CENTRAL MAINE POWER
An AVANGRID Company

Planning & Coordination

DG Cluster Study Workshop

February 21, 2023

Agenda

01 Welcome & Introductions

02 CMP's Cluster Studies: Objectives & Process

03 "New" Terms & Conditions

04 Updated Exhibit 7

05 Network Upgrades

06 Opportunties

9:00-9:20

Welcome & Introductions

9:20-9:50

02 CMP’s Cluster Studies: Objectives & Process

Transmission Cluster Studies for DG

Why do we need to do these studies

In general, near-term growth projections are more accurate, while longer-term projections have usually been underestimated and can be significantly different than actual values.

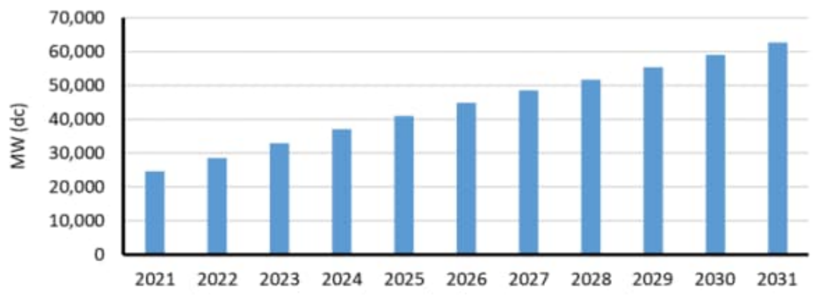

Figure 1: NERC-Wide Cumulative Distributed Solar PV Capacity — 2021 through 2031

DERs have impacted BPS performance in a number of major disturbances in North America and around the world including, but not limited to, the following:

- In August 2019, the United Kingdom experienced a grid disturbance that unexpectedly triggered underfrequency load shedding (UFLS). One of the contributing factors to the UFLS operation was a significant unexpected power reduction of DERs in addition to the other BPS generation losses. The Office of Gas and Electricity Markets (Ofgem) estimates that at least 1,300 MW of DERs were tripped and that "there is a significant possibility that this volume is in excess of the transmission-connected generation lost during the event." Further, Ofgem highlights that "understanding the role of distributed generation in the energy mix and the control of the electricity system" is of paramount importance moving forward.[6]
- In April and May 2018, CAISO experienced two fault events (the Angeles Forest and Palmdale Roost disturbances) that resulted in approximately 130 MW and 100 MW of DERs tripping, respectively.
- In July 2020, CAISO experienced a fault event in the San Fernando Valley that caused approximately 80 MW of DER tripping.[7]

Source: *NERC ERO Enterprise CMEP Practice Guide: Modeling and Studies Involving Distributed Energy Resources, Oct. 13, 2022*

Why are they challenging to perform

- Large Amount of Projects
- Multiple Study Components
- Complex Study Components
- Large Number of Scenarios to Study
- System Saturation
- Evolving Study Requirements
- Evolving Policy
- Unlimited Challenge Sessions

Solar Forecast

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ISO New England's Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report)

- 10-year projections used in power system planning and reliability studies.
- Includes the energy and peak load forecasts integrate state historical demand, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs.

Forecasts Used in Transmission Planning

2019

Gross 90/10 Summer Peak Load Forecast [1]

Load Zone	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	7,719	7,734	7,751	7,769	7,786	7,802	7,818	7,834	7,850	7,866
ME	**2,217**	**2,235**	**2,260**	**2,288**	**2,313**	**2,339**	**2,363**	**2,387**	**2,412**	**2,437**
NEMA	6,722	6,787	6,856	6,928	6,998	7,069	7,138	7,207	7,276	7,346
NH	2,572	2,587	2,604	2,622	2,638	2,654	2,671	2,688	2,706	2,724
RI	2,313	2,340	2,368	2,398	2,429	2,460	2,491	2,522	2,552	2,583
SEMA	4,119	4,151	4,186	4,222	4,257	4,292	4,327	4,361	4,396	4,430
VT	1,123	1,128	1,134	1,141	1,147	1,154	1,159	1,165	1,172	1,179
WCMA	4,047	4,088	4,130	4,175	4,218	4,261	4,304	4,347	4,389	4,433
MA (Sum of Load Zones	14,888	15,026	15,173	15,325	15,473	15,622	15,768	15,915	16,061	16,209
ISO-NE	**30,832**	**31,050**	**31,291**	**31,543**	**31,786**	**32,030**	**32,271**	**32,512**	**32,753**	**32,999**

PV Forecast [3,4,5] (June 1st Total Nameplate Capacity)

Load Zone	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	486	562	655	752	842	913	985	1,056	1,119	1,162
ME	**44**	**51**	**58**	**65**	**71**	**78**	**85**	**92**	**98**	**105**
NEMA	347	398	448	496	544	589	623	654	684	713
NH	88	101	113	125	137	149	161	173	185	197
RI	133	184	235	281	324	366	408	451	493	536
SEMA	714	820	923	1,022	1,121	1,212	1,283	1,346	1,408	1,467
VT	316	345	367	388	410	431	452	473	495	516
WCMA	903	1,036	1,166	1,291	1,416	1,531	1,621	1,701	1,779	1,854
MA (Sum of Load Zones	1,964	2,254	2,537	2,809	3,081	3,332	3,527	3,701	3,870	4,034
ISO-NE	**3,031**	**3,497**	**3,965**	**4,421**	**4,865**	**5,269**	**5,618**	**5,947**	**6,261**	**6,550**

FOOTNOTES:

(1) The "gross" load forecast is from a probabilistic distribution of forecast peak loads without reductions from EE and BTM PV. It represents the 90/10 peak demand forecast, which is a point on the distribution where the peak demand is expected to be exceeded 10% of summer seasons and not met 90% of summer seasons.

(3) This table includes SORs and Generators (per OP-14) that participate only in the energy market. Negative values in this category are due to the transfer of certain resources from energy-only PV to the Forward Capacity Market PV category.

(4) The forecasted nameplate PV that is expected to be in-service as of June 1st of the study year is used to represent the PV forecast in the summer peak load cases for that study year. For example, a summer 2021 peak load case will include a forecast of nameplate PV that is expected to be in-service as of June 1, 2021.

(5) Additional details on the modeling of PV forecast in transmission planning studies are available in the Transmission Planning Technical Guide, section 2.3.10. (https://www.iso-ne.com/static-assets/documents/2017/03/transmission_planning_techical_guide_rev4_1.pdf)

2022

Gross 90/10 Summer Peak Load Forecast [1]

Load Zone	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CT	7,603	7,621	7,641	7,662	7,696	7,730	7,769	7,813	7,865	7,923
ME	2,245	2,267	2,291	2,317	2,350	2,386	2,428	2,475	2,530	2,591
NEMA	6,184	6,211	6,243	6,279	6,324	6,366	6,411	6,457	6,504	6,553
NH	2,617	2,637	2,656	2,675	2,696	2,717	2,738	2,761	2,785	2,811
RI	2,175	2,188	2,202	2,216	2,234	2,252	2,273	2,295	2,319	2,345
SEMA	3,776	3,782	3,791	3,803	3,821	3,836	3,853	3,871	3,890	3,909
VT	1,070	1,074	1,079	1,088	1,105	1,122	1,142	1,165	1,189	1,214
WCMA	3,802	3,814	3,830	3,848	3,871	3,892	3,915	3,939	3,964	3,990
MA (Sum of Load Zones)	13,761	13,807	13,863	13,930	14,016	14,095	14,179	14,267	14,358	14,452
ISO-NE	29,472	29,594	29,732	29,889	30,098	30,302	30,528	30,776	31,046	31,336

PV Forecast [3,4,5] (June 1 Total Nameplate Capacity)

Load Zone	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CT	844	957	1,081	1,219	1,324	1,429	1,534	1,637	1,733	1,820
ME	158	302	523	738	960	1,121	1,147	1,172	1,198	1,223
NEMA	494	565	631	695	760	820	871	919	966	1,012
NH	166	196	224	250	277	304	331	358	384	411
RI	304	356	404	451	498	544	591	638	682	721
SEMA	1,072	1,225	1,370	1,509	1,648	1,780	1,891	1,994	2,095	2,195
VT	443	471	498	523	549	574	600	625	651	676
WCMA	1,526	1,744	1,950	2,149	2,347	2,534	2,692	2,839	2,983	3,125
MA (Sum of Load Zones)	3,092	3,534	3,951	4,353	4,755	5,134	5,455	5,752	6,044	6,331
ISO-NE	5,008	5,815	6,681	7,535	8,362	9,106	9,656	10,182	10,692	11,184

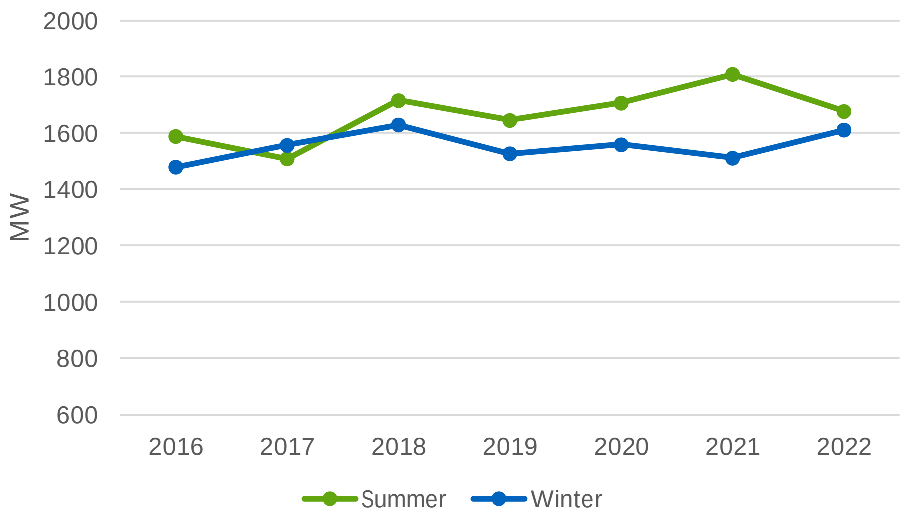
Footnotes for Section 6.2

1. The "gross" load forecast is from a probabilistic distribution of forecast peak loads without reductions resulting from energy efficiency and BTM PV. It represents the 90/10 peak demand forecast, which is a value within the distribution that peak demand has a 10% probability of exceeding in any summer period.
2. These values include an 8% gross-up to reflect avoided transmission and distribution losses.
3. The PV values reflected in this table are the sum of FCM PV, non-FCM PV, and Behind-the-Meter PV. Refer to Section 3.1 for the breakdown of total PV by category.
4. The forecast nameplate PV expected to be in service as of June 1 of the study year is used to represent the PV forecast in the summer peak load cases for that study year. For example, a summer 2023 peak load case will include a forecast of nameplate PV expected to be in service as of June 1, 2023.
5. Additional details on the modeling of the PV forecast in transmission planning studies are available in the Transmission Planning Technical Guide, Section 2.3.11.

Solar & Load Profiles

CMP Peak Load

Adjusted Peak Load (without PTF losses)



CMP, a subsidiary of AVANGRID, serves approximately 646,000 electricity customers

We service an 11,000 square-mile service area in central and southern Maine

Our system is comprised of 25,000 miles of power lines and 280 substations

Solar & Load Profiles

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High Penetration of Distributed Energy Resources

- Primarily solar photovoltaic (PV)
- Connecting to the low-voltage, distribution system
- Under 5 MW
- ISO-NE 2022 CELT forecasts 11,184 MW of PV resources by end of 2031
  - 1,223 MW of PV resources forecasted in Maine

Solar Characteristics

- PV is considered a clean, but intermittent resource
- High solar can occur during a mid-day summer peak or during a daytime light load such as mild spring weekend days
- Low solar can occur during a winter peak or summer evening peak

Result of Increased Solar DERs

- Decreasing load during mid-day periods
- Likely shift to winter peaking
- Reduction in synchronous generation

Solar & Load Profiles

ISO-NE Analysis of Historical Load & Solar Conditions

Low load, high solar: daytime minimum load. Typically occurs between 12 and 2 PM on mild spring weekend days.

High load, relatively high solar: mid-day on a peak load day. Typically occurs between 12 and 3 PM on a hot summer weekday.

Low load, low solar: nighttime minimum load. Typically occurs between 2 and 5 AM on mild spring and fall weekend nights.

High load, low solar: evening on a peak load day. With increased solar penetration, will occur between 6 and 9 PM on a hot summer weekday. Note that power consumption is lower than during the midday hours – approximately 95% of the peak.

Source: *ISO-NE Transmission Planning for the Future Grid, PAC, Sept. 24, 2020*

Solar & Load Profiles

Masking the Load – Different System Behavior

- Current practice in transmission planning studies is to study net load levels.
  - Forecast Load – Energy Efficiency/Demand Resources – DER = Net Load

- Increased DER results in an artificial minimum load, during the day
  - 3 am on a mild spring night:
    8,000 MW – 0 MW DER = 8,000 MW net load
  - 1 pm on a mild sunny spring day:
    14,000 MW – 6,000 MW DER = 8,000 MW net load

Source: *ISO-NE Transmission Planning for the Future Grid, PAC, Sept. 24, 2020*

ISO New England

Review & Approval

- FERC jurisdictional generators in New England must comply with the ISO-NE FERC Electric Tariff No. 3, referred to as the Open Access Transmission Tariff (OATT). This Tariff contains the requirements for applying for a new generator interconnection or changing an existing generation facility.
- Documents that control the level of ISO-NE involvement in non-FERC jurisdictional interconnection processes such as the MPUC's Chapter 324 include but may not be limited to the following.
  - Section I.3.9 of the ISO-NE Tariff
  - ISO-NE Planning Procedure (PP) 5-0
  - ISO-NE PP 5-1
  - ISO-NE PP 5-3
  - ISO-NE PP 5-6
  - Schedule 22 of the ISO-NE Tariff "Large Generator Interconnection Procedures"
  - Schedule 23 of the ISO-NE Tariff "Small Generator Interconnection Procedures"
  - ISO-NE Operating Procedure No. 14 (OP-14) "Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources"
  - ISO-NE Operating Procedure No. 18 (OP-18) "Metering and Telemetering Criteria"
- In general, any project over 1,000 kW requires compliance with Section I.3.9 and participation in the PP 5-1 process.
- OP-14 defines other requirements for generation, depending on their classification with ISO-NE such as requirements to register as a defined Generator, submit PSS/E dynamics models, maintain telemetry equipment defined by OP-18, maintain a 24x7 Designated Entity for dispatch services, and provide voltage regulation through an automatic voltage regulator.

ISO New England

CENTRAL MAINE POWER

Interconnection Requests for Generation, Elective Transmission Upgrades, and Transmission Service in ME

Position	Type	Requested	Unit	Fuel Type	Net MW	Summer MW	Op Date	Sync Date	W/ D Date	IA	Project Status
1342	G	12/15/2022	WT	WND	0	58.79999924	12/20/2024	11/22/2024			
1323	ETU	10/11/2022	NA	N/A			12/31/2027	10/08/2027	11/02/2022		
1322	ETU	10/11/2022	NA	N/A			12/31/2027	10/08/2027	11/02/2022		
1299	G	08/18/2022	PV	SUN	54.0999985	74.80000305	09/25/2026	09/11/2026			Under Study
1295	G	08/03/2022	OT	SUN BAT	205	205	11/28/2025	09/03/2025			
1294	G	07/26/2022	PV	SUN	79.1999969	75.31999969	08/04/2026	07/21/2026			Under Study
1271	ETU	06/07/2022	NA	N/A			12/01/2027	10/01/2027			
1269	G	05/24/2022	PV	SUN	0	50	12/15/2020	11/15/2020		Not Started	
1261	G	05/06/2022	OT	SUN BAT	0	160	06/03/2026	05/20/2026			Under Study
1257	G	05/03/2022	PV	SUN	319.200012	319.2000122	12/09/2026	10/08/2026			
1256	G	05/03/2022	WT	WND	905	905	12/09/2026	10/08/2026			
1255	G	05/02/2022	OT	SUN BAT	103.769997	103.7699966	12/31/2022	12/15/2022			
1254	G	05/02/2022	OT	SUN BAT	92.2590027	92.25900269	12/31/2022	12/15/2022			
1250	G	04/11/2022	OT	BAT	50.7000008	50.70000076	11/01/2024	09/01/2024			Under Study
1244	G	03/31/2022	PV	SUN	75	75	11/01/2025	10/01/2025	11/14/2022		Under Study
1243	G	03/31/2022	PV	SUN	300	300	11/01/2026	10/01/2026			
1242	G	03/28/2022	OT	SUN BAT	87.4639969	87.64600372	12/31/2022	12/15/2022			
1241	G	03/28/2022	OT	SUN BAT	66.4020004	66.40200043	12/31/2022	12/15/2022			
1239	G	03/25/2022	OT	SUN BAT	129	183.6000061	04/21/2026	04/07/2026			Under Study
1236	ETU	03/15/2022	NA	N/A	1200		06/01/2028	06/01/2028			
1230	ETU	03/03/2022	NA	N/A	1200		12/01/2027	10/01/2027			
1228	ETU	02/15/2022	NA	N/A	1200		12/09/2026	10/08/2026			
1227	ETU	02/15/2022	NA	N/A	1200		12/09/2026	10/08/2026			
1211	G	01/10/2022	WT	WND	500	527	11/27/2026	09/03/2026			
1210	G	01/07/2022	WT	WND	500	572	11/28/2025	09/03/2025			
1190	G	10/28/2021	PV	SUN	33.5	33.5	12/30/2024	11/30/2024			Under Study
1171	G	10/25/2021	WT	WND	18.2999992	20.00000954	10/17/2025	09/18/2025			Under Study
1169	G	10/21/2021	PV	SUN	1.99899995	1.998999953	11/01/2024	10/04/2024			Under Study
1165	G	10/01/2021	PV	SUN	1.99899995		07/15/2023	07/15/2023			Under Study
1151	G	08/04/2021	OT	SUN BAT	1.96800005		11/15/2024	11/15/2024		In Progress	Under Study
1150	G	07/29/2021	WT	WND	11.5500002	11.55000019	09/01/2023	08/01/2023			Under Study
1146	G	07/07/2021	PV	SUN	44	40.90999985	07/09/2024	06/25/2024			Under Study
1145	G	07/07/2021	PV	SUN	20.7000008	20.70000076	07/08/2024	06/24/2024			Under Study
1139	G	06/03/2021	PV	SUN	20	20	06/11/2024	05/28/2024			Under Study
1125	G	04/20/2021	PV	SUN	72	72	01/31/2024	12/01/2023			Under Study
1114	G	04/01/2021	PV	SUN	103	103	01/31/2024	11/30/2023	04/20/2021		
1113	G	03/24/2021	OT	WAT BAT	8.5	52.5	02/01/2023	01/25/2023		In Progress	
1104	G	03/11/2021	OT	WAT BAT	8	25.5	02/01/2023	01/25/2023		In Progress	
1100	G	02/19/2021	PV	SUN	164.559998	164.5599976	12/29/2025	10/31/2025			Under Study
1099	G	02/19/2021	PV	SUN	31.3999996	31.39999962	12/31/2024	12/15/2024	12/15/2022		Under Study
1098	G	02/19/2021	PV	SUN	51.4000015	51.40000153	12/31/2024	12/15/2024		Not Started	
1097	G	02/12/2021	PV	SUN	178.589996	178.5899963	11/01/2024	10/01/2024			Under Study
1096	G	02/04/2021	OT	SUN BAT	18.9780006	18.97800064	12/31/2021	09/15/2021			
1095	G	02/04/2021	PV	SUN	28.9009991	28.90099907	12/31/2021	08/15/2021			
1094	G	02/04/2021	OT	SUN BAT	17.7250004	17.72500038	10/15/2022	09/30/2021			
1087	G	12/01/2020	PV	SUN	19.8640003	19.86400032	06/30/2023	06/09/2023			Under Study
1086	G	11/30/2020	PV	SUN	74.5	74.5	06/30/2025	05/31/2025		In Progress	
1085	G	11/17/2020	PV	SUN	100	100	12/30/2024	11/30/2024	01/21/2021		

Position	Type	Requested	Unit	Fuel Type	Net MW	Summer MW	Op Date	Sync Date	W/ D Date	IA	Project Status
1081	G	10/09/2020	PV	SUN	100	100	12/30/2024	11/30/2024	10/21/2020		
1080	G	10/08/2020	PV	SUN	65	66.5	10/24/2024	10/03/2024			Under Study
1065	G	09/25/2020	PV	SUN	100	100	11/30/2024	11/30/2024	10/09/2020		
1064	G	09/17/2020	PV	SUN	11.8000002	11.80000019	09/15/2023	08/20/2023	12/01/2020		
1029	G	05/29/2020	PV	SUN	120	120	12/01/2023	10/02/2023			Under Study
1028	G	05/28/2020	WT	WND	60.5	58.79999924	12/20/2024	11/22/2024		In Progress	
1026	G	05/08/2020	PV	SUN	90	90	11/22/2021	10/25/2021	06/23/2020		
1025	G	04/27/2020	PV	SUN	5	20	11/01/2021	10/01/2021	08/25/2020		
1021	G	04/24/2020	PV	SUN	16.4249992	16.42499924	06/30/2024	06/15/2024		In Progress	
1020	G	04/24/2020	WT	WND	0	20	12/14/2022	09/24/2022		Executed	
1019	G	04/24/2020	OT	BAT	20	20	04/01/2024	01/01/2024		In Progress	Under Study
1018	G	04/24/2020	WT	WND	0	39.97000122	11/15/2021	11/15/2021		Executed	
1015	G	04/21/2020	OT	BAT	112.199997	112.1999969	12/01/2024	09/01/2024		In Progress	
1014	G	04/21/2020	OT	BAT	112.199997	112.1999969	06/01/2024	03/01/2024		Not Started	
1013	G	04/21/2020	PV	SUN	17.2000008	17.20000076	09/30/2025	08/31/2025		In Progress	
986	G	04/02/2020	PV	SUN	19.9899998	19.98999977	11/18/2024	11/18/2024		In Progress	
985	G	04/02/2020	PV	SUN	4	4	07/29/2021	07/15/2021	07/20/2021		Under Study
983	G	03/31/2020	PV	SUN	40	40	11/15/2022	10/16/2022	06/18/2020		
979	ETU	03/26/2020	NA	N/A	0		12/13/2023	09/01/2023		Executed	
972	G	03/25/2020	CC	NG	0.205	271	11/15/2021	11/15/2021		Executed	
953	G	02/19/2020	PV	SUN	20	20	07/01/2024	02/11/2024		Not Started	Under Study
952	G	02/18/2020	PV	SUN	4.98999977	4.989999771	09/30/2021	08/31/2021	04/08/2020		
951	G	01/31/2020	HD	WAT	28.3250008	28.32500076	12/13/2023	10/03/2023			Under Study
950	G	01/20/2020	PV	SUN	17	17.00000024	06/20/2024	06/15/2024	08/23/2022		Under Study
947	G	01/07/2020	OT	BAT	200	200	12/07/2022	12/07/2022	03/12/2020		
946	G	12/27/2019	PV	SUN	18.3999996	18.39999962	08/31/2021	08/15/2021	04/01/2020		
945	G	12/18/2019	ST	BLQ WDS	8	8	06/05/2021	06/05/2021		Executed	In Service
943	G	12/12/2019	PV	SUN	15	15	11/01/2021	10/01/2021	11/12/2021	In Progress	Under Study
937	G	11/14/2019	PV	SUN	0	150	12/31/2022	12/15/2022	08/12/2021	Executed	
935	G	10/28/2019	PV	SUN	17.1000004	17.10000038	03/31/2024	02/29/2024		In Progress	Under Study
931	G	10/22/2019	PV	SUN	55	55	10/24/2024	10/03/2024		Executed	
929	G	10/09/2019	PV	SUN	20	20	07/31/2023	07/13/2023		Executed	
928	G	10/08/2019	PV	SUN	20	20	12/30/2024	12/14/2024		In Progress	
923	G	09/03/2019	PV	SUN	20	20	12/31/2022	12/15/2022			
921	G	08/29/2019	OT	SUN BAT	9.35000038	9.350000381	12/31/2020	12/01/2020	10/17/2019		
920	G	08/29/2019	OT	SUN BAT	11.6800003	11.68000031	12/31/2020	12/01/2020	10/17/2019		
911	G	08/22/2019	PV	SUN	35	35	12/30/2024	12/14/2024	07/05/2022	In Progress	
910	G	08/15/2019	PV	SUN	20	20	12/30/2024	12/14/2024		Executed	
896	G	07/11/2019	PV	SUN	19.6000004	19.60000038	12/31/2023	11/30/2023		In Progress	
889	ETU	04/30/2019	NA	N/A			12/13/2023	09/01/2023		In Progress	
888	G	04/26/2019	OT	WAT BAT	0	126	12/30/2020	12/07/2020		Executed	Under Construction
880	G	04/17/2019	ST	BLQ WDS	24	24	10/30/2020	09/30/2020	05/15/2019		
875	G	04/08/2019	PV	SUN	0	78.40000153	10/27/2021	09/09/2021		Executed	
874	G	04/08/2019	OT	BAT	175	175	11/01/2023	07/15/2023		Executed	
842	G	03/05/2019	PV	SUN	20	20	09/25/2021	06/02/2021		Executed	In Service
840	G	03/01/2019	PV	SUN	0	50	11/07/2020	10/06/2020		Executed	In Service
833	G	01/08/2019	PV	SUN	100	100	10/30/2023	10/15/2023		In Progress	
803	G	12/06/2018	PV	SUN	50	50	07/01/2021	06/01/2021	08/04/2021	In Progress	

Position	Type	Requested	Unit	Fuel Type	Net MW	Summer MW	Op Date	Sync Date	W/ D Date	IA	Project Status
800	G	11/30/2018	PV	SUN	19.7999992	19.79999924	04/01/2022	03/01/2022	02/13/2019		
798	G	11/08/2018	PV	SUN	15	15	11/01/2021	10/01/2021	08/02/2019		Under Study
786	G	09/25/2018	PV	SUN	19.8999996	19.89999962	09/25/2025	07/31/2025		Executed	Under Study
775	G	08/20/2018	PV	SUN	20	20.00000954	11/01/2021	10/15/2021	08/21/2020		Under Study
771	G	07/26/2018	OT	BAT	19.0100002	19.01000023	06/01/2019	05/01/2019	08/28/2018		
767	G	06/13/2018	PV	SUN	20	20	11/30/2020	09/14/2020	06/03/2019		Under Study
760	G	04/26/2018	WT	WND	126	126	11/30/2024	07/31/2024		Executed	
757	G	04/26/2018	PV	SUN	20	20	11/01/2021	10/15/2021	08/12/2020		Under Study
756	G	04/26/2018	PV	SUN	20	20.00000954	11/01/2021	10/15/2021	08/12/2020		Under Study
755	G	04/25/2018	WT	WND	0	184.8000031	12/13/2016	08/15/2016		Executed	In Service
749	G	04/12/2018	PV	SUN	150	150	10/31/2021	08/01/2021	08/27/2019		
748	G	04/12/2018	OT	WND BAT	24.2999992	238.6000061	10/31/2021	08/01/2021	08/27/2019		
747	G	04/12/2018	OT	WND BAT	24.3999996	265.6000061	10/31/2021	08/01/2021	08/27/2019		
746	G	04/12/2018	WT	WND	214.300003	214.3000031	12/15/2021	10/29/2021	08/27/2019		
745	G	04/12/2018	WT	WND	241.199997	241.1999969	10/29/2021	08/01/2021	08/27/2019		
744	G	04/12/2018	WT	WND	150	150	12/01/2022	09/01/2022	02/07/2019		
743	ETU	04/12/2018	NA	N/A	450		12/01/2022	09/01/2022	02/07/2019		
742	ETU	04/12/2018	NA	N/A	540		12/31/2021	11/30/2021	11/29/2020		
741	ETU	04/12/2018	NA	N/A	200		12/31/2021	11/30/2021	11/29/2020		
740	ETU	04/12/2018	NA	N/A	460		12/31/2021	11/30/2021	11/29/2020		
739	G	04/12/2018	WT	WND	89.6999969	89.69999695	01/30/2020	01/15/2020	01/16/2019		
738	ETU	04/12/2018	NA	N/A	400		11/30/2019	10/31/2019	11/30/2020		
737	ETU	04/12/2018	NA	N/A	1200		12/31/2021	11/30/2021	02/07/2019		
736	ETU	04/12/2018	NA	N/A	550		12/31/2021	11/30/2021	02/07/2019		
735	G	04/12/2018	WT	WND	600.599976	600.598999	12/01/2021	11/01/2021	02/07/2019		
734	G	04/12/2018	WT	WND	600.599976	600.5999146	12/01/2021	11/01/2021	02/07/2019		
733	G	04/12/2018	WT	WND	103.5	103.5	11/20/2022	09/03/2022	12/01/2020		
732	G	04/12/2018	WT	WND	103.5	103.5	11/20/2022	09/03/2022	12/01/2020		
731	G	04/12/2018	WT	WND	103.5	103.5	11/20/2022	09/03/2022	12/01/2020		
730	G	04/12/2018	WT	WND	103.5	103.5	11/20/2022	09/03/2022	12/01/2020		
729	G	04/12/2018	WT	WND	103.5	103.5	11/20/2022	09/03/2022	12/01/2020		
672	G	07/26/2017	WT	WND	630	630	12/31/2022	11/30/2022	10/22/2019		Under Study
670	G	07/25/2017	PV	SUN	113.400002	113.4000015	03/31/2024	08/01/2023		Executed	
667	G	07/21/2017	PV	SUN	0	150	10/31/2020	08/01/2020	04/12/2018		Under Study
666	G	07/21/2017	OT	WND BAT	0	238.6000061	10/31/2020	08/01/2020	04/12/2018		Under Study
665	G	07/21/2017	OT	WND BAT	0	265.6000061	10/31/2020	08/01/2020	04/12/2018		Under Study
664	G	07/21/2017	WT	WND	0	214.3000031	10/31/2020	08/01/2020	04/12/2018		Under Study
663	G	07/21/2017	WT	WND	0	241.1999969	10/31/2020	08/01/2020	04/12/2018		Under Study
662	G	07/20/2017	WT	WND	150	150	12/01/2022	09/01/2022	04/12/2018		
661	ETU	07/20/2017	NA	N/A	450		12/01/2022	09/01/2022	04/12/2018		
659	ETU	07/18/2017	NA	N/A	540		12/31/2020	11/30/2020	04/12/2018		Under Study
658	ETU	07/14/2017	NA	N/A	200		12/31/2020	11/30/2020	04/12/2018		Under Study
657	ETU	06/29/2017	NA	N/A			12/31/2020	11/30/2020	09/12/2019		Under Study
656	G	06/28/2017	WT	WND	0	72.59999847	12/12/2020	10/13/2020		Executed	In Service
655	G	06/15/2017	WT	WND	15.3000002	15.30000019	11/30/2021	11/09/2021		Executed	
654	G	06/09/2017	WT	WND	0	312	12/30/2020	09/15/2020	04/12/2018		
653	G	06/09/2017	WT	WND	0	250	10/31/2021	04/05/2021	05/13/2019	Executed	

Cluster Study Results To-date

January 2023

- Prior to the triggering of cluster studies, 123 active projects totaling 539 MW received the requisite approval from ISO New England
- Four (4) cluster studies comprised of 72 active projects and totaling 256 MW have been completed and received the requisite approval from ISO New England
  - Only 38 active projects totaling 135 MW in these cluster studies have been assigned transmission network upgrades
  - Transmission network upgrades from approved projects assigned to-date total approx. $85M

This means 157 active projects totaling 660 MW received the requisite approval from ISO New England and have been allocated no transmission network upgrades

Look Ahead

- Kimball Rd, Cluster 03: 21 active projects totaling 75 MW, ~$250M in Network Upgrades, no projects without a Network Upgrade
- DGB, Cluster 06: 27 active projects totaling 104.5 MW, ~$29M in Network Upgrades, 24 projects without a Network Upgrade
- Midcoast, Cluster 09: 15 active projects totaling 49 MW, ~$11M in Network Upgrades, no projects without a Network Upgrade

Note: Network upgrades and cost estimates subject to change until final revised IAs executed and Network Upgrades invoiced

Cluster Study Results To-date

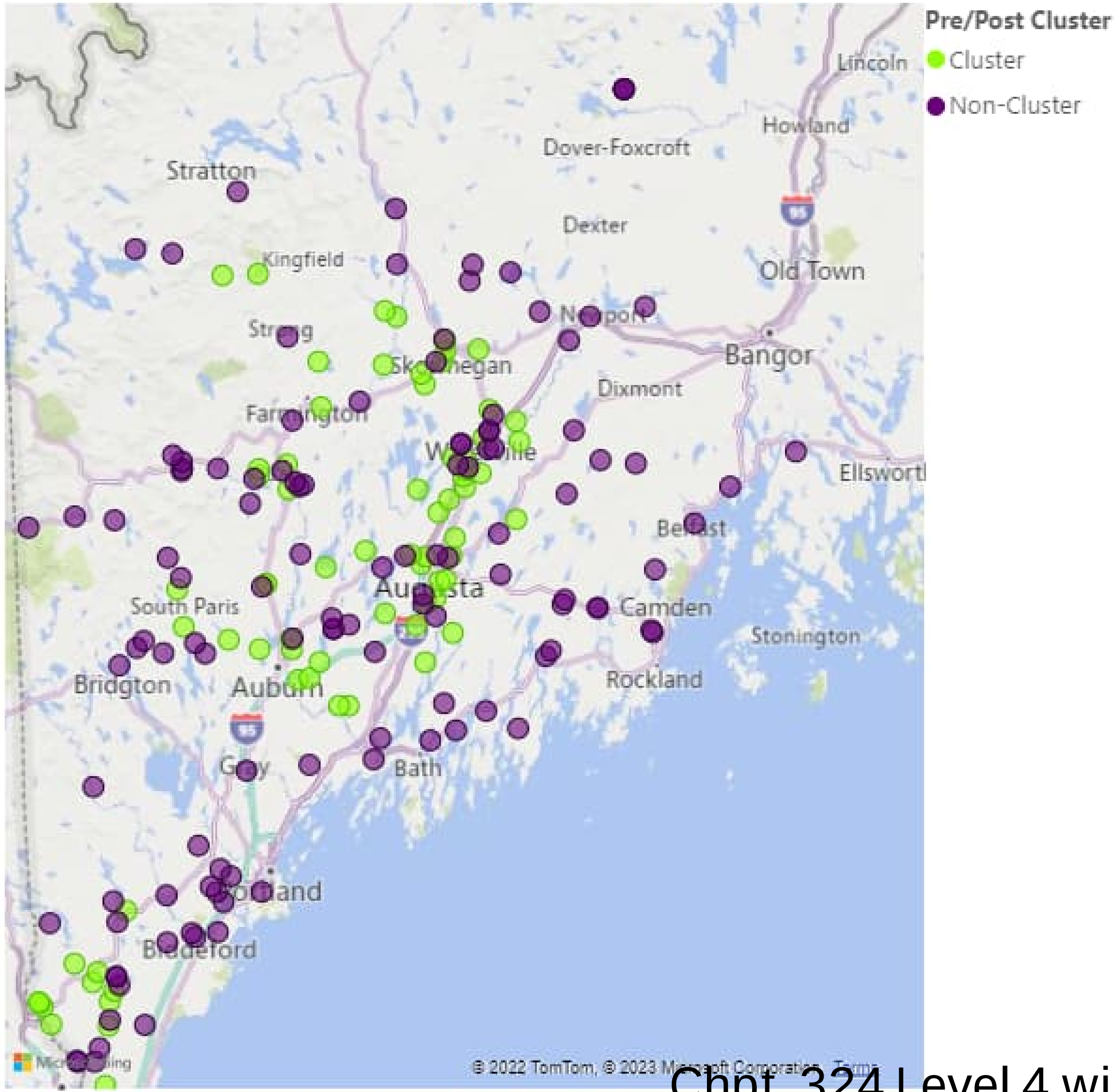
CENTRAL MAINE POWER

Today

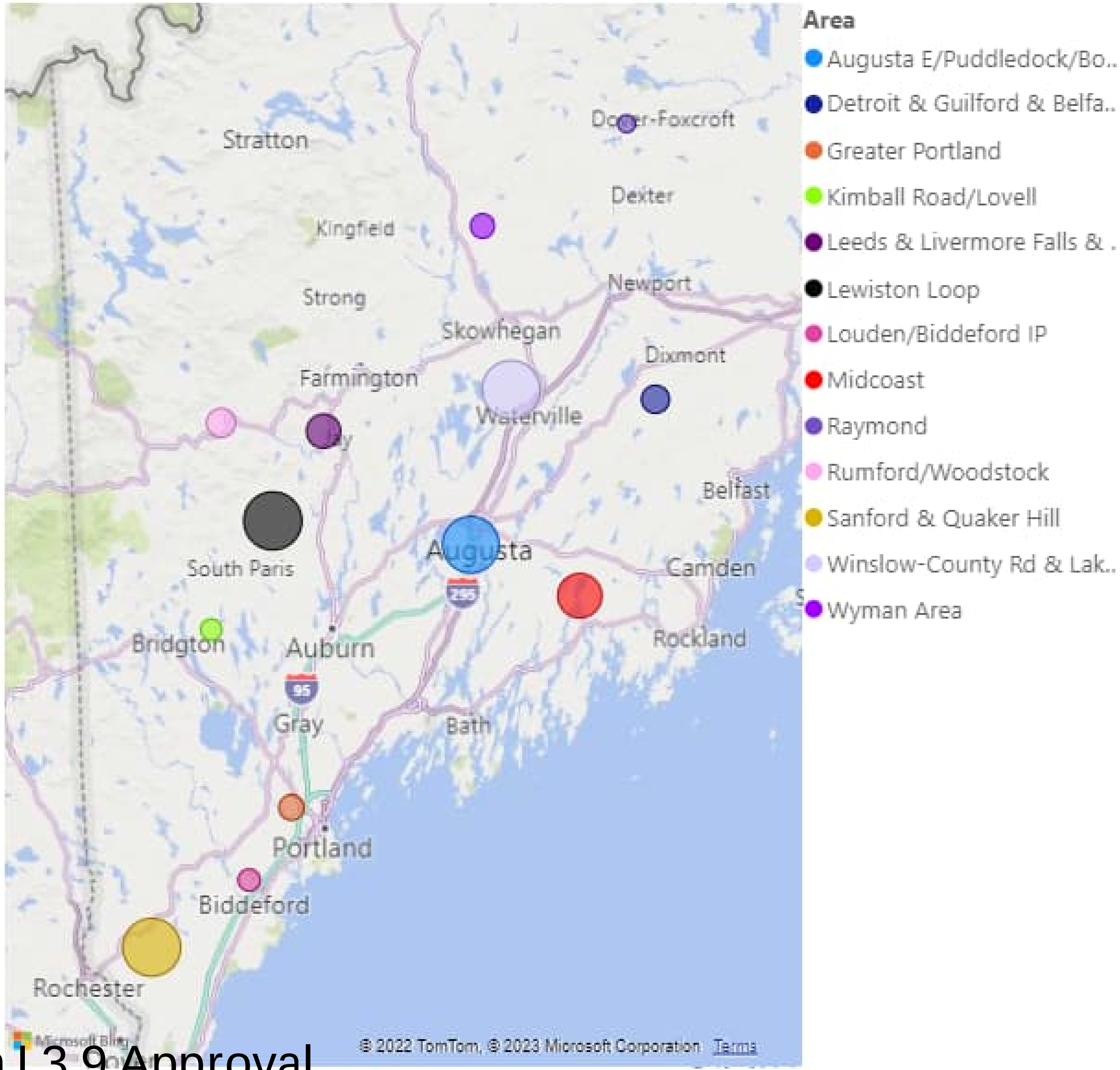
- 15 cluster studies comprised of 115 active projects and totaling 405 MW are underway or slated to commence

Active Cluster Projects									
Cluster Name	Cluster Entry Closed	Study Projects	Active Projects	MW	Active Project MW	Current Milestone	Overall Project Percent Complete	I.3.9 Approval Target
Cluster 03 - Kimball Rd-Lovell - 1	1/1/2021	23	22	80.6	80.0	6-Report Development	90.00%	Mar-23
Cluster 06 - Detroit-Guilford-Belfast - 1	2/1/2021	29	27	105.9	104.5	6-Report Development	95.00%	Mar-23
Cluster 07 - Raymond - 1	3/1/2021	13	13	51.1	51.1	5-PSCAD	70.00%	Apr-23
Cluster 08 - Sturtevant-Leeds-Livermore-Ludden-Riley - 1	3/1/2021	7	7	22.6	22.6	5-PSCAD	70.00%	Apr-23
Cluster 09 - Midcoast - 1	6/1/2021	15	15	49.4	49.4	4-Mitigations Identified & Analysis Completed	60.00%	Mar-23
Cluster 10 - Roxbury-Rumford-Woodstock - 1	5/1/2021	5	4	7.5	6.5	5-PSCAD	70.00%	Apr-23
Cluster 11 - Augusta E-Puddledock-Bowman St - 2	6/1/2021	11	10	33.5	32.5	4-Mitigations Identified & Analysis Completed	60.00%	Jun-23
Cluster 12 - Winslow-County Rd-Lakewood - 2	7/1/2021	8	8	27.9	27.9	4-Mitigations Identified & Analysis Completed	60.00%	Jun-23
Cluster 13 - Kimball Rd-Lovell - 2	To Be Closed	6	4	11.9	10.5	Pending Cluster Entry Closure	5.00%	
Cluster 14 - Louden-Biddeford IP - 1	7/1/2021	4	3	12.3	11.4	4-Mitigations Identified & Analysis Completed	45.00%	May-23
Cluster 15 - Greater Portland - 1	8/1/2021	6	5	18.1	17.2	4-Mitigations Identified & Analysis Completed	45.00%	May-23
Cluster 16 - Wyman Area - 1	10/1/2021	3	1	4.0	2.0	6-Report Development	85.00%	Mar-23
Cluster 17 - Detroit Guilford Belfast - 2	To Be Closed	31	22	76.9	73.9	Pending Cluster Entry Closure	5.00%	
Cluster 18 - Lewiston Loop - 2	To Be Closed	11	9	26.8	24.8	Pending Cluster Entry Closure	5.00%	
Cluster 19 - Sanford-Quaker Hill - 2	To Be Closed	10	9	17.9	17.9	Pending Cluster Entry Closure	5.00%	
	Total:	182	115	413.0	405.3			

I.3.9 Approved Projects



I.3.9 Approved Projects by Cluster Area



Chpt. 324 Level 4 with I.3.9 Approval

195 & 795

PRJ MW

What to Expect Moving Forward

Increasing study complexities

- Flows on the CMP sub-transmission system are shifting from load serving to exporting
- Studies must account for the large amount of DG approved to operate in addition to a number of scenarios to ensure system reliability under a variety of load conditions as well as a very active FERC generation queue.

Increasing impact from FERC-queued generation

- Throughout the lifecycle of a cluster study, ISO-NE is managing a queue of FERC-jurisdictional projects proposing to interconnect to CMP's transmission system. All FERC generator projects take precedence over DERs that do not yet have ISO New England Section I.3.9 approval, as mandated by the ISO New England process. The DER cluster studies must consider the impact of new proposed interconnections as they come under study in the ISO-NE queue.

Anticipate Network Upgrades

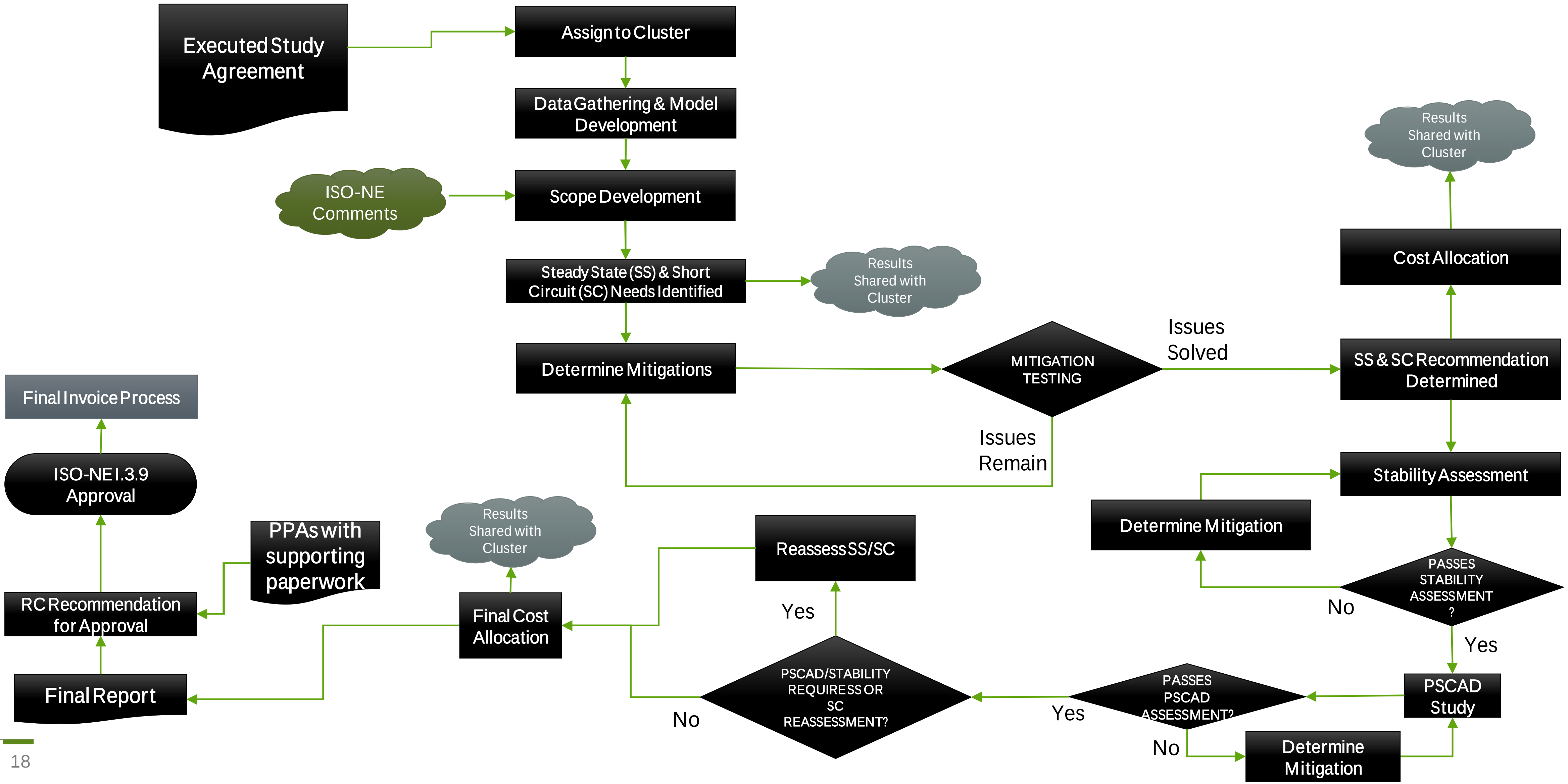
- As evidenced by recent cluster activity, depending on the interconnecting project's location and available system capacity, it is reasonable to anticipate network upgrades
- Some projects may not cause a significant adverse impact and those will be able to proceed with no or limited network upgrades
- Transmission network upgrades will impact a project's interconnection costs and Commercial Operations Date

Purpose & Background

Transmission System Impact Study

- A transmission system impact study evaluates the effects of the proposed Distributed Generation (DG) interconnection on the operation and performance of the electric transmission system.
- The voltage level of the electric transmission system at CMP is 345 kV, 115 kV, and 34.5 kV.
- Historically, the reliability impacts of interconnections including DERs were assessed individually in a queue order of when they materialized. This sequential approach ensures that each project and its impacts were assessed in an orderly manner resulting in discreet incremental system model changes with each new DER which in turn became the basis for the start of the next DER study in the queue. This sequential approach works well for individual requests or gradual increases in DER penetrations; however, the timelines accompanying this approach quickly become impractical with high volumes of DERs seeking interconnections as has been experienced in Maine. DER projects are now assessed in “clusters.”
- The reliability performance of the system is assessed before and after the proposed DER projects.
- Each study must include a sufficiently broad range of system conditions including generation patterns (on/off-line scenarios), load levels (peak, shoulder, light, minimum), and system contingencies (unplanned outage events) to ensure a comprehensive assessment that minimizes the need for restudy or scope expansion at a later date.
- Study components include:
  - Load Flow
  - Short Circuit
  - Stability
  - Power-System Computer-Aided Design (PSCAD)
  - Mitigation, Challenge Work, & Cost Allocation
- Cluster Studies of 20 projects are currently averaging $450,000

Today's Process



Study Components

- DG projects are evaluated to determine if the interconnection or aggregate interconnections have a Significant Adverse Impact on the transmission system.
- “Significant Adverse Impact” is defined by ISO-NE
- On September 29, 2021, in Docket No. 2021-00262, CMP filed a summary document labeled the Cluster Study Whitepaper that describes the transmission cluster study process and its inherent complexities

Steady-State Load Flow

- A change to the transmission system that increases the flow in an Element by at least two percent (2%) of the Element’s rating and that causes that flow to exceed that Element’s appropriate thermal rating by more than two percent (2%). The appropriate thermal rating is the normal rating with all lines in service and the long-time emergency or short time emergency rating after a contingency.
- A change to the transmission system that causes at least a one percent (1%) change in a voltage and causes a voltage level that is higher or lower than the appropriate rating by more than one percent.

Short Circuit

- A change to the transmission system that causes at least a one percent (1%) change in the short circuit current experienced by an Element and that causes a short circuit stress that is higher than an Element’s interrupting or withstand capability.

Study Components

Stability

- With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact: A fault or a disturbance that cause:
  - Any loss of synchronism or tripping of a generator
  - Unacceptable system dynamic response
  - Unacceptable equipment tripping: tripping of an un-faulted bulk power system element (element that has already been classified as Bulk Power System) under planned system configuration due to operation of a protection system in response to a stable power swing or operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required

PSCAD

- The increase in power electronic and inverter-based devices on the system has led to a concern that the typical stability analysis may be overlooking certain possible risks.
  - PSCAD models are much detailed than the simplified stability models.
  - Models are project-specific as opposed to generic (i.e. everything is “user-written”).
  - Simulations are per-phase, as opposed to a simplified balanced system.
  - Allows for much smaller time steps (microseconds vs. milliseconds).
  - Simulations are very processing-intensive so models are generally equivalenced down to just a few buses away from the area of interest. Similarly, fault testing tends to be limited to a relatively short list of critical events.

Table I: Inverters’ Voltage Trip Settings

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters’ Frequency Trip Settings

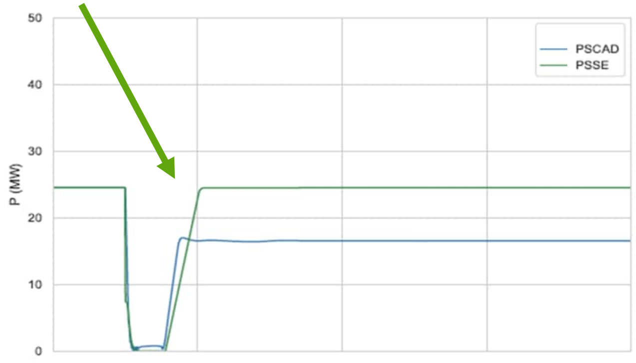
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Study Components

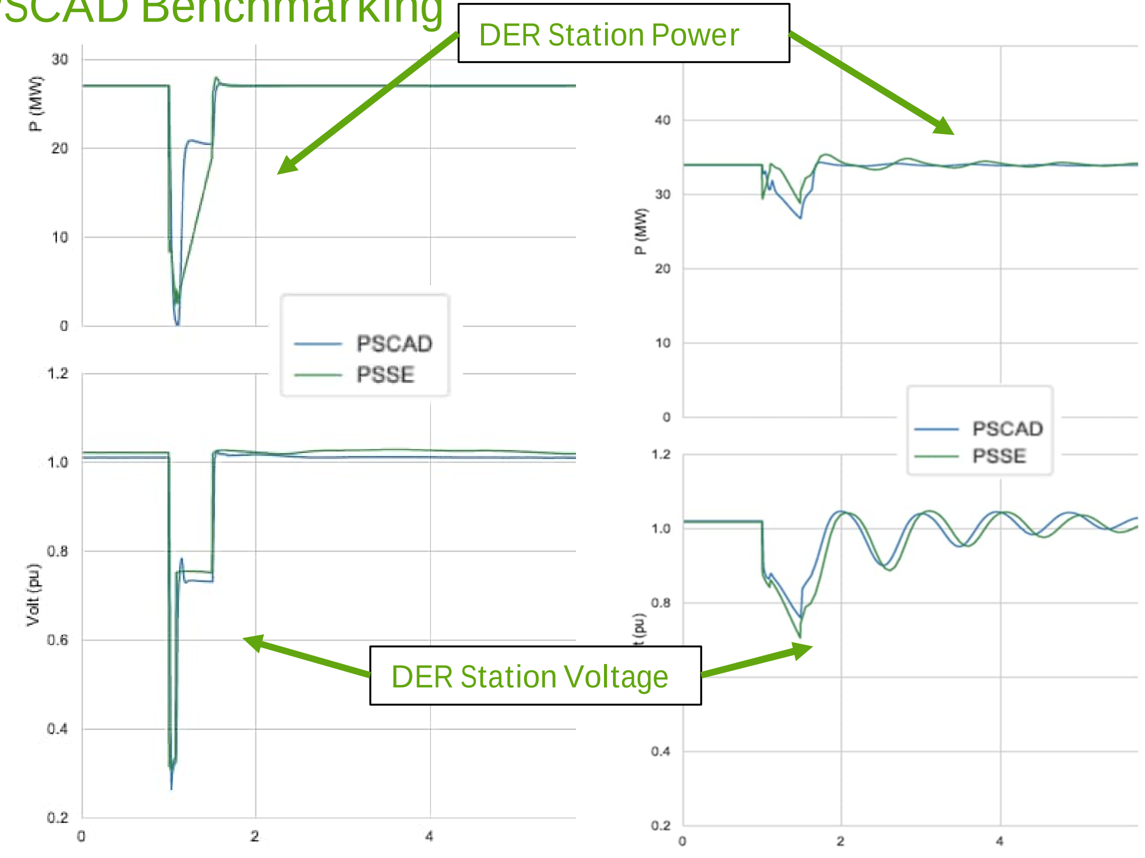
PSCAD Continued

- Stability models are “benchmarked” against PSCAD models to demonstrate that they respond sufficiently similarly to the PSCAD model. This benchmarking is part of ISO-NE’s stability model acceptance process.

DER Station Power – tripping in PSCAD, no trip in typical stability study



PSCAD Benchmarking



Graph Source: *Electranix, ISO-NE 2020*

Study Components

CENTRAL MAINE POWER

PSCAD Continued

- PSCAD analysis is testing for:
  - Weak grid control instability. Particularly at the end of long radial circuits, where available short circuit capacity may be relatively low, inverter-based generator controls are vulnerable to small signal instabilities and control issues.
  - Ride through capability. Following faults on the large lines in the connection area, the generators in the region are expected to recover full power. Inverter Based Resources (IBR) such as the DG being planned may trip for many reasons which may not be accurately represented in conventional transient stability tools.
  - Voltage control coordination. It is likely that the plants will have sufficient impedance between them to avoid voltage controller interactions, particularly since the majority of these DG plants are planned to be operated in constant power factor mode. However, if voltages throughout the distribution system vary significantly under various operating conditions, the individual plants may struggle to maintain their terminal voltages within acceptable ranges.

Local reactive power support to maintain system voltages is more critical in weak systems.

If the system is too weak and has insufficient voltage support, the system may experience post fault steady state voltage violations before the power plant voltage controller is able come into action (which may take 20 to 30 seconds depending on the time constants of these plant level controllers).

Tripping of a significant generator is more likely to result in undesirable poorly damped power oscillations in weak system compared to a strong system.

Source: *Panhandle and South Texas Stability and System Strength Assessment, Electranix, Mar. 28, 2018*

Study Components

CENTRAL MAINE POWER

Mitigation, Challenge Work, & Cost Allocation

- If there are reliability criteria violations, mitigation is proposed and tested against all of the scenarios to ensure that proposed upgrades are sufficient.
- CMP has established “Challenge Sessions” for each cluster study that are designed to challenge the typical network upgrade approach and look for mitigation recommendations that may be both more cost-effective and facilitate more rapid interconnection of DG projects. Results of the Challenge Sessions are provided to cluster participants along with explanations as to why a challenge session mitigation recommendation was either accepted or deemed not a viable alternative.
- Once the pre- and post project mitigation measures are determined, the final step involves a weighted cost allocation analysis designed to determine each DER project’s share of the required upgrade costs. A cost allocation methodology was developed by CMP in collaboration with a team of interested stakeholders as an approach that assigns network upgrade costs to projects in relation to their contribution to the need for the mitigation project. The result is that this methodology can identify projects with limited to no network upgrades that could proceed to interconnection with low-cost or no mitigation obligations. Additionally, it identifies projects that are substantial contributors to the required upgrade costs that can in turn make a determination as to whether they wish to withdraw from the interconnection queue.

On the Horizon

IBR-Related Activities at NERC

- Odessa Disturbance
  - NERC Webinar Website: Webinars/Training and Outreach Videos (nerc.com)
  - NERC 2021 Odessa Report (~1,300 MW generation lost): https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
  - NERC 2022 Odessa Report (~2,500 MW generation lost): https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
- 2022 Odessa Disturbance Webinar Conclusions
  - Elevating the inverter risk issues within the ERO risk framework
  - Immediate action by industry stakeholders to enhance local interconnection requirements
  - Agile NERC Standards development activities
    - Comprehensive ride-through standard
    - New performance validation standard
    - Disturbance monitoring, EMT, planning assessments, etc.
  - Level 2 NERC Alert(s) to understand extent of condition
    - Performance issues and modeling issues
  - Enhancements to the FERC *pro forma* GIAs
  - Improvements to plant commissioning practices
  - FERC NOPR on inverter-based resources
- NERC DER Activities: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf
  - DER Modeling Study, Nov. 2022: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
  - Reliability Guideline: DER Data Collection and Model Verification of Aggregate DER, Dec. 2022 (draft)
  - Project 2022-02: Modifications to TPL-001-5.1 & MOD-032-1 to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.

On the Horizon

IBR-Related Activities at FERC

- FERC Notice of Proposed Rulemaking (NOPR) on Reliability Standards to Address Inverter-Based Resources (IBRs), issued November 17th
  - In the NOPR, the Commission proposes to direct NERC to develop new or modified Reliability Standards addressing four reliability gaps pertaining to IBRs: (1) data sharing; (2) model validation; (3) planning and operational studies; and (4) performance requirements.
  - The solution proposed is to have NERC revise or create new standards that ensure 1) more accurate and comprehensive data about IBR characteristics, 2) verified IBR models from approved software packages as inputs to perform steady-state, dynamic, and short circuit studies, 3) ensure that planning and operational studies assess the performance and behavior of all IBRs, and 4) ensure that registered IBRs are configured and programmed properly to provide voltage and frequency ride-through, unimpeded ramp rates following disturbance, and prevent phase lock loop loss of synchronization.
  - Note that FERC classifies IBRs into 3 categories: 1) registered IBRs (those registered with NERC as they are defined as Bulk Electric System (BES)), unregistered IBRs (connected to the Bulk Power System but not registered with NERC), and IBR-DERs (connected to the distribution system).

9:50-10:10

03 ”New” Terms & Conditions

Docket No. 2021-00277

- Filed September 1, 2021
- Approved May 20, 2022

Phase 1 Steady State Analysis (SSA), Stability

Phase 2 Adjust SSA, Stability PSCAD Analysis

Phase 2 I.3.9 Submittal

Phase 1 Begins
Cluster Study Agreement

Non-refundable Study Fee

Phase 2 Begins
Non-refundable Study Fee

Restudy based on attrition

Conceptual Engineering Study

Post I.3.9 Approval
Study true-up with remaining projects

Projects with I.3.9 approval are invoiced.

Restudy if required based on attrition

Two-Phase Study

Phase 1 & Attrition Window

Within 15 business days of a cluster’s closure, CMP will issue a Transmission System Impact Study Agreement to eligible Customer-Generators along with a data request if required. Each Customer-Generator shall have 10 business days from receipt to execute the Transmission System Impact Study Agreement, provide the study fee as indicated in Section 60.5, and return the completed data request. Completion of the requirements ensures participation in Phase 1 of the Transmission System Impact Study. Phase 1 includes the steady-state, dynamic stability, and short circuit analyses and these analyses may be performed on a variety of generation dispatches and load levels as needed. Failure to complete any of the Transmission System Impact Study requirements for eligibility will result in removal from participation in the Transmission System Impact Study. A Customer-Generator may elect to execute a Non-Disclosure Agreement to obtain study results which contain Critical Energy Infrastructure Information (“CEII”), not unduly withheld, to obtain Phase 1 or Phase 2 results.

Each Customer-Generator shall provide CMP via the Transmission System Impact Study Agreement with a single designated valid email address for all Transmission System Impact Study related data requests. After receipt of the completed agreements, CMP will hold a scoping meeting for the Cluster study within 5 business days. In this meeting CMP will discuss the preliminary assumptions and models that may be used for the study and will provide a high-level timeline for the cluster participants.

CMP will make best efforts to complete Phase 1 study within 140 business days of the scoping meeting and notify Customer-Generators of the results of the steady-state load flow, dynamic stability, and short circuit analyses as soon as those analyses are complete. CMP will coordinate data gathering, model building and verification for Phase 2 in parallel with conducting the Phase 1 analysis. Upon completion of Phase 1, CMP will release a Phase 1 system impact study report for review within 5 business days and will host a results meeting within 5 business days thereafter. The Phase 1 system impact study report will include the results of the analyses, identification of Network Upgrades, and identification of projects that do not contribute to the need for Network Upgrades. The Phase I results will include alternatives that have been considered, including alternatives to Network Upgrades, and an order of magnitude cost accuracy and construction time estimates of the proposed Network Upgrades required to mitigate identified reliability criteria violations as well as cost allocation of the Network Upgrades. Cost allocation shall be determined per Section 60.6.

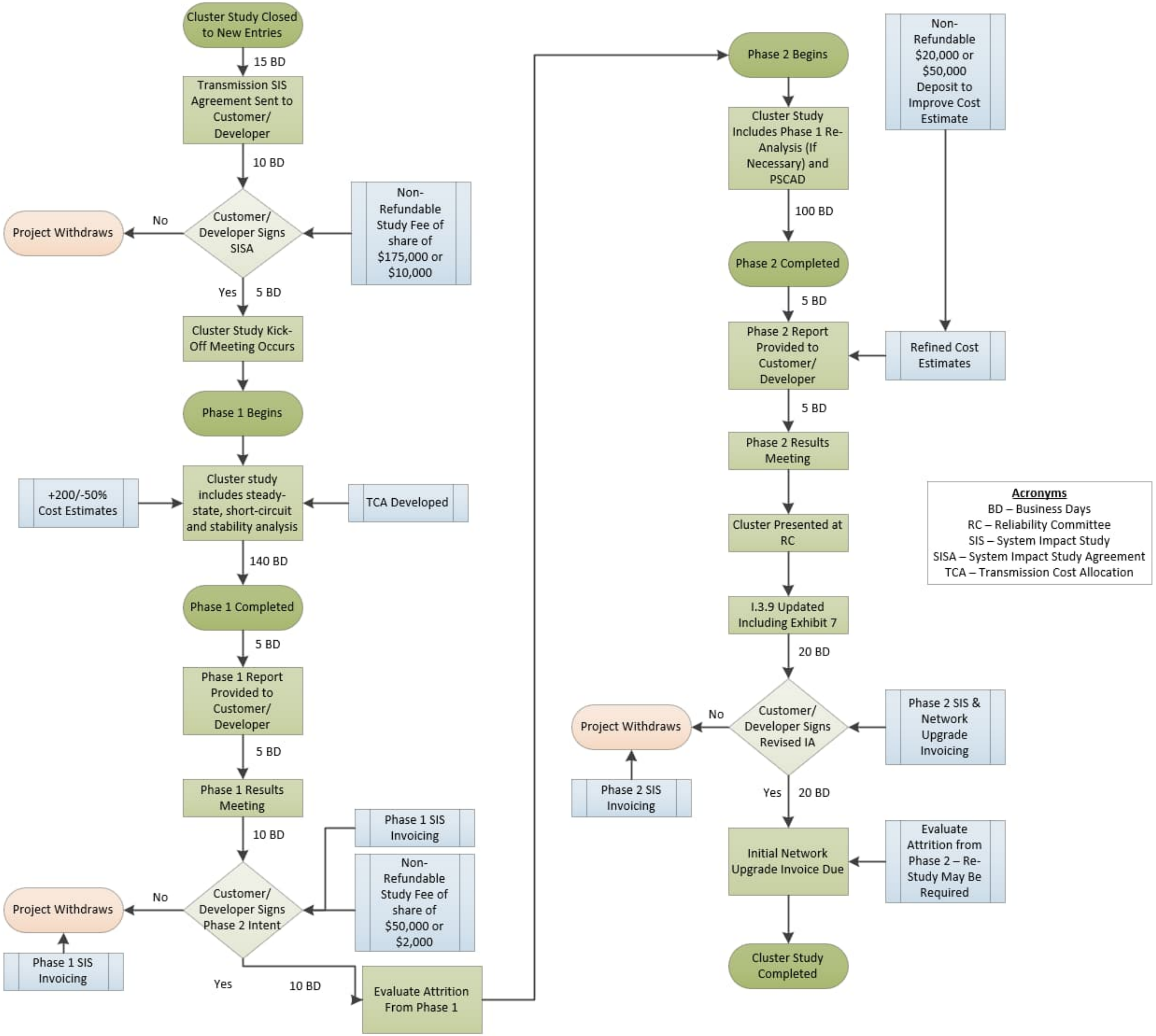
Within 10 business days of the results meeting, Customer-Generators must signal their intent to be included in Phase 2 of the Transmission System Impact Study by submitting the second non-refundable Transmission System Impact Study fee per Section 60.5. Phase 2 of the Transmission System Impact Study will restudy the analyses in Phase 1 as required with the remaining Customer-Generators, will include the Power Systems – Computer Aided Design (“PSCAD”) analysis, and will provide cost allocation of Network Upgrades if required based on the remaining Customer-Generators and results of the Phase 2 analyses.

Phase 2 & Data Requests

In parallel with Phase 2, CMP will perform additional study analyses to refine the scope, schedule and cost of the Network Upgrades identified by the Phase 1 analysis. CMP will make best efforts to complete the Phase 2 analysis within 100 business days, including any potential restudy, updates to mitigation and cost allocation, and the PSCAD analysis. CMP will conduct a customer meeting to inform Customer-Generators of the results of the re-study within Phase 2. The Phase 2 results will include the identification of projects that do not contribute to the need for Network Upgrades that can interconnect and operate prior to completion of Network Upgrades. CMP will provide the results and Transmission System Impact Study Report to Customer-Generators before submittal of PPAs to ISO-NE.

Customer-Generators participating in Phase 2 of the Transmission System Impact Study will have their PPA submitted to ISO-NE for Section I.3.9 approval. Additional study work to address Transmission System Impact Study attrition following receipt of Section I.3.9 approval will be addressed per Section 60.7. The Section I.3.9 approved Transmission System Impact Study will also be provided to the Office of the Public Advocate.

Data requests may be made by CMP throughout the course of a Transmission System Impact Study. CMP will make every reasonable effort to notify Customer-Generators of data requests as early as possible. Customer-Generators shall have 10 business days from receipt to respond to a CMP data request or the Customer-Generator will forfeit its participation in the current Transmission System Impact Studyincluding any study costs.



Cluster Study Closed to New Entries
15 BD
Transmission SIS Agreement Sent to Customer/ Developer
10 BD
Customer/ Developer Signs SISA
Non-Refundable Study Fee of share of $175,000 or $10,000
No
Project Withdraws
Yes
5 BD
Cluster Study Kick-Off Meeting Occurs
Phase 1 Begins
Cluster study includes steady-state, short-circuit and stability analysis
+200/-50% Cost Estimates
TCA Developed
140 BD
Phase 1 Completed
5 BD
Phase 1 Report Provided to Customer/ Developer
5 BD
Phase 1 Results Meeting
10 BD
Customer/ Developer Signs Phase 2 Intent
Phase 1 SIS Invoicing
Non-Refundable Study Fee of share of $50,000 or $2,000
No
Project Withdraws
Phase 1 SIS Invoicing
Yes
10 BD
Evaluate Attrition From Phase 1
Phase 2 Begins
Non-Refundable $20,000 or $50,000 Deposit to Improve Cost Estimate
Cluster Study Includes Phase 1 Re-Analysis (If Necessary) and PSCAD
100 BD
Phase 2 Completed
5 BD
Phase 2 Report Provided to Customer/ Developer
Refined Cost Estimates
5 BD
Phase 2 Results Meeting
Cluster Presented at RC
I.3.9 Updated Including Exhibit 7
20 BD
Customer/ Developer Signs Revised IA
Phase 2 SIS & Network Upgrade Invoicing
No
Project Withdraws
Phase 2 SIS Invoicing
Yes
20 BD
Initial Network Upgrade Invoice Due
Evaluate Attrition from Phase 2 – Re-Study May Be Required
Cluster Study Completed
Acronyms
BD – Business Days
RC – Reliability Committee
SIS – System Impact Study
SISA – System Impact Study Agreement
TCA – Transmission Cost Allocation

Upfront Study Fees

≥ 10 PRJs Study Fees/Costs

1) For Transmission System Impact Studies with 10 or more Customer-Generators, each Customer-Generator will be allocated a non-refundable Transmission System Impact Study fee for participation in the first phase (“Phase 1”) of the Transmission System Impact Study. This fee will be the Customer-Generator’s pro-rata share of $175,000 based on the relative size (kW) of the facility as of the date of their Transmission System Impact Study Agreement.
2) For Transmission System Impact Studies with 10 or more Customer-Generators, each Customer-Generator will be allocated a non-refundable Transmission System Impact Study fee for participation in the second phase (“Phase 2”) of the Transmission System Impact Study. This fee will be the Customer-Generator’s pro-rata share of $50,000 based on the relative size (kW) of the facility as of the date of their Transmission System Impact Study Agreement. Customer-Generators that are identified as contributing to a Network Upgrade will be individually assessed an incremental $20,000 non-refundable deposit to perform additional study analysis.

< 10 PRJs Study Fees/Costs

3) For Transmission System Impact Studies with less than 10 Customer-Generators, each Customer-Generator will be allocated a non-refundable Transmission System Impact Study fee of $10,000 for participation in the first phase (“Phase 1”) of the Transmission System Impact Study.
4) For Transmission System Impact Studies with less than 10 Customer Generators, each Customer-Generator will be allocated a non-refundable Transmission System Impact Study fee of $2,000 for participation in the second phase (“Phase 2”) of the Transmission System Impact Study. Customer-Generators that are identified as contributing to a Network Upgrade will be individually assessed an incremental $50,000 non-refundable deposit to perform additional study analysis.

Study Invoicing

5) Final invoicing of all Phase 1 Transmission System Impact Study costs will occur at the conclusion of Phase 1 with the Customer-Generators participating in Phase 1 and they will beallocated their pro-rata share of the Phase 1 study costs based on the relative size (kW) of their facility as of the date of their Transmission System Impact Study Agreement.
6) Final invoicing of all Transmission System Impact Study costs will occur pursuant to the invoicing timelines in Chapter 324. Final Transmission System Impact Study costs will be reconciled with the Customer-Generators participating in Phase 2 and they will be allocatedtheir pro-rata share of the final study costs based on the relative size (kW) of their facility asof the date of their Transmission System Impact Study Agreement.

Cost Allocation

CENTRAL MAINE POWER

Example: Weighted Allocation Factor Analysis

Network Upgrades required to mitigate thermal violations shall be allocated using a weighted allocation factor analysis which will identify each Customer-Generator’s contribution to the thermal violation. This means that the costs of those facilities are allocated proportionally to the amount of flow each generator contributes on the existing facility with the reliability criteria violation.

First, the outage and contingency scenarios that cause thermal overloads on an impacted facility are determined.

Each Customer-Generator’s distribution factor (“DFAX”) is calculated for each outage and contingency scenario.

A KW Impact is calculated for each Customer-Generator for each outage and contingency scenario as follows:

*KW Impact = DFAX * Gen Output (kW)*

An Allocation Factor is calculated for each Customer-Generator for each outage and contingency scenario as follows:

Allocation Factor = KW Impact / Sum of KW Impact for all Customer-Generators

An Overload Weighting Factor is calculated for each outage and contingency scenario as follows:

Overload Weighting Factor = (% Loading – 100) / Σ (% Loading – 100)

A Weighted Allocation Factor is calculated for each Customer-Generator for each outage and contingency scenario as follows:

*Weighted Allocation = Allocation Factor * Overload Weighting Factor*

Finally, a Total Weighted Allocation Factor for each Customer-Generator is calculated as follows:

Total Weighted Allocation Factor = Σ Weighted Allocation

The Total Weighted Allocation Factor determines each Customer-Generator’s cost responsibility for the Network Upgrade which mitigates the thermal overload condition(s).

Example: Voltage Impact Analysis

Voltage support related Network Upgrades shall be allocated using a voltage impact analysis which will identify each Customer-Generator’s contribution to the voltage violation. This means the Cluster Study identifies the worst-case voltage criteria violation at a transmission facility. Costs for this new voltage support resource are allocated by removing a Customer-Generator from the model (each in turn) and evaluating the impact of that generator on the voltage. For a low voltage violation, if the voltage stays constant or decreases when the generator is removed, it is considered a “Helper” generator. If the removal of a generator from the model elevates the contingent voltage and increases it, then such generator is called “Harmer.” For those Customer-Generators labeled as “Harmers,” cost of voltage mitigation is allocated in proportion to their voltage impact (the voltage delta between the contingent voltage and the contingent voltage with the removal of the Customer-Generator).

Conceptual Engineering Study

Substations

- Site visit to the existing site and potentially to the remote ends
- Complete surveys needed to develop the scope of work, depending on the project
  - Topographical Survey
  - Earthwork Quantities Report
  - Geotechnical Survey
- Improve scope definition by the performance or generation of some or all of the following:
  - Permitting, Real State and Outreach needs assessment
  - Storm Water Pollution Prevention Plan (SWPPP)
  - Site Plan (Install & Removal)
  - General Arrangement (Install & Removal)
  - Engineering notes
  - Preliminary bill of materials
  - SPR (existing site and remote ends)
  - Post fault current study - Aspen model
  - Fault Duty Analysis
  - CT Performance Calculations
  - Power One Line Diagram
  - Relay One Line (existing site and remote ends)
  - Integration One Line (existing site and remote ends)
  - Communication One Line (existing site and remote ends)
  - Ampacity Analysis of Underground Cables (When applicable)
  - Construction Sequence
  - Outage Sequence

Lines

- Develop a Conceptual Design Package by doing the following:
  - Gathering LiDAR topographic survey
  - Developing a design criteria document to summarize:
    - Project scope of work
    - Type of transmission structures, conductor and shield wire to be used
    - Compile electrical and structural standards to be used on the project
  - Creating a PLS-CADD model of the transmission line work
  - Developing a preliminary materials list and construction bid form

The level of improved cost & time estimates will be dependent on the amount of network upgrades and the amount of contributing DG

10:10-10:30

04 Updated Exhibit 7

Transmission Network Upgrades

CENTRAL MAINE POWER

EXHIBIT 7

Transmission Network Upgrades

PRJ### is a part of the **CLUSTER NAME**, Maine Level 3 Distributed Energy Resource Clusters System Impact Study dated DATE, ("Transmission SIS"). An ISO-NE Section I.3.9 approval letter was received on DATE.

PRJ### is responsible for ensuring all inverter settings align with all as-studied inverter settings included in the Transmission SIS.

For Purposes of this Exhibit 7, the following definition is applicable.

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Transmission Network Upgrades associated with another Interconnection Customer(s) with a preceding Transmission SIS or a transmission project that is planned or proposed for the CMP Transmission System upon which the Interconnection Customer's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Customer or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Contingent Facilities

The Transmission Network Upgrades identified as "yes" in Table E7-1 are Contingent Facilities.

Transmission Network Upgrade(s) Cost Estimate

The following Transmission Network Upgrades in Table E7-1 are required to be in-service prior to the commercial operations of **PRJ###**.

DER Projects That Need to Wait for Transmission Network Upgrades									
DER Project	Upgrade 1	Upgrade 2	Upgrade 3	Upgrade 4	Upgrade 5	Upgrade 6	Upgrade 7	Upgrade 8	Upgrade 9
Estimated Upgrade In-SVR Date	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY	Q#. YYYY
PRJ 1	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 2	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
PRJ 3	Yes	Yes	Yes	Yes	No	Yes	Yes	No	Yes
PRJ 4	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 5	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes
PRJ 6	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 7	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 8	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes
PRJ 9	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes
PRJ 10	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 11	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes
PRJ 12	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 13	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 14	Yes	Yes	Yes	Yes	No	Yes	Yes	No	Yes
PRJ 15	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
PRJ 16	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes
PRJ 17	No	No	No	No	No	No	No	No	No

Table E7-1

Transmission Network Upgrades

PRJ### has the following Transmission Network Upgrades cost responsibility. If projects cost sharing in the Transmission Network Upgrade(s) as shown in Tables E7-2 and E7-3 elect not to execute their revised Interconnection Agreements, the Transmission Network Upgrade cost responsibility will be reallocated among the remaining projects with reassessment of the Transmission Network Upgrade determined on a case-by-case basis.

DER Projects' Cost Responsibility for Transmission Network Upgrades									
DER Project	Upgrade 1	Upgrade 2	Upgrade 3	Upgrade 4	Upgrade 5	Upgrade 6	Upgrade 7	Upgrade 8	Upgrade 9
PRJ 1	$0	$9,215	$0	$0	$0	$0	$ 1,979,582	$0	$ 1,910,164
PRJ 2	$0	$8,601	$0	$0	$0	$0	$ 2,034,301	$0	$ 1,589,788
PRJ 3	$0	$12,282	$0	$0	$0	$0	$ 2,262,214	$0	$ 3,006,425
PRJ 4	$0	$12,282	$0	$0	$0	$0	$ 710,196	$0	$ 697,358
PRJ 5	$0	$0	$0	$0	$0	$0	$ -	$0	$ -
PRJ 6	$0	$12,284	$0	$0	$0	$0	$ 2,638,914	$0	$ 2,546,376
PRJ 7	$0	$4,900	$0	$0	$0	$0	$ 1,052,610	$0	$ 1,015,698
PRJ 8	$0	$12,161	$0	$0	$7,610,136	$0	$ -	$0	$ 257,468
PRJ 9	$0	$8,206	$0	$0	$5,135,332	$0	$ -	$0	$ 443,553
PRJ 10	$0	$8,109	$0	$0	$0	$0	$ 1,742,032	$0	$ 1,680,945
PRJ 11	$0	$11,860	$0	$0	$7,421,367	$0	$ -	$0	$ 641,004
PRJ 12	$0	$11,979	$0	$0	$0	$0	$ 2,573,456	$0	$ 2,483,214
PRJ 13	$0	$12,237	$0	$0	$0	$0	$ 2,628,885	$0	$ 2,536,698
PRJ 14	$0	$12,078	$0	$0	$0	$0	$ 2,224,646	$0	$ 2,956,498
PRJ 15	$0	$7,664	$0	$0	$0	$0	$ 861,099	$0	$ 835,195
PRJ 16	$0	$6,143	$0	$0	$3,073,880	$0	$ -	$0	$ 265,499
PRJ 17	$0	$0	$0	$0	$0	$0	$ -	$0	$ -
Total Estimate	$0	$150,000	$0	$0	$23,240,715	$0	$20,707,935	$0	$22,865,883

Table E7-2

Sanford & Quaker Hill DER Clusters SIS Cost Allocation Summary			
DER Project	Cost Allocation ($) for Thermal Based Network Upgrades	Cost Allocation ($) for Voltage Based Network Upgrades	Total Cost Allocation +200/-50% Base Estimate ($)
PRJ 1	$3,898,961	$0	$3,898,961
PRJ 2	$3,632,690	$0	$3,632,690
PRJ 3	$5,280,920	$0	$5,280,920
PRJ 4	$1,419,836	$0	$1,419,836
PRJ 5	$0	$0	$-
PRJ 6	$5,197,575	$0	$5,197,575
PRJ 7	$2,073,207	$0	$2,073,207
PRJ 8	$269,629	$7,610,136	$7,879,765
PRJ 9	$451,759	$5,135,332	$5,587,091
PRJ 10	$3,431,086	$0	$3,431,086
PRJ 11	$652,863	$7,421,367	$8,074,230
PRJ 12	$5,068,649	$0	$5,068,649
PRJ 13	$5,177,820	$0	$5,177,820
PRJ 14	$5,193,222	$0	$5,193,222
PRJ 15	$1,703,958	$0	$1,703,958
PRJ 16	$271,643	$3,073,880	$3,345,523
PRJ 17	$0	$0	$-
Total Estimate	$43,573,818	$23,240,715	$66,964,533

Table E7-3

Interconnection Customer shall be responsible for all costs of such electric system modifications, even if they are in excess of the cost estimate provided. In executing this Interconnection Agreement, Interconnection Customer is agreeing to proceed forward financially as well as within the parameters defined within the Transmission SIS.

Transmission Network Upgrades

Payment of Transmission Network Upgrades

Interconnection Customer will have 30 calendar days from invoice to make payment in full unless Interconnection Customer qualifies for the two-part payment plan.

Two-Part Payment Plan

For Interconnection Customers with Transmission Network Upgrades in excess of one million dollars, Interconnection Customer is eligible to participate in the two-part payment plan. Interconnection Customer will have 30 calendar days from invoice to either make payment in full or make payment of 25% of Interconnection Customer's Transmission Network Upgrades and provide a letter of credit for the balance of the full estimated amount.

If Interconnection Customer does not meet the payment requirements within the 30 calendar days from the receipt of invoice, Interconnection Customer will be removed from the cluster.

After the 30 calendar days from invoicing, projects that meet the payment requirements remain in the cluster. Based on these remaining projects, CMP will re-evaluate the needed upgrades and re-study, if required. The 30 calendar day window will restart with updated invoices if reallocations are required. Interconnection Customer will be alerted once the cluster is "closed," meaning all remaining projects have paid and no further re-study necessary.

Following cluster closure, Interconnection Customer is financially committed to the full amount of their Transmission Network Upgrades obligation. If Interconnection Customer subsequently withdraws, there will be no refund of the full transmission upgrade payment and CMP will exercise the financial security instrument if applicable.

Within 18 months of the cluster closure, Interconnection Customer with the two-part payment plan will be issued a second invoice representing the remainder of the estimated cost as refined by preliminary engineering. Interconnection Customer will have 30 calendar days from invoice to settle financial obligations in invoice. Failure to settle financial obligations including invoices that are the result of recalculated cost allocation will result in termination of the Interconnection Agreement of the non-compliant project(s). This exhibit supersedes Article 6.6 Default.

10:30-10:45

Break

10:45-11:05

05 Network Upgrades

Central Maine Power
February 21, 2023

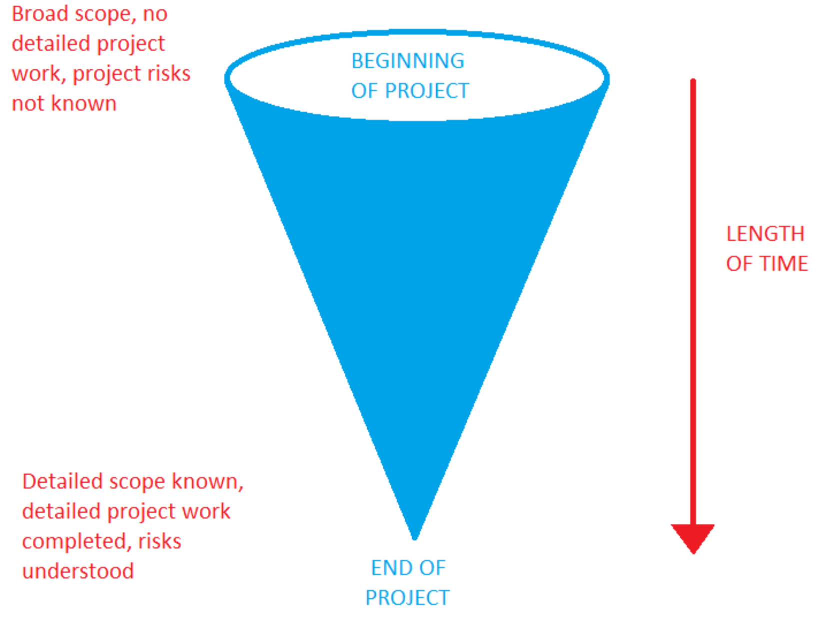
Transmission Cluster Study
Transmission Line and Substations Upgrades

Scoping and Estimation Process

- To estimate for proposed transmission line upgrades, a cost estimation is developed based on a preliminary review of the scope
- The estimates and schedules are completed using an Excel Estimating Tool
- The Tool is populated with:
  - Costs from projects and contracts over the past 3 years
  - Typical durations for project tasks
- Estimations are developed at a -50/+200% accuracy based on the projects being preliminary, with no engineering, permitting, procurement or other project work completed
  - Accuracy based on ISO-NE PP4 Attachment D

Project Stage	Level of Project Definition	Estimate Class	Estimate Type	Regional Review	RSP Listing Target Accuracy
Project Intitation	0% to 15%	-	Order of Magnitude	Need Approval (RSP Listing)	-50% to +200%
Proposed Project	15% to 40%	A	Conceptual Estimate	CRC Review / Retain Proposed Solution	-25% to +50%
Planned Project	40% to 70%	B	Planning Estimate	PPA Approval	-25% to +25%
Final Project Design	70% to 90%	C	Engineering Estimate	CRC Review / TCA Approval	-10% to +10%
Under Construction	80% to 100%	D	Construction Estimate		-10% to +10%

***Table 1**: Cost Estimate types per project phase (From AACE definition & customized for Transmission Project)*



Transmission Line Scoping and Estimation Process

Cost Estimation for Transmission Line Projects					
Project Name:	Construct New 115kV Line, CMP				
Project Scope:	Construct a new 15 mile long 115kV line at CMP. Assume single pole construction. Assume 5 miles of line are in existing right of way where 5 miles of existing 115kV line need to be removed. Also 10 H-frames needed to be replaced along a 1 mile segment hot. Assume 10 miles of greenfield right of way that is 150' wide that needs to be cleared. Assume 2 miles of ADSS needed. 1000' of line has distribution underbuild.				
Estimate Description:	115kV CMP Transmission Line, with Estimate Accuracy of a Project Initiation (-50%, +200%).				
Design Considerations					
Voltage (kV)		**OpCo**		**Total Overhead T-Line Length (mi)**	
115		CMP		15.0	
Installing New Phase Conductor?		**Total Static Wire (OHSW) Length (ft)**		**Total OPGW Length (ft)**	
Yes		83160		83160	
Total Overhead ADSS Length (ft)		**Number of Overhead Circuits per Structure**		**Type of Overhead Conductor**	
11088		1 (Single Circuit, Open Wire)		1192.5kcmil Bunting ACSR	
Type of Static Wire (OHSW)		**Type of OPGW**			
7#7 Alumoweld		72 Fiber 0.583 Inch Diameter			
Number of Overhead Conductors Per Phase		**Overhead Distribution Underbuild Voltage (kV)**		**Percentage of Circuit that has Distribution Underbuild**	
1 (Open Wire AC)		12kV		1%	
Number of Overhead Tangent Structures, Type 1		**Overhead Tangent Structure Type, Type 1**		**Construction PayCU Type**	
164		115kV Single Light Duty Steel Pole, Single Circuit, SCT		Install Cold	
Number of Overhead Tangent Structures, Type 2		**Overhead Tangent Structure Type, Type 2**		**Construction PayCU Type**	
10		115kV Two Pole H-Frame Light Duty Steel, Single Circuit, AR		Replace Hot	
Number of Overhead Angle Structures, Type 1		**Overhead Angle Structure Type, Type 1**		**Construction PayCU Type**	
7		115kV Three Light Duty Steel Pole Guyed, Single Circuit CR		Install Cold	
Number of Overhead Angle Structures, Type 2		**Overhead Angle Structure Type, Type 2**		**Construction PayCU Type**	
0		None		None	

Transmission Line Scoping and Estimation Process

Percentage of Structures Needing Rock Excavation		
50% (Rural Areas)		
Removal Structure Type	**Removal Mileage (mi)**	
115kV Lattice Towers	5.0	
Remove Phase Conductor Distance (mi)	**Remove Phase Conductor Type**	
0.0		
Remove OHSW Distance (mi)	**Remove OHSW Amount**	
0.0		
Permitting/Environmental Considerations		
Acreage of New Corridor	**Real Estate Cost per Acre (USD)**	**Line Survey Required?**
181	$15,000	Yes - LIDAR
Access Road Type	**Vegetation Clearing Acreage**	**Cost Inputs from Environmental Group**
Rural (1000 Mats per Mile)	181	$500,000
Adders		
Sales Tax		**Program Management/Owner's Engineering (%)**
5.50%		8%
Construction Management (%)	**Overheads (%)**	**AFUDC (%)**
5%	26%	5%
Estimate Accuracy	**Is this a CMP Customer or Generator Funded Project?**	
Project Initiation (-50%, +200%)	Yes	
Cashflow		
Project Type	**Project Start Date**	**In Service Date**
115kV+, CMP NWA & CPCN	1/1/2023	2029

Transmission Line Scoping and Estimation Process

Cost Estimation for Transmission Line Projects		
Project Name:	Construct New 115kV Line, CMP	
Estimate Description:	115kV CMP Transmission Line, with Estimate Accuracy of a Project Initiation (-50%, +200%).	
Item	**%**	**Cost**
Real Estate		$2,986,500
Surveying		$25,575
Environmental, Licensing & Permitting		$500,000
Materials		$3,151,432
Material Sales Tax	5.50%	$173,329
Construction		$5,550,705
Vegetation Management		$171,102
Access Roads, Environmental Controls and Restoration		$5,027,088
Removal Costs		$655,238
Construction Sales Tax	0.00%	$0
	Subtotal	$18,240,969
Engineering		$412,399
Program Management/Owner's Engineering	8%	$1,459,278
Construction Management	5%	$912,048
	Subtotal	$2,783,725
AFUDC	0%	$0
Escalation		$12,338,853
Overheads	22%	$4,625,433
	Subtotal	$16,964,286
Contingency	50%	$18,994,490
	Total Low Estimate	$28,492,000
	Total Base Estimate	$56,984,000
	Total High Estimate	$170,952,000

Line Projects – Timeline Details

Activity	External Stakeholders	Duration (Months)
Internal Governance & Procurement	Vendors	10-21
Real Estate (*1)	Landowners	-
Regulatory (CPCN, NWA)	MPUC, OPA, Governor's Office, Intervenors	20
Engineering	Consultants	9
Permitting	Municipalities, Maine DEP, US Army Corps of Engineers	12
Construction	Contractors	6+(*2)
	Project Duration Months	57-68
		Project Duration Years ~5

(*1) Assumed real estate work will occur in parallel with other project activities. If challenging real estate transactions occur, project timeline could lengthen.
(*2) Construction duration variable based on weather, storms, outage availability, permitting restrictions, size of project. 6mos considered as a minimum construction duration for Lines.

Substations Projects – Timeline Details

Project Size	Project Description	Duration
Extra Small	Relay Replacement, relay upgrade, settings, one breaker or switch replacement, minimum intervention in general.	12 months
Small	Project with small intervention, like control house upgrades, multiple breaker replacement or multiple small assets intervention. Projects that don't require a complete rebuilt	32 months
Medium	Medium voltage stations that require a complete rebuilt or 115kV and above stations that require some type of intervention. Adding new Main Plant Equipment (DRD, Tx).	40 months
Large	Large stations that require a complete rebuilt, or new large stations.	48 months

11:05-12:00

06 Opportunties

Lessons Learned

Increased Communications

- Executed NDAs provide projects with access to CEII results for each cluster for which the project developer has at least one participating project has allowed CMP to provide more relevant communication throughout the study process
- Cluster-specific meetings scheduled to discuss results as they become available and communicate cluster-specific updates
- CMP updates and publishes cluster study schedules on a biweekly basis in order to keep cluster participants actively informed. In addition, CMP hosts monthly transmission study webinars

Challenge Sessions

- Using Challenge Sessions to determine any curtailment opportunities
- Incorporating previous Challenge Sessions into proposed standard mitigation

Terms & Conditions

- Benefits of Incorporating the T&Cs (Docket No. 2021-00277)
  - Document the currently undocumented process of conducting required transmission system impact studies to provide for increased schedule certainty
  - Implements a number of process improvements designed to streamline the study process
  - Require timely responses from cluster participants
  - Facilitate the attrition of projects as studies progress which improves network upgrade cost and schedule firmness for impacted DG
  - Equitably allocate the costs of both the studies and any resulting transmission system upgrades
  - Provide for a new “Conceptual Engineering Study” for projects with network upgrades to improve upon the +200/-50% cost estimates

Innovative & Traditional Network Upgrades

- Operate new PV at non-unity power factor
  - New PV consumes reactive power and helps reduce voltage constraints
  - Non-unity PF applications often accompanied by shunt capacitors to address voltage flicker.
  - Net result: new DG appears as unity to the transmission system
- Dynamic Reactive Devices
  - Deploy dynamic reactive compensation to targeted substations to manage voltage constraints
- PV+BESS Coupling
  - Co-locate batteries with large new PV
  - Must be part of the application
- Large BESS
  - Deploy large batteries to targeted substations to manage constraints
  - Today, BESS as a solution must be studied as its own generator interconnection as well
- Traditional Upgrades
  - Line and substation upgrades targeted toward transmission lines and substation capacity constraints
- Active Network Management / Curtailment
  - Regulate power production of PV in real-time to match available capacity and manage constraints

Active Network Management

Active Network Management (ANM)

- The management of DER via control systems to keep system parameters within predetermined limits.
- Provides for real time monitoring and control of the electric system
- If a system constraint is approaching an operational limit, then ANM can act upon the DER asset to ensure the operational limit is not breached
  - Limits can be thermal, voltage or other

Benefits

- Manage system constraints
- Increase hosting capacity
- Reduce interconnection costs
- Reduce time to interconnect

Additional Areas for Improvements

Cluster Definitions (dependencies on other cluster areas)

Additional Areas for Improvements

Scope Definition / Scenarios

Additional Areas for Improvements

Challenge Sessions

DG Solar has arrived in Maine

Challenges

- Balance need to ensure system reliability with efficient study processes
- Flow patterns are shifting from traditional transmission to distribution, reversing direction under lighter loads
- Outside of interconnection space, as solar replaces synchronous generators, meeting demand when solar output is low will be the new challenge

Opportunities

- Find the right mix of solutions
  - Innovative Solutions
  - Traditional Upgrades
- Active Network Management
- Communicate often with stakeholders and manage expectations throughout the study process