Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 | **Date of Response: 06/02/2021**
Request No. STAFF 2-001 | **Page 1 of 1**
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Shamus O'Brien**

Request:
Reference Eversource customer survey filed on April 30, 2021. Please provide:
a. The survey instruments that were used to conduct the customer survey;
b. The responses and any notes from the commercial/industrial customer interviews;
c. An indication of whether Eversource conducted the interviews, or an independent third party firm conducted the interviews; and
d. All worksheets used to develop the tables and graphs throughout the survey, with all links intact and all supporting materials.

Response:
a. The email survey was conducted by the Eversource Voice of the Customer team using the Qualtrics research platform. Customers were invited to participate via email, which contained a link to the survey itself. See Attachment STAFF 2-001a1 and Attachment STAFF 2-001a2 for the surveys.
b. The file provided by the University of New Hampshire Survey Center with responses to the interviews conducted is in Attachment STAFF 2-001b.
c. The interviews conducted with large commercial and industrial customers were conducted by the University of New Hampshire Survey Center, an independent survey research firm. These interviews were conducted by phone with professionally trained survey interviewers.
d. The Voice of the Customer Team at Eversource uses Microsoft Power BI to build the data tables, analytic algorithms and visualizations. The program is not designed in a way that allows these tables to be easily extracted, and the ability to view the data may depend on the reviewer's MS Power BI access. In lieu of attempting to provide the underlying data, Eversource is willing to walk the Staff and/or OCA through a demonstration of the tool, tables and visualizations, if desired.

Residential/Small Business Email Survey

At Eversource, we're always working to serve you better. Ensuring friendly, easy and timely service is our commitment to you. You have been randomly selected to share your feedback on Eversource and the services we provide you, and we thank you for taking a few moments to share your feedback with us. Your comments will help us to improve our tools and service offerings for all customers.

Q1. Thinking for a moment about the reliability of your electric service from Eversource (e.g. lack of outages, consistency of power, etc.), would you say that over the past three years, the reliability of your service has…

1. Improved
2. Declined
3. Stayed about the same

Q2. In the past three years, how many outages do you recall in each of the ranges below while an Eversource customer? [Matrix Question]

A. 1-3 hours

0. None
1. 1-2
2. 3-4
3. 5-6
4. 7 or more
99. Don't recall

B. 4-8 hours
C. 9-12 hours
D. 13-24 hours
E. 25-72 hours
F. More than 72 hours

[If Q2A-E all equal 0, Skip To Q11]
Q3. Thinking about the <u>longest</u> outage you have experienced in the last three years, how would you rate Eversource on how quickly they restored power to your home, using a 1 to 10 scale where 1 is unacceptable, 10 is outstanding and 5 is average?

[1-10 Scale]

Q4. Thinking about the <u>shortest</u> outage you have experienced in the last three years, how would you rate Eversource on how quickly they restored power to your home, using a 1 to 10 scale where 1 is unacceptable, 10 is outstanding and 5 is average?

[1-10 Scale]

[Logic: If Q3 < Q4]
Q5. You rated your satisfaction with Eversource's power restoration for the longest outage a [FILL Q3] and the shortest outage a [FILL Q4]. What caused your satisfaction during your longest outage to be lower compared to your shortest outage?

[Verbatim Response]

Q6. Have you had to spend money out-of-pocket as a result of a power outage for any reason, such as fuel for a generator, replacing spoiled food or medicine, getting a hotel room, etc.?

1.	Yes	
2.	No	[Skip To Q9]
99.	Don't know	[Skip To Q9]

Q7. Thinking about the longest outage you had to spend money out-of-pocket for, approximately how much did you have to spend during that outage?

1	$0
2	$1-$10
3	$11-$25
4	$26-$50
5	$51-$100
6	$101-$250
7	$251-$500
8	$501-$1000
9	More than $1000

Q8. Thinking about the shortest outage you had to spend money out-of-pocket for, approximately how much did you have to spend during that outage?

1	$0
2	$1-$10
3	$11-$25
4	$26-$50
5	$51-$100
6	$101-$250
7	$251-$500
8	$501-$1000
9	More than $1000

Q9. Has an outage ever caused you to lose income, either in the form of wages/salary or the loss of paid time off/vacation time?

1.	Yes	
2.	No	[Skip To Q11]
99.	Don't know	[Skip To Q11]

Q10. Thinking about the longest outage you lost income in some form, approximately how much income did you lose during that outage? If you lost vacation time because of a power outage, please convert this to a monetary value.

1	$0
2	$1-$10
3	$11-$25
4	$26-$50
5	$51-$100
6	$101-$250
7	$251-$500
8	$501-$1000
9	More than $1000

Q11. How concerned would you be if your power reliability declined and you had more frequent outages?

1.	Very concerned	
2.	Somewhat concerned	
3.	Not very concerned	[Skip To Q13]
4.	Not at all concerned	[Skip To Q13]
99.	Don't know	[Skip To Q13]

Q12. Please describe why you would be concerned if you saw more frequent outages?

[Verbatim Response]

Q13. How concerned would you be if your power reliability declined and you had longer outages?

1. Very concerned
2. Somewhat concerned
3. Not very concerned [Skip To Q15]
4. Not at all concerned [Skip To Q15]
99. Don’t know [Skip To Q15]

Q14. Please describe why you would be concerned if you saw more lengthy outages?

[Verbatim Response]

Q15. Since the start of the COVID-19 pandemic in March, 2020, how would you describe your work situation?

1. I’ve been primarily working from home since the pandemic began
2. I was working from home but have now transitioned back to the office
3. I’ve always worked from home
4. I did not work from home during the pandemic
5. I have been unemployed
6. I am retired

88. Other – Please Specify
99. Prefer not to answer

Q16. Thinking about the past year, if you did lose power at your home, would a power outage have been more disruptive, less disruptive, or would it have not changed for you compared to over a year ago?

1. More disruptive
2. Less disruptive
3. No change
99. Don’t know

Q17. Do you feel Eversource does a good job of maintaining their infrastructure?

1. Yes
2. No
99. Don’t know

Q18. What kind of information related to maintaining their infrastructure would you like to hear more about from Eversource?

[Verbatim response]

Q19. How much additional money would you be willing to pay in your Eversource bill to maintain and improve their infrastructure to help minimize future power outages?

1. Not willing to pay any more
2. Less than $1 per month
3. $1 per month
4. $2 per month
5. $3 per month
6. $4 per month
7. $5 per month

Q20. How much additional money would be <u>unacceptable and unaffordable</u> in your Eversource bill to maintain and improve their infrastructure to help minimize future power outages?

1. Not willing to pay any more
2. Less than $1 per month
3. $1 per month
4. $2 per month
5. $3 per month
6. $4 per month
7. $5 per month

Q21. Do you own a backup power generator at your home?

1. Yes
2. No [Skip To Q24]

99. Prefer not to answer [Skip To Q24]

Q22. What is the size of your current backup power generator?

1. Standby generator permanently installed
2. Large portable generator (Able to power many things at a time)
3. Small portable generator (Able to power a few things at a time)

88. Other – Please Specify
99. Don't know

Q23. Approximately how long have you had your current backup power generator?

1. Less than one year
2. 1-3 years
3. 4-5 years
4. 6-10 years
5. 11-15 years
6. 16 years or more
99. Don't know

Q24. What is your age?

[Enter number of years 18-99]

Q25. Approximately how many years have you lived at your current address?

1. Less than one year
2. 1-3 years
3. 4-5 years
4. 6-10 years
5. 11-15 years
6. 16-20 years
7. 21 years or more
99. Don't know

Q26. Which one of the following best described your household’s total annual income before taxes?

1	Under $30,000
2	$30,000 - $39,999
3	$40,000 - $49,999
4	$50,000 - $59,999
5	$60,000 - $69,999
6	$70,000 - $79,999
7	$80,000 - $89,999
8	$90,000 - $99,999
9	$100,000 - $124,999
10	$125,000 - $149,999
11	$150,000 or more
98	Prefer not to answer

Large Commercial Customer Phone Script

At Eversource, we're always working to serve you better. Ensuring friendly, easy and timely service is our commitment to you. You have been randomly selected to share your feedback on Eversource and the services we provide you, and we thank you for taking a few moments to share your feedback with us. Your comments will help us to improve our tools and service offerings for all customers.

1. Thinking for a moment about the reliability of your electric service from Eversource (e.g. lack of outages, consistency of power, etc.), would you say that over the past three years, the reliability of your service has…

   1. Improved
   2. Declined
   3. Stayed about the same

2. In the past three years, how many outages do you recall in each of the ranges below while an Eversource customer? [Matrix Question]

   A. 1-3 hours

      0. None
      1. 1-2
      2. 3-4
      3. 5-6
      4. 7 or more
      99. Don't recall

   B. 4-8 hours
   C. 9-12 hours
   D. 13-24 hours
   E. 25-72 hours
   F. More than 72 hours

NEW5. How would you describe Eversource's ability to restore power after you experience an outage?

   [Verbatim Response]

NEW6. Thinking about the outages you have experience, what kind of costs occur when you experience an outage? Do those costs change significantly depending on the length of the outage?

   [Verbatim Response]

10. How concerned would you be if your power reliability declined and you had more frequent outages?

   1. Very concerned
   2. Somewhat concerned
   3. Not very concerned [Skip To Q11]
   4. Not at all concerned [Skip To Q11]
   99. Don't know [Skip To Q11]

10A. Please describe why you would be concerned if you saw more frequent outages?

   [Verbatim Response]

11. How concerned would you be if your power reliability declined and you had longer outages?

1.	Very concerned	
2.	Somewhat concerned	
3.	Not very concerned	[Skip To Q12]
4.	Not at all concerned	[Skip To Q12]
99.	Don’t know	[Skip To Q12]

11A. Please describe why you would be concerned if you saw more lengthy outages?

[Verbatim Response]

12. Thinking about the past year, if you did lose power at your business, would a power outage have been more disruptive, less disruptive, or would it have not changed for you compared to over a year ago?

1. More disruptive
2. Less disruptive
3. No change
99. Don’t know

13. Do you feel Eversource does a good job of maintaining their infrastructure?

1. Yes
2. No
99. Don’t know

13A. What kind of information related to maintaining their infrastructure would you like to hear more about from Eversource?

[Verbatim response]

NEW7. Would your company be willing to pay additional money in your Eversource bill to maintain and improve their infrastructure to help minimize future power outages?

[Verbatim response]

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Improved	None	None	None	None	None	None	confident in their ability	we have a standby generator here so our outages are not more than 10 seconds but there are costs regarding fuel for the generators as well as staffing costs	Very concerned	anything that split second that one second outage can make a difference so the equipment can be very sensitive so even the smallest thing can bring equipment down for hours and this is a [business type] so we need less outages	Very concerned	all the same question, as a user you don't want to see any more outages causing more wear and tear on equipment	No change	Yes	i have a good relationship with our account executive and i feel like i can reach out to my person to get those answers	that's a decision i couldn't make on my own
Stayed about the same	None	None	None	None	None	None	good	it depends on the time of year, its more impactful in the winter rather than the summer	Very concerned	we need power, pumps and water rely on power	Very concerned	same as the last question, we pay a lot for power we need it	More disruptive	Yes	update with line issues	no comments: there's a bill currently in the house that is talking about increasing the charge for commercial companies for energy conservation which we have no say in and it looks like its going to go up and we shouldn't be the one paying for this, the power company should pay and not us.

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Stayed about the same	1-2	None	None	None	None	None	its pretty great they respond quickly and help us out	we normally get power dips and sometimes the blackouts for like 2 seconds and that has been happening a lot and it costs us a lot of money, one power dip costs us $15,000 to $50,000 and thats just a power dip and not a blackout, and if there is a blackout it costs the same amount	Very concerned	because it is costing us money	Very concerned	that would stop our production and we would have to pay our employees for no production and also it costs us cable cuts, so the employees would be staying without doing anything and we would still have to pay them and we run 24/7 so it is very concerning no matter when the power outage is	More disruptive	Yes	mainly maintaining high voltage lines and making sure that trees are cleared and are cut regularly so that if there is a storm there aren't outages caused	if there was a guarantee there wouldn't be power dips yes
Stayed about the same	1-2	None	None	None	None	None	pretty reliable	lost production and manufacturing	Very concerned	the reliability of the grid, supplying power to our facility, it would be more lost revenues and meeting our customer requirements for supplying product on a timely basis	Very concerned	lost production, unable to meet our customer needs, and the adverse effects that it has on our equipment	No change	Yes	depending on where we are located on the grid in relation to how many customers are affected, they should prioritize areas where there are a lot of commercial customers over rural areas	i cannot answer that right now

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Improved	1-2	1-2	1-2	1-2	1-2	1-2	they do a great job	yes shorter outages we shut the plant down, the extended outages are extremely costly to us, we have to rent a very large generator to continue production	Very concerned	we make [product] so we have a lot of people depending on us to make the [product] we make, we make [product] for the [client] and if we don't have power its very costly for everyone	Very concerned	our corporate offices would have to move the plant to a place without outages	More disruptive	Yes	i don't need to know about it i know they do their best keeping the lights on here	i dont think they would be willing to do that, we would be hesitant, we feel like thats part of what we pay for already
Improved	1-2	None	None	None	None	None	excellent. Very short interuptions affect us more, where the power briefly blinks. It is very costly to us.	the length of the outage does not really affect the cost. really it is if they happen at all.	Very concerned	As stated previously, outages of even small durations have significant impact revenue	Very concerned	more down time, less revenue. never a good thing	No change	Yes	If they are doing it i don't need to hear about it. I'm more interested in why an outage occured then what they are doing to prevent them.	No. we already pay more than any of our competitors.
Improved	3-4	1-2	None	None	None	None	i am fortunate that they gave me a card to call when we do experience an outage, the response has been good, and one time they came down and they wouldn't touch something so they had someone else come down but overall its good	from the companys side, our whole production facility gets shut down without power and we lose money, we lose drives or motors may go bad because of single phasing but we do have protections but our biggest cost is lack of production based on the power outage, dont know the exact cost, we employ 400 people here and we would keep them here up to 2 hours without power, so we lose money that way paying people who cant work with the power down	Very concerned	i wouldnt be able to run a product, we wouldnt be making money, people wouldn't be working, loss of equipment, damage from the power failure	Very concerned	same answer as last time	No change	Yes	if it would pertain to shutting us down, we would need advanced notice, they have been good at letting us know, we just need advanced notice for any planned disruption to power	that would be something i cannot answer, i would have to go to people 2 or 3 levels above me, depending on the cost maybe they would want that

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Improved	3-4	1-2	1-2	1-2	None	None	they are pretty responsive, once i tell them exactly whats going on and they get a crew out to resolve an issue	the costs on minor outages aren't very big, if its in the middle of the work day for multiple hours the tenants that make [product] lose money on production	Very concerned	the importance of my tenants, they build [products]	Very concerned	thats a huge productivity loss for my tenants and a financial loss for them	More disruptive	Yes	not much, i guess	can't speak for the office but potentially, most of the electricity costs are billed to the tenants, and i'm sure they would be open to that
Stayed about the same	3-4	1-2	1-2	1-2	None	None	they respond to it and once they put it on it tends to stay on	production, we sometimes lose transformers and environmental controls, this is very costly and inconvenient. we do have back up generators for some things but it is a huge inconvenience	Very concerned	we just want a reliable power source and when we have interuptions it interupts production and hurts our environmental control and it does damage	Very concerned	similar to the response before, we are looking for reliability, it wreaks havoc on production and environmental systems	No change	Yes	none	if it was a guaranteed improvement
Stayed about the same	3-4	None	None	None	None	None	acceptable	if we lose power for a minute we lose half a weeks production	Very concerned	we lose production every time we have power outages	Very concerned	same answer as before	No change	Yes	no comment	no we would rather relocate to a place with more stable power supply
Improved	3-4	None	None	None	None	None	excellent	it is dependent on the timing and length of the outage, if its overnight and on the weekend it has much less of a cost impact	Very concerned	the critical nature of the work performed in my facilities, it would directly impact tax payers	Very concerned	the same answer as before	Less disruptive	Yes	they keep me up to date, they do a good job communicating	i can't speak on it because its the [business type]
Stayed about the same	3-4	1-2	None	None	None	None	more than adequate	some of our operations if we have to cancel any type of procedures or anything like that, some locations are like $700,000 a day, so we could lose a lot of money	Very concerned	loss of revenue and inadequate [client] care, increased [product] cost	Very concerned	same as last answer	No change	Yes	any information they can provide	we already do

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Stayed about the same	7 or more	7 or more	5-6	3-4	3-4	1-2	very good	we have man power, overtime, the longer the outage the more overtime we have to pay, loss of equipment due to surges, can vary to 100 dollar units or a generator that was 10,000 dollars, 29 pump stations, if we have to call in additional personnel we have to pay equipment charges as well	Very concerned	the nature of our business, [type of business], we have federal and state regulations we have to meet and without power we would get substantial fines, public relations	Very concerned	same as the last question	More disruptive	Yes	more about power bumps, as our instruments get more advanced if there is a power surge it can shut down all of our machines, we need a constant flow of electricity it can't surge or go out or it messes up our whole system	no

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Improved	7 or more	3-4	3-4	1-2	None	1-2	pretty good	our costs are primarily coming from loss of production and the impact on the production side since we are a [business type], we lose the ability to produce [product] and depending on the length of the outage we either send people home or have to pay them overtime we also lose drawing time and we have [equipment] that run 24 hrs a day so outside of business hours so we would lose that time as well. but lack of production is the biggest and we have [equipment] that runs 24 hrs a day but not on weeks but losing hours and then trying to restart the process takes time and restart time takes longer. we also do depending on the outage we've had regular outages that have damaged our electrical systems and we have issues in our manufacturing facility and IT department if we have a rough outage or surge or anything to the [business] which causes more down time and there are repair costs involved that are provided by us and not by eversource. for instance our distrubution line had damage from a local surge and that caused us to lose a lot from loss of production and repairs	Very concerned	there are costs everytime we have an outage, if outages increased then the cost to us would increase and our production would go down and so would our reliability to our customers	Very concerned	the same issues as any outage the longer the outage the bigger the costs and loss of production and it would also question why we pay so much for our distribution and transmission and then more than half of our electric cost goes to eversource and there would be serious questions as to how the company is being run as well as what we are paying	No change	Yes	i dont need to hear much from them as long as they try to stay ahead of things and keep to a schedule that is reasonable and try to build in some redundancy and remote capabitities so they can identify and isolate where issues are occuring, it does sound like they've been doing some of that and the only reason i know that is from power records and they could use to publicize that so that customers and payers know what they are doing and how they are upgrading to improve reliability	i don't know i don't think we have a choice because that's what we pay them now and obviously not all the money we pay them goes to reliability and really if we paid the same amount I'd want more to go to reliability

Q1	Q2A	Q2B	Q2C	Q2D	Q2E	Q2F	Q5	Q6	Q10	Q10A	Q11	Q11A	Q12	Q13	Q13A	Q7
Improved	Don't Recall	None	None	None	None	None	excellent	this is a commercial building with a lot of tenants, the tenants have a loss in money but we don't, i couldn't quantify that, if the servers go down sometimes we lose up to 30-40 days worth of work.	Very concerned	the issue is a high impact on the tenants here	Very concerned	it takes longer in the winter for our building to recover from an outage, to get the heat up and things of that nature	No change	Yes	none I'm sure i can look it up online	we really have no input on that, if eversource ever were to improve their infrastructure i feel as if we would pay it we wouldn't have a choice

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 **Date of Response: 06/02/2021**
Request No. STAFF 2-002 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Brian J. Dickie

Request:
Reference Eversource customer survey filed on April 30, 2021, page 1, stating "In December 2020, many customers experienced an outage in the 13+ hour range. And in March, 2021, customers experienced a storm-related outage in the 4-12 hour range." Please state the percent of Eversource customers that lost power for more than 13 hours in December 2020 and the number of customers that experienced a storm-related outage in the 4-12 hour range in March 2021.

Response:
For the December 5, and December 6, 2020 storm exclusionary day approximately 34% of customers impacted during the event experienced outage conditions for equal to, or greater than, 13 hours. For the March 1, and March 2, 2021 storm exclusionary days approximately 23% of customers impacted during the event experienced power outage conditions in the 4 to 12 hour range.

December 5 - 6 2020 - MED Events - Event Duration Between >=4 hrs and <13 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
261	18,435	8,284,401	535,095	15	449	15%

December 5 - 6 2020 - MED Events - Event Duration >=13 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
1,137	42,517	56,457,622	535,095	106	1,328	34%

December 5 - 6 2020 - MED Events - Event Duration <4 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
268	65,397	4,761,351	535,095	9	73	52%

December 5 - 6 2020 - MED Events - All Events

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI
1,643	126,349	69,503,374	535,095	130	550

March 1-2 2021 - MED Events - Event Duration Between >=4 hrs and <13 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
255	27,988	12,721,246	537,887	24	455	23%

March 1-2 2021 - MED Events - Event Duration >=13 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
458	10,743	14,211,258	537,887	26	1,323	9%

March 1-2 2021 - MED Events - Event Duration <4 hrs

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	Percent of customers
193	81,988	3,588,258	537,887	7	44	68%

March 1-2 2021 - MED Events - All Events

# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI
889	120,719	30,520,762	537,887	57	253

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 **Date of Response: 06/02/2021**
Request No. STAFF 2-003 **Page 1 of 2**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Shamus O'Brien

Request:
Reference Eversource customer survey filed on April 30, 2021, page 2, stating "Using a series of questions designed to measure the customers' willingness and ability to absorb a cost increase in their monthly electric bills with a goal to support additional reliability spending a "break point" of less than $1 per month in additional costs can be established."

a. Please explain how the Company determined the size of a statistically significant sample.
b. Please indicate how many of the survey respondents are residential customers, and how many are commercial customers.
c. Please explain how this break point of less than $1 per month was established, providing all assumptions and equations.
d. Please explain what the annual budget would be for a program that would cost customers $1 per month.
e. Please explain whether a survey designed to "with a goal to support additional reliability spending" is likely to include biased questions and result in biased answers. Please explain why this is the case.
f. Based on the survey instruments, was it the Company's intention that the customers understand the reliability-related price increase and associated breaking point of less than $1 per month to be: (1) a one time increase for a period of 12 months only; (2) a $1 per month surcharge that would continue to grow the Company's rate base between rate cases in perpetuity by the revenue requirement associated with that $1 per month; or (3) a $1 per month surcharge which would be a cumulative addition to the Company's revenue requirement each year? Please explain.

Response:

a. In survey research, when surveying a population consisting of approximately 50,000 or more with an aim of statistically significant results at the 95% confidence level, any n-value of more than 380 allows for results accurate to an industry standard of plus or minus 5.0%. Obtaining more sample will not increase the confidence level until nearly doubling the n-value. As each region had a minimum of 387 completes, each region is statistically significant at the 95% confidence level.

b. Among customers who participated in the email survey, 63 respondents were small or medium business customers, and 1,928 customers were residential customers.

c. Results gathered from two survey questions were mapped together to calculate the break-even point of "Less than $1 per month."

Willingness to pay was charted with a starting point of 100% of customers would be willing to pay nothing more per month for reliability. By subtracting each subsequent response, you are able to map the total percentage of customers willing to pay each response option amount.

The amount that would be unacceptable/unaffordable was mapped in the opposite manner. Starting with the 47.0% of customers who say any additional amount is unacceptable or unaffordable, each subsequent result is added to this amount to chart the total percentage of customers who find each amount unacceptable or unaffordable. (see Attachment STAFF 2-003c)

d. A $1 increase in the monthly bill of a typical residential rate R customer using 600 kilowatthours per month equates to a revenue requirement of approximately $9.25 million dollars. Assuming a capital-only budget, this would equate to approximately $98 million in a year.

e. During the consultation process with representatives of the NH PUC, Eversource was asked to consult with an independent research firm, the University of New Hampshire Survey Center. The purpose of this consultation was to evaluate the survey for any potential biased questions and to correct for them if found. The UNH Survey Center suggested some changes to the survey after reviewing the document, all of which were adopted by Eversource prior to launching the survey.

f. The intent is only to measure their highest tolerance and lowest tolerance to measure the breaking point. The questions specifically said monthly, but there was no specific end time that capped out the potential increase.

Question Response Results	Willing to Pay	Unacceptable/ Unaffordable
Not willing to pay any more	53.29%	44.50%
Less than $1 per month	7.79%	4.87%
$1 per month	11.65%	4.47%
$2 per month	10.05%	5.27%
$3 per month	5.42%	5.73%
$4 per month	0.55%	3.31%
$5 per month	11.25%	31.84%

Chart Values	Willing to Pay	Unacceptable/ Unaffordable
None	100.0%	44.5%
Less than $1 per month	46.7%	49.4%
$1 per month	38.9%	53.8%
$2 per month	27.3%	59.1%
$3 per month	17.2%	64.8%
$4 per month	11.8%	68.2%
$5 per month	11.3%	100.0%

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 | **Date of Response: 06/02/2021**
Request No. STAFF 2-004 | **Page 1 of 2**
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Shamus O'Brien**

Request:
Reference Eversource customer survey filed on April 30, 2021, page 4, showing the number of respondents by region.

a. Please indicate the percent of the Company's customers in each of the five regions identified.
b. If the percentage of customers does not match the percent of respondents in the survey by region, please explain whether this would skew the results of the survey.
c. Please provide the number of respondents by region by customer class (or if not available, by residential and C&I).

Response:

a. Five regions in New Hampshire were identified by adapting regions previously identified by the New Hampshire Office of Strategic Initiatives. This was done to use regional terms that would be commonly understood by all parties. A map of the regions can be found here: https://www.nh.gov/osi/planning/services/gis/documents/towns-counties-rpcs.pdf

After identified, some regions identified in the map above were consolidated, the results of which was the five regions used in the report.

OSI Regional Planning Commission	Survey Region
North Country Council	Northern NH
Lakes Region Planning Commission	Lakes Region
Upper Valley Lake Sunapee Regional Planning Commission	Connecticut River Valley
Southwest Region Planning Commission	
Central New Hampshire Regional Planning Commission	Southern NH
Southern New Hampshire Planning Commission	
Nashua Regional Planning Commission	
Rockingham Planning Commission	Seacoast
Strafford Regional Planning Commission	

b. Because of the concerns of the NH PUC during the design phase of the survey, it was decided that the survey would be conducted with the goal of obtaining a statistically significant sample at the regional level, as opposed to a randomly selected sample of the state overall. This goal was achieved, as outlined in the report and response to Staff 1-3a. As a result, when looking at overall responses to the survey, regions with lower populations, such as Northern NH, would be more heavily represented in relation to more populous regions, such as Southern NH or the Seacoast regions. To address this fact, most of the reporting on the results of this survey focus on region by region results as opposed to overall statewide results. Where statewide results are reported, care was taken to report if any statistically significant regional differences existed.

c. Please see the table below.

Region	Residential Customers	Small & Medium Business Customers	Total
Connecticut River Valley	405	5	410
Lakes Region	381	15	396
Northern NH	369	29	398
Seacoast	395	5	400
Southern NH	378	9	387
Total	1928	63	1991

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 **Date of Response: 06/02/2021**
Request No. STAFF 2-005 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Shamus O'Brien

Request:
Reference Eversource customer survey filed on April 30, 2021, page 13. Please provide the following:
a. The data for the chart;
b. The data on willingness to pay more for reliability by customer class (or if not available, by residential and C&I); and
c. The data on unacceptable/unaffordable by customer class or (if not available, by residential and C&I).

Response:
a. As outlined on Page (12/13), results gathered from two surveys were mapped together to calculate the break-even point of "Less than $1 per month."

Willingness to pay was charted with a starting point of 100% of customers would be willing to pay nothing more per month for reliability. By subtracting each subsequent response, you are able to map the total percentage of customers willing to pay each response option amount.

The amount that would be unacceptable/unaffordable was mapped in the opposite manner. Starting with the 47.0% of customers who say any additional amount is unacceptable or unaffordable, each subsequent result is added to this amount to chart the total percentage of customers who find each amount unacceptable or unaffordable.

Question Response Results	Willing to Pay	Unacceptable/ Unaffordable
Not willing to pay any more	53.29%	44.50%
Less than $1 per month	7.79%	4.87%
$1 per month	11.65%	4.47%
$2 per month	10.05%	5.27%
$3 per month	5.42%	5.73%
$4 per month	0.55%	3.31%
$5 per month	11.25%	31.84%

Chart Values	Willing to Pay	Unacceptable/ Unaffordable
None	100.0%	44.5%
Less than $1 per month	46.7%	49.4%
$1 per month	38.9%	53.8%
$2 per month	27.3%	59.1%
$3 per month	17.2%	64.8%
$4 per month	11.8%	68.2%
$5 per month	11.3%	100.0%

b. & c. Please see the table below.

Question Response Results	Willing to Pay		Unacceptable/ Unaffordable	
	Residential	Small & Medium Business	Residential	Small & Medium Business
Not willing to pay any more	53.01%	61.90%	44.45%	46.03%
Less than $1 per month	7.78%	7.94%	4.98%	1.59%
$1 per month	11.67%	11.11%	4.46%	4.76%
$2 per month	10.11%	7.94%	5.19%	7.94%
$3 per month	5.55%	1.59%	5.81%	3.17%
$4 per month	0.57%		3.32%	3.17%
$5 per month	11.31%	9.52%	31.79%	33.33%

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 **Date of Response: 06/02/2021**
Request No. STAFF 2-006 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Gerhard Walker, Brian J. Rice, Roshan V. Bhakta, Michael R. Goldman

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Request:
Reference the response to data request Staff 1-017, f. and g. Please provide the exact reference in the NH utilities energy efficiency plan for 2020 as approved and proposed plan for 2021-2023 noting the use of an inflation rate of 2.0% and a nominal discount rate of 3.37%. If the plan does not include such a cite, please provide a specific cell reference in Eversource's benefit/cost model for plan year 2020 and plan years 2021-2023. If the referenced rates differ from that used in the NWA, please explain and justify why a different rate should be used for an NWA.

Response:
The Company's response to Staff 1-017, f and g did not state that the NH utilities energy efficiency plan for 2020 as approved and proposed plan for 2021-2023 use an inflation rate of 2.0% and a nominal discount rate of 3.37%. These values were derived from the 2018 AESC and applied as generally applicable assumptions for purposes of initial screening of NWA solutions for all of the Company's affiliated EDCs. Eversource believes values from the AESC are reasonable to apply given that the study is sponsored by energy efficiency program administrators across New England to support evaluation of approved energy efficiency programs with impacts comparable to some of those of NWAs. The AESC is also prepared under the direction of a working group that includes broad participation of many stakeholders, including the NHPUC.

The benefit/cost models used in the NH utilities' energy efficiency plan for 2020 as approved and proposed plan for 2021-2023 cite the sources for the nominal discount rate and inflation rate on the 'Lookups' tab, cells J31 and J32, respectively. The nominal discount rate is based on the Prime Rate "on or around June 1" preceding the filing, in accordance with the Final Energy Efficiency Report, dated July 6, 1999 in DR 96-150. The inflation rate is based on the inflation rate between Quarter 1 of the preceding year and Quarter 1 of the current year, utilizing the Gross Domestic Product: Implicit Price Deflator from the U.S. Bureau of Economic Analysis.

For the NH utilities' energy efficiency plan for 2020 as approved, the benefit/cost models utilize a nominal discount rate of 5.50% and an inflation rate of 1.94%.

For the NH utilities' energy efficiency plan for 2021-23 as proposed, the benefit/cost models utilize a nominal discount rate of 3.25% and an inflation rate of 1.81%.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 **Date of Response: 06/02/2021**
Request No. STAFF 2-007 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Richard C. Labrecque, Gerhard Walker, Lavelle A Freeman, Matthew D. Cosgro

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Request:
Reference March 31, 2021 Supplement, Appendix A-2, Table 1, Bates page 55, please provide the following for Loudon 31W1 and for Loudon 31W2:

a. The historical hourly load by customer on the peak day event(s) for 2016-2020; and
b. The forecasted hourly load by customer (if available) or in total on the peak day event(s) for the forecasted peak day events for 2021-2029.

Response:

a. Hourly historical data is only available for six of the 2,675 customers supplied by Loudon Substation. Detailed interval loading at the substation only became available in October 2018, thus the date of the peak day of each transformer can only be identified for 2019 and 2020. Prior to October 2018 load information was manually gathered during regular inspections of the substation, consisting of instantaneous load (at the time of the meter read) and peak load (maximum load measured since the previous meter read). Attachment STAFF 2-007 is the available hourly load by customer.
b. Eversource does not develop hourly forecasts. Only annual peak load is forecast for the non-bulk transformers as provided in Table 1 and Table 3 of the March 31, 2021 Supplement, Appendix A-2.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 20-161

Date Request Received: 05/19/2021 | **Date of Response: 06/02/2021**
Request No. STAFF 2-008 | **Page 1 of 1**
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Richard C. Labrecque, Matthew D. Cosgro, Lavelle A Freeman**

Request:
Reference October 1, 2020 LCIRP, Appendix D, Bates page. Please provide a copy of all of the referenced documents list in Section 7.1.

Response:
The Eversource internal documents referenced in Section 7.1 of the Distribution System Plan Guide (October 1, 2020 LCIRP, Appendix D, Bates 47) are attached below.

The two (2) IEEE standard documents referenced, IEEE 1547-2018 and IEEE C57.12.00-2015, are IEEE copyrighted material which Eversource is licensed to use with restrictions. The Company is not at liberty to share these documents but, if needed, can seek permission from the IEEE to share them. However, we may or may not receive permission, and it is possible that we will be charged a fee.

Eversource Internal Documents:
1. SYSPLAN 010 - Bulk Distribution Substation Assessment Procedure (see **Attachment STAFF 2-008a - SYS PLAN 010 - Bulk Distribution Substation Assessment Procedure Rev1 Final.pdf**)
2. SYSPLAN 008 - Calculation and Documentation of Bulk Distribution Transformer Ratings (see **Attachment STAFF 2-008b - SYS PLAN 008 - Calculation and Documentation of Bulk Distribution Transformer Ratings Rev 1 2018-06-11 Signed.pdf**)
3. DSEM 03.30 - Reliability Project Cost Effectiveness (see **Attachment STAFF 2-008c - DSEM 03-30 - Reliability Project Cost Effectiveness.pdf**)
4. DSEM 02.11 - Reliability Indices (see **Attachment STAFF 2-008d - DSEM 02-11 - Reliability Indices.pdf**)
5. DSEM 05.131 - Voltage Limits (see **Attachment STAFF 2-008e - DSEM 05-13 - Voltage Limits.pdf**)
6. Distribution System Planning and Design Criteria Guidelines (ED-3002) (see **Attachment STAFF 2-008f - ED-3002 - Distribution System Planning and Design Criteria Guideline.pdf**)
7. Distribution System Planning Substation Project Template (see **Attachment STAFF 2-008g - Planning Project Template.pdf**)
8. Capital Project Approval Process, Revision 5 (see **Attachment STAFF 2-008h - JA-AM-2001-A, Rev 5, Capital Project Approval Process.pdf**)

Bulk Distribution Substation Assessment Procedure

SYS PLAN 010 Rev. 1

Approval Signature: George P. Wegh

Process Owner:	George P. Wegh Director, System Planning	Effective Date: August 1, 2018

TABLE OF CONTENTS

Appendices

I. SCOPE AND APPLICABILITY

This procedure applies to Eversource System Planning Engineers when performing annual assessments of Eversource bulk distribution substation facilities.

II. REFERENCE DOCUMENTS

ISO-NE Documents
ISO-New England Planning Procedure No. 3 (Reliability Standards for the New England Area Pool Transmission Facilities)
ISO-New England Planning Procedures No. 5 (Proposed Plan Application Procedure), 5-1 (Section I.3.9 Applications: Requirements, Procedures and Forms), and 5-3 (Guidelines for Conducting and Evaluating Proposed Plan Application Analysis).
ISO-New England Planning Procedures No. 7 (Procedures for Determining and Implementing Transmission Facility Ratings in New England).
ISO-New England Planning Procedure No. 9 (Major Substation Bus Arrangement Requirements and Guidelines)
ISO-New England Transmission Planning Technical Guideline

Note: ISO-NE Documents are available at iso-ne.com.

Eversource Documents
System Planning Procedure No 1 (SYSPLAN-001) Transmission System Reliability Standards
System Planning Procedure No. 8 (SYSPLAN-008) Calculation and Documentation of Bulk Distribution Transformer Ratings

Other Documents Referenced
ANSI C84.1 – 2006: American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

III. INTRODUCTION

Eversource System Planning Engineers perform annual assessments of all Bulk Distribution Substations to ensure there is adequate capability to reliably supply customers during both normal and contingency conditions. These studies are also the basis for, and document the “need” for expansion of existing facilities and/or construction of new substations.

To perform assessments of Eversource Bulk Distribution Substation facilities, the following tools/information may be required (based upon the type of assessment):

- Software tools appropriate to the study scope/objectives. The following tools are typically used for the types of studies mentioned:
  - PSSE (Siemens PTI): Steady State thermal and voltage analyses.

  - CYMEDist, Distriview, or Synergi: Distribution feeders and/or short circuit analyses
  - ASPEN: Short circuit analyses
- A model of the electric transmission system representative of the time period under study.
- A model of applicable parts of the distribution system for the time period under study.
- Loads representative of the time period under study. Loads may be adjusted for the effects of energy efficiency programs and/or distributed generation when appropriate. Studies conducted for peak load periods should use the load forecast generated by the Sales and Revenue Forecasting department.
- Generation pattern(s) representative of the time period under study with the inclusion of variations that create stressed conditions as deemed appropriate.
- Contingencies derived from the applicable reliability criteria referenced or provided in this document, for the time period and the area of the system that is under study.

The above items are discussed in more detail below.

A. Software Tools/Applications

System Planning Engineers shall utilize the most appropriate software application to model the Bulk Distribution Substation under study, based upon any of the following;

- Consistency with other Eversource developed models
- Existing available base cases
- Suitability for the topic/area under study
- Direction from System Planning Manager
- Any combination of the above

B. Electric System Models

The electric system model used shall cover the area of the electric system under study. The substation and distribution feeders that supply the area shall be modeled when they are used as the secondary supply to the Bulk Distribution Substation Supply Bus that is under study.

C. Loads

Substation loads from the current Eversource load forecast should be used and adjusted for planned load transfers/additions where applicable. Substation load power factors should be modeled at 0.99 lagging on the load side of the bulk transformer unless actual system conditions warrant the use of a different value. Measures should be taken, where feasible, to achieve a minimum 0.99 lagging substation load power factor (load side).

Distributed generation (DG) facility outputs will typically appear as reductions in the metered transformer secondary loads. However, exceptions include:

- Contractual obligations to provide uninterrupted service when DG is offline
- Contingencies resulting in DG isolation during restorative switching actions
- Intermittent resources that may not provide output during peak loading

When a bulk distribution transformer is removed from service by relay action, all DG units connected to the impacted secondary distribution facilities are required to isolate from the distribution system per IEEE-1547.

IEEE-1547 requires a minimum five minute "off-line" interval before a DG facility can automatically restart and generate into the distribution system. This may result in larger load transfers to other transformers by automatic bus restoration (ABR) actions. Because this load increase could violate a transformer's STE/DAL rating, loads should be adjusted to account for DG output when appropriate.

D. Generation

Generation patterns for generation connected to the transmission system have no effect on Bulk Distribution Substation Facility loading, however transmission system voltage schedules (per ISO-NE OP-12) should be maintained to ensure proper voltage ranges can be maintained on the substation bulk distribution buses.

When dispatchable generation is connected to the distribution facilities of a bulk distribution substation, the substation shall be tested at zero, minimum and maximum generating unit output(s).

Distributed generation output (connected to the distribution system) should also be considered as described in the loads section above.

E. Battery Energy Storage Systems (BESS)

Battery Energy Storage Systems (BESS) have a wide array of power system applications and control variations to consider when evaluating system performance and impact.

When the BESS is connected to distribution facilities, the system shall be evaluated at zero, minimum, and maximum BESS unit output (discharge or injection) under the applicable system loading conditions that would be expected for its intended operation.

Additionally, the system shall be evaluated with the BESS functioning as a load for its minimum and maximum intended charging demand under the applicable system loading conditions that would be expected for its intended operation.

For circumstances where the BESS performs the function of a reliability-based resource where it is being reserved and dispatched by Eversource for certain planned circumstances to alleviate adverse system conditions, the energy capacity (MWh) of the BESS shall be considered for supply adequacy in the forecasted planning horizon. The designed energy capacity shall also consider actual or expected device degradation impacting it's the total energy capacity for the forecasted planning horizon.

F. Applicable Reliability Criteria

It is Eversource's ultimate goal to have customers electric service automatically restored upon loss of supply to Bulk Distribution Supply Buses.

Each distribution bus, within a bulk distribution substation, shall have at least two means of supply (primary and secondary). In this context, primary supply is provided by;

- Connection to the secondary winding of a Bulk Distribution Transformer.

And secondary supply is provided by either;

- A connection to a tie breaker (either normally open or normally closed) that connects to another bus that is supplied by the secondary winding of a different Bulk Distribution Transformer.
- Connections to distribution facilities (supplied by different Bulk Distribution Transformers that are located at different substations), that can supply the bus (and/or its loads) using applicable equipment ratings denoted in Appendix A upon the loss of the primary supply.

G. Performance Criteria

Each Bulk Distribution Substation shall meet or exceed the performance criteria in Appendix B. When the performance criteria of Appendix B are not met, plans shall be developed to address the deficiencies in that substations' performance. Consult Appendix C and determine the "next step" in the evolution of the substation facility.

H. Distribution System Supply (DSS) Elements

Distribution System Supply (DSS) elements are distribution lines or cables that have similar characteristics and function to transmission supply lines since they feed bulk area load but are designed and operated at lower voltages. DSS elements can supply bulk distribution area loads either through downstream Eversource distribution facilities or directly to customer stations. These reside predominantly in the Eastern Massachusetts portion of the Eversource System. For the purposes of this procedure, DSS elements shall be treated the same as bulk distribution transformers where the system is assessed for the loss of a single DSS element.

IV. PROCEDURE

The Eversource System Planning Group performs periodic assessments/studies of Bulk Distribution Substation facilities to ensure continued compliance with the performance criteria given in this document. Studies may also be performed for any of the reasons given below:

- Studies required by State Regulators, such as;
    - The Annual Reliability Report to the Massachusetts Department of Public Utilities (DPU).
    - The Massachusetts Annual Loss Study
    - Other regulatory entities
- Eversource initiated studies to investigate potential weaknesses in the reliability of electric supply and identify potential plans for system reinforcements or mitigating measures
- Studies used in support of ISO-NE study processes, such as;
    - I.3.9 submittals

Annual Studies

System Planning Engineers should perform annual assessments of all bulk distribution substations. These assessments are intended to ensure that bulk distribution substations meet or exceed Eversource's Bulk Distribution Substation Planning Criteria (given in Appendix A) and the Bulk Distribution Substation Performance Criteria (given in Appendix B).

Study Reports

A report summarizing the results of the study should be produced by the responsible System Planning Engineer. The report should address:

- The substations current configuration/capacity with transformer ratings
- Considers historical actual peak loads, actual/planned load transfers and most recent (10 year) load forecast
- Assessment of distributed generation connected to each transformer's secondary load feeders and any load adjustments made because of these facilities
- System reinforcements or mitigating measures to plan or investigate further

Eversource Submission of Proposed Bulk Distribution Substation Changes for ISO – New England Review and Approval

All proposed upgrades, additions or retirements of Bulk Distribution Transformers in Eversource Bulk Distribution Substations shall be developed by System Planning into Proposed Plans & Applications (PPAs) and presented to the ISO-NE per the requirements of Tariff Section I.3.9 and ISO- New England Planning Procedures #5: Reporting Notice of Intent to Construct, Retire or Change Facilities; Procedure #5-1 Review of Proposed Plans; and Procedure #5-3 Guide for Conducting and Evaluating Proposed Plan Application Analyses. Those projects submitted for PPA approval include the proposed changes for the PTF facilities as well as non- PTF facilities. The ISO-NE review and approval is required for projects impacting the transmission system to ensure that each proposal has no adverse impact on the New England transmission network and is consistent with NERC, NPCC and ISO-NE reliability standards and requirements.

V. REVISION AND REVIEW

This procedure shall be reviewed periodically for revision and updating as required.

SYS PLAN 010: Revision Control Table

Rev. No.	Date	Reason
0	5/15/2014	Original Issue
1	8/01/2018	Updated the document for use in all Eversource service areas (MA, CT, NH)

APPENDIX A

Eversource

RELIABILITY CRITERIA

For the

Planning/Design

of Bulk Distribution Substation

Facilities

BULK DISTRIBUTION SUBSTATION PLANNING CRITERIA

Introduction

The goal of these Bulk Distribution Substation design criteria is to meet or exceed Eversource Customer's increased expectations regarding electric supply reliability. To accomplish this, the reliability of Bulk Distribution Substations must match these increased expectations. While it may not be possible to design, build, and operate substation facilities that are completely resilient to any event which could result in customer outages, there are economic designs and technologies that minimize the occurrence and/or impact of substation-based events to improve reliability.

It is Eversource's goal to have customer's electric service automatically restored upon loss of supply to Bulk Distribution Supply Buses. To accomplish this, certain technologies/designs are considered, which typically include but are not limited to:

1. Reliable Transmission Station bus arrangements: Connecting Bulk Distribution Transformer primaries to breaker and one/half or ring bus terminals. This improves the reliability of supply to all customers supplied by the transformer and ensures that problems with the transformer do not adversely affect transmission system reliability. Refer to ISO-NE Planning Procedure #9 "Major Substation Bus Arrangement Application Guidelines" for supporting information.
2. Substation Automation: In particular, automatic bus restoral schemes (ABR). ABR schemes (on the transformer secondary side) are designed/intended to restore supply to distribution buses after loss of supply due to transmission and/or substation events that results in loss of the transformer that normally supplies that distribution bus. These schemes automatically isolate the secondary breaker of the primary transformer supply to the bus and then close (after a suitable delay ~5 seconds) a normally open tie breaker to another bus/transformer, restoring supply to the affected customers.
3. Transformer Supply Transfer Schemes (primary): These schemes are typically used in substations that have two transmission lines supplying three (or more) bulk distribution supply transformers. Upon loss of a transmission line, the scheme will automatically operate so that two (or more) transformers are supplied from the transmission line remaining in service.
4. Distribution Automation: Dispatcher initiated switching using remotely controlled switches in the distribution system.
5. Manual Distribution Switching: This involves Dispatchers working with field crews to manually reconfigure distribution system switches and restore supply to all affected customers. This restoration method may take several hours to implement and should only be used as a backup to the methods above.

Eversource substations may use one or more of the designs listed above. When major work is required at any substation, consideration shall be given to performing an upgrade of the method currently in use.

BULK DISTRIBUTION SUBSTATION – GENERAL DESIGN CRITERIA

Bulk Distribution Substation designs should be in accordance with the following design criteria, when existing substation designs do not conform to these criteria or future potential non-conformances are identified, plans shall be developed to address the issue(s).

Bulk Distribution Substation designs should address the following areas:

- Short circuit interrupting capability.
- Reliable primary and secondary supply capabilities to Bulk Distribution Buses.
- Capability to ensure Bulk Distribution Transformer winding loads can be maintained within the applicable rating for both normal and post-contingency conditions.
- A single transmission system contingency that causes loss of supply to more than one Bulk Distribution Supply Bus.
- A mobile transformer or mobile substation installed to address emergent loading or contingency operations shall only be installed and utilized on a temporary basis while a permanent solution which meets the criteria outlined in this document is expeditiously pursued.

Short Circuit Interrupting Capability

Short circuit currents that exceed protection equipment interrupting capability can result in equipment damage, widespread outage events, and concerns in maintaining personnel and/or public safety near such equipment. To minimize the risk, impact, and possibility of such events, simulations shall be conducted to evaluate the maximum short circuit current in a substation against the protection equipment's capability of interrupting it. The System Protection and Control department is responsible for this determination.

Reliable Bulk Distribution Bus Supply

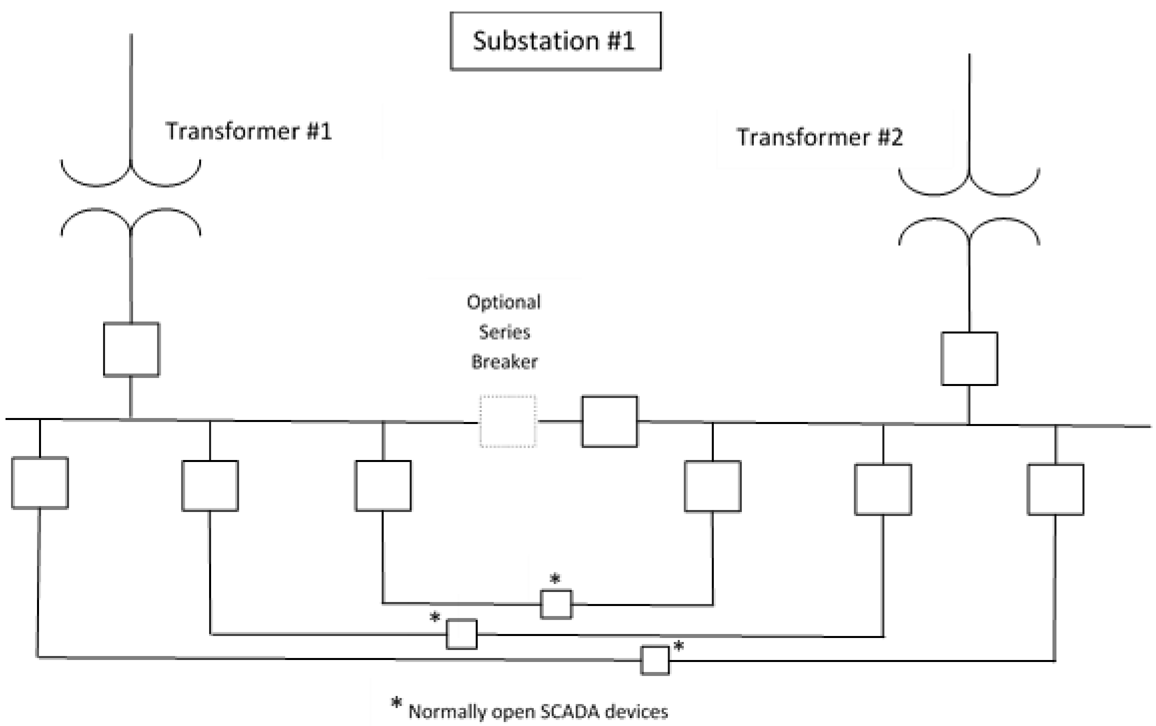
Each distribution bus, within a bulk distribution substation, shall have at least two means of supply (primary and secondary). In this context, primary supply is provided by;

- Connection to the secondary winding of a Bulk Distribution Transformer.

And secondary supply is provided by either;

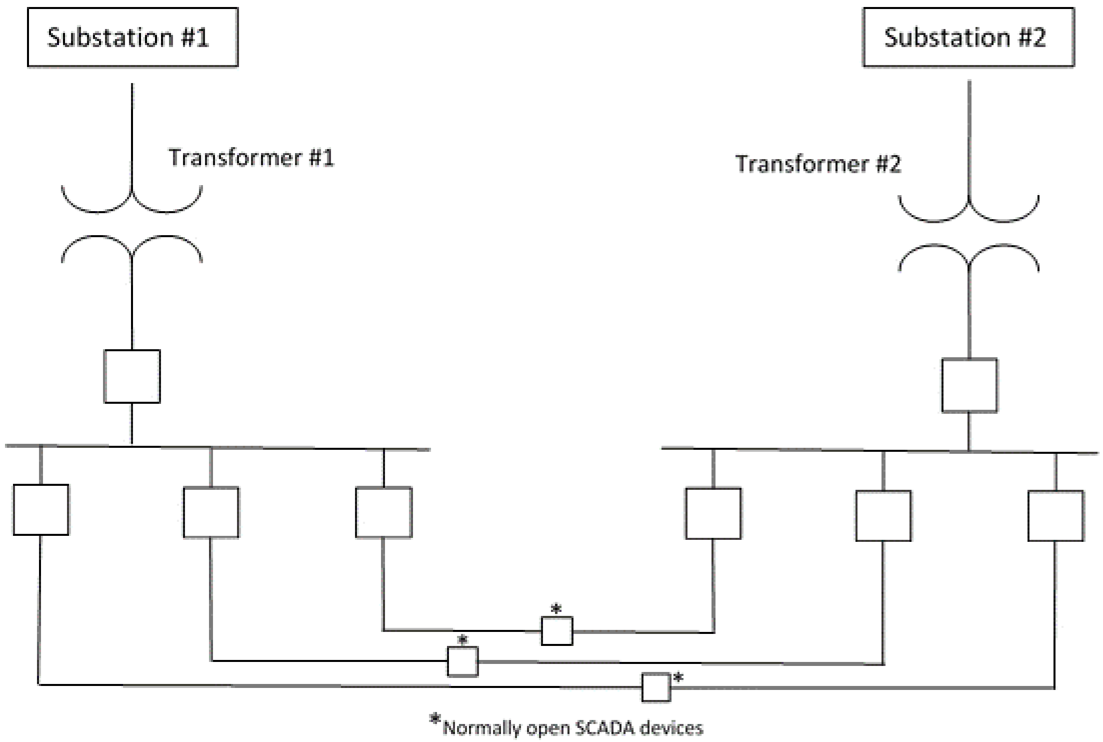
1. Connection to a tie breaker or switch (either normally open or normally closed) that connects to another bus that is supplied by the secondary winding of a different Bulk Distribution Transformer. (Refer to Figure 1) The application of a series bus tie breaker is optional and will be based on such criteria as green field construction, available space, number of customers/load served, and the capability of circuit ties from neighboring substations.

FIGURE 1



2. Connections to distribution facilities (supplied by different Bulk Distribution Transformers that are located at different substations), that can supply the bus (and/or its loads) upon loss of the primary supply. (Refer to Figure 2)

FIGURE 2



When the secondary supply to a bulk distribution bus is via distribution facilities, the following potential issues shall be considered;

- Low voltage conditions on distribution feeders when supplied by the secondary distribution facilities.
- Overloading the secondary supply distribution facilities when providing backup supply to other facilities.
- Low values of available fault current on portions of the distribution feeders when supplied by the secondary bus. This is due to the additional impedance of the distribution line(s) supplying the bus.
- Overloading the bulk distribution transformer that is supplying its primary loads along with the additional secondary loads.
- Adverse reliability impact of potential load transfers to adjacent facilities

Bulk Distribution Transformer Loading

Bulk Distribution Substations have one or more transformers. These transformers all have one primary winding and may be equipped with one (or more) secondary winding(s).

Bulk Distribution Transformer loading is evaluated on a winding basis, that is the load carried by each individual winding is evaluated against that winding's rating(s).

Bulk Distribution Transformer windings shall have ratings determined per the requirements of Eversource Procedure SYSPLAN 008 "Calculation of Bulk Distribution Supply Transformers Ratings". Ratings shall be applied in the following manner.

- **Loading Up To 75% of The Normal Rating:**
  Bulk transformer winding loads (expressed in Amperes or MVA), should not exceed 75% of the normal rating, under normal (scheduled) operating conditions/configurations.
  Notes:
  1. When determining the Long Term Emergency (LTE) rating of a transformer winding, a 75% pre-load condition is assumed. To protect the integrity of the LTE rating, normal loads should be limited to 75% of the normal rating. The 75% of normal rating loading restriction does not apply when a transformer does not provide secondary supply to another bulk distribution supply bus.
  2. Loading up to 100% of normal ratings can be used for single transformer substations, when that transformer is not relied upon to provide secondary supply to another bulk distribution supply bus.

- **Loading Between 75% of The Normal Rating and the Long-Term Emergency (LTE) Rating:**
  Bulk transformer winding loads above the normal rating, but below the LTE rating are allowed for one load cycle per event. Transformer winding loads within this range result from contingency events in the distribution system or within substations (loads in this range may result from ABR operations).

  Note: Load transfers (within the distribution system) or installation of a mobile transformer should be available to lower winding loads to the normal rating (or below) for subsequent load cycles, until the system can be returned to normal conditions.

- **Loading Between the Long-Term Emergency (LTE) Rating and the Short-Term Emergency (STE)/ Drastic Action Limit (DAL) Rating:**
  Bulk transformer winding loads above the LTE rating, but below STE/DAL rating must be lowered to below the LTE rating within 30 minutes.

- **Loading Above the Short-Term Emergency (STE)/Drastic Action Limit (DAL) Rating**
  Loading transformer windings above the STE/DAL rating is not accepted under planning criteria for any duration. This is intended as an operational rating only.

  Automatic protection schemes will be applied when needed to avoid loading above the STE rating of bulk substation transformers.

Note: Operating a transformer, for any duration, at loading levels above the STE rating can result in loss of life or in extreme cases, increased risk of catastrophic internal failure of the transformer.

Bulk Distribution Transformer Winding Loading Evaluations

Normal Conditions

- All **Elements** in service
  - All customer load shall be served.
  - Distribution bus voltages shall be able to be maintained at their normal scheduled value (typically 1.03 p.u. in MA and NH, and 1.02 in CT) using transformer load tap changers and/or substation distribution capacitor banks (when transformers are not equipped with LTC's).
  - Transformer winding loads should not exceed 75% of the **Normal Rating** and no other **Element** should exceed its **Normal Rating.** Loading up to 100% of normal ratings can be used for single transformer substations, when that transformer is not relied upon to provide secondary supply to another bulk distribution supply bus.

When transformer winding loads approach 75% of the normal rating (under normal operating conditions), there are three options available:

1. Permanently transfer loads to other supply sources with available capacity
2. Temporarily close a normally open bus-tie where the second transformer is under-utilized, when balancing load is impractical and there is no adverse impact on available fault current, circulating flows, or voltage
3. Provide additional transformer capacity by;
   a. Installing a larger transformer
   b. Installing additional transformers in the area

The decision to install an additional transformer or a larger transformer should be based on several factors including; availability of existing space or additional land, siting/permitting concerns, age and/or condition of existing transformers, specifying standard transformer sizes for which a spare is maintained, reliability implications (e.g. Firm Capacity), and cost.

Contingency Conditions

- **Loss of a Bulk Distribution Supply Transformer,**
  - After operation of automatic restoration systems or the use of distribution automation capabilities, all customer load shall be served.
    Note: Loads may require upwards adjustment to account for DG facilities that have tripped due to the initiating event.
  - Distribution bus voltages should be able to be maintained at their normal scheduled value using transformer load tap changers and/or distribution capacitor banks (substation distribution capacitors banks should be in service under these circumstances to supply increased reactive losses resulting from the loss of a transformer).
  - Bulk Distribution Transformer winding loading should be below the **Long-Term Emergency Rating** and shall not exceed the **Short-Term Emergency/Drastic Action Limit Rating.** Refer to the note below.

NOTE: Dispatcher initiated load transfers (using distribution automation capabilities, manual switching is not used for this purpose) must be available to lower transformer winding loads to below the LTE rating, within the time frame given below.

- When distribution load transfers are credited for reducing transformer winding loads to below the LTE rating, the following time frames shall be used:
- The initial post-event assessment period for Dispatchers to identify/assess the event shall be 10 minutes.
- The time to affect each load transfer is 5 minutes.
- All load transfers are sequential, when more than one is needed:
  - Two transfers take 10 minutes
  - Three transfers take 15 minutes
  - Etc
- Where possible, there shall be at least one extra load transfer available for Dispatchers to use. This shall be available for use in the event that one of the primary load transfers cannot be accomplished.

- **Loss of Transmission Lines That Supply More Than One Bulk Transformer**

  When individual transmission lines provide the supply to two (or more) Bulk Transformers, the coincident loss of the transformers (from a transmission line event) shall be evaluated.

- o After operation of automatic restoral systems or the use of distribution automation capabilities, all customer load shall be served.
  Note; Loads may require upwards adjustments to account for DG facilities that have tripped due to the initiating event.
- o Distribution bus voltages should be able to be maintained at their normal scheduled value using transformer load tap changers and/or distribution capacitor banks (substation distribution capacitors banks should be in service under these circumstances to supply increased reactive losses resulting from the loss of a transformer).
- o Bulk Distribution Transformer winding loading should be below the **Long-Term Emergency Rating** and shall not exceed the **Short-Term Emergency/Drastic Action Limit Rating.** Refer to the note below.

  NOTE: Dispatcher initiated load transfers (using distribution automation capabilities, manual switching is not used for this purpose) must be available to lower transformer winding loads to below the LTE rating, within the time frame given below.
  When distribution load transfers are credited for reducing transformer winding loads to below the LTE rating, the following time frames shall be used:
  - The initial post-event assessment period for Dispatchers to identify/assess the event shall be 10 minutes.
  - The time to affect each load transfer is 5 minutes.
  - All load transfers are sequential, when more than one is needed:
    - o Two transfers take 10 minutes
    - o Three transfers take 15 minutes
    - o Etc
  - Where possible, there shall be at least one extra load transfer available for Dispatchers to use. This shall be available for use in the event that one of the primary load transfers cannot be accomplished.

- **Stuck Breaker Affecting Substations Serving Three or More Bulk Transformers**

A transmission stuck breaker contingency that results in the loss of two or more bulk substation transformers causing a permanent loss of customer load or thermal/voltage violations on the transmission system or the bulk substation equipment shall be evaluated. System Planning will consider the following options as applicable:

- Distribution line and distribution automation enhancements
- Load Power Factor Improvement
- Install motor operators on each of the circuit breaker disconnects such that the disconnects of the failed circuit breaker would be tripped for a breaker failure relay operation once the fault has been cleared. Implement automatic reclosing that will restore the elements that were tripped as a result of the stuck breaker, and not the original contingency.

- Station reconfiguration and/or installation of a series circuit breaker(s)
- Installation of a transmission capacitor bank

The option that is selected would be based on cost, constructability, operability, available space within the substation, and associated siting/environmental concerns.

- **Substations Serving Major Secondary Network Systems**

Because of the nature of secondary network loads there is no transfer switching capability with other substations. This results in the substation Load Carrying Capability (LCC) being equal to the LTE rating of the smallest transformer and that STE/DAL ratings can not be applied because there is no capability to relieve transformer winding loads.

- **Substations With One Transmission Line Supply**

Substations with one transmission supply line must use distribution feeders as the secondary supply to the loads. This type of configuration provides acceptable levels of reliability when the substation loads are light and the distribution feeders are short. Over time as loads grow and the distribution system expands, this method will encounter some (or all) of the following issues:

- Low voltage on distribution feeders when providing backup service
- Loading on distribution feeders exceeding emergency ratings when providing backup
- Loading on bulk transformers exceeding emergency ratings when providing backup
- Low available fault current levels on the distribution feeders when providing backup supply.
- Cascading switching which exacerbates restoration efforts

The following criteria apply to all situations where distribution feeders and remote bulk transformers are relied upon to restore electric service to customers:
To determine that distribution feeders provide an adequate secondary source for the bulk distribution bus loads, the distribution feeders shall be modeled in a loadflow simulation and the following performance criteria under the projected operating loads shall be demonstrated:

- Bulk Distribution Transformer(s) that provide the secondary supply, shall be within LTE loading criteria for the first load cycle following loss of the primary supply. Additional distribution switching (both manual and remotely controlled) and/or a mobile transformer shall be available that would lower transformer winding loads to the normal rating or below. This additional switching (or mobile installation) will be implemented when problems will require multiple load cycles to be resolved. It is preferred that system design limit the loading of remote bulk transformers to normal ratings.

- Distribution feeders providing the secondary supply to bulk distribution supply buses, shall not exceed the long-term emergency rating. It is preferred that system design limit the loading to the normal rating.
- To provide acceptable voltage levels at customer service points, distribution feeders primary voltage levels must also be at acceptable levels. In this context, acceptable voltage levels are defined by "Voltage Range B – Service Voltages" (95% of nominal distribution system voltage) as given in ANSI C84.1 - 2006 "Electric Power Systems and Equipment Voltage ratings (60 Hertz)".
- Distribution feeder primary, available short circuit current levels;
  When one distribution feeder is tied to another feeder in a radial configuration, portions of the feeder that is being supplied can experience inadequate levels of available fault current. When fault current levels are too low, protective devices (reclosers, sectionalizers, fuses, etc.) cannot differentiate between load currents and fault currents. The result is that faults may not be cleared from the distribution system properly, creating safety hazards for the general public and Eversource employees. In general, available fault current should be a minimum of three times the load current.

Appendix B: Glossary of Terms

Bulk Distribution Supply Bus – A bus, within a substation that supplies multiple distribution feeder breakers. Nominal voltage shall be below the 69 kV level.

Contingency — An event, usually involving the loss of one or more **Elements**, which interrupts the flow of power on the power system at least momentarily.

Distribution Transfer Switching – Load that can be moved from one distribution feeder to another using remotely controlled switches (manual switching operations are not acceptable) within the distribution system. This switching transfers the load from its original transformer supply to a different transformer supply

Element — Any electric device with terminals that may be connected to other electric devices, e.g.; a transformer, circuit, circuit breaker, line, or generator.

Emergency — Any abnormal system condition that requires automatic or manual action to prevent or limit the loss of substations, or distribution that could adversely affect the Reliability of the electric system.

Firm Capacity (of a substation) -

- Single Transformer Substations: The **Firm Capacity** of a substation equipped with a single transformer is equal to zero.
- Double Transformer Substations: The **Firm Capacity** of a substation equipped with two transformers is equal to the smallest LTE (Long Term Emergency) rating of the transformers as determined using SYSPLAN-008.
- Three (or more) Transformer Substations: The **Firm Capacity** of a substation equipped with three (or more) transformers is equal to the total substation supply capability (typically limited by transformer LTE ratings) after loss of a single element, assuming proper operation of automatic transfer/restoral schemes.

Long Term Emergency (LTE) Rating - The rating based on the operational limit of an **Element** under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the **Element**, the maintenance history and the calculated capacity that is available in the **Element** based on the life expectancy of the **Element**.

Load Carrying Capacity (LCC) – The capacity of a Substation is equal to the **Firm Capacity** plus available **Distribution Transfer Switching** capacity to adjacent Substations, limited by the **Short-Term Emergency Rating** of the transformer being relieved by the **Distribution Transfer Switching and the transfer capability limit of the affected distribution system elements**.

Normal Rating - The rating that specifies the level of electrical loading, usually expressed in mega-volt amperes (MVA) or other appropriate units that a system, facility, or **Element** can support or withstand under continuous loading conditions.

Short Circuit Interrupting Rating – The rating of system protection equipment designed to interrupt service under short circuit conditions. The rating is expressed as the amount of short circuit power or current the device can safely interrupt under fault conditions.

Short Term Emergency (STE) Rating - The rating based on the operational limit of an **Element** under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the **Element**, the maintenance history and the calculated capacity that is available in the **Element** based on the life expectancy of the **Element**.

Appendix C: Eversource Electric – Bulk Distribution Substation Performance Criteria

	Bulk Distribution Bus Voltage Criteria	Bulk Distribution Transformer Winding Loading Criteria	Loss of Firm Load (Load Shed)	Other Planning Criteria
Normal Conditions	Maintain normal scheduled voltages	Below 75% of Normal Rating or 100% when unit does not provide secondary source to another bus or circuit.	None allowed	N/A
Loss of the Primary Bulk Distribution Supply Transformer, when secondary supply is through bus ties.	Maintain normal scheduled voltages	• Loading up to LTE • Loading up to STE may be used when distribution load transfers are per criteria	None allowed	N/A
Loss of the Primary Bulk Distribution Supply Transformer, when secondary supply is through distribution feeder ties.	N/A	• Loading up to LTE • Loading up to STE should NOT be used because switching to restore load will take precedence over switching to transfer load)	None allowed	-Distribution feeder primary voltage above 95% of nominal. -Distribution feeder loading below LTE rating for overhead, normal rating for underground.(see Note 1) -Available short circuit current within acceptable range.
Loss of One Transmission Line Supplying More Than One Bulk Transformer	N/A	• Loading up to LTE • Loading up to STE should NOT be used because switching to restore load will take precedence over switching to transfer load)	None allowed	-Distribution feeder primary voltage above 95% of nominal. -Distribution feeder loading below LTE rating for overhead, normal rating for underground.(See Note 1) -Available short circuit current, at least 3 times load current.

Note 1) For planning purposes: Overhead conductors will be limited to LTE. Underground and aerial cables will be limited to normal ratings. At the discretion of the Manager – System Planning, different ratings may be used where deemed appropriate.

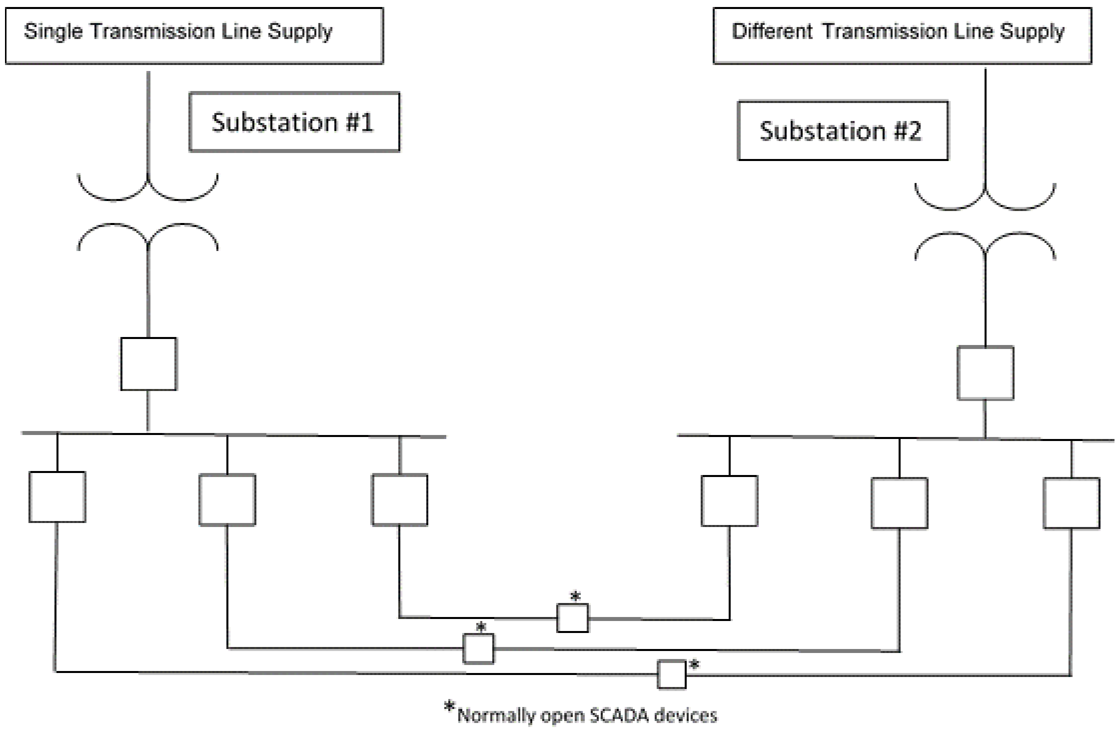
Appendix D: Eversource Standard Substation Configurations

The design of reliable substation facilities has a natural progression based upon the amount of load served by the facility. Substation facilities generally follow the progression below.

1. A single transformer with a single transmission line supply. Backup is provided via distribution ties using distribution automation capabilities.
2. Two transformers with two transmission lines providing supply. Bulk distribution supply buses back each other using automatic bus restoral (ABR) schemes.
3. Two transformers with three transmission lines providing supply. A ring bus is used on the primary side so that no single contingency will result in the loss of both transformers.
4. Three transformers with two transmission lines providing supply. A ring bus or a transfer scheme is used on the primary side so that two transformers will always remain in service. The primary transfer scheme is coordinated with the secondary side ABR scheme. A ring bus or breaker and one-half scheme are preferred when conditions allow.
5. Four transformers with two or more transmission lines providing supply. A ring bus or breaker and one-half scheme is used on the primary side of the transformers to ensure reliable supply, along with an ABR scheme on the secondary.

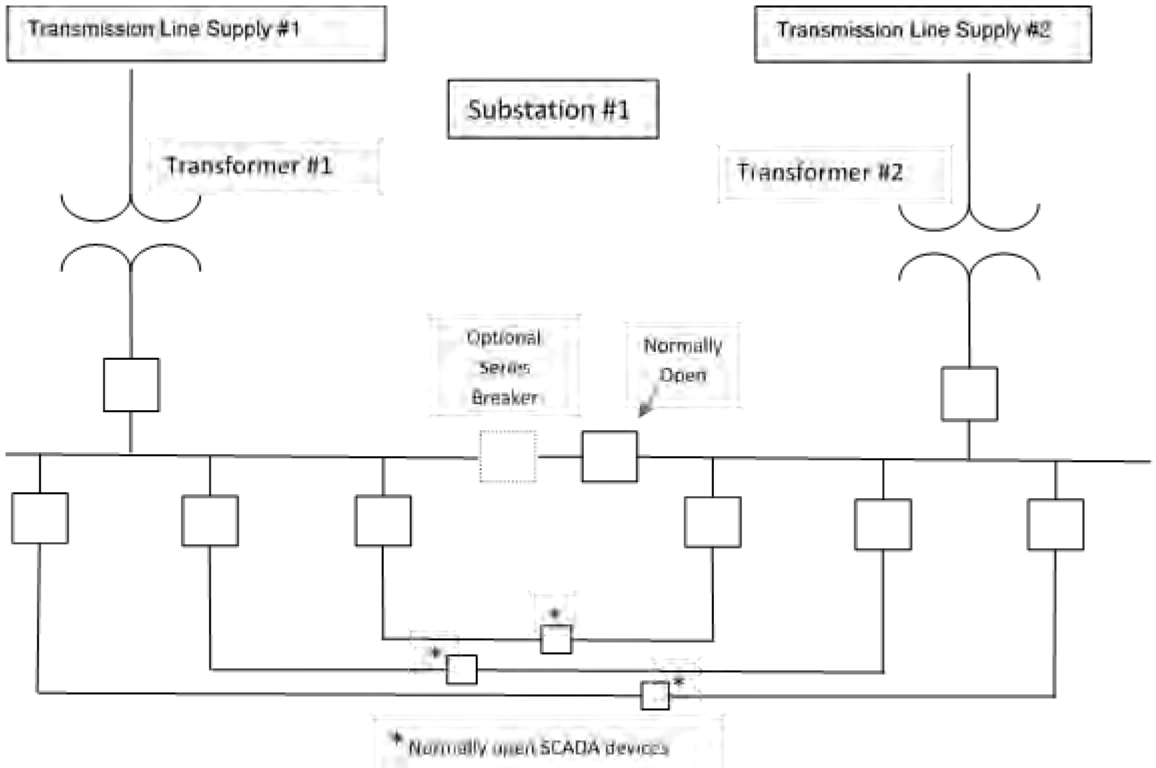
Note: The one-lines depicted below provide commonly representative recommended configurations, however, secondary voltages, land constraints or other factors may influence the final configuration.

1. Single Transformer with Single Transmission Line Supply



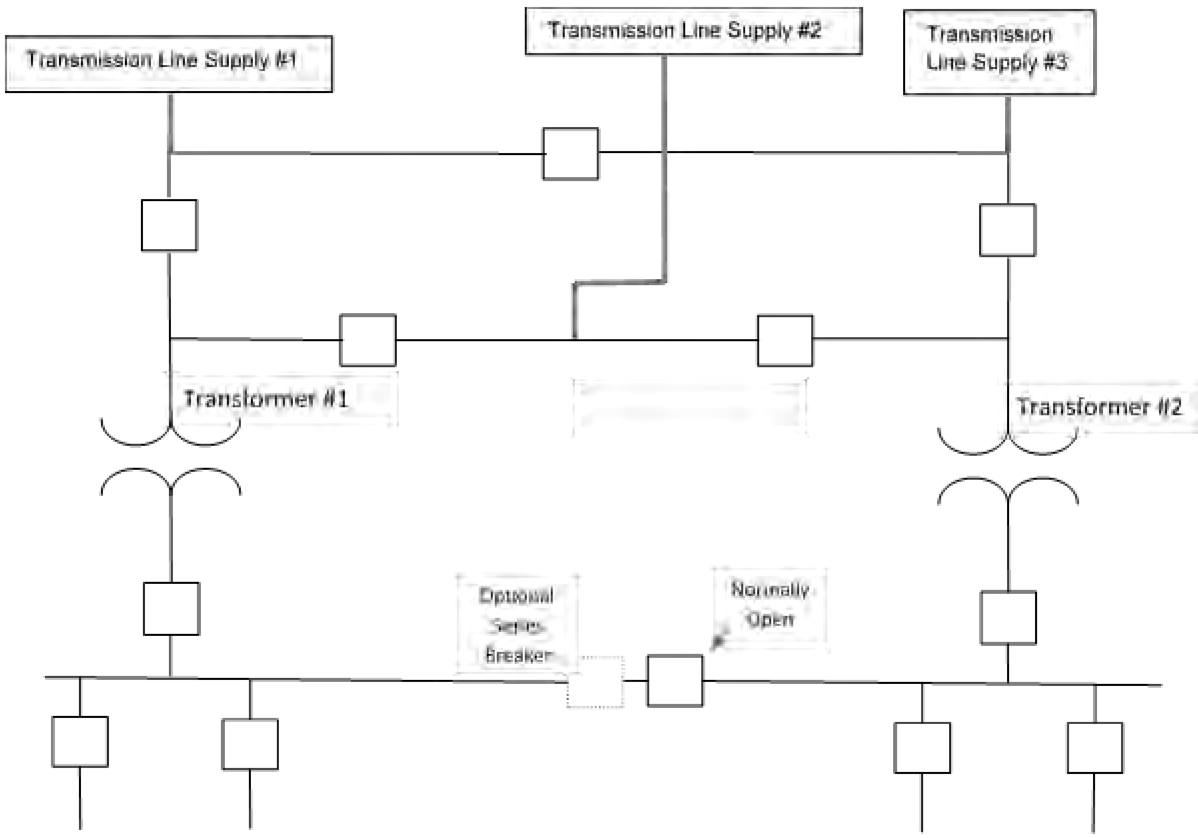
The single transformer with single transmission line supply configuration is limited by the ability of the distribution system infrastructure to supply the secondary supply for the area upon loss of the single transformer or transmission line. The area distribution supply voltage will also play a role in the amount of load a single transformer substation can reliably carry.

2. Two Transformers with Two Transmission Line Supply



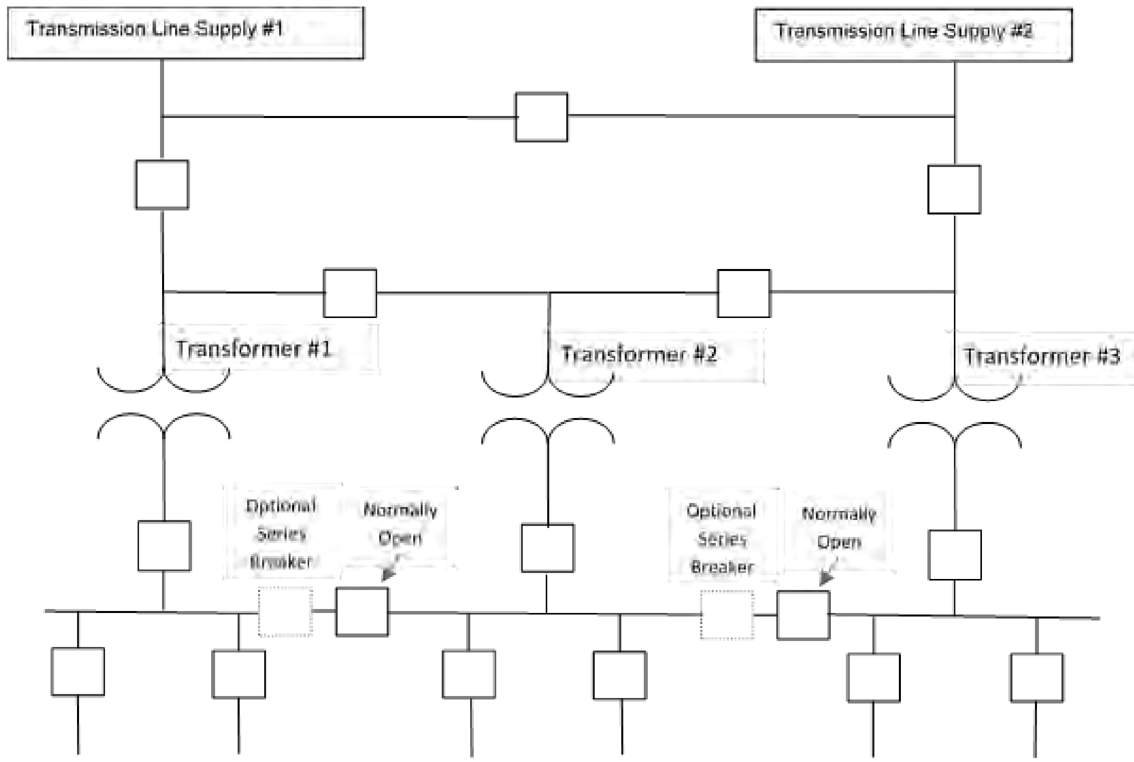
Two transformers with two transmission supply lines is limited by the long-term emergency (LTE) rating of the smaller of the two transformers for one load cycle. This is because the smaller transformer must supply all substation load after ABR operation. Additional measures should be taken to limit the remaining transformer to the normal rating within one load cycle. Where additional SCADA controlled circuit ties exist, the smaller transformer may be limited by the STE rating until load is reduced to below LTE (no longer than 30 minutes).

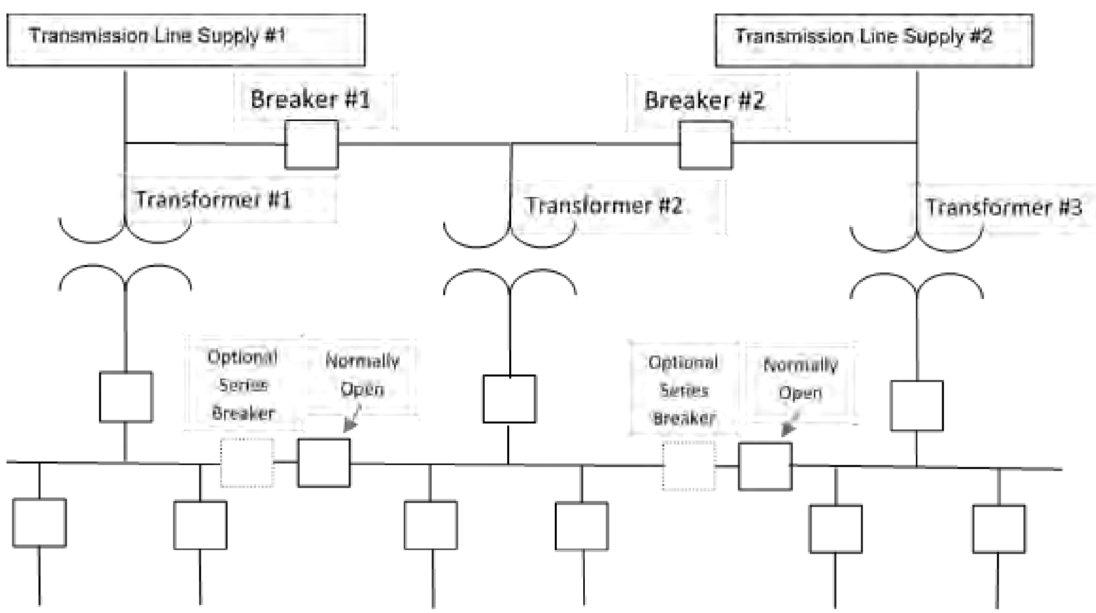
3. Two Transformers with Three Transmission Line Supply



Two transformers with three transmission supply line configuration uses a ring bus which prevents the loss of both transformers for a single contingency. The load would generally be limited by the LTE rating of the two smaller transformers.

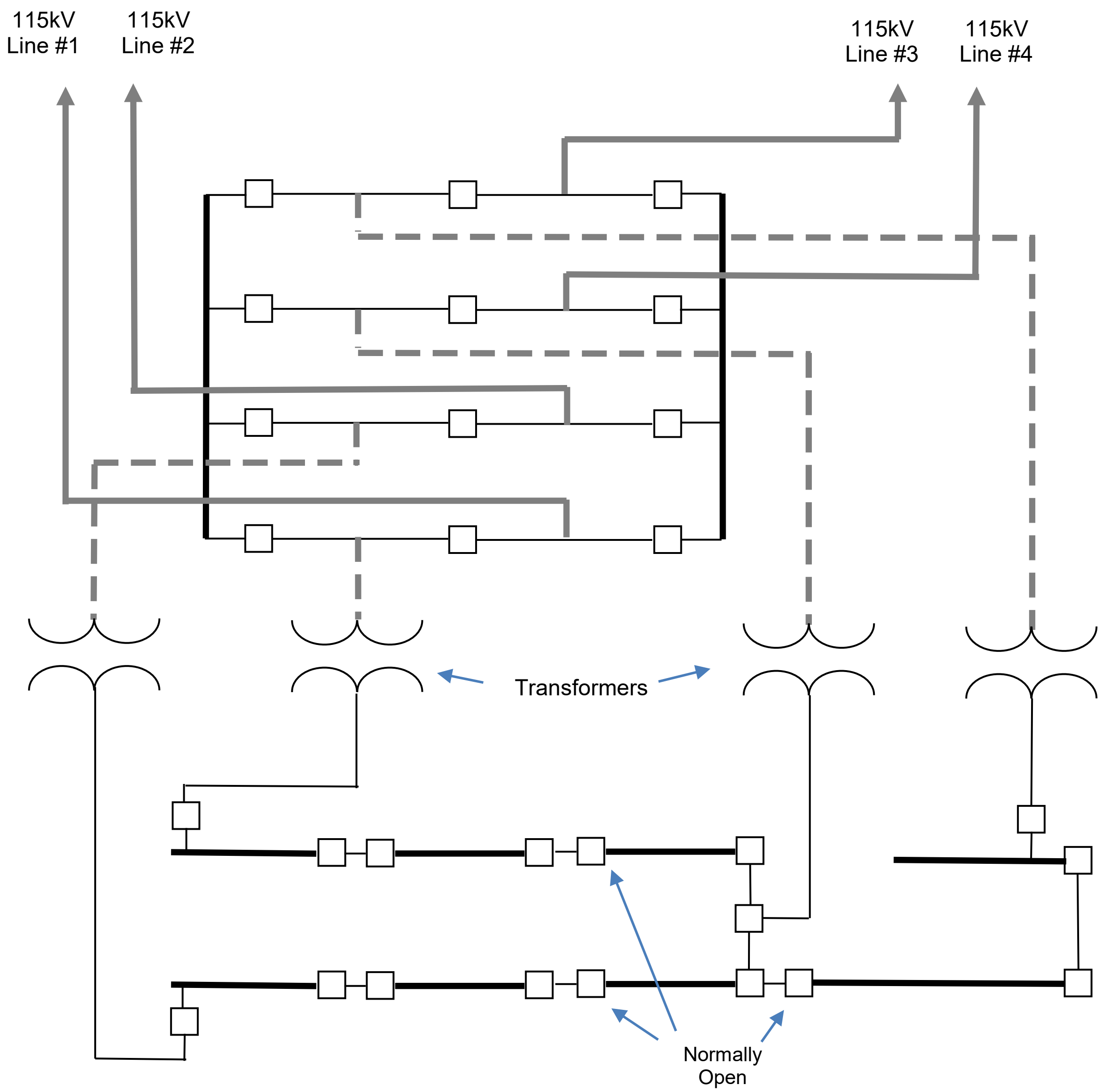
4. Three Transformers with Two Transmission Lines Supply





Three transformers with two or more transmission supply line configuration uses a ring bus or a primary transfer scheme to ensure that two transformers remain in service post-contingency. The load would generally be limited by the LTE rating of the two smaller transformers. Consideration should be given to construct a ring bus or breaker and one-half scheme on the primary side when serving a three-transformer substation.

5. Four Transformers with Two or More Transmission Lines



The one-line above represents a primary breaker and one-half scheme supplying four transformers and an example of a typical distribution switchgear configuration.

EVERSOURCE

Calculation and Documentation of Bulk Distribution Transformer Ratings

SYS PLAN 008 Rev. 1

Approval Signature: George P. Wegh

Process Owner:	George P. Wegh Director, System Planning	Effective Date: June 11, 2018

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Appendices

I. SCOPE AND APPLICABILITY

This procedure defines the responsibilities of Eversource personnel for the calculation and documentation of ratings for Eversource Bulk Distribution Transformers (transformer secondary voltage of 46kV and below). It describes a recommended procedure for the calculation of the transformer ratings and the recommended tools to be used for the calculation. It also provides a description of the required documentation and where the completed documentation will be stored.

This procedure also applies to any associated personnel or contractors performing calculations on behalf of Eversource personnel. It also requires close coordination with the Substation Technical Engineering and Control and Protection Groups.

II. REFERENCE DOCUMENTS

NERC

NERC Standard FAC-008-3 – Facility Ratings Methodology

NPCC

N/A

ISO-NE

ISO New England Operating Procedure No. 16 Transmission System Data

ISO New England Planning Procedure PP7 – Procedures for Determining and Implementing Transmission Facility Ratings in New England

Eversource

SYS PLAN 006 – Determining Transmission System Facility Ratings (EMA)

SYS PLAN 007 - Auto Transformer Ratings Calculation Procedure and Documentation (EMA)

SYS PLAN 010 – Bulk Distribution Substation Assessment Procedure

SUB 009 – Thermal Ratings for Transmission (CT, WMA, NH)

IEEE

IEEE Standard C57.91-2011, “IEEE guide for Loading Mineral-Oil-Immersed Transformers and Step Voltage Regulators”

IEEE Standard C57.12.00-2015 “IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers”

Other

EPRI PTLOAD Version 6.2 Software Manual

III. INTRODUCTION

Bulk Distribution Transformers are integral to the electric distribution system as well as large capital investments. The cost of premature/unexpected failure of these assets can amount to several times the initial cost of the transformer. The cost of failure not only includes refurbishment or replacement of the transformer, but also costs associated with clean-up, loss of revenue and possible deterioration in the quality of service to customers. It is integral to Eversource the ratings for bulk distribution transformers are calculated accurately and the results are well documented. The following methodology applies to Eversource Bulk Distribution Transformers. This document was developed in a collaborative effort between Eversource System Planning, Substation Design Engineering, and Substation Technical Engineering Departments and relies upon input from Industry Standards, ISO-NE Planning Procedures, and Eversource operating experience.

To calculate the ratings of a Bulk Distribution Transformer, the following information is needed:

- The Transformer's Nameplate
- The Factory Test Report which provides:
    - Load Loss
    - No Load Loss
    - Temperature Rise Test (a "sister unit" temperature rise test can be used in the case a temperature rise test has not been performed).

The information above should be readily available for most transformers, however for some units the use of data from similar transformers may be required. Consult with Substation Engineering or the Substation Technical Engineering Group when the exact data is not available.

IV. TRANSFORMER RATING CATEGORIES

ISO-NE PP-7 section 2.3 requires transmission owners in New England to provide four categories of load carrying ratings: Normal, Long Time Emergency (LTE), Short-Time Emergency (STE) and Drastic Action Limit (DAL). Per ISO-NE PP-7 Appendix D, since operation of load-serving transformers does not impact the high voltage transmission system, the transformer owner may determine the criteria for rating a load-serving transformer. Also, the duration associated with LTE, STE and DAL limits may vary from the durations in PP7 Section 2.3. Therefore, Eversource utilizes the following time durations for these four categories of ratings:

Normal Ratings – Continuous
Winter LTE (W LTE) - 4 hours
Summer LTE (S LTE) - 12 hours
Winter STE (W STE) - *30 minutes
Summer STE (S STE) - *30 minutes
Drastic Action Limits – *DAL is equal to the STE for Summer and Winter ratings)

More specific rating definitions can be found in SYSPLAN 010

*Note - For operational practicality purposes, there is not enough time for an operator to respond when a transformer is loaded at or above STE. Hence, Eversource generally sets the STE as a 30-minute rating as opposed to the guideline of 15-minutes, and sets the DAL equal to the STE rating.

V. TRANSFORMER RATING CALCULATION

Normal ratings for Bulk Distribution Transformers will be set at the highest nameplate MVA of the transformer assuming all nameplate associated cooling equipment is intact.

Information within the Transformer's Nameplate and Factory Test Report is needed as input for the "PTLOAD" software application used to calculate transformer ratings for emergency loading (includes LTE and STE for both Summer and Winter).

Exceptions to the use of either the transformer nameplate rating for normal ratings or PTLOAD for emergency ratings are acceptable under certain circumstances that are in accordance with good utility practice. Examples include but are not limited to:

- An assessment of the transformer condition indicates elevated risk (testing, oil sample, etc)
- Equipment described on the nameplate is either not installed, not functional, or in poor working condition (typically refers to thermal equipment – fans, pumps, etc.)
- Information from test reports have limited detail or are missing which may require engineering judgement or assumptions based on the information that is available
- Historical issues when operating at certain thresholds despite the calculated ratings
- Indoor or confined space considerations where thermal assumptions may not apply
- Engineering studies or analysis conducted by an engineering consultant or the manufacturer which uses more definitive calculations to determine ratings
- Use of PTLOAD calculated winter normal ratings instead of nameplate ratings based on appropriate engineering judgement and where transformer condition is acceptable.

Note: Use of PTLoad calculations that conflict with the highest nameplate rating for "normal" is not an acceptable justification to apply a rating exception alone.

Rating exceptions should supersede the applicable rating approach. The associated personnel impacted by the rating exception should be consulted, which at minimum should include Substation Engineering. The exception should be documented and retained in an asset repository for the associated equipment with corresponding detail explaining the circumstances.

VI. EMERGENCY INPUT PARAMETERS FOR "PTLOAD" SOFTWARE APPLICATION

Tables 1 and 2 below show the assumptions used to calculate emergency ratings for an oil-immersed 65 degree rise and 55 degree rise transformers under LTE, STE, and DAL scenarios. An explanation of these assumptions can be referenced in the IEEE Std. C57.91-2011 Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators. The rating for step-down transformers are calculated using Nominal voltage.

Assumptions	Summer LTE/STE/DAL	Winter LTE/STE/DAL
Ambient temperature (°C)	40/40/40	10/10/10
Duration in hours	12/0.5/0.5	4/0.5/0.5
Top oil temperature (°C)	110/110/110	110/110/110
Winding hot spot temperature (°C)	140/140/140	140/140/140
Maximum rating (% of nameplate)	150%	150%
Minimum Preload (% of nameplate rating)	75%	75%
Minimum Post load (% of nameplate rating)	100%	100%

Table 1: Assumptions for 65 Degree Rise Step-Down Transformer Ratings

Assumptions	Summer LTE/STE/DAL	Winter LTE/STE/DAL
Ambient temperature (°C)	40/40/40	10/10/10
Duration in hours	12/0.5/0.5	4/0.5/0.5
Top oil temperature (°C)	100/100/100	100/100/100
Winding hot spot temperature (°C)	140/140/140	140/140/140
Maximum rating (% of nameplate)	150%	150%
Minimum Preload(% of nameplate rating)	75%	75%
Minimum Post load (% of nameplate rating)	100%	100%

Table 2: Assumptions for 55 Degree Rise Step-Down Transformer Ratings

VII. DOCUMENTATION AND PROCEDURE

Thorough documentation of transformer ratings calculations is necessary to preserve data accuracy and to demonstrate data integrity to regulators. The transformer rating calculations will be recorded on the cover sheet located in **Appendix A** of this document and saved on a System Planning Shared Drive.

Rating exceptions as described in 'Section V Transformer Rating Calculation' should be well documented and agreed upon by the personnel impacted by the exception, which at minimum should include Substation Engineering.

Eversource uses PTLOAD Software to calculate emergency transformer ratings. The following is a recommended PTLOAD procedure for documenting the transformer ratings calculation. An example calculation is in **Appendix E** of this document.

- **PTLOAD Modeling Document Preparation**

The user of PTLOAD software for calculating the transformer ratings should have the test report including the heat rise test data along with the nameplate information.

The following transformer parameters are needed for PTLOAD input.

- Transformer Insulation (55C or 65C)
- No-Load (Core) Loss
- Load Loss at rated load
- Weight of Core and Coils (lbs)
- Weight of tank and fittings (lbs)
- Total Oil Volume (gals)
- Nameplate Rating for the different cooling stages
- Top Oil temperature rise over ambient temperature
- Average winding temperature rise over ambient temperature
- Oil Flow Design (Please see Appendix A)

1) Input the Nameplate voltage in kV for the transformer. Specify whether the transformer is a three phase or a single-phase transformer.
    a. Choose the insulation system for the transformer whose rating needs to be calculated. Aging rate constant B and Normal Insulation life are default values based on section 5.0 and Annex I of IEEE Standard C57.91-1995. Generally, the Top Oil Model is used for the Design Mode rating calculations.

2) Cooling: A transformer can have three cooling stages. If the test report data is available for all the three levels of cooling, the user is requested to input the data or use the available cooling data for the specific stage from the test report.

3) Ambient Cycle: For the summer conditions, an ambient temperature of 40 degrees C is used for Emergency rating calculations. For the winter conditions, an ambient temperature of 10 degrees C is used.

4) Load Cycle: Input the Preload in MVA for the 24-hour load cycle. Typically, for emergency rating calculations 75% of the Top Name Plate Rating is used as the preload.

5) Bubbles: Eversource does not evaluate bubble evolution. The Winding Hot Spot temperature is limited to 140C for all emergency contingencies, which will prevent the formation of bubbles.

6) Calculation Type: The rating calculations can be continuous or limited time ratings (LTE and STE ratings). The maximum criteria for ratings calculations regarding the Top Oil Temperature and Winding Hot Spot temperatures in degrees C are specified in PTLOAD as shown below.

Calc Type Parameter Setting

Temperature Rise	Contingency		Calculation Type: Continuous Rating	Calculation Type: Limited Time Rating	Maximum Criteria for Rating Calculation: Top Oil Temp C	Maximum Criteria for Rating Calculation: Hot Spot Temp C	Duration (hour)
65 C	Summer	Normal	X		*105**	*120**	∞
		LTE		X	110	140	12
		STE		X	110	140	0.5
	Winter	Normal	X		*105**	*120**	∞
		LTE		X	110	140	4
		STE		X	110	140	0.5
55 C	Summer	Normal	X		*95**	*105**	∞
		LTE		X	100	140	12
		STE		X	100	140	0.5
	Winter	Normal	X		*95**	*105**	∞
		LTE		X	100	140	4
		STE		X	100	140	0.5

**Note: Temperature parameters associated with normal ratings are for informational purposes only*

7) Results: The final step in determining the ratings for the auto transformers is to go to Results tab in the PTLOAD software and click on calculations to run the calculations. Lastly click on Output Manager to determine the ratings.

VIII. OTHER EQUIPMENT CONSIDERED IN TRANSFORMER RATINGS

Eversource has additionally considered the effect of overloading transformers above nameplate rating on bushings, and load tap changers. For Bushings, Eversource refers to IEEE Std C57.91-2011 Annex B.1. In it, it summarizes overload limits that are established for coordination of bushings with transformers. Please refer to the following table shown in Annex B.1:

Ambient air	40 °C maximum
Transformer top-oil temperature	110 °C maximum
Maximum current	2 times rated bushing current
Bushing insulation hottest-spot temperature	150 °C maximum

Eversource either meets, or is more conservative than all the above criteria. Thus, it can be assumed the bushing will not fail before the transformer. Regarding Load Tap Changers, Eversource refers to IEEE Std C57.91-2011 Annex B.2. On page 44 it states:

The top-oil temperature in the LTC compartment may not be readily available unless the LTC is located in the main tank of the transformer. If the LTC is located in a separate tank, the LTC oil may be in the order of 5-15 °C cooler than the top-oil temperature in the main tank at rated load. As a rule of thumb, it can usually be assumed that the temperature rise of the oil in a separate tank is 80% of the oil temperature rise in the main tank.

Preceding the above statement, it is mentioned that the contacts of the tap changer should not exceed 120 ºC, due to the development of carbon on the contacts. Since Eversource limits the top oil temperature to 110 ºC, and the LTC is 5-15 °C cooler than the top-oil temperature in the main tank with a temperature rise of 80% of the rise in the main tank, it can be assumed Eversource transformer tap changers oil will never exceed 120 ºC.

Eversource publishes the auto transformer ratings and bulk distribution transformer ratings via a transmission system application known as the NX-9 Database to ISO-NE. This database is available at the ISO New England website as a web based application and can be found at the following website:

https://smd.iso-ne.com/

The procedure described above is used to determine the transformer normal and emergency ratings. However, the ratings that are available in the NX-9 database are the equipment with the most limiting ratings for the entire transformer facility. Please see SysPlan 006 (Eastern Ma) or SUB009 (CT, WMA, NH) for a more detailed explanation of how this information is collected and recorded.

The final ratings published in the NX-9 database for the transformers should be submitted only after the user calculates the ratings via the PTLOAD software and submitting all possible limiting equipment into Thermal Ratings Analyzer to confirm if there are any other equipment limitations.

IX. REVISION AND REVIEW

This procedure shall be reviewed periodically for revision and updating as required.

SYS PLAN 008: Revision Control Table

Rev. No.	Date	Reason
0	5/15/2014	Original Issue
1	06/11/2018	Updated the document for use in all Eversource service areas (MA, CT, NH)

Appendix A – Sample Distribution Transformer Rating Cover Sheet

Bulk Distribution Transformer Ratings Calculation Cover Sheet

Transformer Information
Substation:
Designation:
Manufacturer:
Serial Number:
Nameplate Rating:

Ratings Summary

Season	Summer		Winter	
Rating	**PT Load Actual**	***Adjusted Rating**	**PT Load Actual**	***Adjusted Rating**
Normal				
LTE				
STE				
DAL	-		-	

*Normal ratings are determined using the top nameplate rating. All emergency ratings are limited to 1.5 times the top nameplate rating. Drastic Action Limits are set equal to the Short Time Emergency limits.

Signatures:

Prepared By:

Reviewed By:

Appendix B – Transformer Cooling Codes

First letter: **Internal cooling medium in contact with the windings**

O mineral oil or synthetic insulating liquid with fire point < 300°C

K insulating liquid with fire point > 300°C

L insulating liquid with no measurable fire point

Second letter: **Circulation mechanism for internal cooling medium:**

N natural convection flow through cooling equipment and windings

F forced circulation through cooling equipment (cooling pumps), natural convection flow in windings (non-directed flow)

D forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings

Third letter: **External cooling medium**

A air

W water

Fourth letter: **Circulation mechanism for external cooling medium**

N natural convection

F forced circulation (fans, pumps)

Previous Designations	Present Designations
OA	ONAN
FA	ONAF
OA/FA/FA	ONAN/ONAF/ONAF
OA/FA/FOA	ONAN/ONAF/OFAF
OA/FOA*	ONAN/ODAF
OA/FOA*/FOA*	ONAN/ODAF/ODAF
FOA	OFAF
FOW	OFWF
FOA*	ODAF
FOW*	ODWF

Appendix C –Dover 110A Station Transformer Nameplate (Generic) and Test Report

HICO

THREE PHASE POWER TRANSFORMER

VOLTAGE RATING	
H.V	117,000 V
X.V	15,120 V

BIL OF WINDING	
H.V	450 kV
X.V	150 kV
X.V.N	150 kV

kVA RATING (65°C RISE)	ONAN	ONAF1	ONAF2
H.V	37,000	50,000	65,470
X.V	37,000	50,000	65,470

% IMPEDANCE		
H.V–X.V	%	AT 37,000 kVA

SOUND LEVEL		
	BASE STAGE(OA)	dB
	ONE STAGE OF COOLING	dB
	TWO STAGE OF COOLING	dB

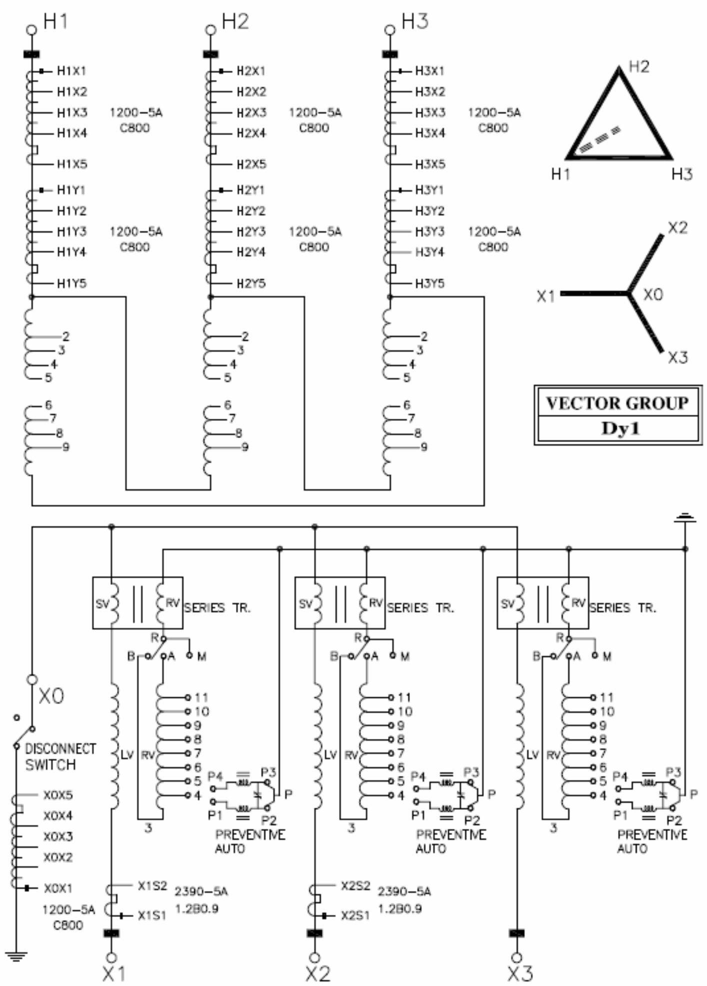
MATERIAL	
INSULATING OIL	ASTM D-3487 TYPE I
CONDUCTOR	COPPER

RATED FREQUENCY	60Hz
COOLING METHOD	ONAN/ONAF1/ONAF2

OIL QUANTITY		
MAIN	9,032	GALLONS
LTC	268	GALLONS
CONSERVATOR	433	GALLONS

WEIGHT		
TOTAL	284,172	lbs
TRANSPORTATION	177,000	lbs
UNTANKING	102,954	lbs
INSULATING OIL	73,192	lbs

TEMPERATURE RISE ONAN/ONAF1/ONAF2	
OIL	65°C/65°C/65°C
WINDING	65°C/65°C/65°C



VECTOR GROUP
Dy1

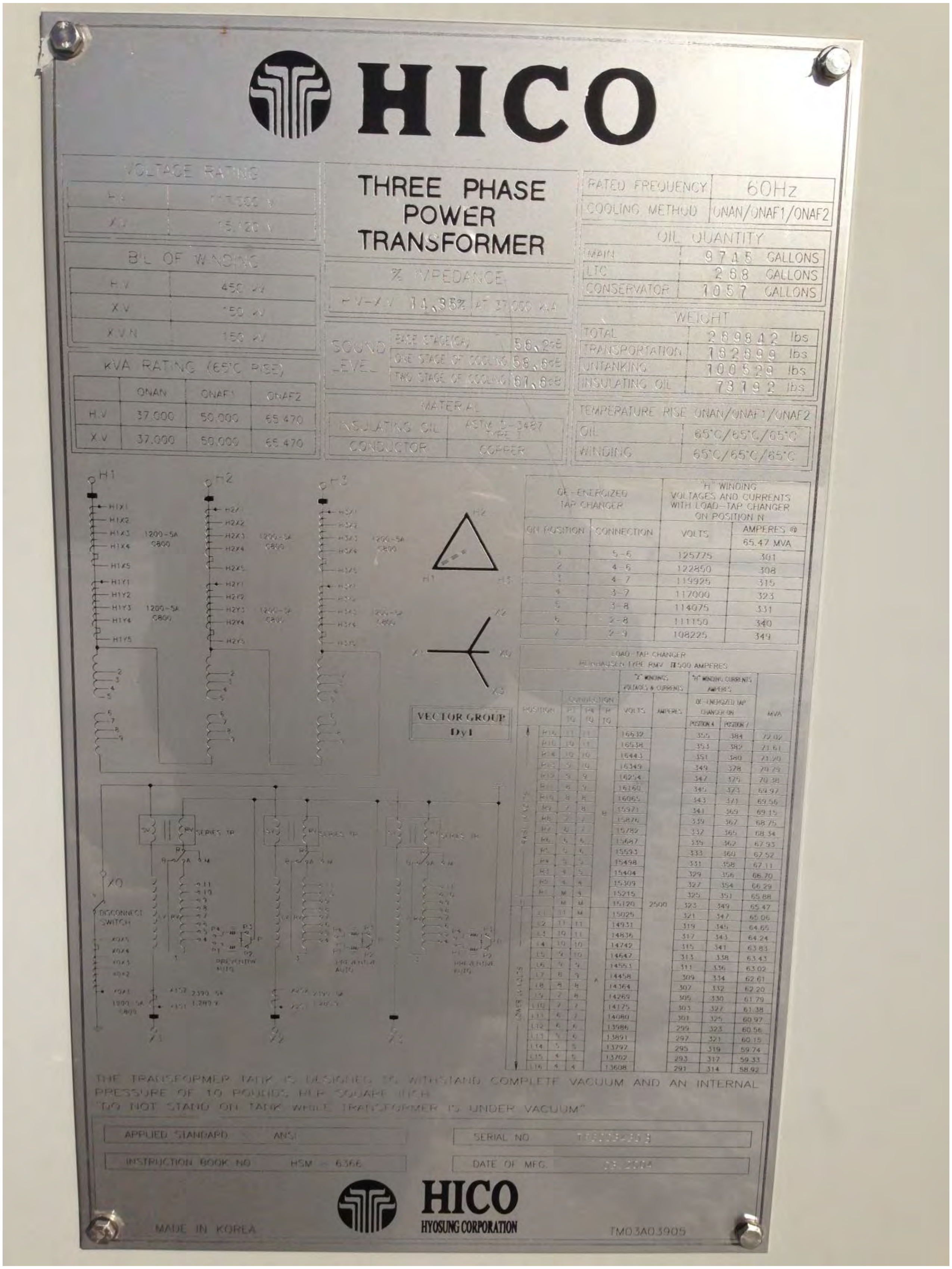
DE-ENERGIZED TAP CHANGER		"H" WINDING VOLTAGES AND CURRENTS WITH LOAD-TAP CHANGER ON POSITION N	
ON POSITION	CONNECTION	VOLTS	AMPERES @ 65.47 MVA
1	5–6	125775	301
2	4–6	122850	308
3	4–7	119925	315
4	3–7	117000	323
5	3–8	114075	331
6	2–8	111150	340
7	2–9	108225	349

LOAD-TAP CHANGER
REINHAUSEN TYPE RMV II 500 AMPERES

POSITION		CONNECTION P1 TO	CONNECTION P4 TO	CONNECTION R TO	"X" WINDINGS VOLTAGES & CURRENTS VOLTS	"X" WINDINGS VOLTAGES & CURRENTS AMPERES	"H" WINDING CURRENTS AMPERES DE-ENERGIZED TAP CHANGER ON POSITION 4	"H" WINDING CURRENTS AMPERES DE-ENERGIZED TAP CHANGER ON POSITION 7	MVA
RAISE LV VOLTS	R16	11	11		16632		355	384	72.02
	R15	10	11		16538		353	382	71.61
	R14	10	10		16443		351	380	71.20
	R13	9	10		16349		349	378	70.79
	R12	9	9		16254		347	375	70.38
	R11	8	9		16160		345	373	69.97
	R10	8	8		16065		343	371	69.56
	R9	7	8	B	15971		341	369	69.15
	R8	7	7		15876		339	367	68.75
	R7	6	7		15782		337	365	68.34
	R6	6	6		15687		335	362	67.93
	R5	5	6		15593		333	360	67.52
	R4	5	5		15498		331	358	67.11
	R3	4	5		15404		329	356	66.70
	R2	4	4		15309		327	354	66.29
	R1	M	4		15215		325	351	65.88
N		M	M		15120	2500	323	349	65.47
LOWER LV VOLTS	L1	11	M		15025		321	347	65.06
	L2	11	11		14931		319	345	64.65
	L3	10	11		14836		317	343	64.24
	L4	10	10		14742		315	341	63.83
	L5	9	10		14647		313	338	63.43
	L6	9	9		14553		311	336	63.02
	L7	8	9	A	14458		309	334	62.61
	L8	8	8		14364		307	332	62.20
	L9	7	8		14269		305	330	61.79
	L10	7	7		14175		303	327	61.38
	L11	6	7		14080		301	325	60.97
	L12	6	6		13986		299	323	60.56
	L13	5	6		13891		297	321	60.15
	L14	5	5		13797		295	319	59.74
	L15	4	5		13702		293	317	59.33
	L16	4	4		13608		291	314	58.92

THE TRANSFORMER TANK IS DESIGNED TO WITHSTAND COMPLETE VACUUM AND AN INTERNAL PRESSURE OF 10 POUNDS PER SQUARE INCH.
"DO NOT STAND ON TANK WHILE TRANSFORMER IS UNDER VACUUM"
PCB IS NON-DETECTABLE IN INSULATING OIL.

Appendix C – Dover 110A Station Transformer Nameplate and Test Report



주식회사 효성 HYOSUNG CORPORATION

TEST REPORT 시험성적서

Customer or Project: NSTAR (MA주 Boston시 소재 Utility)

Product No. TP80034301

Number of Sheets /

No Load Loss & Excitation Current Measurement(무부하손 및 여자전류 측정)

Tested Winding	Tap No.	Rated MVA	Rated Voltage[kV]	Rated Current[A]	Ambient Temp.[℃]
XV	N	37	15.12	1412.83	15

Measured Value

Voltage			Current		No Load Loss[W]		
[%]	RMS[V]	Avg.[V]	[A]	[%]	Pm	P	Pr
96.94	14657	14658	1.092	0.077	23528	23533	23456
103.56	15658	15661	1.233	0.087	27864	27870	27779
110.54	16714	16719	1.363	0.096	32783	32790	32683

Corrected Value

Voltage[%]	Current		K	No Load Loss[W]		
	[A]	[%]		Pm	P	Pr
100	1.157	0.082	0.9996	25539	25544	25461
110	1.354	0.096		32372	32378	32273

Remark

Pm	: Measured Loss	K	: (RMS Voltage / Average Voltage)^2
P	: (Measured Loss/(0.5+0.5*K))	Tm	: Measured Temp.(Ambient Temp.)
Pr	: P * (1+(Tm-Tr) * 0.00065)	Tr	: Reference Temp. : 20.0 ℃

Test Date	2004-03-26
Tested By	H.J.KIM
Used Instruments	Loss Measurement System

Acceptance Criteria
- No Load Loss : Below 26000W (at 100 %)

Result Good

주식회사 효성 HYOSUNG CORPORATION	TEST REPORT 시험성적서	Customer or Project NSTAR (MA주 Boston시 소재 Utiltiy)
	Product No. TP80034301	Number of Sheets /

Load Loss & Impedance Voltage Measurement(동손 및 임피던스 전압 측정)

[H-X]

2. At 85 [℃]

Tap Position HV	XV		%Imp.	X/R Ratio	No Load Loss [W]	I² R Loss [W]	The other Loss [W]	Load Loss [W]	Total Loss [W]	Base Power [MVA]
1	16R	-	19.67	49.91	25461	130422	66441	196863	222324	50
1	16R	-	24.59	49.87	25461	203784	104183	307967	333428	62.5
1	N	-	14.16	46.11	25461	78490	35095	113585	139046	37
1	N	-	19.14	46.00	25461	143335	64478	207813	233274	50
1	N	-	23.91	45.97	25461	223960	100857	324817	350278	62.5
1	16L	-	14.04	40.33	25461	88135	40718	128853	154314	37
1	16L	-	18.96	40.16	25461	160948	74809	235757	261218	50
1	16L	-	23.70	40.16	25461	251482	117380	368862	394323	62.5
4	16R	-	14.87	48.58	25461	74242	39016	113258	138719	37
4	16R	-	20.08	48.49	25461	135577	71630	207207	232668	50
4	16R	-	25.10	48.45	25461	211839	112136	323975	349436	62.5
4	N	-	14.38	44.65	25461	81313	37779	119092	144553	37
4	N	-	19.43	44.66	25461	148489	68860	217349	242810	50
4	N	-	24.28	44.62	25461	232015	108069	340084	365545	62.5
4	16L	-	14.12	38.89	25461	90958	43487	134445	159906	37
4	16L	-	19.07	38.75	25461	166103	79698	245801	271262	50
4	16L	-	23.85	38.77	25461	259536	124773	384309	409770	62.5
7	16R	-	15.61	45.90	25461	77505	48145	125650	151111	37
7	16R	-	18.26	45.87	25461	106195	66346	172541	198002	43.31
7	16R	-	21.09	45.84	25461	141536	88577	230113	255574	50
7	16R	-	26.35	45.74	25461	221150	138895	360045	385506	62.5
7	16R	-	30.37	45.59	25461	293651	185668	479319	504780	72.02
7	N	-	15.02	42.78	25461	84576	45332	129908	155369	37
7	N	-	20.31	42.84	25461	154448	82598	237046	262507	50
7	N	-	25.36	42.61	25461	241326	130274	371600	397061	62.5
7	N	-	26.56	42.69	25461	264806	142543	407349	432810	65.47
7	16L	-	14.64	37.91	25461	94221	48723	142944	168405	37
7	16L	-	19.79	37.83	25461	172062	89330	261392	286853	50
7	16L	-	23.32	37.78	25461	238930	124788	363718	389179	58.92
7	16L	-	24.74	37.70	25461	268847	140931	409778	435239	62.5

Test Date	2004-03-26	Acceptance Criteria 393000W (85℃ Tap 4 - N 62.5MVA) 15% (85℃ Tap 4 - N 37MVA)
Tested By	H.J.KIM	
Used Instruments	Loss Measurement System	Result Good

주식회사 효성 HYOSUNG CORPORATION	TEST REPORT 시험성적서	Customer or Project NSTAR (MA주 Boston시 소재 Utiltiy)
	Product No. TP80034301	Number of Sheets /

Temperature Rise Test(온도 상승 시험) [H-X, 43.310 MVA 7-16R]

2. Measured Hot Resistance [m-ohm/sec.]

Time	222	252	282	312	342	372	402	432	462	492	522	552			
HV	675.336	674.505	673.688	673.398	672.289	671.202	670.656	669.526	668.985	668.329	667.894	667.186			
XV	6.104	6.099	6.078	6.056	6.036	6.015	6.019	5.998	5.992	5.988	5.988	5.983			

3. Calculation Temperature Rise

-. Calculated total loss current for oil rise [I_T] ------------------ 247.50 [A]
-. Rated current for winding rise [I_R] ------------------ 231.05 [A]
-. Supplied total loss current for oil rise [I_{ST}] ------------------ 243.77 [A]
-. Supplied current for winding rise [I_{SR}] ------------------ 230.54 [A]
-. Cold resistance of HV (at 13.00℃) [R_{HV_COLD}] ------------------ 581.737 [m-ohm]
-. Cold resistance of XV (at 13.00℃) [R_{XV_COLD}] ------------------ 5.278 [m-ohm]
-. Hot resistance of HV [R'_{HV_HOT}] ------------------ 681.078 [m-ohm]
-. Hot resistance of XV [R'_{XV_HOT}] ------------------ 6.174 [m-ohm]

(Temperature When The Oil Saturated)
-. Ambient Temperature [T_{AMB}] ------------------ 13.00 [℃]
-. Top Oil Temperature [T_{TOP}] ------------------ 47.00 [℃]
-. Radiator Top Temperature [T_{R_TOP}] ------------------ 43.00 [℃]
-. Radiator Bottom Temperature [T_{R_BOTTOM}] ------------------ 28.00 [℃]

(Temperature Before shut down)
-. Ambient Temperature [T'_{AMB}] ------------------ 13.00 [℃]
-. Top Oil Temperature [T'_{TOP}] ------------------ 47.00 [℃]
-. Radiator Top Temperature [T'_{R_TOP}] ------------------ 43.00 [℃]
-. Radiator Bottom Temperature [T'_{R_BOTTOM}] ------------------ 28.00 [℃]

	HV	XV	
Average Oil Temperature when the Oil saturated	39.50	39.50	
Average Oil Temperature before shut down	39.50	39.50	
Top Oil Temperature Rise	34.84	34.84	
Average Oil Temperature Rise	27.15	27.15	
Average Winding Temperature	55.26	55.02	
Winding Temperature Gradient	15.82	15.57	
Winding Temperature Rise	42.97	42.72	

Test Date	2004-03-26	Acceptance Criteria 65/80℃/65℃ (Winding/Winding Hot Spot/Top Oil)
Tested By	S.K.KIM	
Used Instruments	Digital Power Meter 133964-0004	Result Good

주식회사 효성 HYOSUNG CORPORATION	TEST REPORT 시험성적서	Customer or Project NSTAR (MA주 Boston시 소재 Utiltiy)
	Product No. TP80034301	Number of Sheets /

Temperature Rise Test(온도 상승 시험) [H-X, 72.020 MVA 7-16R]

2. Measured Hot Resistance [m-ohm/sec.]

Time	202	232	262	292	322	352	382	412	442	472	502	532			
HV	722.724	720.799	719.552	717.705	715.466	713.982	712.434	710.867	709.567	708.363	707.310	705.938			
XV	6.552	6.527	6.492	6.463	6.433	6.410	6.399	6.380	6.374	6.361	6.356	6.339			

3. Calculation Temperature Rise

-. Calculated total loss current for oil rise [I_T] ---------------- 394.28 [A]
-. Rated current for winding rise [I_R] ---------------- 384.21 [A]
-. Supplied total loss current for oil rise [I_{ST}] ---------------- 396.75 [A]
-. Supplied current for winding rise [I_{SR}] ---------------- 385.42 [A]
-. Cold resistance of HV (at 13.00℃) [R_{HV_COLD}] ---------------- 581.737 [m-ohm]
-. Cold resistance of XV (at 13.00℃) [R_{XV_COLD}] ---------------- 5.278 [m-ohm]
-. Hot resistance of HV [R'_{HV_HOT}] ---------------- 732.803 [m-ohm]
-. Hot resistance of XV [R'_{XV_HOT}] ---------------- 6.659 [m-ohm]

(Temperature When The Oil Saturated)
-. Ambient Temperature [T_{AMB}] ---------------- 20.00 [℃]
-. Top Oil Temperature [T_{TOP}] ---------------- 69.00 [℃]
-. Radiator Top Temperature [T_{R_TOP}] ---------------- 65.00 [℃]
-. Radiator Bottom Temperature [T_{R_BOTTOM}] ---------------- 37.00 [℃]

(Temperature Before shut down)
-. Ambient Temperature [T'_{AMB}] ---------------- 21.00 [℃]
-. Top Oil Temperature [T'_{TOP}] ---------------- 69.00 [℃]
-. Radiator Top Temperature [T'_{R_TOP}] ---------------- 65.00 [℃]
-. Radiator Bottom Temperature [T'_{R_BOTTOM}] ---------------- 37.00 [℃]

	HV	XV	
Average Oil Temperature when the Oil saturated	55.00	55.00	
Average Oil Temperature before shut down	55.00	55.00	
Top Oil Temperature Rise	48.51	48.51	
Average Oil Temperature Rise	34.65	34.65	
Average Winding Temperature	77.27	77.76	
Winding Temperature Gradient	22.16	22.65	
Winding Temperature Rise	56.81	57.30	

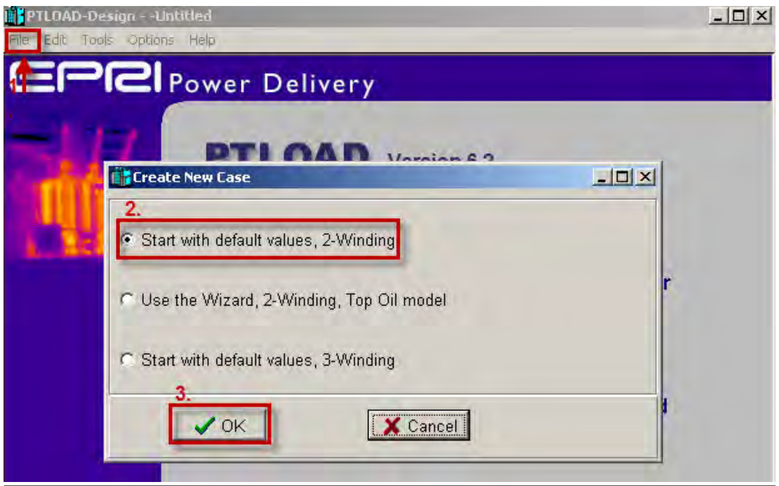
Test Date	2004-03-27	Acceptance Criteria 65/80℃/65℃ (Winding/Winding Hot Spot/Top Oil)
Tested By	H.J.KIM	
Used Instruments	Digital Power Meter 133964-0004	Result Good

Appendix D – PTLOAD Application Guideline

Example: Dover 110A Distribution Transformer Rating Calculations

Transformer 110A at station #456 Dover is employed to illustrate how to use PTLOAD to calculate transformer ratings. The following is the step by step modeling procedure:

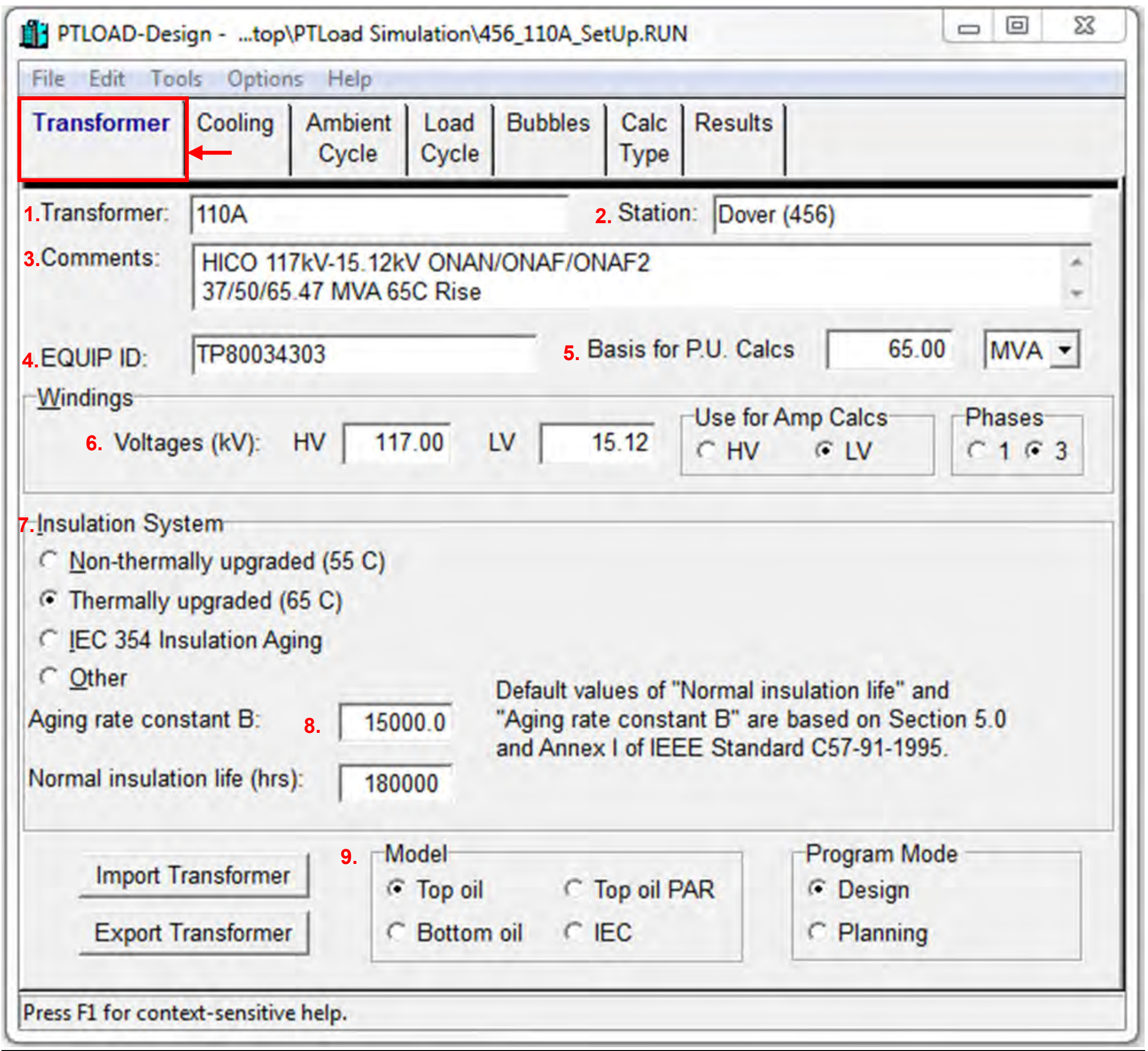
Step1: Open PTLOAD and create new case, choose transformer winding type:



Step2: Input transformer nameplate information in "Transformer" Tab:

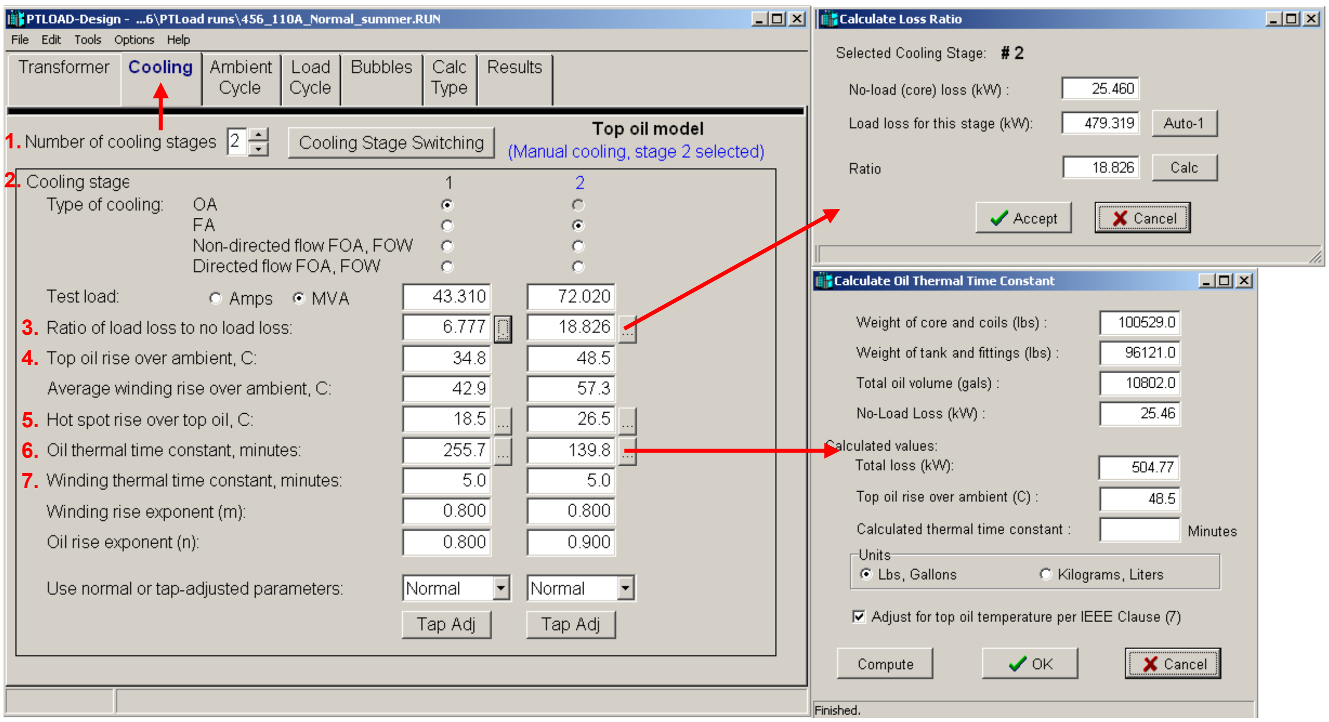
Input transformer nameplate info to the # blank box:

1. Transformer name
2. Station Name (Number)
3. Comments: Serial number, transformer manufacturer, winding information, capacity etc
4. Equipment ID which is the Serial number for the transformer
5. Top nameplate capacity
6. Windings: High side and low side voltage in kV, phase info
7. Insulation system: Choose either (55C) or (65C)
8. Set Aging rate constant B (15000) and Normal insulation life (hrs) (180000) as default
9. Choose "Top oil" Model and "Design" Program Mode



Step3: Input transformer information in "Cooling" Tab:

A temperature rise test report is needed for this step. For help interpreting the temperature rise data and terms, reference the following link: \\mwwd-vf03\Vol1\shared\SystemsPlanning\SysPlan1\Transformer Rating\Ratings\References\



1. Number of Cooling Stages: A transformer can have three cooling stages. If the test report data is available for all three levels of cooling, the user is requested to input the data. If not, input the data for the number of different MVA ratings at which the temperature rise was performed at. If the test report has the temperature rise test data only for two stages or only one stage, which can typically be stage 3 or the top nameplate rating, use Manual cooling and constrain to stage 1 or 2 as shown above.

2. Cooling stage: specified cooling type at each stage, see Appendix A: Transformer Cooling Codes
Test load: choose MVA, and input rating at which the temperature rise test was run at.

3. Click the ellipsis button on right, and input load loss and no load loss for every stage, click the "calc" button for the ratio to populate. No load loss for each stage is the same; At least one set of load loss data at specified load (MVA) is provided by the test report. If the load loss data is not specified for each temperature rise run, apply the following formula to calculate the load loss at each stage (MVA):

Load Loss $_{\text{new stage}}$ =(Loading $_{\text{new stage}}$/Loading $_{\text{old stage}}$)^2 * Load Loss $_{\text{old stage}}$

4. Input Top oil rise over ambient and Average winding rise over ambient degree

5. Input the Hot spot rise over top oil if provided by the temperature rise data. If the Hot spot rise over top oil is not provided use the following equation:
Hotspot Rise Over Top Oil = Winding Temperature Gradient * HV Hotspot factor
If none of the above information is provided, click the ellipsis button on right; choose “IEEE Std C57.91-1995” and “Accept”.

6. Click the ellipsis button on right, input “weight of core and coils (lbs)”, “Weight of tank and fitting (lbs)”, “Total oil volume (gals)” and check “Adjust for top oil temperature per IEEE Clause(7)” and click “Compute”

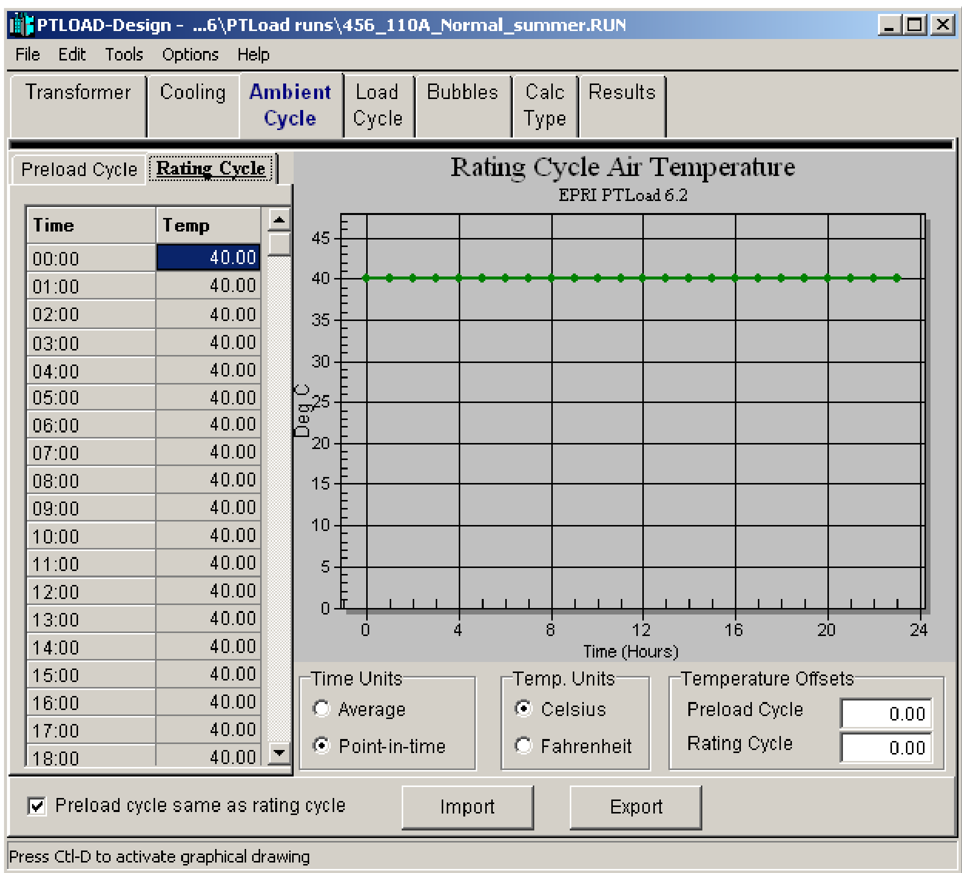
7. Winding thermal time constant: If values determined by test are available, they should be used, otherwise set as default 5.0. Winding rise exponent and oil rise exponent: The example transformer cooling type is OA/FA/FA at 24/32/40 MVA. Based on the mathematical relationship given in Equation 11 of IEEE Std C57.91-2004, the typical value of winding rise exponent and oil rise exponent for different types of cooling are:

Cooling Type	OA	FA	FOA/FOW Non-directed	FOA/FOW Directed
Winding rise exponent	0.8	0.8	0.8	1.0
Oil rise exponent	0.8	0.9	0.9	1.0

Step4: Input ambient temperature at "Ambient Cycle" Tab:

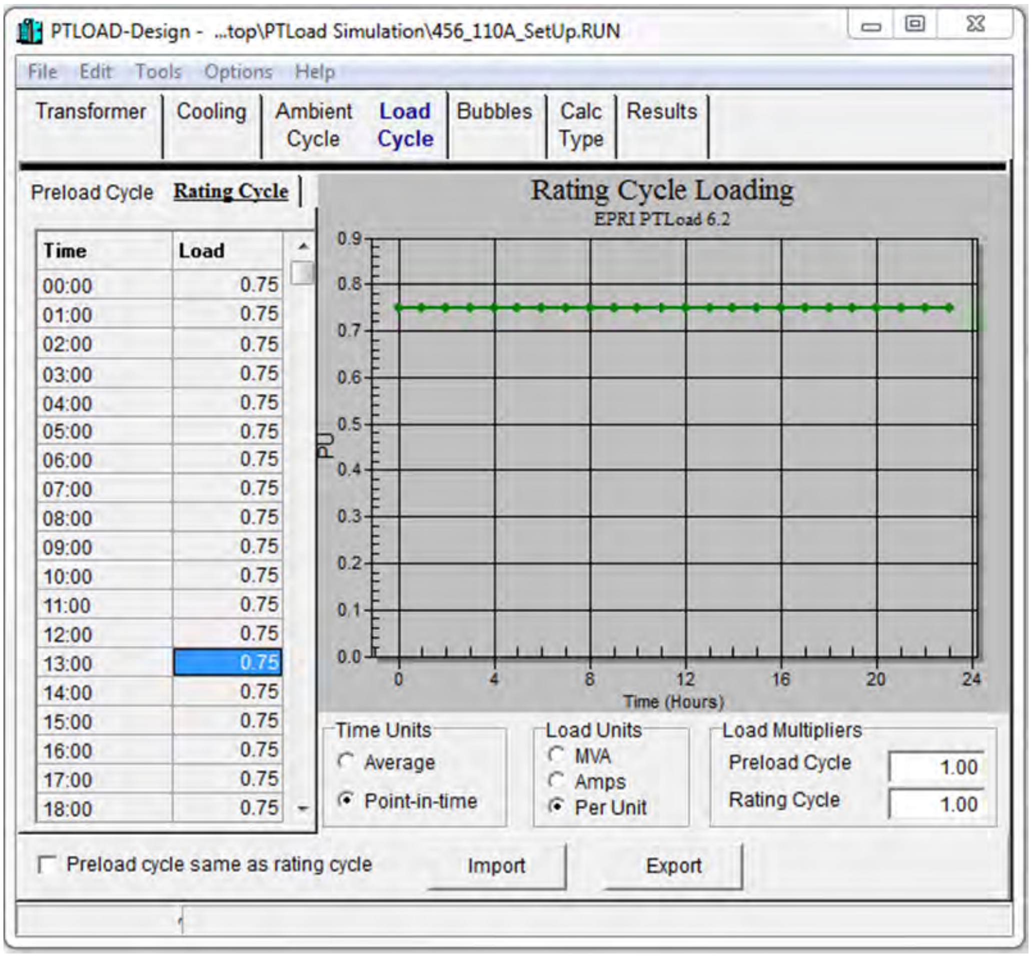
Ambient Cycle: For summer conditions, an ambient temperature of 40 degrees C is used for emergency rating calculations. For winter conditions, emergency rating calculations use an ambient temperature of 10 degrees C. Check "Preload cycle same as rating cycle".

Temperature Assumption (degree C)			
	Normal	LTE	STE/DAL
Summer	Nameplate	40	40
Winter	Nameplate	10	10



Step5: Input load profile at "Load Cycle" Tab:

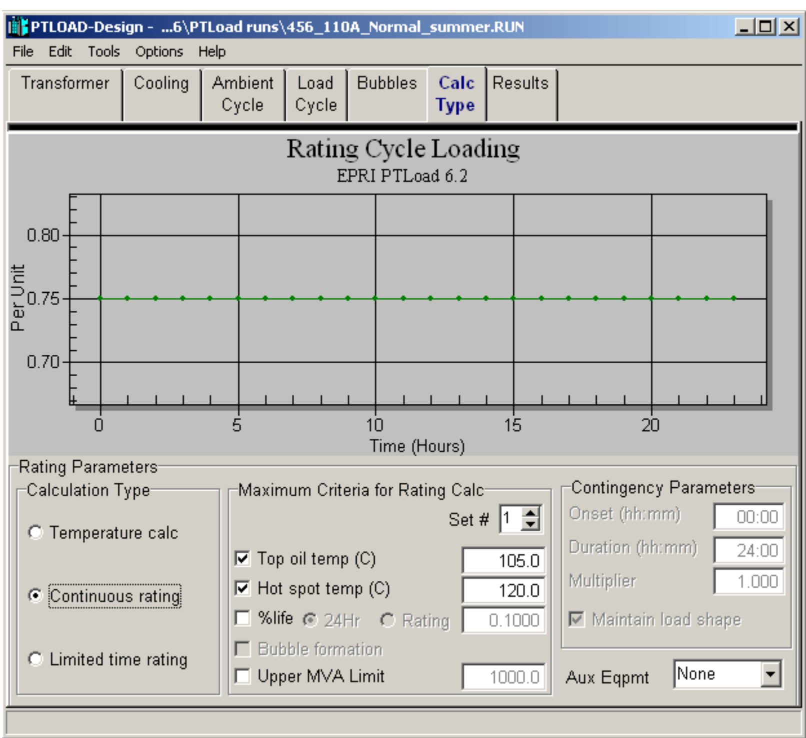
Load Cycle: Constant load model is used. Input the Preload and Rating Cycle Load as 75% for the complete 48-hour load cycle (in per unit or MVA). It is recommended to leave the "Preload cycle same as rating cycle" box unchecked, and manually input 75% preload.



Step6: Input the criteria for rating calculation at "Calc Type" Tab:

The rating calculations can be continuous (Normal) or limited time ratings (LTE and STE ratings). The following table specifies the maximum top oil temperature, Hot spot temperature and the time duration for the specific rating to be calculated at the "Calc Type" Tab. It is recommended to first run a temperature calculation to determine that the numbers from the heat run are accurate.

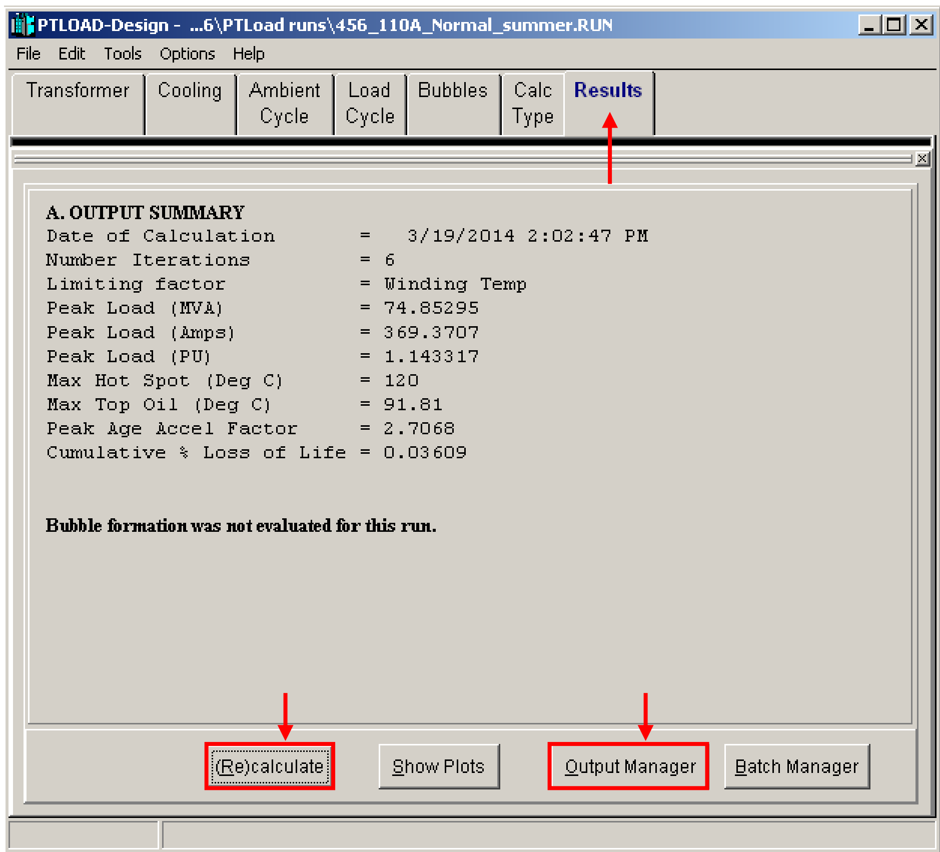
Calc Type Parameter Setting							
			Calculation Type		Maximum Criteria for Rating Calc		
Temperature Rise	Contingency		Continuous Rating	Limited Time Rating	Top Oil Temp C	Hot Spot Temp C	Duration (hour)
65 C	Summer	Normal	V		Nameplate	Nameplate	24
		LTE		V	110	140	12
		STE		V	110	140	0.5
	Winter	Normal	V		Nameplate	Nameplate	24
		LTE		V	110	140	4
		STE		V	110	140	0.5
55 C	Summer	Normal	V		Nameplate	Nameplate	24
		LTE		V	100	140	12
		STE		V	100	140	0.5
	Winter	Normal	V		Nameplate	Nameplate	24
		LTE		V	100	140	4
		STE		V	100	140	0.5



Step7: Station Transformer Rating output at "Results" Tab:

Go to “Results” tab and click on calculations to get the station transformers PTLOAD ratings. Click “Output Manager” and save PTLOAD output file. For detailed output, please refer to Appendix C. Document a PTLOAD output for every case, and save using the following format:
Station#_transformer#_Season_SystemLoading_PTLoadResultsInMVA.RUN

There should be a total of 4 PT Load simulation runs, as well as temperature calculation runs for every heat run you used in the simulations. These act as a good “check” that all of the information was inputted correctly.



<u>Appendix E</u> – Example Calculation Documentation Package

Bulk Distribution Transformer Ratings Calculation Cover Sheet

Transformer Information
Substation: Dover (456)
Designation: 110A
Manufacturer: HICO
Serial Number: TP80034303
Nameplate Rating: 37/50/65.47

Ratings Summary

Season	Summer		Winter	
Rating	**PT Load Actual**	***Adjusted Rating**	**PT Load Actual**	***Adjusted Rating**
Normal	-	**65**	-	**65**
LTE	85.49	**85**	102.3273	**97**
STE	115.4255	**97**	139.35	**97**
DAL	**-**	**97**	**-**	**97**

*Normal ratings are determined using the top nameplate rating. All emergency ratings are limited to 1.5 times the top nameplate rating. Drastic Action Limits are set equal to the Short Time Emergency limits. LTC de-rates are applied where applicable. Per ISO-NE PP-07, all ratings are rounded down to the nearest whole number.

Signatures:

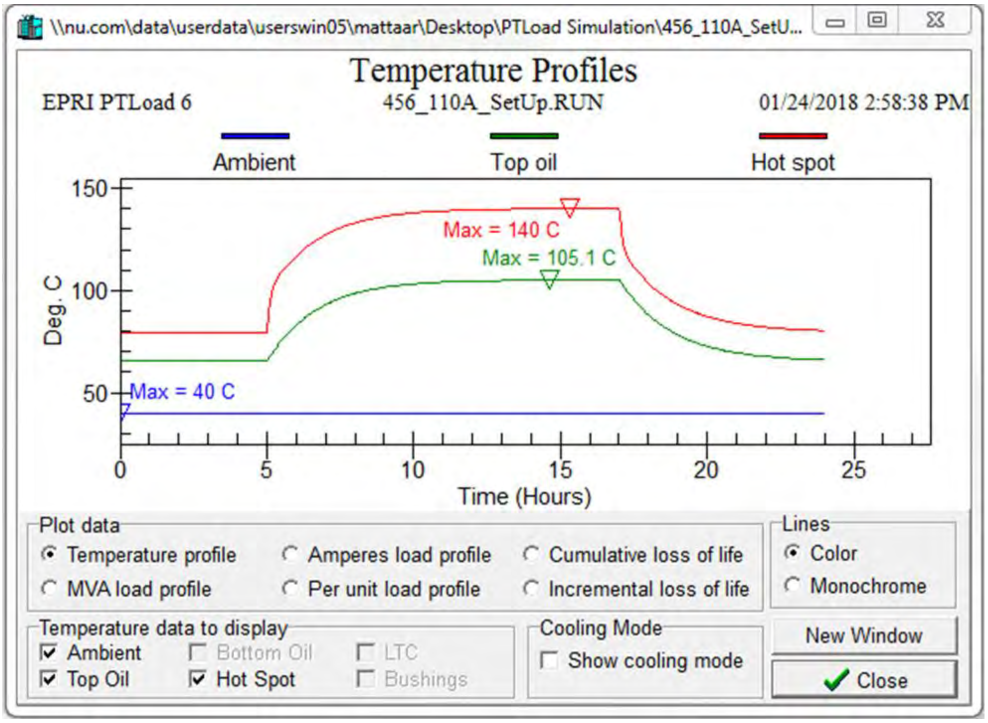
Prepared By:

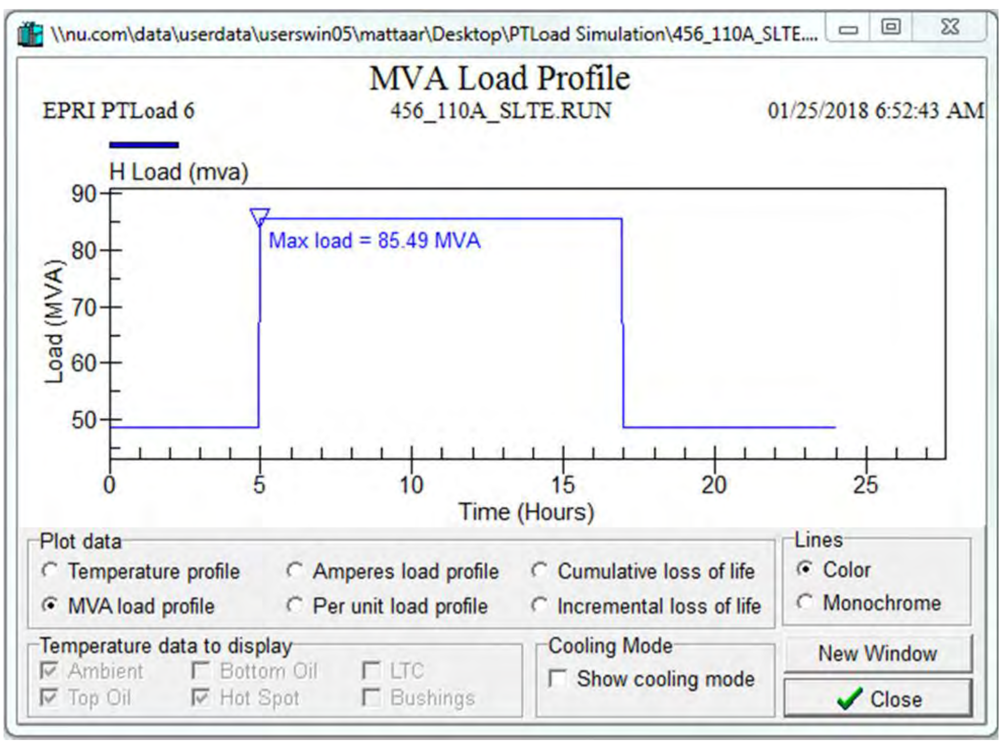
Reviewed By:

:

Dover (456) 110A Summer LTE Rating Outputs

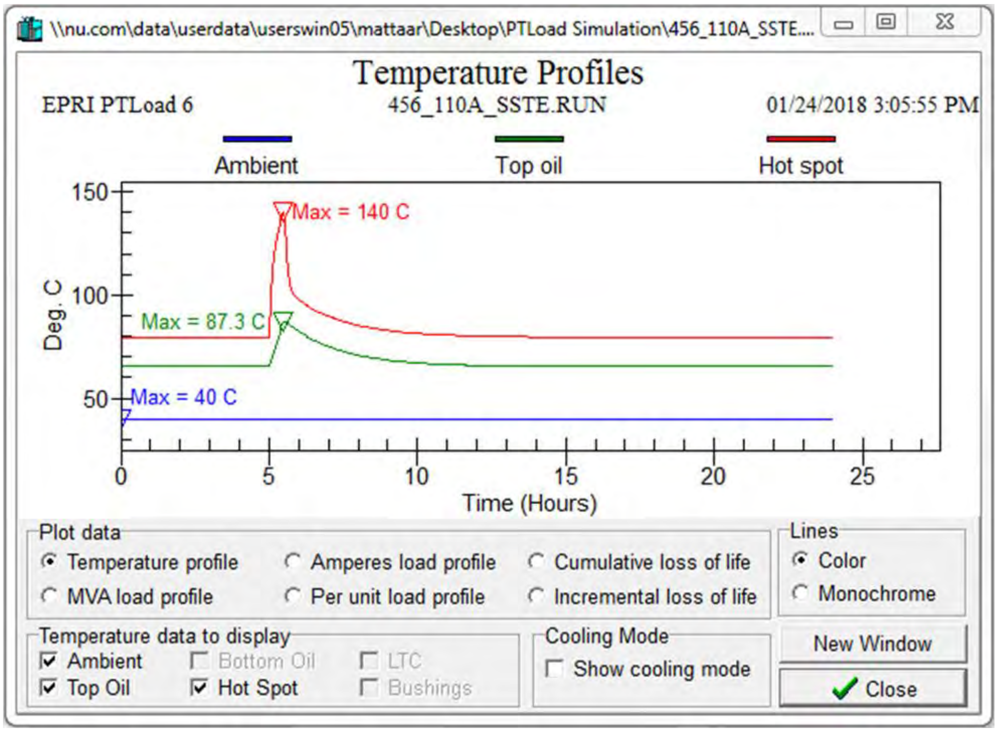
Summer LTE Rating:

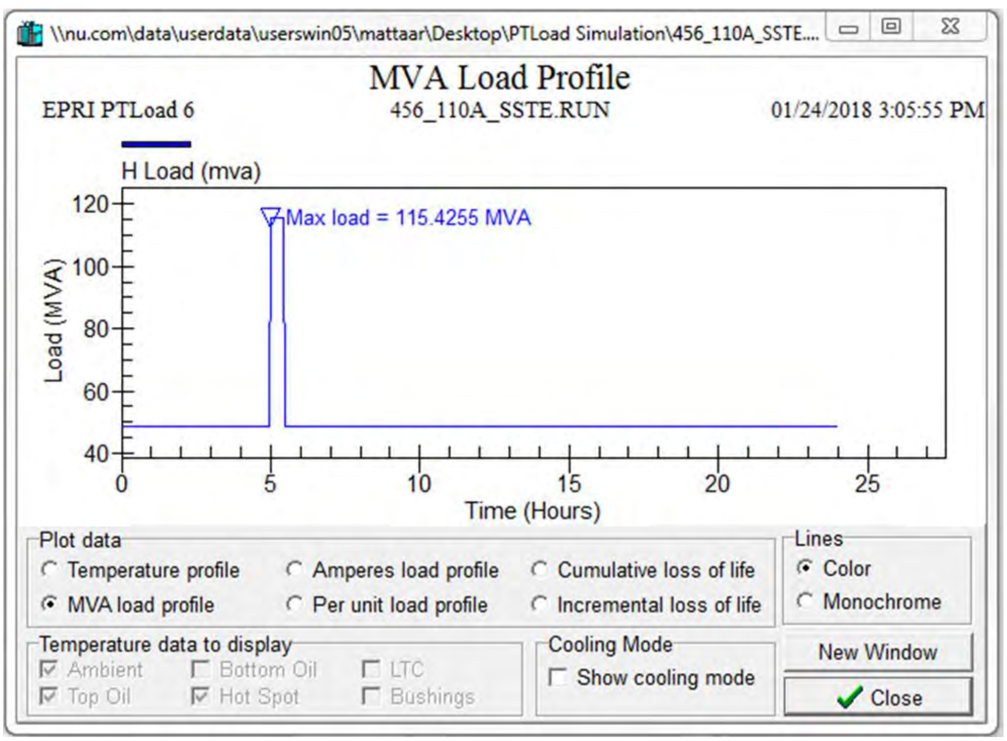




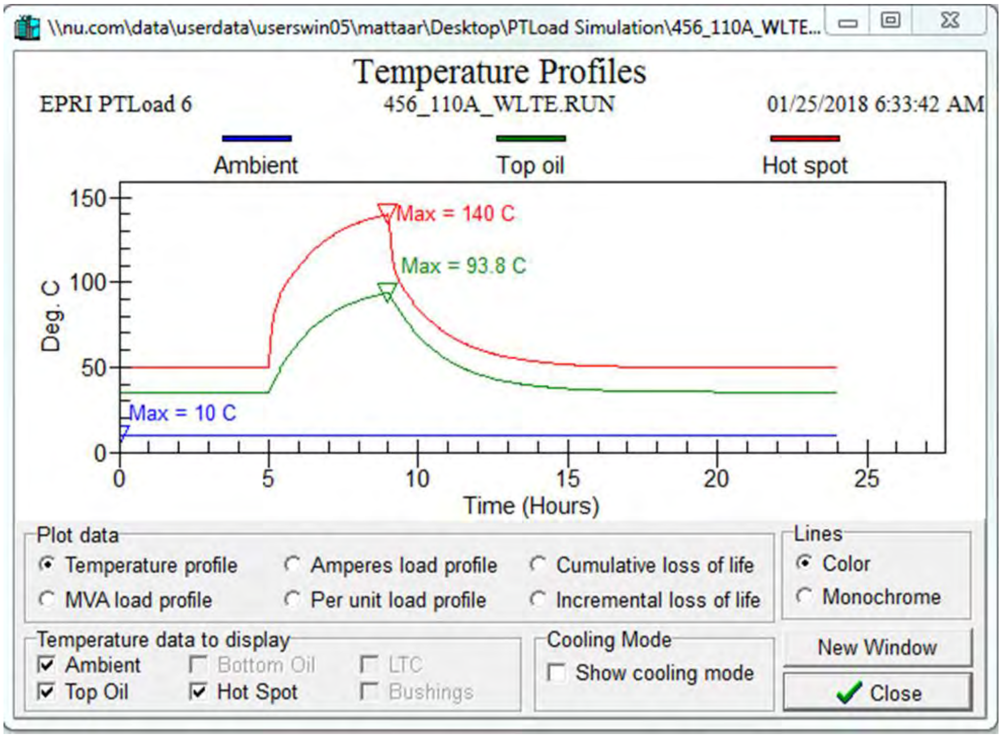
Dover (456) 110A Summer STE & DAL Rating Outputs

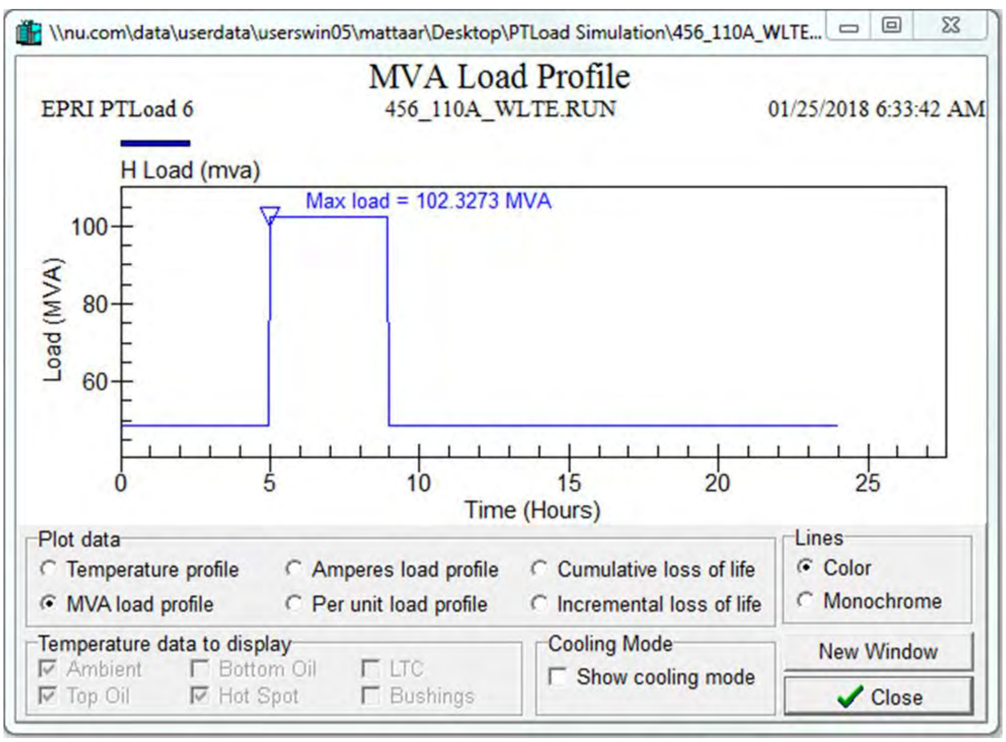
Summer STE Rating:



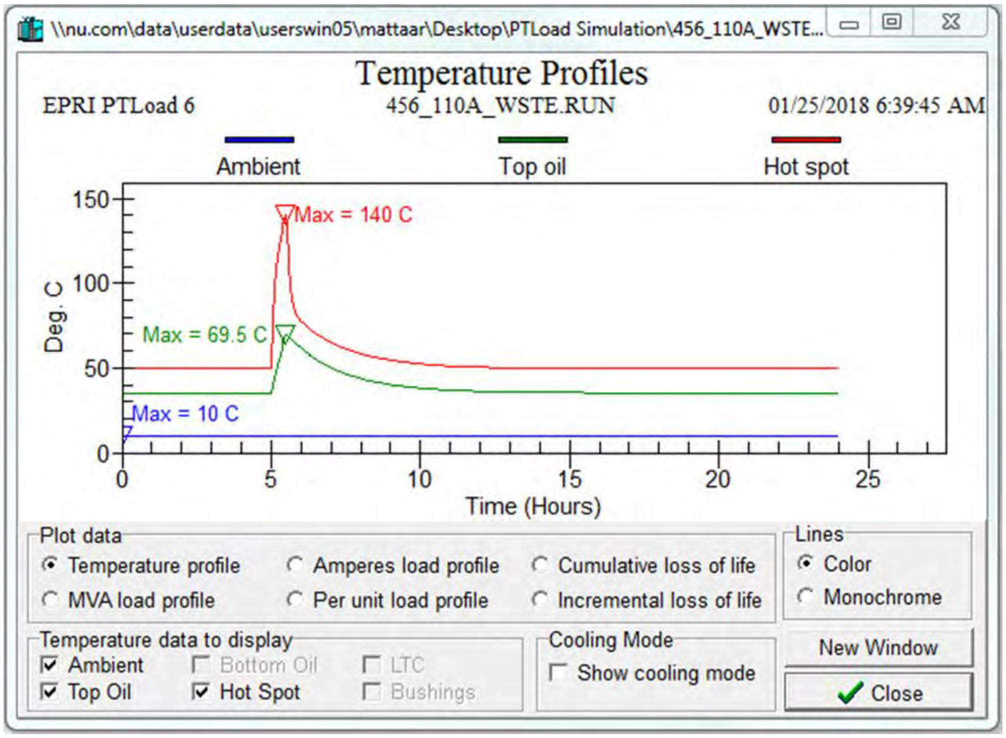


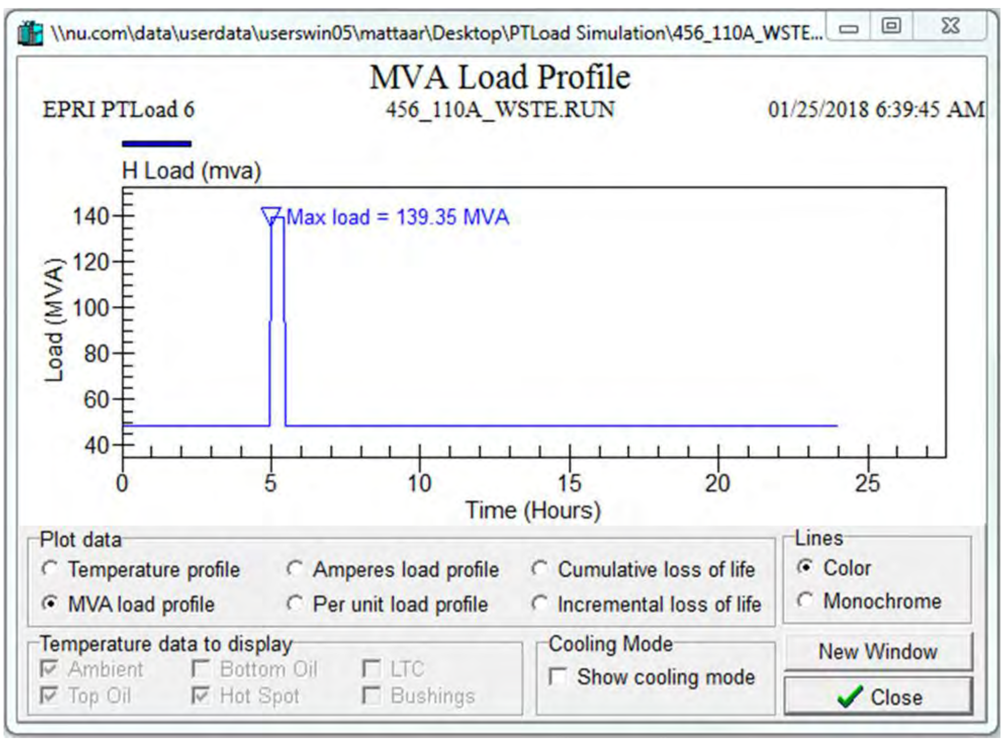
Dover (456) 110A Winter LTE Rating Outputs
<u>Winter LTE Rating</u>:





Dover (456) 110A Winter STE & DAL Rating Outputs
Winter STE Rating:





SCOPE – This DSEM lists the formulas used to evaluate the cost effectiveness of reliability projects. These formulas provide measurements for the Distribution Operating Company Review Committee (OCRC) to use to evaluate project alternatives

QUANTIFIED CRITERIA

Cost per Customer–Minute Saved or "$/CMS"

The cost effectiveness of projects that reduce or eliminate outage duration is based on the cost of the project divided by the product of the outage time avoided and the number of customers benefited. These projects reduce the System Average Interruption Duration Index (SAIDI).
See **DSEM Section 02.11 – Reliability Indices**.

The measurement is called "Cost per Customer–Minute Saved" or "$/CMS." *Customer–minutes saved* is the sum of the product of customers that would have benefited and outage duration avoided for them in minutes per outage for all outages that would have been avoided if the project were to have been in place when the outage occurred.

Data for determining $/CMS is found by examining the past four years of experience from the time the project is proposed. Benefits are then considered on a four–year average. Other time periods needed to capture unusual circumstances or events might be allowed if the reasoning for choosing them is explained and accepted by the OCRC. However, to compare projects on an equal basis, the same time period must be used for data collection and averaging.

$$\frac{\$}{CMS} = \frac{(Project\ Cost)}{\left[\frac{[\Sigma(\#\,of\ Customers\ Benefitted)(Outage\ Duration\ Avoided)]}{(Years\ of\ Data)}\right]}$$

$$\frac{\$}{CMS} = \frac{[(Project\ Cost)(Years\ of\ Data)]}{[\Sigma[(\#\,of\ Customers\ Benefitted)(Outage\ Duration\ Avoided)]]}$$

At one time, the reliability budget was set at a fixed amount and $/CMS was calculated for all proposed projects. The lowest $/CMS projects were then selected until the budget was filled. Since then, the $/CMS has evolved into guidelines as follows:

- Guideline to consider projects based on all outages including major storms = $1.25/CMS or less
- Guideline to consider projects NOT including major storm outages avoided = $4.00/CMS or less
- Guideline to consider projects NOT including major storm outages avoided for very large areas such as entire towns or entire substations = $8.00/CMS or less

These guidelines are subject to change at any time due to the availability of capital funds and financial constraints on the Company.

Cost per Customer Interruption Saved or "$/CIS"

The Cost per Customer Interruptions Saved ($/CIS) is a measure to compare the cost effectiveness of projects to reduce SAIFI. See **DSEM Section 02.11 – Reliability Indices.** This measurement does not take into account outage duration; it only addresses outage occurrence. (An outage is a continuous loss of service for five minutes or more in CT or NH by IEEE Standard; but only one minute in MA by Commonwealth of Massachusetts DPU definition).

This guideline is usually applied only to parts of the system that have experienced five or more interruptions per year.

Data for determining $/CIS is found by examining the past four years of experience from the time the project is proposed. Benefits are then considered on a four–year average. Other time periods needed to capture unusual circumstances or events might be allowed if the reasoning for choosing them is explained and accepted by the OCRC. However, to compare projects on an equal basis, the same time period must be used for data collection and averaging.

$$\frac{\$}{CIS} = \frac{(Project\ Cost)}{\left[\frac{[\Sigma(\#\,of\ Customers\ Benefitted)(Outages\ Avoided)]}{(Years\ of\ Data)}\right]}$$

$$\frac{\$}{CIS} = \frac{[(Project\ Cost)(Years\ of\ Data)]}{[\Sigma[(\#\,of\ Customers\ Benefitted)(Outages\ Avoided)]]}$$

The $/CIS has evolved into guidelines as follows:

- Guideline to consider projects, high priority = $800/CIS or less
- Guideline to consider projects, medium priority = $800/CIS to $1200/CIS
- Guideline to consider projects, low priority = $1200/CIS or more

These guidelines are subject to change at any time due to the availability of capital funds and financial constraints on the Company.

Cost per Interruption Avoided or “$/IA”

This measurement takes only into account the number of interruptions avoided, and not the duration of the outage or the number of customers affected. This measurement addresses the need to dispatch line crews to restore service. Whether the interruption affects one customer or 1000, a line crew must respond, and the fixed cost to respond can be the same for both. Reducing interruptions reduces call outs and the fixed cost to respond.

Data for determining $/IA is found by examining the past four years of experience from the time the project is proposed. Benefits are then considered on a four–year average. Other time periods needed to capture unusual circumstances or events might be allowed if the reasoning for choosing them is explained and accepted by the OCRC. However, to compare projects on an equal basis, the same time period must be used for data collection and averaging.

$$\frac{\$}{IA} = \frac{(Project\ Cost)}{\left[\frac{(Interruptions\ Avoided)}{(Years\ of\ Data)}\right]}$$

$$\frac{\$}{IA} = \frac{[(Project\ Cost)(Years\ of\ Data)]}{(Interruptions\ Avoided)}$$

At present, there are no acceptance guidelines for this measurement, but it is, nevertheless, a way to compare one project to another for this benefit.

EQUIVALENT RESIDENTIAL CUSTOMERS FOR C/I LOADS

Recognizing that commercial and industrial (C/I) customers consume more energy and have a higher demand per meter than residential customers, it is often desirable to consider a commercial or industrial customer as being equivalent to a certain number of residential customers. While SAIDI statistics, by which the performance of a utility is judged, are simply based on the number of customers without regard to load size, it is usually recognized that some consideration should be based on the size of the customer's load. If possible, a simple kVA total divided by kVA per home would be ideal.

The results of a March, 2000 survey of ten three–phase customers, all fed off separate transformers ranging in size from 75 kVA to 1,500 kVA, by Mark Santoro yielded the following results:

Equivalent Residential Customers for Commercial/Industrial (C/I) Load Based On Average kVA Demand

- Peak *diversified* demand for a residential customer: Derived from winter peaks for three typical feeders in 1999
  21K4 7.84 MVA, 1108 customers = 7.1 kVA per customer (Heavy electric heat)
  30L26 8.38 MVA, 2610 customers = 3.2 kVA per customer
  11S14 5.44 MVA, 1518 customers = 3.6 kVA per customer
  For a typical feeder without heavy electric heat load, the average is 3.5 kVA per house.
- Diversity factor for the connected three–phase kVA. PTI powerflow models typically recommend the following diversities: commercial customers, 40% diversity; machine shops, 50% diversity; and industrial customers, 75%–diversity. For practical purposes, assume 50% for diversity. Thus connected kVA represents twice the number of customers in actual load. Multiply equivalent customers found using connected kVA by 0.5.
- Distribution transformers are generally oversized by 30%. Therefore, actual peak demand = 0.70 x connected kVA.
- Since SAIDI is dependent on customer count, not load, and utility performance is primarily judged by SAIDI, divide final equivalent customer count by 2.
- Equivalent Residential Customer Formula:

$$Residential\ Equivalent = \frac{[(SAIDI\ Factor)(C/I\ Conn.\ kVA)(effect\ of\ oversized\ xfmrs)(diversity\ effect)]}{(peak\ diversified\ residential\ demand)}$$

$$Residential\ Equivalent = (1/2) \times \left[\frac{[(C/I\ Conn.\ kVA)(0.7)(0.5)]}{(3.5\ kVA/customer)}\right] = \frac{[(C/I\ Conn.\ kVA)\ customers]}{(20\ kVA)}$$

Residential Equivalent for C/I Load = Total Connected [C/I kVA/20 kVA] equivalent customers

This formula is designed to give a close approximation for converting commercial and industrial loads to a residential equivalent, without the tedious task of calculating yearly uses for all the customers involved. Other methods, based on actual loads or usage, may also be used for analysis.

Reliability Indices

GENERAL – Reliability generally addresses interruptions of service exceeding five minutes in length.

INDICES – The industry has adopted measures of reliability. Eversource Energy uses three of these:

1. **SAIDI** (System Average Interruption Duration Index) is expressed in *minutes*. It represents the average cumulative interruption time (in minutes) over a period of one year for a group of customers. SAIDI can be expressed on a system–wide basis, on a state bases, or on a region, district, zone, town basis. It can also be expressed on a circuit basis or even on a portion of a circuit basis. Mathematically, SAIDI is expressed as the following:

$$SAIDI = \frac{(\Sigma \text{ Customer interruption durations in customer } - \text{ minutes})}{(\text{Total number of customers served in the group})}$$

2. **CAIDI** (Customer Average Interruption Duration Index) is also expressed in *minutes*. It is the average time required (or experienced) to restore service to the average customer per sustained interruption (in our case, if the interruption lasted 5 minutes or more). CAIDI is our average restoration time. As with SAIDI, we can choose to calculate CAIDI for different groups of customers from the whole system to parts of a feeder.

$$CAIDI = \frac{(\Sigma \text{ Customer interruption durations in customer } - \text{ minutes})}{(\text{Total number of customers interrupted})}$$

3. **SAIFI** (System Average Interruption Frequency Index) is dimensionless. It is a number that represents the number of times the average customer experienced an interruption over one year. As with SAIDI and CAIDI, we can choose to calculate SAIFI for different groups of customers from the whole system to parts of a feeder.

$$SAIFI = \frac{(\text{Total number of customers interrupted})}{(\text{Total number of customers served in the group})}$$

$$\text{Note that } CAIDI = \frac{SAIDI}{SAIFI}$$

SPECIAL INDICES

1. **Contribution to System SAIDI**. This quantity is the portion of SAIDI attributable to the customer–minutes of outage time that occurred on a particular part of the system (usually a circuit or a portion of a circuit) divided by the total number of customers served by the entire company (usually per state).

2. **SAIDI Minutes** are the contribution to the SAIDI of a given unit (say a feeder or a district) contributed by a particular outage. It is the customer–minutes interrupted for the outage divided by the total number of customers in the given unit.

SCOPE – The following two graphs depict voltage limits that are allowable on Eversource Energy distribution circuits principally for residential or commercial services. These voltage limits should be used when analyzing customer voltage problems and designing distribution circuits. The graphs illustrate the appropriate allocations of the total voltage range between the primary and secondary systems.

Connecticut upper and lower voltage limits are those prescribed in Section 16−11−115, Voltage Variations, of the Regulations of Connecticut State Agencies. Voltage excursions above the upper limit shall not exceed one minute. American National Standards Institute (ANSI) C84.1−2016 shall be used to determine the lowest temporary voltage excursions permissible.

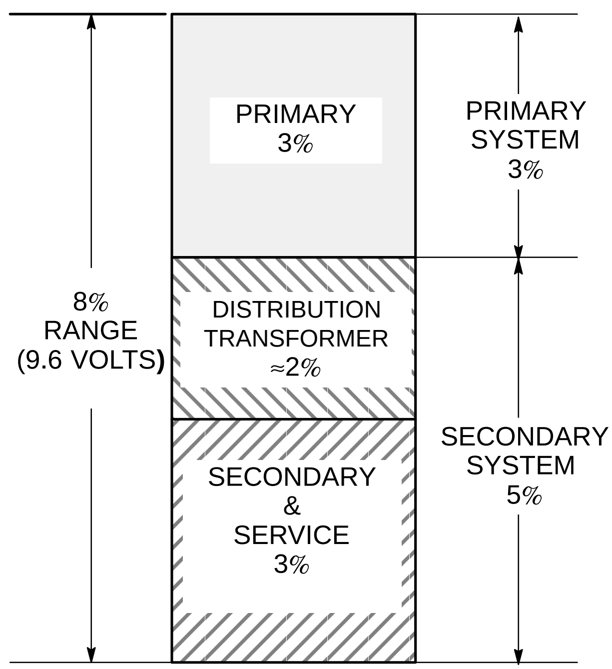
Massachusetts limits are based on voltage guidelines in ANSI C84.1−2016.

New Hampshire limits are based on New Hampshire Code of Administrative Rules, Rule 304, Quality of Electric Service. These limits are based on voltage guidelines in ANSI C84.1.

Refer to **DSEM 05.133** and Tables 3 and 4 for normal and contingency high and low voltage limits.

APPROXIMATE PERCENT
VOLTAGE DROP ALLOCATIONS FOR
CT DISTRIBUTION SYSTEMS

UPPER VOLTAGE LIMIT +3% (123.6 VOLTS)



LOWER VOLTAGE LIMIT − 5% (114.0 VOLTS)

Note

1. All voltages shown in parenthesis are on a 120 volt base.

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Data Request STAFF 2-008
Dated 5/19/21
Attachment STAFF 2-008e
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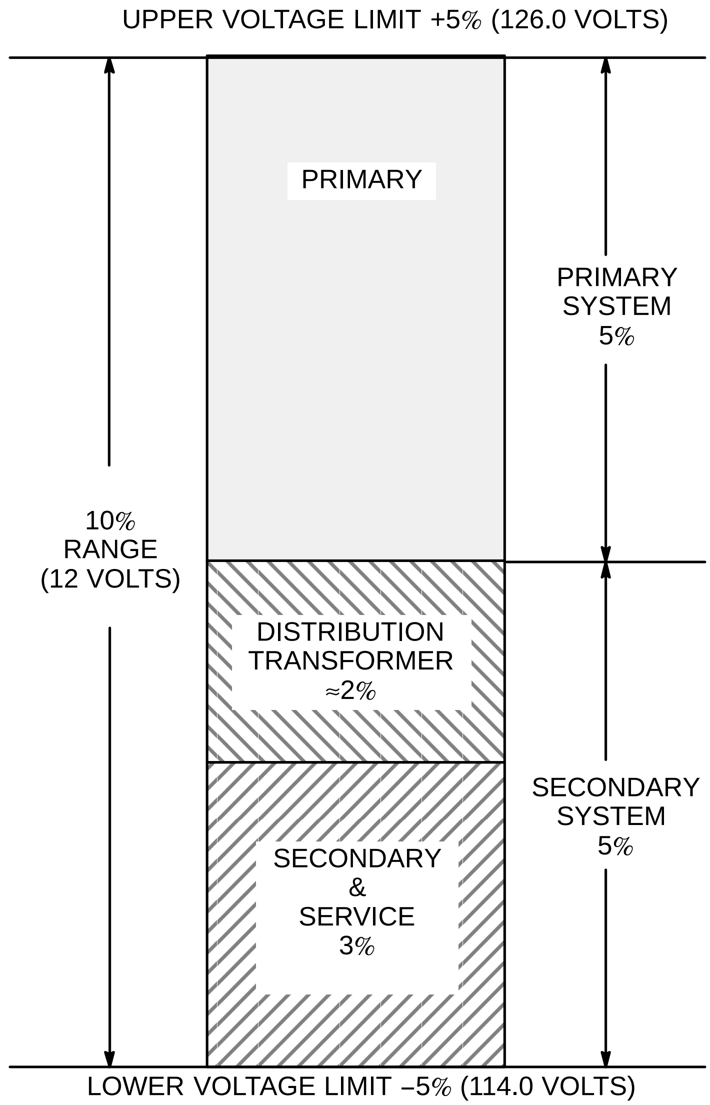
**APPROXIMATE PERCENT
VOLTAGE DROP ALLOCATIONS FOR
WMA & NH DISTRIBUTION SYSTEMS**



Notes

1. All voltages shown in parenthesis are on a 120 volt base.

CONTINGENCY VOLTAGE LIMITS – CT, MA, and NH state regulations allow for temporary voltage excursions outside the normal range at the customer service entrance during contingency operating conditions. Some examples of temporary contingency conditions are listed below. For CT, temporary voltage below the lower limit should not exceed 24 hours where practical. Voltage excursions above the upper limit are not identified by magnitude but shall not exceed one minute. For WMA and NH, voltages above and below normal limits are based on ANSI C84.1 guidelines and shall be limited in extent, frequency, and duration. When they occur, corrective measures shall be undertaken within a reasonable time to improve voltages to meet normal voltage range requirements.

Contingency operating conditions include the following:

- Autoloops when a circuit, or part of a circuit, is being supplied through a tie recloser
- Automatic transfer schemes when fed by the backup feeder
- Contingent, manually switched supply to load in response to an interruption of normal supply routes or as needed for line construction, not exceeding 24 hours in expected duration
- Secondary networks with one or more supply feeders out of service
- Secondary networks with one or more network transformers out of service
- Forced outages of bulk power transformers
- Forced outages of transmission lines
- Supply through jumpered secondaries from neighboring transformer secondary cribs when changing transformers.

VOLTAGE VARIATION AMONG PHASES – Most of the load on distribution feeders is single-phase load, especially on feeders that supply predominantly residential load. As a result, the load per phase of the distribution circuit may be unequal, especially further from the circuit source. This imbalance is enough to lead to differing primary voltage drops per phase among the three phases of the circuit. The presence of single-phase customer-owned generation can also contribute to voltage variation among phases. The result of the differences in phase current due to load imbalance or generation imbalance is that the magnitude of voltage to neutral per phase, or between pairs of phases, will not always be equal.

Another contributor to different voltage magnitudes per phase at the secondary service level can be attributed to transformer connections. When an isolated three-phase load, such as a municipal water pump, exists in an area that could otherwise be supplied by one phase only, an economical solution (borne by the customer) is to extend only one additional primary phase and use an open wye/open delta transformer connection to supply the three-phase load. Such a connection poses different source impedances to the three secondary phases and results in unequal voltage drops per phase in the transformer bank for balanced three-phase loads.

According to ANSI C84.1–2016, “Electric supply systems should be designed and operated to limit the maximum voltage unbalance to 3 percent when measured at the electric-utility revenue meter under no-load conditions.” Table 1 below indicates the voltage variation allowed for some common service voltages.

Table 1 – Allowable Voltage Variations

Service Voltage	3% Variation
120 volts	3.60 volts
208 volts	6.25 volts
240 volts	7.20 volts
277 volts	8.30 volts
480 volts	14.40 volts

It should be noted that motor manufacturers generally prescribe adherence to the more restrictive National Electrical Manufacturers' Association (NEMA) standards which limit the maximum voltage unbalance to just 1 percent. When the voltages between the three phases (AB, BC, CA) are not equal (unbalanced), the current increases dramatically in the motor windings, and if allowed to continue, the motor will overheat and possibly be damaged. A relatively small difference in phase voltage leads to a much greater difference in phase current in the motor.

It is possible, to a limited extent, to operate a motor when the voltage between phases is unbalanced. To do this, the motor must be de-rated. Table 2 below indicates a general "rule of thumb" for de-rating motors when voltage imbalances exist. For specific motors consult the motor manufacturer.

Table 2 – Voltage Unbalance Motor De–rating Guide

Voltage Unbalanced (in Percent)	De–rate Motor to these Percentages of the Motor's Rating
1% (NEMA Limit)	98%
2%	95%
3% (ANSI Limit)	88%
4%	82%
5%	75%

It can be seen that the 1 percent tolerance in voltage variation prescribed by the motor manufacturer and the 3 percent ANSI Standard tolerance for voltage supplied by the utility can pose a difficult situation. Solutions to reduce unbalance include avoidance of open delta connections wherever possible, over-sizing of motors to allow loads to be met with de-rating of the motor, and improving primary load balance on the feeder. However, the Utility is not obliged to provide service exceeding ANSI guidelines in voltage variation. Keep in mind also that individual high and low voltage limits per phase must all conform to state regulatory voltage limits prescribed in **DSEM 05.131 – 05.133**.

Calculating Voltage Unbalance

$$Maximum\ Percent\ Voltage\ Unbalance\ \% = \frac{[100 \times Maximum\ Deviation\ From\ Average\ Voltage]}{(Average\ Voltage)}$$

$$Average\ Voltage = \frac{(V_A + V_B + V_C)}{3}$$

Where V_A, V_B, and V_C are the three phase voltages. They may be three line–to–neutral voltages or three phase–to–phase voltages.

The maximum deviation from average voltage is the largest difference of V_A, V_B, and V_C from the average voltage.

Example

Three phase−to−phase voltages are measured as 472/481/487 volts. What is the maximum percent voltage unbalance?

$$Average\ \ Voltage = \frac{(472 + 481 + 487\ \ volts)}{3} = 481\ \ volts$$

Deviations from average voltage:
481−472 = 9 volts
481−481 = 0 volts
487−481 = 6 volts
Maximum deviation from average voltage = 9 volts

$$Maximum\ \ Percent\ \ Voltage\ \ Unbalance\ \ \% = \frac{[100 \times (Maximum\ \ Deviation\ \ From\ \ Average\ \ Voltage)]}{(Average\ \ Voltage)} = \frac{(100 \times 9)}{481} = 1.87\%$$

VOLTAGE LIMIT QUICK REFERENCE TABLES

Tables 3 and 4 below list the high and low normal and contingency service voltage limits for all three states in the Eversource system.

Table 3 – Connecticut Service Voltage Limits (volts)

Nominal Voltage	Normal High Limit	Normal Low Limit	Contingency Low Limit
120	123.6	114.0	110.0
208	214.2	197.6	190.7
240	247.2	228.0	220.0
277	285.3	263.2	253.9
480	494.4	456.0	440.0
600	618.0	570.0	550.0

Table 4 – Massachusetts & New Hampshire Service Voltage Limits (volts)

Nominal Voltage	Normal High Limit	Contingency High Limit	Normal Low Limit	Contingency Low Limit
120	126	127	114	110
208	218	220	197	191
240	252	254	228	220
277	291	293	263	254
480	504	508	456	440
600	630	635	570	550

ED-3002 Distribution System Planning and Design Criteria Guidelines

I. PURPOSE

To establish guidelines to assist in planning and designing a distribution system that meets customer needs and regulatory requirements.

II. AREAS/PERSONS AFFECTED

This procedure applies to:

- Energy Delivery - system planning and design personnel

III. POLICY

It is the policy of PSNH:

A. To provide a reliable, cost effective, and efficient distribution system to meet customer needs while meeting regulatory requirements.

B. To insure adequate power distribution capacity during all times including normal summer and winter **peak load conditions**.

C. To examine **contingent** outages of substation equipment and circuits to identify areas subject to risk.

D. To insure a consistent approach to the planning for expansion and enhancement of the local area system.

E. To use sound engineering judgment when recommending construction for long term solutions when the design guidelines are exceeded.

F. To design the 34.5 kV distribution system to maximize performance and minimize cost by adhering to design criteria as outlined in this procedure.

IV. DEFINITIONS

Throughout the guideline, defined terms appear in bold and have a specific definition, which can be found in Appendix A.

V. OVERVIEW

This Operating Procedure provides distribution system design and planning guidelines for the 34.5kV and below systems. The 115kV and 345kV transformation to 34.5kV is included.

It is the intent of this guideline to promote the development of long term system solutions based on sound engineering and financial judgment. Short-term solutions **shall** be utilized only when prudent in the long-term planning of the system.

VI. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy or designee.

Annually, the Procedure Owner **shall** review design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline **shall** be revised, rewritten, or cancelled.

As required, the Procedure Owner **shall** recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner **shall** change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VII. GUIDELINES

A. Normal Operation

Normal Operation is how the system is designed to operate during **peak load conditions**. The system **shall** be designed such that during normal operation no switching is required to maintain equipment within its normal thermal ratings.

For design purposes, the system **shall** be capable of serving native PSNH load during **peak load conditions** without relying on the facilities of customers or neighboring utilities unless in accordance with a specific contract.

Areas that may require system enhancements for Normal Operation are identified when **distribution power transformers** are loaded to within 85% of their **TFRAT** (transformer rating). Those areas will be specifically evaluated in order to determine proper budget and construction schedule such that system enhancements are in place the year prior to distribution power transformers exceeding their TFRAT. Refer to ED-3023, Appendix B, for guidance.

No load loss **shall** be permitted under normal Summer or Winter **peak load conditions**.

Each **system generator** will be modeled on and off during **peak load conditions** to assure adequate supply to the area. One generating unit at a time or the largest unit at a facility will be removed from the system model to examine the effect.

Distribution circuits to which **Independent Power Producers (IPP)** are connected will be designed to carry load in accordance with IPP contractual guidelines. IPP

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will be modeled on, off, and at varying power factors in accordance with the generator capabilities.

The use of **dispatchable peak shaving generation** as defined in Appendix A is acceptable for managing peak load issues in specific locations to manage capital investments on the system.

Known common supply conditions for generation facilities will be considered for impact on the system. This includes the effect of drought on all hydro-electric generation in an area, common fuel/gas supplies for multiple generation units, air emission standard constraints, etc.

B. Contingent Operation

Contingent Operation is the result of the failure of equipment during **peak load conditions**. The following **contingencies shall** be examined for system impact during **peak load conditions**.

1. Loss of 34.5 kV line breaker.
2. Loss of a **distribution power transformer**.
3. Loss of radial transmission lines.
4. Loss of non-radial transmission lines.
5. Loss of **dispatchable peak shaving generation**.

Each **system generator** will be modeled on and off during Contingent Operations. The reliability and ability to utilize the generation during **peak load conditions** will be examined in the event that a specific generating facility supports the system during Contingent Operation.

During Contingent Operation some loss of power to customers (load isolation) will be accepted at the time of **peak load conditions**. The following guidelines **shall** be used to determine the level of severity and need for construction:

1. The load isolation does not exceed 30 MVA and the duration of the outage does not exceed 24 hours.
2. **Load block transfers** on the 34.5kV system are an acceptable means for reducing exposure and typically **shall** not exceed three.

This design criteria recognizes that most PSNH transformers can be backed up by a mobile transformer or faulted circuits can usually be repaired in less than twenty-four hours unless under very adverse conditions.

C. Voltage Regulation

Power delivery systems **shall** maintain acceptable voltage levels to all customers under the conditions for which the power delivery system is designed. This voltage **shall** be maintained during all loading periods in addition to Contingent Operations.

Acceptable primary 34.5 kV bus voltage levels modeled **shall** be maintained at all locations under Normal and Contingent Operations for all load levels. Planning for these operations **shall** recognize where 34.5 kV load is regulated and unregulated (not including the 34.5 kV transformer LTC at **Bulk Power Facilities** as regulation):

1. **Regulated Load:** The acceptable voltage range is 95 – 105% under normal conditions. During **contingencies** voltage levels may drop no lower than 92% in a localized area. Where a customer is responsible for supplying its own voltage regulation, the acceptable voltage range is 90% - 110%.

2. **Unregulated Load:** The acceptable voltage range is 97.5 - 105% under normal conditions. During **contingencies** voltage levels may drop no lower than 95% in a localized area.

The voltage at customer service terminals **shall** not exceed those minimum and maximum values as outlined in the New Hampshire Code of Administrative Rules PUC 304.02 Voltage Variation, revised October 2005, or latest revision thereof.

NOMINAL VOLTAGE	MINIMUM VOLTAGE	MAXIMUM VOLTAGE
120	114	126
240/120	228/114	252/126
208Y/120	198Y/114	218Y/126
240	228	252
480Y/277	456Y/263	504Y/291
480	456	504
600	570	630

D. Power Factor

The power factor during normal operation **shall** be maintained at levels which limit reactive current flow on the system and maintain proper voltage. Additionally, PSNH **shall** strive for a **load power factor** which satisfies ISO-NE Operating Procedure No. 17. This contains the methodology for developing the ranges of acceptable **load power factor** at the point of interconnection to the transmission system.

PSNH **shall** strive to maintain unity (1.00) power factor at 34.5kV line breakers during **peak load conditions**. Substation capacitors at 34.5kV and above **shall** be designed as required primarily to compensate for transformer losses in accordance with OP17.

The consideration of power factor correction guidelines **shall** include all load levels and **contingent** operation. The 34.5kV and below circuits **shall** be modeled and designed to maintain distribution power factor (p.f.) ranges in accordance with the following table:

Load Level(% of Peak)	Minimum p.f.	Maximum p.f.
80-100%	.98 lag	1.00
65-80%	.95 lag	1.00
up to 65%	.94 lag	1.00

The location, control device, and size of capacitor banks **shall** be determined in accordance with good engineering judgment and operation of the system.

E. System Protection

Except for transformers and buses at **bulk distribution facilities**, distribution primary elements **shall** normally be supplied with one system of protection, although remote devices may provide some inherent backup. Transformers and buses at **bulk distribution facilities shall** normally be supplied with two systems of protective relays.

Protective provisions **shall** be included with all distribution system designs to limit exposure to the public, personnel, and equipment from abnormal events and conditions. Control provisions **shall** be included with all distribution system designs to allow the system to operate in a manner consistent with the intent of planning and operating criteria. Protection and Controls Engineering **shall** be included early in the system planning process such that the related protection and control designs may be designed to support all intended system operating modes. The approach will avoid loading, operating, and/or protection limitations, which could otherwise prevent the primary system from providing the desired support during critical periods.

The intent of system protection design guidelines is that the above **shall** apply to new installations. Existing equipment **shall** be reviewed, as appropriate, and brought into conformance with these guidelines where prudent.

F. Equipment Loading Limits

Substation Transformers: The Normal limit, computer calculated **TFRAT** rating, is the maximum equipment load rating without incurring loss of life above the design loading limit, adjusted for ambient conditions. Transformer loading under Normal and Contingent Operation **shall** not exceed the **TFRAT** ratings.

Conductors: Conductors **shall** be rated for Normal and Contingent Operation. Under Normal Operation the conductors will be loaded within the normal rating limit of the conductors. The normal rating limit is the maximum equipment loading without incurring loss of life above the design-loading limit, adjusted for ambient conditions. During Contingent Operation the conductors will be within the emergency-rating limit of the conductors. The emergency-rating limit may involve loss of life or loss of tensile strength and is for Contingent Operation only. Any normal rating limit exceeded under Normal Operation **shall** be resolved by making prudent system changes or system enhancements to get the conductor within normal ratings. Any emergency-rating limit exceeded under Contingent Operation will result in switching, load isolation, and/or construction.

G. Economic

Economic evaluation of various alternatives will be made using the ‘revenue requirements’ method, or other economic evaluation methods as directed by management. Various alternatives **should** be projected to the end of their useful lives for making comparisons. System Planning and Strategy **should** determine operating and maintenance costs and useful life for purposes of economic studies.

H. Load Forecasts

Short and long-range load forecasts for the Company can be obtained from the System Planning and Strategy Department. These engineers will develop forecasts for localized planning based on load growth history and field input while working within the confines of the Company forecasts.

I. Substation Design

1. Transformers with secondary voltages of 34.5kV and below **shall** have secondary breakers. Each circuit fed from the substation **shall** have a designated circuit breaker.

   EXCEPTION: If only one circuit is fed from the substation, the transformer breaker may be utilized as the circuit breaker. Provisions **shall** be made for circuit breakers for future circuit additions.

2. Bus tie breakers **shall** be incorporated into substations with two or more transformers.

a. Existing substations **shall** be modified when major construction takes place in the substation or a specific project is proposed for this purpose.

b. Existing single transformer substations **shall** be designed to include the bus tie breaker when a second transformer is added.

c. New substations **shall** be designed with provisions for a future bus tie breaker if only one transformer is being constructed.

d. The bus tie breaker **should** be operated normally open at the substation.

3. Standard wire size for substation take-off construction **should** not exceed 477 kcmil ACSR.

J. 34.5 kV Circuit Design

1. Circuits looped between two substations

a. Standard wire size for all backbone circuits **shall** be 477 kcmil ACSR.

b. Looped circuit may have a normally open point between the two substations, in which case:
   i. Each circuit **should** be limited to a peak load of 400 amps at each substation.
   ii. The total load on the looped circuit(s) **shall** be no greater than 800 amps.

2. Three Phase Radial Circuits

a. Standard wire size for a backbone radial circuit **should** be 477 kcmil ACSR. If the potential for the radial circuit to become part of a loop system is greater than 10 years, 1/0 ACSR is an acceptable wire size.

b. Three phase 34.5 kV radial circuits consisting of primarily residential load **should** be limited to:
   i. 200 amps OR;
   ii. 2500 customers (per **DSEM** 02.303) OR;
   iii. 6 miles of three phase backbone (per **DSEM** 02.101) OR;
   iv. 50 miles of line for the entire circuit

c. An alternate/additional source to the radial circuit **should** be provided when any of the constraints in 2.b.i.-iv. above are exceeded. A separate source is preferred if available.

3. Single phase circuits

a. Standard wire size for a single phase circuit **should** be 1/0 ACSR.

b. A single phase circuit design **should** incorporate a recloser to protect a circuit with over 200 customers instead of a fuse.

c. Load **shall** be limited to 70 amps, maximum.

K. Conversion to 34.5kV

1. Circuits **shall** be reconductored if existing conductor being converted is smaller than 1/0 copper.

VIII. APPENDIX

Appendix A – Definitions
Appendix B - References

IX. ED-3002 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	01/10/03	Original issue
Rev 1	10/04/05	
Rev 2	06/27/06	
Rev 3	06/28/09	Revised to incorporate distribution peak shaving – DCI Team recommendations
Rev 4	09/12/11	Correction of section VII, A.

A. **Bulk Distribution Facilities** - Any distribution facility with a primary voltage 115 kV or greater.

B. **Contingency** (or **Contingencies**) - A failure of a single piece of equipment, which may require a reconfiguration of the system to restore load to customers. This includes a **distribution power transformer**, circuit, or circuit breaker.

C. **Dispatchable Peak Shaving Generation** – Electric power generators located at substations or other strategic locations to manage potentially overloaded transformers at peak load conditions. Examples: Combustion turbines, micro-turbines, reciprocating engines, or any other source of electric power which can be switched on or off as required and under the control of PSNH.

D. **Distribution Power Transformer** - Transformers supplying load at distribution levels including 34.5kV, 12.47kV, 4.16kV, and equivalent voltages.

E. **DSEM** - Northeast Utilities' Distribution System Engineering Manual

F. **Independent Power Producers (IPP)** – Non-PSNH generation interconnected to the PSNH system that meets the FERC definition of being a qualifying facility either by operating as a cogenerator or by producing generation with a renewable fuel source.

G. **Load Block Transfers** - Transfers of load between system areas that can be performed by operation of breakers and switches controlled by or under the direction of PSNH's Electric System Control Center (ESCC).

H. **Load Power Factor** - The **load power factor** is determined by adding real and reactive load at the transformation low side with transformer losses, generation below 115kV, and 115kV capacitors designated for system power factor correction. This methodology is defined in ISO-NE Operating Procedure No. 17.

I. **Peak Load Conditions** - The one-hour annual system and/or area peak MVA load for the season identified.

J. **Regulated Load** – Load that has voltage regulation at a 34.5kV primary voltage beyond the **Bulk Distribution Facility**. The system load is all beyond a PSNH voltage regulated source. Primary metered customers are considered **regulated load** because regulation is their responsibility in accordance with the Tariff.

K. **Shall** – An expression of command requiring conformance.

L. **Should** – An expression of condition which requires consideration but not immediate action.

M. **System Generation** - All generation on the PSNH System.

ED-3002 APPENDIX A - DEFINITIONS

N. **TFRAT** Rating - Maximum load on a **distribution power transformer** to utilize its capacity without overheating the equipment and causing damage that will reduce its normal life. **TFRAT** Rating is determined utilizing a computer program at PSNH. System Planning and Strategy maintains these records.

O. **Unregulated Load** – Load that has no voltage regulation at the 34.5 kV primary voltage beyond a **Bulk Distribution Facility**. The voltage of the system load is not regulated beyond the 34.5 kV point modeled for planning by System Planning and Strategy.

ED-3002 APPENDIX B - REFERENCES

January 2004 - Transmission Reliability Standards for Northeast Utilities

Decmeber 8, 2006 or most recent version - ISO-NE Operating Procedure No. 17 – Load Power Factor Correction

DSEM 02.10 Reliability General

DSEM 02.30 Automatic Sectionalizing Device Guidelines

DSEM 05.30 Contingency Planning

DSEM 10.20 Recloser Guide

DSEM 18.30 Feeders per Substation

ED-3023 - Procedure for Comprehensive System Planning Studies

Distribution System Planning Substation Project

Type: Capacity, Power Quality, Reliability
Level: Proposed, Planned

Substation Name:

Summary

Ratings:

Transformer	Nameplate	Cyclic Rating (LTE)

Station Capabilities:

Total Station Capacity (N)	Station Firm Capacity (LTE)	Remote Control Transfer	Manual Transfer	Total LCC

2020 Actual Peak Load: MW

2020-2024 Projected load:

	2020	2021	2022	2023	2024

Distribution System Planning Substation Project

Summary of System Review:

Possible Mitigation Actions

Timeline for Long-Term Solution:	
Initial Funding Request (IFR)	
Solution Selection Form (SSF)	
Project Authorization Form (PAF)	

Eversource

Job

Aid

Capital Project Approval Process

JA-AM-2001-A, Rev. 5

Process Owner:

John Dipaola-Tromba

Director, Business and Quality Assurance, Transmission

Effective Date: 6/1/2020

Eversource

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Table of Contents

1 Purpose

This job aid provides instructions and guidance on the process for initiating and then obtaining technical and financial approval for capital projects within all three states. This job aid will focus on project initiation, solution vetting by the Solution Design Committee (SDC), and approval of the Project Authorization Form (PAF) by the Eversource Project Approval Committee (EPAC) for transmission and substation projects and by each of the state Project Approval Committees (state PACs) for distribution projects. The authorization forms used by each committee can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. Completed samples of each form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\Sample Forms\. This job aid supports the guidance contained in Accounting Policy Statement 1 (APS01), Operations Project Authorization, which can be found on the Eversource intranet at https://eversourceenergy.sharepoint.com/sites/Accounting/SitePages/Accounting-Policies-%26-Procedures.aspx.

2 Affected Groups

As described in Responsibilities and General Instructions, the System Planning, Asset Management, Transmission Interconnections, and Project Management groups, along with the SDC, EPAC, and state PAC committees will have primary responsibility for the project review and approval process. The following general groups will also be affected by this job aid as their participation is critical to the successful initiation, development, review, and approval of capital projects.

- Transmission Line, Substation Design, Substation Technical, Transmission Protection and Control, and Distribution Engineering
- Construction
- Scheduling
- Siting/Permitting
- Environmental
- Siting and Construction Services
- Procurement
- Investment Planning
- Operations
- Engineering Project Controls
- Transmission Project Controls

3 Responsibilities

3.1 Project Initiator

In general, Transmission and Substation Projects will be initiated by either the System Planning (Reliability and Capacity Projects), Asset Management (Asset Condition Projects), or Transmission

Interconnections Department (Interconnection Projects). Distribution street and line projects with no substation scope will be initiated by the Distribution Engineering group. Telecom projects (aside from OPGW projects which will be initiated by the Asset Management group) will be initiated by the Communications Engineering Group. Distributed generation interconnection projects will be initiated by the Distributed Energy Resources Technology Group.

The project initiator will be responsible for securing initial funding from the EPAC for Transmission and Substation projects or from a state PAC for Distribution projects, coordinating conceptual engineering activities, and coordinating the development of conceptual grade cost estimates for alternatives (-25%/+50%). For applicable projects (See Section 3.4.1 below for details), the project initiator will be responsible for presenting the choice of a preferred solution to the SDC. The project initiator will own the PAF, including Program Level PAFs and Program Release Forms, that will be required documentation at the project approval committee meetings. The project initiator shall submit a PAF that includes the financial and technical details, a detailed backup cost estimate, a project checklist, and a Constructability Review Form at least seven working days prior to the next scheduled EPAC meeting for Transmission and Substation projects or three working days prior to the next scheduled state PAC meeting for Distribution projects. For transmission projects, the detailed cost estimate must be in accordance with Attachment D to PP4 (ISO-New England Planning Procedure 4). If a project manager is assigned, the project initiator will support the engineering phase and be responsible for updating the PAF to secure full funding.

For projects that do not have a project manager assigned, the project initiator will be responsible for leading preliminary engineering activities and developing an updated +/-25% planning grade cost estimate. The project initiator will then be responsible for updating the PAF and securing full funding from the EPAC or a state PAC. Once a project is fully approved and funded, project ownership transfers to the project manager for the project execution and closeout phases.

3.2 Project Manager (PM)

Once assigned, the PM will manage the project's schedule and budget and support the conceptual engineering phase by driving collaboration with the various engineering disciplines and affected departments. With support from the project initiator, the PM will be responsible for facilitating preliminary engineering activities and coordinating with the Cost Estimating team to develop cost estimates. Ultimate ownership of the project transfers from the project initiator to the PM once the project is fully approved and funded. The PM will also be responsible for any required supplemental approval with support from the project initiator, if necessary.

3.3 Project Sponsor

Typically, the Project Sponsor will be the director of the project initiator. The Project Sponsor will be responsible for review and approval of project documents before they are submitted to the committees for approval.

3.4 Solution Design Committee (SDC)

The SDC will serve as solution development gate keepers to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process. The SDC administrators will use the email address SolutionDesignCommittee@eversource.com to communicate with project initiators and for all committee communications. More information on solution vetting can be found in Section 4.3 and the full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter.

3.4.1 Project Types

The SDC will review and approve solutions for the following Transmission and Substation project types:

- System Planning – Reliability and Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.
- Other Telecom projects and programs

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project or program will require review and approval by the SDC.

3.5 Eversource Project Approval Committee (EPAC)

The EPAC will be responsible for the review and approval of the technical and financial merits of transmission and substation projects. For project and program initiations, the EPAC will review and authorize Initial Funding Request Forms (IFRs) typically up to $250,000, including Program Level PAFs with initial funding. The EPAC may also review requests for initial funding beyond $250,000 if a larger funding amount is required to complete preliminary engineering activities. For previously initiated projects and programs, the EPAC will review partial and full funding PAFs, Program Level PAFs, and Program Release Forms. The EPAC will review conceptual grade cost estimates (-25%/+50%) for projects looking to secure partial funding and will review planning grade cost estimates (+/-25%) for projects looking to secure full funding authorization. The EPAC administrators will use the email address TranEPAC@eversource.com to communicate with project teams and for all committee communications The full responsibilities of the EPAC are contained in Attachment B, Eversource Project Authorization Committee Charter.

3.5.1 Project Types

The EPAC will review and approve the following project types:

- Transmission line and/or substation projects (Transmission projects over $300,000 total cost and distribution substation projects over $100,00 direct costs)
- Transmission line and/or substation programs (OPGW Programs, Breaker Programs, etc.)
- Telecom projects that impact transmission lines and/or substations
- New or reconfiguration of a distribution substation (regardless of voltage level)
- Substation projects with transmission and distribution components will be reviewed as a package, only by the EPAC
- Customer interconnection requests that require transmission or substation work
- Any other project per the discretion of the EPAC chairperson(s)

All other distribution projects will be reviewed and approved by the state PAC (see section 3.6.1). See Section 5 for review process for transmission projects less than $300,000 total cost.

3.6 State Project Approval Committees (CT PAC, MPAC, and NH PAC)

The state PACs will be responsible for the review and approval of the technical and financial merits of Distribution projects. There will be three different project approval committees to review and approve the projects; one from each state (CT PAC, MPAC, and NH PAC). The state PACs will review PAFs with conceptual grade (-25%/+50%) estimates for distribution projects looking to secure initial funding and will review PAFs with planning grade (+/-25%) estimates for distribution projects looking to secure full funding authorization. The full responsibilities of the state PACs are contained in Attachment C, State Project Approval Committee (State PAC) Charter.

3.6.1 Project Types

The state PACs will review and approve the following project types:

- Underground distribution project greater than $250,000
- Overhead and underground-overhead mixed distribution projects over $1 million
- Customer interconnection requests with total cost estimates (including indirect costs) greater than $1 million. Customer interconnection projects less than $1 million are reviewed and approved in PowerPlan and typically will not require review and approval by the state PAC.
- DG interconnection request without substation scope that require a new feeder (regardless of cost) or with total cost estimate greater than $500,000. Note that DG interconnection projects with substation scope will be reviewed by EPAC as described in Section 3.5.1.)

Note that per APS01, all other underground, overhead, and underground-overhead mixed distribution projects under the dollar thresholds listed above but over $100,000 direct costs still require PAF documentation. These PAFs will be reviewed and approved directly in PowerPlan. The approving director can use his/her discretion to require any of these projects to be reviewed at the state PAC. See Section 5 for review process information for distribution projects under $100,000 direct costs. All other transmission and substation projects will be reviewed and approved by the EPAC (see section 3.5.1).

3.7 Cost Estimating

The Transmission Cost Estimating team will support development of project cost estimates for Transmission and Substation projects. Depending on the complexity of the project, the approximate cost, and other factors the level of support provided by the Cost Estimating team may range from taking the lead in developing the estimate to reviewing an estimate prepared by the project team. To request support from the Cost Estimating team, project teams should complete the Estimate Request Form which can be found at \\nu.com\data\SharedData\Estimating-Shared\2) Estimate Templates\1) Est Request form\ and submit it to the Manager of Transmission Cost Estimating.

4 General Instructions

The process to proceed with each successive phase of a capital project is designed to ensure that there is a valid need, the right solution alternatives are evaluated, the technical approach is sound, and resources are budgeted and prudently spent. The overall process flow for Transmission and Substation projects is depicted in Attachment D, Transmission and Substation Project Approval Process Flow Charts. Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart is a 17”x11” flowchart with more detailed descriptions. The overall process flow for Distribution projects is depicted in Attachment F, Distribution Project Approval Process Flow Chart. The initiation and major engineering and approval phases of the process flow charts correspond to the sections below.

These general instructions are for the project types listed in Sections 3.5.1 and 3.6.1. Refer to Section 5 for instructions for planned transmission projects less than $300,000 or planned distribution projects less than $100,000. Refer to Section 6 for instructions for securing approval of emergent work.

4.1 Project Initiation

Following the identification of a project need the initiator will secure a project number. Project initiators can email TranEPAC@eversource.com for assistance securing a project number. Project initiators will then complete an IFR and submit it to EPAC via TranEPAC@eversouce.com. The IFR may be used to request funding per Section 3.5. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. The initiator will be required to state the project need and objectives and include an explanation of the funding request amount, including a budget for conceptual and preliminary engineering activities and a schedule for returning to EPAC with a full funding request. The IFR may include a budget for initial internal siting and permitting preparation activities. The IFR should not include funding for detailed engineering or procurement of any material. The EPAC chairman may decide to approve the request directly or may request that the initiator present the request for input and feedback to the EPAC.

Once an IFR is approved, the EPAC administrator will send the approved form to Investment Planning to create a project and submit it for Delegation of Authority approvals in PowerPlan, the Eversource software tool for financial approval. The initial funding is obtained once delegation of authority has been performed through PowerPlan in accordance with APS01 (See Section 4.5.3 for more information on Delegation of Authority Policy). Once fully approved in PowerPlan a Work Order (WO) will be assigned. The EPAC administer will copy the Directors of Project Management on the submittal to Investment Planning so that a Project Manager can be assigned as appropriate. For some projects the Project Manager role may remain with the Project Initiator, be assigned to a lead engineer, or be assigned to a Transmission Line Construction Manager.

4.2 Project Initiation for Programs

Initial funding can also be requested at the program level using the Program Level Project Authorization Form. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The funding can be used to advance specific project scope under an approved program. Sections 4.5.1 and 4.5.2 contains more information on full approval of programs and program level releases.

4.3 Conceptual Engineering

The project initiator should follow the Project Alternative Process in procedure M2-TP-2018 for the identification, development and selection of project alternatives. As described in detail in M2-TP-2018, the project initiator will lead and coordinate the following activities with support from the PM and input from affected departments:

- Incorporate designs from standards library and develop scope and major equipment lists for all alternatives under consideration.
- Conceptual engineering of all appropriate alternatives including early field review and desktop analysis.
- Identification of key project risks with the appropriate level of detail with respect to constructability, routing, outage planning, possible Single Contingency Loss of Load (SCLL) conditions and applicable mitigation actions, siting and permitting, environmental impacts, community and external stakeholder impacts, site control, procurement, etc.
- Identification of any land rights needs.
- High level routing determinations (for linear projects).
- Develop project strategies to mitigate identified risks.
- Conceptual grade cost estimates (-25%/+50%) for all appropriate alternatives (at least the preferred solution and leading alternative). The project team should request support from the Cost Estimating team for all estimates.

The project team will then recommend a preferred solution and document the rationale for the choice of preferred solution. The Engineering Deliverables document which details activities required for estimating purposes can be found at N:\Estimating-Shared\2) Estimate Templates\4) Estimate Categories & Scope Deliverables\.

4.4 Solution Vetting

Prior to proceeding with Preliminary Engineering of the preferred solution, more comprehensive projects and asset condition projects at the program level will need to be reviewed and approved by the SDC (See Section 3.4.1 for list of project types the SDC will review). Project initiators will submit a Solution Selection Forms (SSF) to the SDC via SolutionDesignCommittee@eversource.com at least five business days prior to the next scheduled SDC meeting. The SDC will review the SSF and confirm that the project team has selected the best solution. The SSF will require a statement of project need and objectives, documentation of the alternatives analysis, scope and major equipment list for the preferred solution, and a conceptual grade cost estimates for the preferred solution and a leading alternative. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter. Once reviewed and approved by the Solution Design Committee, projects will proceed with Preliminary Engineering.

Transmission and substation projects that do not require review and approval by the SDC such as like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will proceed directly with preliminary engineering activities and development of a full funding request to present to EPAC.

Distribution street and line projects without substation components may also require a solution vetting process. The state PAC chairperson may require more complex distribution street and line projects to complete a distribution design review prior to state PAC approval.

4.5 Preliminary Engineering

Once the project team has chosen a preferred solution with scope definition, it can proceed with preliminary engineering and development of an updated cost estimate of the preferred solution. In order to receive full funding approval, projects will require planning grade (+/-25%) cost estimates. The project team should request support from the Cost Estimating team to develop the planning grade cost estimate. The preliminary engineering phase will typically include:

- General requirements/specifications
- Preliminary design for civil, electrical, T-Line, and P&C
- Nomenclature, relay, metering, and equipment rating one-line diagram and preliminary three-line diagram
- More in-depth constructability review
- Below grade investigation
- Preliminary outage plan and Operations review
- Preferred route selection
- Equipment specifications and Bill of Materials
- Critical Path Schedule
- The project team will work with the affected groups listed in Section 2 to complete more in-depth investigations, develop a mitigation plan for project risks, and refine project strategies

The Engineering Deliverables document which details activities required for estimating purposes can be found at N:\Estimating-Shared\2) Estimate Templates\4) Estimate Categories & Scope Deliverables\.

If the initial funding is not sufficient to complete preliminary engineering and develop a planning grade cost estimate, then the project team can prepare a PAF and make a request for partial funding at EPAC per Section 3.5. The partial funding request should be for the budget amount that will be required to complete the detailed scope definition of the project and prepare a full funding request. As with IFRs, partial funding requests may include a budget for internal siting and permitting preparation activities but should not include funding for procurement of any material. The request should also include a proposed schedule to complete these activities and return to EPAC with a full funding request.

4.6 Full Project Authorization

After preliminary engineering is complete, the PAF will be completed and the project will be presented to either the EPAC or the state PAC for full approval and funding authorization. PAFs that will be reviewed at EPAC should be submitted to TranEPAC@eversource.com at least seven business days prior to the next scheduled EPAC meeting. For the project types listed in Section 3.4.1, the EPAC will not review full funding requests unless the project has already been approved by the Solution Design Committee. The project checklist, a Constructability Review Form, and a detailed backup cost estimate as described in Section 4.4 in accordance with Attachment D to ISO-NE Planning Procedure 4 (PP4) must accompany the PAF.

4.6.1 Program Approval

EPAC will review and approve Asset Management programs using the Operations Program Level Project Authorization Form. The form can be found at\\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. In addition to the information required on the PAF for a regular project (need, objectives, scope, background/justification, etc.) the Program Level PAF will also require:

- A financial evaluation completed on a unit cost basis so that the capital cost of each application of the program can be fully understood. The unit cost is often based on a similar project that has been completed.
- A listing of proposed circuits or substations by state that will be included in the scope of the program.
- An estimate of the program capital investment value by state.
- A proposed schedule for bringing forward and executing the program level releases.
- A description of the investigations that will be needed at each location to develop the scope and cost estimate at a specific site.

As described in Section 4.1.1 Program Level PAFs may also be combined with an initial funding request at the program level so that the initiator will have funds to develop the scope of the program at specific sites and bring forward full funding program release requests.

4.6.2 Program Release Authorization

Once the scope, site-specific cost estimate, and constructability reviews are completed for a particular location or circuit, a Program Release Form will be submitted for full funding. The Program Release Form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. Each Release will summarize the scope and cost estimate at a specific location and discuss any variances between the scope or cost estimates from the expected unit costs and scope approved in the Program Level PAF. Once an individual program release is approved at EPAC, any initial funding costs that were originally charged at the program level will be journaled to the specific project, which will allow those costs to be capitalized along with the specific project and also make more budget available at the program level to develop additional Program Release Forms. Once approved, the approval process for a Program Release Form will be the same as stated above for the full funding PAF.

4.6.3 Delegation of Authority

Once approved, the EPAC or state PAC administrator will submit the EPAC-approved PAF to Investment Planning for approvals in PowerPlan in accordance with the company Delegation of Authority Policy (DOA). The DOA specifies the capital authorization level of various company positions (manager, director, vice president, senior vice president / subsidiary president, Executive vice president, etc.). The MS Excel file "Power Plan Project Approval Trees" found at N:\EPAC\Administrative\ lists which specific individuals at each authorization level that will be required to approve projects authorized by EPAC. There are separate approval trees listed for transmission line and substation major projects, transmission line maintenance projects, and distribution substation projects. The full project funding is attained once delegation of authority has been performed through PowerPlan in accordance with APS01. PMs should include up to thirty days in project schedules to complete approvals in PowerPlan and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

Projects must be fully approved in PowerPlan before their scope or cost estimates can be shared publicly. This includes but is not limited to sharing cost estimates with ISO-NE, sharing cost estimates with customers for customer or interconnection projects, filing a siting or permitting application that includes a cost estimate, and conducting project outreach. If a project schedule requires the release of project information prior to full project approval in PowerPlan is possible, then a project team can request approval from EPAC to release the information. If EPAC approval is also not possible, then the project team can seek the SDC's approval to release the information.

4.7 Detailed Engineering, Siting, and Permitting

Once the project is fully authorized in PowerPlan, the project team can proceed with detailed engineering, siting and permitting application filings, project outreach, ordering major material, and other development activities.

4.8 Construction and Construction Variance Monitoring

The project manager or lead will manage the project's execution and construction. The project manager or lead will monitor spend vs. authorized costs and submit a revised PAF or Supplemental Request Form (SRF) to the EPAC or state PAC if any of the following occur:

- The project cost will exceed APS01 tolerances.
- Significant Scope change (even if cost alone does not trigger a supplement) such as an added unit of property (i.e. switches, relays, CCVTs, etc.) or a change in technology

- Technical Design Change (i.e. OH vs UG, air vs. GIS, etc.)

A revised PAF can be used for scope changes without significant cost changes and the SRF should be submitted for all other instances of project cost being expected to exceed APS01 tolerances. Supplemental authorization requests should be prepared as soon as it is likely that the project cost is expected to increase and the updated project estimate exceeds the APS01 tolerance for the current authorization. Supplement requests should also be submitted once a scope change is identified. The SRF can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms.

If a supplement is approved by the EPAC or state PAC, the committee administrator will send the approved SRF to Investment Planning for submittal for Delegation of Authority approvals in PowerPlan. When determining when to submit a supplement, PMs should note that attaining full approval in PowerPlan may take up to thirty days and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

4.9 Project Closeout

All project documents will be closed and affected databases updated upon project closeout in accordance with M6-PM-2001, Project Management Process, or applicable local project closeout process.

5 Instructions for Small Planned Projects

Each year annual distribution substation budgets are approved and funded to support the many small planned projects that will be completed that year. Per APS01, transmission projects less than or equal to $300,000 in total cost and distribution substation projects less than or equal to $100,000 in direct costs do not require their own PAFs.

5.1 Distribution Substation Projects Less Than or Equal to $50,000 in Direct Cost

To be issued a work order that will charge against one of these annual budgets for a small planned distribution substation project, the project lead must complete a Planned Annual Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Planned Annual Request Form is then attached in PowerPlan when a new work order is created with an EPAC Administrator included as a required approver.

5.2 Transmission Projects Less Than or Equal to $300,000 in Total Cost & Distribution Substation Projects with Direct Cost Over $50,000 and up to $100,000

To request project approval the project lead must complete a Planned Annual Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Planned Annual Request Form is then submitted to TranEPAC@eversource.com. The completed Planned Annual Request Form will be reviewed and approved directly in PowerPlan.

6 Instructions for Emergent Work

Each year annual transmission and distribution substation budgets are approved in each region and funded to support the many small projects that classify as emergent work within that year. Per APS01, transmission projects less than or equal to $300,000 in total cost and distribution substation projects less than or equal to $100,000 in direct costs do not require their own PAFs. Emergent work refers to work that could not be planned that is completed to repair or replace capital equipment that broke or failed.

To be issued a work order that will charge against one of these annual budgets for small transmission or distribution substation emergent work, the project lead must complete an Emergent Work Order Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Emergent Work Order Request Form is then attached in PowerPlan when a new work order is created with an EPAC Administrator included as a required approver.

7 Definitions & Acronyms

Annuals	Annuals refers to the annual project budgets that are approved to support small projects and small emergent work projects.
APS	Eversource Accounting Policy Statement
Conceptual Engineering	An optional project phase, for the engineering needed to obtain a project cost estimate accurate to -25%/+50% and to generate a PAF
Conceptual Estimate	A cost estimate with target accuracy of -25% to +50%
Construction	The project phase for the implementation of an engineered project
DOA	Delegation of Authority
Detailed Engineering	The project phase for the engineering needed for construction to begin, to obtain a project cost estimate accurate to ± 10%.
Emergent Work	Refers to work that could not be planned that is completed to repair or replace capital equipment that broke or failed
Engineering Estimate	A cost estimate with target accuracy of +/-10%
EPAC	Eversource Project Approval Committee
IFR	Initial Funding Request Form required to initiate a project with funding and setup a Work Order, the initiator will complete an IFR and submit it to the EPAC.
ISO-NE	The independent operator of New England's bulk electric power system and transmission lines. ISO-NE manages a comprehensive regional planning process.
M2-TP-2018	The Project Alternative Strategy procedure document published by the System Planning organization.
M6-PM-2001	The Project Management Process procedure document

PAF	Project Authorization Form required by Accounting Policy Statement 2 for the purpose of requesting authorization of capital funds for a particular project
Planning Estimate	A cost estimate with target accuracy of +/-25%
PM	Project Manager
PowerPlan	Eversource financial approval tool
PP4	ISO-NE Planning Procedure 4
Preliminary Engineering	The project phase for the engineering needed to obtain a project cost estimate accurate to ± 25% and to generate a PAF
Program Level PAF	Authorization document for programs. A program is a substation need that will be addressed at numerous sites (i.e. Oil Circuit Breaker Replacements, Relay Replacements, etc.) or a line need that will be addressed on numerous circuits (i.e. Structure Replacements, Fiber Optic Expansion, etc.)
Program Release Form	Authorization form for a specific site or circuit of an approved program.
SCLL	Single Contingency Loss of Load
SDC	Solution Design Committee is a three-state committee that reviews substation and transmission projects and programs to ensure that the best solution is selected and standardization is implemented across the company
SSF	Solution Selection Form – Document that the SDC will review and approve
SRF	Supplement Request Form
State PAC	State Project Approval Committee. There will be three state project approval committees for distribution projects: MPAC, CT PAC, and NH PAC
WO	Work Order

8 Revision History

Revision 5 – June 1, 2020

- Added Sections 4.1.1, 4.5.1, and 4.5.2 containing description and instructions for initiating programs, Program Level PAFs, and Program Release Forms
- Added Sections 4.5.3 to add additional description of Delegation of Authority Policy
- Added Sections 5 and 6 to include instructions for securing authorization for emergent work and annual projects
- All Sections: Added detail and instructions for distribution line projects, distributed generation interconnection projects, and communications engineering projects.
- Other minor updates

Revision 4 – November 2, 2018

- Updated all sections to align with updated project lifecycle including new Project Initiation Process and Solution Design Committee Process

Revision 3

- Minor updates

Revision 2 – October 27, 2017

- All Sections: Changed from TRC and CPAC to EPAC and state PACs

Revision 1 – December 7, 2016

- 4 General Instructions – Added location of forms
- 4.2 Detailed Engineering Approval – Added requirement to complete TAF Transmission Checklist
- 5 Definitions and Acronyms – Added acronyms used in Attachment F
- 6 Summary of Changes – Added section
- Added Attachment F, TAF Transmission Checklist and Instructions

Revision 0 – August 28, 2016

- Original issue

Attachment A, Solution Design Committee Charter

Purpose

The Solution Design Committee (SDC) will serve as solution development approval committee to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process.

Applicability

The SDC is responsible for solution selection review of electrical Transmission and Substation projects in all three states of the following types:

- System Planning – Reliability & Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project will require review and approval by the SDC.

Objectives

The objectives of the SDC are as follows:

1. Confirm that the right subject matter experts from affected departments were appropriately involved in the conceptual engineering, alternatives analysis, and solution selection.
2. Confirm project teams identified and considered a robust set of alternatives when selecting the best solution in accordance with M2-TP-2018 Project Alternative Process.
3. Ensure the development of project solutions and alternatives incorporate standardized design and equipment, where practical/possible.
4. Review initial conceptual engineering, scope, and cost estimates for all potential project alternatives. Cost estimates should be of conceptual grade (-25%/+50%) for the preferred solution and the leading alternative.
5. Review and confirm that project teams identify project risks for the preferred solution and its alternatives with the appropriate level of detail with respect to constructability, routing, outage planning, possible SCLLs, siting and permitting, environmental impacts, community and external stakeholder impacts, land rights needs and site control, procurement, etc.

6. Review and confirm project team's alternatives analyses and choice for preferred solutions and ensure the rationale is appropriately documented.
7. Coordinate with EPAC to initiate any needed process changes on at least a biennial basis.

Membership

SDC shall consist of an executive sponsor, a chairperson, voting members, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting members, if required.

SDC Membership List

SDC Role	Company Position
Executive Sponsor	VP, Substation and Transmission Engineering
Co-Chairperson	Director, Substation Design Engineering
Co-Chairperson	Director, Substation Protection and Controls
Administrator(s)	As appointed by the Chairperson
Voting Member	Director, Transmission Business and Quality Assurance
Voting Member	Director, System Planning
Voting Member	Director, Transmission Line Engineering
Voting Member	Director, Substation Technical Engineering
Voting Member	Director, System Solutions
Voting Member	Director, Engineering Capital Projects
Voting Member	Manager(s), Transmission Projects
Voting Member	Manager of Standards
Voting Member	Manager of Transmission Siting
Voting Member	Manager of Siting and Construction Services
Attendee	Director, Transmission Project Controls
Attendee	Director, Engineering Project Controls
Attendee	Manager of Project Solutions
Attendee	Manager of Estimating
Attendee	Manager of Asset Management
Attendee	Manager(s) of Substation Engineering
Attendee	Manager(s) of Protection and Controls
Attendee	Manager(s)/Lead(s) of Transmission Line and Civil Eng.
Attendee	Manager(s) of Substation Technical Engineering
Attendee	Manager(s) of System Planning
Attendee	Manager of Licensing and Permitting
Attendee	Manager(s) of Environmental Affairs
Attendee	Manager(s) of Procurement
Attendee	Supervisor(s)/Manager(s) of Outage and Ops Planning
Attendee	Manager of Generation Interconnections
Attendee	Manager of Operational Compliance
Attendee	Manager(s) of Transmission Line Operations
Attendee	Manager(s) of Station Operations/ Field Engineering/ System Dispatch
Attendee	Manager(s) of Systems Engineering
Attendee	Manager of ISO Policy and Economic Analysis

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the SDC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at SDC meetings
- Designate a Voting Member as an alternate to preside at meetings in his/her absence
- Solicit Voting Member appointments
- Appoint a SDC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the SDC meeting
- Hold votes as required
- Participate in discussions and votes to meet the SDC objectives
- Initiate the biennial review of the SDC process in coordination with EPAC
- Create subcommittees as required

Voting Member

- If required, designate a manager in the same organization as a voting alternate to participate in the SDC
- Review meeting materials on the agenda prior to the SDC meeting
- Participate in discussions and votes to meet the SDC objectives
- Participate in the biennial review of the SDC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening of Project Documentation
- Distribute meeting materials to attendees five working days prior to a scheduled SDC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record Solution Select Forms presented and their attachments and meeting results
- Attend to and manage the SolutionDesignCommittee@eversource.com email inbox

Project Lead/Initiator

- Complete a Solution Selection Form (including statement of need, project objectives, alternatives analysis, and scope for preferred solution) for any proposed capital project that meets the applicability criteria described above

- Ensure that SDC objectives listed above are fully met, and that subject matter experts from affected departments were included in the alternatives analysis.
- Submit the Solution Selection Form to the SDC administrator via SolutionDesignCommitee@eversource.com at least five working days prior to the next scheduled SDC meeting (ensures document screening and review by committee members)
- Attend the SDC meeting and present the Solution Selection Form to SDC members
- Revise the Solution Selection Form and/or respond to comments from the SDC as required

Quorum

The Chairperson(s) (or alternate) plus a minimum of four Voting Members (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule and Location

The SDC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required. The location of the SDC meeting will rotate between MA, CT, and NH.

Voting

The Voting Members and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

Subcommittees

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the SDC. Subcommittees shall be chaired by a voting member of the SDC or their designated alternate.

Attachment B, Eversource Project Authorization Committee Charter

Purpose

The Eversource Project Authorization Committee (EPAC) reviews and approves the technical and financial merits of Transmission and Substation projects, including the selection of preferred solutions that are consistent with Eversource priorities (e.g. safety, reliability, cost efficiency). The EPAC authorizes, monitors and adjusts capital expenditure and resources for projects; prioritizes projects for the capital program and defers projects based on budget and resource availability.

Applicability

The EPAC is responsible for the technical review and financial approval of electrical Transmission and Substation projects in all three states.

Objectives

The objectives of the EPAC are as follows:

1. Receive, review, and approve Initial Funding Request Forms
    a. Review the need and confirm that a capital project is needed to address the need.
    b. Review and approve the project's objectives.
    c. Ensure the funding request amount, planned development activities, and schedule are appropriate.
2. Receive, review, and approve PAFs for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the EPAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    d. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization.
    e. The committee has the ability to review detailed engineering designs, ensuring the proposed work is in accordance with Eversource Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure the PAF project checklist is complete.
    h. Ensure the Constructability Review Form is complete
    i. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    j. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase
    k. Ensure risks and mitigation plans are identified.
3. Evaluate project funding and priorities relative to the five-year capital plan.

4. Ensure project approval statuses and DOA progress are reviewed at least monthly.
5. Prioritize projects for deferment or cancellation.
6. Review EPAC process performance and lessons learned and coordinate with the state PACs to initiate any needed changes on at least a biennial basis.

Membership

EPAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting member directors, if required.

EPAC Membership List

EPAC Role	Company Position
Executive Sponsor	VP, Transmission Projects
Co-Chairperson	Director, Transmission Project Controls
Co-Chairperson	Director, Transmission Business and Quality Assurance
Administrator	EPAC Program Manager
Member Director	Director(s), Transmission Projects
Member Director	Director, Transmission Line Engineering
Member Director	Director, Substation Design Engineering
Member Director	Director, Substation Technical Engineering
Member Director	Director, Substation Protection and Controls
Member Director	Director, Transmission System Planning
Member Director	Director, Siting and Compliance
Member Director	Director, Investment Planning
Member Director	Director(s), Engineering
Member Director	Director, Reliability, Compliance and Implementation
Member Director	Director(s), Transmission/System Ops
Member Director	Director, System Operations
Member Director	Director(s), Field Operations Lines
Member Director	Director(s), Field Operations Substations
Member Director	Director(s), Field Engineering
Member Director	Director, Engineering Project Controls
Member Director	Director, Engineering Capital Projects
Attendee	Manager of Project Solutions
Attendee	Manager of Transmission Siting
Attendee	Manager of Siting and Construction Services
Attendee	Manager of Capital Program & Estimating
Attendee	Manager of Licensing and Permitting
Attendee	Manager(s) of Procurement
Attendee	Manager(s) of Substation Engineering
Attendee	Manager(s) of Protection and Controls
Attendee	Manager(s)/Lead(s) of Transmission Line and Civil Eng.
Attendee	Program Manager- Transmission Capital Program
Attendee	Supervisor(s)/Manager(s) of Outage and Ops Planning
Attendee	Manager of Standards

Attendee	Manager of Budget and Investment
Attendee	Manager of Generation Interconnections
Attendee	Manager of Asset Management
Attendee	Manager of Operational Compliance
Attendee	Manager(s) of Line Operations
Attendee	Manager(s) of Substation Technical Engineering
Attendee	Manager(s) of System Planning

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the EPAC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at EPAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a EPAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the EPAC meeting
- Hold votes as required
- Participate in discussions and votes to meet the EPAC objectives
- Initiate the biennial review of the EPAC process in coordination with the other EPACs
- Create subcommittees as required

Member Director

- If required, designate a manager in the same organization as a voting alternate to participate in the EPAC
- Review meeting materials on the agenda prior to the EPAC meeting
- Participate in discussions and votes to meet the EPAC objectives
- Participate in the biennial review of the EPAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening and Quality Measurement of Project Documentation.
- Distribute meeting materials to attendees three working days prior to a scheduled EPAC meeting
- Record the result of any votes
- Prepare and distribute meeting notes

- Record PAFs and SRFs presented and meeting results
- Submit PAFs and SRFs approved to Investment Planning for Delegation of Authority approvals in PowerPlan
- Attend to and manage the TranEPAC@eversource.com email inbox

Project Lead/Initiator

- Complete a PAF (including financial and technical details, cost estimate, project checklist, and Constructability Review Form) for any proposed capital project or change, ensuring that EPAC objective one items are fully met, and obtain any necessary reviews and approvals prior to submittal to the EPAC
- Submit the PAF to the EPAC administrator via TranEPAC@eversource.com at least seven working days prior to the next scheduled EPAC meeting for engineering approval (ensures document screening and review by committee members)
- Attend the EPAC meeting and present the PAF to EPAC members
- Revise the PAF and/or respond to comments from the EPAC as required
- Once fully authorized, if costs exceed the approved PAF levels by more than the amounts shown in Accounting Policy Statement No. 1, create a SRF, attach to the previously approved PAF, and resubmit to EPAC for review and approval.

Quorum

The Chairperson(s) (or alternate) plus a minimum of four Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule and Location

The EPAC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required.

Voting

The Member Directors and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

Subcommittees

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the EPAC. Subcommittees shall be chaired by a voting member of the EPAC or their designated alternate.

Attachment C, State Project Approval Committee (State PAC) Charter

Purpose

The State Project Approval Committees (State PACs) review and challenge the technical merit of proposed distribution projects, and approve them as consistent with Eversource priorities (e.g. safety, reliability, cost efficiency).

Applicability

This charter applies to the three state PACs in Connecticut, Massachusetts and New Hampshire that are responsible for all Eversource electrical distribution projects originating in their respective states.

Objectives

The objectives of a state PAC are as follows:

1. Receive, review and approve Project Authorization Forms (PAFs) for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the state PAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization and to -25%/+50% for projects seeking initial funding.
    d. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    e. The committee has the ability to review detailed engineering designs, ensuring the proposed work is in accordance with our Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure risks and mitigation plans are identified.
    h. Ensure the PAF project checklist is complete.
    i. Ensure the Constructability Review Form is complete.
    j. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    k. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase.
    l. If CEO or subsidiary board approval is required, ensure project and cost analysis has been reviewed by the Enterprise Risk Management and Financial Planning & Analysis departments.
2. Release engineering labor and funds for detailed engineering on approved PAFs.
3. Review projects authorized for detailed engineering at least monthly to control engineering spend.

4. Review state PAC process performance and lessons learned and coordinate with the other state PACs and the EPAC to initiate any needed changes on at least a biennial basis.
5. Provide a forum for design review for more complex distribution street and line projects. The state PAC chairperson will use their judgement to determine which projects require distribution design review prior to state PAC approval.

Membership

Each state PAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator and non-voting attendees as shown in the below table. The chairperson may designate additional voting member directors, if required.

State PAC Membership List

State PAC Role	Company Position
Executive Sponsor	VP, Engineering
Chairperson	Director, Distribution Engineering
Administrator	Appointed by Chairperson
Voting Member	Manager, Distribution Engineering
Voting Member	Manager, Investment Planning
Voting Member	Manager, Distributed Generation
Voting Member	Manager/Supervisor, Field Engineering
Voting Member	Manager, Integrated Planning, Scheduling
Voting Member	Manager, System Operations
Voting Member	Manager, Field Operations
Voting Member	Manager, Substation Technical Engineering
Voting Member	Manager, Engineering Standards
Attendee	Project Manager(s)

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the state PAC
- Appoint the Chairperson

Chairperson

- Preside at state PAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a state PAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the state PAC meeting

- Hold votes as required
- Participate in discussions and votes to meet the state PAC objectives
- Release funds on approved PAFs for detailed engineering
- Initiate the biennial review of the state PAC process in coordination with the other state PACs
- Create subcommittees as required
- Determine which projects should complete a design review prior to state PAC approval

Voting Member

- If required, designate a voting alternate to participate in the state PAC
- Review meeting materials on the agenda prior to the state PAC meeting
- Participate in discussions and votes to meet the state PAC objectives
- Participate in the biennial review of the state PAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Distribute meeting materials to attendees three days prior to a scheduled state PAC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record PAFs presented and meeting results in the capital project database

Project Initiator (typically engineer level)

- Complete a PAF for any proposed capital project, ensuring that state PAC objective 1 items are fully met, and obtain any necessary reviews and approvals prior to submittal to the state PAC
- Submit the PAF to the state PAC administrator at least three working days prior to the next scheduled state PAC meeting for engineering approval
- Attend the state PAC meeting and present the PAF to state PAC members
- Revise the PAF and/or respond to comments from the state PAC as required
- Once fully authorized, if costs exceed the approved PAF levels by more than the amounts shown in Accounting Policy Statement No. 1, create a SRF, attach to the previously approved PAF, and resubmit for review and approval.

Quorum

The Chairperson(s) (or alternate) plus a minimum of two Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule

Each of the state PACs shall schedule meetings at least bimonthly. The Chairperson may cancel a meeting or require more frequent meetings from time to time as required.

Voting

The Member Directors and the Chairperson, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

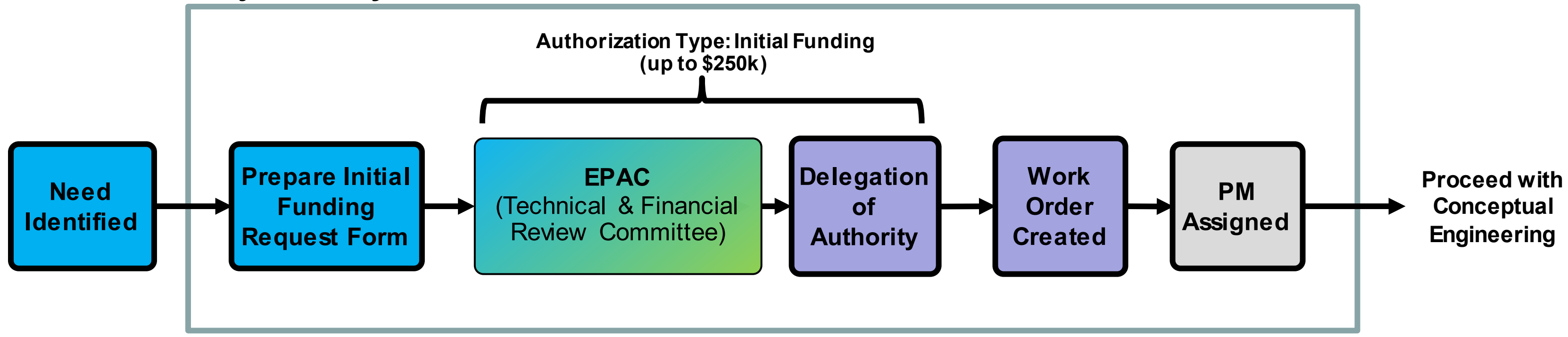
Subcommittees

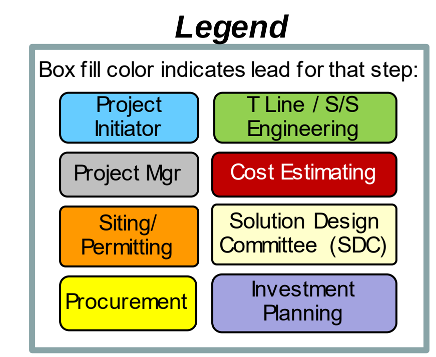
The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the state PAC. Subcommittees shall be chaired by a voting member of the state PAC or their designated alternate.

EVERSOURCE
Capital Project Approval Process

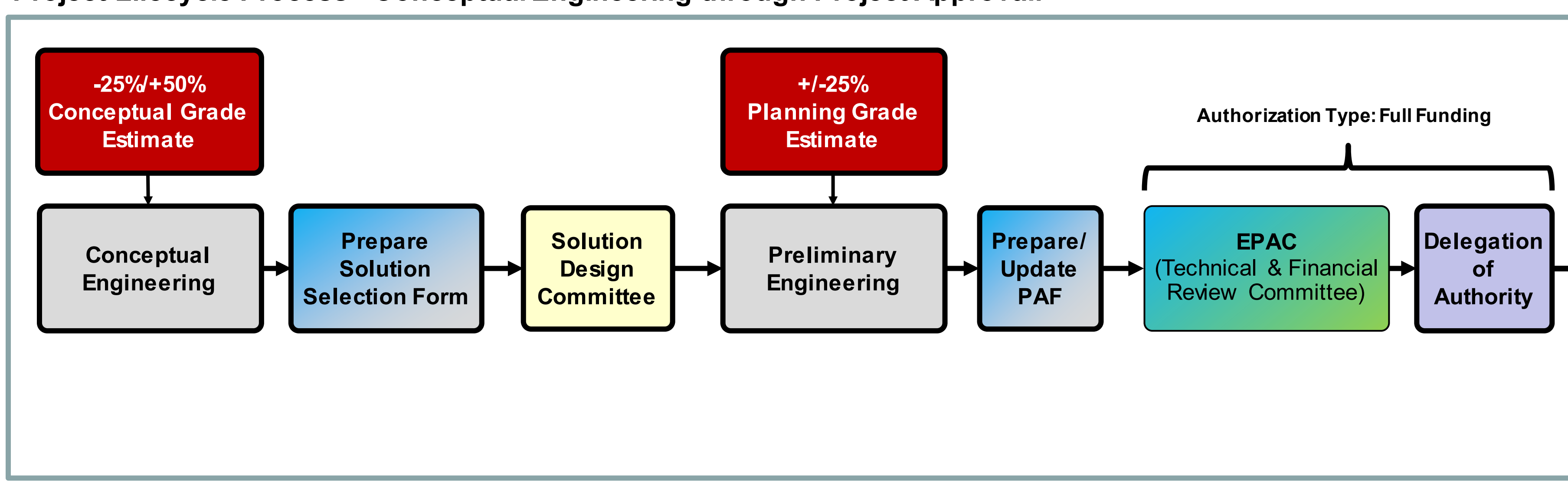
Attachment D, Transmission and Substation Project Approval Process Flow Charts

Project Lifecycle Initiation Process

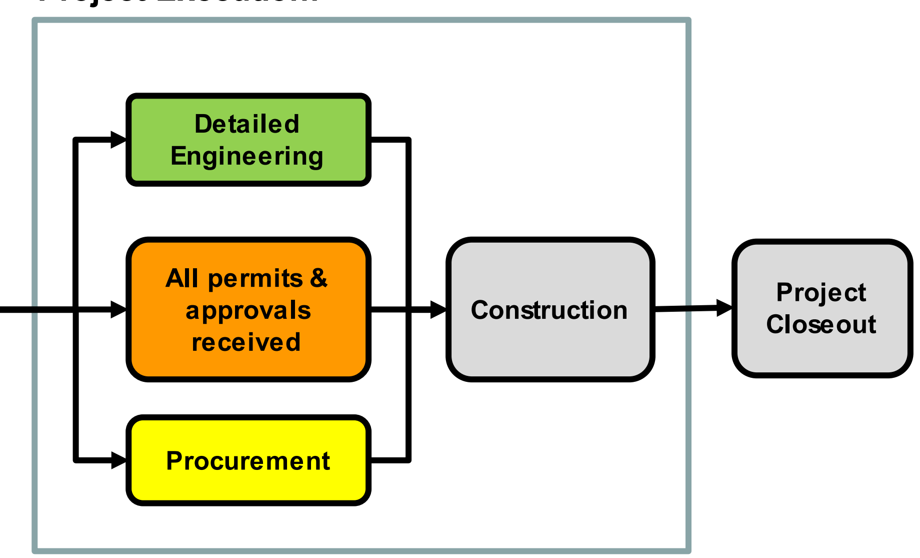




Project Lifecycle Process - Conceptual Engineering through Project Approval:

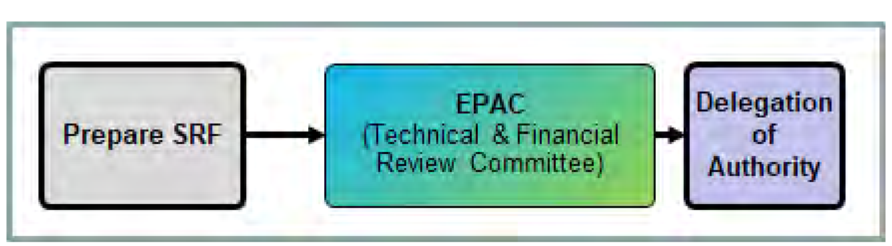


Project Execution:



Supplemental Authorization Process

(if required per APS guidelines)



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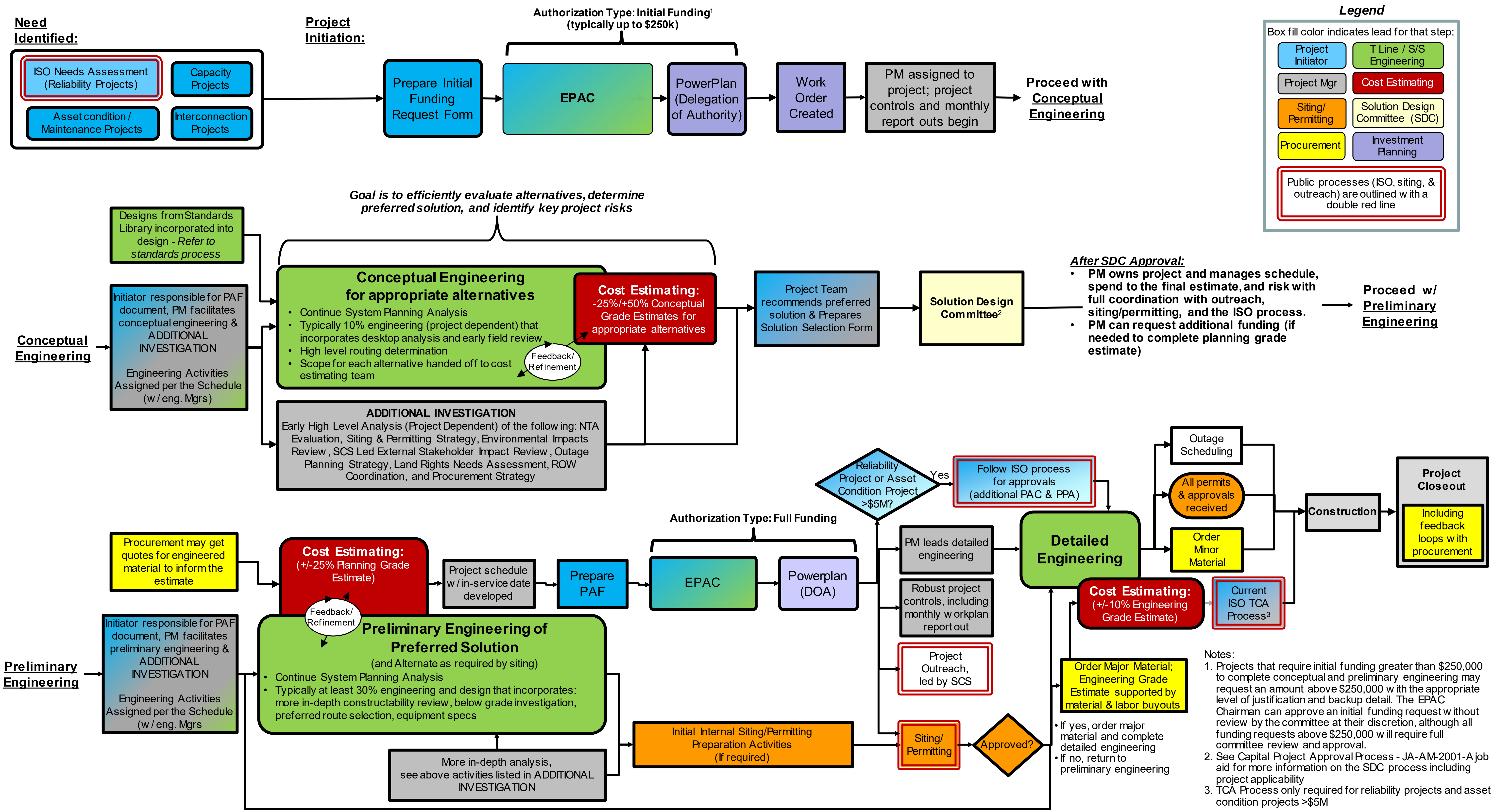
Exh. 10

EVERSOURCE
Capital Project Approval Process

Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart



Notes:
1. Projects that require initial funding greater than $250,000 to complete conceptual and preliminary engineering may request an amount above $250,000 with the appropriate level of justification and backup detail. The EPAC Chairman can approve an initial funding request without review by the committee at their discretion, although all funding requests above $250,000 will require full committee review and approval.
2. See Capital Project Approval Process - JA-AM-2001-A job aid for more information on the SDC process including project applicability
3. TCA Process only required for reliability projects and asset condition projects >$5M

Attachment F, Distribution Project Approval Process Flow Chart