BUSINESS PROCESS AUDIT

OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a

EVERSOURCE ENERGY'S NEW HAMPSHIRE

DISTRIBUTION CAPITAL PROJECTS

NOVEMBER 2022

APPENDICES

REQUESTED BY

THE NEW HAMPSHIRE

DEPARTMENT OF ENERGY'S

DDIVISION OF REGULATORY SUPPORT

ELECTRIC DIVISION

PREPARED BY

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Appendix A

2020 Design Violations Summary Report

Bulk Substations

Non-Bulk Substations

RCG River Consulting Group, Inc.

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 2029	# 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 Timber 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 2029	# 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

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 single 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.

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 Tool[1] – 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

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

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
CIII	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

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

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

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

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

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

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

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

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

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

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

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 reviewed[2] 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 Requsts 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 Station[4] (project still under review; no approved PAF as of this writing[5])

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.

- o 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.
- o 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 transformer[8]; (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

- 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)
    - o 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 equipment[15]; 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.

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[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: $8,929000 - 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 filing[21] 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:

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[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 1[25]

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 Transformer[26]

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