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Request IR-1:

The report states that actual measurements were unavailable for the Metro region and forecast values from December 19, 2025, at 04:00 were used instead. Please explain:

(a) Why actual Metro observations were unavailable;

(b) What alternative observed weather sources existed;

(c) Whether actual observations from nearby stations were reviewed; and

(d) How reliance on forecast data affects the report's conclusions.

Response IR-1:

(a) The missing data from the Halifax station is a result of an issue with a data stream provided by Environment Canada that delivers historical data to NS Power's weather forecasting vendor. This data stream was not functioning as intended impacting the delivery of hourly weather conditions, resulting in missing data for this station. NS Power's vendor is currently troubleshooting the issue to address the missing data.

(b) Other Environment Canada and private weather stations are present within the region; however, the Halifax Airport station is considered the representative station for the Metro region.

(c) In terms of the overall severity of the storm, other observations were reviewed as evidenced by the weather event summary provided on slide 2 of the December 19-20, 2025 Storm Report. Although detailed hourly data was unavailable, this data points to the significant wind gusts occurring within the Metro region.

(d) The availability of hourly data from the Halifax station does not change the conclusion that this storm represented a strong wind and rain event causing impacts across the province.

Request IR-2:

Please provide NS Power's storm event cause assignment methodology, including definitions, decision rules, hierarchy of cause coding, and the proportion of events whose causes were confirmed by field inspection versus inferred from outage management system records.

Response IR-2:

NS Power applies Electricity Canada's outage cause-coding methodology consistently across all events, including during storm events. Outage causes are field-validated wherever possible, where sufficient evidence is not available, the cause is coded accordingly. Please see additional details on cause code application provided in Attachment 1.

CEA DEFINITIONS

CI = Customer Interruptions

Total number of customers without power

CHI = Customer Hours of Interruption

Combination of customers and duration

SAIFI = Average Outage Frequency

Customer interruptions / # of customers

SAIDI = Average Outage Duration

Customer hours of interruption / # of customers

CAIDI = Average Outage Duration (for those interrupted)

Customer hours of interruption / # of customer interruptions

Unknown/other

Interruptions with no apparent cause or reason identified that could have contributed to the outage

Scheduled outage

Interruptions due to the planned disconnection for construction or maintenance purposes

Loss of supply

Interruptions due to problem in the bulk electricity system (transmission)

Tree contacts

Interruptions caused by trees or tree limbs contacting energized circuits

Lightning

Interruptions due to lightning strike on energized circuits

Defective equipment

Interruptions resulting from equipment failures

Adverse weather

Interruptions resulting from weather conditions (e.g. Rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost)

Adverse environment

Interruptions due to equipment being subjected to abnormal environmental conditions (e.g. Salt spray, contamination, humidity, corrosion, vibration, fire, or flooding)

Human element

Interruptions due to errors of utility staff in construction, maintenance, or operations

Foreign interference

Interruptions due to external contacts beyond the control of the utility (e.g. Birds, animals, vehicles, dig-ins, or other foreign objects)

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Request IR-3:

For all outages attributed to tree contact, please provide a detailed breakdown, including:

(a) The number and percentage of incidents involving trees located within the maintained right-of-way;

(b) The number and percentage involving hazard or "danger" trees located outside the right-of-way;

(c) The number and percentage attributable to customer-owned trees;

(d) A comparison of impacts to service lines versus primary distribution lines;

(e) A classification of affected feeders by urban versus rural designation;

(f) The date of the most recent vegetation management work performed on each affected line segment;

(g) Any prior patrol records, inspections, or hazard notifications associated with those segments; and

(h) The total number of unique customer impacts from this storm attributable specifically to tree-related outages.

Response IR-3:

(a–b) In its outage event data, NS Power does not specifically attribute tree contact events with reference to right-of-way location of the tree. Consequently, specific percentages of events attributable to in-ROW versus out-of-ROW trees for the December 19-20, 2025 event is not available.

(c-d) As detailed above in (a-b), NS Power does not record the exact tree outage fault location for distribution events in its outage event data, and therefore, cannot summarize the outage data by primary, secondary/service, or property ownership.

(e) Please refer to IR-03 Attachment 1 for affected feeders with urban, suburban, and rural classifications.

(f-g) Please refer to IR-03 Attachment 2 for a list of feeders affected by vegetation-related outages during the December 19–20 storm event. Columns 3 and 4 of the table display each feeder's most recent intervention year and its average vegetation condition. As outages are not tracked at the span level, the table identifies impacted feeders along with their last recorded intervention year. Vegetation condition is a key indicator used to assess risk from a vegetation management perspective and is scored on a scale of 1 to 5, where 1 represents the lowest level of concern and 5 the highest. Any imminent threats from vegetation identified through routine patrols are addressed immediately.

(h) Based on outage events coded as tree-contacts, 124,035 unique customers were impacted by these events. Should a percentage of adverse weather-related outages be considered, this impact would be higher.

Feeder	Classification
100C-421	rural
100C-422	rural
101H-411	suburban
101H-412	suburban
101H-413	suburban
101H-421	suburban
101W-411	rural
102W-312	rural
103H-432	suburban
103H-433	suburban
103H-434	urban
103W-311	rural
103W-312	rural
104H-411	urban
104H-413	urban
104H-421	urban
104H-441	urban
104S-311	suburban
104S-313	rural
111S-314	urban
113H-432	suburban
113H-434	suburban
113H-443	suburban
113H-444	suburban
11S-301	rural
11S-302	rural
11S-411	rural
126H-311	suburban
127H-411	suburban
12V-302	rural
12V-304	rural
131H-422	suburban
131H-423	suburban
137H-411	rural
137H-412	suburban
137H-413	rural
137H-414	suburban
13V-303	rural
141H-401	Urban
143H-412	Urban
15N-401	suburban
15N-403	rural
15N-404	suburban

Feeder	Classification
15S-303	suburban
16N-301	rural
16N-302	rural
16V-314	rural
16V-315	rural
16W-301	rural
16W-302	rural
18V-411	rural
18V-412	rural
18V-413	rural
1C-411	rural
1H-415	urban
1H-427	urban
1H-454	urban
1N-402	suburban
1N-403	suburban
1N-404	rural
1N-405	rural
1N-421	suburban
1V-443	rural
20V-311	rural
22C-401	rural
22C-402	rural
22C-403	rural
22C-404	rural
22N-402	rural
22V-321	suburban
23H-304	urban
24C-443	rural
25W-301	rural
2C-402	rural
2H-413	urban
2H-421	Urban
2H-422	Urban
2H-424	Urban
36V-301	rural
36V-302	rural
36V-303	rural
36W-304	rural
37N-411	rural
37N-413	rural
3N-412	rural
3S-303	suburban

Feeder	Classification
3S-307	suburban
3S-309	suburban
3S-403	rural
40H-302	urban
48H-303	suburban
48H-304	suburban
4C-424	rural
4C-430	rural
4C-432	rural
4C-441	rural
4N-311	rural
4N-312	rural
4N-313	rural
4S-322	suburban
4S-334	suburban
50N-410	rural
50N-411	rural
50N-412	suburban
50V-401	suburban
50V-402	suburban
50W-412	suburban
55N-204	suburban
55V-313	rural
55V-314	rural
55V-322	rural
56N-401	rural
56N-414	rural
57C-422	rural
57C-426	rural
57S-401	rural
57S-402	rural
57W-401	rural
57W-402	rural
58C-403	rural
58C-405	rural
58H-421	suburban
58H-431	suburban
59C-401	rural
59C-402	rural
62N-413	rural
62N-414	rural
62N-415	rural
62N-416	rural

Feeder	Classification
63V-313	rural
65V-302	suburban
65V-303	suburban
67C-411	rural
67C-412	rural
6N-302	rural
70W-313	rural
70W-314	urban
70W-321	suburban
73W-411	rural
74N-411	rural
74N-412	rural
76V-301	rural
77V-302	rural
78W-301	rural
78W-302	rural
79V-401	rural
79V-403	rural
81N-411	rural
81N-412	rural
81S-303	suburban
81S-304	suburban
82V-401	rural
82V-402	rural
82V-403	rural
82V-422	suburban
82V-423	rural
83V-301	rural
83V-303	rural
84W-301	rural
84W-302	rural
85S-401	rural
87H-311	suburban
87H-312	suburban
87H-313	rural
87W-311	rural
87W-312	rural
88H-401	rural
88H-402	rural
88W-322	rural
88W-323	rural
89W-302	suburban
89W-303	rural

Feeder	Classification
91W-411	rural
92H-331	rural
92W-302	rural
93V-311	rural
93V-312	rural
93V-313	rural
93V-314	rural
96H-411	rural
96H-412	rural
99V-311	suburban
99V-312	suburban
99V-314	rural
9C-303	rural

FEEDER	CLASSIFICATION	TRIMYEAR	AVGVEGCONDITION
100C-421	rural	2026	2.08
100C-422	rural	2025	2.37
101H-411	suburban	2025	3.38
101H-412	suburban	2025	2.51
101H-413	suburban	2025	2.88
101H-421	suburban	2025	2.91
101W-411	rural	#N/A	#N/A
102W-312	rural	2024	3.48
103H-432	suburban	2023	2.45
103H-433	suburban	2022	1.42
103H-434	urban	2023	2.83
103W-311	rural	2025	3.45
103W-312	rural	2025	3.88
104H-411	urban	2025	3.09
104H-413	urban	2025	3.36
104H-421	urban	2022	3.17
104H-441	urban	2023	2.72
104S-311	suburban	2025	3.12
104S-313	rural	2026	2.86
111S-314	urban	2015	2.47
113H-432	suburban	2026	2.33
113H-434	suburban	2023	1.96
113H-443	suburban	2025	1.86
113H-444	suburban	#N/A	3.72
11S-301	rural	2023	3.16
11S-302	rural	2025	2.19
11S-411	rural	2025	2.83
126H-311	suburban	2025	3.32
127H-411	suburban	2025	2.61
12V-302	rural	2024	2.52
12V-304	rural	2025	3.05
131H-422	suburban	2025	2.79
131H-423	suburban	2023	2.82
137H-411	rural	2025	2.42
137H-412	suburban	2025	2.46
137H-413	rural	2025	2.29
137H-414	suburban	2019	2.26
13V-303	rural	2023	3.73
141H-401	Urban	#N/A	0.46
143H-412	Urban	#N/A	#N/A
15N-401	suburban	2025	2.10
15N-403	rural	2026	2.28
15N-404	suburban	2025	2.10

FEEDER	CLASSIFICATION	TRIMYEAR	AVGVEGCONDITION
15S-303	suburban	#N/A	1.02
16N-301	rural	2025	2.53
16N-302	rural	2025	2.83
16V-314	rural	2025	2.59
16V-315	rural	2025	2.22
16W-301	rural	2025	1.98
16W-302	rural	2026	3.10
18V-411	rural	2023	2.77
18V-412	rural	2025	1.85
18V-413	rural	2023	2.74
1C-411	rural	2018	1.40
1H-415	urban	2019	1.81
1H-427	urban	2022	3.11
1H-454	urban	2022	2.92
1N-402	suburban	2025	2.15
1N-403	suburban	2025	1.47
1N-404	rural	2019	2.58
1N-405	rural	2025	2.58
1N-421	suburban	2025	1.49
1V-443	rural	2025	3.16
20V-311	rural	2025	2.49
22C-401	rural	2022	2.17
22C-402	rural	2025	2.60
22C-403	rural	2017	2.73
22C-404	rural	2024	1.59
22N-402	rural	2025	1.77
22V-321	suburban	2016	2.56
23H-304	urban	2025	3.55
24C-443	rural	2025	2.36
25W-301	rural	2026	2.92
2C-402	rural	2025	2.34
2H-413	urban	2025	3.74
2H-421	Urban	2022	3.25
2H-422	Urban	2024	3.10
2H-424	Urban	2023	3.29
36V-301	rural	2024	1.98
36V-302	rural	2024	2.40
36V-303	rural	2025	3.04
36W-304	rural	2024	3.50
37N-411	rural	2025	2.17
37N-413	rural	2024	2.39
3N-412	rural	2025	2.38
3S-303	suburban	2017	2.00

FEEDER	CLASSIFICATION	TRIMYEAR	AVGVEGCONDITION
3S-307	suburban	2021	1.13
3S-309	suburban	2021	1.79
3S-403	rural	2026	2.92
40H-302	urban	2025	2.80
48H-303	suburban	2024	0.65
48H-304	suburban	#N/A	1.62
4C-424	rural	2025	2.37
4C-430	rural	2026	2.41
4C-432	rural	2025	2.40
4C-441	rural	2025	2.32
4N-311	rural	2023	2.23
4N-312	rural	2025	2.19
4N-313	rural	2024	2.74
4S-322	suburban	#N/A	1.16
4S-334	suburban	#N/A	1.26
50N-410	rural	2025	2.52
50N-411	rural	2024	2.19
50N-412	suburban	2026	1.97
50V-401	suburban	2025	2.60
50V-402	suburban	2022	2.36
50W-412	suburban	2026	3.17
55N-204	suburban	2025	2.10
55V-313	rural	2024	2.81
55V-314	rural	2025	2.66
55V-322	rural	2024	3.20
56N-401	rural	2025	2.74
56N-414	rural	2025	2.28
57C-422	rural	2025	3.04
57C-426	rural	2025	2.24
57S-401	rural	2024	2.41
57S-402	rural	2020	3.08
57W-401	rural	2025	3.74
57W-402	rural	2026	3.47
58C-403	rural	2025	2.29
58C-405	rural	2025	2.63
58H-421	suburban	2023	1.73
58H-431	suburban	2024	1.29
59C-401	rural	2017	2.46
59C-402	rural	2025	2.41
62N-413	rural	2026	2.42
62N-414	rural	2025	2.37
62N-415	rural	2025	2.38
62N-416	rural	2025	2.22

FEEDER	CLASSIFICATION	TRIMYEAR	AVGVEGCONDITION
63V-313	rural	2025	2.82
65V-302	suburban	2026	3.31
65V-303	suburban	2019	2.50
67C-411	rural	2024	2.36
67C-412	rural	2024	2.82
6N-302	rural	2023	1.83
70W-313	rural	2025	3.27
70W-314	urban	2017	1.39
70W-321	suburban	2024	2.95
73W-411	rural	2026	3.29
74N-411	rural	2024	2.07
74N-412	rural	2026	2.39
76V-301	rural	2025	3.77
77V-302	rural	2025	3.24
78W-301	rural	2022	3.11
78W-302	rural	2021	2.91
79V-401	rural	2025	2.82
79V-403	rural	2025	2.35
81N-411	rural	2025	1.92
81N-412	rural	2025	2.63
81S-303	suburban	2019	1.49
81S-304	suburban	#N/A	0.93
82V-401	rural	2025	2.24
82V-402	rural	2026	2.40
82V-403	rural	2025	2.65
82V-422	suburban	2024	2.74
82V-423	rural	2021	2.71
83V-301	rural	2024	2.28
83V-303	rural	2025	3.05
84W-301	rural	2025	3.64
84W-302	rural	2025	3.64
85S-401	rural	2025	2.57
87H-311	suburban	2024	3.26
87H-312	suburban	2024	2.95
87H-313	rural	2023	3.17
87W-311	rural	2025	3.33
87W-312	rural	2025	3.23
88H-401	rural	2025	2.43
88H-402	rural	2024	2.80
88W-322	rural	2025	1.57
88W-323	rural	2025	1.83
89W-302	suburban	2017	3.02
89W-303	rural	2025	3.50

FEEDER	CLASSIFICATION	TRIMYEAR	AVGVEGCONDITION
91W-411	rural	2024	3.67
92H-331	rural	2025	2.66
92W-302	rural	2020	3.39
93V-311	rural	2016	2.20
93V-312	rural	#N/A	1.33
93V-313	rural	2015	2.50
93V-314	rural	#N/A	0.34
96H-411	rural	2022	2.96
96H-412	rural	2022	2.38
99V-311	suburban	2021	2.79
99V-312	suburban	2025	2.40
99V-314	rural	2025	3.25
9C-303	rural	2021	2.87

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Request IR-4:

For all outages attributed to adverse weather, please provide:

(a) The observed or inferred cause or contributing factor for each outage (e.g., wind, lightning, ice, flooding); and

(b) A summary of customer interruptions and Customer Hours of Interruption (CHI), categorized by each identified adverse weather mechanism.

Response IR-4:

(a) Wind was identified as the only inferred cause for outages attributed to adverse weather during this windstorm event.

(b) Outages attributed to wind resulted in a total of 569,313 Customer Hours of Interruption (CHI).

Request IR-5:

Please provide a comprehensive list of all outages classified as resulting from equipment failure or mechanical failure. For each outage, include:

(a) The type of equipment involved;

(b) The age of the equipment at the time of failure;

(c) Any known prior defects or issues; and

(d) The findings of any post event review, including whether the failure was determined to be primarily driven by weather, age, or maintenance factors.

Response IR-5:

A list of outages coded as failed equipment are provided in Attachment 1.

(a) See list below for equipment identified as defective or failed equipment during the Dec 19-20 storm event, including the associated Customer Hours of Interruption (CHI) and event counts.

Failed Equipment	Sum of CHI	Count of Events
Cutout	123	2
Fuse Link	20	1
Inline Disconnector	14,557	1
Jumper	2,032	2
Lead	57	3
Pin Insulator	1,719	3
Pole mount TX	230	2
Primary Aerial Conductor	399	4
Secondary Aerial Conductor	15	1
Service	8	1
Tie Wire	918	1

Failed Equipment	Sum of CHI	Count of Events
Wedge Grip	91	3
Wood Pole	70	1
Total	20,242	25

(b) NS Power does not maintain age profiles for the vast majority of its distribution equipment, so no age information is available for the specific failed equipment during this event. NS Power uses a variety of factors to determine the specific assets targeted for replacement and generally, targeted assets have experienced degradation in performance manifesting in decreased reliability, increased maintenance frequency and cost, or reduced functionality. These effects are largely identified through reliability tracking and field inspections of the impacted assets rather than simply the age of the assets.

Asset age is a concern when the frequency of required maintenance is increased, the availability of replacement parts or critical spares is limited, or performance is negatively impacted. This information can be used to inform project prioritization. However, age would only be used in concert with asset condition, performance, and legislated requirements; it is never the single determining element in risk-based decision-making.

(c) NS Power's distribution inspection program collects data on an exception-only basis; inspection records are created only when defects are identified by line inspectors. Consequently, not all individual assets have an inspection record created following an inspection. Additionally, even when a record is created, it may capture a range of defects and/or conditions, with only a minority requiring short-term action. A large majority of asset defects or conditions do not present an immediate reliability concern and arise from conditions that can be addressed with a planned capital project in a future year and are prioritized accordingly. Furthermore, in general, NS Power's outage data only includes the type of asset failed (insulator, pole, etc..) but does not include the facility ID of the asset which failed.

(d) NS Power does not re-evaluate all equipment failures associated with weather-related outages unless new evidence warrants further review. Further investigation may be undertaken where anomalies are identified during restoration or where equipment performance results in unexpected or material customer impact.

For this event, outages attributed to device failure or defective equipment represent a small proportion of overall storm impact. Specifically, 20,242 Customer Hours of Interruption (CHI), out of a total 2,112,088 CHI, were associated with Device Failure/Defective Equipment, representing less than 1 percent of total attributable outage causes. NS Power did not consider that any of the failures experienced during this event met the threshold for subsequent investigation.

Date	Source	Duration (mir	Duration (Hr)	CI	CH	CEA Description	Sub-Cause	Storm Day	Device Failed
2025-12-20	50N-410	1982.3	33.0	1	33.0375	Defective Equipment	Mechanical Failure	Event Day	Cutout
2025-12-20	143H-413	1791.8	29.9	3	89.589	Defective Equipment	Mechanical Failure	Event Day	Cutout
2025-12-20	36V-302	1226.4	20.4	1	20.4405	Defective Equipment	Mechanical Failure	Event Day	Fuse Link
2025-12-20	23H-304	243.7	4.1	3584	14557.01333	Defective Equipment	Mechanical Failure	Event Day	Inline Disconnector
2025-12-20	37N-411	142.0	2.4	858	2030.6	Defective Equipment	Mechanical Failure	Event Day	Jumper
2025-12-20	81S-306	94.9	1.6	1	1.581333333	Defective Equipment	Mechanical Failure	Event Day	Jumper
2025-12-19	101H-423	119.9	2.0	14	27.97666667	Defective Equipment	Mechanical Failure	Event Day	Lead
2025-12-19	131H-424	178.5	3.0	8	23.796	Defective Equipment	Mechanical Failure	Event Day	Lead
2025-12-20	103H-433	342.4	5.7	1	5.707	Defective Equipment	Mechanical Failure	Event Day	Lead
2025-12-19	58C-403	6.3	0.1	1038	109.336	Defective Equipment	Mechanical Failure	Event Day	Pin Insulator
2025-12-19	81S-303	1132.3	18.9	11	207.5828333	Defective Equipment	Mechanical Failure	Event Day	Pin Insulator
2025-12-19	81S-302	712.8	11.9	118	1401.781	Defective Equipment	Mechanical Failure	Event Day	Pin Insulator
2025-12-19	58C-403	839.9	14.0	1	13.99833333	Defective Equipment	Electrical Failure	Event Day	Polemount TX
2025-12-20	2C-402	419.0	7.0	31	216.4678333	Defective Equipment	Mechanical Failure	Event Day	Polemount TX
2025-12-20	59C-402	272.7	4.5	60	272.65	Defective Equipment	Mechanical Failure	Event Day	Primary Aerial Conductor
2025-12-20	85S-401	210.6	3.5	4	14.03666667	Defective Equipment	Mechanical Failure	Event Day	Primary Aerial Conductor
2025-12-20	22V-322	107.7	1.8	41	73.58133333	Defective Equipment	Mechanical Failure	Event Day	Primary Aerial Conductor
2025-12-20	58C-403	1163.5	19.4	2	38.78166667	Defective Equipment	Electrical Failure	Event Day	Primary Aerial Conductor
2025-12-20	93V-311	901.7	15.0	1	15.0275	Defective Equipment	Electrical Failure	Event Day	Secondary Aerial Conductor
2025-12-20	93V-311	509.3	8.5	1	8.487833333	Defective Equipment	Electrical Failure	Event Day	Service
2025-12-19	58C-403	36.5	0.6	1509	918.478	Defective Equipment	Mechanical Failure	Event Day	Tie Wire
2025-12-19	127H-411	29.9	0.5	1	0.498666667	Defective Equipment	Mechanical Failure	Event Day	Wedge Grip
2025-12-20	16N-301	2903.0	48.4	1	48.3825	Defective Equipment	Mechanical Failure	Event Day	Wedge Grip
2025-12-20	1N-403	2543.2	42.4	1	42.38616667	Defective Equipment	Mechanical Failure	Event Day	Wedge Grip
2025-12-20	56N-414	2111.1	35.2	2	70.36833333	Defective Equipment	Mechanical Failure	Event Day	Wood Pole

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Request IR-6:

Please provide a detailed explanation for each loss of supply or transmission outage referenced in the report. For each event, include:

(a) The number of unique customers affected and the duration of the outage;

(b) Whether system redundancy existed and how it functioned during the event; and

(c) Whether this failure mode had been previously identified in planning studies or maintenance assessments.

Response IR-6:

(a-c) 13 outage events on the distribution system were a result of a loss of supply during the December 19-20 storm event. Each event impacted a full feeder, but all 13 were a result of a single initiating event on the transmission system that, due to the configuration of the system, led to outages for customers at four substations. The outage was caused by a broken transmission line lead within a substation as a result of high winds. 19,379 unique customers were impacted by the event, and duration of customer outages ranged from 4.5 to 8.5 hours depending on the specific substation impacted. Three of the four impacted substations are fed via radial transmission lines, which meant that until the source was restored, no customer restorations could take place from those substations. One of the impacted feeders at the fourth substation was able to be restored due to available switching opportunities. This response was consistent with the expected operation of the system configuration in this area. While the condition of the failed asset was not specifically identified in previous inspections, the potential for high winds to result in equipment failure is not an unexpected failure mode.

Request IR-7:

Please provide restoration performance in the following additional forms:

(a) Restoration within 6,12,24 and 48 hours measured from each outage start, not storm onset; and

(b) The number of outages by region and by cause category.

Response IR-7:

(a) Based on the duration of each outage, customer restoration for 6, 12, 24, and 48 hours is provided in the table below:

Provincial	%
Within 6 Hours	51.75
Within 12 Hours	75.74
Within 24 Hours	96.85
Within 48 Hours	99.75

(b) The number of outage events by region and cause code is provided in the table below:

Region	Unknown / Other	Scheduled Outage	Loss of Supply	Tree Contacts	Failed Equipment	Adverse Weather	Adverse Environment	Foreign Interference
Valley	2	2	-	115	4	140	-	-
South Shore	9	3	-	116	-	139	1	-
Northern	-	-	6	28	1	64	-	-
Northeastern	10	-	7	185	4	254	1	2
Metro	6	4	-	186	6	225	-	-
Eastern Shore	1	-	-	16	-	12	-	-

Region	Unknown / Other	Scheduled Outage	Loss of Supply	Tree Contacts	Failed Equipment	Adverse Weather	Adverse Environment	Foreign Interference
CB West	1	-	-	38	6	33	-	-
CB East	2	1	-	53	4	99	-	1

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Request IR-8:

Please provide Customer Hours of Interruption (CHI), Customer Interruptions (CI), and average outage duration, categorized by the following event types:

(a) Transmission-supplied events;

(b) Substation events;

(c) Feeder backbone events;

(d) Lateral events;

(e) Service line events; and

(f) Customer specific outages.

Response IR-8:

(a) The loss-of-supply outages detailed in IR-06 although originating on a transmission line lead, fell within a substation and were coded accordingly and included in part (b) below.

(b)

Event Type	Sum of CI	Sum of CH	Average of Duration (Hrs)
Substation	24,064	170,634	6.72

(c) NS Power does not classify outage events based on "Feeder Backbone", but has provided a subset of events that would represent larger events consistent with outages originating on feeder mainlines.

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Event Type	Sum of CI	Sum of CH	Average of Duration (Hrs)
Feeder Source	107,240	619,316	5.81

(d) Similar to part (c), NS Power does not classify outage events based on "Lateral", but has provided a subset of events that would represent smaller events consistent with (but not necessarily limited to) outages impacting feeder laterals and smaller sections.

Event Type	Sum of CI	Sum of CH	Average of Duration (Hrs)
Feeder Section	136,090	1,302,238	19.5

(e) The "Service Line Events" included below are those impacting a single customer. Depending on the specific configuration of the system feeding these customers, these events may also include outages not originating on a customer's service line, but would still only impact a single customer.

Event Type	Sum of CI	Sum of CH	Average of Duration (Hrs)
Service Line Events (CI = 1)	960	19,898	20.7

(f) The "customer-specific" outages would be the same set of events as the outages summarized in part (e) above.

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Request IR-9:

Section 5 refers to the storm bringing, "… upwards of 40 mm of heavy rain that tapered off before temperatures fell below freezing". Provide the following for each zone where customers were restored after temperatures fell below freezing:

(a) The number of customers restored after temperatures fell below freezing;

(b) How far below freezing temperatures fell before customers were restored; and

(c) How long temperatures were below freezing until customers were restored.

Response IR-9:

(a) The table below shows the number of customers restored after the first recorded time where temperatures reached 0 degrees Celsius.

Weather Zone	First Freezing Time	Customers Restored after First Freezing Time
Valley	2025-12-20 09:00:00	19,596
South Shore	2025-12-20 22:00:00	1,341
Northern	2025-12-20 09:00:00	4,457
Northeast	2025-12-20 11:00:00	19,076
Metro	2025-12-20 12:00:00	30,173
Eastern Shore	2025-12-20 13:00:00	1,465
CB West	2025-12-20 12:00:00	3,182
CB East	2025-12-20 14:00:00	10,712

(b) The table below shows the minimum temperature recorded during the weather event.

Weather Zone	Minimum Temperature During Weather Event (°C)
Valley	-11
South Shore	-7
Northern	-12
Northeast	-10
Metro	-10
Eastern Shore	-7
CB West	-8
CB East	-10

(c) The table below represents the average duration a customer was without power after the first time temperatures fell below freezing.

Weather Zone	Customer Weighted Average Duration of Outages After First Freezing Time
Valley	6.3
South Shore	6.3
Northern	9.2
Northeast	3.8
Metro	7.5
Eastern Shore	7.5
CB West	18.2
CB East	4.7

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Request IR-10:

The report refers to a January 4-5, 2018 storm. Compared to the December 19-20, 2025 storm, the January 2018 storm included snow, ice pellets and freezing rain; interrupted 144,439 more customers; had 17,994 fewer customer hours of interruption; had 0.95% more customers restored in 48 hours; involved >160 fewer field resources; and had peak winds 35 km/h higher. The January 2018 storm appears to have been more severe and interrupted more customers yet involved significantly less resources, resulting in fewer customer hours of interruption and having more customers restored within 48 hrs. Why?

Response IR-10:

While the January 4–5, 2018 storm affected a larger number of customers and recorded higher peak wind speeds, storm severity metrics alone do not directly translate into restoration duration or customer hours of interruption (CHI). Although peak winds were higher during the January 4–5, 2018 storm, wind speeds during the December 19–20, 2025 storm were still well above warning levels and sufficient to cause substantial equipment and vegetation damage across the system. When field resources are compared on a like-for-like basis, the number of internal and external PLTs deployed during the two events was effectively the same, with 288 PLTs utilized in each case. As such, differences in restoration outcomes are not attributable to materially different PLT deployment levels.

The primary driver of the higher CHI and lower percentage of customers restored within 48 hours during the December 19–20, 2025 storm relates to event timing and operating conditions. The January 4–5, 2018 storm unfolded largely during daytime hours, allowing for immediate damage assessment and more productive early restoration activity. In contrast, the December 19–20, 2025 storm's peak outages occurred around 1:30 a.m., limiting safe response and assessment during the initial hours of the event, delaying restoration progress, extending the overall event duration, and increasing accumulated CHI. While storm-to-storm comparisons are included at the request of the NSEB, large weather events are inherently unique, and differences in timing, damage characteristics, and operating conditions mean that direct comparisons will not align perfectly and should be interpreted with this context in mind.

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Request IR-11:

The report states that "Over 600 field resources were mobilized to restore power in affected areas" and that "Transmission crews were staged near possible transmission events to allow for quick response".

(a) What was the actual number of field resources used?

(b) What is the average hourly cost of 1 field resource?

(c) What is the total number of hours that field resources were on stand-by or unable to work but still being paid?

Response IR-11:

(a) The exact number of resources in the field varied over the duration of the event but a total of 826 resources were active in the field at some point during the event. This includes resources such as safety specialists, power line technicians, substation technicians, crew leads, supervisors, damage assessors, traffic control, vegetation crews, runners, and mechanics.

b) The average hourly storm rates of the above-mentioned resources vary greatly. They range from $46 for traffic control personnel to $213 for contractor PLTs.

(c) For safety reasons, crews do not do any aerial work in buckets when winds exceed 80 km/h, however crews are able to continue with work at ground level including preparing job sites or patrolling lines, therefore there are no times that field resources were solely on stand-by or unable to work.

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Request IR-12:

Section 6 refers to a "Prediction model".

(a) Explain the prediction model used by NS Power for this storm.

(b) How does the model work?

(c) What was the model used to predict?

(d) How did NS Power use the information from the model?

Response IR-12:

(a) As detailed in section 4.0 of NS Power's Emergency Services Restoration Plan, most recently filed as part of M12441, the damage prediction model is a tool available to NS Power that correlates weather forecasts and predictions with historical outage and damage experience to provide an indication of the impact on the system from an adverse weather event.

(b) In general, the model translates or correlates the weather inputs obtained from pre-event forecasts into a level of weather severity and then into regional-level estimates of customer outage and damage to the system using the experience and outage data obtained from previous storm events.

(c) The model is used to predict the volume of customer outages and damage to the system as a result of an adverse weather event.

(d) The outputs from the model are used to used to enable faster and better escalation and deployment decisions prior to arrival of an event. This ultimately provides inputs to support effective pre-storm planning processes contained within the ESRP.

Request IR-13:

In M12592, the Board recently approved NS Power's capital expenditure application for ECC Dynamic Line Rating (DRL) Implementation on transmission lines L-6415a, L-6415b, L-7003, L-7004, L-7005, L-8001, and L-8004. In response to IR-11 (d-f), NS Power said:

> **In cases where the unexpected loss of a transmission line or corridor would result in larger system impacts, such as in November 2018, advanced notice of emerging issues provided by the DLR sensors and software allows NS Power System Operators and other personnel to implement mitigation measures. This can have a positive impact on the overall system performance. For extreme events such as the November 2018 ice storm, NS Power estimates that with earlier knowledge of the developing adverse conditions, proactive actions to stage additional mainland generation and limit imports could have been taken and customer impacts could have been significantly reduced (by an estimated 50%). [Emphasis added]**
>
> **[M12592, Exhibit N-2, response to IR-11(d-f)]**

(a) Did any of the transmission lines approved for the DLR project, L-6415a, L-6415b, L-7003, L-7004, L-7005, L-8001, and L-8004, cause impacts to customers from the December 19-20, 2025 storm? If so, which ones and what were the Causes and Sub-Causes?

(b) For each of the above transmission lines that caused impacts to customers from the storm, provide the Zone, Date/Time, Weather Station, Direction (Degrees), Wind (km/h), Max Wind Gusts (km/h), Temp (°C), Cause, Sub-Cause, Description, Customers Impacted and Duration (Hours).

(c) Explain any differences in how this storm was handled compared to how it would have been handled if the DRL project was complete and the sensors fully operational.

For each zone, explain and quantify the expected differences in the number of customers impacted and the duration of outages.

Response IR-13:

(a) No.

(b) N/A

(c) In this event, no customer impacts were ultimately the result of outages to the transmission lines now enabled with DLR technology. No change to the outage impacts would have therefore been expected for this event.

However, in general, in future weather events where this functionality would be enabled, particularly where heavy wet snow and/or freezing rain was expected, there would be some differences in response supported by DLR. The new DLR functionality will allow NS Power to monitor the status of the DLR-enabled lines and to take pre-emptive corrective action should adverse conditions impact those lines. In the past, this monitoring would need to be undertaken by human observers who would be inherently limited by the accessibility to and visibility of these lines. Consequently, it would not be unexpected that adverse line conditions could develop without the knowledge of NS Power personnel and potentially leading to line outages and significant system and customer impacts. With the DLR technology, NS Power can monitor the entirety of the line in real time and make informed interventions well in advance of potential outages.

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Request IR-14:

The report's lesson learned section identifies observations but does not demonstrate what action NS Power has/will take. Please provide a comprehensive action plan arising from this storm. Does NS Power intend to make any changes to its vegetation management program as a result of lessons learned from this storm? If so, what changes? If not, why not?

Response IR-14:

As outlined in the NS Power Emergency Services Restoration Plan, NS Power conducts a Post-Event Critique led by Storm Leads across various teams and departments. Expanding on the lessons learned, the associated action items are as follows:

- The Restoration, Planning and Performance team will update the prediction model and undergo its annual calibration as planned with no special considerations from this storm.

- Transmission team to explore the use of additional drone contractors when helicopters cannot fly.

- Regional Operations to continue to use overnight damage assessment teams to keep crews focused on high priority work and have a dedicated lead to triage non-outages.

- Regional Operations to continue to provide media content where appropriate and educate the field from the media and communication perspective on content gathering and creation.

- Expand content creator roster for Communications Lead.

- Access passwords for some systems expire 30 days and mass resets need to be explored by the Operational Technology lead.

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NS Power does not intend to make any changes to its vegetation management program as a result of this storm. NS Power will maintain its vegetation management spending as outlined in the Five-Year Reliability Plan and prioritize annual plans based on condition assessments. The standards of clearance remain the same based on safety standards and the Normal Limits of Approach in the Occupational Health and Safety Act, Part 11, Section 126(4) and NS Power's Safe Work Practice 35. The industry standard for distribution right-of-way maintenance is generally a total width of 6 meters, or 3 meters on either side of the conductor, where feasible. The standard for transmission right-of-way is based on line voltage.