential NWA solutions. However, it is not known if the NWA tool had been used for all projects. Nevertheless, NWA status should be included on the PAF forms, even if it is only a statement that NWA was not applicable due to the project being asset-condition based (for example). This has **not** been a Company practice and has led to NWA questions when reviewing PAF forms.

²⁷ Interview #61

²⁸ Attachment Data Request BPA 1-006